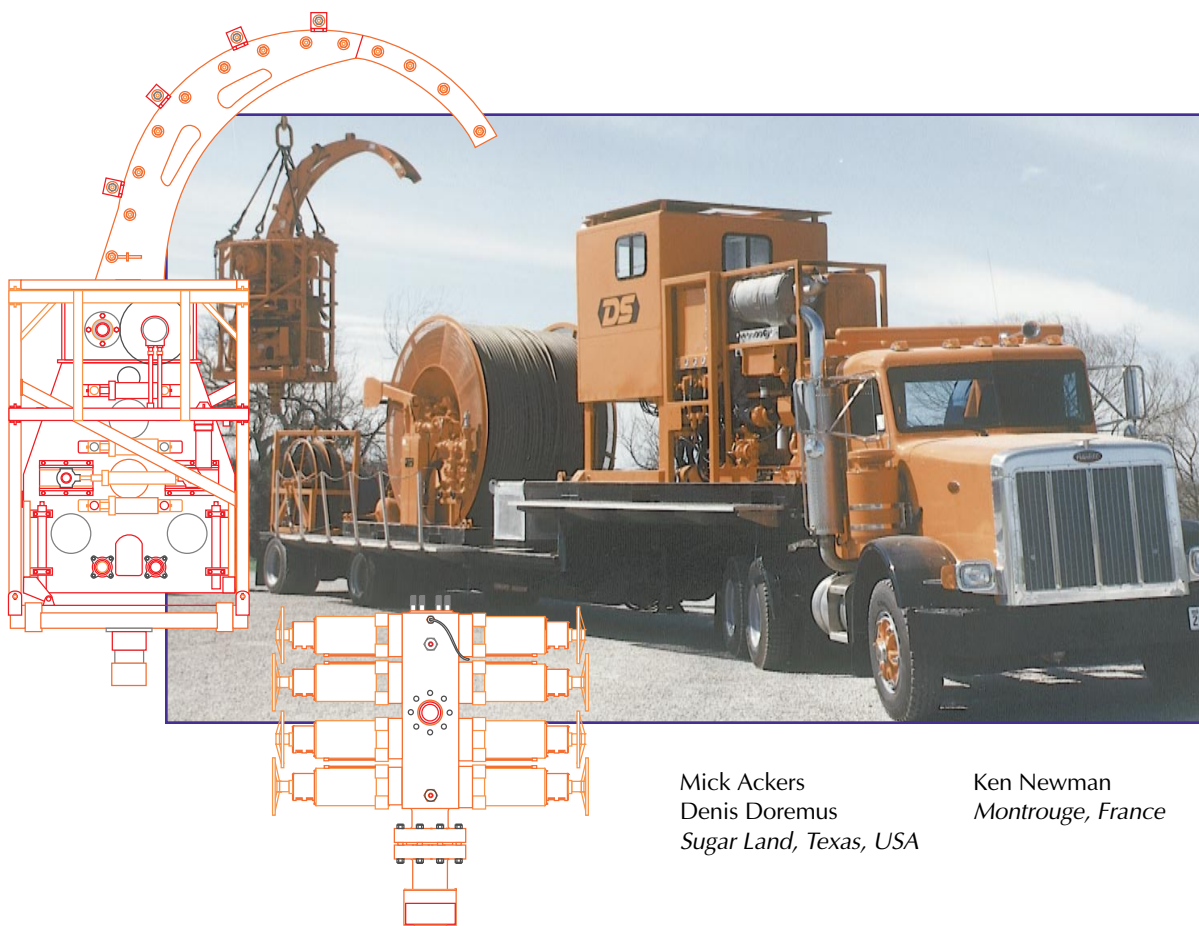


An Early Look at Coiled-Tubing Drilling



□ A coiled-tubing unit with diagrams of the injector head (left) and blowout preventers (center).

Mick Ackers
Denis Doremus
Sugar Land, Texas, USA

Ken Newman
Montrouge, France

Interest in drilling slimhole wells with coiled tubing is high. So far, only a few experimental wells have been drilled and many technological issues remain unresolved. But if these challenges are met, coiled-tubing drilling could become the medium that finally delivers slimhole wells across the industry.

In this article, FSTS (Formation Selective Treatment System), SideKick and CoilLIFE are marks of Dowell Schlumberger. SLIM1 is a mark of Anadrill.

For help in preparation of this article, thanks to Bruce Adam, Dowell Schlumberger, Rosharon, Texas, USA.

1. For details of coiled-tubing hardware and its applications to workover and logging:

Ackert D, Beardsel M, Corrigan M and Newman K: "The Coiled Tubing Revolution," *Oilfield Review* 1, no. 3 (October 1989): 4-16.

2. Littleton J: "Coiled Tubing Springs into Horizontal Drilling," *Petroleum Engineer International* 2 (February 1992): 20-22.

In recent years, workover and logging using coiled tubing has become increasingly widespread (*above*).¹ During workover operations, coiled tubing has been used successfully to drill out cement plugs and remove scale—in most cases harder to drill than formation. Now attention is focused on coiled-tubing drilling as a technique to deliver cost-effective slimhole wells for both exploration and production.²

Slimhole wells are normally defined as having at least 90% of their diameter less than 7 in. They are drilled using rotary rigs that are much smaller than normal rigs—about 20% of their weight, requiring about a quarter of the drillsite area. Over half of drilling costs depend on factors other than drilling time, such as construct-

ing the drill pad and access roads, moving the rig, and the cost of casing and consumables like mud.³ A coiled-tubing unit (CTU) is even smaller than a slimhole rig, is easier to mobilize and requires less equipment and personnel. Its smaller site requirement leads to lower civil engineering costs. The smaller, quieter CTUs have a reduced environmental impact.

There are also particular benefits offered by use of continuous tubing. It avoids the need for connections, speeding up trip times and increasing safety—many drill floor accidents and blowout/stuck-pipe incidents occur when drilling is stopped to make a connection. CTUs have pressure control equipment designed to allow the tubing to be safely run in and out of live wells. The stripper above the blowout preventers (BOPs) seals the annulus during drilling and tripping. This offers increased safety during drilling—similar to having a conventional rig's annular preventer closed all the time. This safety feature also facilitates underbalanced drilling, in which drilling is carried out while the well is flowing.

A range of different uses has been proposed for slim holes drilled by a CTU (right). So far, lateral production and vertical re-entry wells have been drilled. These experimental wells were designed to prove that the technique can effectively meet design specifications.

Three re-entry horizontal production wells have been drilled in the Austin chalk, Texas, USA, using 2-in. directionally-controlled coiled tubing with 3 7/8-in. bits. In an effort to prove the efficacy of coiled-tubing drilling for exploration, a vertical well was deepened in the Paris basin, France, using 1 1/2-in. coiled tubing with 3 7/8-in. bits. This was also a re-entry, but a new vertical well is also planned.

This article reviews one of the Austin chalk wells and the Paris basin well. Then it will look at the technological challenges arising from these experiences.

Lateral Re-Entry for Production

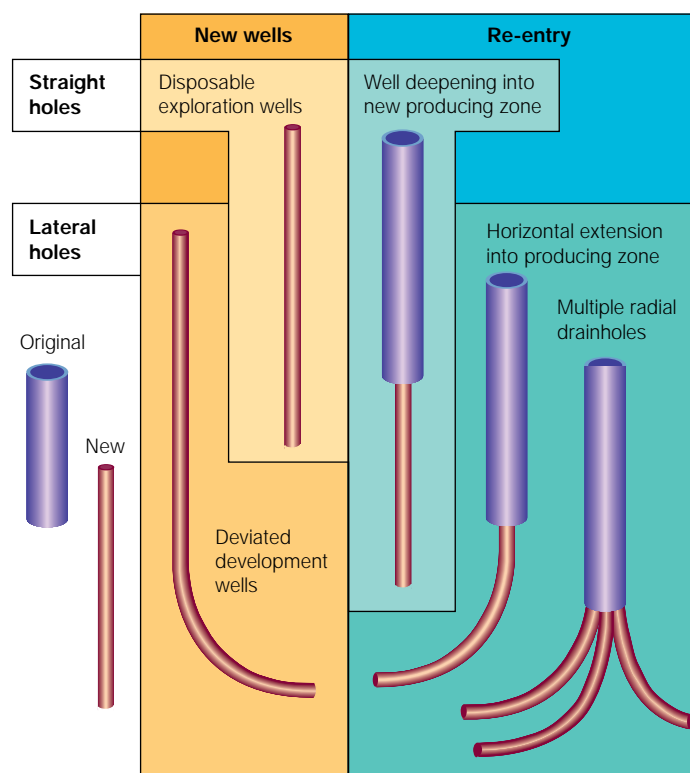
Last year, Oryx Energy Company re-entered a vertical well in the Pearson field, Texas, USA, completed in Austin chalk. Horizontal drilling in Austin chalk using mud commonly encounters almost total lost circulation. To reduce mud losses, formation damage and costs, water is often used as drilling fluid. This decreases bottomhole hydrostatic pressure to less than formation pressure—underbalanced drilling. To combat annular pressure from formation flow during drilling, conventional rigs use a rotating stripping head or rotating BOPs to seal the annulus. The wells are killed each time a trip is made.

By using a CTU, which has its annulus sealed throughout drilling by the stripper, Oryx was able to run in and out of hole without killing the well. This improved safety

and avoided the expense and potential damaging effects to the formation of pumping brines to kill the well prior to tripping.

To prepare the well, Oryx used a conventional service rig to remove the existing completion hardware, set a whipstock and sidetrack out of 4 1/2-in. casing at a true vertical depth of 5300 ft [1615 m]. Drilling was then continued using 2-in. coiled tubing, downhole mud motors, wireline steering tools, a mechanical downhole orienting tool and 3 7/8-in. bits. An average buildup rate of 15°/100 ft [15°/30 m] was achieved and a horizontal section drilled for 1458 ft [444 m].⁴ The main bottomhole assembly (BHA) components were:

Drillstring—Oryx employed a reel comprising 10,050 ft [3060 m] of 2-in. outside diameter coiled tubing with 5/16-in. mono-conductor cable installed inside the tubing.



□ Potential applications for coiled-tubing drilling.

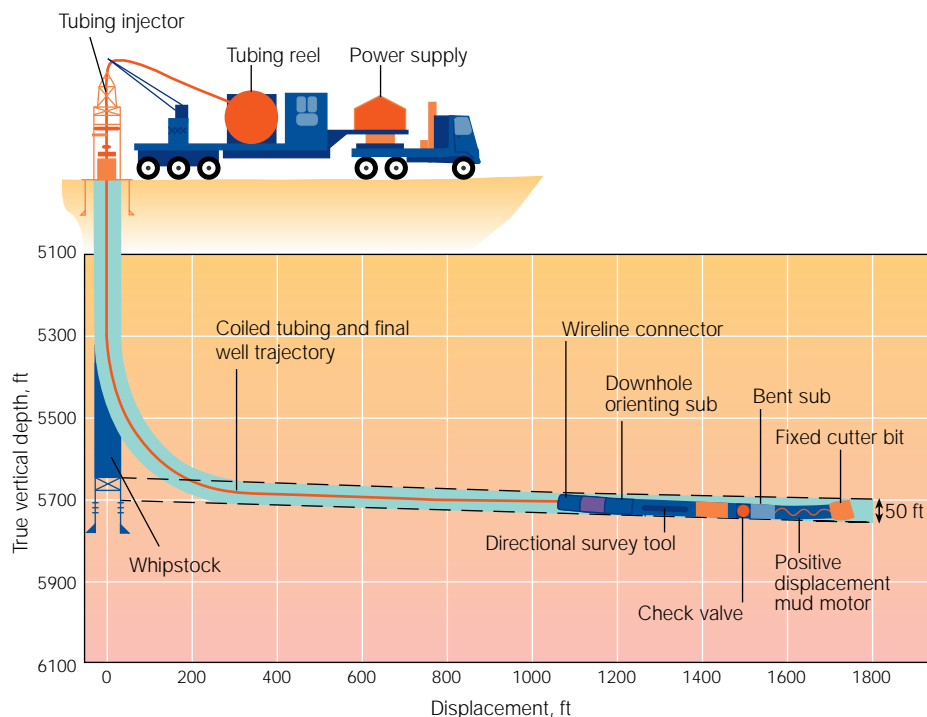
3. Randolph S, Bosio J and Boyington B: "Slimhole Drilling: The Story So Far..." *Oilfield Review* 3, no. 3 (July 1991): 46-54.

4. Ramos AB, Fahel RA, Chaffin M and Pulis KH: "Horizontal Slim-Hole Drilling With Coiled Tubing: An Operator's Experience," paper IADC/SPE 23875, presented at the 1992 IADC/SPE Annual Drilling Conference, New Orleans, Louisiana, USA, February 18-21, 1992.

Wesson HR: "New Horizontal Drilling Techniques Using Coiled Tubing," paper SPE 23951, presented at the 1992 Permian Basin Oil and Gas Conference, Midland, Texas, USA, March 18-20, 1992.

5. Traonmilin E, Courteille JM, Bergerot JL, Reyssset JL and Laffiche J: "First Field Trial of a Coiled Tubing for Exploration Drilling," paper IADC/SPE 23876, presented at the IADC/SPE Annual Drilling Conference, New Orleans, Louisiana, USA, February 18-21, 1992. Traonmilin E and Newman K: "Coiled Tubing Used for Slim Hole Re-entry," *Oil & Gas Journal* 90 (February 17, 1992): 45-51.

6. Ackert et al, reference 1.



□ **Final analysis of the Oryx well in Austin chalk, Texas, USA. With a steerable bottom-hole assembly, the horizontal section was drilled within its 50-ft vertical window.**

Orientation tool—Because coiled tubing cannot be rotated from surface to alter drilling direction, a downhole method of changing tool face orientation is needed. To achieve this, Oryx deployed a mechanical tool that converts tubing reciprocation into rotation—compression rotated the tool face to the right, extension to the left. Once adjusted, the tool face was locked in place using a minimum 250-psi differential pressure across the tool.

Directional survey tool—The survey tool inside a nonmagnetic collar relayed directional information to surface via the wireline.

Directional BHA—Two assemblies were used, depending on the build rates required—a double-bend assembly consisting of a conventional 27/8-in. bent housing mud motor coupled to a single bent sub, or a steerable assembly comprising a single-bend motor.

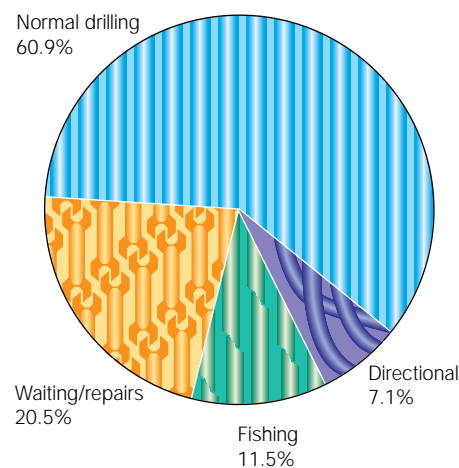
Bit—Thermally stable diamond bits were used to drill the curve and build sections and polycrystalline diamond compact (PDC) bits to drill the lateral section.

Oryx's motive for drilling this well was to prove that coiled tubing could be used to drill a lateral well in a controlled manner. This was achieved—the final wellbore trajectory came within a 50-ft [15-m] vertical window along the horizontal section (above).

Because this well was the first of its kind, new techniques had to be developed, and much of the drilling equipment had to be adapted from existing conventional hard-

ware. Orienting the tool face was not difficult, but maintaining it was hard because of the unpredictable reaction of the coiled tubing to the torque generated by the drilling motor's rotation. Drilling was also slowed by failure of BHA components, particularly the orienting and directional survey tools.

These difficulties affected the final cost analysis. Total cost was estimated by Oryx at twice that of using a conventional rig—nondrilling time was responsible for nearly 40% of this (below). However, as purpose-designed equipment becomes available and drilling procedures are refined, coiled tubing should deliver more cost-effective, slimhole, lateral wells.



□ **Cost breakdown for the first Oryx well.**

Vertical Exploration Well

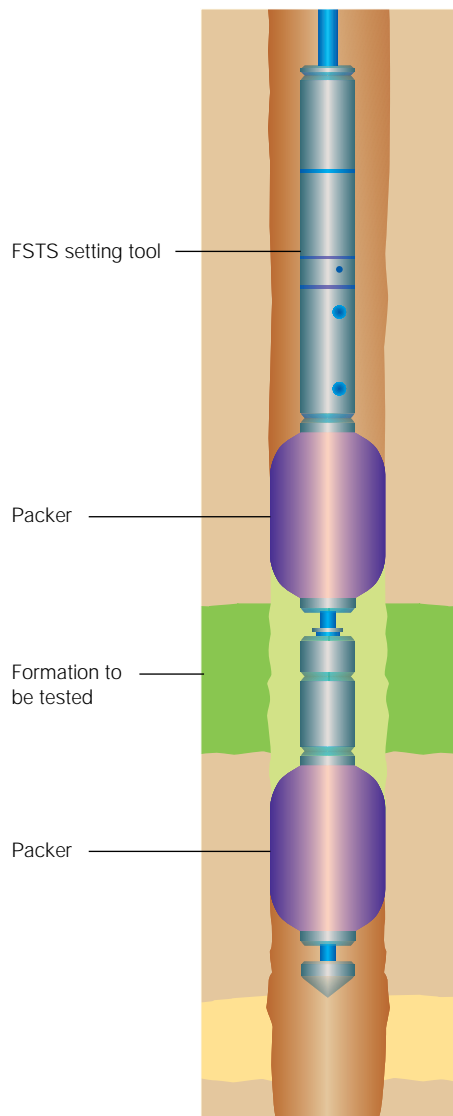
Last year, Elf Aquitaine embarked on a series of trials to determine whether coiled tubing could be used to drill slimhole wells, cutting exploration drilling costs. The goal of the first well was to demonstrate that a CTU can drill a vertical well sufficiently fast, cut cores and test formations. Elf envisions initially drilling these slimhole wells with a single openhole section—avoiding the need for casing—with the surface casings set using low-cost, water well rigs.

This first trial involved the re-entry of well Saint Firmin 13 in the Paris basin.⁵ The plan was to use the CTU to set cement plugs across the existing perforations at 2120 ft [646 m] and then drill a 2105-ft [642-m] vertical section of 37/8-in. diameter. Directional measurements using a coiled-tubing-conveyed survey were to be taken every 500 ft [150 m]. Then a 50-ft interval was to be cored and logged. Finally, a zone was to be flow tested by measuring pressure between two straddle packers.⁶

The trial was carried out by Dowell Schlumberger using a trailer-mounted CTU with a reel of about 6000 ft [1830 m] of 1½-in. tubing. To avoid the need for costly modifications, standard surface hardware, like injector head with stripper and BOP stack, were used. A workover rig substructure was installed over the existing wellhead to act as a work platform.

The operation encountered difficulties at the outset—not with the drilling but with the integrity of the well's 30-year-old casing. After cement plugs were set, the well would not hold the 360 psi above hydrostatic pressure required to withstand the anticipated formation pressures. Because of this, drilling depth was limited to 2955 ft [901 m] which allowed limestone coring but did not extend to a high-pressure aquifer.

The drilling BHAs employed a high-speed, low-torque motor with PDC bits. For coring, a high-torque motor was used. The drilling and coring assemblies were made to hang vertically by incorporating heavy drill collars into the BHA, creating a pendulum assembly. At the start, the deviation at the casing shoe was 2° and, as expected, the BHA did not build angle—at 2362 ft and 2795 ft [720 m and 852 m], the deviation angles were 2¾° and 2¼° respectively. During drilling, the rates were comparable to those drilled by conventional rigs at work in the area. This showed that a CTU can drill vertical wells at commercial rates. Two cores were cut and retrieved with good recovery—meeting the second objective of the trial.



□ **The FSTS Formation Selective Treatment System.** The coiled-tubing conveyed FSTS straddle packers were set across the formation to allow reservoir fluids to flow, proving that drillstem tests can be carried out using coiled tubing.

Because the program had to be revised to avoid high-pressure zones, no oil-bearing formation could be tested. To prove the testing technology and meet the third objective, a drawdown test was carried out on a zone between 2221 ft and 2231 ft [677 m and 680 m]. The FSTS Formation Selective Treatment System was deployed with its two packers straddling this zone. The formation was successfully isolated and, if it had been a reservoir, would have produced into the coiled tubing (above).

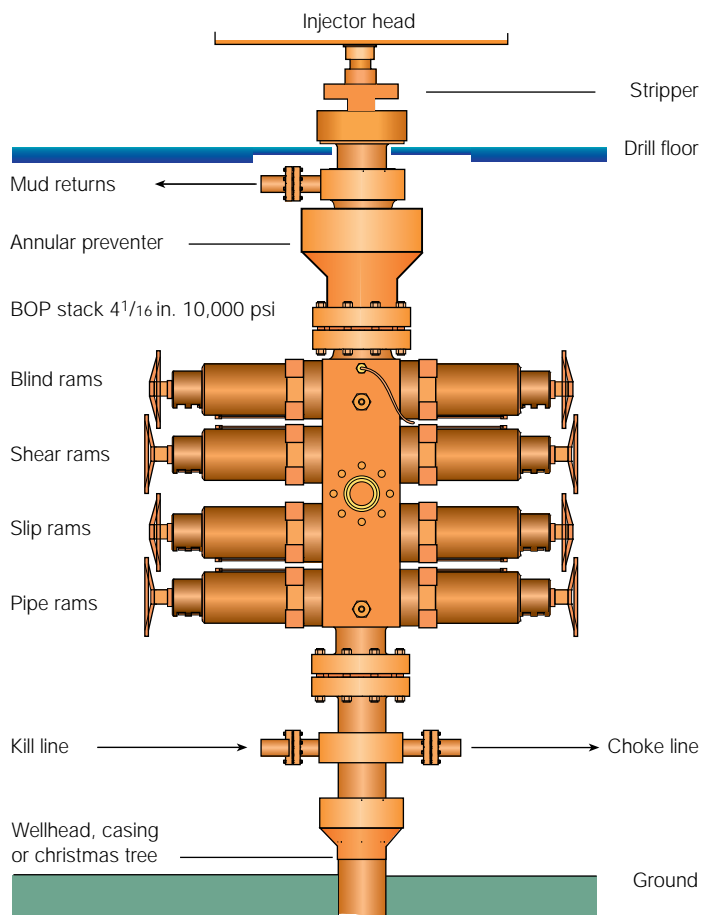
Looking to the Future

In addition to proving that coiled tubing can be used to drill wells, the trial pointed out how procedures could be changed and where future hardware development is required. For example, rate of drilling could be increased by incorporation of measurement-while-drilling tools to make directional surveys, improving surface handling and weight-on-bit (WOB) control techniques and better optimization of the BHA.

To address these issues, Dowell Schlumberger has assembled a multidisciplinary task force with Sedco Forex and Anadrill. Its wide-ranging agenda covers equipment needs, operational and safety procedures, tubing limits and personnel requirements.

Equipment needs—The Elf job utilized a workover rig substructure. In the future, a purpose-built substructure will be employed. Standing 10 ft [3 m] off the ground and over the wellhead, this substructure will act as the drill floor to make or break the BHA and also to support the injector head.

□ **Blowout preventer configuration for a well drilled with a hole size less than 4-in. diameter.**



The BOPs will be mounted below the injector head directly on top of the wellhead, casing or christmas tree. If the hole diameter is less than 4 in. [10 cm], 4 1/16-in., 10,000 psi coiled-tubing BOPs will be used. If the hole is larger, a standard set of 7 1/16-in., 5000 psi drilling BOPs will be used instead. In both cases an annular preventer will also be incorporated into the stack (below and next page, left).

In the directional wells drilled so far using coiled tubing, BHA direction has been altered using reciprocation of an orienting tool. This technique has the dual disadvantages of interrupting drilling and requiring manipulation with pressure in the tubing, which has a severe fatiguing effect. The task force has therefore designed BHAs that incorporate an orienting tool controlled by using mud flow rate.

Directional information can be sent to surface either using wireline or mud-pulse telemetry. Wireline offers real-time transmission of high volumes of information. How-

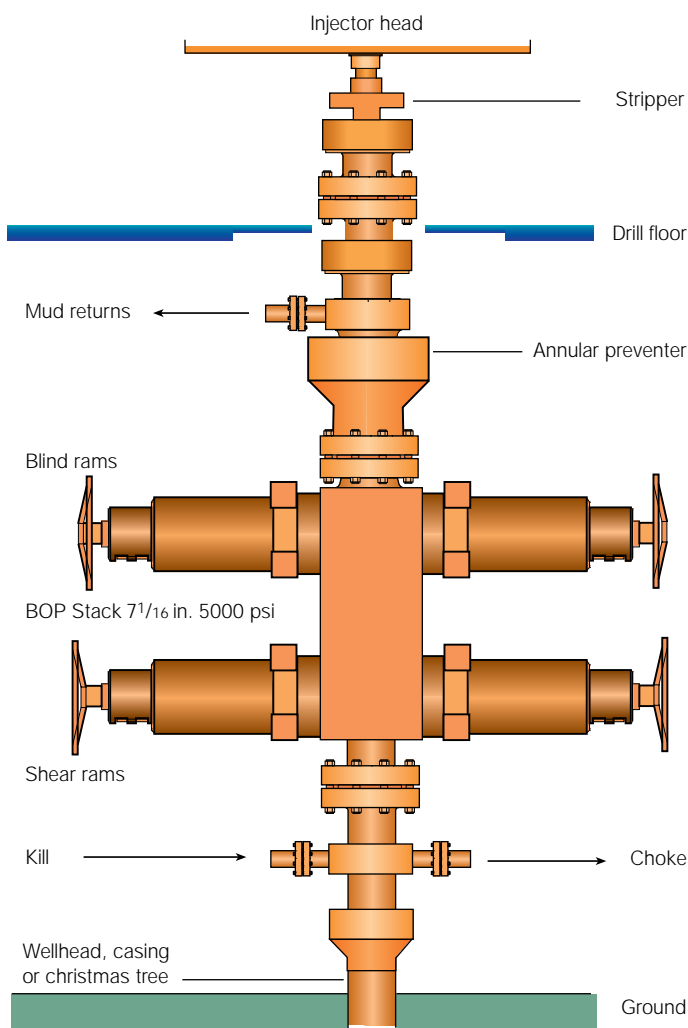
ever, having wireline in the tubing requires a high level of maintenance and cuts down pumping options—like acidization treatments. To avoid the need for a cable link, the task force has adapted Anadrill's SLIM1 measurement-while-drilling system—which uses mud pulse telemetry—so that it fits inside a 3¹/₁₆-in. diameter nonmagnetic drill collar (right).

The chemistry of muds used when drilling with a CTU is not expected to be significantly different from muds used in conventional wells. However, the technique does have some special rheological requirements. In a re-entry well, the coiled tubing/casing annulus may be relatively large—perhaps 2 in. inside 7 in.—slowing the annular velocity of the fluid and possibly compromising the cuttings-carrying capacity of the mud. Further, because the fluid is pumped through small-diameter tubing, friction must be kept to a minimum by using low solids muds with low viscosities and yield points. To mix and treat drilling

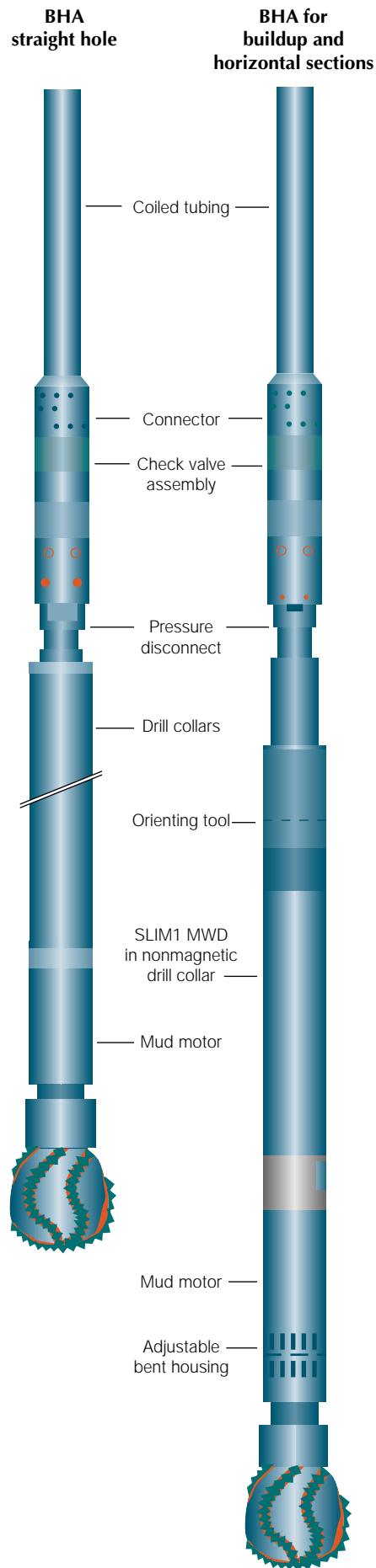
□ **Straight hole and buildup/horizontal bottomhole assemblies (BHAs).** In both, fullbore check valves prevent backflow to surface. The pressure disconnect sub allows recovery of the coiled-tubing string if the BHA gets stuck. A ball is dropped and pumped through the tubing until it seats in the disconnect sub. Internal tubing pressure is then applied that shears pins in the sub and releases the string.

The straight hole BHA includes drill collars, so that the string acts as a pendulum and tends to the vertical. Buildup and horizontal BHAs include an adjustable bent housing to facilitate deviated drilling. The housing angle is fixed at surface before the BHA is run, and its effect on the drilling angle is controlled by using the orienting tool to rotate the tool face. Progress is monitored by the SLIM1 MWD tool, which relays the information to surface via mud pulses.

A CTU employs a low WOB, 2000 lb [900 kg] compared to 4000 to 6000 lb [1800 to 2700 kg] for conventional slim-hole drilling. So high-speed—700 rpm—low-torque drilling motors are expected to be most effective. Polycrystalline diamond compact or thermally stable bits are used.



□ **Blowout preventer configuration for a well drilled with a hole size greater than 4-in. diameter.**



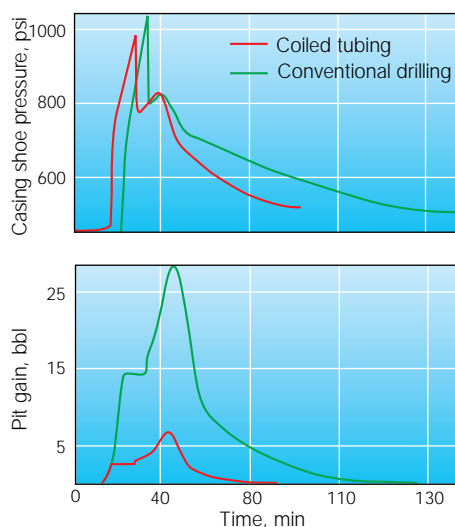
fluid, a trailer-mounted pumping and treatment unit has been constructed.

In a vertical hole, the setdown weight read at surface is equivalent to the WOB. However at high angles, the tubing compresses inside the wellbore. If too much weight is set down, the tubing may lock against the walls of the well, failing to transfer any further weight to the bit.⁷

Experience from the Paris basin well showed that while manual control of set-down weight was possible, it was tedious and required absolute concentration from the operator. To improve drilling efficiency, the CTU has been fitted with a system that automatically maintains a setdown weight. With this autodrilling system, the operator can monitor progress without having to make continual minute weight changes.

The task force is reviewing three other areas of equipment development under review. All involve handling tubulars: removing the existing production tubing in re-entry wells, deploying the BHA into a live well, and running casing.

Operational and safety procedures—Procedures for controlling a slimhole well when drilling with a CTU differ from those needed when drilling with a conventional slimhole rig. At the heart of this is the difference in annuli. Conventional slimhole wells have a narrow annulus and the mud traveling up it creates a back pressure, called the equivalent circulating density (ECD). The ECD increases with pump rate and raises bottomhole hydrostatic pressure. This provides the option of dynamic kill—increasing the rate to increase the pressure—but also a potential disadvantage of losing mud due to ECD exceeding the formation fracture gradient.



Comparison of gas kicks in 5000-ft wells drilled using coiled-tubing and conventional methods with 3 1/8-in. and 6 1/2-in. BHAs, respectively. SideKick software was used to compare the effects of influxes that gave similar annular heights. In both cases, the driller's method was used to circulate out the kick, during which casing shoe pressures were about the same. Because of its smaller annular volume, the well being drilled by CTU experienced much smaller pit gains.

When drilled with a CTU, the annulus is larger—particularly in re-entry wells—ECD is not a factor and dynamic kill cannot be applied. To evaluate other well-kill strategies, the task force used SideKick software to model gas influxes in a full size well being drilled conventionally and a slimhole well being drilled by a CTU.⁸

The SideKick model was used to assess the significance of the volume of influx. First, it modeled influxes that gave comparable heights of gas in conventional and coiled-tubing annuli (about 7.5 and 3 barrels, respectively). The shut-in casing pressure (SICP) at surface and the casing shoe pressure (CSP) were broadly similar in both

wells (left). But in modeling an influx of 7.5 barrels in the slim and conventional annuli, the SICP and CSP in the coiled-tubing well were much higher—double or more.

Therefore, early detection of gas influxes during coiled-tubing drilling is vital. The CTU's stripper seals the annulus and ensures that the mud return line is full, improving the reliability of delta flow measurements—the difference between mud flow rate in and out of the well. Delta flow is measurable down to 10 gal/min [0.8 liter/sec], permitting rapid detection of kicks after allowing for the volume increase due to cuttings. In the mud pits, resolution of conventional level sensors is improved by having mud tanks with a smaller base area than is normal.

All drilling operations are subject to safety regulations limiting operational equipment to zones—in Europe, Zone I allows only the most stringent explosion-proof equipment, Zone II the next most, and so on. Ironically, the compactness of a CTU complicates compliance with these regulations.

In the Paris basin well, the Zone II classification was specially reduced by the authorities from a 100-ft to a 50-ft radius from the wellhead. If the radius had been any larger, it would have extended the zone's requirements to the cars on the edge of the lease (next page). Changes in local regulations and in equipment classification may be required in the future.

Tubing limits—Coiled tubing had a slow start as a workover service because of unreliability and propensity for unpredicted failure. To combat this, Dowell Schlumberger has developed a better understanding of the factors governing tubing fatigue; this is now being applied to drilling operations.⁹ Repeated use of coiled tubing has three types of limitation:

7. Ackert et al, reference 1.
 8. White D and Lowe C: "Advances in Well Control Training and Practice," paper, presented at the Third Annual IADC European Well Control Conference, Noordwijkerhout, The Netherlands, June 2-4, 1992.
 9. Newman KR: "Coiled-Tubing Pressure and Tension Limits," paper SPE 23131, presented at the Offshore Europe Conference, Aberdeen, Scotland, September 3-6, 1991.
 10. Newman KR and Newburn DA: "Coiled-Tubing-Life Modeling," paper SPE 22820, presented at the 66th SPE Annual Technical Conference and Exhibition, Dallas, Texas, USA, October 6-9, 1991.
- Newman K: "Determining the Working Life of a Coiled Tubing String," *Offshore* 51 (December 1991): 31-32, 34-36.

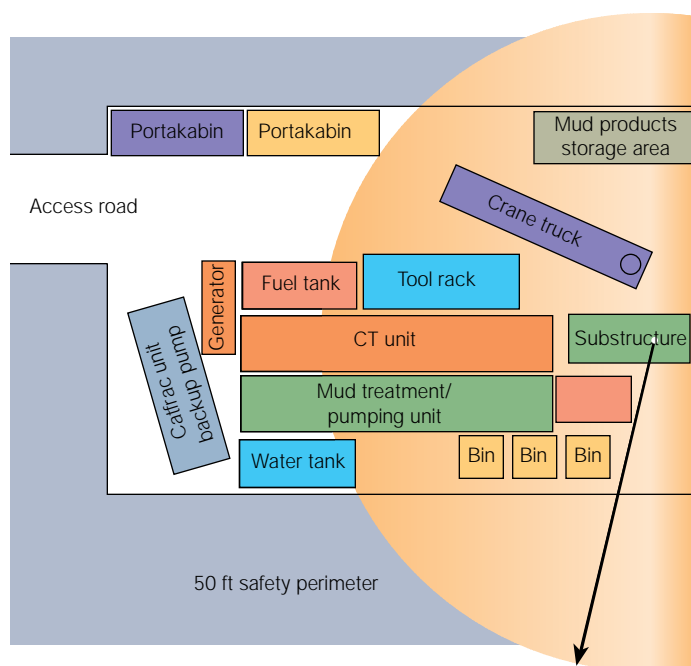
- Pressure and tension limits—the burst and collapse pressures and the maximum tension and compression at various pressures. These are analogous to the limits experienced by drillpipe and can be calculated through tests and carefully avoided during operations.
- Diameter and ovality limits—the degree to which the pipe is collapsed, ballooned or mechanically damaged. This also has an analogy in drillpipe where damaged pipe and couplings have to be detected. With coiled tubing, the physical shape of the tubing can be continuously monitored during the job to detect damage.
- Life limits—primarily due to bending in the pipe at the gooseneck and on the reel as it is spooled on and off, often with the tubing pressured. Anticipating life limits of tubing has proved difficult, but is vital to avoid catastrophic failure. At its crudest, the fatigue of a reel of tubing can be equated to the number of times it is run into and out of the well—termed cycles.

After extensive research, Dowell Schlumberger has developed a way of assessing coiled-

tubing fatigue that is more sophisticated than simply counting cycles—the CoillIFE model.¹⁰ During jobs, all tubing movement and pressures are monitored and recorded. The CoillIFE software then calculates the amount of life remaining in the string. It takes into account the relative severity of each cycle, the nature of the fluids that have been pumped and the sequence in which the cycle occurred—which affects the accumulated damage.

Personnel requirements—The number of personnel required for coiled-tubing drilling is likely to be about 50% of that needed for conventional operations. Not only are day-to-day operational requirements lower, but the number of service personnel can also be reduced. For example, when running casing, the mud system could be employed to mix and pump cement—eliminating the need for a cementing engineer. All the drilling information, along with basic mud logging data and general surface data, will be centralized in a computerized information system, eliminating the need for a full-time mud logger.

—CF



□ **Layout of Elf's coiled-tubing drilling site in the Paris basin, France.**