Coiled Tubing Drilling on the Alaskan North Slope

Drilling with coiled tubing has evolved from an experimental technique to a proven technology now used for nearly half of all new wells on the North Slope of Alaska, USA. Specially designed arctic coiled tubing units can move, rig up and begin work in a matter of hours. By working concentrically through large production tubulars, wells can be sidetracked at lower cost than with conventional drilling rigs.

Reentering existing wellbores is an efficient and effective way to increase recovery from mature fields. ¹ Use of coiled tubing avoids the significant time and cost incurred by conventional drilling units, which require removal of the existing tubing, packer and wellhead before drilling can begin. Through-tubing reentry with coiled tubing allows a lateral wellbore to be drilled without removing the production tubing, provided the production tubing has a large enough internal diameter. This difference promoted the advancement of CTD Coiled Tubing Drilling technology and is the main driver for its proliferation on the North Slope of Alaska, USA.

In many areas, CTD techniques are still viewed as experimental. This is not the case on the North Slope, where it has taken center stage as an economic means of tapping new pools of oil.² Numerous factors have come into play to make the CTD process economically and technically successful in Alaska. The vast number of wells and unique operating conditions presented many opportunities for remedial well operations. The repetitive nature of coiled tubing workovers gave engineers and crews extensive experience and fostered efficiency.

ARCO Alaska Inc. (ARCO) and BP Exploration (Alaska) Inc. (BPX) have become leaders in the development and use of coiled tubing. The majority of their CTD techniques have been developed by working together and in partnership with Dowell and other service companies.

Prudhoe Bay is the largest reservoir in the USA and accounts for 5% of the total US oil production. The field, discovered in 1968, is jointly operated by ARCO and BPX. First production came on-stream in 1977, and peak production reached 1.5 million BOPD [240,000 m³/d] in 1989.

The Prudhoe Bay field, with numerous wells of similar design, was ideal for rapid development and growth of CTD technology. In the early 1980s, the development of coiled tubing cement-squeeze techniques, inflatable packers and electric line inside the reel increased confidence in expanding the role of coiled tubing beyond intervention.

Prudhoe Bay field has 1338 wells: 1128 producers and 210 injectors. Of these wells, 1062 are conventional vertical wells, 261 horizontal, and 15 multilateral. Coiled tubing reentry drilling is currently used on vertical producer and injection wells that have reached their economic limit. The drilling schedule for rotary and CTD rigs targets about 100 wells per year, with slight increases from year to year. On average, 85 of these wells are sidetracks, and 15 are new wells. Each CTD rig can drill about 20 sidetracks a year. In 1998, CTD rigs drilled more than 40% of the wells (below). About 60 will be drilled with three CTD rigs next year, accounting for more than half of planned Prudhoe Bay drilling. To date, ARCO has drilled more than 70 wells with coiled tubing and BPX more than 50. All were drilled in the Prudhoe Bay field, except for two in the Kuparuk field.

Economics encourage growth in CTD use on the North Slope. The prize is large—more than 3 billion bbl [476 million m³] of oil remain to be recovered.3 The reserve size of new targets continually decreases as the field matures. The cost to drill a CTD well is about half that of a conventionally drilled well. The comparison is not exact, because conventional rotary rigs can drill longer horizontal stepouts. Nonetheless, CTD units routinely drill several thousand feet horizontally, keeping development cost per barrel low. CTD technology currently delivers new production at an average development cost of 60% of rig costs on a per barrel basis.

This article discusses strategies for drilling with coiled tubing, drilling techniques and tools developed in Alaska, and the rig designs that have played a crucial role in the technical and economic success there.

Reservoir Strategies
As the Prudhoe Bay field matures, new wells are needed to recover small pockets of oil missed by previous wells. Targeting new wells in this large, mature field is challenging. It calls for consensus among interdisciplinary groups of reservoir, drilling, facility and production engineers as well as geoscientists.4 To help mitigate field decline, an extensive infill-drilling program, predominantly horizontal reentry wells, was undertaken.

The field is a combination structural and stratigraphic trap, and the producing formations comprise the Sag River, the Shublik and the Sadlerochit group. The most important interval is the Ivishak, part of the Sadlerochit group, which accounts for the majority of reserves.


proven and potential reserves. The Ivishak formation is a gradual upward fining sequence of fluvio-deltaic, fine-to-medium grained sandstones with thin interbedded siltstones and shales. The interbedded siltstones and shales play a key part in the accelerated use of CTD techniques in this field because the streaks isolate small pools of oil that are currently economically accessible only by coiled tubing. Permeability of the producing intervals varies widely throughout the field—from about 10 mD in the peripheral regions to several hundred millidarcies.

The four dominant recovery processes are gas-cap expansion and gravity drainage, waterflood, miscible flood and gas cycling. Continuous management of these processes and analysis of field performance have led to identification of attractive targets for further development.

In the gravity drainage area, which is the predominant recovery mechanism, oil production is controlled initially by well productivity. Once gas breaks through, however, wells become rate-restricted because of the gas-handling capacity of the production facilities. As gas/oil ratios increase, wells become uneconomic to keep on-stream. Once an existing well reaches its economic limit, it is typically shut in and considered a candidate for reentry drilling.

Horizontal wells in the gravity drainage area have greater initial production rates than vertical wells for a given drawdown, but because of a greater standoff from the gas/oil contact, gas breakthrough is delayed. The amount of oil produced by these wells increases with increased standoff between the perforated section of the wellbore and the gas-oil contact. Geoscientists evaluate the untapped pools of oil in relation to recently shut-in wells. Smaller pools close to vertical wellbores are prime candidates for CTD use, which currently has a maximum horizontal reach of some 3000 ft [900 m]. Conventional rotary drilling rigs tap the larger pools more distant from existing wellbores because they can drill longer horizontal sections.
Coiled tubing services were first developed for the workover market. Most coiled tubing units are not capable of running casing or pulling and running completions. As a result, the first applications of CTD techniques were reentry drilling, usually performed in conjunction with a workover rig.\(^8\)

Currently, three CTD rigs operate in Prudhoe Bay. The first unit consists of a conventional arctic well service unit coupled with a coiled tubing unit. The second unit is a purpose-built hybrid containing a coiled tubing unit permanently attached to the end of a mobile arctic workover unit. Nordic Calista and Dowell built that rig in a joint venture to drill reentry wells specifically for BPX. In mid-1998, ARCO brought in a third CTD rig.
CT Unit 4—The first dedicated CTD rig at Prudhoe Bay combined a conventional arctic well service unit, Nabors Drilling Rig 3S, with a coiled tubing unit, Dowell CT unit 4 (previous page). This setup drills exclusively for ARCO on the North Slope. The standard rig up for the CTD operation requires removal of the protective well house and Christmas tree, excluding the master valve. The well service rig main carrier is then centered over the well, and the derrick raised. The main carrier provides a heated, enclosed rig floor and a protective enclosure for the blowout preventer (BOP) stack. The main carrier also houses the primary mud pump system, pump and choke manifolds, and diesel-powered generators. The pit module is located adjacent to the main carrier and provides steam boilers, 300-bbl [50-m³] fluid-storage capacity, fluid mixing and degassing equipment, and limited solids-removal capability.

Once the rig modules are in place, the coiled tubing unit is positioned adjacent and perpendicular to the main carrier. The injector head is placed inside the rig floor wind walls and moved into position over the well. The injector head is protected from extreme weather and can be continuously monitored during operations. Drilling and tripping are controlled from the coiled tubing unit operations cab. Hydraulic tongs on the rig floor make up bottomhole assemblies (BHAs), jointed pipe liners and completion strings. The rig pump and BOP equipment can be controlled in the coiled tubing unit operations cab or from the well service rig floor.

A solids processing unit, in combination with the rig pit module, maintains critical drilling fluid properties. The unit contains a linear motion mud shaker and a high-speed centrifuge to remove drilled solids. To minimize operational cost, the portable unit is rigged up and operated only during drilling in openhole.

The BOP stack consists of two sets of double rams, one annular preventer and a conventional coiled tubing lubricator and stripper head (right). Other surface equipment includes a measurements-while-drilling (MWD) trailer for monitoring and maintaining directional equipment, a trailer for the directional driller and geologist, and a trailer for rebuilding drilling tools. Upright tanks are used to store up to 800 bbl [130 m³] of clean auxiliary fluids (methanol-water for freeze protection and seawater) and 800 bbl of used fluids.

Typical CTD BOP configuration. The lower 71/16-in., 5000-psi [3.5-MPa] double ram set and annular preventer are used during BHA makeup and for running liners. The upper 51/2-in., 10,000-psi [6.9-MPa] double ram set contains combination blind/shear and pipe/slip rams for the coiled tubing workstring. A hydraulic stripper head sits atop the BOP stack and provides an additional level of protection.

Hybrid rig—The Dowell/Nordic Calista hybrid CTD rig began working at Prudhoe Bay in November 1996. This one-piece, self-propelled unit is capable of running both 2 3/8-in. coiled tubing and jointed pipe (right). The unit is uniquely suited to the harsh arctic environment. It was originally developed as an arctic workover rig by Nordic Calista and serviced wells for ten years on the North Slope. In January 1996, Dowell and Nordic Calista developed a conceptual foundation for completely modifying the unit to accept coiled tubing components.

The rig package is fully self-contained and comprises mud pumps, mud pits and fluid-handling equipment, and a pipe-handling shed. In most cases, the rig can be moved with pipe standing in the raised derrick. The rig floor cantilevers over the wellhead to allow access to wells in tight clusters and is capable of leaving the tree and flowline intact during reentry drilling. This capability reduces system cost and maintains tree and tubing integrity.

The hybrid rig provides a fast, efficient method of running jointed pipe for liners, as well as running and pulling the 1 1/4-in. tubing that is used for perforating and cementing liners. The rig mast and traveling block simplify picking up and laying down BHA components and handling the injector head. Although the rotary table has been removed to facilitate coiled tubing operations, all support components remain in place and the rotary table can be replaced quickly to allow use of jointed pipe and drill collars for special operations or complex fishing jobs. If the mechanical integrity of a well’s production tubing is questionable, the rig can pull, repair and rerun the tubing prior to sidetracking operations.

Where possible, existing rig components that could satisfy both coiled tubing drilling operations and jointed pipe operations were left intact. The hydraulic system for coiled tubing components remains independent of the rig. A hydraulic power pack works in combination with electronic controls developed for the hybrid coiled tubing unit. The hydraulic pumps are powered by a DC traction motor, the same motor that powers the two mud pumps. Although this motor delivers more horsepower than required to operate the coiled tubing components, it was chosen because replacement parts are identical to those for the mud pumps, thereby reducing inventory.

The hydraulic power pack operates the injector, reel, power tongs and hydraulic rams on the doors that enclose the coiled tubing reel. Other than using the DC traction motor for power to the hydraulic pumps, the power pack is nearly identical to other units currently in service. To date, the electric motor has been failure- and maintenance-free, and maintenance costs and downtime are expected to be less than for a conventional diesel power pack.

The fluid-handling system is rated to 5000-psi [34.5-MPa] working pressure. The two mud pumps can be operated independently from either the coiled tubing operator console or the driller console on the rig floor. The triplex pumps had to be sized to handle the relatively low rate but high-pressure requirements of coiled tubing drilling. Typical pump pressures are 4000 psi [27.6 MPa] at 2.7 bbl/min [0.4 m³/min]. A linear motion shaker and high-speed centrifuge maintain solids content in the drilling fluid below 1% by volume. BOP equipment can be controlled from the rig floor, the coiled tubing operator console, or the main accumulator closing unit.

Coiled tubing electronic monitoring systems, in general, have evolved significantly since 1990. Most equipment and well parameters are currently recorded and displayed on two computer screens and three video monitors in the operations cab. The hybrid CTD rig system records and displays information from more than 40 sensors.

The unit electronics package was upgraded to include a “watchdog” network, which monitors all critical rig equipment and alerts the operator through audible warnings if readings go outside a preset operating window. Explosion-proof video cameras are part of a closed-circuit television system that monitors critical areas of the rig and allows the operator located in the control cab to visually check on components. Along with the watchdog system, they give the operator extra eyes to compensate for reduced rig personnel and provide earlier problem detection. Another significant upgrade to the electronics package uses a computer to override the injector in case the operator attempts to exceed coiled tubing limits.

The electronics package and computer can perform some drilling functions, and an electronic autodriller with downhole feedback has also been developed for this system, which advances the coil into the hole at a rate based on the pressure drop across the downhole motor. As the motor is subjected to additional weight from the coil, more torque is required to rotate the bit as indicated by a pressure increase at surface. Generally, the operator sets the pressure limit at a value less than the pressure at which the motor stalls. The computer advances the coil into the hole until the upper pressure limit is attained; coil movement is stopped until the motor pressure drops below the preset limit. When this occurs, the motor no longer drills ahead, indicating that additional weight can be applied to the bit. The computer then reengages the injector and begins advancing coil into the hole.
This system allows maximum penetration rates while limiting the number of motor stalls. An experienced coiled tubing operator can drill at least as effectively as the auto-driller, which is measured by rate of penetration and frequency of stalls. For the inexperienced operator, however, the system can increase drilling efficiency.

Personnel requirements are minimized by using specialized equipment to monitor engines, fluid levels, pit levels and hydraulic components. This technology allows the CTD rig to be manned by a toolpusher, driller, motorman, coiled tubing supervisor and service technician; a conventional rotary rig has a crew twice this size. Because of operational differences between CTD operations and jointed-pipe drilling, the roles of team members change with each operation. For example, during drilling operations, responsibilities typically assigned to the driller become the responsibility of the coiled tubing supervisor. Cooperation is required by all personnel as the reporting status changes depending on the operation.

**CDR-1**—Nabors/Transocean Drilling Rig CDR-1 began CTD operations on the North Slope in June 1998. It is a purpose-built coiled tubing drilling rig and has drilled more than 20 underbalanced wells in Canada. The design is unique because the reel sits above the injector head, directly over the well. The injector head is placed at the rig floor, and tubing feeds directly off the reel into the injector head without having to pass through a gooseneck. Bending at the gooseneck causes a great deal of stress on the coil, so eliminating this point of fatigue should increase coil life. Transocean Drilling estimates that the coil will last three to four times longer than that for CTD rigs using a standard gooseneck.

**Drilling Operations**

The techniques and equipment associated with CTD operations have undergone rapid development since the first operations in 1991. A principal stimulus for this activity was the availability of reliable, large-diameter coiled tubing to allow sufficient hydraulic horsepower to power the downhole motor and provide sufficient flow rate to ensure adequate hole cleaning. Larger, heavier-wall tubing gives the necessary weight for efficient drilling and withstands drilling torque and fatigue.

The CTD process has several advantages over conventional drilling rig operations. Well-control equipment configuration for coiled tubing provides a higher degree of control and safety, which is maintained throughout drilling and tripping because tubing is pulled continuously through a sealed stripper. The equipment allows underbalanced drilling to be conducted safely and efficiently, which can reduce reservoir damage from invasion of drilling-fluid filtrate. Under many conditions, CTD techniques have the potential to cut drilling and well costs significantly. The principal areas of cost savings come in reduced hole size, reduced trip time and lower mobilization and mobilization costs.

Coiled tubing drilling has its limitations, however. In formations prone to sloughing or washing out, coiled tubing is not appropriate. If wellbore stability problems develop, coiled tubing cannot be rotated, nor can it withstand the stress that conventional drill collars and drillpipe can.

Due to the size, strength and weight of coiled tubing, horizontal drilling reach and hole size are generally less than for conventional equipment. The longest horizontal section drilled using coiled tubing has a reach of nearly 3000 ft, whereas the longest extended-reach well drilled by rotary means has a step-out length ten times farther (above left).

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Leising et al, reference 3.
A dual-flapper check-valve system prevents backflow of wellbore fluids into the coiled tubing drillstring. The checks are positioned just below the coiled tubing connector. A ball-actuated hydraulic disconnect is located below the check valves. The hydraulic disconnect provides the option to release the BHA should it become stuck in the wellbore.

The circulation sub is positioned below the hydraulic disconnect and is activated by circulating a ball onto a seat. When the sub is opened, the fluid path is diverted above the MWD tools and mud motor and directed radially through side exit ports. The circulation sub allows increased circulation rates by eliminating the pressure loss and flow rate constraints through the BHA. The sub is normally opened when tripping out of cased hole. The higher flow rate improves cuttings removal. Circulation to surface is possible without concern for bit or production tubing damage because the bit does not rotate with the circulation sub open.

It is often necessary to deploy tools into the hole in two or more sections due to the length of the BHA. After the lower BHA is deployed, it is held in place by the BOP slips. String rotation is no longer possible and a conventional threaded connection cannot be made up. A splined nonrotating joint is used to make up this connection. The two pieces slide together and lock with internal splines to prevent rotation. A threaded collar slides over the splined section to secure the BHA.

An orienting tool rotates or indexes the lower section of the BHA to adjust the toolface in the desired direction. The tool is actuated by cycling the flow rate through the tool. An internal-to-annulus pressure differential drives a piston which, in turn, indexes the tool. A clutch and cam rotate the tool clockwise by a preset amount, typically 20°. The orienter generates up to 500 ft-lb [680 N-m] of torque. A jetted sub is installed below the orienter and is used to increase the pressure drop through the tool string and enhance the torque generated. The jetted sub also has a bleed port that allows approxi-
mately 10% of the drilling mud to escape to the annulus prior to reaching the motor. The bleed port allows the pressure to equalize below the orienter; this pressure might otherwise be trapped by the motor when the pumps are shut down. Pressure built up in the tool string as a result of high-viscosity mud can prevent the orienter from cycling.

The MWD system currently in use is a positive-pressure, turbine-powered, mud-pulse system. Mud-pulse telemetry allows gamma ray, toolface, inclination and azimuth measurements to be transmitted to surface through the mud column by pressure pulses generated by the pulser assembly. Nonmagnetic collars house directional and gamma ray probes between the mud motor and flow tube. Inclination is typically recorded 12 ft [3.7 m] behind the bit, and the gamma ray sensor is approximately 24 ft [7.3 m] behind the bit. The tool has performed satisfactorily through doglegs up to 56º.

A 1½-stage, 2¾-in. [73-mm] positive-displacement mud motor with a 7:8 lobe ratio has been used to drill most wells on the North Slope. Larger 3½-in. [89-mm] motors are sometimes used when production tubing is larger than 4½ in. Nonmagnetic rotor/stator combinations have been developed for drilling through the formation. The use of the nonmagnetic material reduces magnetic interference sufficiently to allow the steering tools to be placed within 2 ft [0.6 m] of the motor. Conventional steel motors require the use of 10 to 15 ft [3.0 to 4.6 m] of nonmagnetic collars below the directional probe to eliminate magnetic interference, resulting in bit-to-sensor spacing up 25 ft [7.6 m]. Wellbore trajectory projections are greatly improved with shorter bit-to-sensor spacing, resulting in more precise directional control.

Polycrystalline-diamond-compact (PDC) bits have been used extensively in CTD operations on the North Slope. The typical bit has a five-bladed design and contains a combination of round and flattened 8-mm cutters to reduce motor stalling and reactive torque. Rates of penetration typically range 30 to 70 f/ft/hr [9 to 21 m/hr] in sands and 10 to 20 f/ft/hr [3 to 6 m/hr] in shale zones. Cutter breakage typically limits bit life to approximately 1000 ft [300 m] of hole or 60 to 70 hr of rotating time.

Coiled tubing geometry changes and the coil begins to buckle as compressive force is increased behind the bit. Initially, the coiled tubing buckles in a two-dimensional, sinusoidal fashion and then deforms into a helical shape when the compressive force exceeds a critical level. Additional slackoff at the surface reduces the pitch of the helix and increases the normal force of the coiled tubing against the hole wall. This normal force, combined with wall friction, results in a net force that opposes coiled tubing movement into the well, and eventually this force prevents advancement of the coiled tubing. This condition is known as helical lockup.12

Helical lockup is modeled during the well planning process (below). Predictions of maximum weight on bit before helical lockup occurs help in designing the BHA and coil size to match the desired well path. Available weight on bit falls rapidly once the well begins the horizontal section. Many wells on the North Slope are drilled with 2-in. diameter coiled tubing, due in part to the operational efficiency realized from working inside the 2½-in. liner completions run after drilling the sidetrack. However, 2¾-in. coiled tubing is used in wells where available weight on bit would not be sufficient to attain the desired horizontal reach with the smaller diameter coiled tubing.

![Diagram of Maximum weight on bit before helical lockup occurs helps determine the total measured depth possible for a given well design with a particular BHA and coil. Once the well reaches horizontal, the available weight on bit drops dramatically, limiting the total possible length of the well.](image-url)


**Figure 1:** Predicted weight on bit. A model of the maximum weight on bit before helical lockup occurs helps determine the total measured depth possible for a given well design with a particular BHA and coil. Once the well reaches horizontal, the available weight on bit drops dramatically, limiting the total possible length of the well.
Window Milling

In 1991, operators began encouraging suppliers to develop a mechanical whipstock that could be run through 4½-in. tubing and set inside 7-in. casing. Although initial results were encouraging, tool reliability was a problem. The capability to mill a window was crucial to sustaining the entire CTD project. An alternative method was needed. Milling off a cement plug was originally conceived as a stop-gap measure until mechanical whipstocks could be made more reliable, but what was originally thought of as a risky technique turned into a reliable, economic method of sidetracking.

Cement sidetracking, the most straightforward technique, is generally used in wells with 4½-in. production tubing set inside 7-in. or 9¾-in. casing. A specially designed cement plug is placed in the casing and directionally drilled with a bent housing motor to cut the window and lateral wellbore. Time drilling (increasing depth by small increments at specified time intervals) is used to start the window.

The cement plug technique has several advantages over mechanical whipstocks. No iron whipstock is left in the well. The cement can easily be drilled out at a later date. Moreover, if the existing wellbore must be plugged and abandoned with cement, there is effectively no additional cost for the plug.

The method has several disadvantages, however. The windows tend to be shorter than those drilled with a mechanical whipstock. The cement ramp tends to be fragile, so care must be taken when the BHA is run through the window. Despite these disadvantages, more wells are sidetracked off cement plugs than with mechanical whipstocks on the North Slope.

In 1994, a coiled tubing BHA cut the first window below production tubing. The window was cut off a fiber-cement plug without the use of a mechanical whipstock. The time required to mill a window off cement dropped to less than one day once the capability to cut a window in a single mill run was developed. The majority of windows cut off cement plugs use a 3.8-in. (96.5-mm) diamond speed mill run on a 2¾-in. motor or a 4.55-in. (115.6-mm) mill on a 3½-in. motor.

The first step in sidetracking without a whipstock is to spot a cement kickoff plug. The cement provides a foundation for window-milling operations, and most importantly, access through the window until the well reaches total depth. The cement system is a 17-ppg [2-sg], Class G formulation with nylon fibers added for strength, although some current cement plugs no longer include the fibers. The cement placement technique was adapted from the successful coiled tubing cement-squeeze program.

Nylon fibers are often added to the sidetrack cement because they help bind fragments together. The fibers provide impact resistance when the bit mills on top of or through a cement plug, reducing the likelihood of cracking. If the cement does develop cracks during milling, the fiber holds the cement intact, so cement pieces are less likely to fall on top of tools run in the well during subsequent operations. The fibers reduce cement compressive strength somewhat, but so far that has not been a problem. The benefits of the fibers cannot be measured with standard oilfield test procedures; however, examination of cement test cubes after compressive failure has shown the fiber's benefits qualitatively.

The next step is the drilling of the pilot hole to just above the kickoff point. The shape of the pilot hole sets the stage for the remainder of the milling operation. A conventional, short parabolic diamond bit has proven the best choice in drilling the pilot hole. It is run on a steerable positive displacement motor with a 1º bent housing. A downhole orienter and mud pulse MWD steering tool provide directional control for the BHA. This BHA also mills a 3.725-in. [94.6-mm] no-go nipple in the tubing string to 3.8 in. Each bit can drill five to ten pilot holes and nipples.

The typical pilot hole trajectory is curved. The pilot hole is drilled down the opposite side from the window, and the toolface is rotated 180º to the direction of the window. The pilot BHA builds angle across the cemented liner to the opposite wall. This method provides easy BHA orientation and predictable build. When the bit contacts the wall, a counterclockwise reaction in toolface occurs. The pilot assembly is pulled, and the milling assembly is then run.

The milling assembly has an aggressive double-bend BHA to start cutting the casing wall. The milling BHA is the same as the drilling BHA used later in the well, except it includes four to six 3½-in. [79-mm] drill collars between the steering tools and tubing. The coiled tubing string is compliant in compression due to helical buckling. The collars provide weight on bit during milling and keep the coiled tubing in tension, making weight and depth control more precise. Milling occurs at 1 ft/hr [0.3 m/hr] using a hesitation procedure; once the mill contacts the casing wall, it is time drilled by advancing the coil in 0.1 ft [0.03 m] increments. The time required to mill a window is primarily determined by the metal-cutting process.


Window-milling test. In a mockup test, a mechanical whipstock was set inside 7-in. casing, and a mill run on coiled tubing drilled a window out of the casing. This proof-of-concept test early in the CTD program helped in refining the design of through-tubing whipstocks and the drilling parameters to cut an optimum window.
Several types of through-tubing mechanical whipstocks are available. All consist of an anchor that reacts against torsional and axial loads and are designed to allow the small through-tubing diameter to span from the high side to the low side of the much larger casing inside diameter. Through-tubing whipstocks are run inside the 4 1/2-in. casing and expand to fit inside a 7-in. or 5 1/2-in. liner. These whipstocks are typically used for a near-high-side exit. Gravity forces the upper whipstock taper to lie against the low side of the casing. The disadvantage to this design is that it requires significant hole angle.

A through-tubing mechanical whipstock, developed by Baker Hughes, is used on the North Slope for sidetracking. The procedures and BHAs used to mill through the liner with minimum dogleg severity, while providing a clean window area, were developed at a test facility in Shreveport, Louisiana, USA, and refined during the subsequent window-milling operations. This whipstock was designed with a maximum diameter of 3 5/8-in. [92 mm] so it could easily run through the 4 1/2-in. nipple in the typical 4 1/2-in. completion. The whipstock is run and set on electric line to allow good depth control and whipstock face orientation.

The windows are milled with filtered, slick produced water or seawater. Viscous pills have been pumped to clean the metal debris, but downhole videos have shown that significant amounts of metal cuttings remain in the wellbore. There is significant annular area, however, around the whipstock body to allow the metal cuttings to settle inside the liner, so the cuttings have not caused overpull problems on any wells to date. The windows are usually milled in two runs. The first mill opens up the nipple, which later serves as a reference point for depth control.

In 7-in. casing, the initial point of contact is 3 ft down on the whipstock (previous page). The mill breaks through the casing and contacts the cement sheath 2 ft [0.6 m] later. The length of window is typically 6 ft [1.8 m] from this point, and the mill enters the formation. The initial BHA is normally pulled, and a second BHA is run with a pilot mill designed to drill formation. This BHA includes a string reamer to dress off the window and drills a pilot hole just far enough for the reamer to clear the window (right).

Whipstock window-milling procedure. A 12-ft long through-tubing whipstock is first run and set with electric line in a directional well. The mechanical whipstock is permanently anchored in the well and orients toward the high side of the well. A flex-joint BHA opens the window out of the casing, and a second, stiff BHA with a tungsten carbide mill then opens a 3 5/8-in. by 6-ft long window through the casing. A key to developing and refining the operational procedure was the use of downhole video technology to inspect the various steps in the window-milling process.
Drilling Techniques

Because the CTD string is not rotated, hole cleaning and weight-transfer benefits attributed to pipe rotation are not realized. Effective hole cleaning and weight-transfer techniques for both cased and openhole operations have been established, however. Many of the drilling mechanics and hole cleaning problems experienced in early wells have been reduced or eliminated with the use of a low-solids polymer drilling fluid.

Satisfactory drill rates with coiled tubing or rotary drilling require adequate transfer of weight to the bit. Conventional rotary drilling relies primarily on BHA weight. For rotary drilling of horizontal wells, weight is often transferred to the bit by placing a section of heavy-weight drillpipe or drill Collins in the drillstring above the build section to push the lower end of the drillstring in the horizontal section. Drillstring rotation improves weight transfer to the bit by reducing drag; it changes the direction of friction from drag to torque.

Weight transfer in CTD operations occurs primarily by pushing on the resilient coiled tubing drillstring in the horizontal section. Due to its smaller diameter, coiled tubing is less rigid than drillpipe, and helical buckling and eventually lockup will occur as the coiled tubing is increasingly compressed. Maximum weight on bit with coiled tubing is less than with rotary drilling in horizontal wells. Because of the small hole sizes, however, the weight on bit in pounds per inch of bit diameter is adequate, and high-speed motors yield comparable penetration rates to those of rotary drilling.

Cuttings beds, which accumulate around the coiled tubing in deviated and horizontal hole sections, reduce weight transfer and can result in differential sticking unless removed by frequent short trips. The combination of mechanical agitation by the bit, jetting force at the nozzles and continuous circulation of drilling fluid during short trips mitigates the problem of cuttings bed accumulation. Short trips to the start of the build section or the casing window are performed after 50 to 100 ft of new hole are drilled. Extended short trips to the tubing tail to remove cuttings from the large casing annulus above the window are made once per 12-hour tour, or as necessary. Short trip rates of 15 to 20 ft/min [4 to 6 m/min] while pulling out of the hole are used to allow adequate agitation and cuttings sweep. Trip speeds while returning to bottom are typically 40 to 50 ft/min [12 to 15 m/min] to reduce the possibility of accidentally sidetracking. Drill rates in soft sands are normally limited to 75 ft/hr [23 m/hr] to prevent rapid buildup of a cuttings bed and to allow adequate hole cleaning.

The drilling fluid influences weight to bit transfer, particularly in the horizontal section. Weight transfer diminishes as the horizontal section is extended and the drilling fluid is spent. The coiled tubing and BHA, which move freely at normal tripping speeds, can become differentially stuck with a spent drilling fluid at normal drill rates. Dead crude oil is typically circulated into the openhole to free the drillstring in stuck pipe conditions involving differential sticking. The drillstring is commonly freed before sufficient crude is pumped to significantly reduce the hydrostatic pressure, perhaps because the crude increases lubricity or breaks a drilled solids filter cake. As weight-transfer problems become significant, the standard practice is to displace the well with new drilling fluid.

In addition to weight-transfer techniques, coiled tubing drilling requires special methods or tools for orienting the BHA. The indexing hydraulic orienter is used to make directional changes. The orienter is actuated by bleeding off and then restoring coiled tubing pressure. Each cycle results in a preset toolface change of 20°. Small toolface changes can often be made by altering weight on bit. The resulting change in reactive motor torque causes variations in toolface. To minimize drilled doglegs, directional changes are made in 20° increments, when feasible, to correspond with orienter capabilities. If a dogleg or tight spot is observed, the section is backreamed. Three passes upward, typically at 60 to 120 ft/hr, are made with 120° toolface changes between each pass. Reaming while running in the hole at slow rates is avoided to reduce the possibility of accidentally sidetracking.

Directional drilling with a conventional drilling rig is usually accomplished using a combination of rotating and sliding. Rotating results in straight hole, while sliding (not rotating the drillstring) creates a turn. With this technique, the turn rate of a particular bent motor BHA can be controlled by drilling combinations of angle build and straight (tangent) sections. This combination of sliding and rotating results in an average directional change over a given interval of hole. Directional changes in CTD jobs occur only by sliding because the drillstring cannot rotate.

Motor bend selection is critical for drilling the build section. If the drilled build rate exceeds the target build rate, a series of S-shaped turns may be used to reduce the effective build rate. If the resulting doglegs are projected to be severe enough to cause weight-transfer problems while drilling the remainder of the well, the motor is tripped and replaced. Motor selection while drilling the horizontal section is less critical. The most common CTD well types have short build sections with longer horizontal sections.

![Typical CTD well. A typical CTD well on the North Slope has a short build section and a long horizontal section into the reservoir. The liner is made up in the derrick of the rig, run at the end of the coiled tubing string and cemented in place. The wells are then perforated with coiled tubing-conveyed perforating guns.](Image)
Accurate depth control is important in high-build-rate directional calculations and critical to successful window-milling operations. Depth control with coiled tubing is accomplished by first accurately locating a production string component of known depth, such as the tubing tail or profile nipple, and then marking or flagging the coiled tubing at surface. The BHA depth on subsequent runs can be corrected to the flag point, independent of mechanical depth counters on surface. CTD operations use real-time, MWD gamma ray data for accurate depth control. Gamma ray tie-in is obtained during each trip in the hole. Bit depth is correlated to a baseline log, and a flag is then painted on the coiled tubing at surface (right).

The use of gamma ray tie-in logs confirms the phenomenon of pipe stretch. The elongation of the coiled tubing is determined by the depth shift of the reference flag painted on the pipe. Up to 4 ft [1.2 m] of coiled tubing stretch is often measured for a 10,000-ft [3000-m] round trip using 2-in. diameter pipe with a 0.156-in. [4-mm] wall thickness. The stretch probably reflects deformation of the coiled tubing as it is bent over the coiled tubing gooseneck, straightened out by the injector chains and then loaded axially.

**Drilling Fluid**

Critical fluid functions are to provide cuttings transport and suspension in large annuli, optimize pump pressure and flow rate, minimize stuck pipe, provide lubricity between the coil and wellbore, control leakoff or fluid loss, minimize formation damage, provide wellbore stability, allow accurate MWD and logging data acquisition, and enhance cementing operations.

The rheologically engineered, solids-free drill-in fluid was designed to address the unique challenges of CTD operations on the North Slope. Rheologically engineered fluids exhibit viscoelastic, time-dependent properties and are designed to have elevated low shear-rate viscosity (LSRV). A high LSRV correlates with the drilling fluid’s capability to suspend drilled solids, especially in the wide annulus between the coil and original casing. LSRV is measured at a shear rate of 0.06 sec\(^{-1}\) on a Brookfield viscometer (right). The drilling fluid contains five basic components: base liquid phase, biopolymer, lubricant, biocide and potassium hydroxide.

**Low Shear-Rate Viscosity**

Low shear-rate viscosity (LSRV) drilling fluid. High frictional pressure losses inside the coil and BHA limit the flow rate possible during CTD operations. The low flow rate leads to low annular velocity for the fluid carrying drilled solids in the wide annulus between the coiled tubing and casing. The xanthan biopolymer drilling fluid used in CTD wells provides better particle suspension at these low flow rates than hydroxyethyl cellulose (HEC) polymer fluid. The measure of this property is low shear-rate viscosity, taken at a shear rate of 0.06 sec\(^{-1}\) on a Brookfield viscometer.
A premium-grade, clarified xanthan gum produces LSRV in the fluid. Clarified xanthan has had bacterial residue from the manufacturing process removed. Conventional rheological properties can be adjusted at relatively low polymer concentrations, but LSRV does not develop until a critical polymer concentration has been exceeded. As LSRV is the last property to develop, it is also the first to degrade.

Conventional drilling experience has shown that a 60,000 to 80,000 cp LSRV controls leakoff to permeable zones up to 5 D. Unfortunately, LSRV alone cannot control losses to secondary permeability, such as faults and fractures, which have been a problem in Prudhoe Bay where wells have crossed faults. Once a wellbore crosses a fault, losses can range from simple seepage to severe, depending on fault size. Lost returns contribute to problems with hole cleaning, well control, lubricity and stuck pipe. Conventional lost-circulation materials are routinely pumped to attempt to control losses. Different crosslinked polymer pills and other ways of controlling these losses are under investigation.

The typical brine concentration is 5% potassium chloride and 3% sodium chloride, for a total chloride concentration of 40,000 mg/L. This concentration optimizes polymer performance, provides adequate density at 8.8 ppg [1.06 sg] and achieves more than a two-to-one potassium-to-sodium ion ratio for shale inhibition and formation protection. Potassium hydroxide maintains pH around 9.0 to 9.5 to optimize polymer performance and lower corrosion rates from the drilling fluid.

“Solids free” does not mean the fluid never contains solids; rather, it means no solids are added during preparation or maintenance of the fluid. No particulate matter is used for either density or fluid-loss control. Obviously, some drilled solids will enter the fluid system, but aggressive solids removal minimizes their effect on fluid performance. The solids-control program uses linear-motion shakers and a high-speed centrifuge to keep the drilling fluid clean and maintain total solids concentration less than 1%. Once the solids content reaches 1%, the system is diluted with fresh solids-free fluid.

The fluid relies on viscoelastic properties and elevated LSRV, not filter cake, to control invasion of filtrate into the formation, creating a high differential pressure gradient. As fluid leaks off radially into the formation, the shear
rate decreases, and the viscosity prevents further penetration. Temperature, overbalance pressure, formation permeability and porosity, and formation fluid viscosity control the depth of fluid penetration into the formation.

A gradual pressure gradient develops as drilling fluid enters the formation, reducing the potential for differentially stuck pipe, which is critical because there is no pipe rotation to minimize the chance of stuck pipe. The fluid invasion depth has not been quantified yet, but well productivity has met or exceeded expectations, demonstrating the fluid’s nondamaging characteristics.

Minimal solids provide several benefits. Pump pressures remain low, improving coil life. Stuck-pipe potential drops if the fluid system has less than 1% solids. At greater solids concentrations, a filter cake begins to form along with a greater differential pressure gradient. With lower solids content, the coefficient of friction in the wellbore decreases, and lubricants function better because of less solids surface area to coat. Plastic viscosity increases with increasing solids content; a higher plastic viscosity results in higher pump pressures and lower penetration rates.

Outlook

CTD technology has proven to be a viable drilling method in Prudhoe Bay, and operators in Alaska are considering its expansion into the nearby fields of Milne Point, Lisburne, Endicott and Kuparuk. CTD techniques are also used, but to a lesser extent, offshore in the Kenai fields of Alaska. Both BPX and ARCO are evaluating their Alaskan CTD experience for use in other fields worldwide. There is some concern that the unique operational and reservoir conditions on the North Slope which have fostered CTD development may not necessarily be the case in other fields. Another issue is the high startup cost of CTD techniques, especially for on-well projects.

The success of through-tubing CTD jobs has spawned development of through-tubing rotary drilling (TTRD). TTRD is in its infancy and is an emerging technology that may provide many of the same benefits as coiled tubing drilling. Both types of through-tubing drilling offer the main economic benefits of drilling and is an emerging technology that may provide many of the same benefits as coiled tubing drilling. Both types of through-tubing drilling offer the main economic benefits of drilling.

CTD technology is maturing, as evidenced by the focus on improving operational efficiency (previous page). The current challenge to contractors is to provide incident-free operations while delivering 15% year-on-year cost reduction and achieving annual production targets (above).

Wells will become increasing complex as Prudhoe Bay production continues to decline. The length of horizontal sections drilled by coiled tubing will need to increase. Operators expect to drill wells with multilateral sections to tap even smaller pools of oil from a single surface site.

Several technical areas warrant further improvements. Drilling fluids and hydraulics are critical to operational efficiency. The biopolymer drilling fluid works adequately, yet there is much room for improvement. The drilling fluid wears out rapidly, but the exact cause is unknown. The used drilling fluid must be replaced, as it typically lasts for about 1000 ft (half a typical well). The next generation of fluids will need to improve hole cleaning, thereby reducing wiper trips, and improve lubricity to allow better weight transfer to the bit.

Equipment reliability has been a concern and will continue to be a focus for improvement. The goal is to decrease failures in MWD tools, injector heads, tubing and pumps. To that end, there has already been significant improvement. Downtime comparisons between rotary rigs and CTD rigs are unfair, however, because rotary rigs typically have built-in redundancy and backup systems. Coiled tubing units have historically been designed for compactness with only one of each critical item.

In Alaska, there have been more problems with downhole drilling tools during CTD operations than during conventional rotary drilling. These problems primarily stem from the smaller tools used. Service providers working in Alaska are focusing on strengthening these tools, while simultaneously developing the next generation of even smaller tools for drilling through 3%/in. completion strings, using the same electronics as in larger tools.

The drilling engineer’s wish list is obvious: a desire for every tool and service available for conventional rotary drilling, only made smaller and less expensive. Realistically, these advancements will take some time and there will be many problems to solve during development. Building bigger, stronger tools is typically easier than building smaller ones.

The number of skeptics is fewer than in the early days of coiled tubing drilling. Although coiled tubing drilling will not replace rotary drilling, some applications are particularly well-suited for CTD techniques. Of these, Prudhoe Bay is the biggest success story.

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