Coiled-Tubing Drilling

Larry J. Leising, SPE, and **Kenneth R. Newman,*** SPE, Schlumberger Dowell

Summary. In the 1980's, a "coiled-tubing revolution" began when coiled-tubing services were expanded to include most workover services. In 1991, this revolution expanded to include openhole drilling with a coiled-tubing unit (CTU) in place of a drilling rig. This paper discusses the design process and the limits associated with the use of coiled tubing (CT) to drill new wells and horizontal re-entry wells.

Introduction

For several years, CT has been used to drill scale and cement in cased wells. Recently, CT has been used (in place of a rotary drilling rig) to drill vertical and horizontal open holes. At this time, <30 openhole CT drilling (CTD) jobs[1-5] have been performed. However, there is a tremendous interest in this technique in the oil industry; many companies are actively involved in developing CTD technology.

This paper discusses CTD applications and presents an engineering analysis of CTD. This analysis attempts to define the limits of what can and cannot be done with CTD. These limits are calculated with CT and drilling models used for other applications. The basic limits associated with CTD are weight and size, CT force and life, and hydraulic limits. Each limit is discussed separately. For a specific application, each limit must be considered.

CTD Applications

Table 1 divides CTD applications into four main categories. First, re-entry drilling in existing wells and new well drilling are considered. Second, vertical and deviated wells are considered. **Table 2** is a list of CTD attempts to date that we are aware of. Any errors or omissions from this table are unintentional. Table 2 highlights the applications attempted, CT size, and hole size. It is not surprising that most of these attempts are re-entries because CT services were developed for the workover market. When working in an existing well, there is no need to spud the well or to set surface casing, neither of which can be done with most existing CTU's.

Vertical deepening with a pendular assembly to keep the hole vertical is probably the most straightforward CTD application.[2,3] A long bottomhole assembly (BHA) is used to provide weight on bit (WOB) without buckling the CT. The neutral point is in the BHA so that the CT is always in tension. Lateral drainhole drilling (**Fig. 1**) requires milling a window in the casing. A lateral then is drilled through the window with a directional measurement and control system.[4,5]

Currently, when new wells are drilled, a small rig is used to spud the well and set the surface casing. CTD then is used to drill the rest of the well.

For all these applications, CTD can be used to drill underbalanced safely. Drilling underbalanced minimizes formation damage, increases the rate of penetration (ROP), and eliminates differential sticking.

Technical Feasibility Procedure

The following procedure is used to determine whether a proposed CTD job is technically feasible. The calculations mentioned in this procedure are discussed later.

1. Select the CT size, hole size, drilling fluid, and BHA.
2. Calculate the CT reel weight and size; can it be transported? If not, go to Step 1.
3. Calculate the tubing forces and stresses to ensure that the stress will never exceed 80% of the yield stress and that the minimum acceptable downhole WOB can be provided at total depth (TD). Be sure to include the friction associated with bending the BHA around any curves. Also, ensure that the injector can supply the necessary pulling and pushing (if kickoff point is shallow) capacity to pull the CT and BHA out of the hole. If these conditions are not met, go to Step 1.
4. Calculate the drilling-fluid pressure drop in the CT, the BHA, and the annulus when drilling at 100% of the motor flow capacity and determine absolute pressure in the CT during drilling. If this pressure is greater than the maximum allowable working pressure, go to Step 1.
5. Calculate CT fatigue life for the pressure calculated above. If the CT will not last for the entire job, go to Step 1.
6. Determine whether the drilling fluid can carry the cuttings out of the hole/casing when drilling at 80% of the maximum motor flow rate. If not, go to Step 1.

Once these requirements are met, the CTD job is technically feasible.

Weight and Size Limits

Table 3 shows the CT sizes and weights used in this engineering analysis, along with the maximum tension and pressure limits, as defined in Ref. 6. Many other CT sizes and weights exist along with various materials and yield strengths. However, only five sizes and weights were considered in this analysis.

The CT length is limited by the reel size and weight limit. A large trailer-mounted reel was chosen to investigate these limits. This reel was designed to meet U.S. road restrictions. Actual storage capacity was calculated with a 146-in. reel diameter and a 72-in. width. The core diameter depends on the CT size, as Table 3 shows.

The weight of empty CT that can be carried on this reel depended on the weight of the tractor, trailer, and empty reel. **Fig. 2** shows the maximum length of CT for various maximum CT weights. For the larger sizes, space on the reel becomes the limiting factor. The maximum CT weight that this trailer-mounted reel can carry legally on U.S. roads was ≈40,000 lbm.

These limits must be calculated on the basis of local road restrictions and offshore crane/space limitations. It is possible to take multiple reels to location, weld together or connect the CT, and spool the CT onto a large work reel for drilling. In many cases, the cost of such an operation may not be justified.

CT Mechanical Limits

Vertical Wells. Because of tension in the CT, depth limits for vertical wells will depend on the drilling-fluid density, yield strength of the CT material, and variations in the CT wall thickness. If a constant wall thickness with depth is assumed, the maximum depth of the CT in the drilling fluid without exceeding 80% of the yield strength of the material is given by

$$D_{max}=\frac{\sigma_y}{4.245-0.06493W_{df}}. \qquad (1)$$

For 70,000-psi yield material and 8.6-lbm/gal drilling fluid, the maximum depth is 19,000 ft, independent of CT size and weight. It also assumes that the well remains full of drilling fluid. No additional pulling strength for fishing operations is considered.

Special tapered or high-strength material strings can be used to allow CT operations to greater depths. A tapered string contains sections with CT of various wall thicknesses. A heavy wall thickness is used at the surface, and a lighter wall thickness is used at bottom. Conventional CT operations have been performed in excess of 23,000-ft measured depth using tapered strings.

Deviated Wells. For deviated wells, a tubing-forces model is needed to calculate forces in the tubing. van Adrichem and Newman[6]

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TABLE 1—CTD APPLICATIONS SUMMARY

	Vertical	Deviated
Re-entry Drilling	Deepening of existing wells	Lateral drainholes
New Well Drilling	Disposable exploration wells	Steam injection
	Observation and delineation wells	Environmental observation
	Slim-hole production/injection wells	

TABLE 2—INDUSTRY CTD ATTEMPTS TO DATE

Date	Location	Client	Well Status	Deviation	CT Size (in.)	Hole Size (in.)
June 1991	Paris	Elf Aquitaine	re-entry	vertical	1.50	3.88
June 1991	Texas	Oryx	re-entry	horizontal	2.00	3.88
Aug. 1991	Texas	Oryx	re-entry	horizontal	2.00	3.88
Dec. 1991	Texas	Chevron	re-entry	horizontal	2.00	4.75/3.88*
May 1992	Canada	Lasmo	new	vertical	2.00	4.75
July 1992	Texas	Chevron	re-entry	horizontal	2.38	3.88
July 1992	Canada	Gulf	re-entry	horizontal	2.00	4.13
July 1992	Canada	Imperial	new	vertical	2.00	4.75
July 1992	Texas	Arco	re-entry	horizontal	1.75	3.75
Sept. 1992	Canada	Pan Canadian	re-entry	vertical	2.00	4.75
Oct. 1992	Canada	Canadian Hunter	re-entry	vertical	1.75	3.88
Oct. 1992	Paris	Elf Aquitaine	new	vertical	1.75	3.88
Nov. 1992	Canada	Gulf	re-entry	vertical	2.00	4.75
Nov. 1992	Austria	RAG	re-entry	vertical	2.00	6.13
Dec. 1992	Alaska	Arco	re-entry	deviated	2.00	3.75
Jan. 1992	Canada	Petro Canada	re-entry	vertical	2.00	3.88
Feb. 1993	Holland	NAM	re-entry	horizontal	2.00	4.13
Feb. 1993	North Sea	Phillips	re-entry	deviated	1.75	3.75
Feb. 1993	Canada	Petro Canada	re-entry	horizontal	2.00	4.75
March 1993	Alaska	BP	re-entry	deviated	2.00	3.75/UR
April 1993	California	Berry Petroleum	new	vertical	2.00	6.25
April 1993	California	Berry Petroleum	new	vertical	2.00	6.25
May 1993	Alaska	Arco	re-entry	deviated	2.00	3.75
June 1993	Alaska	Arco	re-entry	deviated	2.00	3.75/UR 5.75

Note: this table is to the best of our knowledge; any errors or omissions are unintentional. UR = underreamed.
*Downsized.

describe the theory and results for a model developed specifically for CT. When CT is in compression in the vertical section of a well, it immediately forms a helical shape.[7] When the well is deviated, the CT first forms a sinusoidal shape. As compressive forces increase, it forms a helical shape.[8,9] As the compressive forces on the helical CT increase, the wall-contact forces associated with the helix increase. This increases friction.[10] "Helical lockup" is reached when the friction forces increase to a point that the CT helically "locks" in the hole. The tubing-forces model discussed in Ref. 6 calculates when and where helical lockup will occur.

The force that can be applied to the CT to push the BHA around the curve and into the deviated section may be limited by the maximum force that can be applied in the vertical section. **Fig. 3** shows the maximum setdown weight that can be applied in a vertical hole, as predicted by the tubing-forces model for the casing sizes indicated. Once this weight is applied, the CT is helically locked. Slacking off more weight on surface does not increase the weight at bottom. This setdown weight does not vary significantly with depth. At shallow depths, however, it will be necessary to use a significant compressive force to force the CT into the hole at surface to reach this setdown weight.

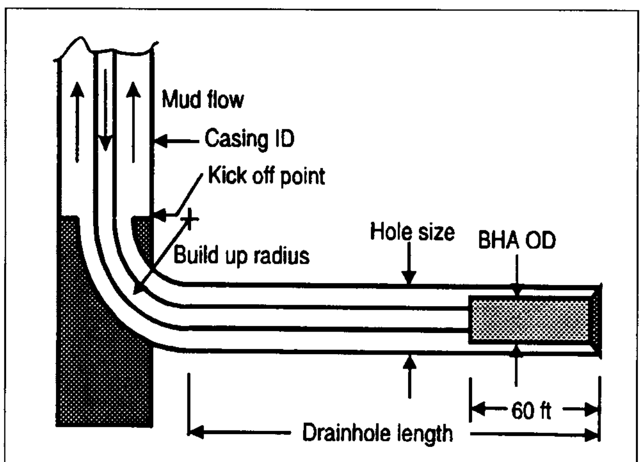

Fig. 1—CTD horizontal well model.

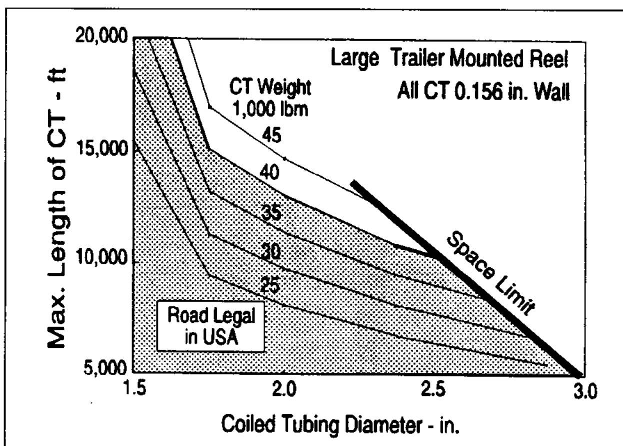

Fig. 2—Maximum CTD length available as a result of weight and space limits.

TABLE 3—CT SIZES USED FOR THIS ANALYSIS						
Diameter (in.)	Wall Thickness (in.)	Weight (lbm/ft)	Maximum Tension (lbf)	Maximum Allowable Working Torque (lbf-ft)	Maximum Allowable Working Pressure (psi)	Reel Core Diameter (in.)
1.500	0.156	2.24	32,000	1,044	7,700	76
1.750	0.156	2.66	37,900	1,484	6,700	76
2.000	0.156	3.07	43,900	2,002	5,900	84
2.375	0.156	3.70	78,100	2,926	5,300	84
2.875	0.156	4.53	95,000	4,431	4,400	96

Note: 70,000-psi yield stress material for all CT sizes. Maximum pressure and tension defined in Ref. 6.

The BHA's used for this analysis each have a 2.25-in. ID, a 60-ft length, and an OD shown in Table 3. **Fig. 4** shows the friction force required to push these BHA's around a curve of constant build rate. The build rate can prevent drilling penetration when the maximum force that can be applied by the CT will not overcome the friction force required to push the BHA through the curve.

The tubing-forces model[6] was used to study the five CTD cases in **Table 4.** Cases 1 through 3 consider drilling out existing vertical 4.5-, 5.5-, and 7-in. casings with the largest appropriate bit size. Case 4 considers use of the BHA from the 4.5-in. casing in Case 1, only with 5.5-in. casing. Likewise, Case 5 considers using the hole/BHA from the 5.5 in. in Case 2, only with 7-in. casing.

For all these cases, we assumed that a hole was drilled out of the casing to horizontal with a buildup rate of 15°/100 ft. Then the hole was drilled horizontally until helical lockup prevented the downhole WOB (DWOB) (given in Table 4) from being maintained. The length of horizontal section that could be drilled with the given DWOB is called the "maximum drainhole length."

In all cases, 8.6 lbm/gal brine was used for the drilling fluid, and the CT sizes defined in Table 3 were used without a wireline in the CT. The DWOB's were chosen to maintain 500 lbf/in. of bit diameter.

Fig. 5 shows the resulting maximum drainhole length (horizontal section) for each of the five cases. For the three circled points, the CT would lock up in the vertical section before pushing the BHA through the curve with the required DWOB. At least 1.75-in. CT is needed to drill a horizontal lateral in any of these cases.

Fig. 6 shows the weight-indicator load predicted by the tubing-forces model that would be measured at surface as the well is drilled for Case 1 with 2-in. CT and a 25°/100-ft buildup rate. If no DWOB was needed, it would be possible to push the BHA to a measured depth of ≈ 10,000 ft (4,400 ft drainhole) before helical lockup would occur. Maintaining a 2,000-lbf DWOB causes lockup to occur at ≈7,600 ft (2,000 ft drainhole).

The difference between the DWOB=0-lbf curve while running in the hole and the DWOB=2,000-lbf curve while running in the hole is called the surface WOB (SWOB) (see **Fig. 7**). The SWOB is determined by comparing the weight-indicator load (hook load) while running in the hole to the weight-indicator load during drilling. The wall-contact friction causes the SWOB to increase significantly with depth. Thus, the DWOB cannot be measured easily by determining the SWOB.

Torsional Limits. Table 3 indicates the maximum working torque suggested for CTD. These values were calculated with the von Mises distortion-energy criterion with minimum wall and 80% of the minimum yield strength. The downhole motor-stall torque should be no larger than the maximum working torque listed in Table 3. When the downhole motor stalls, it will generate a stall torque 1.5 to 2.5 times the maximum operating torque. When the string is picked up, torque will be near zero. During drilling, the torque again will be at the maximum operating torque. This torsional cycling will compound with the bending cycling and reduce the fatigue life shown in **Fig. 8.** If the downhole motor stall torque is less than that shown in Table 3, however, the CT fatigue life will not be reduced appreciably. This was evaluated with the same cumulative fatigue model discussed in the section on CT life limits.

Stall-torque values should be obtained from the motor manufacturer. In general, torque is not a significant limitation unless large-hole drilling is performed with small-diameter CT. This is most relevant to shallow, vertical-hole drilling. The effect of drilling torque on helical buckling also was investigated and was found to be minimal with high-speed motors. If the drilling torque is significant compared with the maximum allowable working torque, then this effect must be considered.

CT Life Limits

The large CT diameters used for CTD and the continuous drilling-fluid pressure used while running the CT greatly increase the amount of fatigue damage being done to the CT compared with normal CT service operations. Over the last several years, an engineering project has been undertaken to develop a CT-life prediction model. This

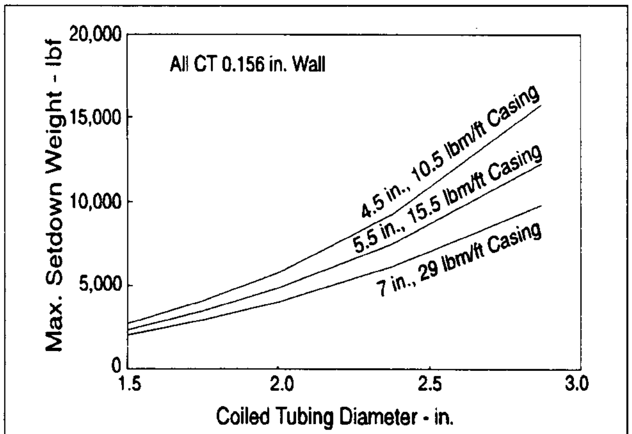

Fig. 3—Maximum setdown weight in a vertical well.

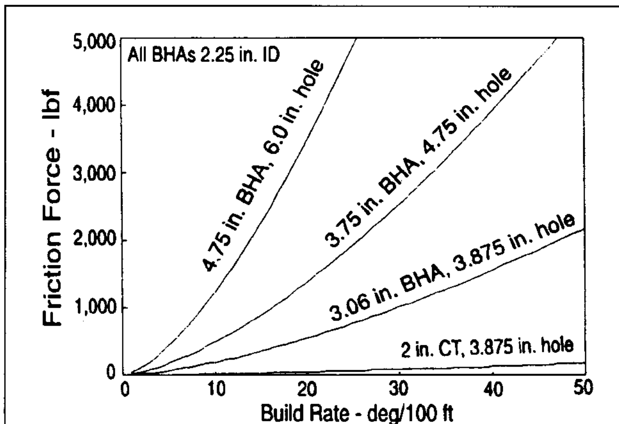

Fig. 4—Friction force on the BHA as a result of buildup curve.

TABLE 4—RE-ENTRY DRILLING CASES

	Case 1	2	3	4	5
Casing					
Diameter, in.	4.5	5.5	7	5.5	7
Weight, lbm/ft	10.5	15.5	29	15.5	29
ID, in.	4.052	4.950	6.184	4.950	6.184
Hole size, in.	3.875	4.750	6.000	3.875	4.750
BHA OD, in.	3.060	3.750	4.750	3.060	3.750
DWOB, lbf	2,000	2,500	3,100	2,000	2,500

model determines when the CT will fail as a result of fatigue caused by pressure and bending cycles. Full-scale fatigue tests using actual well-service equipment were conducted while monitoring multiaxial strains.[11] This data, combined with laboratory test data, were used as input to a strain-controlled incremental plasticity algorithm. The resulting life prediction model[12] has been validated with field results.

This model was used in this analysis to predict the CT cycle life in and out of the well during CTD before CT failure occurred. The CT life depends on the pressure inside the CT when it is being bent on and off the reel and over the gooseneck at the surface.

Fig. 8 shows the relative CT life for various CT sizes. One curve shows the CT life with 65% of the maximum allowable working pressure inside the CT for all CT sizes (Table 2). In this case, the CT life decreased significantly as the CT diameter increased. The other curves (Fig. 8) show the CT life with the pressure based on a constant flow rate at an 8,000-ft measured depth. In this case, the optimum CT diameter depends on the drilling-fluid flow rate.

Many parameters affect CT life, including reel and gooseneck geometry, pumping pressure, CT diameter, and wall thickness and material. CT life should be calculated when designing a CTD job.

When trying to predict the life of the CT that will be used on a job, it is necessary to estimate the number of cycles that will be made and what the pressure will be in the CT when it is being bent on each of these trips. This estimation can be based only on experience. Experience so far has shown that a typical CTD job uses roughly 50% of the life of certain sections of the CT.

Hydraulic Limits

Three hydraulic limits are considered in this analysis: (1) the drilling-fluid flow rate must be high enough to carry the cuttings out of the hole, (2) the drilling-fluid flow rate is limited by the pressure drops through the CT and back up the annulus, and (3) the downhole motors have a maximum flow rate that often limits the drilling-fluid flow rate.

Minimum Flow Rates for Hole Cleaning in Vertical Wells. Cuttings transport depends on drilling-fluid rheology. This analysis assumes that 8.6-lbm/gal brine is the drilling fluid. To prevent excessive drill-cuttings concentration in the annulus, an annulus velocity of 100 ft/min is assumed[13] for the drilling fluid. This velocity should provide adequate cuttings transport with moderate ROP's or cuttings slip velocity.[14]

With the low DWOB and high-speed motors typical of CTD, very small cuttings normally are produced. It may be possible to reduce the annular velocity requirement if cuttings slip velocity, drilling-fluid rheology, and ROP are known.

In the case of underbalanced drilling, the slip velocity of the larger cuttings may have to be evaluated and the annulus velocity of the drilling-fluid carrying capacity may have to be increased.

Minimum Flow Rates for Hole Cleaning in Horizontal Wells. In this section, a "horizontal well" is defined as any well with a horizontal section. The drilling-fluid flow rate must be high enough to carry the cuttings in the horizontal section. In a small section of the curve, a higher flow rate may be required, but this is neglected in this analysis.

The critical velocity equation for the transport of large solids by a Newtonian liquid in a horizontal annulus[15] was used to provide a guideline for the critical (minimum) flow rate shown for the horizontal well in **Fig. 9.** As is obvious from the figure, the critical flow rate[16] required to provide full transport in a horizontal well is greater than that required in a corresponding vertical well because cuttings have only a short distance to fall out of the flow stream in a horizontal well. The critical flow rate for 2-in. CT in a 4.75-in. hole is 3.2 bbl/min, which equates to 180 ft/min annular velocity (Fig. 9). The minimum flow rate may be reduced by 25% if a stationary cuttings bed can be tolerated. The most important factors are annular velocity, drilling-fluid density, and annular clearance. Increased drilling-fluid density helps "float" the cuttings.

Maximum Flow Rates Resulting From Pressure Drops. The maximum flow-rate predictions for the hole size and CT diameter were calculated by use of conventional friction factor analysis for smooth pipe with 8.6-lbm/gal brine. Surface pressure was set at 65% of the maximum allowable working pressure of the CT, as defined in Ref. 5 and given in Table 2. Annular friction was calculated with an equivalent diameter equal to the diametral clearance. The pressure drop from the BHA was 1,400 psi. This allowed for the bit, downhole motor, a measurement-while-drilling (MWD) tool and directional-orientation tool pressure drops.

Fig. 9 shows the maximum flow rate at 8,000 ft. It was assumed for the pressure calculations that 500 ft of coiled tubing was left on the reel at maximum depth. For 2.875-in. CT (not shown in Fig. 9), the maximum flow rate in 3.875-in. hole is reduced appreciably because of a high annular pressure drop.[17] This high annular pressure drop (more than 500 psi) would increase the equivalent circulating density significantly, thus reducing the ROP and increasing the risk of lost circulation.

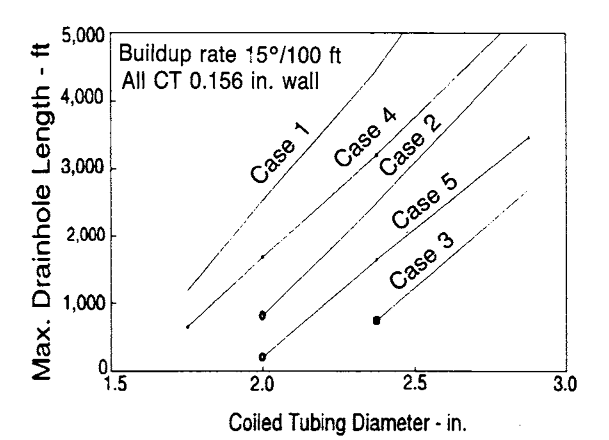

Fig. 5—Maximum drainhole length in a horizontal well.

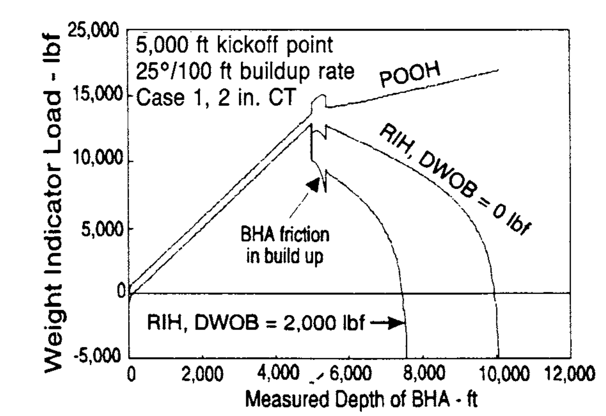

Fig. 6—Weight indicator load for Case 1 (POOH = pulling out of the hole and RIH = running in the hole).

If friction-reducing agents were added to the drilling fluid, the maximum allowable flow-rate curves would increase from those shown. In one CTD experiment,[1,2] the flow rate was increased by 15% by use of drilling fluid instead of water at the same surface pressure.

Maximum Flow Rates Resulting From Motors. Fig. 9 has a reference line at 4 bbl/min. This represents the typical maximum allowable flow rate for downhole motors with 3.75-in. OD's. Recently, motors with higher flow capabilities have become available. To maximize hydraulics, use of a high flow motor may be desirable.

Directional Drilling Considerations

As Ramos *et al.* reported,[3] torsional windup angle (reactive torque) affects toolface orientation control. If the tubing is too limber, small WOB and torque changes will change toolface angle. An orienting tool is used to make toolface changes during CTD. This tool can be controlled from the surface by means of pressure, weight, or an electric wireline[18] and causes a relative rotation upon command from the surface. This relative rotation changes the orientation of a bent sub or bent housing and causes drilling to proceed in a different direction.

The maximum torsional windup (reactive torque) is easily calculated, but fortunately is not fully effective because it is reduced significantly by frictional forces. The reactive torque was calculated in a manner analogous to that used for Fig. 5 and results were obtained that are consistent with the observed windup reported in Ref. 3.

BHA analysis is the same for CTD as for conventional sliding downhole motor drilling. Because the CT cannot be rotated, to drill straight ahead, either the natural tendency of the formation must be countered by the BHA, or the orienting tool must be actuated periodically to prevent undesired uniform build.

Either a pressure-pulse-telemetry MWD tool or a wireline steering tool may be used to provide directional information. Steering tools offer the advantages of fast data rates and short lengths but also have the disadvantage of complex wireline and connector requirements.[4] MWD tools have the disadvantage of limited availability in small diameters and less debris tolerance. Pressure pulse attenuation is not a limiting factor with CTD.

Conclusions

The main limitations to CTD are reel size/weight, maximum WOB/frictional drag, fatigue, and hydraulics. In general, larger tubing allows higher loads, drainhole lengths, and flow rates; however, the tubing diameter may be restricted by space, weight, and fatigue life.

A "typical" CTD job might use 50% of the life of the CT in certain sections of the reel. These sections may be removed to increase the useful life of the reel.

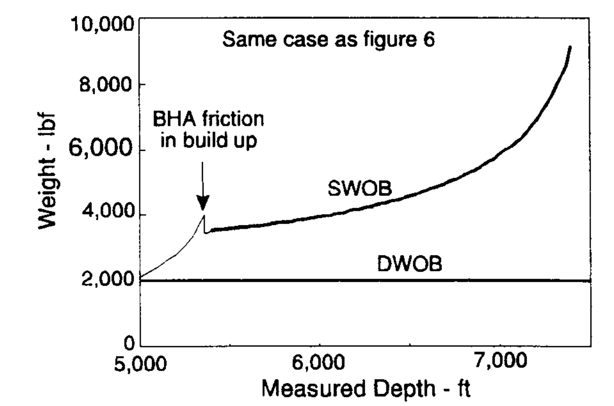

Fig. 7—SWOB vs. DWOB.

The flow-rate limitations of downhole motors limit the flow-rate gains of large tubing in many cases. For large tubing in a small hole, the annular pressure drop is significant.

We have presented a method that may be used to evaluate potential applications given the necessary calculation models. Generic constraints were considered that may be inconsistent with a specific application. Any specific CTD well planned should be evaluated thoroughly to address all potential limits and any interdependencies of these factors (e.g., rheology, hole cleaning, and mechanical friction).

Nomenclature

D_{max} = maximum depth, L, ft
W_{df} = drilling-fluid weight, m/L^3, lbm/gal
σ_y = yield stress, m/Lt^2, psi

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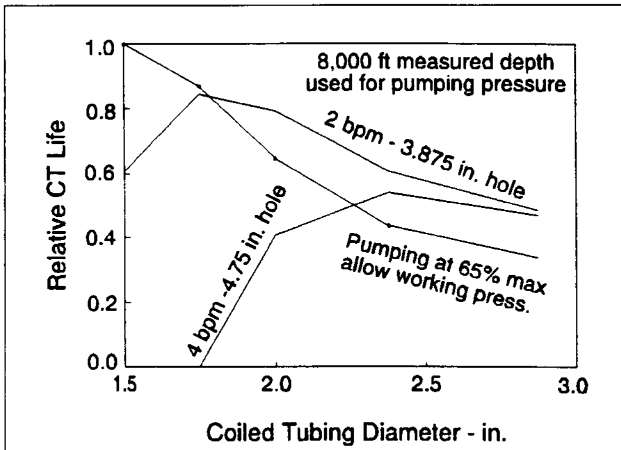

Fig. 8—Relative CT life limits (bpm = bbl/min).

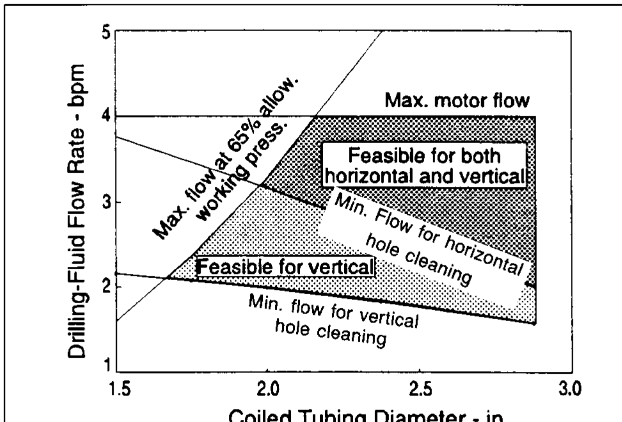

Fig. 9—Hydraulic limits on an 8,000-ft-deep well with a 4.75-in. hole (Max. = maximum and Min. = minimum).

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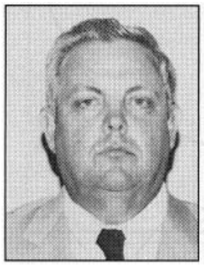

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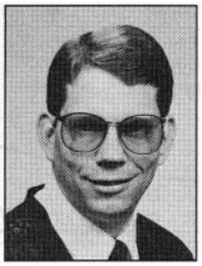

Newman

Larry Leising was an engineering specialist for Schlumberger Dowell in Rosharon, TX. He has worked on coiled-tubing engineering and MWD at Schlumberger for 17 years. He holds several patents on downhole tools. Leising has a BS degree from Purdue U. and an MS degree from Massachusetts Inst. of Technology, both in mechanical engineering. **Kenneth R. Newman** is the vice president of marketing and engineering for Drexel—Coiled Tubing Products, Conroe, TX. He previously was the coiled tubing businessline manager for Dowell in Paris. He holds a BS degree from the U. of Maryland and an MS degree from MIT, both in mechanical engineering.

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SI Metric Conversion Factors

bbl	× 1.589 873	E−01	=	m^3
ft	× 3.048*	E−01	=	m
gal	× 3.785 412	E−03	=	m^3
in.	× 2.54*	E+00	=	cm
lbf	× 4.448 222	E+00	=	N
lbm	× 4.535 924	E−01	=	kg
psi	× 6.894 757	E+00	=	kPa

*Conversion factor is exact.

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