

Beyond Deep—The Challenges of Ultradeep Water

Not many years ago, the E&P industry was forced to develop radically new technologies and methods for prospecting in deep waters beyond the continental shelf. The industry is now advancing into ultradeep water and drilling much deeper into the subsurface, which requires a continued evolution of technology and project workflows.

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When the E&P industry moves into untried territories, the costs can be significant, and drilling and completion engineers are required to manage such costs and expenses through reduced nonproductive time. For challenging new arenas such as deep water, where spread costs run to more than US\$ 1 million per day, reducing nonproductive time is a logical strategy. But emphasis on cost reduction is today being joined, if not replaced, in the minds of ultradeepwater operators by other considerations.

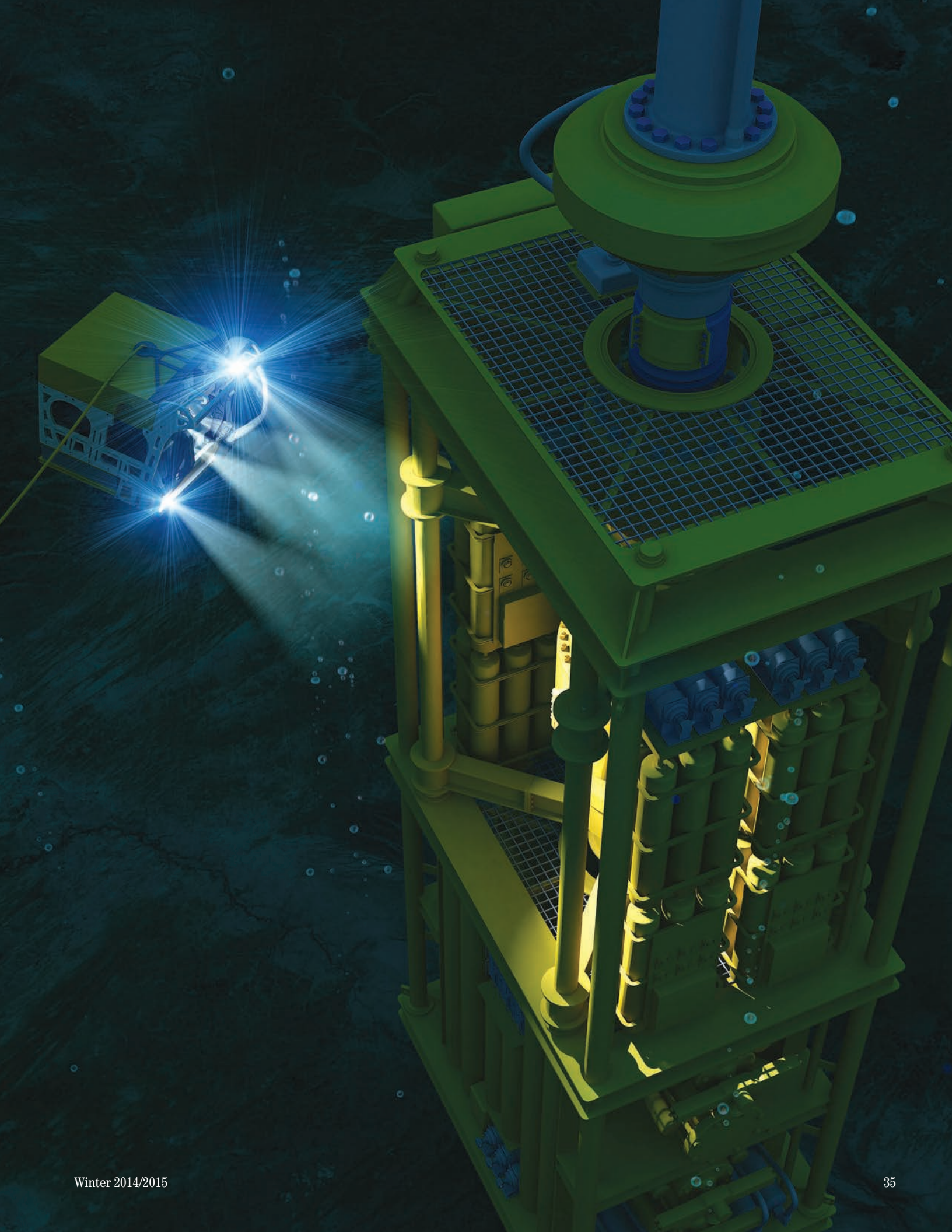
Many operators now understand that the value realized through reduced nonproductive time (NPT) is usually not sufficient to economically redeem extremely costly ultradeepwater projects if the wells are not optimally placed within the reservoir and constructed with equipment able to last the life of the well. In addition, recent events have made operators keenly aware that risk management and strict adherence to regulatory dictates must be of primary importance when working in an environment in which mistakes can result in human, environmental and financial catastrophe.

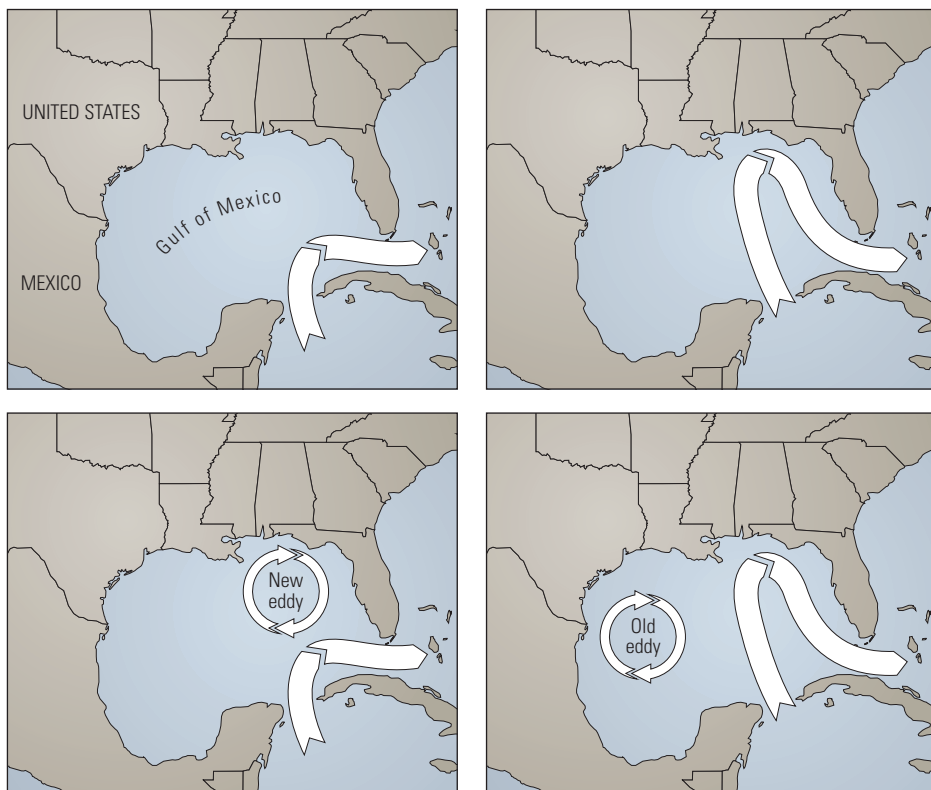
Safety and environmental concerns are not limited to the deepwater arena, water depths generally considered greater than 500 m [1,600 ft] or in ultradeep water deeper than 1,500 m [5,000 ft]. However, the stakes are substantially higher in these water depths than in shallow water or onshore, and the consequences of missteps are proportionally more costly. To navigate this challenging world, ultradeepwater operators and service

companies are rediscovering the virtues of close collaboration across all the disciplines that bring projects to fruition.

The ultimate driver for this renewed call for an integrated approach to ultradeepwater exploration may be the inability of current tools and workflows to adequately model the Earth's subsurface. The degree of uncertainty embedded within subsurface data acquired through technologies such as seismic surveys or downhole logging requires experts to interpret their datasets using probabilistic estimations and contingency planning. Geophysicists, who use such data to create mechanical earth models (MEMs), include assumptions about rock types, pressure during the life of a field and the effect of changing pressure on permeability and effective porosity. Based on MEMs and other models, drilling engineers make key well design assumptions to determine parameters such as mud weights, bit types, casing points and wellbore angles to build the drilling program. Uncertainty in the subsurface model, however, can lead to uncertainty in the well design, which may cause engineers to construct overly conservative, unnecessarily costly wells.

The practice of reliance on the input of others is carried through to completion, production and facilities designs because each discipline must work with decisions that are at least in part based on the assumptions of others and the data limitations each discipline has to face during the process of exploration. To minimize the inefficiencies inherent in such sequential processes,





^ Eastern Gulf of Mexico Loop Current. The Loop Current in the Gulf of Mexico may form a short loop (top left) or may become elongated (top right). When the loop is long, it often pinches off a spinning body of water called an eddy (bottom left). These eddies drift westward over many weeks (bottom right) and eventually lose energy in the western Gulf. The cycle of loop and eddy currents repeats itself several times a year.

all members of an ultradeepwater project team must understand the uncertainties that are embedded in the data they receive and communicate these to the entire team throughout the field design process.

Sources of uncertainty are recognized and addressed at each step of an ultradeepwater exploration and development project. Before operators select the location of the drillbit entry into the seabed, they consider seafloor and shallow geologic hazards that they might encounter. Drilling ahead requires knowledge of expected pore pressures, but pore pressure models are created from seismic velocity calculations and modified based on drillers' experience in similar environments. Predictions of pressure and temperature gradients, complex geology, geomechanical properties, formation fluid chemistry and other factors ahead of the bit all incorporate effective risk management that has allowed the industry to successfully drill wells in this uncertain ultradeepwater environment.

This article describes defining, drilling, completing and producing ultradeepwater reservoirs through an integrated workflow. It also explains the prominent role of regulatory agencies since the 2010 Macondo incident in the Gulf of Mexico (see "Offshore Regulations in a Post-Macondo World," page 38). A case history from Mexico illustrates how cross-discipline teams played a key role in the successful drilling and evaluation of a complex well in the ultradeep waters of the Gulf of Mexico. Another from northern South America demonstrates how an integrated approach can ensure success in remote operating areas.

Known Unknowns

The challenges that operators face drilling and completing wells in ultradeep water are the same, if more pronounced, as those the industry encounters in previous deepwater operations. For instance, in the Gulf of Mexico, the Loop Current—streams of warm water that flow beneath the ocean surface and that travel from the Caribbean Sea into the Gulf and back out

again—can cause considerable operational difficulties for deepwater drilling units (left). The Loop Current plays havoc with drilling rig station keeping and the running and retrieving of drilling risers and can cause riser fatigue from vortex-induced vibration.¹

Station keeping refers to holding the vessel against wind and currents to within a specified circle, or watch circle, about the center line of the riser. The watch circle extent depends on water depth, riser geometry, riser tension distribution and the limits of the flex joint angles for a particular operation.

Deepwater drilling units achieve station keeping in most sea states through dynamic positioning, which uses multiple, computer-controlled subsurface thrusters. The thrusters are able to rotate 360° and thus exert force on the vessel hull in any direction required to counter sea forces. Thrusters are continuously computer monitored and adjusted in response to changing seas and currents. This process, however, may require the rig to use significant amounts of fuel and thus add costs that impact overall project economics.

The Loop Current and straight-line currents push risers laterally, which makes landing them in subsea blowout preventers difficult. The deepwater drilling industry has developed special equipment to guide risers, but this equipment is very expensive, and as a consequence, some mobile drilling units are not equipped to handle drilling in offshore areas with strong currents.

In addition, as currents flow around a riser in place, vortices form downstream from it. Vortex-induced vibration—the transverse oscillation of a pipe placed in strong current—is caused by vortex shedding around the riser and can lead to pipe fatigue damage. To combat this phenomenon, helical fins called strakes, or fairings, are placed along the length of the riser as each section is lowered from the rig floor. These devices break up the current and suppress creation of vortices, but because they are installed on individual riser joints on the rig as they are being prepared for deployment, strakes add considerable time and thus cost to riser running operations.²

Another hurdle addressed by operators in deep water is the narrowing drilling window that is a function of the diminishing difference between formation pore pressure and formation fracture initiation pressure as the water depth increases. The formation fracture initiation pressure is reduced relative to the pressure on land or in shallow water because the Earth's overburden has been replaced by seawater, which results in

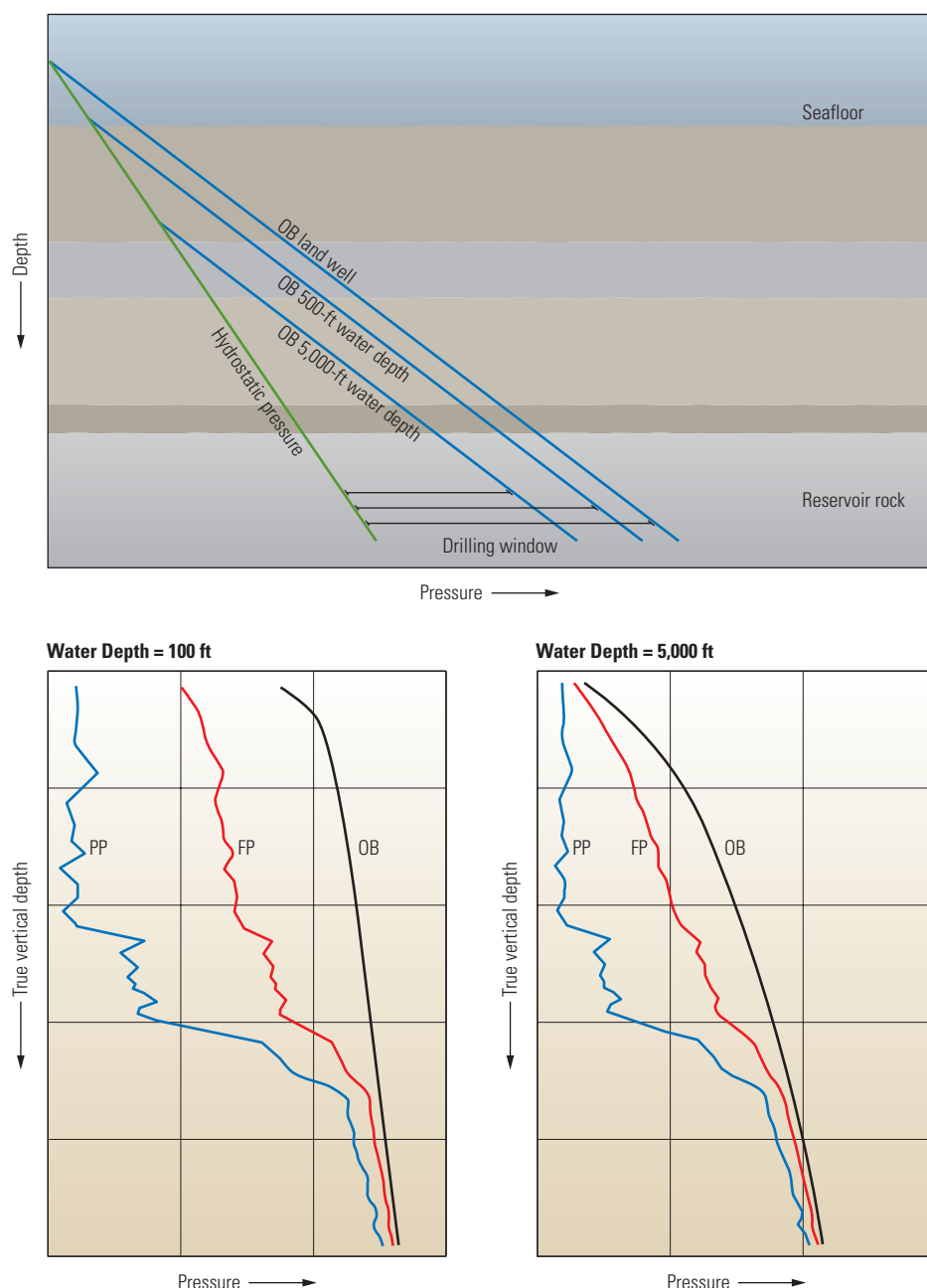
lower vertical stress. Fracture initiation pressure can be reduced further by the structurally weak uncompacted and unconsolidated sediments typical of shallow sections of a deepwater wellbore. Because pore pressure typically increases with depth, the drilling window becomes increasingly narrow as water depth increases (right).³

Under ultra-deepwater conditions, the hydrostatic pressure of the column of drilling fluid above the bit may exceed the fracture initiation pressure of the formation being drilled. If the well reaches a depth at which the window between the fracture pressure and pore pressure closes, drilling mud will be lost to the formation, and the operator will have little choice but to set casing. With each casing string, the operator must reduce the bit size of the next interval. This process can lead to a final hole size that impedes the ability to acquire formation evaluation data or result in a production casing size that is too small to accommodate economic production volumes. These smaller diameters may also be too small to accommodate the required completion architecture such as sand control, flow control and artificial lift systems. Added casing strings may threaten project economics through material costs and additional rig days.

Numerous solutions have been developed to address the shrinking drilling window. Drilling fluids that have flat rheologies that remain constant with varying temperature and low-density cements, which sometimes are infused with nitrogen, have been used to reduce the hydrostatic pressure of fluid columns in the well. In some instances, when casing must be set above the targeted casing seat depth, the driller can avoid a reduction in the next casing size by underreaming—drilling out and enlarging the hole beneath the casing seat—and then setting casing that can be expanded to the size of the previous casing.

Alternatively, some deepwater drilling units are equipped with dual-gradient drilling or managed pressure drilling systems. In the former, pumps are placed at the seafloor to lift the fluid to the surface. The effect is to reduce the hydrostatic pressure on the formation by lowering the top of the fluid column to the seafloor. This extends the depth to which the well may be drilled before the hydrostatic pressure of the fluid column exceeds the formation's fracture initiation pressure. In the latter application, the formation is permitted to flow in a controlled manner, allowing the driller to control the well using a lower density mud while reducing the hydrostatic pressure on the formation.⁴

(continued on page 40)



▲ Pore pressure and fracture initiation pressure. In deepwater environments, the Earth's overburden of rock is replaced by seawater and the vertical stress imposed on the subsurface, or overburden (OB), is reduced (top). As the depth below the seafloor increases, the pore pressure (PP) and the fracture initiation pressure (FP) move increasingly toward equality (bottom left). Consequently, the drilling window shrinks. The reduction of both FP and OB is more pronounced in deepwater environments (bottom right).

1. Koch SP, Barker JW and Vermersch JA: "The Gulf of Mexico Loop Current and Deepwater Drilling," *Journal of Petroleum Technology* 43, no. 9 (September 1991): 1046–1119.
2. Koch et al, reference 1.
3. Rocha LAS, Falcão JL, Gonçalves CJC, Toledo C, Lobato K, Leal S and Lobato H: "Fracture Pressure Gradient in Deepwater," paper IADC/SPE 88011, presented at the IADC/SPE Asia Pacific Drilling Technology Conference and Exhibition, Kuala Lumpur, September 13–15, 2004.

The drilling window is the difference, at a given depth, between the pore pressure and the fracture initiation pressure. For safe drilling, the weight of the drilling fluid in the borehole must be within the drilling window.

4. For more on managed pressure drilling: Elliott D, Montilva J, Francis P, Reitsma D, Shelton J and Roes V: "Managed Pressure Drilling Erases the Lines," *Oilfield Review* 23, no. 1 (Spring 2011): 14–23.
- Cuvillier G, Edwards S, Johnson G, Plumb D, Sayers C, Denyer G, Mendonça JE, Theuvsen B and Vise C: "Solving Deepwater Well-Construction Problems," *Oilfield Review* 12, no. 1 (Spring 2000): 2–17.

Offshore Regulations in a Post-Macondo World

Safety and environmental concerns have long been a priority for offshore operators. On the heels of the Macondo incident in the Gulf of Mexico in 2010, however, US operators, who have historically policed themselves, must now comply with new offshore safety and environmental regulations. Compliance with these regulations is overseen by the US Bureau of Safety and Environmental Enforcement (BSEE), which requires operators to employ a specific Safety and Environmental Management System (SEMS) to be qualified to operate in the US Gulf of Mexico. Among its other charges, the bureau reviews applications for permits to drill and conducts inspections of drilling rigs and production platforms.

The SEMS tool was created in 1990 when the US National Research Council Marine Board found that although the industry worked to comply with regulatory agencies, operators did not encourage an environment of identifying risk or developing accident mitigation procedures. In response, the BSEE, in cooperation with the American Petroleum Institute (API), developed Recommended Practice (RP) 75: *Recommended Practice for Development of a Safety and Environmental Management Program (SEMP) for Offshore Operations and Facilities*. The API also produced RP 14J, *Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities*, for identifying safety hazards on offshore production facilities.¹

Following the April 2010 Macondo incident, the BSEE began requiring all operators in US waters to have a well-documented SEMS program in place by November 15, 2013. At that time, 12 of 84 operators subject to the deadline had not satisfied the rule and were cited by BSEE for noncompliance. Eventually, 5 of those 12 were notified to halt operations.

Initially, the BSEE allowed companies to conduct internal audits. Today, under what has become known as SEMS II, operators are required to hire a qualified independent third party as a SEMS auditor or to lead an internal audit of the company SEMS program. In addition to forced shutdown of operations, non-compliance with the SEMS program may result in civil penalties.

Also called the workplace safety rule, SEMS is a management system that includes the following 13 elements:

- general provisions for program implementation, planning and management review
- safety and environmental information
- hazard analysis
- management of change
- operating procedures
- safe work practices
- training
- quality and mechanical integrity of critical equipment
- prestartup review
- emergency response and control
- investigation of incidents
- audit of safety and environmental management elements
- documentation and record keeping.

The BSEE mandates are directed at operators. The incidence of noncompliance reports issued after the Macondo incident, however, makes it clear that the BSEE, which is an agency within the US Department of the Interior, also intends to hold service and contractor companies accountable for safety and environmental compliance.

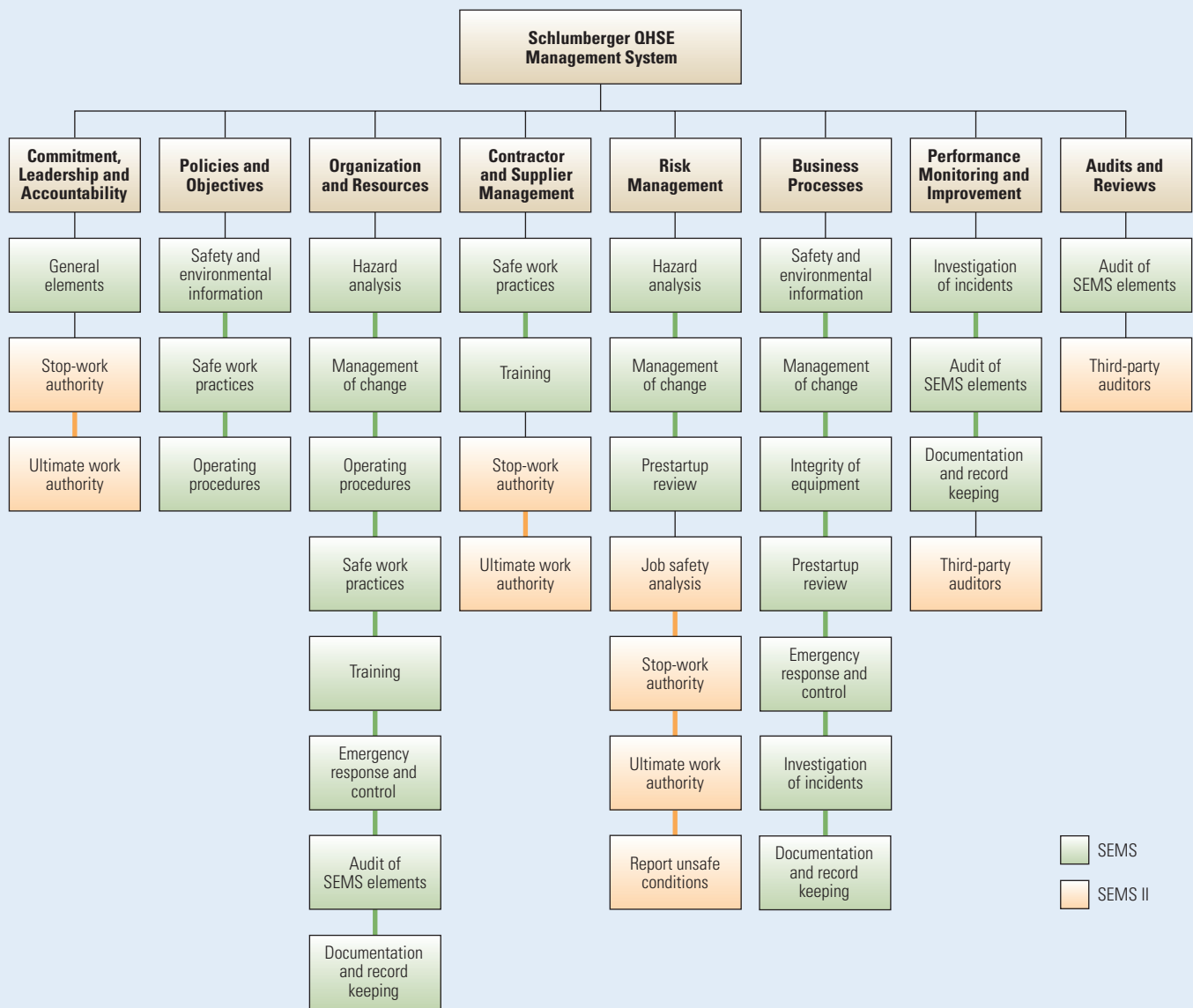
SEMS II, which has an audit deadline of June 4, 2015, adds requirements not included in the first version; these new requirements are designed to empower field personnel with safety management decisions under the stop-work authority and ultimate work authority

policies. To implement the intent of SEMS II, operators must establish procedures that authorize all employees on an offshore facility to assume stop-work authority. In addition, operators have to clearly define the individual or individuals who have the ultimate work authority on the facility for operational and safety decision making at any given time and must develop an employee participation plan for SEMS implementation and guidelines for reporting unsafe work conditions.

Although service companies are not technically responsible for meeting the requirements of SEMS, operators are responsible for all personnel on their facilities. As a consequence, the facility operator must ensure that all contract companies and their personnel are in compliance with SEMS requirements; operators have already refused some workers access to offshore facilities for noncompliance. Similarly, service companies must ensure that their subcontractors comply with SEMS to fulfill their responsibility to the operator.

For some operating and service companies, the implications of this approach include significant changes in safety programs and training to ensure employees are equipped to assume responsibility for recognizing, halting and reporting unsafe practices. Schlumberger, however, will require few changes to meet the SEMS II intent as it has a long-standing policy aligned closely with the aims of RP 75 ([next page](#)). Schlumberger offshore personnel must have a current job description on file and have completed a training plan based on that job title; the company must make certain that all offshore-bound employees have completed North Gulf Coast GeoMarket and client required training, have had their skills and

1. Gordillo G and Lopez-Videla L: "Managing SEMS Audits: Past, Present and Future," *Journal of Petroleum Technology* 66, no. 2 (February 2014): 72–75.



^ Schlumberger and SEMS. Schlumberger quality, health, safety and environment (QHSE) practices dovetail with SEMS and SEMS II recommendations from API RP 75. Schlumberger needs few adjustments to pass a SEMS II audit.

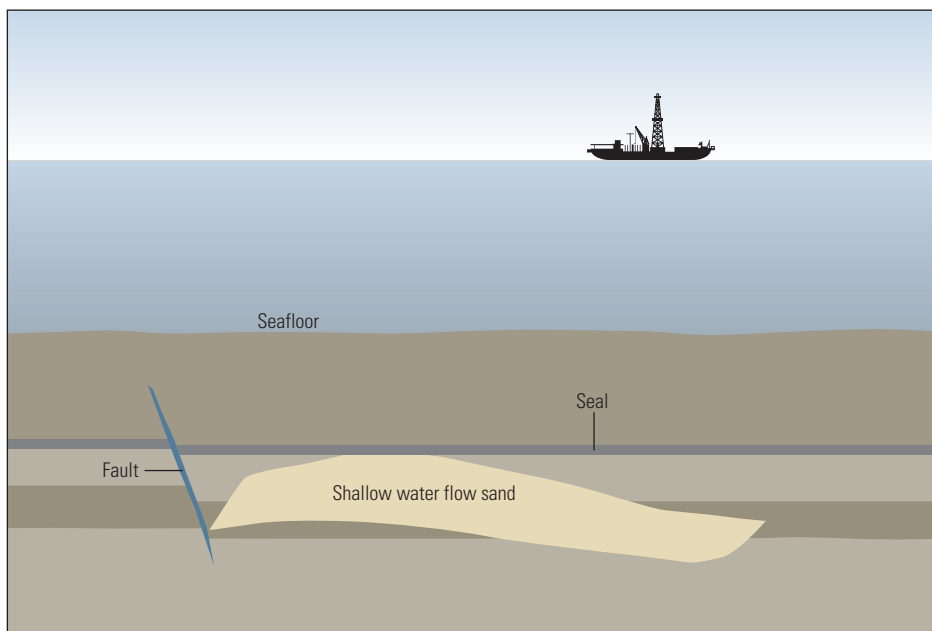
knowledge verified and have passed a valid drug and alcohol test.

Because many operators and service companies that work in US offshore waters are global companies, their SEMS-based safety and environmental practices are likely to

travel with them to markets elsewhere.

Corporate policies designed to comply with SEMS should be increasingly accepted on a global scale as companies not based in the US seek to work in US offshore areas. In addition, because the typical final outcome of safe and

efficient work habits is less down time and fewer expensive mistakes, it may be argued that although implementation of SEMS policy may incur some costs, the overall financial impact on deepwater development projects will likely be positive.



^ Formation of shallow water flow hazards in deep water. As sediments are deposited, rates of fluid escape may or may not keep pace with the rate of compaction. If the fluids are unable to escape at a rate that allows equilibrium with hydrostatic pressure, the sands become overpressured. Drilling into an overpressured sand allows the trapped water to be released, often suddenly. Silty sediments rich in clay minerals, which eventually become shales, typically are not overpressured.

Shallow Hazards of the Deep

Operators begin the process of deepwater drilling by picking drilling targets and locations. In the early days of deepwater drilling, operators were surprised to encounter surface and subsurface phenomena that they had not observed in shallower areas or onshore; such phenomena represent threats to ocean bed and wellbore stability. Some areas of the seafloor contain—in addition to man-made obstacles such as cables, pipelines, wellheads and even unexploded ordnance—natural hazards to drilling such as active fluid escape pockmarks, mud volcanoes and active fault scarps that can create unstable substrate, making anchoring rigs and spudding wells impossible. In deep water, the floor of the ocean may also be characterized by unstable slopes, slumping, sliding and sinkholes.

Just below the seafloor, threats to drilling come from shallow water and gas flows, buried water- and gas-bearing channels and splays, active faults, gas clouds, chimneys and plumes, disassociating gas hydrates and lateral pressure transfer effects that can bring higher pressures up into shallower depths. If unrecognized before drilling begins, these geohazards may force drillers to abandon their original locations or at least

suspend operations until a plan can be made for drilling through or around the problem. On the shallower continental shelf, especially in areas of deltas, the primary subseafloor hazard is the presence of shallow water or gas pockets that pose a risk of blowouts or seafloor destabilization during and after drilling operations. In the deeper water beyond the shelf and in ultradeep water, shallow water flows (SWFs), the most commonly encountered geohazard, pose significant risk to drilling operations.

Shallow water flows are prevalent in basins with high deposition rates and result from the rapid burial of sand and silt deposits followed by differential compaction and dewatering. These phenomena occur in water depths exceeding about 500 m and are usually found in sandstone formations at about 250 to 1,000 m [800 to 3,300 ft] below the mudline (above).⁵ Drilling into these trapped sands can cause water and sediments to flow into, up and sometimes around the wellbore and may threaten the viability of the wellsite. In the Gulf of Mexico, for example, one operator was forced to move a tension leg platform because 10 of 21 drill slots became unusable when the casing buckled after an SWF washed out the sediment supporting them.⁵

When possible, engineers avoid drilling through geohazards because mitigation can be difficult and may incur significant NPT. When the hazard is unavoidable, the drilling plan must include contingency casing and mud programs designed to contain abnormal pressures. In deep water, well control using increased mud density, which drilling engineers commonly use to combat abnormal pressure, is often problematic because of the narrow drilling window.

Operators protect their wellbores from shallow hazards through identification and appropriate site selection and planning. In deep water, however, offset data are often sparse or nonexistent during the exploration phases of projects, and operators identify shallow hazards through site or hydrographic and exploration seismic surveys, pilot hole drilling or stratigraphic modeling. In addition, modern high-quality seismic data have significantly improved the industry's ability to detect these shallow geohazards. But all these hazard identification techniques have both advantages and drawbacks (next page).

In addition to identifying the existence of an SWF, geophysicists must quantify the potential risk from the phenomenon. For example, thick SWF sands that extend over large areas are capable of flowing for an extended period of time, during which flow rates typically increase for part of that time. Formation dip associated with an SWF can also contribute to risk level because significant dip allows higher pore pressure from deeper portions of the sand to move updip, which increases overpressure effects.⁷

Because of a lack of quality offset data, assessing the potential for geohazards in deep water can also be difficult. Geohazard data gathered using traditional seismic methods cannot be used to quantify risk because those data are acquired using a short-cable streamer that lacks sufficient offset to extract physical properties through quantitative analyses such as inversion.

To counter this deficiency, geophysicists have begun recently reprocessing large offset, conventional 3D seismic data to quantify shallow hazards. They then develop quantitative measurements of shallow hazards using attributes such as a compressional-wave velocity to shear-wave velocity ratio (V_p/V_s), effective stress and density.⁸ Sands in an SWF are highly unconsolidated, featuring a V_p approaching that of water and V_s approaching zero. Therefore, SWFs may be identified by a high V_p/V_s compared with that of adjacent sediments.

Because of the burial and compaction process that formed SWF sands, they have poor grain-to-grain contact and thus low effective stress and high porosity. As a result, remediation through pumping cement or high-density pills—solutions for other lost circulation circumstances—is nearly impossible, and the most reliable approach for SWFs is to avoid them altogether. Surface bathymetry mapping in deltaic areas can produce a risk probability map indicating where seismic data should be carefully checked for buried channel or lobe features that might host SWFs so that they can be avoided.

Mapping Uncharted Ground

Because many technical solutions were developed in early deepwater operations and because the costs, risks and rewards are so high, operators in ultradeep water tend to focus more on maximizing the return on their investments than on reducing NPT. Although efficient operating practices remain a priority, the overarching con-

cern for ultradeepwater operators is optimal well placement within the reservoir; such placement promises higher production and ultimate recovery rates. As a consequence, geology and geophysics have assumed greater roles throughout the ultradeepwater E&P workflow than in more traditional exploration and development arenas.

Typically, in ultradeep water, little well control or direct measurements of reservoir properties are available to calibrate seismic interpretations and earth modeling. Therefore, operators rely on models to understand the financial and technical risks associated with developing their assets. The process of modeling ultradeepwater reservoirs includes geologic and geophysical modeling, reservoir characterization, reservoir flow modeling, facilities design, flow assurance and uncertainty and risk analyses. Developing each of these components is complicated by the lack of available hard data such as well logs, tests and core data.

Geologic and geophysical modeling typically uses seismic data, calibrated against what few logs may have been run in the area to map major features such as faults and possible stratigraphic barriers to fluid flow. Reservoir characterization relies heavily on seismic data, and to lessen the degree of uncertainty inherent in these data, geophysicists and engineers use geostatistical methods to describe reservoirs through trends, variability of properties and subjective interpretations.⁹ These models allow the scientists to predict the effects of geologic features on fluid movement throughout the field.¹⁰

In situations in which offset well information is limited, engineers plan drilling programs based on seismic depth imaging and estimated properties to map structures and geologic targets and to identify formation characteristics such as pore pressure gradient, fracture pressure gradient and geomechanical properties. Because data are limited, uncertainties are high and the resulting geologic model is interpretive and not unique; each

	Site Surveys	Hydrographic Surveys	Exploration Seismic Surveys	Pilot Hole Drilling	Stratigraphic Modeling
Description	Standalone seismic measurements acquired over proposed drill location High-frequency focus (high-frequency source, shallow tow and ultrashort offset)	A range of measurements including bathymetry, side-scan sonar, multibeam and seafloor photography	High-resolution reprocessing of exploration seismic measurements	Shallow pilot holes drilled to log near the surface	Interpretation of available seismic reflection measurements
Penetration	Limited (1 to 2 s below seafloor)	Seafloor only	Ultradeep (10 s)	Limited by drilling cost	Measurement dependent
Resolution	Medium (200 to 300 Hz)	High (500 to 1,000 Hz)	Low (100 to 150 Hz)	Not applicable	Equivalent to seismic input
Value	Identifies man-made and geologic seafloor anomalies Identifies shallow faulting Can identify shallow hazards through stratigraphic interpretation	High-resolution measurement of the seafloor	Indirect estimate of rock properties, which identify shallow hazards Wide spatial coverage Time-lapse potential	Direct measurement of rock properties	
Deficiencies	Not suitable for rock physics workflow Limited spatial coverage	Limited penetration below the seafloor Not suitable for rock physics workflow	Limited resolution at the seafloor	Cost	Based on geologic interpretation using pilot hole information for calibration

^ Shallow hazard identification. Numerous methods for identifying shallow hazards exist. Each method has advantages and disadvantages.

5. Dutta NC, Utech RW and Shelander D: "Role of 3D Seismic for Quantitative Shallow Hazard Assessment in Deepwater Sediments," *The Leading Edge* 29, no. 8 (August 2010): 930–942.

6. Eaton LF: "Drilling Through Deepwater Shallow Water Flow Zones at Ursa," paper SPE/IADC 52780, presented at the SPE/IADC Drilling Conference, Amsterdam, March 9–11, 1999.

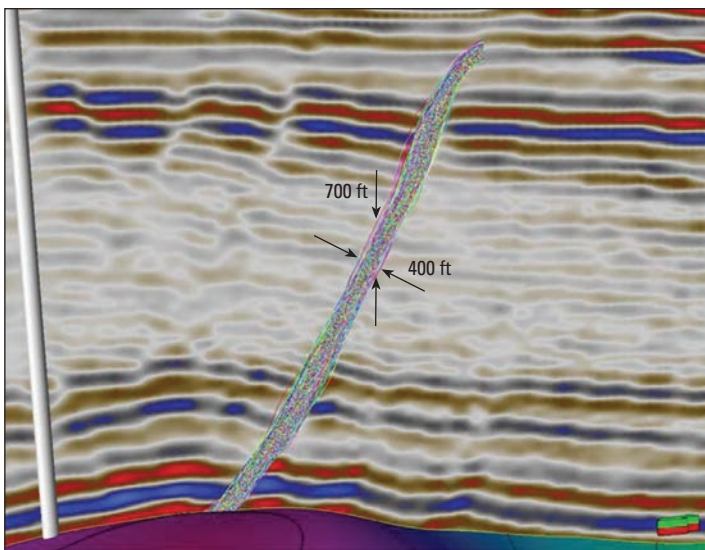
7. Dutta et al, reference 5.

8. For more on the V_p/V_s ratio: Alsos T, Eide A, Astratti D, Pickering S, Benabentos M, Dutta N, Mallick S, Schultz G, den Boer L, Livingstone M, Nickel M, Sønneland L, Schlaf J, Schoepfer P, Sigismondi M, Soldo JC and Strønen LK: "Seismic Applications Throughout the Life of the Reservoir," *Oilfield Review* 14, no. 2 (Summer 2002): 48–65.

9. Ezekwe JN and Filler SL: "Modeling Deepwater Reservoirs," paper SPE 95066, presented at the SPE Annual Technical Conference and Exhibition, Dallas, October 9–12, 2005.

Using geostatistical models, geologists use statistical information to indicate the probable distribution of features throughout a reservoir, although they do not know the precise location of those features.

10. Rossi D, Malinverno A and Carnegie A: "Trends in Geostatistics," *Middle East Well Evaluation Review* 14 (November 1993): 45–53.

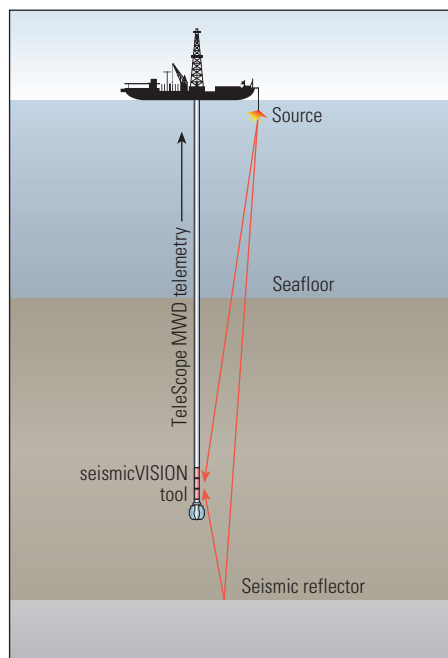
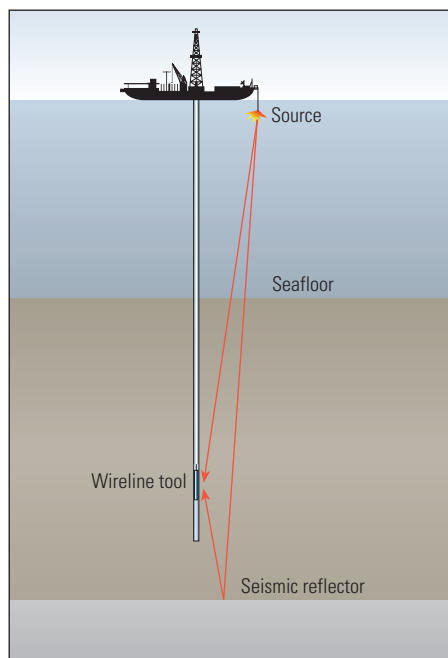


^ Fault location uncertainty. During seismic survey processing, map migration converts time surfaces into depth surfaces. An overlay of 500 map-migrated realizations of a fault reveals that uncertainty across this fault plane is about 400 ft [120 m]. For a vertical well, this translates to more than 700 ft [200 m] of uncertainty in pinpointing where the well should cross the fault. (Adapted from Esmersey et al, reference 11.)

model has multiple options that fit the same surface seismic data (above).¹¹

To steer the well through uncertain intervals, engineers and geophysicists use real-time check-

shot surveys.¹² This technique, which uses mud pulse telemetry and does not disturb drilling operations, allows drillers to take a checkshot, or seismic reference survey, at each connection and



^ Checkshot techniques. Wireline checkshots (left) require the driller to stop drilling and rig up and run a wireline seismic tool. The seismicVISION tool (right) is part of the bottomhole assembly. Data acquisition occurs during pipe connections and thus requires no extra rig time. The seismicVISION waveforms are transmitted uphole from the LWD tool using the TeleScope high-speed telemetry-while-drilling service. (Adapted from Chandrasekhar et al, reference 13.)

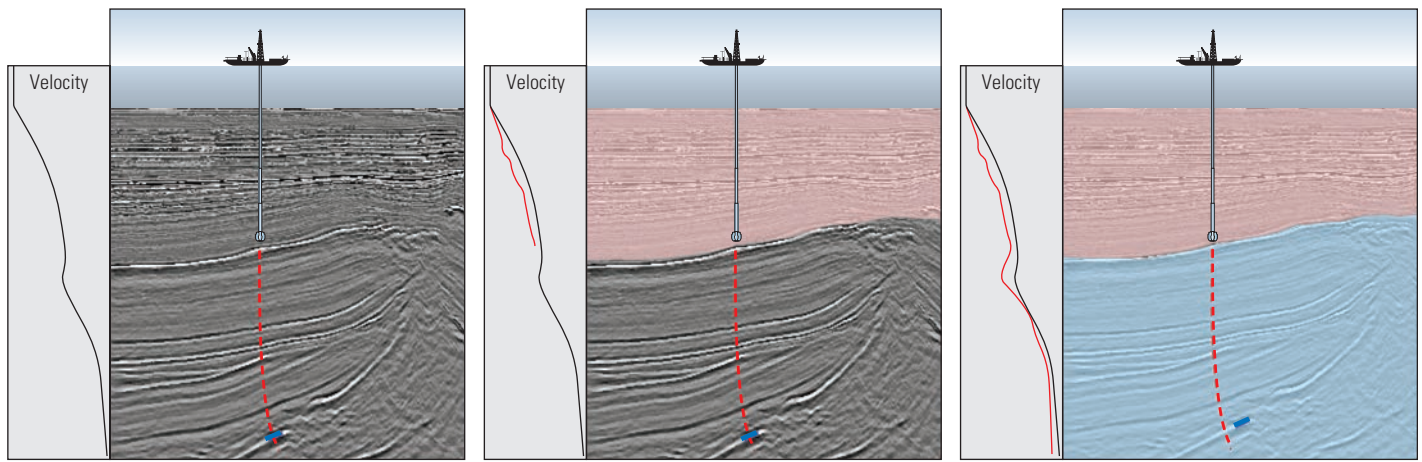
receive the data at the surface in real time (below left). Geophysicists use these data to refine the predrill velocity model, which is then used to update the drilling target depths and the geologic model.¹³ Additionally, real-time seismic-while-drilling (SWD) methods, such as the Schlumberger seismicVISION seismic-while-drilling service, confirm the bit position on the seismic image.

Researchers at Schlumberger have built on the SWD approach by developing a method to integrate while-drilling data and offset and surface seismic data. With these data, teams revise and, if necessary, generate a new 3D model, which includes a new seismic image, and recalculate the pore pressure prediction and fracture gradient, thus reducing uncertainty ahead of the bit.¹⁴ During drilling operations, the Seismic Guided Drilling integration of surface seismic and downhole measurements workflow measures formation velocities down to the bit (next page, top). Typically covering about 100 km² [40 mi²] around a proposed well location, Seismic Guided Drilling studies use a baseline earth model built from seismic imaging, inversion and offset well data. Earth modelers then produce an image of a small volume around the well location, allowing geophysicists to create a velocity model of near-wellbore geology.

Geophysicists then analyze the proposed well using the seismic image and estimated rock properties such as pore pressure, fracture gradient and other geomechanical properties. Drilling engineers design the well and make predrilling decisions on trajectory, casing depth points, casing sizes, mud types and mud weights.

While an interval is being drilled, or immediately thereafter, field personnel measure the properties of the subsurface using LWD and wireline tools as well as mud logging and other drilling data. At a predetermined depth, or if real-time drilling data suggest the presence of significant errors in the starting model, geophysicists perform a Seismic Guided Drilling workflow. They reprocess the surface seismic data near the wellbore and use checkshot-constrained local tomographic inversion to obtain new velocities, perform a full depth migration and develop an updated model ahead of the bit that includes a new velocity profile.

Geoscientists use the well logs to update the local earth model used for pore pressure and fracture pressure prediction. This is then applied to the new velocity model to predict pore pressures ahead of the bit. In this way, the data from the well being drilled are fully incorporated into the newly generated predictive model. In certain



^ The Seismic Guided Drilling method. The predrill seismic image (*left*) based on estimated formation velocity (black curve) includes the well trajectory (red dashed line) and the target (dark blue). Using the Seismic Guided Drilling technique, engineers can measure formation velocities to the depth of the bit (*middle*, red curve) and use these data to update the model in the drilled section of the well (pink shading). The data are then used to rebuild the earth model and the structural image (*right*, blue shading). The rebuilt model may reveal a change in the target location, requiring modifications to the well trajectory.

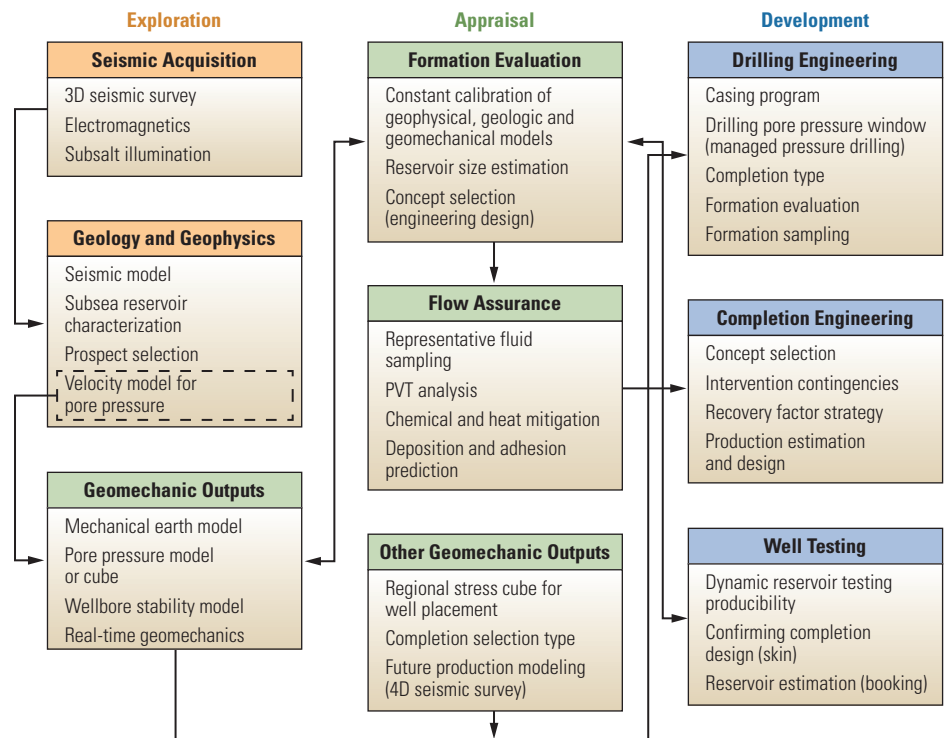
locations or in early stage exploration drilling, this may be the only appropriate well data available. Because the entire workflow is performed in near real time, engineers are able to modify the drilling program and adjust key planning elements such as well trajectory, mud weights, casing designs and target locations.

Getting to TD in Ultradeep Gulf Waters

In practice, many of those in the various E&P disciplines involved in most drilling, completion and production projects have typically performed much of their work in isolation, despite industry claims for the virtues of integration (*right*). However, the Mexican national oil company Petróleos Mexicanos (PEMEX), working in the Gulf of Mexico, is using an integrated workflow to manage some of its exploration projects in deep and ultradeep waters. The technique—visualice, conceptualice, defina, de seguimiento y evalúe, known by its Spanish acronym VCDSE—is defined by the following five stages:

- visualization: identifying options and validating the well project
- conceptualization: analyzing and selecting best options
- definition: performing detailed engineering
- follow-up: performing well construction
- evaluation: documenting and evaluating lessons learned during execution of the well.

Throughout the process, a project leader coordinates the disciplines within the exploration VCDSE team, operational teams and service companies. Disciplines include geophysics; geology; petrophysics; geomechanics; and reservoir, drilling, completion and risk-assessment engineering.

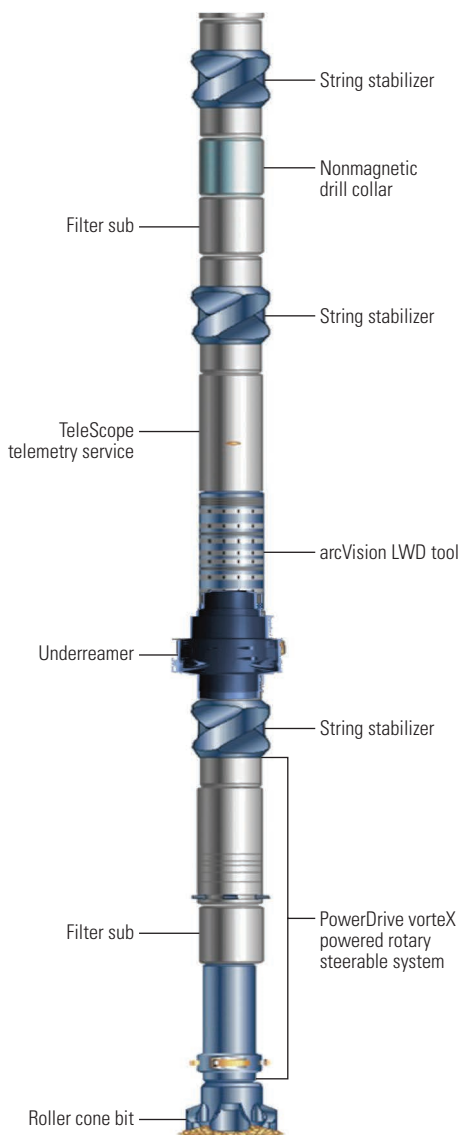


^ Interdependencies in deepwater operations. In deepwater projects, exploration, appraisal and developments are directly dependent on each other. Within each of these broad categories, the disciplines are also interdependent and across categories; all disciplines are at least indirectly dependent on each other.

- Esmeroy C, Ramirez A, Hannan A, Lu L, Teebenny S, Yang Y, Sayers CM, Parekh C, Woodward M, Osypov K, Yang S, Liu Y, Shih C, Hawthorn A, Cunnell C, Shady E, Zarkhidze A, Shabrawi A and Nessim M: "Guiding Drilling by Look Ahead Using Seismic and LWD Data," paper SPE 164786, presented at the North Africa Technical Conference and Exhibition, Cairo, April 15–17, 2013.
- A checkshot is a type of borehole seismic survey designed to measure the signal traveltime from the surface to a known depth.
- Chandrasekhar S, Dotiwala F, Kim TK, Khaitan ML and Kumar R: "Reducing Target Uncertainties and Guiding Drilling Using Seismic While Drilling Technology, A Novel Approach in Andaman Sea Deepwater," paper SPE 165834, presented at the SPE Asia Pacific Oil and Gas Conference and Exhibition, Jakarta, October 22–24, 2013.
- Peng C, Dai J and Yang S: "Seismic Guided Drilling: Near Real Time 3D Updating of Subsurface Images and Pore Pressure Model," paper IPTC 16575, presented at the International Petroleum Technology Conference, Beijing, March 26–28, 2013.

These teams are supported by specialists and international service companies.¹⁵

PEMEX and Schlumberger engineers identified options and validated a well design for three ultra-deep wells—Supremus-1, Maximino-1 and Trion-1—in the Perdido fold belt in the North



^ Keeping the hole vertical. For a well drilled in the Perdido fold belt offshore Mexico, engineers used a BHA that included an underreamer positioned above a PowerDrive vortex drilling motor. They first drilled a 26-in. pilot hole section to accommodate arcVision LWD logging tools, which acquired real-time resistivity, gamma ray, inclination and annular pressure-while-drilling measurements. The underreamer was then opened and they enlarged the hole diameter to 33 in. Throughout the drilling interval, they were able to maintain a vertical well trajectory of less than 1° inclination as required for the casing program.

Tamaulipas region of the Gulf of Mexico. The team employed a methodology called No Drilling Surprises (NDS) to integrate the project design and execution.¹⁶ The NDS workflow incorporates information from the design stage to define steps for identifying and mitigating potential drilling risks and includes contingency measures produced with the DrillMAP drilling engineering management and operations plan software.

Though these three wells were the first drilled in the ultra-deep waters of the Mexican side of the Perdido fold belt, PEMEX has been drilling in nearby deep water since 2004. Based on analysis of data from those early wells and wellbore stability forecasts, the DrillMAP software generated a visual drilling tool that displayed the well design, including casing sizes and depths, drilling mud weight windows and locations of potential drilling hazards. The DrillMAP software also provided engineers with the risks per hole section, severity index, the method used to detect the risk and the mitigation plan developed during the predrill phase by the project team.

While the three ultra-deepwater wells were being drilled, Schlumberger and PEMEX engineers monitored progress using the geomechanics real-time monitoring service and continuous comparison against the DrillMAP plan. At a drilling visualization center in Poza Rica de Hidalgo, Veracruz, Mexico, petrophysicists, geomechanics engineers and drilling optimization engineers monitored and analyzed LWD data from the rig. The multidisciplinary team used validated and updated predrill geologic, geomechanical and pore pressure models, which helped reduce uncertainty in the next drilling interval.¹⁷

After the Supremus-1 well was drilled, engineers reviewed how the surface conductor was jetted into place and were able to optimize ROP to ensure the casing reached the desired depth. In addition, because drillers had experienced difficulty maintaining a vertical hole while drilling the surface section of the CAZA-1 deepwater well using a straight bend housing and conventional drilling motor, the planning team redesigned the bottomhole assembly (BHA). The new assembly included a PowerDrive vortex powered rotary steerable system, 26-in. roller cone bit and hole opener to enlarge the hole to 33 in. (left).¹⁸

In the shallow sections of the well, drillers had to employ a unique directional well trajectory to avoid shallow hazards and to intersect shallow reservoir targets. The team also drilled a 12¼-in. hole to be able to successfully acquire

wireline logs, sidewall cores and modular pressure and fluid sampling data. The BHA design allowed engineers to drill the 12¼-in. pilot hole and deploy LWD tools and hole openers on the same run.

Engineers chose to acquire rock property and petrophysical data via LWD measurements to allow preliminary assessment of the potential reservoir and updating of the geomechanical model. If no zone of interest was encountered, the 12¼-in. hole section was drilled and logged to total depth at the same time the underreamer enlarged the hole and thus saved time on a subsequent hole opener run.

If the zone proved of interest, engineers could drill the 12¼-in. hole through the reservoir and collect LWD data before reconfiguring the BHA without the reamer to drill the pilot hole to total depth. The 12¼-in. hole size allowed engineers to run a full suite of wireline logs to acquire the essential data for rock and fluid reservoir characterization. This strategy resulted in a successful operation and good hole quality and met drilling design objectives while reducing drilling risks.¹⁹

To accurately compute reserves for the Perdido area, PEMEX engineers designed and ran a drillstem test (DST) on the Maximino-1 well. The DST set a world record for the water depth at which such a test was performed. The team used lessons learned and formation evaluation data acquired in the drilling of three previous area wells, the Trion-1, the Supremus-1 and the PEP-1, to design the DST and define its objectives.

15. Vallejo VG, Olivares A, Saavedra O, Lopez JR and Torres ME: "Drilling Evolution of the Ultra Deepwater Drilling Campaign in Mexico, Perdido Fold Belt," paper OTC 25030, presented at the Offshore Technology Conference Asia, Kuala Lumpur, March 25–28, 2014.

16. For more on the No Drilling Surprises process: Bratton T, Edwards S, Fuller J, Murphy L, Goraya S, Harrold T, Holt J, Lechner J, Nicholson H, Standiford W and Wright B: "Avoiding Drilling Problems," *Oilfield Review* 13, no. 2 (Summer 2001): 32–51.

17. Vallejo et al, reference 15.

18. For more on rotary steerable drilling: Copercini P, Soliman F, El Gamal M, Longstreet W, Rodd J, Sarssam M, McCourt I, Persad B and Williams M: "Powering Up to Drill Down," *Oilfield Review* 16, no. 4 (Winter 2004): 4–9.

Downton G, Hendricks A, Klausen TS and Pafitis D: "New Directions in Rotary Steerable Drilling," *Oilfield Review* 12, no. 1 (Spring 2000): 18–29.

19. Vallejo et al, reference 15.

20. For more on the extension of the Jubilee play across the southern Atlantic: Bryant I, Herbst N, Dailly P, Dribus JR, Feinstein R, Harvey N, McCoss A, Montaron B, Quirk D and Tapponnier P: "Basin to Basin: Plate Tectonics in Exploration," *Oilfield Review* 24, no. 3 (Autumn 2012): 38–57.



^ Sand control option. To prevent sand flowing into the wellbore while creating sufficient drawdown to conduct well tests of the PEMEX ultradeepwater Maximino-1 well, the operator chose to use standalone MeshRite screens and to deploy them at twice the length of the interval to be evaluated. This added screen length reduced the pressure drop across the screen area; this flow area distribution allowed the system to avoid excessive flow at any specific point. The presence of such points creates hot spots. The screen's filter is formed by wrapping layers of compressed stainless steel wool onto perforated base pipe and then covering it with a perforated outer shroud. That configuration creates a 40% open flow area and more than 3,000-D air permeability.

To avert sand production, the well test planners needed to optimize drawdown pressure. They used a sand management study performed by Schlumberger geomechanics specialists. Based on the outcome of that study, the team chose MeshRite standalone screens (above). To address problems that might arise when flowing formation fluids to the surface through a long riser bathed in a column of seawater, a flow assurance study was conducted to predict and mitigate potential hydrate formation. Data collected from a drillstem test were a priority for the recognition of reserves and production potential but also important to all geomechanical engineers, reservoir engineers, wireline and testing personnel and PEMEX engineers.

The completions team and well testing team designed the downhole string and the operations group coordinated between the two teams. The successful DST provided PEMEX with sufficient data to book the reserves. Encouraged by the success of these cross-discipline operations in highly challenging circumstances, PEMEX is now appraising the remainder of its Perdido fold belt assets.

The Ultradeep Ahead: Remote, Challenging and Integrated

The risks, complexities and costs of working in water depths greater than 1,500 m demand coordinated efforts and seamless communication between the various technical disciplines that identify prospects and design and drill wells to confirm hydrocarbon accumulations. In addition to the need to quantify the uncertainties associated with shallow geohazards, seismic survey data and geology for each step of the operation from drilling to production, operators exploring in ultradeep water are further challenged by the remote nature of these areas. Materiel and personnel cannot be delivered quickly to rigs hundreds of kilometers from shore; therefore, to ensure both technical and economic success, operations must not be delayed by miscommunication.

When Tullow Oil plc proposed drilling a wildcat well 150 km [93 mi] from the coast of French Guiana, it was an oilfield frontier in every sense; because the country had no established oil industry presence, the support base was located in the Republic of Trinidad and Tobago with some support from Suriname. The operator was exploring in a remote area with water depths of

2,048 m [6,719 ft] to determine if its giant Jubilee play off the coast of West Africa could be traced across the Atlantic to the east coast of South America.²⁰

The project was further complicated by the fact that there were no offset well data and no established supply chain, and the team would be using an untested, newly built rig. After finalizing a conceptual well design, the company chose the Schlumberger business and operation model, Integrated Services (IS), which included a dedicated Integrated Services Project Manager (ISPM). Integrated services included directional drilling, MWD and LWD, wireline logging, mud logging, drill bits, drilling mud and completion services. The IS project leveraged the Schlumberger global presence to obtain the necessary personnel and equipment and the import, transport and storage permits for oilfield supplies.

The ISPM worked in the Tullow operational office as a direct support to the Tullow drilling superintendent and worked closely with the Ensco plc rig manager in Cayenne, French Guiana. The ISPM coordinated the prejob planning, risk management processes and equipment and personnel delivery schedules. The Project Readiness Assessment process, which consisted of a personnel and equipment plan and a risk assessment register to identify problems or challenges requiring remedial action, reduced the likelihood of unplanned events and associated NPT. Experts in an operations support center shared real-time data with the team on location and with the Tullow staff via the Internet. During specific challenges, the center staff included relevant bit, drilling, BHA and fluids experts. The project reached the operator's targeted depth and encountered 72 m [236 ft] of net oil pay in two turbiditic sandstone fans, proving that the Jubilee play analog from across the Atlantic was appropriate.

Many ultradeepwater projects, like that carried out by Tullow Oil in French Guiana are in remote frontiers and typically marked by few offset data and difficult logistics. These two factors exacerbate the complexity and potential risk of already complex undertakings. To manage them, operators and service companies have little choice but to embrace cross-discipline teams and strive for seamless communication. —RvF