

Managing Drilling Risk

Everyone loves a surprise. Everyone, that is, except a driller. Avoiding drilling surprises means more than being prepared for problems when they occur; it means averting them in the first place. New risk management tools help foretell well behavior with enough advance notice to allow drilling teams to calmly make technically sound operational decisions that lead to optimal drilling performance.

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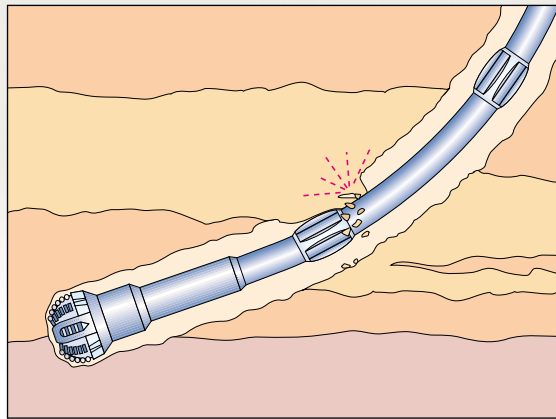
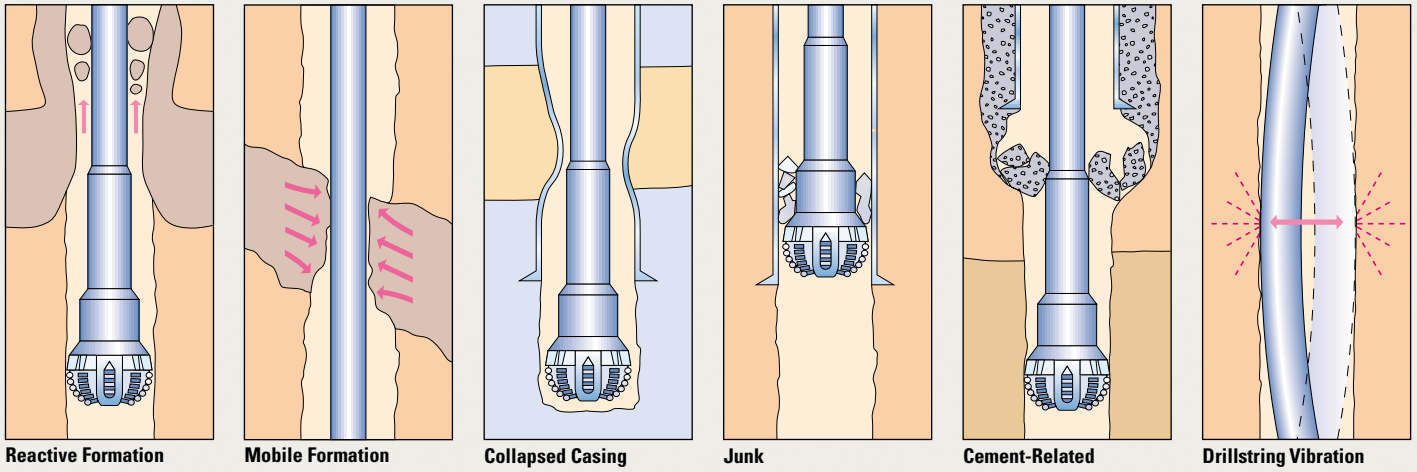
Oil and gas companies spend about \$20 billion annually on drilling. Unfortunately, not all of that money is well spent. A significant portion, around 15%, is attributed to losses. These include loss of material, such as drilling equipment and fluids, and loss of drilling process continuity, called non-productive time (NPT). These losses are incurred while searching for and implementing remedies to drilling problems. Avoiding drilling problems cuts finding and development costs and allows billions of dollars now spent on losses to be better spent—building and replacing reserves.

No well is drilled without problems. Managing drilling risk means not letting small problems become big ones. Knowing what the risks are and when they are likely to occur keeps surprises to a minimum. Most of the time spent drilling, and most of the cost, is encountered not in the reservoir, but in getting to it.

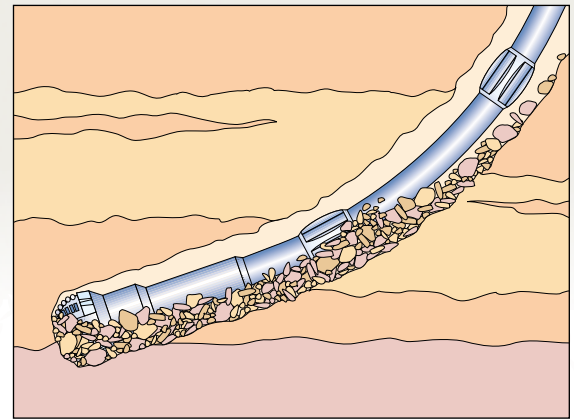
Numerous problems taunt the driller, and solutions may be expensive if not impossible in some cases (above and next page). Drillpipe can become stuck against the borehole wall by differential pressures or lodged in borehole irregularities, requiring skill and force to free it.¹ When this fails, sometimes the only solution is to abandon the stuck portion and drill a sidetrack around it, changing the drilling program completely and

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APWD (Annular Pressure While Drilling), ARC5 (Array Resistivity Compensated), DrillCast, DrillMap, DrillTrack, IDEAL (Integrated Drilling Evaluation and Logging), MDT (Modular Formation Dynamics Tester), PowerPak, RFT (Repeat Formation Tester), Schlumberger PERFORM and SPIN Doctor are marks of Schlumberger.



Wellbore Geometry



Poor Hole Cleaning

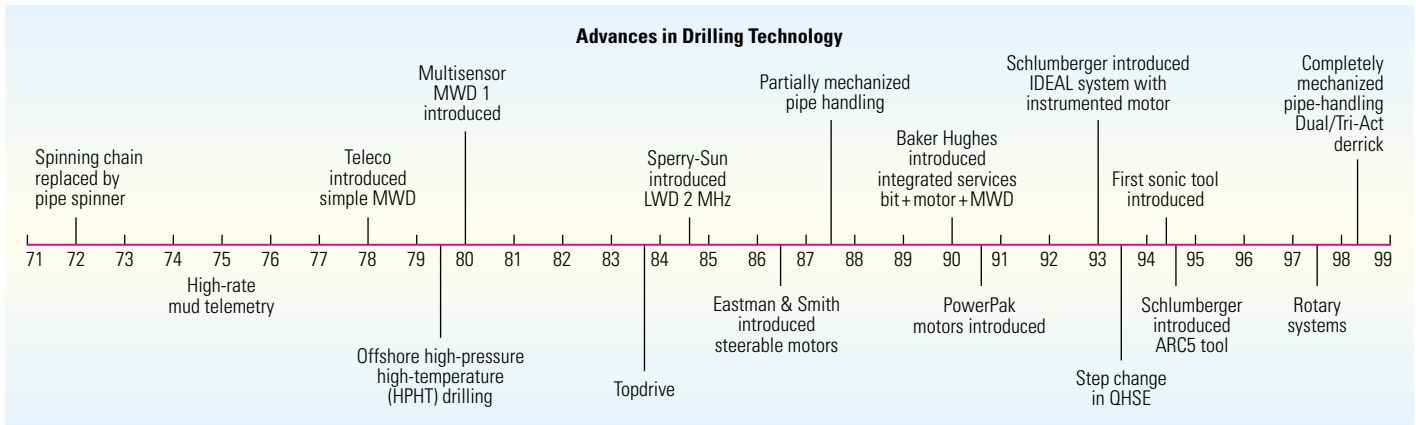
^ Common drilling problems.

potentially adding millions of dollars to the well cost. Drilling at a high rate of penetration can save time and money, but when accompanied by too low a drillstring rotation rate or mud flow rate that fails to lift rock cuttings to surface, the result is stuck pipe. Faults and fractures that the wellbore encounters open conduits for loss of drilling fluid to the formation.² Excessively high mud pressure can fracture the formation and cause lost circulation. Too low, and the mud pressure fails to keep high-pressure formations under control, resulting in gas kicks or worse, blowouts. Drillstring vibrations can weaken and destroy pipe and equipment as well as seriously damage the wellbore. And some of these problems, even if they don't completely suspend the drilling process, jeopardize subsequent logging, completion and production.

Making drilling decisions to correct these problems is a complex process because many factors have to be considered. For example, increasing mud weight to control wellbore stability in one interval in the well may cause fracturing elsewhere. Solutions are often well- or field-specific.

Successful drilling hinges on developing a sound plan, continually updating it in light of new information and keeping the involved personnel informed on a timely basis. The plan must include procedures to follow under normal circumstances and methods for dealing with the most likely and most severe problems that may be encountered. With the proper training, a well-defined drilling process, sufficient data and tools for interpretation, successfully drilling a well should be a routine process.

1. Bailey L, Jones T, Belaskie J, Houwen O, Jardine S, McCann D, Orban J and Sheppard M: "Causes, Detection and Prevention," *Oilfield Review* 3, no. 4 (October 1991): 13-26.
2. Adelung D, Askew W, Bernardini J, Campbell AT Jr., Chaffin M, Congras G, Hensley R, Kirton B, Reese R and Sparling D: "Techniques for Breaking Free," *Oilfield Review* 3, no. 4 (October 1991): 27-35.
- Cline M, Granger G, Hache J-M and Lands J: "Backoff Basics," *Oilfield Review* 3, no. 4 (October 1991): 48-51.
2. Addis T, Last N, Boulter D, Roca-Ramisa L and Plumb D: "The Quest for Borehole Stability in the Cusiana Field, Colombia," *Oilfield Review* 5, no. 2/3 (April/July 1993): 33-43.



^ Time line from 1971 to 1999 showing recent advances in drilling technology.

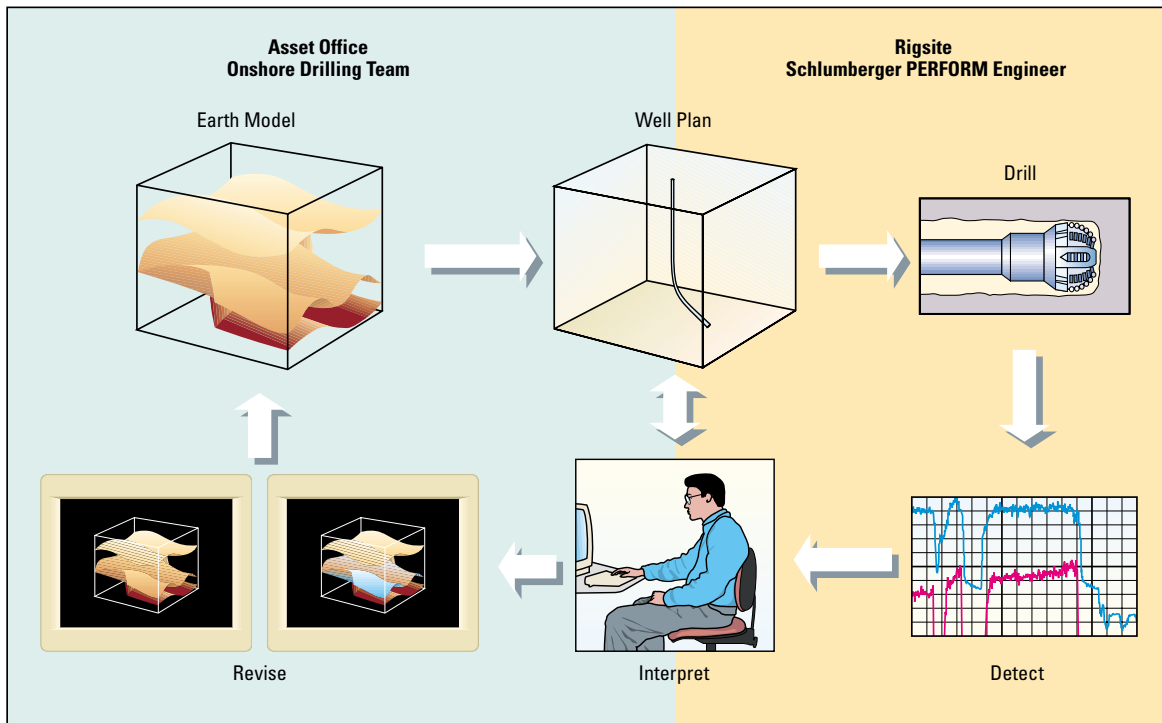
Background

During the last twenty years, the industry has celebrated innovations in drilling practices from the introduction of measurements-while-drilling (MWD) and steerable motors to computerized rigsite displays and high-resolution while-drilling logs (above). In the early 1990s, different operator and service companies applied the power of maturing while-drilling measurements to adopt new methods of stuck-pipe avoidance and other drilling training programs.³ Why, ten years later,

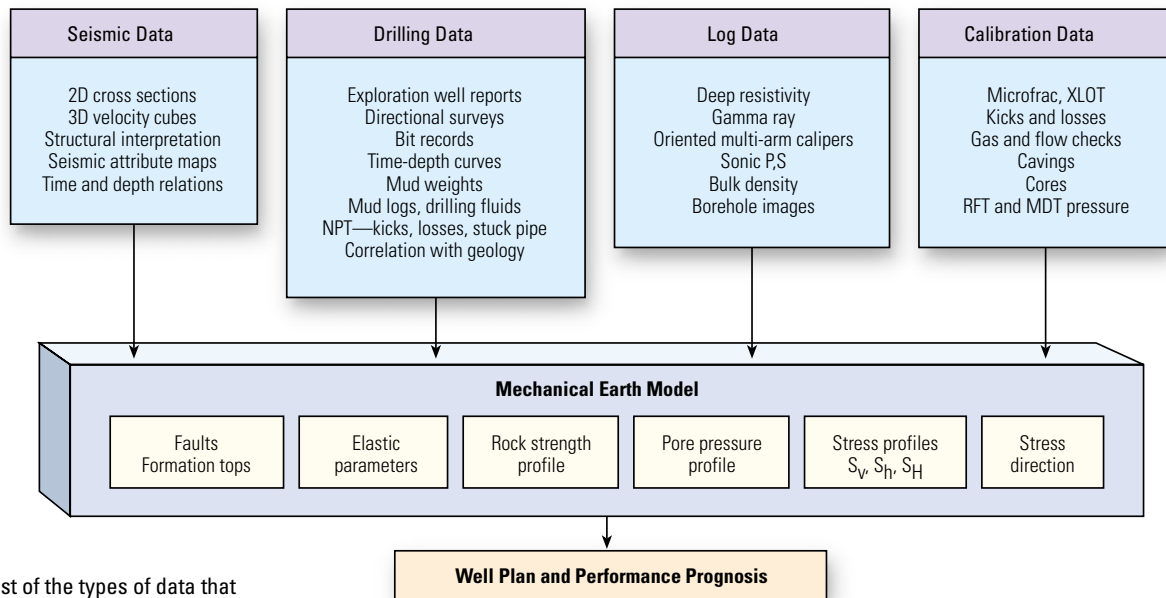
do operating companies acknowledge that the drilling process still needs to improve? The physical forces acting on the borehole haven't changed. What has happened?

Two things have changed. First, exploration and production (E&P) companies have altered their internal structures and reduced their work forces. Many senior, experienced hands have left the industry. Companies are operating with a bare minimum of personnel. Experienced people who remain may be specialized, and hence not suited for the integrative role required.

Second, wells are becoming more complex. Extended-reach and horizontal wells react differently to earth stresses than do vertical or low-angle wells. Drilling multilateral wells requires extraordinary accuracy and control. Deepwater and high-pressure, high-temperature wells offer additional challenges. Wells are being drilled in tectonically active and remote areas where the infrastructure may be less well developed and communication problematic.



^ Integrated drilling process. The phases of a drilling project require joint effort by the asset office and the rig, and encompass construction of the earth model and well plan, the actual drilling, detection and interpretation of information obtained while drilling, and ultimately, revision of the model.



^ A partial list of the types of data that contribute to a complex mechanical earth model.

A New Approach

To drill successfully amid these changes and challenges requires a new approach to the drilling process. In recent years, oil companies and service companies have developed more cooperative relationships that make it easier for both to achieve their objectives. The way of doing business together has evolved from one of managed opposition to one of aligned objectives, with oil and service companies cooperating to face the uncertainty and risks of the subsurface.

The approach taken by the Schlumberger companies to provide technical and decision support to operators has reduced drilling costs by as much as 50% in a wide variety of drilling environments. The complete process integrates the efforts of oil company and service company personnel at the office and on the rig, during all stages of well planning and drilling and through every phase of a drilling project (previous page, bottom).

Simply put, the process begins in the office with construction of an earth model. The model is then used as part of the well planning process to create the best drilling plan. This is a multidisciplinary optimization process in which the drilling

engineer and geologist balance the requirements of target location, cost and drillability. Many more factors must be incorporated into a complete well plan. These include casing design, completion requirements, life-of-field issues, rig size and selection, personnel considerations, costs, cement design, liners, drillstring and BHA design, and availability of equipment.

The best drilling plan optimizes well location and trajectory, but also minimizes the risk of wellbore instability and stuck pipe, improves well productivity and accelerates the drilling learning process. The plan should flag intervals in which geologic risks such as pore pressure, fracture pressure and other wellbore instabilities can threaten wellbore integrity. To achieve this, the plan must be evaluated to identify all risks before any action takes place.

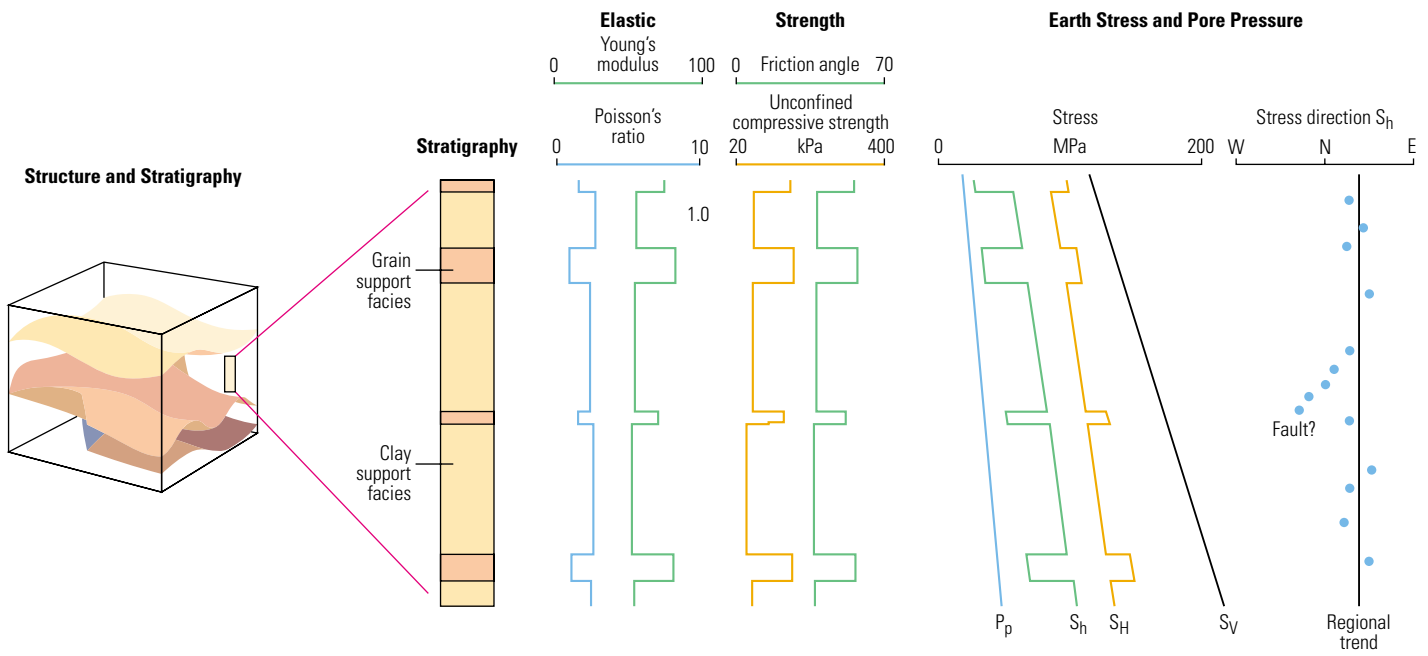
On the rig, the well is drilled according to the drilling plan. During drilling, information is collected, interpreted and fed back to the drilling process, to the well plan, or to the earth model itself. Through modification and updating, the well plan becomes a living document rather than a static one. Drilling risks are also continually reevaluated. The process is valid for wells drilled throughout

the life of a field, but at its core remain the three principal phases that govern the very existence of a well: developing the proper plan, executing it, and learning from the ongoing process.

The earth model can be simple or complex, depending on the information available and the requirements of the well. Creating a complex earth model can require dozens of input and data integration steps. In short, every pertinent data source is used, from drilling reports, logs and tests in offset wells to seismic sections, velocity cubes and structural interpretations (above).

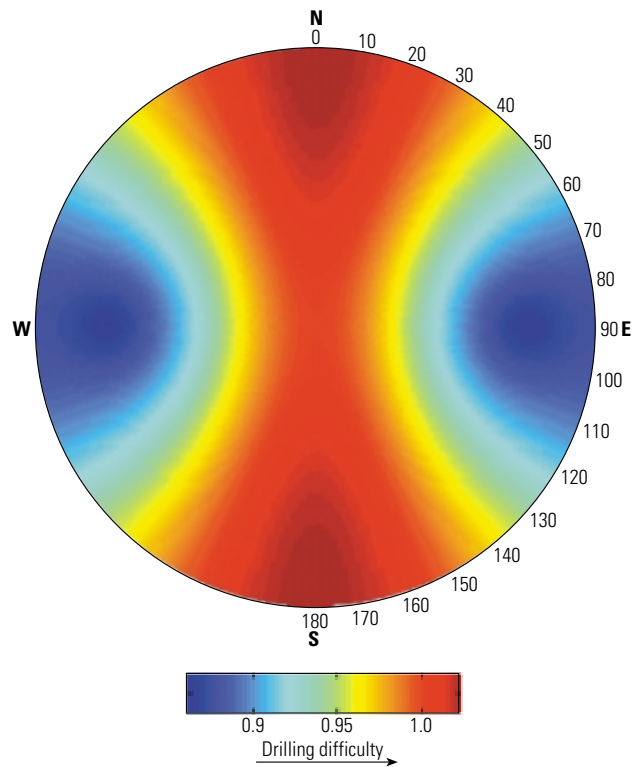
3. Bradley WB, Jarman D, Auflick RA, Plott RS, Wood RD, Schofield TR and Cocking D: "Task Force Reduced Stuck-Pipe Costs," *Oil & Gas Journal* 89, no. 21 (May 27, 1991): 84, 86, 88-89.

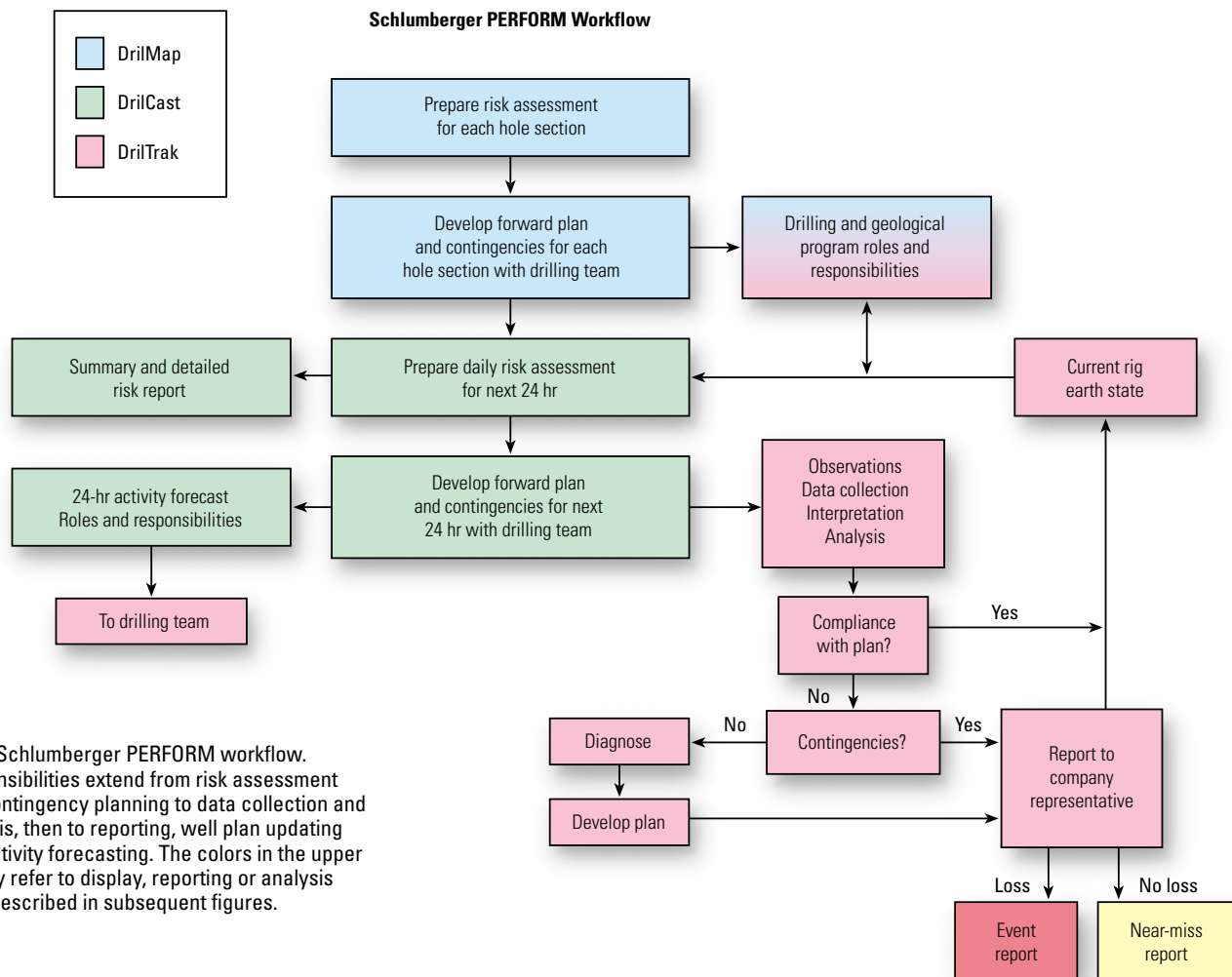
Nordt DP and Stone MS: "Professional Development of New Rig Supervisors a Must," *Oil & Gas Journal* 90, no. 43 (October 26, 1992): 77-80, 83-84.



^ Earth model example. The earth model houses all information on rock properties and behavior and is used during all phases of the life of the well, including trajectory and wellbore stability planning, bit and rate of penetration (ROP) selection, pore-pressure prediction, casing design, sand control and reservoir stimulation.

> Which way to drill in a South American field. With rock mechanics data such as expected stress state, pore pressure and rock failure parameters from a variety of sources, a drilling risk profile can be plotted. Red signifies risky, difficult drilling and blue is less risky and easier. The numbers around the arc represent azimuth; traveling along a radius is the same as taking a path of constant azimuth. Distance from the center depicts inclination from vertical. The center of the circle represents a vertical wellbore, and the outer edge represents all possible horizontal wellbores. This plot indicates that it is easier to drill a horizontal well than a vertical well given the particular stress state.





> The Schlumberger PERFORM workflow. Responsibilities extend from risk assessment and contingency planning to data collection and analysis, then to reporting, well plan updating and activity forecasting. The colors in the upper left key refer to display, reporting or analysis tools described in subsequent figures.

(A full treatment of the rock mechanics involved is beyond the scope of this article.⁴) The resulting mechanical earth model consists of formation tops, faults, elastic parameters, stress directions and variations with depth, and rock strength and pore-pressure profiles (previous page, top).

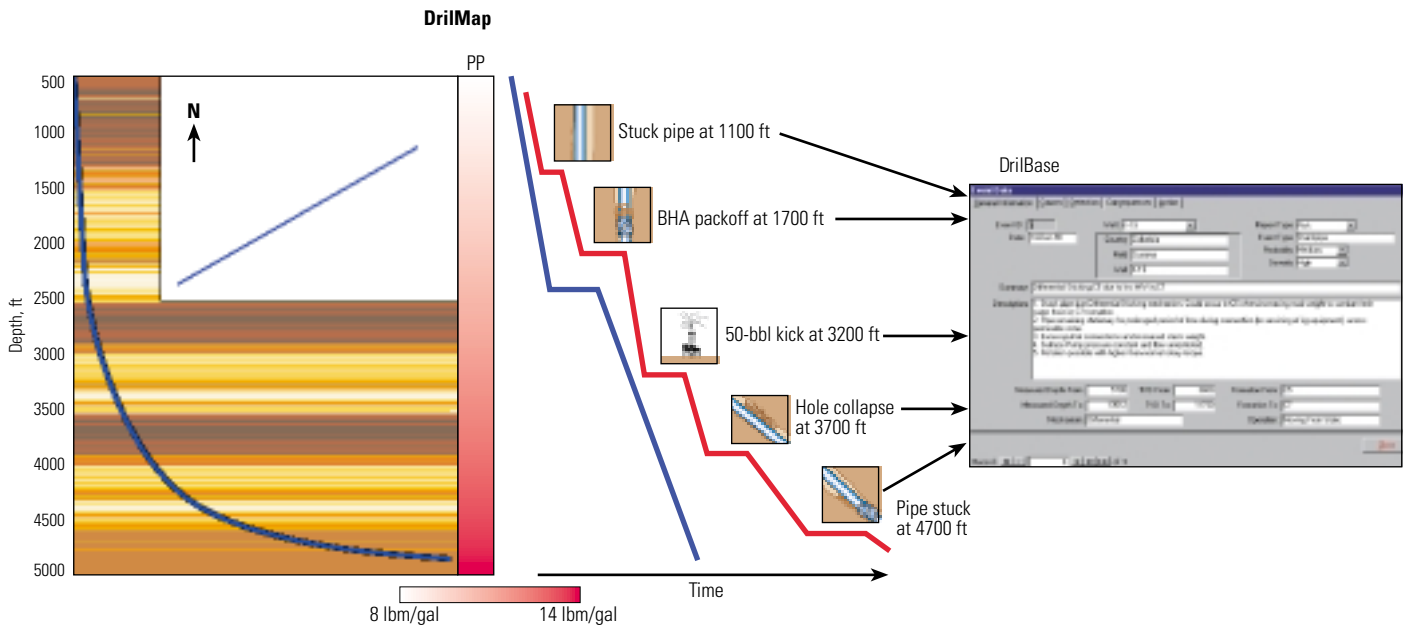
Once a target has been selected, it can be reached from many directions. Selecting the path with the least risk requires an understanding of the stress state and the rock parameters, and how the drilling process will interact with them. An example of the information that can be extracted from an accurate mechanical earth model comes from a South American field. For this field, a risk profile was created that color-coded the difficulty with which particular trajec-

tories could be drilled (previous page, bottom). Drilling a horizontal well at a 90° azimuth was predicted to be the least risky: wells at other inclinations and azimuths would be prone to borehole collapse.

The best plan according to any earth model must be reconciled with trajectory goals of that well to optimize the process as a whole. For example, in one well, the preferred trajectory may have a 62°-inclination in one section, but hydraulics analysis may indicate that hole-cleaning problems at this inclination could endanger well integrity. Two or more sections drilled at safer angles, though seemingly more time-consuming, could optimize the overall drilling process.

Once the best plan has been formulated, following it through at the rig can be a surprisingly challenging feat. To accomplish this, the Performance through Risk Management effort, or Schlumberger PERFORM initiative for short, has been launched within Anadrill. Schlumberger PERFORM efforts have already reduced NPT by as much as 40%, saving as much as \$300,000 per well. The concept is simple and most of the steps are almost intuitive, but a structured approach is required for success. The approach comprises a workflow, software tools and engineer to ensure that the technical solutions derived in the planning stage become operationally effective solutions to aid decisions that help avoid drilling problems (above).

4. For more: Fjaer E, Holt R, Horsrud P, Raaen A and Risnes R: *Petroleum Related Rock Mechanics*. New York, New York, USA: Elsevier Science Publishing Company, 1992. Alsen J, Charlez P, Harkness R, Last N, McLean M and Plumb R: "An Integrated Approach to Evaluating and Managing Wellbore Instability in the Cusiana Field Colombia, S. America," paper SPE 30464, presented at the SPE Annual Technical Conference and Exhibition, Dallas, Texas, USA, October 22-25, 1995.



^ Mapping out the drilling plan. The DrilMap screen displays the planned well trajectory, expected pore pressures (PP), and two drilling time-versus-depth curves—one optimal (blue) and the other taking into account potential hazards (red). Hazards are identified with specific depths and tied to the DrilBase database containing previous drilling and near-miss reports and contingency plans.

The goal of the Schlumberger PERFORM engineer is to work with operators to significantly reduce cost and nonproductive time through integration of planning and real-time drilling solutions. A risk-management and loss-control framework combines Schlumberger technical expertise and measurements with operator knowledge and experience to develop operational solutions. Communications and teamwork are essential in implementing these solutions.

The process concentrates on the following areas:

- wellbore stability and fluid loss
- pore-pressure analysis
- stuck pipe and pipe lost in hole
- drillstring failure prevention
- drilling efficiency, rate of penetration and bit optimization.

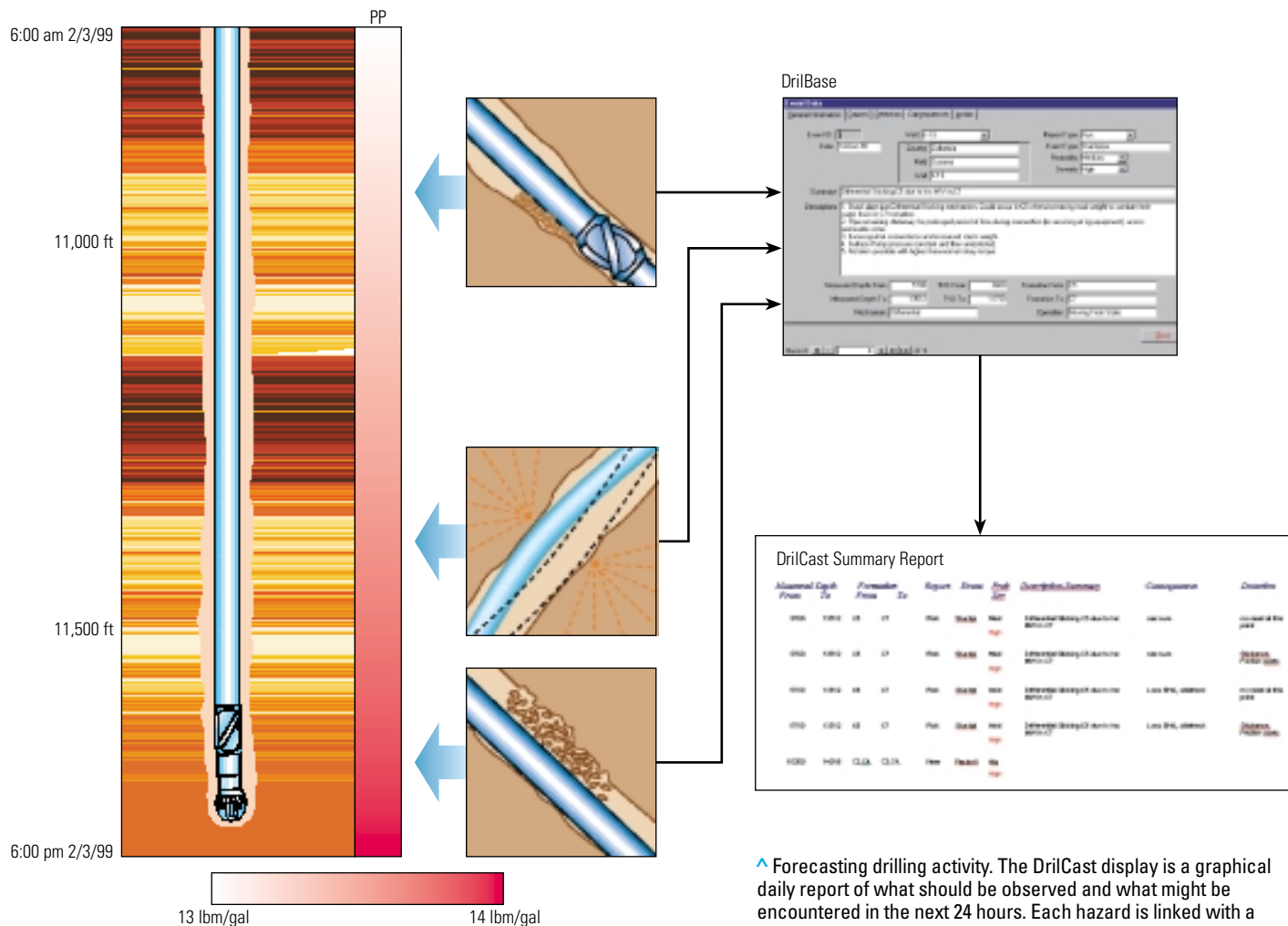
Because each well can host a distinct set of these problems, a specially trained engineer is assigned to each job. The quality of the personnel can make or break the process. As general qualifications, the engineer must have good problem-solving, data-integration and communication skills, a solid technical background in petroleum or drilling engineering, ample seniority and experience with operator organizations. Technical training includes Schlumberger courses on drilling mechanics, wellbore stability, pore-pressure analysis, bit performance and drilling fluids. Operational problem-solving techniques and communication skills are sharpened through problem-simulation exercises. Additional training includes industry-standard courses in stuck-pipe prevention and well control.

In the planning stage of a drilling project, the Schlumberger PERFORM engineer works with the operator staff to identify potential hazards, develops methods for detecting them, and finally with the drilling team, formulates contingencies to complete the drilling plan. The engineer delivers a DrilMap display that links well geometry, geological and hazard information with contingency plans to form a complete process map for the well (above).

During drilling, the engineer evaluates the well condition to identify any new hazards that may have developed and at every tour provides an updated risk assessment and 24-hr forecast (next page). The DrilCast report enumerates the conditions and potential hazards ahead and explains how to detect and manage them. Detailed planning before a potential hazard is encountered and accurate identification of the hazards reduce the risks of losses and significantly improve performance.

(continued on page 11)

DrilCast



▲ Forecasting drilling activity. The DrilCast display is a graphical daily report of what should be observed and what might be encountered in the next 24 hours. Each hazard is linked with a method for its detection and a contingency plan for mitigating actions. A summary report is distributed to the drilling team at the morning meeting. Detailed reports, including roles and responsibilities, are given to each drilling team member.



PERFORM Daily Report

Client **IPM**
 Well **Deepwater location.**
 Section **14 3/4 X 17 1/2 Drilling Assembly**

Client Representative
Randall Anderson

Date 2/24/99 6:00

Perform Engineer
William B. Standifird

24-Hour Summary

For Time Period... 2/23/99 6:00 To 2/24/99 6:00

RIG OPERATIONS			
Start Time	Rig Operation	Comments	
2/23/99 6:00	Under-reaming	Under-reamed to 7038 ft	
2/23/99 7:30	Short trip	Hole stable, 500u B/U gas	
2/23/99 15:30	Drilling ahead	Drilling new formation	
TRENDS			
Time Period	Variable	Noteworthy Behavior	
24 hr	MWD SHOCKS	Transverse shocks increase while reaming sands.	
24 hr	WOB,TOA,ECD,SPP,TFLOW,TRPM	ECD and TQA spiking when annulus loads above under-reamer.	
EVENTS			
When?	What?	How?	Why?
2/24/99 6:00	Drilled sand lobe at 7228 ft		

24-Hour Forecast

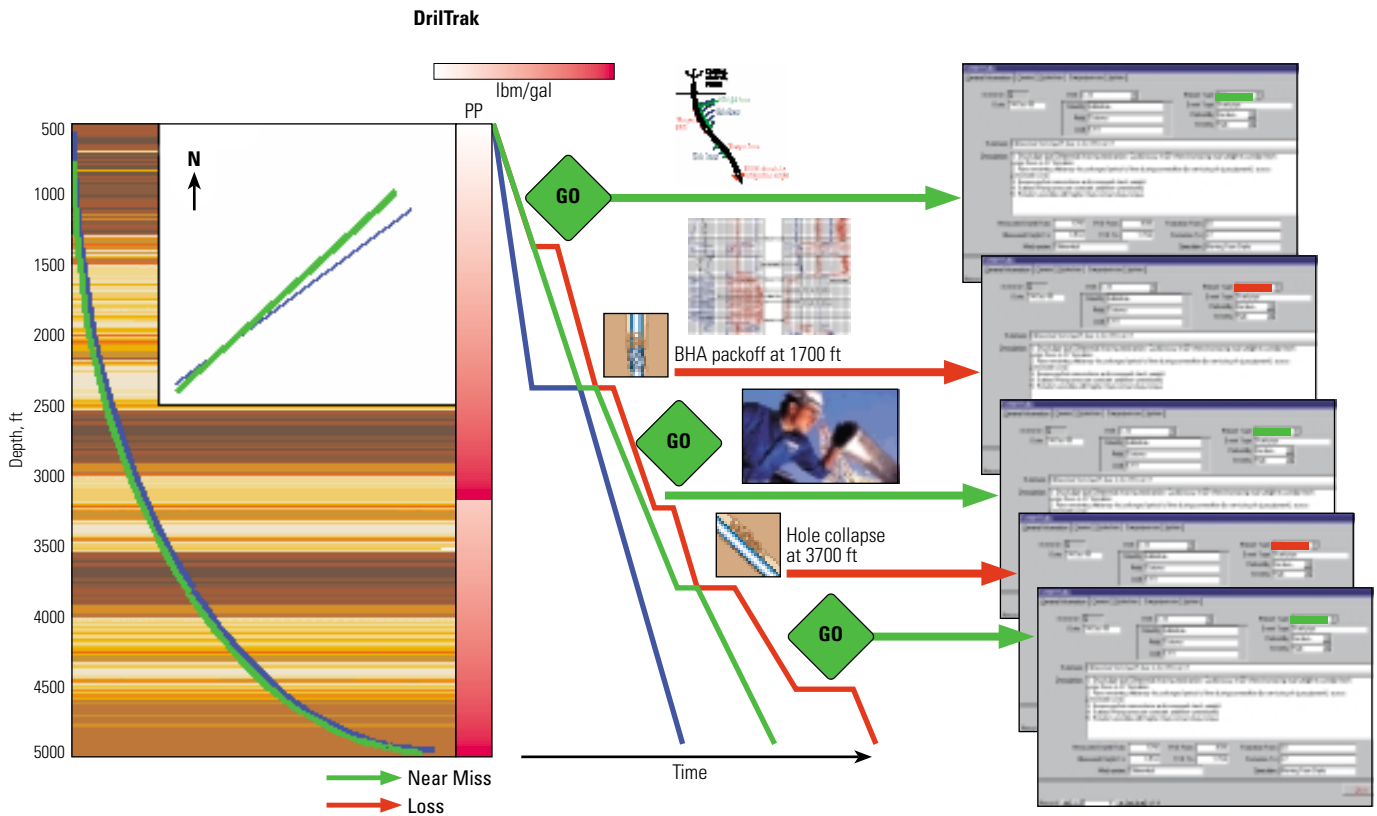
For Time Period... 2/24/99 6:00 To 2/25/99 6:00

This is a tough section. Depleted zone at 7375 ft is next major hazard.

RIG OPERATIONS					
ITEM	Operation	When?	Possible Hazards	Severity	Probability
1	Drilling	Cutting sands	First depleted sand at 7375 ft. Stuck pipe, lost circulation.	High	High
2	Drilling	Cutting sands	MWD shock high when U/R hits sands. MWD shock > 22 can damage BHA quickly.	High	High
3	Drilling Back-reaming, U/R	Pumping	ECD will spike as U/R packs off. Stuck-pipe situation.	High	High
4	Short Trip Back-reaming	Pulling up	Swab formation into wellbore. Gas or fluid entering wellbore.	Med	High
HAZARD DETECTION METHODS					
ITEM					
1	Identify sand locations and verify stability. 7215, 7375, 7565 and 7745. Use offset e-logs/mud logs				
2	Monitor MWD shocks on Anadrill display.				
3	Monitor ECD closely. Spikes are rapid and must be addressed quickly.				
4	Monitor trip speeds (swab-surge), gain/loss and gas.				
PROPOSED HAZARD PREVENTION ACTION					
ITEM					
1	Prepare LCM and other LC systems. Keep the pipe moving. Survey at 7200, 7350 and 7800. DO NOT survey if formation is unstable. Stuck pipe is more expensive than a GYRO in casing. <i>Torque and Slump</i> is first action to differential sticking or coming off slips.				
2	Rotate during connections. Notify PERFORM Engineer. May need to adjust RPM/WOB to control vibrations and avoid BHA damage.				
3	Consider picking up and back-reaming until ECD stabilized. First move is in opposite direction of resistance.				
4	Back-ream or pump out of hole. Circulate gas out of hole if encountered. Work tight spots and keep pulling speeds minimal.				

Please contact the Schlumberger PERFORM Engineer if there are any questions or transmission errors: Call Ext. 158 (rig) 3460 (town)

^ Daily report of past and future drilling activity.



^ Tracking drilling progress. The DrilTrak plot updates the drilling map while drilling. Changes in the trajectory are recorded along with the response of the well and the effectiveness of the drilling plan. Hazards that were avoided with no material or process loss are reported as near misses (green arrows). Losses are reported as events (red arrows).

In this example from a deepwater well coordinated by the Schlumberger Integrated Project Management (IPM) group, the daily report includes a summary of rig operations, trends and events of the past 24 hours along with the forecast for the next day (previous page). The look-ahead portion lists four possible hazards that may be encountered in the upcoming hole section. The section is ranked as a tough one, with a depleted zone ahead posing the next major hazard. The hazards are identified according to several factors: the operation (drilling, back-reaming or tripping), and the specific procedure (cutting

sands, under-reaming or pumping), underway when the hazard is met; the type of hazard and its consequences; the severity; and the probability. Methods for detecting each hazard are listed, as are actions to prevent an event from causing loss.

A member of the drilling team monitors well conditions continuously to determine if the well is behaving as planned (above). If the well is not proceeding as expected, the appropriate contingency is identified. The driller can then follow the plan for that contingency. If none of the planned contingencies is appropriate, the problem is analyzed, and a new action plan is developed with the drilling team.

Suites of data evaluation and problem diagnosis tools have been developed to support these drilling displays. Diagnostic tools, such as the SPIN Doctor stuck drillstring prevention software, zero in on the most probable cause for each problem by asking the user a series of questions. The SPIN Doctor application also contains links to electronic documents such as the Schlumberger Stuck Pipe Handbook for more in-depth investigation into unforeseen problems, and can be custom-hyperlinked to any desired electronic resource, including proprietary drilling process manuals and help files (next page).

SPIN DOCTOR

DIAGNOSIS

Welcome to
Schlumberger

Stuck drillstring prevention software.

Version 3.4

Click on a diagnosis name for a handbook date.

To proceed, is this:

a real stuck pipe incident? just a training exercise?

[Schlumberger Drillers Stuck Pipe Handbook](#)

SPIN DOCTOR

DIAGNOSIS

Overpull in New Hole

Is the overpull in the new hole section?

Definitely yes
 Probably yes
 Possibly yes
 Indeterminate
 Possibly no
 Probably no
 Definitely no

[Schlumberger Drillers Stuck Pipe Handbook](#)

SPIN DOCTOR

DIAGNOSIS

Restricted Circulation

Is circulation restricted?

Definitely yes
 Probably yes
 Possibly yes
 Indeterminate
 Possibly no
 Probably no
 Definitely no

[Schlumberger Drillers Stuck Pipe Handbook](#)

^ Three panels from the SPIN Doctor stuck drillstring prevention software. As the user answers questions about a drilling problem and the accompanying well conditions and drilling activity, the system rules out some mechanisms and highlights increased probability for others. In this case, the final diagnosis is poor hole cleaning.

In addition to connecting to analysis and diagnostic programs, the DrillTrak system incorporates drilling alarms that analyze while-drilling measurements in real time to alert drillers to severe problems. These alarms warn of high friction factors, bearing failures, low drilling efficiency and bit performance, washouts and kicks.

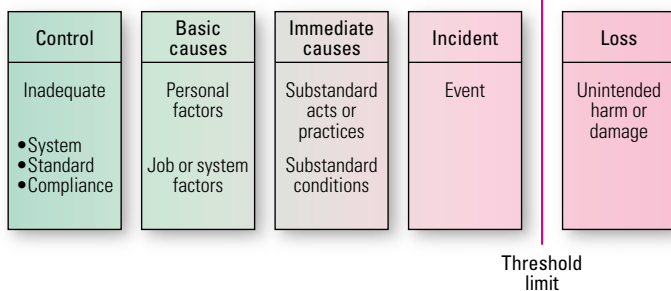
Understanding Risk

The Schlumberger PERFORM approach is built on a foundation of risk management and loss-control methodologies. Controlling loss requires an understanding of event causation, or the act or process of causing events, problems or accidents that lead to loss. A model of event causation catalogs the stages in the evolution of an event from its original controlled state (next page). In the earliest stage preceding an event, inadequacies in the system, or in standards or compliance generate the potential for an event. In the case of drilling, the system is the basis of design for the well; the standard is the drilling program; and compliance is making sure the well is behaving as anticipated. Underlying problems that can be traced back to this first stage might be inappropriate casing or drilling fluids design or a drilling rig unsuitable for the particular drilling program. In and of themselves, these do not cause a drilling mishap, but trying to adjust daily drilling activities to work around these fundamental flaws requires human energy that could be better spent following the drilling routine. This first stage is the one in which the longest decision time—months in most cases—is available to avert a problem, and the most brain-power, in terms of numbers of highly trained personnel, can focus effort on a solution.

In the second stage, basic causes of an event can be attributed to personal factors and job or system factors. Examples in drilling could be inferior or insufficient training, delaying a bit change in anticipation of the end of the work shift or not putting a cover on the hole when the drillstring is pulled out. Taken individually or even together, these factors do not cause a problem, but may allow problems to develop. Actions at this stage typically are based on decisions made days to hours before an event, by one person or a few on the rig.

The third stage describes immediate causes of an event, such as substandard conditions, practices or acts—letting equipment fall into disrepair, accidentally dropping a small hand tool down the hole, or improperly interpreting a measurement. Decisions—not to report the faulty hardware or lost screwdriver or not to mention what the shale shaker is accumulating—are made days to minutes before the event, by someone on the rig, often acting under stress.

Causation Model



^ Evolution of an event. Inadequacies in the basic system, personal factors and substandard practice all contribute in more or less identifiable ways to a drilling problem. Most events are not even reported until past the critical state of loss.

In the fourth stage, the event, or incident, occurs. Drillpipe gets stuck or the well takes a kick. There may be only minutes to make the right decision. The person making the decision that might free the pipe or prevent disaster is acting under tremendous stress, and so with reduced ability. Experts in the management of crises, such as wars and natural disasters, report that under comparable levels of stress, decision-makers utilize only one-fourth of the information available.

The final stage, the actual loss, results in unintended loss or damage to property and the drilling process. The bottomhole assembly (BHA) and a section of drillpipe are lost in the hole, or a kick advances to a situation that can be controlled only by killing the well. Afterwards, the incident is finally reported.

These risk management and cause analysis concepts have their origins in health, safety and environment (HSE) awareness initiatives. Most companies in the E&P industry have comprehensive, effective HSE awareness and training programs. Maintaining an active training program is recognized as being as important as any other aspect of doing business. HSE training programs are based on the understanding that most incidents that lead to loss are caused by human error, error that could be prevented with proper care.

In the E&P industry, operators have examined occurrences of drilling problems and report that most unscheduled events can be attributed to human error. In one published report, 65% of stuck-pipe incidents could be directly related to inadequate planning; 68% of incidents occurred within two hours of a tour change.⁵

Most of the techniques used in HSE training courses are designed to combat human nature—to slow down speedy driving, do away with lazy waste-disposal habits or avoid distraction during machine operation. Managers understand the need for constant vigilance and annual retraining, and employees are required to keep their training records up to date. Near-miss reporting helps employees become more aware of situations and conditions that could lead to accidents.

The same elements make an effective approach to dealing with drilling incidents, and several of these have been incorporated into this new strategy for drilling. Better communication in the form of near-miss reporting, documentation of process compliance, increased awareness of team goals and understanding of the technical reasoning behind contingency actions is the most important factor in applying these risk management and cause analysis methods to drilling operations.

Near-miss reporting is considered standard HSE practice for successfully reducing the frequency of workplace errors and accidents, but before the introduction of the Schlumberger PERFORM methodology, it had not been applied to drilling. In the past, when a well was completed on schedule without major problems, everyone involved congratulated each other on a job well done, but little thought was given to analyzing the process that produced the successful result. The well may have been drilled without major problems, but it almost certainly was not drilled without any problems at all. That it appeared to be so was because each of the small difficulties encountered along the way had been dealt with successfully. The story behind each of the forgotten small problems and its solution is the secret of the well's success.

Identifying drilling predicaments and reporting them as soon as possible increases the likelihood that a small problem will be recognized and solved at an early causation stage, before it becomes unmanageable. Documenting the steps taken to solve the problem produces two additional benefits: the first is a report of the drilling history, complete with a record of how personnel responded to problems. This record shows how successfully workers comply with procedures. The second is an archive of problems and solutions that can be tapped in the future, whether in deeper sections of the same hole, or in other wells or other fields.

Making known to all rig personnel the technical reasons behind contingency actions is another area in which good communication plays an important role. As in most situations influenced by habit, the easiest thing for a driller to do is what's been done before. But if, when the time comes, it's important to do something different, the driller is much more likely to react correctly if the reason is understood. The case study in the next section demonstrates how communication, risk analysis, proper measurements and a team approach help drill wells where success previously had been elusive.

Controlling Instability

Experts estimate that wellbore instability costs the industry more than \$1 billion per year. The industry average cost of nonproductive time—often due to wellbore instability—works out to about \$1.5 million per well, and in extreme cases can reach \$16 million for a single well.

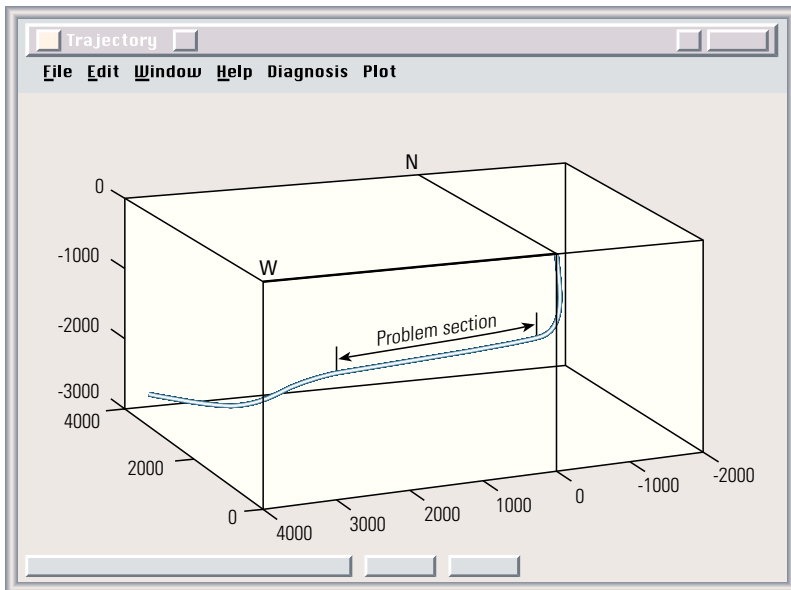
Wellbore instability occurs when earth forces or interactions between the formation and the drilling fluid act to squeeze, stretch, constrict or otherwise deform the borehole. Consequences of wellbore instability are stuck pipe and BHAs, excessive trip and reaming time, mud losses, fishing or loss of equipment, sidetracks, inability to land casing, and poor logging and cementing conditions.

Drilling plans include stability studies based on information from neighboring wells so that optimal drilling trajectories, mud programs and drilling practices can be established in advance. However, the earth doesn't always behave as predicted and sometimes the forces act contrary to expectations.

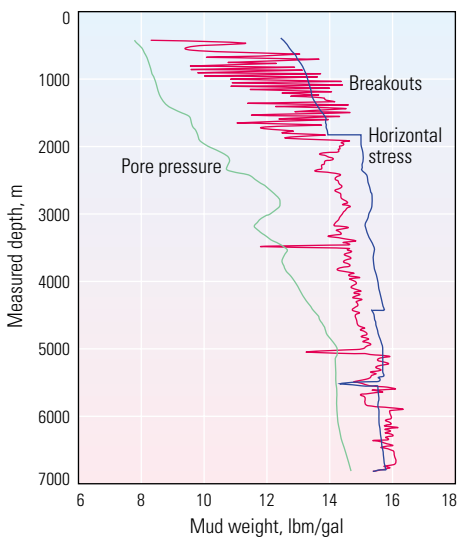
Wellbore instability often can be managed if it can be detected in time. Control mechanisms include changing mud chemistry, mud weight and flow rate to exert more or less pressure on the formation or changing rate of penetration (ROP) or drillstring revolutions per minute (rpm) to facilitate hole cleaning.

In an effort to develop a capability for real-time detection and control of wellbore stability—while the well is being drilled—a partnership was formed in 1996 between Amoco, The Netherlands Institute of Applied Geoscience, GeoQuest and Schlumberger Cambridge Research, England. Partial funding was supplied by the European Union THERMIE program.

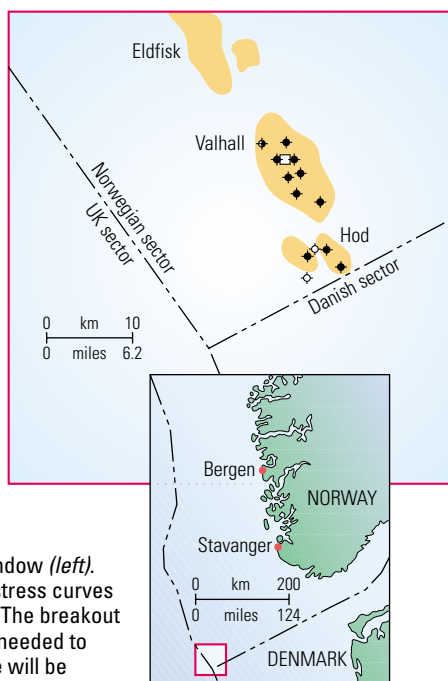
5. Watson B and Smith R: "Training Reduces Stuck Pipe Costs and Incidents," *Oil & Gas Journal*, 92, no. 38 (September 19, 1994): 44-47.



^ Problem section predicted in Valhall trajectory. Borehole inclination, earth stresses and formation characteristics combine to make this inclined section of the borehole prone to cavings that could lead to stuck pipe if not properly managed.



^ Valhall location (right) and mud-weight window (left). The pore pressure and minimum horizontal stress curves are taken from the mechanical earth model. The breakout curve (red) is calculated as the mud weight needed to ensure that none of the rock around the hole will be stressed beyond failure. Mud weight needs to lie between the breakout curve and the horizontal stress curve (blue). In some sections of the hole, this is not possible.



The methodology was tested in the Valhall field, a major chalk reservoir discovered in 1975 and operated currently by BP Amoco Norge, with partners Elf, Amerada Hess and Enterprise. The field contains 600 million bbl [95 million m³] oil reserves, with a centralized production complex in 70 m [230 ft] of water. Reservoir depth is 2500 m [8200 ft]. Overall development objectives are to increase the value of Valhall assets to 1 billion barrels [160 million m³], partly through extended-reach drilling into downflank reserves.

Earlier drilling problems on Valhall were numerous and typically included packoffs and stuck pipe, tools lost in hole, mud losses, side-tracking and inability to land casing or drill out of casing. As a consequence, there is a high risk that wells will be suspended or abandoned before reaching the target.

The field test of the methodology, which was developed at Schlumberger Cambridge Research, called for an integrated approach to wellbore instability control. The design stage comprised data gathering, mechanical earth model construction, well stability strategizing and formulation of a drilling plan. Execution included drilling monitoring, data acquisition and instability detection. Evaluation consisted of interpretation of observations, updating the model and recommending future actions.

In the planning phase for Well 2/8-A3C, a mechanical earth model was generated that described the state of stress, rock properties and failure mechanisms active in this region of the Valhall structure. A mud-weight window was calculated taking into account traditional wellbore instabilities, and other problems such as fracture zones—existing natural fractures—were identified. A problem interval at 4000 m [13,100 ft] measured depth in the 12¼-in. hole section was flagged as a zone where fracture zones could become destabilized (above left).⁶

Depending on depth, the calculated mud-weight window is either extremely narrow or nonexistent (left). Instability was inevitable. At too high an effective mud weight, the fracture zone would be driven beyond its precarious balance and cause irreparable borehole collapse. But for any mud weight below the fracture pressure, breakouts would occur. The solution, therefore, was based on recognition of the inevitability of formation failure. The only way to drill the well was to let the instability occur, then manage it. Breakout problems would be controlled by good hole cleaning. Fracture zones, however, are uncontrollable, and must be kept stable.

Typically, drilling in the Valhall Tertiary strata started with a mud weight of 14.3 lbm/gal [1.71 g/cm³]. As drilling proceeded and cavings, caused by shear failure of the wellbore wall, were observed, the mud weight would be increased steadily, often exceeding 16 lbm/gal [1.92 g/cm³]. This caused problems in the lower section, as it produced wellbore pressures above the fracture gradient. Mud was lost, and large amounts of blocky cavings were produced from the naturally fractured zones, resulting in pack-offs. The new strategy proposed that drilling should begin with mud at 14.2 lbm/gal [1.7 g/cm³], barely lower than usual, but that this value should not be increased unless absolutely necessary in response to gas, positive flow checks or other signs of overpressure. If cavings were produced by shear failure, they would be removed by good hole-cleaning practices rather than be suppressed by higher mud weight.

The equivalent circulating density (ECD) would be kept lower than the minimum horizontal stress—15.3 lbm/gal [1.83 g/cm³] in the problem zones, except in extreme circumstances. ECD is the effective mud weight that generates the downhole pressure observed while pumping, and is generally greater than the mud weight measured at surface because of frictional pressure drop in the annulus and cuttings loading in the mud. In earlier Valhall wells, ECD was allowed to exceed 15.3 lbm/gal, with consequent loss of mud to the fractures in the formation—an expensive problem, but not one previously regarded as threatening to wellbore integrity.

This new drilling strategy made the explicit assumption that cavings produced by shear failure stemming from low mud weight would occur in quantities controllable by hole cleaning, but that cavings produced by mud invasion and stimulation of fracture zones would be uncontrollable. It was clearly important to know whether mud invasion was occurring, and so a further part of the strategy was to monitor mud volume for losses, and also monitor cavings at surface to identify their source. This would be done by classifying their shapes; shear-induced cavings from breakouts are angular, those from fracture zones are tabular and parallel-sided (above right).

6. Kristiansen TG, Mandziuch K, Heavey P and Kol H: "Minimizing Drilling Risk in Extended Reach Wells at Valhall Using Geomechanics, Geoscience and 3D Visualization Technology," paper SPE/IADC 52863, presented at the SPE/IADC Drilling Conference, Amsterdam, The Netherlands, March 9-11, 1999.

If, in spite of the low mud weight, blocky cavings were seen at surface, it would mean that the fracture zones were being invaded. This would require addition of lost-circulation material to the mud in order to seal the fractures.

A Schlumberger PERFORM engineer was stationed on the rig to monitor surface and downhole measurements and advise on stuck-pipe issues: in particular to monitor and analyze cavings and act as liaison between the drilling staff on the rig and the wellbore-stability team onshore.

Three aspects of cavings information were tallied. First, the rate of cavings production at the shale shakers—the coarse solids separators on any rig—was recorded every 30 minutes by measuring the time required to fill a bucket. This method may seem crude, but is reliable and versatile in terms of the number of different rigs to which it can be applied. More sophisticated solids-measuring devices have been tried, but few have been satisfactory.

Second, the dominant shape of the cavings was noted. Initially, the intention was to classify cavings into three types: angular ones originating from breakouts, blocky from naturally fractured zones, and elongate or splintery cavings from zones of elevated pore pressure. Unfortunately, most cavings were just nondescript pieces of broken rock. However, some did indicate they were from breakouts, and some from overpressured zones. Only two cavings were seen during the entire drilling program that came unambiguously from fracture zones, attesting to the correctness of the selected drilling strategy.

Third, the geological age of the cavings gives an idea of where they are coming from in the interval. This required micropaleontological analysis that was not available immediately. When the results did arrive, they indicated that all cavings were coming from the upper openhole section that had been exposed to drilling fluids the longest.

Onshore at the BP Amoco drilling team office, real-time data were displayed. The real-time drilling parameters display proved popular, and gave the onshore drilling and wellbore-stability staff close contact with drilling operations. The wellbore-stability team attended morning drilling meetings, advised on stability issues and gave a class on wellbore stability to this group and one from another platform in the Valhall. The classes focused the attention of the crew on the avoidance of instability problems, rather than the traditional reactive approach, and allowed the staff to meet and question the scientists and engineers who would be influencing their drilling procedures.

Angular Caving



Tabular Caving



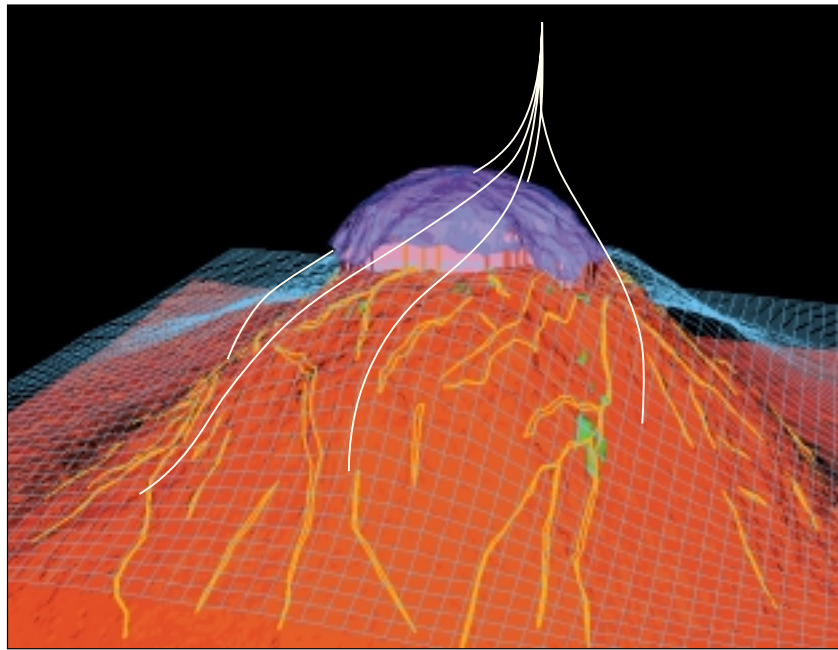
▲ Tabular caving (bottom) from natural fractures and angular caving (top) caused by breakouts. Scale is in mm.

One of the tasks was to carefully monitor the rate of penetration and the ECD. If the latter crept up to 15.3 lbm/gal, there would be the risk of mud invading fracture zones and causing permanent formation damage. If the ECD got too low, cuttings and cavings could be accumulating around the bottomhole assembly, eventually preventing fluid flow and sticking the drillstring in the hole. Rate of penetration is important in controlling ECD. If too much rock is drilled too quickly, the suspended cuttings increase the mud density and hence the ECD. While it is clear this might lead to problems, one of the traditional aims of the drilling crew on a rig is to drill as fast as possible. Crews assume that high ROP will help reach target depth more quickly, and sometimes pay bonuses are tied to beating drilling schedules. In most areas, however, including the North Sea, a longer term view must be taken; high instantaneous drilling rates can lead to problems that cost more to solve than is saved in drilling time.

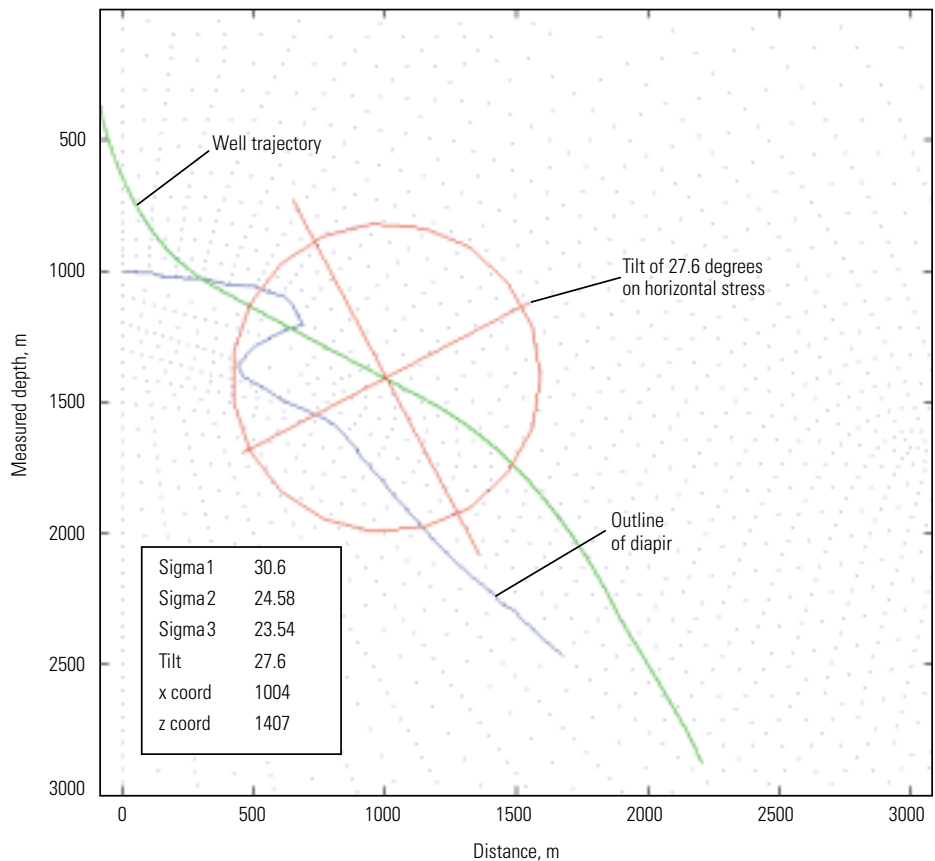
An example of the Schlumberger PERFORM process in action can be seen in the crew's reaction to an anticipated problem. During drilling, gas levels and fluid volumes require continuous monitoring to ensure that any gas is detected and there is no risk of a kick developing. When background gas levels were high in the interval from 2100 to 2200 m [6890 to 7220 ft], the standard response would have been to increase mud weight substantially to suppress gas influx into the borehole. This would have led to the destabilization of the critical fractured zone lower, between 4100 and 4300 m [13,450 to 14,100 ft]. The driller was advised that mud weight had to be kept low, and that another way to control gas leakage was to slow down. The mud-weight increase was restricted to 14.6 lbm/gal [1.75 g/cm³] and the rate of penetration was reduced to below 30 m/hr [98 ft/hr]. The lower ROP decreased the rate at which crushed rock released gas into the annulus, and these actions reduced background gas levels from the 20 to 35% range down to less than 5%, while avoiding problems deeper in the well.

The reservoir was penetrated ahead of schedule, with much lower mud loss to the formation than usual and negligible activation of fracture zones. The asset team acknowledges that the implementation of real-time wellbore-stability control significantly reduced the risk and drilling costs to the top of the reservoir, and achieved optimal well construction technique earlier in the field development cycle.

> Wellbore trajectory on a vertical slice through the stress field modeled around the Mungo field. In an unperturbed earth, the maximum principal stress is vertical, and the intermediate and minimum ones, horizontal. With the intrusion of salt, the stress field has been perturbed and tilted. This earth model can be interrogated at any point and the stresses visualized as axes through a sphere. In this example, the model has been interrogated at 1500 m: the red crosshairs and circle indicate that the maximum and intermediate principal stresses are tilted 27.6 degrees.



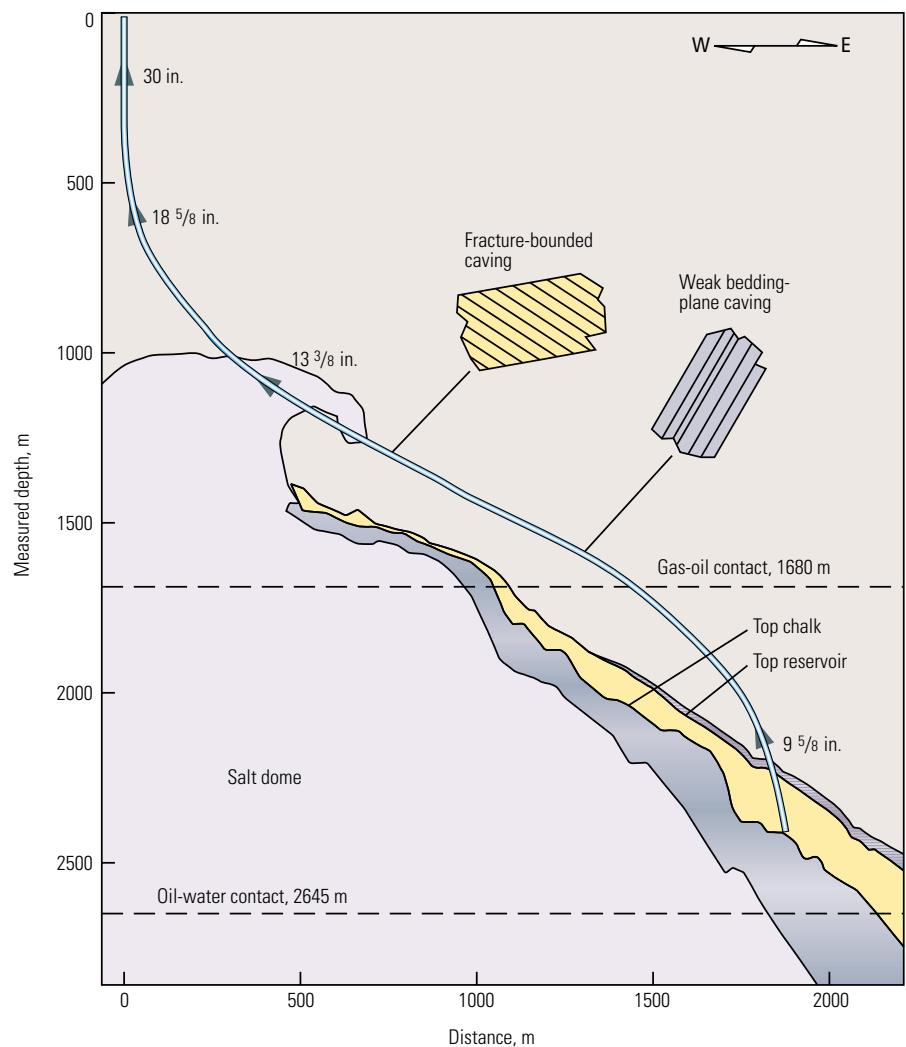
▲ Structure of the salt dome responsible for the Mungo field accumulation. White curves are well trajectories and the yellow lines on the dome are interpreted faults.



Another field in the North Sea experienced similar gains in drilling efficiency through optimized planning and monitoring of wellbore stability and hole-cleaning practices. Development wells in the Mungo field in the Eastern Trough Area Project (ETAP) encountered extreme instability problems as they neared the flanks of the overhanging salt diapir (previous page, top). Tectonic activity associated with the salt emplacement had fractured and weakened formations through which wells were to pass on their way to the reservoir. The highly disturbed sediments around the salt intensified the hole-cleaning problem. Cavings, whether bounded by fractures or by weakened bedding planes, clogged the wellbore. Stuck-pipe problems were especially severe in the long, inclined 60° sections of the S-shaped trajectories that were necessitated by the centrally located platform. Overpressured formations and high-pressure chalk rafts added further risk to the drilling program.

The four wells in the first phase of Mungo development drilling had experienced large cost overruns in the 12¼-in. sections. For the subsequent phase of development, a mechanical earth model was constructed for the Mungo structure and used to plan the second phase of development wells. Some of these wells pierced the salt for a 13¾-in. casing point then followed the salt downflank to the reservoir sand (previous page, bottom). As in some sections of the Valhall wells, stress profiles indicated cavings would be abundant, so good hole-cleaning practices would be crucial to successful drilling. Downhole monitoring of ECD with the APWD Annular Pressure While Drilling tool would help the engineer detect hole-cleaning problems before they could cause stuck pipe.⁷

In Well P2, the first well of the second phase of Mungo development, wellbore instability did cause large amounts of cavings to enter the borehole (right). However, the combination of surface detection of cavings and cuttings, downhole measurements for hydraulics monitoring and attentive drilling overcame this problem. The NPT was significantly reduced, with substantial cost savings.



▲ Cavings shapes predicted and found along the trajectory. The volume around the top of the salt dome was predicted to be highly fractured and prone to fracture-bounded cavings. Deeper along the inclined section, cavings were found to separate along weaknesses in bedding planes.

Currently, the Mungo wells team has a Schlumberger PERFORM engineer offshore and a geomechanical expert onshore as part of the drilling team. This engineer and members of the onshore team, consisting of the geomechanical expert, drilling engineer, directional planner and geologist, hold a morning conference call to discuss what has occurred over the last 24 hours and what can be expected for the upcoming day. The results of this meeting are presented at the regu-

lar morning call where everyone is briefed and made fully aware of any potential problems for the next 24 hours. This process worked well on the recently drilled P3 well. A situation involving possible losses was avoided by keeping the ECD low while drilling through a fracture. A small volume of mud was lost, but drilling continued unabated.

7. For more on the application of the APWD tool in the Mungo field and others: Aldred W, Cook J, Bern P, Carpenter B, Hutchinson M, Lovell J, Rezmer-Cooper I and Leder PC: "Using Downhole Annular Pressure Measurements to Improve Drilling Performance," *Oilfield Review* 10, no. 4 (Winter 1998): 40-55.



^ Cabinda, a northern enclave of Angola on the west coast of Africa, having crude oil as its dominant export.

Optimizing Bits and Drilling Practice

The Schlumberger PERFORM techniques for optimizing drilling performance can be applied to other drilling challenges. In addition to managing wellbore instability and promoting good hole-cleaning practice, the methodology has been used to improve drilling efficiency by supporting bit selection and appropriate drilling practice to reduce damage to drillstring components.

Chevron is drilling and operating offshore in the Cabinda enclave of Angola (above). Their current efforts concentrate on the South Sanha fields where the main reservoir, the Pinda formation, is the deepest and hardest to drill. The interbedding of hard and soft layers in the Pinda formation plays havoc with drilling equipment, and it is a challenge to prolong the lives of bits and other BHA components. In one instance, after drilling just two wells, Sedco Forex had to scrap about 80 joints of heavy-weight and standard drillpipe due to eccentric wear.

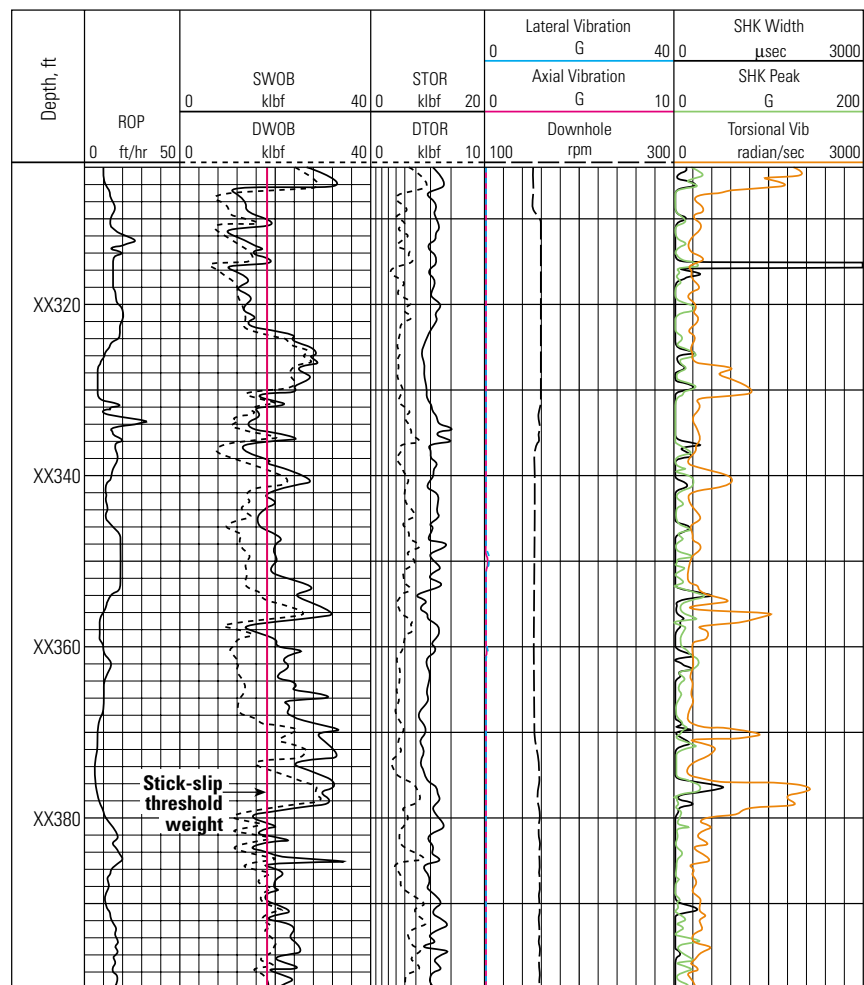
The main goals for the Schlumberger PERFORM engineer were to improve ROP and eliminate drillstring failures. In essence, this meant finding ways to ensure that all the rig energy imparted through the rotary table or topdrive to the drillstring and bit be used constructively to cut rock rather than to destroy the bit and drillstring. The difference between the two situations sometimes can be small, and the best way to avoid the latter is by careful planning, understanding the process and monitoring both surface and downhole measurements in real time.

Standard practice for increasing ROP was to increase weight on bit (WOB). But increasing WOB can cause other problems, including increased stick-slip and torsional vibration, which in turn damage the drillstring and

ultimately lead to higher per-foot costs. Stick-slip occurs when high friction between the bit and the formation actually stops the bit from rotating—the stick phase—even though the drillpipe is still being turned at a constant rate on surface. After a short delay, slip takes over when torque built up in the twisted drillpipe overcomes the friction and the bit turns, but several times faster than the speed transferred from the rotary table or topdrive. Torsional vibration, or oscillation of the drillstring around its rotational axis, is one of the three modes of drillstring vibration, the other two being axial—along the long axis of pipe, and lateral—from side to side across the pipe.⁸

Introduction of the Schlumberger PERFORM technique produced immediate results. In the first well to use such an engineer, monitoring surface

and downhole measurements of weight on bit torque, shocks and vibrations provided a clear guide to controlling stick-slip, shocks and vibrations by modifying WOB (below). Surface (SWOB) and downhole weight on bit (DWOB) were seen to correlate closely with the occurrence of torsional vibrations at XX325 ft brought on by stick-slip, so a stick-slip threshold weight was determined, under which the WOB would allow smooth drilling. For thresholding purposes, the downhole weight on bit measurement was more reliable than that measured on surface. For example, at XX360 ft, where torsional vibrations are low, the DWOB lies below the threshold, but the SWOB is above it. This is in contrast to the next lower section in which DWOB (and SWOB) are above the threshold, and vibrations are set in motion.



^ Surface and downhole measurements for optimizing drilling in a Chevron Cabinda well. Increases in surface (SWOB) and downhole (DWOB) weight on bit (track 2) correlate with the onset of dangerous torsional vibrations (track 5) induced by stick-slip, first seen in the zone from XX325 to XX330 ft. To avoid torsional vibrations, a stick-slip threshold weight was determined and tied to measured DWOB, which is more reliable than SWOB. This can be seen in the interval from XX360 to XX369 ft: there are no torsional vibrations when DWOB is below the threshold, but SWOB is above the threshold and would have given a false alarm.

The well took 11 days and one bit run to drill the 10,000 ft [3050 m] to the top of the Pinda, then 23 days with 6 bit runs to drill through the 3000-ft [900-m] Pinda. The sporadic success of any particular bit and BHA combination in this field was unexplainable. Sometimes one combination would achieve excellent ROP and footage, and at other times it would fail after the initial few feet.

The engineer combined data from surface and downhole measurements and rock strength analysis and related these to previous bit and BHA performance. This allowed estimation of optimal ranges for the while-drilling measurements and helped in subsequent bit and BHA selection. Then specific drilling performance measurements were monitored in real time on the rig and kept within the optimized range so as to achieve optimal cost per foot.

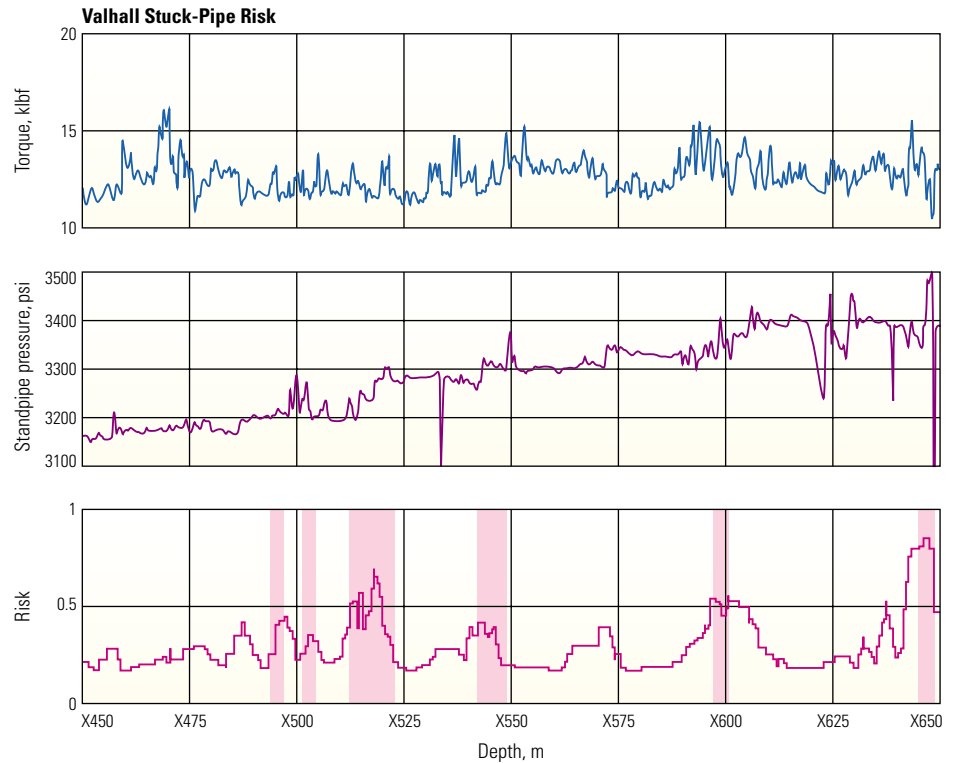
The experience gained while drilling this well was applied to subsequent wells. In all later wells, the number of shocks measured with a threshold shock sensor that detects shocks greater than 100 G decreased from a range of 6 to 8 million in the Pinda formation to almost zero. The problems of eccentric drillpipe wear disappeared completely and the learning curve for selecting the right bit and BHA sped up, resulting in improved drilling performance.

Tools for Success

The successes delivered by the Schlumberger PERFORM process stem from the combination of Schlumberger technical strengths in measurement and interpretation with the operator's drilling expertise. High-quality while-drilling data and accompanying analyses are vital for successful drilling, but they are most valuable when used in a consistent way to support decisions made during the drilling process.

This process is a series of decisions and associated actions taken during the planning and execution of a project that result in a completed well. The degree of success or failure and efficiency of the well is determined by the quality of those decisions. Effective decision-making depends on having an accurate view of current

8. Jardine S, Malone D and Sheppard M: "Putting a Damper on Drilling's Bad Vibrations," *Oilfield Review* 6, no. 1 (January 1994): 15-20.



^ Predicting the possibility of stuck pipe in the Valhall field. Torque (*top*) and standpipe pressure (*middle*) measured while drilling are two elements, along with signal processing techniques, that help identify well sections where the risk of stuck pipe is high (*bottom*). The shaded bars indicate where the drilling team did experience drilling difficulties, mostly related to hole-cleaning issues.

well conditions, understanding the consequences of a decision and being prepared for the future with contingency plans. The Schlumberger PERFORM initiative impacts this process most significantly by helping to provide an accurate view of the current conditions and a look ahead at potential hazards. The result is that better decisions can be made by transferring the decision-making period from the stressful moments surrounding an incident to some earlier time when judgment is not impaired by anxiety and pressure.

Researchers are investigating ways to improve the decision-making process by making more data available faster and using knowledge gained in other areas. For example, new techniques are being devised for estimating the risk of a drilling incident such as stuck pipe. Using standpipe pressure and torque data from the

Valhall wellbore stability case study discussed earlier, scientists at Schlumberger Cambridge Research have produced a stuck-pipe risk profile that begins to foretell hole-cleaning problems (*above*). With further testing and experience, these advances will eventually change alarms from signaling a surprising event when it occurs to advising drilling teams long before the problem becomes dangerous.

The oil industry, like all others, strives for cost-effectiveness and productivity. Elimination of waste and losses, whether in process or materials, is a key goal for all successful companies, regardless of prevailing economic conditions. Increasing drilling efficiency by managing drilling risk is a sure way for E&P companies to achieve that objective.

—LS