Integrated Wellbore Cleanout Systems: Improving Efficiency and Reducing Risk

Accumulation of sand and solids in wellbores significantly impairs oil and gas production. In fact, nearly half of all coiled tubing operations involve well cleanouts to remove debris. Innovative integration of hardware, software, fluid cleanout systems and treatment monitoring helps engineers reduce the cost and risk of wellbore cleanout operations and return wells to production more quickly.

Movement of sand and accumulation of debris can have a considerable impact on fluid flow. On the surface, a river can deposit so much silt that it blocks its own flow, changing its course and perhaps threatening farmland and communities. Similarly, downhole in a well, influx of sand can impair or stop the flow of oil from a reservoir.

Sand fill and debris are not new wellbore problems. Generations of oilfield engineers have faced the challenge of keeping wellbores cleaned out. In 1901, the Jennings Oil Company Clement No. 1 well in southwestern Louisiana, USA, gushed oil at an estimated rate of 7,000 bbl/d [1,113 m³/d]. Unfortunately for these early oil pioneers, prosperity was short-lived. After seven hours of production, formation sand plugged more than 1,000 ft [305 m] of casing, stifling oil production along with dreams of riches and wealth. Attempts to remove the sand from this wellbore eventually failed and the prospect was abandoned.

Around the same time, oil prospectors in Texas began using a novel technique to deal with oil-production decline—the torpedo. A “torpedo man” carefully lowered substantial quantities of nitroglycerine down the wellbore. Once the nitroglycerine containers reached their target, a weight was dropped in the hole, initiating a sequence of events that climaxed in a spectacular explosion, and with any luck, stimulated the well, removing debris from the wellbore and reinitiating the flow of oil.

Today, engineers use safer and more efficient methods to remove sand and other debris from a wellbore. In this article, case histories from North America, the North Sea and Malaysia demonstrate how carefully designed and integrated wellbore cleanout processes save time, reduce cost and risk, and improve operational efficiency, while also allowing operators to produce more oil.

Moving Solids up the Wellbore

Wellbore fill is a major concern for operators throughout the world. This production-inhibiting problem is commonly dealt with through coiled tubing (CT) interventions. However, as wellbores and completions become more complex and as reserves are produced under increasingly difficult conditions, there are environments where conventional coiled tubing cleanout techniques are not adequate for effective fill removal.

Wellbore cleanouts were among the first applications for coiled tubing services. Global estimates suggest that nearly 50% of CT jobs are performed to remove mobile solids and debris, such as produced sand or residual proppant from hydraulic-fracturing treatments. Continued developments in CT conveyance systems generally have allowed operators to keep pace with increasingly greater well depths, more tortuous boreholes and more difficult downhole environmental conditions.
The most common technique for deviated wellbore cleanout uses a jetting tool conveyed downhole by CT. While pumping cleanout fluid down the tubing, the tool is lowered, or washed, into the sand or other debris, often called fill. At some distance, or bite, into the fill, downward motion is stopped. While continuing to circulate cleanout fluid, the jetting tool is slowly pulled uphill some distance in a process known as sweeping. How large a bite is taken and how far the tool is pulled uphill is dependent on many parameters including flow rate, the type of fill, tubing and casing sizes, the cleanout fluid used, nozzle design, bottomhole pressure and wellbore trajectory. Occasionally, the sweep will have to be brought all the way back to surface before taking the next bite. Once the fill has been swept upward to a predetermined depth, the tool

returned to bottom, taking the next bite of fill. The process is repeated until all fill has been mobilized and removed from the wellbore (left).

The jetting tool, or wash nozzle, is generally designed to create fluid turbulence that helps mobilize and suspend solid particles. However, for inclined wellbores, turbulence decreases as distance from the nozzles increases, and solids often form beds on the lower side of a wellbore as they fall, or slip, from suspension. As the height of this solids bed increases, less of the wellbore cross section is available for flow, so fluid velocity across the surface of the bed increases until it reaches a critical mobilization velocity. Once this velocity is achieved, all or a portion of the fill disperses, is remixed with the cleanout fluid and is transported toward the surface, often forming a new bed farther up the hole.

As the jetting tool moves upward toward a newly formed bed, turbulence generated by the jetting action also helps to mobilize the fill, transporting it uphole until solids again settle. The cycle repeats, pushing the bed uphole as the CT is pulled up the wellbore. If the CT speed is too fast or the jetting nozzle is inappropriate for the application, solids will be bypassed and unevenly distributed along the wellbore, resulting in only a partial cleanout and the need for further remedial treatment. This problem may also occur when flow rates are too low or the carrier fluid is incorrectly designed.

<Steps in the cleanout process. A typical wellbore cleanout process involves several steps. First, coiled tubing conveys the cleanout tool to the top of the fill (A). In image B, the tool enters the fill while circulating, is washing and mobilizing the solids, and has taken a bite. Then, in image C, a preplanned bite length has been reached and the jetting tool is being pulled up toward the liner top, initiating the sweeping process. In image D, the fill is being swept through a portion of the critical angle (40 to 65 degrees) section of hole. Generally, once solids are swept to the top of the liner, the nozzle is returned to bottom, the next bite is taken, and the process repeats until all solids have been removed from the wellbore.>
Integrating Cleanout Systems

Engineers consider many factors when designing wellbore cleanouts, including well-completion geometry, wellbore deviation, cleanout fluid properties, fluid flow rate, circulating pressure limits, bottomhole pressure and temperature, the type of solids that must be removed, and the length along which solids must be transported. Most often, higher flow rates, smaller completion sizes, lighter and more angularly shaped solids, lower deviations and downhole temperatures, and shorter distances for solids transport lead to easier cleanouts. However, at angles between 40 and 65 degrees, the effects of well inclination can make almost any wellbore difficult to clean.

Schlumberger began integrating wellbore cleanout systems in 2002 at the Schlumberger Integrated Productivity and Conveyance Center (IPC) in Sugar Land, Texas. Engineers first used flow-loop data to validate and improve earlier theoretical models and computer algorithms (right). Realizing that no single aspect of the cleanout process determines success or failure, engineers exploited system synergies and developed the integrated PowerCLEAN engineered fill removal system. Software applications, cleanout fluids, jetting-tool and nozzle design and solids-removal monitoring were combined into one system enabling engineers to design cost-effective cleanout solutions for sand, bauxite and other debris under a wide range of wellbore conditions, including wells with large casing sizes, high temperatures and difficult borehole trajectories.

Software—The PowerCLEAN job-design software serves as the integrating platform for wellbore cleanout optimization. For any given set of wellbore and operating conditions, the software evaluates and optimizes cleanout fluids with respect to a series of variables, including the maximum fluid flow rate for a maximum allowable circulating pressure; bottomhole pressure limitations; maximum CT run-in-hole (RIH) speed and bite length when penetrating the fill; solids bed formation and behavior relative to sweeping requirements; optimal CT pulling speed for sweeping; and sweep length before taking the next bite of fill.

Additional parameters may be set in the design software to ensure a safe, efficient and problem-free cleanout. For example, the software can predict the height of solids beds that form on the low side of an inclined wellbore. By adjusting operating procedures, engineers ensure that the solids bed height will not exceed a predetermined portion of the wellbore cross-sectional area, thereby minimizing friction and tubing drag, equivalent circulating density (ECD), and the risk of stuck tubing.

Cleanout fluids—Fluids used in wellbore cleanout operations were often developed for other oilfield operations, such as hydraulic fracturing and gravel packing. In CT operations, cleanout performance demands on fluid systems are high. Hydraulic diameters are often small and require that engineers balance solids-transport efficiency requirements and fluid viscosity against flow rates, and bottomhole temperatures and pressures. These and other demands make many existing cleanout fluids inadequate in difficult wellbore environments. To address this critical need, Schlumberger researchers developed the PowerCLEAN fluid system.

Engineers carefully considered the implications of thermal effects on viscosity and subsequent hole-cleaning efficiency. Although velocity plays a more important role in transport efficiency under dynamic conditions, increasing fluid viscosity can forestall static settling.

Higher fluid viscosities tend to increase frictional pressures and reduce flow rates at the expense of...
Evaluating cleanout fluids. Laboratory analysis shows that the PowerCLEAN fluid exhibits thermal stability to just below 325°F (orange curve - left). Laboratory tests have shown that circulating friction pressures of PowerCLEAN gel (orange) are low when compared with those of common cleanout fluids (middle). In this test, a low-friction solution of water and friction reducer is shown for comparison purposes (light blue curve). Also, when compared with xanthan-base fluid (pink), the PowerCLEAN fluid (orange) shows a 100% improvement in carrying capacity at lower concentrations (right).

Monitoring solids removal from the wellbore. The solids monitoring system uses acoustic signals to monitor the amount of solids being removed from the wellbore. The measuring device is noninvasive and attaches to the return line from the wellhead (top left and right). A computer interface monitors the device throughout the job. Data output (right) shows the solids return rate versus time (red) and an estimate of total solids removed (black). Unusual changes in the data alert engineers to potential problems during the job.
Washing fill from the wellbore. The PowerCLEAN nozzle (bottom right) outperforms other nozzle designs. In laboratory tests using a 7.5-in. [190.5-mm] flow loop, higher achievable pumping rates and annular velocities coupled with the swirling effects (left) achieved by the nozzle design help keep solids in suspension longer, allowing the CT to be pulled at faster rates, saving time and improving efficiency (top right).

Nozzles—Available designs include nozzles that jet both forward and backward, those that jet forward only, those that jet backward only and those that can be switched on demand from forward to backward. Any of these combinations may include radial swirl-inducing features. IPC engineers designed new nozzles using theoretical studies and empirical cleanout tests in 3.5- and 7-in. test loops. The nozzles are designed to ensure complete and efficient removal of solids from most wellbore configurations using fluids ranging from water to viscosified cleanout fluids.

PowerCLEAN nozzles have no moving parts and provide continuous jetting to create a swirling effect. Nozzle focus, direction, size and spacing are specifically designed for wellbore cleanouts of unconsolidated fill, optimizing available fluid energy for particle lift and suspension (right). The pressure drop across the PowerCLEAN nozzle is relatively small, typically 100 to 400 psi [689 to 2,758 kPa] at flow rates between 1 and 3 bbl/min [159 and 477 L/min]. The small pressure drop across the nozzle allows for higher flow rates and fluid velocities in the wellbore, which are essential for effective removal of wellbore fill.

Solids monitoring—Ensuring that solids are being removed from the wellbore at predicted rates is critical to job success. An important component of the PowerCLEAN system is the solids monitoring device, an acoustic sensor that measures the energy associated with the collisions of solids on the inside surface of a pipe (previous page, bottom). This energy is processed to detect the volume of solids passing by the sensor location as a function of time. Observing the trend of solids returning to surface during a cleanout job provides a means of verifying the performance of PowerCLEAN systems. Potential problems can be anticipated and corrective action taken.

Cleaning Undulating Trajectories in Alaska

Integrating wellbore cleanout system components allows engineers to successfully remove solids and debris from wellbores that were previously considered too complex for cleanout or those in which remedial treatments were not considered cost-effective.

Wells operated by ConocoPhillips in the Kuparuk River Unit on the North Slope of Alaska, USA, often have wellbore fill that hampers production and increases operating cost at some point in their life cycle.8 Wellbore trajectories can be tortuous; in some cases, undulations more

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than 140 ft [43 m] from crest to trough make sand removal efforts difficult (right).

Early in 2003, drillers completed a well across a 5,000-ft [1,524-m] horizontal section of the low-pressure West Sak sand. With the assistance of a jet pump, the well initially produced up to 660 bbl/d [105 m³/d] of oil.

In September 2003, the well was shut in to change the artificial lift system. During the workover, the slickline encountered fill near the top of the liner at 6,580 ft [2,006 m]. During the next month, Schlumberger field specialists ran CT into the wellbore, tagging fill at 8,775 ft [2,675 m] coiled tubing measured depth (CTMD).

Although slick-water with biopolymer gel pills and slick-diesel combined with gelled diesel pills were pumped through the CT to remove wellbore debris, no significant amount of solids was brought to surface. Later, a review of the running-weight log indicated that the CT had not tagged sand, but had reached its sliding-friction limit, or a condition called helical lockup.

In November 2003, the cleanout attempt was repeated with larger outside diameter (OD) CT. The CT field specialist encountered greater than normal resistance while reentering the well, which indicated that sand was distributed along the length of the wellbore. A solid sand plug was tagged just above the liner top at 6,521 ft [1,987 m] CTMD. A diesel-base cleanout fluid was pumped down the tubing at 2.1 bbl/min [333.5 L/min] while taking 100-ft [30.5-m] bites into the fill before sweeping to the bottom of the production tubing, or tubing tail. At 7,449 ft [2,270 m], returns were lost and the CT was immediately pulled out of the wellbore.

While pulling the CT to the surface, the field specialist noted high CT overpull, indicating that some solids were being left behind along the wellbore and were sliding down the tubing. However, as the jetting tool approached surface, returns were regained and engineers observed a significant amount of sand, wetted with gelled diesel, being returned to surface. Following this cleanout, the well produced for about a month before sanding off again.

Engineers from ConocoPhillips and Schlumberger planned a third cleanout, this time using the PowerCLEAN integrated cleanout system. The wellbore cleanout design modules from CoilCADE coiled tubing design and evaluation software allowed engineers to evaluate several locally available cleanout fluids, including 2% potassium chloride [KCl], welan-base, xanthan-base, diesel, gelled diesel and the PowerCLEAN gel system. Because of low bottomhole pressures (BHP), all fluid options required gas lift, either from natural gas, nitrogen or both. Due to the undulating geometry of this well, the exact concentration of fill was unknown.

For fluid volume comparison, engineers assumed cleanouts in 500-ft [152-m] increments, starting at 6,521 ft measured depth. Single-sweep cleanout simulations predicted that use of the PowerCLEAN gel would allow completion of cleanout operations in 6 hours using 1,000 bbl [159 m³] of fluid and 220,000 ft³ [6,230 m³] of nitrogen. Xanthan gels would require about 24 hours, 5,200 bbl [826 m³] of fluid and 740,000 ft³ [20,956 m³] of nitrogen, while welan fluids would need 29 hours, 5,200 bbl of fluid and as much as 920,000 ft³ [26,054 m³] of nitrogen. As for diesel-base fluids, the high time estimates for a single-sweep cleanout and fluid volume requirements precluded further consideration.

Before the production liner was reached, gas hydrate and multiple sand bridges were cleaned from the production tubing. The PowerCLEAN software model recommended a fluid flow rate of 4.6 bbl/min [731 L/min] with 900 ft³/min [25.5 m³/min] of nitrogen through the optimized nozzle. The model also indicated that a single-sweep operation was possible with a penetration rate of 7.2 ft/min [2.2 m/min] and bites of 124 ft [37.8 m]. Each bite would need to be circulated for 14 minutes before taking the next.

During execution, an unexpected increase in wellhead pressure occurred. Rather than risking losing returns, ConocoPhillips and Schlumberger engineers reevaluated the job design and reduced the flow rate to 3 bbl/min. The remodeled design based on this new flow rate decreased nitrogen flow to 800 ft³/min [22.6 m³/min], slowed the penetration rate to 7 ft/min [2.1 m/min] and reduced the bite size to 120 ft [36.6 m]. Reducing the flow rate precluded a single-sweep circulating cleanout, so engineers reverted to a multiple-sweep process, bringing each sweep to the liner top.

Throughout the job, the Schlumberger field engineer monitored the solids-removal rate using the solids monitoring system, verifying the efficiency of the cleanout design and solids-carrying capacity of the PowerCLEAN system. Unlike the earlier conventional cleanout systems, no heavy sand loads were seen while jetting out the last 1,000 ft to surface. Periodic manual
sampling of fluid returns verified the accuracy of the automated solids monitoring system.

A total of about 3,000 bbl [477 m³] of PowerCLEAN fluid, 11,120 gal [42 m³] of nitrogen followed by about 500 bbl [79 m³] of diesel were pumped. The surface fluid-handling equipment had limited capacity for nitrogen removal, so the PowerCLEAN fluid could not be recirculated and a higher than expected fluid volume was required. Improvements in degassing methods are expected to significantly reduce PowerCLEAN fluid volume requirements on future jobs. After the cleanout, CT running forces predicted by CoilCADE modeling closely matched actual measured values, indicating that no sand fill remained across the cleaned liner.

Experience gained working with ConocoPhillips in Alaska helped Schlumberger engineers fine-tune the PowerCLEAN software modules to more accurately simulate and plan the entire wellbore cleanout process. Initial post-job production rates from this well were around 1,000 bbl/d, later stabilizing at 800 bbl/d [79 m³/d] of oil. The integrated cleanout system was successful in a well with low BHP, large internal-diameter completion and a long, undulating, horizontal wellbore. ConocoPhillips and Schlumberger plan to continue using the system to help improve cleanout efficiency on other difficult wells in the Kuparuk River Unit.

Improving Post-Stimulation Cleanout Efficiency

As operators develop more low-permeability reservoirs, hydraulic-fracturing stimulation of highly deviated or otherwise complex horizontal wellbores has become a relatively standard practice. After fracturing, however, varying amounts of proppant are left behind and must be removed before production begins (see “New Fibers for Hydraulic Fracturing,” page 34).

Since 1996, hydraulic fracturing in the Valhall field, offshore Norway, has become the preferred method of stimulation by operator BP, formerly Amoco. In the North Sea, the cost of CT operations is high and often requires a stimulation vessel and a team of more than 20 completions and operations specialists. With proppant-cleanout operations accounting for about 35% of CT utilization time in the Valhall field, improving the efficiency of cleanout operations would not only reduce cost, but would also bring wells on line faster, generating incremental production revenue (below).11

9. Slick-water refers to a water-base fluid with additives designed to reduce friction pressure. Slick-diesel refers to an oil-base fluid with friction-reducing additives.
10. A gas hydrate is a solid crystalline structure consisting of water with gas molecules in an ice-like cage configuration. Water molecules form a lattice structure into which many types of gas molecules can fit. Most gases, except hydrogen and helium, can form hydrates.

Proppant removal in the North Sea. In the Valhall field, centered approximately between Norway, Denmark, Germany and the UK in the North Sea (bottom right), engineers at BP spend about a third of their time (top) dealing with post-stimulation wellbore cleanup.
During 2004, engineers at BP and Schlumberger built a database and documented the CT cleanout processes used during 29 runs in four completions. Each step in the cleanout process was benchmarked with 24 parameters including proppant properties, start depth, penetration speed and rates, sweep-range depths, circulation rate, time at bottom, pulling out of hole (POOH) rate and time consumed on each step. Of these parameters, engineers focused on optimizing total effective time (TET), defined as the sum of penetrating time, time circulating bottoms-up and time washing from bottom to surface.

Using PowerCLEAN software modules, engineers analyzed previous cleanout operations and defined opportunities for improving efficiency. Of particular note was the finding that residual fracturing proppant appeared in the wellbore in varying distribution patterns, requiring that each of the design elements had to be optimized for each specific wellbore section.

As a part of the optimization process, engineers verified that a simple seawater cleanout fluid, already in use, provided sufficient carrying capacity for single-run cleanouts. Further analysis, modeling and simulations using the PowerCLEAN software modules led to recommendations for maximum CT speed when penetrating fill or beginning the process of fill removal. Specific parameters, such as whether solids formed a bed on the low side of a wellbore and the most efficient bite length into or out of the fill, helped determine nozzle selection, flow rates and fluid rheology requirements.

The new design and recommendations helped engineers optimize circulation rate and select proper nozzles for each application. They also were able to determine cleanout-fluid rheology requirements, calculate running speeds and bite increments, and minimize or eliminate time on bottom circulating bottoms-up. Speeds as fast as 20 m/min [66 ft/min] in the liner and tubing sections were obtained while sweeping out of the hole.

For BP, the Valhall proppant-cleanout optimization project achieved project goals by improving operational efficiency and reliability, and by reducing stuck-pipe risk. A total of 22 runs across three completions used the PowerCLEAN integrated cleanout system. The average TET was reduced from 17.6 h/run to a new average of 11.1 h/run (below). A savings of 6.5 h/run represents a 37.2% reduction in average effective cleanout time and indicates a significant improvement in performance efficiency.

Improving Cleanout Efficiency in Mature Fields

Located about 170 km [105.6 miles] northeast of Kemaman, Terengganu, offshore Malaysia in the South China Sea, the Dulang field began production in the early 1980s. Operated by PETRONAS, the field comprises four platforms, each with 15 to 22 wells. In many maturing oil fields, maintaining production rate in the Dulang field is a daunting task.

Although oil and gas wells in the Dulang field experience wax deposition, scaling and high water cut, sand production remains the primary cause of production decline. In 2004, at least eight wells were shut in because of sand fill, while production slowly declined in many others. Wells in the Dulang field often require intervention due to sand production every three to six months. For PETRONAS, the speed and efficiency of borehole cleanout operations directly affect field production, revenue and return on investment.

Large casing sizes, highly deviated wellbores, elevated borehole temperature, low reservoir pressure and limited production-platform deck space all challenged the efficiency of wellbore cleanout operations. Early in 2004, PETRONAS and Schlumberger engineers evaluated eight
wells for sand and wax cleanout utilizing the PowerCLEAN integrated systems approach (above). Using the CoilCADE wellbore cleanout module, engineers developed unique treatment solutions for each of the eight wells. Cleanout fluids varied from gel and water to a combination of nitrified seawater and wax solvent, and were designed for specific borehole conditions and well configurations.

To restore and potentially enhance oil production, engineers needed to clear the wellbores of sand and debris, thus allowing conveyance of slickline reservoir evaluation tools. Then, each well could be evaluated, stimulated if necessary and brought back on line in a minimal amount of time.

Most wells in the field are similar, with borehole deviations of approximately 63 degrees and bottomhole temperatures (BHT) of 180 to 250°F [82 to 121°C]. Depending on design requirements, engineers optimized fluid cost on several wells by selecting two different cleanout fluid systems, an HEC-base fluid for tubing cleanout and the PowerCLEAN fluid system to remove sand from the larger, and more difficult to clean, tubing-to-casing annular space.

With the exception of Well C-22L, all cleanout jobs were performed in one pass. Each treatment was evaluated by slickline to confirm the effectiveness of sand removal. On several wells, engineers modified the design by switching to nitrified foam fluids to compensate for lost circulation and leaking completion tubing.

The integrated job design improved efficiency and reduced time in hole by optimizing pump rates, defining sand-bite sequences, properly selecting nozzles for sand mobilization and suspension, and accurately estimating chemical consumption. Production was restored in seven of the eight wells immediately following treatment, while the other came back on line following acid stimulation.

On average, the PowerCLEAN integrated systems approach to borehole cleanout reduced time in hole by 75%. The average job time was reduced from two days to around one half-day per treatment. The operator saved time, improved return on investment, and returned the wells to production at a much faster rate, realizing as much as 900 bbl [143 m³] of incremental oil per day.

Process Efficiency
Efficiency is essential in optimizing production from aging oil fields and reservoirs that are difficult to produce. By understanding the interrelationships and potential synergies in process elements, new technologies emerge, helping operators return wells to production faster. As nonproductive time decreases, costs decrease and field output increases.

Understanding key process elements is not always straightforward, and often requires the insights of experts from diverse disciplines. For example, chemists generally develop cleanout fluids, while mechanical engineers and fluid-mechanics specialists develop nozzle technology; the PowerCLEAN integrated wellbore cleanout system exemplifies this type of multidisciplinary collaboration.

Engineers have the tools and computing support to quickly model, perform multiple iterations and optimize cleanout system performance for most wellbore conditions and requirements. The successful integration of cleanout processes is helping many operators keep oil flowing from their fields. This basic understanding of interdependent processes will lead the way to many more efficiency improvements in exploration and production systems. —DW

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### Table: Cleanout Summary

<table>
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<tr>
<th>Number</th>
<th>Well</th>
<th>Treatment</th>
<th>Depth at top of fill, ft</th>
<th>Deviation, deg</th>
<th>Number of runs</th>
<th>Tubing, in.</th>
<th>Casing, in.</th>
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<td>B-22L</td>
<td>Sand cleanout</td>
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<td>71</td>
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<td>2 7⁄8</td>
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<td>B-11L</td>
<td>Sand cleanout</td>
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<td>2 7⁄8</td>
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</tbody>
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^ Improving cleanout efficiency in a mature field. In the South China Sea, PETRONAS has been operating the Dulang field for more than 25 years. The average wellbore deviation is 65 degrees, making cleanout operations difficult. Eight wells with trajectories similar to Well C-18L (right) were evaluated as candidates for efficiency improvement using the PowerCLEAN integrated system (left).