COILED-TUBING DRILLING IN PERSPECTIVE

T.G. Byrom, SPE, T.G. Byrom & Assocs.

SUMMARY

Coiled-tubing (CT) drilling is a technology of the current decade. The question that many operators have regarding CT drilling is, "Should we consider using CT drilling in our operations?" CT drilling has a considerable number of advantages over conventional drilling methods in certain applications, but it also has a number of limitations that an operator must be aware of. The decision to use CT for drilling must be based on its capabilities because conventional economics seldom favor its use as a drilling method. CT does have unique capabilities that make it excel in true underbalanced drilling and in certain re-entry applications.

INTRODUCTION

Openhole drilling with CT technology is truly a product of the 1990's. In 1990, Fultz and Pitard[1] showed that it was a feasible concept, and Ramos *et al.*[2] reported on its use in a successful producing-horizontal-well case history in 1992. The technology was conceived, was born, and grew within this decade, and its growth and successes in this brief time interval are astounding. CT offers a number of advantages and unique capabilities over conventional methods for openhole drilling and likewise has a number of disadvantages and limitations.

CT Capabilities.

- Drill and trip under pressure.
- Fast trips.
- Continuous circulation while tripping pipe.
- Continuous, high-quality two-way telemetry between surface and downhole for real-time data and control.
- Slimhole capability.
- Small location size.
- Portability.

CT Limitations.

- Cannot rotate.
- Limited fishing capabilities.
- Small diameters.
- Limited reach in horizontal laterals.
- Low circulating rates.
- High circulating pressures.
- Short tube life.
- High maintenance.
- High daily costs.
- Limited availability of high-capacity units.

This is paper SPE 51792. **Distinguished Author Series** articles are general, descriptive representations that summarize the state of the art in an area of technology by describing recent developments for readers who are not specialists in the topics discussed. Written by individuals recognized as experts in the area, these articles provide key references to more definitive work and present specific details only to illustrate the technology. **Purpose:** to inform the general readership of recent advances in various areas of petroleum engineering. A softbound anthology, *SPE Distinguished Author Series: December 1981–December 1983*, is available from SPE's Customer Service Dept.

Despite these limitations, there are a number of applications where the unique capabilities of CT make it a better choice than conventional methods. In geographic areas where it has proved itself, before recent oil price declines, there were waiting lists of several months for the available CT-drilling units.

CT-DRILLING EQUIPMENT

A common misconception is that a CT-drilling unit is a small self-contained unit that drives up on location ready to drill with a minimum of rigup involved. In truth, the typical CT-drilling unit must have much of the same equipment that a conventional drilling unit has (e.g., circulating pumps, mud tanks, solids-removal equipment, mud-mixing facilities, well-control equipment). It commonly requires about five to six truckloads of equipment and possibly more if the drilling operation is to be done underbalanced. Also, CT-drilling units with $2^3/_8$-, $2^7/_8$-, or $3^1/_2$-in. outer diameters (OD's) are not exactly the small unit most operators are accustomed to seeing on location for typical well-service jobs. These are necessarily high-capacity units with more associated equipment. Newer units built specifically for CT drilling are designed to overcome some of these mobility problems. Some of these units also have conventional pipe-handling capability, which greatly enhances their utility. Others are being constructed primarily as small drilling rigs that also have CT-drilling capability.

Downhole Equipment. The downhole equipment for CT drilling can be simple or quite complex. For a simple vertical-drilling project, it may consist of a bit, a downhole motor, and a few drill collars. It is much more elaborate for a directionally drilled well.

A typical directional bottomhole assembly (BHA) consists of a bit; a bent-housing mud motor; a steering tool to sense and transmit the directional data; an array of optional sensing devices, such as gamma ray and other logs, bottomhole-pressure (internal and external), weight on bit, bit torque, temperature, and vibrations; and an orientation tool to change the direction of the bit (**Fig. 1**). All sensing and control devices are in continuous two-way communication with the surface through one or more electric and often hydraulic lines inside the CT.

An electric cable with one or more separate conductors is inside the CT itself. In addition, some units also have one or more hydraulic tubes inside the CT. These cables and tubes provide two-way telemetry and control between the operator on the surface and the devices in the BHA. Units with only an electric cable usually have downhole hydraulic pumps to operate the equipment as dictated by the electric signals from the surface. Those that also have one or more hydraulic tubes rely on a surface hydraulic pump for tool operation. Although these cables and tubes add weight to the CT string and restrict internal flow, they provide the CT unit with a marked advantage over conventional measurement-while-drilling (MWD) systems by providing two-way communication and high-quality real-time data from downhole instruments. However, a number of specific applications exist where

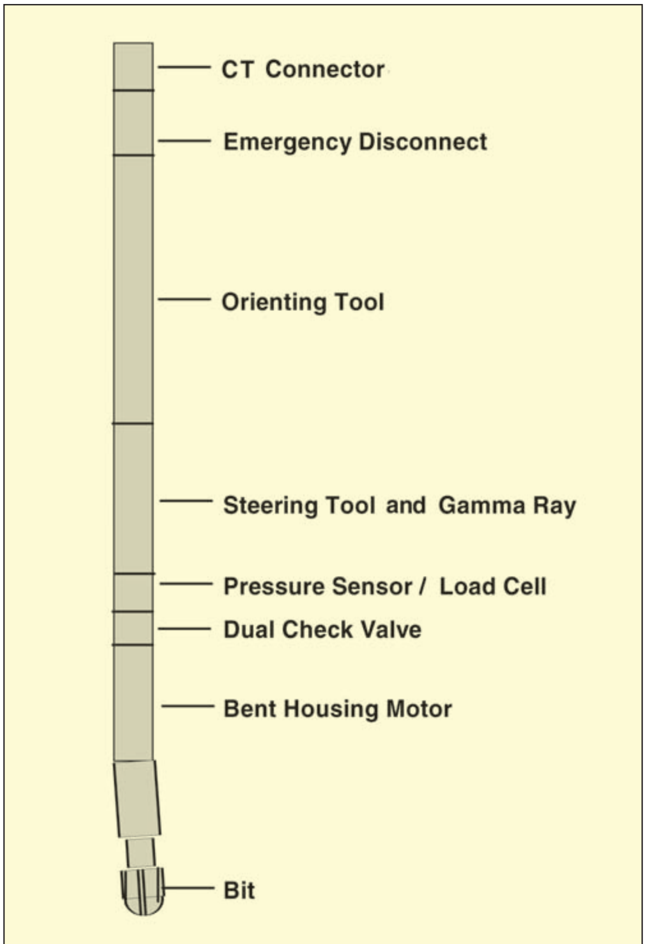

Fig. 1—Typical bottomhole assembly for CT horizontal drilling.

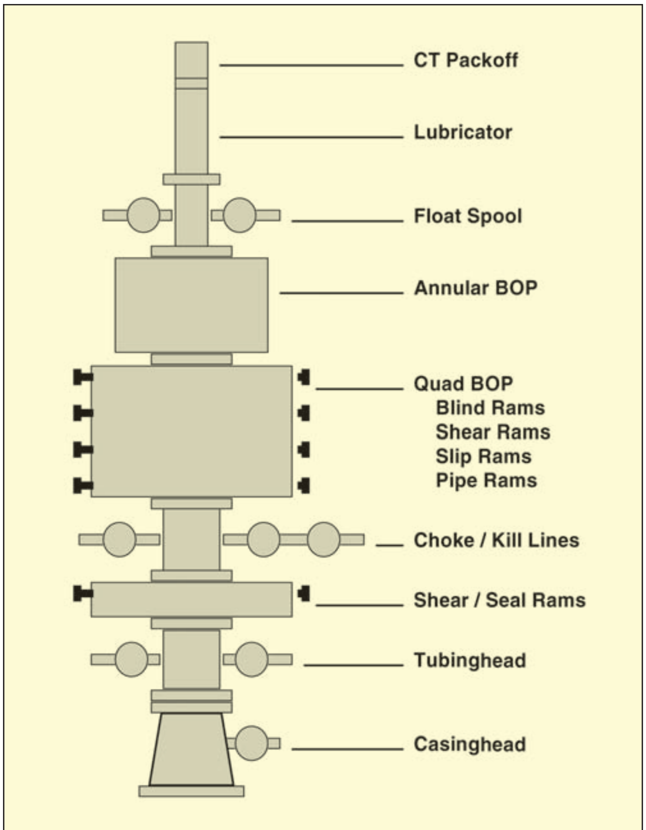

Fig. 2—Typical BOP assembly for underbalanced CT drilling.

weight and size limitations preclude use of the internal cables. Then, the only choice is conventional pulse-type MWD tools and static orienting tools.

Two other important items in the BHA are a check valve and an emergency disconnect. Unlike a conventional drillstring, if the well is under pressure, all CT that is not in the hole also is under pressure. If a leak initiates in the tubing on the reel, there is no way to shut it off other than to cut the tubing inside the blowout-preventer (BOP) stack with the shear rams. For this reason, a check valve (usually two) is run in the BHA and is required by law in many locations. The emergency disconnect allows a CT-unit operator to disconnect the CT from the BHA if it becomes stuck. Most of these are shear-type devices that preclude the use of jars in the BHA, but some are operated electrically and/or hydraulically.

Surface Equipment. Surface equipment for a CT-drilling operation typically is a high-capacity CT unit with some type of mast for handling the wellhead equipment plus the associated drilling-fluids-handling equipment. Aside from the presence of a circulating-fluid system, a notable difference between a drilling CT unit and a well-service CT unit is in the BOP stack. A typical CT BOP stack contains pipe, blind, slip, and shear rams; however, for drilling, the assembly must also contain some means of snubbing the BHA into and out of the hole under pressure. This is done with additional ram-type preventers and/or with an annular preventer, depending on wellhead pressures and toxicity of the produced fluids. The operation of deploying the BHA under pressure is not standardized, and the equipment used varies (**Fig. 2**). It is a time-consuming phase of the operation that needs improvement.

The control unit of a modern CT-drilling unit is highly sophisticated compared with that of just a few years ago. In addition to having the capability to monitor downhole conditions and change tool settings, it has a computerized capability to monitor CT conditions and update CT service-life predictions continually, to do hydraulics calculations, to predict borehole friction, and much more.

CT as a Drillstring. Until the 1990's, the available CT was actually too small in diameter to drill efficiently in open hole. Although Fultz and Pitard[1] advanced the feasibility of drilling with $1^3/_4$-in. OD, the first openhole lateral was drilled with a 2-in.-OD unit,[2] which had only recently become commercially available. That size now is considered too small for most applications, and we prefer OD's of $2^3/_8$, $2^7/_8$, or $3^1/_2$ in. because of the increased bending stiffness and reduced clearance between the tube and the borehole wall.

A severe limitation of CT in drilling highly deviated laterals is its propensity for helical buckling and subsequent "lockup" (cessation of string motion as the helix exerts increasing contact force against the borehole wall to the point where the frictional force is too great to be overcome by forcing additional CT into the hole). Because helical buckling and lockup are directly related to bending stiffness and clearance, if a choice is available, $3^1/_2$-in. or larger OD (hole size permitting) would always be selected. However, there is another limiting factor. Size and weight restrictions exist for most public highways, bridges, underpasses, and tunnels. Therefore, the choice is not always the best size but the size that can be transported to location.

Much has been written about CT service life. The only thing we want to add is some comments about the commonly asked question, "What is the service life of a CT string used for drilling?" In a word, short. A typical CT string used in well-service work might be expected to last through 30 or more jobs, depending on well conditions. For simple deepening jobs that involve only vertical drilling, a CT string might be expected to last for as many jobs, but the number drops significantly for directional drilling. For horizontal wells that have casing set through the build section to horizontal so that the CT string drills only the lateral, the string might drill six to eight wells. If the build section (or sidetrack kickoff and build) also is drilled with the CT string, the life may be only two to three wells, and possibly only one. This is not encouraging from a cost standpoint; however, new approaches (discussed later) to reduce the number and severity of the bending cycles on the tubing show a lot of promise by increasing fatigue life by as much as 300%.

UNIQUE CT-DRILLING CONSIDERATIONS

Drilling with CT is necessarily different from conventional drilling in several respects. Because CT does not rotate, a number of operations, such as directional orientation and cuttings removal, must be addressed differently.

Directional Orientation. One of the more problematic areas of CT drilling is in the mechanics of directional orientation. As mentioned previously, a downhole orienting device orients the tool face in the desired direction to drill the required trajectory because the tubing itself cannot be rotated. This presents several problems.

One problem is the reactive torque in the tubing caused by the torsion generated by the motor and the drag of the bit as it rotates. CT has relatively low torsional stiffness, which makes orientation difficult in systems that require orientation under static conditions. It is not unusual to have to orient the tool face as much as 270º clockwise from the desired orientation to compensate for reactive torque once the motor starts turning. In addition, an inability to maintain a constant weight on the bit while drilling also affects the magnitude of the reactional torque and, hence, the orientation.

Another directional problem arises from the inability to rotate. In conventional rotary drilling of directional wells, there are two modes of drilling with a downhole motor, sliding and rotating. In slide drilling, the drillstring is not rotated, which allows the bent housing and/or subs to build angle or turn in the desired direction. Once the desired inclination and direction are established, the drillstring is rotated so that both the drillstring and motor are rotating. The drillstring rotation offsets the effects of the bent housing and a constant direction can be maintained (at least in theory). An added benefit of drillstring rotation is that the penetration rate often is twice that attained with slide drilling alone. Because all CT drilling is slide drilling, the effects of the bent housing cannot be offset by rotation to maintain a constant direction. The CT procedure is to change the orientation of the tool face continually to drill in the desired direction and to maintain a relatively smooth wellbore. With static orienting tools, this requires a lot of downtime for orientation. This leads to the temptation to drill too far before making corrections, which results in a tortuous wellbore trajectory through which it may be difficult, or impossible, to retrieve the BHA.

One more factor that adds to the orientation difficulty is residual curvature in the CT. The CT is straightened as it passes through the injector into the wellbore, but the tubing still retains some curvature as it unloads elastically from the injector. This residual curvature affects directional orientation and control.

Newer systems have real-time dynamic orienting tools that can be reoriented continually while drilling.This allows an experienced CT operator to make course corrections so that a relatively smooth wellbore can be drilled without stopping the pumps or injection into the hole. Not all CT-drilling units currently have this capability. As a next step, closed-loop orientation that does not require direct operator intervention is being tested and adjustable stabilizers to eliminate the bent housing and orienting tool altogether are under development. If successful, these tools could offer significant improvement to current methods.

Cuttings Removal. Rotation is a primary factor in cuttings removal in highly deviated wells. It helps propel the cuttings into the flow stream; induces crosscurrents; and crushes cuttings into smaller, more transportable sizes. In the absence of rotation, cuttings removal in a highly deviated well becomes difficult and failure to remove cuttings often results in stuck pipe and/or lost circulation.

In highly deviated laterals drilled with CT, special measures must be taken to ensure that cuttings are removed from the wellbore. A common method is to make periodic short trips based on a maximum distance or time drilled between short trips and/or pressure buildup as seen on a downhole annular-pressure monitor. Although the CT unit lacks rotational capacity, a short trip with CT often is a more effective means of cuttings removal than the same operation with a conventional rig because the CT unit can maintain continuous circulation throughout the trip. Other successful methods include viscous-fluid sweeps and foam sweeps. One of the more common causes of stuck pipe in CT drilling appears to be a tendency to drill too far between periodic efforts to remove cuttings buildup.

Penetration Rates. Several factors contribute to why penetration rates for CT drilling usually are somewhat lower than those for conventional methods in highly deviated directional wells. These factors are related primarily to the inability to rotate the CT string. The fact that all CT drilling is slide drilling with a downhole motor is one reason for the lower penetration rates. As previously discussed, this method results in a penetration rate nearly half that of drillstring rotation with the same downhole motor.

Another reason for lower penetration rates is the difficulty in getting consistent weight on the bit. A conventional drillstring in rotation transmits weight to the bit almost continuously as it is applied from the surface. However, because CT does not rotate, maintaining a constant weight on the bit is difficult because of the slip/stick nature of borehole friction on the CT drillstring. Experimental thrusters have been designed to lock onto the borehole wall and apply constant weight to the bit by means of a hydraulic piston, but the success of this type of device depends on having a relatively in-gauge hole and on resetting the anchor and piston in minimum time.

Another predominant reason for lower penetration rates is the additional time required to remove cuttings buildup, as discussed earlier. Despite all this, higher penetration rates on the order of 60 to 200 ft/hr are being achieved, especially in underbalanced situations.[3] With experience in particular areas, CT operators are achieving fast enough penetration rates that this is no longer considered to be the impediment it once was.

Depth Control. Determining measured depth with CT is approximate at best, especially in highly deviated wellbores. Depth normally is measured by a counter device between the reel and the injector similar to that used on a wireline unit. Unlike a wireline unit, however, the CT is not under full tension (or compression) in that location because the injector on top of the wellhead supports all the CT in the hole. (Some units do have a depth-measuring device between the injector and the pressure packoff, but the distance between these is very small and a support device may have to take the place of the depth meter to prevent buckling of the tube if the well is under pressure.) In addition, the fact that the CT is not totally straightened by the injector as it enters the wellbore also produces a fair amount of drag on the wellbore wall (there is residual elastic bending in the tube, causing the lower portion of the tube to curve). All this indicates that CT depth measurements are not considered reliable.

Alternatives exist, however, for most CT-drilling operations. If the well is a new well, a radioactive collar (which can be detected by a gamma ray device on the CT for depth correlation) can be run on the bottom of the casing. In the case of an existing well, the magnetic device in the steering tool often can be used to detect the existing casing shoe. For re-entries, electric wireline often is relied on to set sidetracking tools so that an accurate depth can be attained. Once in open hole, the last known measurement checkpoint, the depth counter, and logging-while-drilling correlations have to be used.

Fishing Operations. While the ever-present specter of a fishing operation looms in any drilling operation, it is much greater in CT drilling. The inability to rotate, lack of bending stiffness, and poor depth control are significant, if not critical limitations, to CT-fishing success. The most common fishing event for CT in open hole is a stuck BHA. While CT does have the advantage of allowing the well to flow to reduce differential pressures and to spot pipe-freeing agents or acid readily around the BHA, the advantages stop there.

It is impossible to run a free point, to back off, or to cut off a string of CT downhole with the presence of an electric line and/or hydraulic lines inside the tubing. Therefore, a disconnect is run on top of the BHA. The disconnect most commonly is a force/shear device; however, hydraulic and/or electrically actuated devices have been developed recently. If the pipe is not stuck above the BHA, it usually is possible to disconnect the BHA and retrieve the CT. The BHA sometimes can be recovered successfully by fishing with the CT. However, conventional tools and methods are required in most cases, which means moving the CT unit off the well and moving a conventional workover rig on. Here, a combination conventional/CT rig has a distinct advantage. Despite all this, some operators report relatively successful fishing experience for BHA's with wash pipe and slow-rotating downhole motors.

If a disconnect cannot be accomplished, the fishing job is a virtual nightmare if it is worth doing at all. The process is tedious, time-consuming, and expensive, and the prospects for success are grim.

SELECTING CT FOR DRILLING

Most operators who have not used CT for drilling have similar questions. "Should we use CT in our drilling operations?" "If so, what are the applications, what are the economics, what are the benefits of success, and what are the consequences of failure?" For those pondering these questions, here are some points to consider.

Proven CT-Drilling Applications. Two applications stand out from all others in terms of economics and success.

True Underbalanced Drilling—Preventing Formation Damage. The application where CT drilling has proved itself to have no peer is in true underbalanced drilling. While underbalanced drilling with conventional means has been used successfully for a long time, some are beginning to question whether the objectives are actually being met. If the objective is to prevent formation damage by drilling with an annular pressure lower than the formation pressure, the effectiveness of this process has to be questioned if the well has to be killed for a bit trip or is killed at the end of drilling to pull the drillstring from the hole. If a well is drilled underbalanced with a clean formation face, how much is it damaged when the well is killed and the balance is reversed? Is the damage possibly greater than if the well had been drilled conventionally overbalanced with a high-quality drilling fluid?

Obviously, CT can drill in a truly underbalanced state, but it also can maintain the underbalance for the entire operation. Even depleted formations with very low pore pressures can be drilled with foam or nearly pure nitrogen (with a small amount of oil to lubricate the downhole motor). The BHA in these underbalanced operations contains a pressure-sensing device so that the unit operator can monitor the annular pressure in real time. With CT, true underbalanced conditions are not guesswork but a reality.

Through-Tubing Laterals. Although fairly new, the use of CT to drill laterals from existing wellbores without killing the well and/or removing the Christmas tree has a lot of potential. This is especially true for offshore fields with existing platforms and maturing reservoirs. The ability to set a small CT unit on the platform and drill directional laterals to intercept bypassed reserves or access additional reservoir compartments without having to remove the tree or pull the tubing from existing wells has a lot of advantages. Buset and O'Neil[4] reported a recent success with this use of CT drilling that surely is typical of things to come because there are few offshore operators who cannot think of several immediate applications for this technology.

Costs. The single biggest negative for the use of CT drilling probably is high daily costs. Few, if any, situations currently exist where an equivalently sized conventional drilling rig does not have a lower daily cost than a CT-drilling unit. The key here is "equivalently sized." In some locations, there are no equivalently sized conventional rigs (e.g., most offshore locations). In a comparison of CT-drilling-unit and conventional-drilling-rig costs, the CT unit often costs four to six times more than the equivalent conventional rig. The decision to use CT for drilling cannot be based on a simple one-to-one economic comparison because the CT would lose almost every time, except where an equivalent conventional rig is not available or where the mobilization cost of a conventional rig is much greater than that for the CT unit.

The question that faces many operators is how to quantify formation damage in terms of cost. As an example, in Canada, where the majority of the CT drilling is done, the cost of drilling underbalanced with CT typically is about 40% higher than the cost of a conventionally drilled balanced well. Despite this significant difference, many operators have found that the cost of the CT underbalanced drilling is more than offset by reduced formation damage and increased production. So, one must often look further than conventional economics based on daily rig costs to justify the use of CT for drilling. The unique capabilities of CT are almost always the deciding factor for its use.

Experience Factor. An extremely important criterion in the decision to use CT drilling is the experience of the CT service company. A good CT driller must be an accomplished slimhole directional driller with a high degree of working knowledge of both CT and MWD. Currently, this is rarity. It is not unusual to find two service companies drilling with CT in the same area, with one company outperforming the other by a margin of as much as two to one on time to drill. This obviously is an indication of the newness of the application of the technology and certainly will improve with time and experience. For now, however, operators must be aware that large discrepancies in drilling time often exist because of differences in training and experience. Unfortunately, at this time, there are only a few geographical areas in the world where experience truly is adequate.

CT-Drilling Failures. CT-drilled wells now number in the thousands, with relatively few experiencing serious problems. While we prefer not to think about the possibility of failures in any of our operations, it is foolish not to consider the consequences of a failure should one occur. Anyone who drills a well with any type of equipment must consider the possibility of a fishing job. We must assume that, if a CT fishing job becomes necessary, it likely will have to be accomplished with a conventional-type rig with jointed pipe. The first obvious question is whether a conventional rig can be used in this particular application (i.e., mobilization, location size, portability, costs, and other such factors). This is a serious consideration that can mean long delays and excessive costs.

While the literature on CT drilling is full of success stories (which conspicuously never mention actual costs), Cox[5] reported one trouble-filled case history that stands alone in its honesty and candor. Much has been learned since that paper was written, but it should be required reading for anyone contemplating the use of CT for drilling. To be totally fair, however, one should also note that, despite the myriad problems that arose in that particular case, public records indicate that the well involved has been producing at more than 10 times the rate of the conventionally drilled vertical wells surrounding it.

EVOLVING TECHNOLOGY

Predicting what we can expect to see in the future is not pure speculation; the technology is already moving in new directions. Underbalanced drilling to reduce formation damage is now a proven success for many operators, and the advantages of using CT for this operation are unparalleled. So-called hybrid rigs that have both CT and jointed-pipe-handling capabilities show promise in eliminating many of the problems associated with CT alone. Means of increasing CT fatigue life by 200% by placement of the reel above the injector and by as much as 300% by a special guide in conjunction with a larger reel diameter are already in operation. Riserless subsea drilling and intervention systems with CT are being developed. Almost anything written about CT drilling is out of date by the time it is in print because any number of CT-drilling-related projects currently are in the conceptual to advanced stages of development.

CONCLUSIONS

CT drilling has become one of the fastest growing technologies of the decade. The technology currently is operable and continues to improve.

The ability to monitor downhole conditions (such as bottomhole pressure, actual weight on bit, and vibrations, among others) and to obtain wireline-quality logs in real time while drilling is unique to CT drilling and can provide invaluable information for the operator.

Selection of CT drilling over conventional drilling methods must be based almost entirely on the unique capabilities of CT rather than on a conventional day-rate cost comparison.

In areas where high mobilization costs and/or restricted location space requirements prevail, CT drilling is an attractive alternative.

Currently, the most obvious niche for CT drilling is in underbalanced drilling to prevent formation damage. In this arena, it is unequaled.

Through-tubing re-entry for multilateral drilling is a relatively new application in most areas, but CT is being used successfully and the future potential is encouraging as improved tools are developed.

The future of CT drilling looks encouraging. From the first CT-drilled horizontal well reported in 1992,[2] the technology has improved to the point of wide acceptance and application. Developments under way and those slated for the near future should add increased potential and reliability to this rapidly growing technology. JPT

ACKNOWLEDGMENTS

I thank the many people who have shared their experiences, insight, opinions, and visions regarding CT drilling. Significant among these are Al Ramos, Rob Cox, and Nigel Lakey.

REFERENCES

1. Fultz, J.D. and Pittard, F.J.: "Openhole Drilling Using Coiled Tubing and a Positive-Displacement Mud Motor," paper SPE 20459 presented at the 1990 SPE Annual Technical Conference and Exhibition, New Orleans, 23–26 September.
2. Ramos, A.B. Jr. *et al.*: "Horizontal Slim-Hole Drilling With Coiled Tubing: An Operator's Experience," *JPT* (October 1992) 1119.
3. Elsborg, C., Carter, J., and Cox, R.: "High-Penetration-Rate Drilling With Coiled Tubing," paper SPE 37074 presented at the 1996 International Conference on Horizontal Well Technology, Calgary, 18–20 November.
4. Buset, P. and O'Neil, J.: "Coiled Tubing Sidetrack Taps Bypassed Reserves," *World Oil* (April 1998) 87.
5. Cox, R.: "Horizontal Underbalanced in a Sour Gas Carbonate Using Coiled Tubing," paper SPE 37075 presented at the 1996 International Conference on Horizontal Well Technology, Calgary, 18–20 November.

SI METRIC CONVERSION FACTORS

ft	× 3.048*	E−01 = m
in.	× 2.54*	E+01 = mm

*Conversion factor is exact.

***Ted G. Byrom** is an independent consultant and a training instructor for Oil & Gas Consultants Intl. Actively involved in drilling and completions for 40 years, he has been a consultant since 1974, dividing his time between the oil industry and the aerospace industry, where he has worked in computational mechanics. He was a lecturer in computation methods at Texas A&M U. and is the coauthor of a recent text on the finite-element method. Byrom also worked as a drilling-technology consultant for Oryx Energy and as a district drilling superintendent for Unocal. He holds a BS degree in petroleum engineering and MS and PhD degrees in aerospace engineering, all from Texas A&M U. He is a member of the Editorial Review Committee.*