

Stabilizing the Wellbore to Prevent Lost Circulation

Lost circulation—the loss of whole drilling mud to the formation—raises significant costs and risks to drillers around the world and threatens to pose greater challenges in the future. The industry is meeting this threat with diverse wellbore strengthening materials that work by different mechanisms but share a common goal: to stop fracture growth and keep drilling mud in the wellbore.

John Cook
Cambridge, England

Fred Growcock
Occidental Oil and Gas Corporation
Houston, Texas, USA

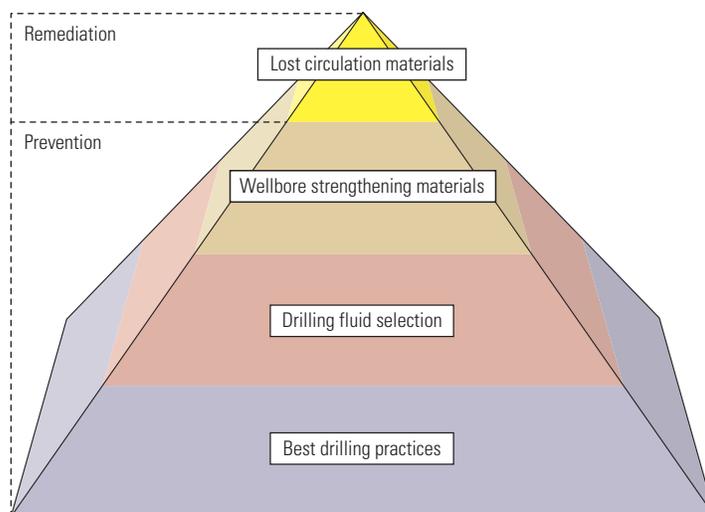
Quan Guo
Houston, Texas

Mike Hodder
M-I SWACO
Aberdeen, Scotland

Eric van Oort
Shell Upstream Americas
Houston, Texas

Over the past century, the oil and gas industry has made great strides in developing drilling technologies and techniques that make well construction a cost-effective and safe enterprise. However, as new hydrocarbon sources are found in increas-

ingly remote and geologically complex reservoirs, the industry continues to develop technologies to meet wellbore integrity challenges that present safety hazards and economic risks to the long-term viability of a well.



^ Comprehensive lost circulation management program. The bottom three tiers of the pyramid focus on lost circulation prevention. Best drilling practices may encompass implementing accurate geomechanical models to calculate the risk of hole collapse or lost circulation and may also make use of expandable casing, managed pressure drilling or casing-while-drilling techniques. Drilling fluid selection includes the implementation of drilling fluid with the proper rheological properties to minimize or cure lost circulation. Wellbore strengthening materials consist of specially formulated and sized particulate materials that enter a fracture and arrest its propagation by isolating it from the wellbore. The top tier is devoted to remediating losses through the use of lost circulation materials such as cure or stop-loss pills.

Oilfield Review Winter 2011/2012: 23, no. 4.
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For help in preparation of this article, thanks to Raul Bermudez, Clamart, France; Jim Friedheim, Houston; Guido Leoni, Ravenna, Italy; and Mark Sanders, Aberdeen.

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1. Dodson T: "Identifying NPT Risk," Keynote presentation at the Atlantic Communications Drilling and Completing Trouble Zones Forum, Galveston, Texas, USA, October 20, 2010.
2. Redden J: "Advanced Fluid Systems Aim to Stabilize Well Bores, Minimize Nonproductive Time," *The American Oil & Gas Reporter* 52, no. 8 (August 2009): 58–65.
3. Growcock F: "Lost Circulation Solutions for Permeable and Fractured Formations," *Proceedings*, Southwestern Petroleum Short Course 54 (2007): 175–181.
4. ECD is a function of the hydrostatic head generated by the mud density and the frictional pressure losses that the mud pump must overcome to move fluid and cuttings up the wellbore.

In the Gulf of Mexico alone, wellbore integrity issues in the form of stuck pipe, wellbore collapse, sloughing shales and lost circulation account for as much as 44% of nonproductive time (NPT) that prevents progress of the drill bit toward its target.¹ The financial ramifications of wellbore integrity-related NPT are so great that operators may add 10% to 20% to authorizations for expenditures to cover the anticipated downtime.²

Lost circulation, in which drilling fluid, or mud, flows partially or completely into a formation through areas known as thief zones, is a common contributor to NPT (right). These zones effectively steal drilling fluid from the wellbore. Although the fluid has several purposes, those most affected by lost circulation are the needs to maintain hydrostatic pressure in the annulus and prevent formation fluids from entering the borehole during the drilling process.

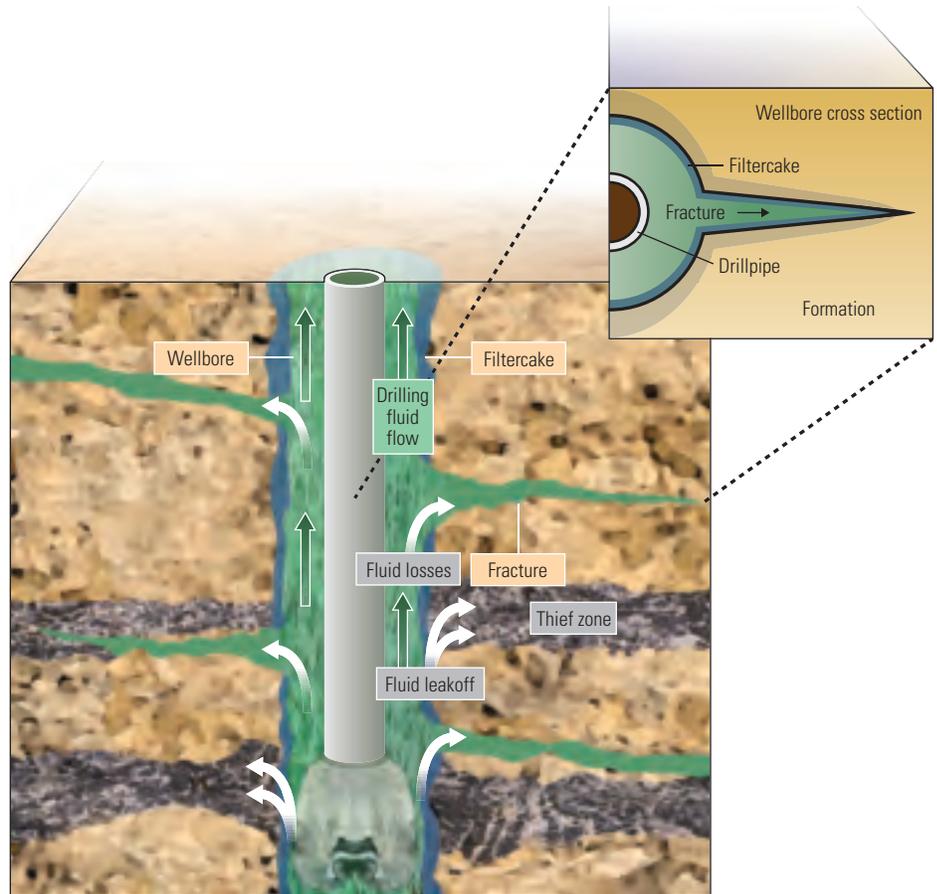
To counter this phenomenon, a comprehensive lost circulation management program provides a staged approach to mitigating fluid losses, depending on the severity of the problem. One such approach is a four-tiered strategy consisting of both prevention and remediation measures (previous page). Industry experience has proved that it is often easier and more effective to prevent the occurrence of losses than to attempt to stop or reduce them once they have started.

Fluid losses occur typically through fractures induced by the drilling process. These fractures tend to propagate easily because the pressure required to lengthen a fracture is often lower than that required to initiate it.³ Therefore, remediation is commonly considered a contingency to be used only after preventive measures have failed.

This article reviews the drilling conditions that contribute to lost circulation events and explains why lost circulation threatens to become a greater contributor to NPT than it has been in the past. The article also discusses lost circulation prevention through the use of wellbore strengthening materials and describes various schools of thought within the industry on mechanisms for stabilizing the wellbore and preventing fracture propagation.

Lost Circulation Fundamentals

Lost circulation events arise most commonly as a consequence of the method used to drill a well. Traditionally, wells are drilled in an overbalanced condition in which drilling fluid, or mud, is circulated down the drillstring, through the bit and up the annulus.



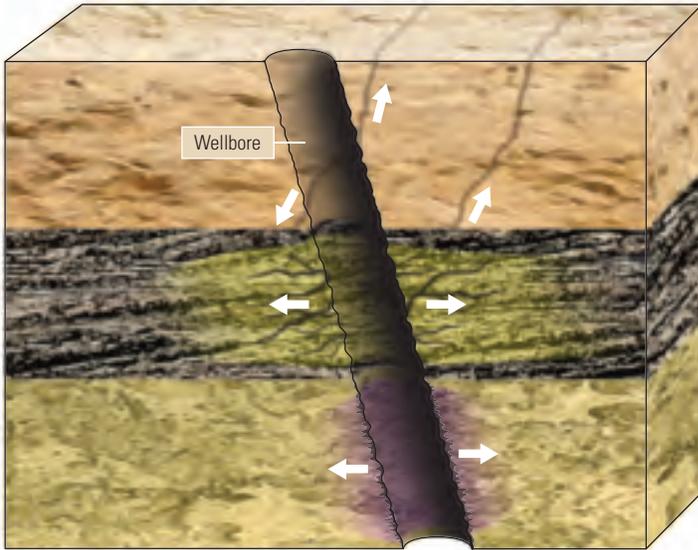
^ Mechanisms for drilling fluid egress from the wellbore. During circulation of drilling mud back to the surface (green arrows), the fluid comes into contact with the wellbore. In traditional drilling practices, the pressure in the wellbore exceeds that of the formation, which prevents formation fluids from entering the wellbore. In one method of fluid loss from the wellbore, a filtration process takes place in the permeable rock, whereby the liquid component of the drilling mud moves into the rock, leaving the solid particulates and emulsion droplets to collect on the wellbore wall and form a filtercake. The low permeability of this cake keeps the volume of fluid lost by leakoff very low, and this is not considered a lost circulation event. Lost circulation occurs if the rock is naturally fractured, vugular or highly porous. If the wellbore pressure is higher than the rock's tensile strength, fractures will form. Each of these cases results in the loss of large volumes of drilling fluid (white arrows) into thief zones. In severe cases, an appreciable quantity, or even all, of the drilling fluid enters the formation, propagating further fracture growth (inset).

Mud weight, or density, is the primary source of hydrostatic pressure in a well. When circulating through the wellbore, the mud contributes to a pressure in the wellbore that can be expressed in terms of the equivalent circulating density (ECD).⁴ In an overbalanced state, this ECD helps create a hydrostatic pressure in the wellbore that is greater than the pore pressure of the exposed formation. A drilling fluid of insufficient density may yield a hydrostatic pressure that is lower than the pore pressure. This may lead to a kick: an unplanned influx of formation fluids into the wellbore. Most kicks are managed using established well kill operations, but in rare instances an uncontrolled kick may manifest itself in the form of a blowout, with associated

risks to wellhead equipment and potential injury to rig personnel.

Other obstacles to the safety and economic viability of the well may arise if the hydrostatic pressure is too low to support the rock face at the wellbore. Drilling mud must be heavy enough to counter the instability in the borehole that is created when rock is removed through the drilling process. If the driller selects a drilling mud of insufficient density, the result may be wellbore instability and, in extreme cases, wellbore collapse.

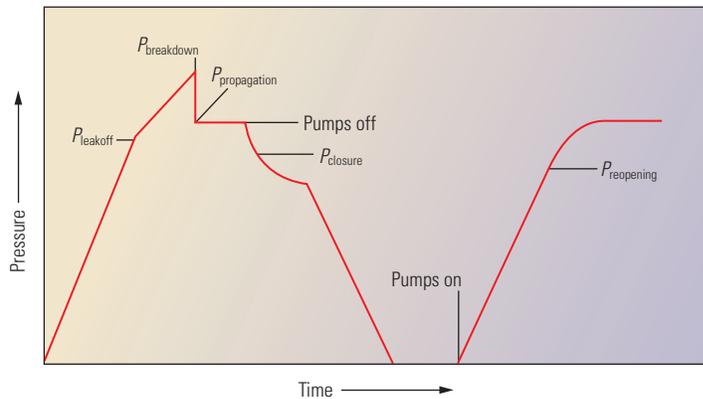
Conversely, a drilling fluid with an excessively high mud weight exerts a hydrostatic pressure that may exceed the formation's mechanical



^ Types of lost circulation events. The upper formation experiences loss of drilling mud (white arrows) into natural fractures that were intersected by the wellbore. The middle formation exhibits the propagation of a fracture that was hydraulically induced by the drilling process. The lower formation highlights losses caused by seepage.

integrity, forcing drilling fluid into natural fractures (above). Naturally occurring fractures may be present in any type of formation, but they occur most commonly in geologic settings with ongoing tectonic activity.

Lost circulation management can also be quite challenging when fractures are induced during the drilling process.⁵ Fracture creation results from tensile failure, which occurs when the stress exerted on the formation exceeds the



^ Pressure thresholds. During the initial stages of an extended leakoff test (XLOT), pressure increases linearly with the volume of fluid pumped. As more fluid is pumped into the wellbore, the pressure increase eventually departs from linearity at the leakoff pressure ($P_{leakoff}$) point, which also leads to initiation of a fracture. The fracture propagates until the formation breakdown pressure ($P_{breakdown}$) is reached. The pressure curve falls off quickly at this point, and fractures propagate in a more controlled fashion at a lower and somewhat steady pressure called the fracture propagation pressure ($P_{propagation}$). If pumping is stopped, pressure in the fracture will bleed off to the formation, which lowers pressure in the fracture and causes the fracture to close at the fracture closure pressure ($P_{closure}$). When pumping resumes, pressure builds again and the fracture can reopen at the reopening pressure, ($P_{reopening}$), which is similar to $P_{closure}$. The fracture will then resume propagating at a pressure similar to $P_{propagation}$. An XLOT curve may not exhibit this shape or possess a peak or plateau. The shape is driven by a host of factors, including in situ stresses in the rock, pore pressure, inherent rock strength and wellbore orientation.

hoop stress around the wellbore and the tensile strength of the rock, most commonly because of excessive mud density or wellbore pressure.⁶

Typically, a pressure-integrity or extended leakoff test (XLOT) measures the ability of the formation and wellbore to sustain pressure. Engineers conduct the test after a new casing string has been run and cemented, immediately after drilling out beneath the casing shoe. To initiate the test, the rig crew shuts in the well and pumps fluid into the wellbore to gradually increase the pressure exerted on the formation (below left).

The driller must stay within a pressure regime that avoids a kick or a lost circulation event; an XLOT can provide insight into that pressure regime. The upper limit on ECD is typically represented by the fracture gradient (FG), the pressure in the well that would cause the surrounding formation to fracture, creating potential loss of fluid from the well. FG is not defined precisely; some drillers identify FG as the pressure at which a fracture is initiated ($P_{leakoff}$), others may select the more conservative value of the fracture closure pressure ($P_{closure}$), and some select a pressure for FG between these two parameters.

The lower limit on ECD is normally determined by either the pore pressure (P_{pore}) or the wellbore collapse pressure ($P_{collapse}$), below which the flow of formation fluids into the wellbore causes such severe mechanical instability problems that operations must be modified or halted. The range between the upper and lower limits is the mud weight window or drilling margin. These upper and lower limits are influenced by in situ rock stress orientations and magnitudes, pore pressure, rock strength and wellbore orientation. These parameters vary with wellbore depth and act to significantly change the size of the mud weight window (next page, left).

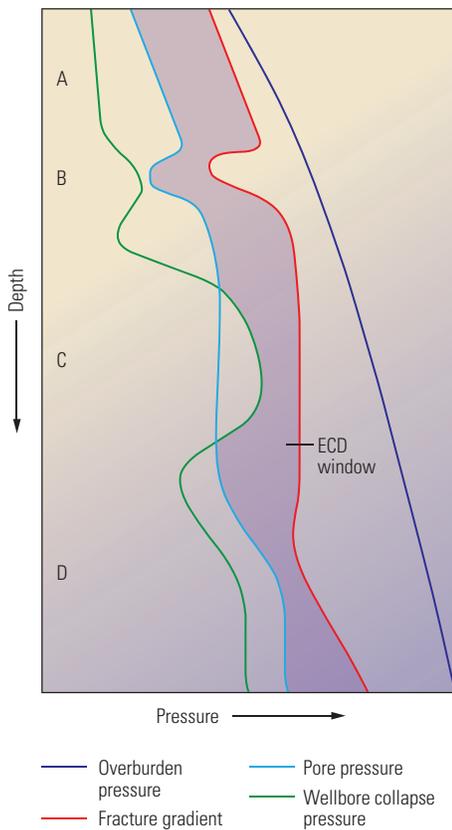
To avoid lost circulation or wellbore instability events, drillers pay close attention to maintaining the ECD within the confines of the mud weight window. Failure to do so causes the wellbore's physical stability to change along a continuum of possible profiles, ranging from formation fluid influx to severe or total drilling fluid losses and even wellbore collapse (next page, right).

Whether lost circulation occurs while drilling, running casing, or completing and cementing the well, its impact on well construction costs is significant, representing an estimated US\$ 2 to 4 billion annually in lost time, lost drilling fluid and materials used to stem the losses. The US Department of Energy reports that on average 10% to 20% of the cost of drilling high-pressure, high-temperature wells is expended on mud losses.⁷

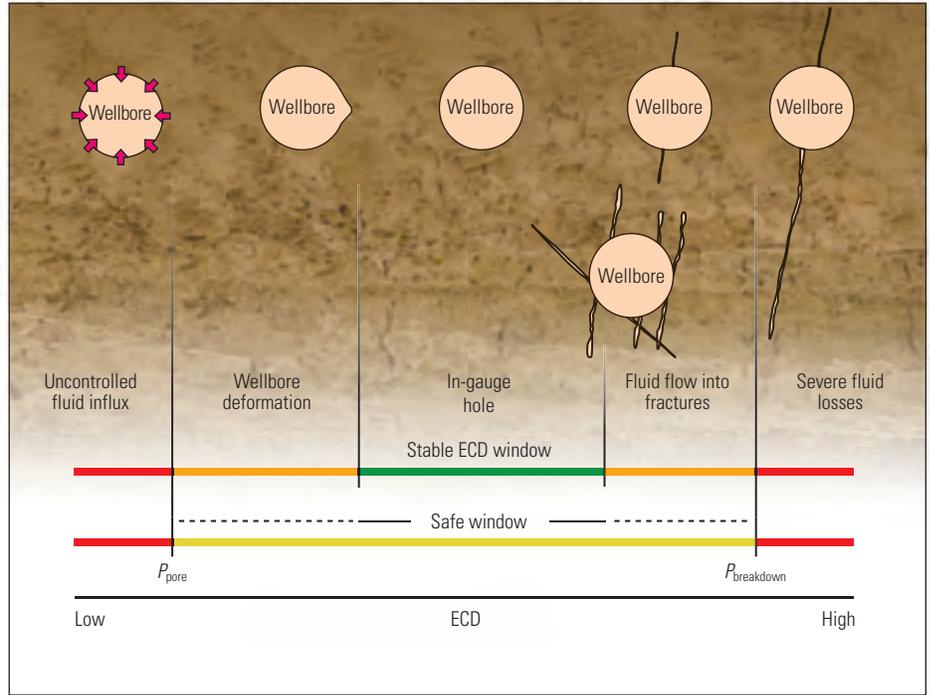
Circulation Risks in Complex Reservoirs

Worldwide, the portion of NPT attributable to lost circulation is increasing as drillers pursue more complex and technically challenging prospects than have been attempted in the past. For example, to reach isolated reservoirs located at a significant horizontal distance from the surface well pad, operators are increasingly implementing extended-reach drilling (ERD) techniques.⁸ These wells present unique fluid management challenges because drilling margins change dramatically, depending on location in the wellbore.

In the vertical section of the wellbore, while the section is being drilled to the next casing shoe, the mud weight may safely reside in a wide envelope with no danger of wellbore instability,



Pressure gradient regimes in a wellbore. In Interval A, the ECD window, or mud weight window (purple shading) is bordered by the pore pressure (blue) and the fracture gradient (FG) (red). In a depleted interval (B), in which production from the interval leads to a reduction in pore pressure, the mud weight window narrows and both pore pressure and FG shift to lower pressures. In an interval with a mechanically weak formation (C), the lower limit of the mud weight window is defined by wellbore collapse pressure (green) and not pore pressure. In Interval D, pore pressure is high and FG is low, resulting in a very narrow mud weight window, which would present a challenge to controlling the ECD.

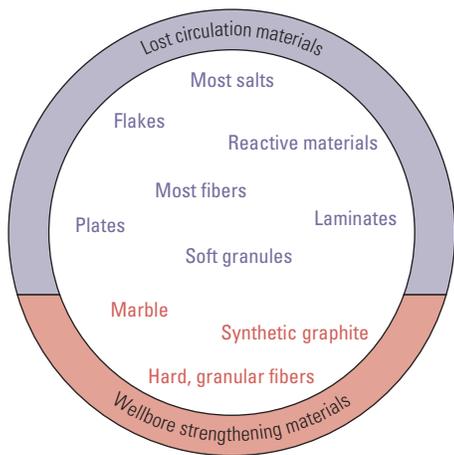


Wellbore profiles as functions of mud weight. If the drilling mud weight, or ECD, is closely monitored and maintained within the wellbore's stable ECD window (green line), an in-gauge hole is ensured, with no fluids entering or exiting the wellbore (top center). If the ECD drops below this stable window, the wellbore enters an instability regime, in which reservoir fluid begins to exert pressure on the hole to begin hole deformation (top, second from left). The ECD continues to drop and reaches the pore pressure (P_{pore}). Below this pressure, the formation fluid (red arrows, top left) enters the wellbore unabated and may cause wellbore collapse and the uncontrolled release of production fluids to surface via the wellbore. The other end of the ECD continuum (orange line, right) begins with a mud weight that is too high, which causes the drilling mud to induce fracture formation or enter existing fractures (top, second from right). If the ECD is too high, the formation breakdown pressure ($P_{breakdown}$) is reached; above this pressure, severe fluid losses occur (top right).

formation fluid ingress to the wellbore or drilling fluid egress to the formation. However, as the well becomes more inclined, the minimum required ECD increases because friction losses increase. In addition, the influence of drilling parameters on ECD may increase because of the great length of the ERD well. These factors can decrease the drilling margin significantly—in some cases to as low as 60 kg/m^3 [0.5 lbm/galUS] or less—which elevates the risk of lost circulation. This is especially true in ERD wells drilled into unconsolidated formations with relatively low FGs.

Deepwater drilling in the Gulf of Mexico and offshore Brazil and West Africa has introduced lost circulation challenges beyond narrow drilling margins. These challenges include high ECDs and drilling fluid that is cooled by the near-freezing seawater surrounding the drilling riser. Additionally, the cost of lost circulation and NPT is exacerbated by the use of synthetic-base muds (SBMs) that range from US\$ 100 to US\$ 200 per barrel and by high rig time costs.⁹

- M-I SWACO Technical Service Group: "Chapter 1: Fundamentals of Lost Circulation," Houston: M-I SWACO, *Prevention and Control of Lost Circulation* (March 17, 2011): 1-7.
- Hoop stress refers to the stress acting circumferentially around a wellbore, which is generated as a result of removing the rock volume when the wellbore is created. For more information: Fjaer E, Holt RM, Horsrud P, Raaen AM and Risnes R: *Petroleum Related Rock Mechanics*, 2nd ed. Amsterdam: Elsevier (2008): 139-140.
- Growcock F: "How to Stabilize and Strengthen the Wellbore During Drilling Operations," SPE Distinguished Lecturer Program (2009/2010), <http://www.spe.org/dl/docs/2010/FredGrowcock.pdf> (accessed September 21, 2011).
- For more on extended-reach wells: Bennetzen B, Fuller J, Isevcan E, Krepp T, Meehan R, Mohammed N, Poupeau J-F and Sonowal K: "Extended-Reach Wells," *Oilfield Review* 22, no. 3 (Autumn 2010): 4-15.
- Synthetic-base muds are nonaqueous, water-internal emulsion drilling fluids in which the external phase is a synthetic fluid rather than oil.



^ Lost circulation materials. While wellbore strengthening materials (WSMs) are considered a preventive measure for lost circulation challenges, they may be categorized as a specialized subset of lost circulation materials (LCMs). Most LCMs are added to the drilling fluid once a lost circulation event has begun.

The risks of lost circulation events are even greater for deepwater fields that experience depletion-related stress changes, which increase the risk of fault activation and leads to the creation of new lost circulation zones. ERD wells of more than 10-km [6.2-mi] total depth also present challenges for managing ECD.¹⁰

Lost circulation challenges arise when drillers target depleted zones within maturing fields. Production from these fields leads to reduced pore pressure in some of the formation layers, which in turn leads to a reduced FG and a requirement for reduced mud densities. Where overlying and interbedded shales are also present, a high mud density is required to prevent wellbore collapse and possible fluid influx. In such scenarios, the depleted layers must be drilled with a high overbalance, and drillers must take measures to prevent lost circulation. While overbalances as high as 90 MPa [13,000 psi] have been recorded in some Gulf of Mexico formations, more typical values are in the range of 20 to 30 MPa [2,900 to 4,300 psi], such as those observed in the North Sea.¹¹

Framing the Challenge

The industry has developed a range of technologies and services designed to prevent or mitigate lost circulation. Selecting the proper solution typically begins with classifying the rate or magnitude of fluid loss. These fall into three categories: seepage, partial fluid losses and severe losses.

The least severe loss, seepage, takes the form of whole mud loss at a rate lower than 1.6 m³/h [10 bbl/h]. Typically these losses arise from flow of fluid into formation pores and not fractures. Seepage losses are usually associated with loss of whole mud into the pore network system in which filtercake has not yet developed.¹² The seepage rate is strictly a function of the overbalance and the permeability of the rock.

To accurately track seepage losses, engineers must account for other volume changes to the drilling mud. These include removal of cuttings—rock pieces dislodged by the drill bit as it cuts rock to form the wellbore—and evaporation of the fluid portion of the drilling mud at the surface. Engineers must accurately determine the drop in drilling mud volume, which is caused by the removal of cuttings and any residual mud on them. Evaporation of the water phase of a water-base mud was a greater problem in the past, when open mud pits—large holes dug into the ground to hold drilling fluid—were used. Environmental concerns have prompted the industry to exchange these pits for closed steel vessels that hold from 160 to 320 m³ [1,000 to 2,000 bbl] of drilling mud.

Drillers verify seepage losses by pulling the drill bit off-bottom, turning off all mixing and nonessential solids removal equipment and then checking mud volumes with and without circulation. Once it is established that a volume of drilling mud is being lost due to seepage, the operator must decide whether to cure the losses or drill ahead. This decision often depends on the costs of drilling fluid and rig time, the narrowness of the drilling margin and the likelihood of NPT resulting from events such as formation damage or stuck pipe.¹³

Partial fluid losses—1.6 to 16 m³/h [10 to 100 bbl/h]—represent the next rung of the lost circulation ladder. Drillers face the same decisions for partial losses as they do for seepage losses, but because greater volumes of drilling fluid are lost, the driller more carefully considers remedial measures. The cost of the drilling fluid plays an important role: If the fluid is relatively inexpensive and the mud weight can be reasonably managed within the drilling margin, drilling ahead without remediation may be considered. The point at which the cost of lost drilling fluids becomes too high to ignore varies from well to well and operator to operator.

When drilling fluids enter the formation through fractures, vugs or caverns at a rate greater than 16 m³/h, the losses are classified as severe. These include total losses, in which no volume of drilling fluid makes the return trip to the surface. The consequences of such events may include well control events and dry drilling events, in which continued drilling after a total loss leads to damage to the drill bit, drillstring or wellbore.

Wellbore Strengthening

Fluids experts have developed a variety of methods to enhance the integrity of the wellbore and prevent lost circulation. Collectively, these practices are called wellbore strengthening methods, and include strategies that both alter stresses around the wellbore and minimize fluid losses. Operators employ a number of techniques to prevent lost circulation by physical or mechanical means, which are theorized to work in fundamentally different ways:

- Fracture propagation resistance isolates the tip of the existing fractures and mechanically increases the fracture reopening pressure, which increases the resistance to fracture propagation.¹⁴
- Hoop stress enhancement mechanically increases the near-wellbore stresses and the $P_{leakoff}$ or, more likely, the $P_{breakdown}$.¹⁵
- The fracture closure stress technique fills and enlarges fractures while isolating the fracture tip and increasing near-wellbore stresses.¹⁶
- Wellbore isolation physically isolates the formation from the wellbore pressure.¹⁷

While there is no industrywide consensus for which underlying technique is at work, there is agreement that wellbore strengthening is a real phenomenon. The overall effects of these mechanisms is to elevate the pressure at which uncontrolled losses occur and thereby widen the drilling margin. The borehole is then able to withstand greater pressures and, as measurement data illustrate, appears stronger, although no actual change in rock strength has occurred. For this reason, some have proposed calling the phenomenon wellbore stabilization or drilling margin extension, but the historical precedent and industry's long-standing use of the term wellbore strengthening contribute to its continued widespread use.¹⁸

These theoretical wellbore strengthening mechanisms share a common component: specifically sized and specially designed particulates, which are added to the drilling fluid. Any

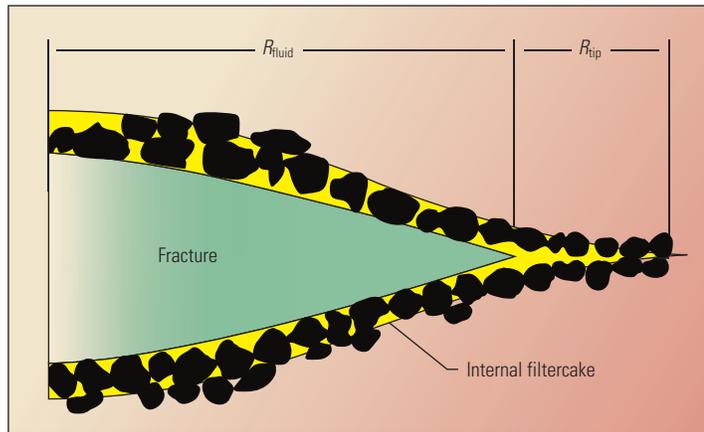
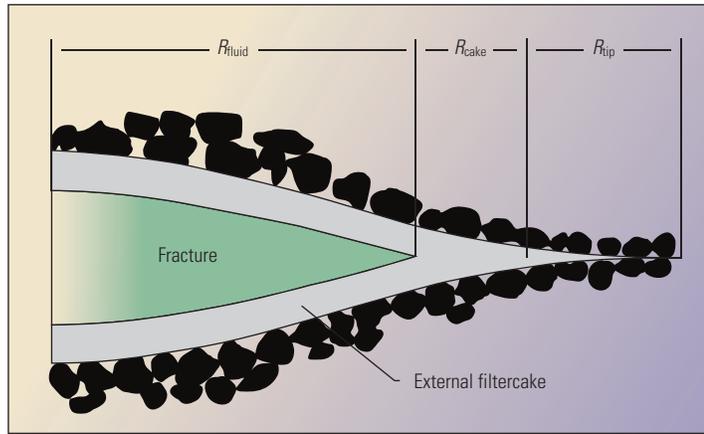
particulate material that acts to stop or slow mud loss is called a lost circulation material (LCM), and may include soft granules, insoluble salts, flakes or fibers (previous page). Most of these may prove useful to mitigate, or cure, loss of whole mud. Wellbore strengthening materials (WSMs), a category of LCMs, have proved effective not only for mitigating losses but also for preventing them.

Operators choose a WSM based on the desired wellbore strengthening mechanism. A description of the principal mechanisms follows.

Fracture propagation resistance (FPR)—The FPR theory of lost circulation prevention posits that LCM is pushed into an incipient or existing fracture to bridge, seal and isolate the fracture tip, thereby increasing the formation's resistance to fracture propagation. Halting this propagation also stops the lost circulation event.

The mechanism for FPR has its origins in a joint industry project (JIP) known as the Drilling Engineering Association (DEA)-13, which was conducted in the mid-1980s to determine why oil-base mud (OBM) seemed to yield a lower FG than water-base mud (WBM).¹⁹ The project found no difference in fracture initiation pressure for different fluid types and formulations in intact boreholes, but noted significant differences for fracture propagation behavior, which was influenced by fluid type and composition.

This difference was explained through a phenomenon known as fracture tip screenout.²⁰ When fracture growth begins, the wellbore instantaneously loses a volume of drilling fluid into the new void space of the fracture. If the fluid contains LCM, the introduction of fluid into the fracture causes a buildup of LCM that isolates, or screens, the fracture tip from the full pressure of the invading mud. The means by which this LCM buildup occurs varies with the type of fluid used (right).



▲ Mud type, filtercake and fracture propagation. In a system using a WBM (top), the fracture tip is sealed by an external filtercake that builds to prevent effective pressure communication between the drilling fluid and the tip, thus preventing fracture extension. The radial distance from the wellbore that the drilling fluid occupies in the fracture is defined as R_{fluid} . The thickness of the filtercake that builds up between the drilling fluid and the beginning of the fracture tip is defined as R_{cake} . The length of the filter tip, R_{tip} , is measured from the end of R_{cake} to the outer edge of where the drilling fluid solids (black particles) meet the formation. In a system using an OBM or SBM (bottom), an internal filtercake allows for full pressure communication to the tip, which facilitates fracture extension at lower propagation pressures than with a WBM. R_{fluid} is defined in the same manner as in a WBM technique. R_{tip} is the distance between R_{fluid} and the length of the filter tip, which also incorporates the drilling fluid solids. (Adapted from van Oort et al, reference 10.)

10. van Oort E, Friedheim J, Pierce T and Lee J: "Avoiding Losses in Depleted and Weak Zones by Constantly Strengthening Wellbores," paper SPE 125093, presented at the SPE Annual Technical Conference and Exhibition, New Orleans, October 4–7, 2009.

11. Growcock F, Kaageson-Loe N, Friedheim J, Sanders M and Bruton J: "Wellbore Stability, Stabilization and Strengthening," presented at the Offshore Mediterranean Conference and Exhibition, Ravenna, Italy, March 25–27, 2009.

12. Filtercake is the solid residue deposited on the wellbore when the drilling mud slurry is forced against it under pressure, which occurs during an overbalanced drilling condition.

13. Stuck pipe occurs when the drillpipe is not free to move up, to move down or rotate as needed in the wellbore. Seepage losses increase the risk of differential sticking by generating thicker filtercakes on the wellbore wall, which increases the contact area between the drillpipe and wellbore.

14. Morita N, Black AD and Fuh G-F: "Theory of Lost Circulation Pressure," paper SPE 20409, presented at the SPE Annual Technical Conference and Exhibition, New Orleans, September 23–26, 1990.

van Oort et al, reference 10.

15. Aston MS, Alberty MW, McLean MR, de Jong HJ and Armagost K: "Drilling Fluids for Wellbore Strengthening," paper IADC/SPE 87130, presented at the IADC/SPE Drilling Conference, Dallas, March 2–4, 2004.

16. Dupriest F: "Fracture Closure Stress (FCS) and Lost Returns Practices," paper SPE/IADC 92192, presented at the SPE/IADC Drilling Conference, Amsterdam, February 23–25, 2005.

17. Benaissa S, Bachelot A and Ong S: "Preventing Mud Losses and Differential Sticking by Altering Effective Stress of Depleted Sands," paper IADC/SPE 103816, presented at the IADC/SPE Asia Pacific Drilling Technology Conference and Exhibition, Bangkok, Thailand, November 13–15, 2006.

18. van Oort et al, reference 10.

19. Morita et al, reference 14.

20. van Oort et al, reference 10.

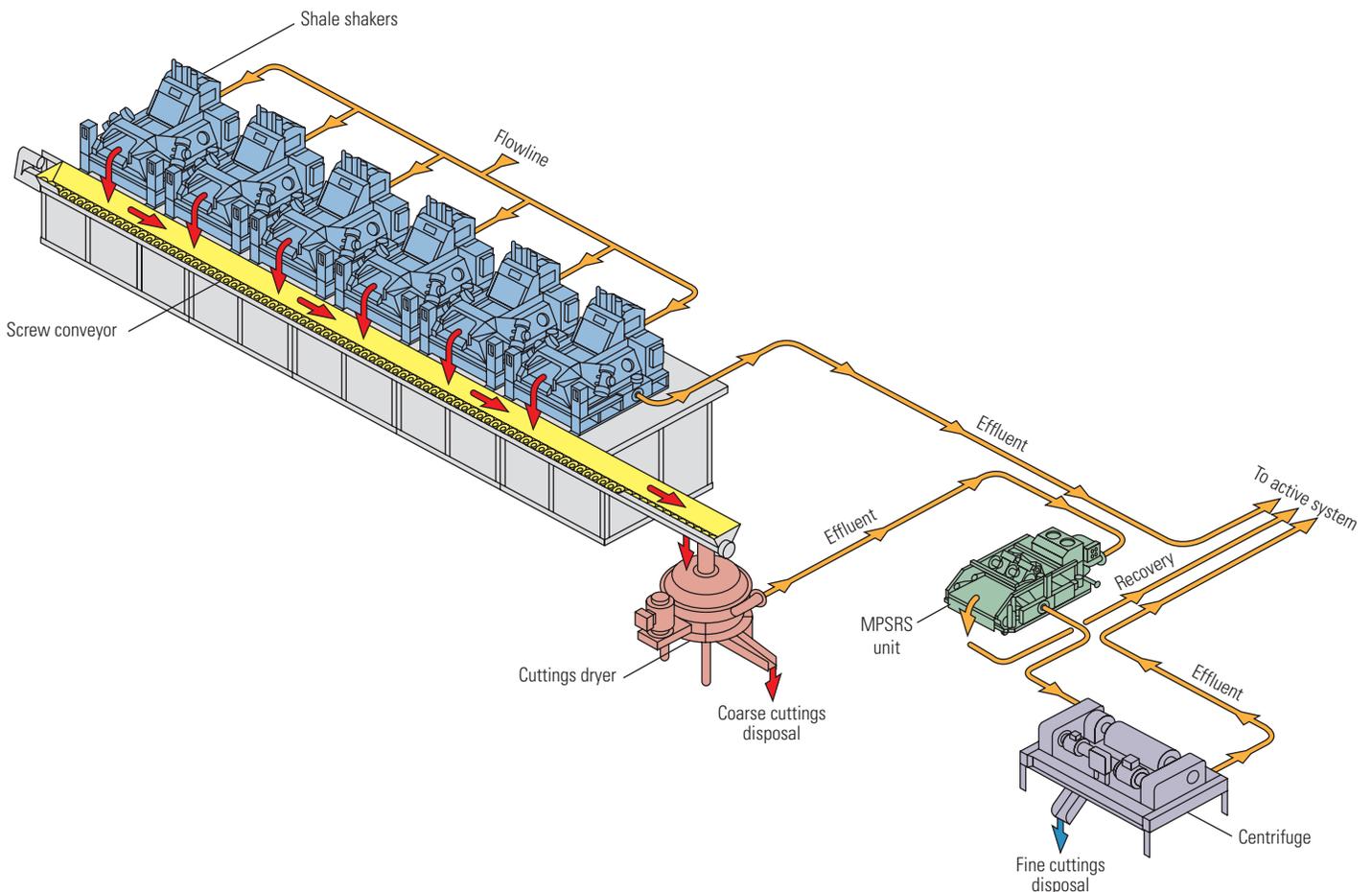
If a WBM is used, the growth of the fracture leads to a dehydrated cake, or plug, of LCM that isolates the fracture tip and curtails further growth. The use of LCM in a WBM generally causes elevated fracture propagation pressures; the fracture continues to grow only if the mud pressure is high enough to puncture the LCM barrier and reach the fracture tip again. However, once this occurs and fracture propagation begins anew, additional LCM begins collecting at the tip until it is sealed again.

Nonaqueous fluids (NAFs), a collective term for OBMs and SBMs, use the emulsified aqueous fluid to penetrate the permeable rock and create a very tight and ultrathin filtercake that is internal to the fracture wall. When a fracture propagates in the presence of an NAF, the invert

emulsion quickly seals off fracture faces, which limits fluid loss into the formation. Consequently, very little solid material is deposited in the fracture, and a coherent barrier of LCM or mudcake is not built. For NAFs, the result is that the pressure near the fracture tip is close to that in the wellbore, whereas for WBMs, the pressure near the fracture tip drops significantly. As a consequence, fracture propagation occurs less readily for WBMs than for NAFs, so that the effective FG for WBMs is greater than for NAFs. This translates to narrower drilling margins for an NAF than for a WBM, which may present significant challenges when constructing wells with low drilling margins.

The DEA-13 project also revealed that the composition and size distribution of particulates in the fluid were critically important to the success of FPR. Laboratory research conducted outside of the DEA-13 project resulted in the development of a specialized WSM known as a loss prevention material (LPM) that inhibited fracture tip growth.²¹

This research showed that the LPM must be present in the mud at all times during drilling because FPR is a continuous, preventive treatment method. The findings also suggested that LPM should be present at a size distribution of between 250 and 600 microns [60 to 30 mesh], although subsequent work by Shell—a proponent of the FPR method—suggests that size distribution should be a function of the type of formation to be strengthened.²²



▲ WSM recovery. The process to recover WSM for subsequent reuse begins with a flowline that collects drilling fluid solids (including cuttings and WSMs originally pumped downhole for wellbore strengthening) from the wellbore and passes them through shale shakers, which remove very large particles. The remaining fluid and particles (red arrows) are then passed through a screw conveyor and cuttings dryer to remove residual cuttings from the drilling fluid. The fluid then passes through the MPSRS Managed Particle Size Recovery System unit, which further separates the WSM from smaller drill cuttings. A centrifuge conducts the last separation process, removing the very smallest drill cuttings from the WSM (blue arrow). The effluent, or WSM, from the shale shakers, MPSRS unit and centrifuge are sent back to the active system for reintroduction into the wellbore.

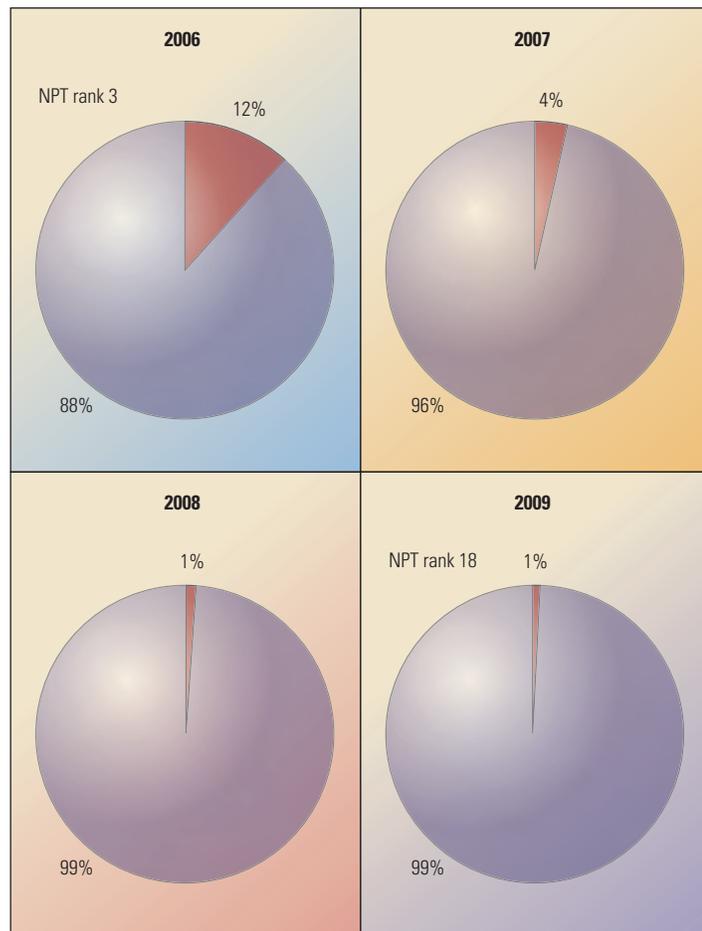
The types of WSM deemed most effective in consistently sealing a fracture and minimizing leakoff through the fracture tip include synthetic graphite, ground nut hulls and oil-dispersible cellulose particles. Blends of these materials in various ratios have demonstrated synergistic performance benefits in both laboratory and field trials. These materials must be present in the mud at concentrations ranging from 43 to 57 kg/m³ [15 to 20 lbm/bbl] and are continuously recycled and reintroduced to the wellbore to ensure continuous protection as new sections are drilled.

Field trials have demonstrated the importance of maintaining both the concentration and size distribution of WSM in the mud.²³ This need led to the development of in-field WSM recycling equipment, such as the MPSRS Managed Particle Size Recovery System technology. The system removes drill cuttings and low-gravity solids that may negatively impact mud rheology and ECD while recovering WSM in the appropriate size ranges for raising the FPR (previous page).²⁴

Shell introduced the FPR concept with the MPSRS technology in 2006 in Gulf of Mexico sub-sea wells. Lost circulation's contribution to NPT diminished significantly in these wells over a four-year period (right). This is in contrast to alternative drill cuttings removal systems that are composed of shakers with three levels that are configured in series. Cuttings are removed from the top level (fitted with the coarsest screens), fines are removed from the bottom level (with the finest screens) and most of the coarse, relatively undegraded WSM is trapped on the middle level and shunted back into the active system.²⁵

Hoop stress enhancement: The stress cage concept—A second wellbore strengthening model, the stress cage theory, proposes that the hoop stresses at the edge of the wellbore may be increased by adding a suitable WSM to the drilling fluid. A drilling mud pretreated with WSM circulates in an overbalanced state to induce shallow fractures in the near-wellbore region.

These newly created fractures act to compress the wellbore, generating an additional hoop stress, or stress cage. The WSM-laden mud enters these shallow fractures, and the sized WSM particles begin to collect and bridge close to the wellbore face. Additional buildup of WSM forms a hydraulic seal near each fracture mouth; as a result, no additional mud can enter from the wellbore, and the fluid within the fracture leaks off into the formation.



■ Lost circulation NPT
■ Other NPT

▲ NPT attributed to lost circulation. After Shell introduced the FPR mechanism and MPSRS equipment in the third quarter of 2006, lost circulation's contribution to NPT dropped significantly, from 12% at the onset of the wellbore strengthening strategy to 1% in 2009. Lost circulation fell significantly as a major trouble category in a Shell NPT ranking, from rank 3 to rank 18. (Adapted from van Oort et al, reference 10.)

21. Fuh G-F, Morita N, Boyd PA and McGoffin SJ: "A New Approach to Preventing Lost Circulation While Drilling," paper SPE 24599, presented at the SPE Annual Technical Conference and Exhibition, Washington, DC, October 4-7, 1992.

22. van Oort et al, reference 10.

23. Sanders MW, Young S and Friedheim J: "Development and Testing of Novel Additives for Improved Wellbore Stability and Reduced Losses," paper AAE-08-DF-HO-19, presented at the AAE Fluids Technical Conference and Exhibition, Houston, April 8-9, 2008.
Friedheim J, Sanders MW and Roberts N: "Unique Drilling Fluids Additives for Improved Wellbore Stability and Reduced Losses," presented at the Seminario Internacional de Fluidos de Perforación, Completación y Cementación de Pozos (SEFLU CEMPO) Conference, Margarita Island, Venezuela, May 19-23, 2008.

Tehrani A, Friedheim J, Cameron J and Reid B: "Designing Fluids for Wellbore Strengthening—Is It an Art?" paper AAE-07-NTCE-75, presented at the AAE National Technical Conference and Exhibition, Houston, April 10-12, 2007.

24. van Oort E, Browning T, Butler F, Lee J and Friedheim J: "Enhanced Lost Circulation Control Through Continuous Graphite Recovery," paper AAE-07-NTCE-24, presented at the AAE National Technical Conference and Exhibition, Houston, April 10-12, 2007.
Butler F and Browning T: "Recovery System," US Patent No. 7,438,142 (October 21, 2008).

25. Growcock F, Alba A, Miller M, Asko A and White K: "Drilling Fluid Maintenance During Continuous Wellbore Strengthening Treatment," paper AAE-10-DF-HO-44, presented at the AAE Fluids Conference and Exhibition, Houston, April 6-7, 2010.

This leakoff lowers the hydraulic pressure within the fracture, causing it to begin to close. However, the presence of the WSM bridge, wedged at the fracture mouth, prevents total closure and maintains a degree of additional hoop stress. The presence of one or more of these propped fractures increases the hoop stress, and thus a higher wellbore pressure is needed to extend or create additional fractures (below).

Industry research suggests that for this mechanism to be successful, high concentrations of bridging additives are required; they must be strong enough to resist closure stresses and they have to be appropriately sized to bridge near the fracture mouth rather than deeper into the fracture. They must also create an impermeable bridge so that leakoff through the bridge is minimized, allowing the pressure within the fracture to drop. Materials such as graphitic blends, marble, nut husks and ground petroleum coke work

well, just as with the FPR mechanism. For a fracture opening of 1 mm [0.04 in.], a particle size distribution ranging from colloidal clays up to values approaching 1 mm has been suggested.²⁶

Historically, the WSM was applied as a dedicated squeeze in pill form—a relatively small volume (less than 32 m³ [200 bbl]) of fluid added to the wellbore at one time. However, the WSM has been continuously applied to the whole mud when field engineering and logistics permitted it. Stress cage treatments typically require at least 25 kg/m³ [9 lbm/bbl] of WSM in the mud. A solids-recovery system, such as a three-level shaker system configured in series, may be used to scalp the cuttings and remove the fines while capturing WSM-sized particulates for routing back to the active system. Shakers fitted with coarse (10- to 20-mesh) screens alone may suffice, although these would remove only cuttings and leave WSM and drilled fines in the mud. The buildup of fines

might be tolerable, particularly for strengthening short intervals drilled with solids-tolerant NAF, but removing all unnecessary solids is considered best practice.

Fracture closure stress—A third wellbore strengthening model, fracture closure stress (FCS), was developed in the mid-1990s and is still widely applied in the industry.²⁷ This method has some similarities to the stress cage concept, particularly in how WSM is theorized to plug and wedge open fractures to increase hoop stress near the wellbore and arrest fracture propagation.

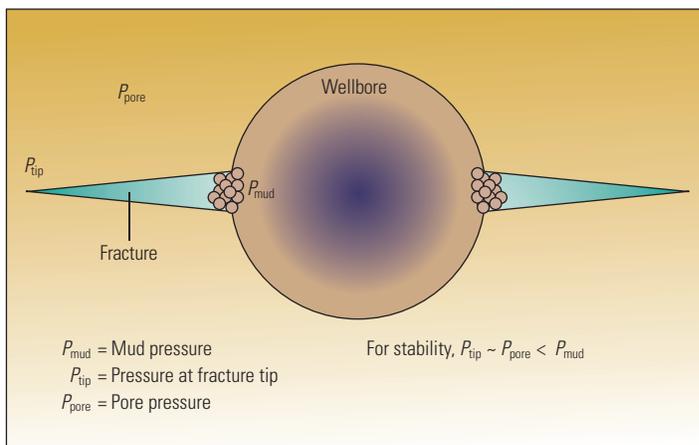
However, unlike stress caging—which initiates fractures before quickly stopping their growth—FCS is a high-fluid-loss treatment for existing fractures. While the WSM in this method may be applied as a whole mud treatment, it is commonly applied via high-fluid-loss pills.

FCS theory holds that an effective treatment must isolate the fracture tip. Scientists believe this occurs because of rapid drainage of carrier fluid from the mud mixture as the particles are compressed and agglomerate during the squeeze phase and then form a plug in the fracture. The plug quickly becomes immobile and cuts off communication between the fracture tip and the wellbore, thus preventing transmission of pressure to the tip and halting fracture propagation, allowing an increase in the wellbore pressure and a consequent increase in fracture width.

As a result, it is important that the particles are able to deform, or be crushed, during the application of a squeeze treatment. The ideal WSM should be composed of relatively large particles of similar size and considerable roughness that do not pack well; examples include diatomaceous earth and barite.²⁸ Often, more than one FCS treatment is required.

The FCS theory holds that the particulate plug can manifest anywhere in the fracture, not only near the mouth as in stress caging. For this mechanism, although compressive strength of the WSM is not important, high fluid loss is critical because it accelerates formation of the immobilized plug. Alternatively, leakoff of filtrate may occur through generation of microfractures or extension of the existing fracture, thus permitting deliquescence of the WSM and formation of a plug before the onset of whole mud loss.

Wellbore isolation—As a fourth wellbore strengthening strategy, various methods have been proposed to isolate a wellbore while drilling to seal off the formation in a manner similar to protecting a wellbore with casing.²⁹ In some cases, the WSMs for this application are flexible fluid-loss control materials that have the



▲ Stress cage concept. In this wellbore strengthening strategy, a fracture is formed and quickly sealed by WSMs (small brown circles) that bridge and seal the fracture mouth. This seal forms a compressive stress, or stress cage, in the adjacent rock, which effectively strengthens the wellbore. For fracture stability to be realized, P_{tip} —which is, in practical terms, equivalent to P_{pore} —must be less than P_{mud} , which is isolated behind the WSM seal.

26. Aston et al, reference 15.

27. Dupriest, reference 16.

28. M-I SWACO Technical Service Group: "Chapter 7: Wellbore Strengthening Solutions," Houston: M-I SWACO, *Prevention and Control of Lost Circulation* (March 17, 2011): 7:1–7.

29. Benaissa et al, reference 17.

30. Karimi M, Moellendick E and Holt C: "Plastering Effect of Casing Drilling; a Qualitative Analysis of Pipe Size Contribution," paper SPE 147102, presented at the SPE Annual Technical Conference and Exhibition, Denver, October 30–November 2, 2011.

31. For more information: Lund JW: "Characteristics, Development and Utilization of Geothermal Resources," *Geo-Heat Center Quarterly Bulletin* 28, no. 2 (June 2007), <http://geoheat.oit.edu/bulletin/bull28-2/bull28-2-all.pdf> (accessed October 15, 2011).

Beasley C, du Castel B, Zimmerman T, Lestz R, Yoshioka K, Long A, Lutz SJ, Riedel K, Sheppard M and Sood S: "Mining Heat," *Oilfield Review* 21, no. 4 (Winter 2009/2010): 4–13.

32. For more information: Oliver JE: "New Completion System Eliminates Remedial Squeeze Cementing for Zone Isolation," paper SPE 9709, presented at the SPE Permian Basin Oil and Gas Recovery Symposium of the SPE of the AIME, Midland, Texas, March 12–13, 1981.

capability of penetrating or sealing the rock. The concept involves reducing the permeability of the rock to near zero by plastering the rock with a material of equal or greater tensile strength.

Various low-fluid-loss materials have been implemented to achieve this effect, which essentially attempts to build a cement-like sheath on the wellbore surface. Such a barrier serves to isolate the wellbore from both fluid invasion and wellbore pressure. Advances in mud chemistry have developed micro- and nanoparticulates that may reduce permeability to a negligible level, but isolation of wellbore pressure remains an elusive goal. The smear effect, which is thought to occur during casing or liner drilling operations, may be considered an example of wellbore isolation because fines are thought to be plastered onto the wellbore walls to create a tight barrier to fluid invasion.³⁰

Some wellbore strengthening techniques defy easy classification. An example is the Losseal lost circulation treatment, an engineered pill that blends a flexible fiber with a firm fiber to synergistically bridge fractures and stop fluid loss.

Theoretically, the treatment creates an impermeable grid that prevents fluid from entering the fracture; it is strong enough to withstand additional pressure buildup caused by increasing mud density. The pill can be pumped through a bottomhole assembly or open-ended drillpipe and is applicable in wellbores affected by natural fractures, depleted reservoirs and drilling-induced lost circulation zones.

The Losseal solution has also been applied to lost circulation scenarios outside of the oil and gas industry. Enel Green Power recently used the system to solve a lost circulation problem while drilling a geothermal well in Italy. To extract energy from a geothermal well, the operator drills into high-temperature subsurface zones and injects water, which is heated and pumped back to surface, where it is used to provide a source for home heating or, at higher temperatures, electricity generation for industrial applications.³¹

Geothermal wells drilled previously in the same area passed through a shale section at shallow depths, followed by a limestone formation where fluid losses ranged from 10 m³/h [63 bbl/h] to total loss of fluid.

Historically, lost circulation solutions in these wells included a remedial squeeze cement job to achieve vertical isolation of a completion interval. For the newest well, the operator wished to avoid the additional cost and time associated with a squeeze job. Additionally, in some instances, squeeze jobs had created formation damage that impaired productivity.³²

Category	Fracture Propagation Resistance	Stress Cage	Fracture Closure Stress
Application technique	Continuous in mud	Continuous in mud or pill squeeze	Continuous in mud or pill squeeze
Formation or closure stress applied?	No	No	Yes
Fracture tip isolation required?	Yes	No	Yes
High fluid loss required?	No	No	Yes
WSM particle strength	Unimportant	Somewhat important	Unimportant
WSM particle size	Important	Important	Unimportant
WSM particle type	Important	Important	Unimportant

^ Differences among wellbore strengthening techniques. A comparison of the tenets of wellbore strengthening techniques reveals some fundamental differences.

The operator pumped a 32-m³ [200-bbl] Losseal pill to the lost circulation zone and monitored the pressure in the wellbore as a function of time. While the pressure initially increased by as much as 200 psi [1.4 MPa] during the pill's movement through the wellbore, a sudden drop in pressure indicated that the Losseal pill reached the fractures and plugged them. The liner was then run to total depth and cemented in one stage using conventional completion techniques. No fluid losses were recorded during this operation, and the pressure reached closely matched what modeling had predicted.

By implementing the single-stage cement job and improving well integrity, the company was able to avoid a cement squeeze job, thus saving three days of rig time. The improved zonal isolation and casing protection afforded by having the entire string encased in cement are expected to increase the productive life of the well.

Investigating Mechanisms

Fundamental differences exist among the proposed wellbore strengthening mechanisms (above). Because it is impossible to see what takes place in a fracture during a wellbore strengthening treatment, the industry has not reached a clear consensus on the exact mechanism at work.

This lack of industrywide agreement has spurred a series of JIPs designed to study the fundamentals of fracture sealing, develop product solutions and set industry standards for wellbore strengthening investigations.

The initial JIPs were hosted by Shell E&P Company, but now are being led by M-I SWACO, a Schlumberger company. M-I SWACO conducted the first JIP from 2004 to 2006 and counted Shell, BP, ConocoPhillips, Chevron and Statoil among its members. The JIP was designed to first define

the best laboratory-based fracture modeling method that would yield reproducible data. The resulting fracture model was tested with a device used to screen LCM candidates for wellbore strengthening. Acceptable WSMs identified by this method included marble, graphite, ground petroleum coke, nut husks and proprietary cellulosic blends.

A second JIP, conducted from 2007 to 2010, included several additional operators and focused on clarifying, through laboratory testing, the fundamental differences among the various wellbore strengthening theories. Research priorities included comparing sealing at the fracture mouth—hoop stress enhancement—versus sealing throughout the fracture (FPR), matching LCM size distribution in relation to fracture width and investigating LCM performance as a function of material type and concentration.

A third industry project, the Research Cooperative Agreement III, began in December 2010 with a focus on developing lost circulation solutions for extreme downhole conditions and for wells in high-value plays.

Numerous operators working in concert have committed resources to research projects dedicated to finding solutions to lost circulation; wellbore strengthening is the focus of that research. As the industry attempts to feed the growing global appetite for energy from increasingly expensive and unconventional hydrocarbon resources, it will likely rely on wellbore strengthening solutions to help operators drill wells more efficiently.

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