Coiled Tubing Takes Center Stage

For many years, coiled tubing (CT) operations occupied the twilight zone of a fringe service offering niche solutions to specialized problems. However, over the past five years, technological developments, improved service reliability, gradually increasing tubing diameter and an ever-growing need to drive down industry costs have combined to dramatically expand the uses of coiled tubing (above).

Today for example, coiled tubing drills slimhole wells, deploys reeled completions, logs high-angle boreholes and delivers sophisticated treatment fluids downhole. This article will look at the technical challenges presented by these services and discuss how they have been overcome in the field.1

Coiled tubing drilling on Lake Maracaibo, Venezuela. With the well control equipment of the CT unit, wells are drilled into suspected pockets of shallow gas. The gas is drained to prevent it from becoming a hazard to conventional drilling.

When it comes to coiled tubing, there can be few doubters left. What was once a fringe service has moved to center stage in the oilfield theater of operations.

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In this article, SLIM 1, DLL (Dual Laterolog Resistivity), Litho-Density, SRFT (Slimhole Repeat Formation Tester), RST (Reservoir Saturation Tool), Pivot Gun, Power Pak and FoamMAT are marks of Schlumberger.

SPOOLABLE is a mark of Camco International Inc.

1. This article is an elaboration of a speech given by Roberto Monti, President, Schlumberger Dowell: “Cost-Effective Technology Levers to Improve Exploration and Production Efficiency” presented at the Offshore Northern Seas Conference, Stavanger, Norway, August 23-26, 1994.
Drilling Slimhole Wells

Slimhole wells—generally those with a final diameter of 5 inches or less—have the potential to deliver cost-effective solutions to many financial and environmental problems, cutting the amount of consumables needed to complete a well and producing less waste. Other benefits depend on what kind of rig drills the well. Compared to conventional rigs, purpose-designed smaller rotary rigs can deliver slimhole wells using fewer people on a much smaller drillsite, which cuts the cost of site preparation and significantly reduces the environmental impact of onshore drilling.3

Coiled tubing drilling combines the virtues of a small rig with some unique operational advantages, including the capability to run the slim coiled tubing drillstring through existing completions to drill new sections below. There is also the opportunity to harness a coiled tubing unit’s built-in well control equipment to improve safety when drilling potential high-pressure gas zones. This allows safe underbalanced drilling—when the well may flow during drilling.4

Although there were attempts at CT drilling in the mid-1970s, technological advances were needed to make it viable. These include the development of larger diameter, high-strength, reliable tubing, and the introduction of smaller diameter positive displacement downhole motors, orienting tools, surveying systems and fixed cutter bits. Furthermore, currently available coiled tubing engineering software enables important parameters to be predicted, such as lock-up—when tubing buckling halts drilling progress—available weight on bit, expected pump pressure, wellbore hydraulics and wellbore cleaning capability.5

It was not until 1991 that the first positive results of CT drilling were seen with the deepening of a vertical well in France by Schlumberger Dowell and Elf Aquitaine, and the drilling of two horizontal reentry wells in West Texas, operated by Oryx Energy Co.6 Today, experience has been built up, technology development continues and the number of wells drilled worldwide is set to increase rapidly (above, right).7

More than two thirds of 1994’s expected 150 CT-drilled wells will be injection or shallow gas wells—including steam injection wells in California and pilot wells to relieve pockets of shallow gas in Lake Maracaibo, Venezuela. However, these wells tend to be no deeper than 1640 ft [500 m] and take only one day to drill.

Through-tubing reentry in underbalanced conditions is a category of CT drilling that may grow significantly. Reentering wells extended using underbalanced CT drilling, resulted in production three times greater than predicted rates (see “Prudhoe Bay CT Drilling Reentry Well” next page).

Wells in Prudhoe Bay are drilled in clusters from pads—the same way that they are drilled from platforms offshore. The logistics of supplying and servicing an extreme location are also similar to those encountered in the North Sea. However, with about 1200 wells—of which ARCO operates half—Prudhoe Bay benefits from potential economies of scale.

As with any mature operation, there is a need to extend field life and gain incremental reserves at a cost that reflects today’s oil price. While the primary aim is to devise a strategy for low-cost well redevelopment, a secondary aim is to improve the productivity of horizontal wells by reducing formation damage associated with conventional overbalanced drilling.

In line with these objectives, candidate wells for CT drilling are divided into two classes:

- the replacement of waterflood wellbores that have corroded because of the high carbon dioxide content of the water
- horizontal sidetracks to replace conventional gravity drain wells, tapping new zones and improving recovery

Four years ago, ARCO began sidetracking the existing wells using conventional Arctic rigs. The corroded tubing was pulled and new well sections drilled. ARCO realized that this was going to be a necessary procedure for the future, but that conventional technology was going to incur considerable costs. Using a traditional Arctic rig to enter a Prudhoe Bay well, drill the sidetrack and run a completion costs over $1 million—as many as 800 sidetracks may be needed in ARCO’s Prudhoe Bay unit.

The goal of the Arco-Dowell alliance is to develop a lower cost alternative to conventional rig sidetracks. To date, promising results show that CT sidetracks can ultimately be performed at half the cost of rig operations.  

(continued on page 14)

Prudhoe Bay CT Drilling Reentry Well

Drilled 3 3/4-in. openhold underbalanced through 4 1/2-in. tubing into two target sands.

Drilled in 1980, Well 2-16 had been worked over a number of times but despite two matrix stimulation treatments had become a poor producer. As such, it was shut in 50% of the time. To alleviate this, operator ARCO decided to use underbalanced CT drilling to exploit a horizontal section of the relatively poor-quality reservoir—pay zone permeability is about 50 millidarcies (md).

A rig was used to pull the completion hardware and sidetrack out of the existing casing in the deviated well, drilling until the wellbore was at 90° and had just entered the target formation. Prior to the start of coiled tubing operations, the rig was used to set a 7-in. liner and install a 4 1/2-in. production string including gas-lift hardware.

With 2-in. CT through the 4 1/2-in. production tubing, a 3 3/4-in. diameter open hole was drilled. Artificial lift was used to reduce the hydrostatic pressure of the mud in the annulus and therefore the bottomhole pressure during drilling, creating an underbalanced situation.

Nearly 600 ft of horizontal section was drilled through two target sands separated by a thin shale layer. Drilling proceeded smoothly until a measured depth of 11,933 ft [3637 m] was reached; at that point, penetration slowed and the hole became sticky.

There had been indications of an acceptable production rate from the interval already drilled so the well was put on production. Short-term testing yielded some 3500 barrels of oil per day (BOPD), about three times that expected from a conventionally drilled horizontal well in the area.

The well was completed barefoot for an extended test period with a view to running a slotted liner later. From the start of CT drilling operations to first production took 11 days.

The openhole size was limited by restrictions in the production string and 3 3/4-in. natural diamond bits were employed. Above the bit, the bottomhole assembly (BHA) included:
- a 2 7/8-in. motor with a bent housing, a check valve and a nonmagnetic collar
- a SLIM 1 measurements-while-drilling (MWD) system and gamma ray log
- an orienting tool to change the tool face downhole and steer the drilling—needed because it is not possible to rotate the coiled tubing.

The Dowell orienting tool is actuated by pulling...
off bottom slightly and reducing the rate of drilling fluid pumped through it to create a pressure differential of at least 1000 psi inside the tool’s indexing section. Then, by increasing the pump to the maximum rate allowed by the motor, the tool face is changed by a 30° increment.

However, once drilling starts, reactive torque—which tends to twist the BHA clockwise—will alter the actual orientation of the BHA. To allow for this, before the tool angle is adjusted the effect of reactive torque is measured by simply tagging bottom at the intended weight on bit (WOB) and rotation speed. Once the extent of reactive torque has been measured, the tool face may be altered accordingly. Reactive torque may also be used to fine-tune the tool face—the higher the WOB, the greater the reactive torque.

A key element of underbalanced drilling is the deployment of the drilling assembly into a live well. To do this, the BHA was divided into three segments (next page, right), the longest of which was just over 30 ft [9 m]. These were introduced
a section at a time from the wellhouse work platform into the wellbore via a 34-ft [10-m] lubricator (previous page and below).1 Once all three segments had been successively made up, the entire assembly was ready to be run into the well.

During underbalanced drilling, some oil did flow to surface. To cope with this, the drilling fluid was directed through a test separator. Gas was separated and returned to the production system while the polymer mud was cleaned. Cuttings settled in the bottom of the separator.

For a few months, the well produced prolifically compared to its neighbors. Then the open hole began sloughing, blocking part of the production. To combat this, the well was reentered and the hole underreamed to 4 3/4 in. Then a 2 7/8-in. predrilled liner was run and hung off in the 4 1/2-in. tubing at the end of the 7-in. liner. The predrilled holes and the end of the liner were plugged with aluminum, allowing the liner to be safely deployed into the live well. The plugs were dissolved using acid once the liner was in place.

The well is now producing about 4000 BOPD—by comparison, the best well in the area had previously produced 1200 BOPD.

For ARCO, the well helped prove a number of technologies: support equipment was field tested; deployment procedures and equipment were shown to be effective for long tool lengths; the Anadrill SLIM 1 MWD and gamma ray logs provided reliable directional surveys; steering with the Dowell orienting tool proved effective; and the responses of the three bent-motor BHAs run during the job helped to better indicate the directional capabilities of CT drilling.

1. A number of different drilling platforms and jacking systems are available for CT drilling. One of the earliest and simplest examples is described here.

□ Running in hole for Prudhoe Bay CT drilling jobs. The first of the three BHA sections was installed inside the lubricator in easily handled subsections no longer than 18 ft [5 m]. With the well’s master valve closed, the lubricator—containing the BHA connected to the coiled tubing—was made up to the top of the wellhead blowout preventers (BOP) and pressured up to wellhead pressure. The valve was then opened and the first BHA segment run in hole using the coiled tubing.

The 2 7/8-in. gripper pipe rams of the double-ram BOPs and the annular BOPs were closed around the BHA to ensure isolation from wellbore pressure. After the pressure inside the lubricator was bled down, the CT was disconnected and the lubricator was detached from the BOP and lifted off.

The second segment was then installed into the lubricator with enough protruding below to allow its make-up to the joint of the first section left protruding above the annular preventer. Hydraulic tongs were used to tighten the connection between the first and second segments and the lubricator was stripped over the joint and made up once again above the BOPs. With the pressure equalized, the annular and gripper BOPs were released and the BHA run in hole. The third segment was added in a similar way.

□ Bottomhole assembly divided into three segments, each short enough to be run in hole using the lubricator system.
The second objective of improving productivity employs underbalanced drilling in new, low-permeability zones. Underbalanced drilling offers the opportunity to minimize formation damage incurred during drilling and to optimize the productivity of the completion. As the first case study shows, the technique does seem to offer some benefits.

Underbalanced drilling sometimes helps alleviate other problems like differential sticking. Oil production during drilling helps the string slide better and aids hole cleaning by carrying cuttings to surface more effectively.

Drilling and directional control equipment for through-tubing CT drilling is largely proven, although systems require continued refinement and improvement. As higher build rates are achieved, slimmer CT directional tools may be necessary to accommodate through-tubing operations in some existing wells.

Bit selection must match the geology, motor specifications and the maximum allowable pumping pressure, while at the same time offer viable rates of penetration with less weight on bit and higher rotation speeds than is normal. Polycrystalline diamond compact (PDC) bits are commonly used in medium-to-soft formations, and thermally stable diamond or natural diamond bits for harder formations.

A positive displacement mud motor is used to rotate the bit. Most CT drilling is performed using motors with a diameter less than 3½ in, such as Anadrill’s 2½-in. PowerPak steerable motor.

For directional control, Dowell uses an orienting tool operated by mud-pump flow rate to alter the tool face. Anadrill’s SLIM 1 MWD system coupled with a gamma ray log is used to monitor the wellbore’s progress through the formation in real time. Data are transmitted to surface using conventional mud-pulse techniques.

There are systems available that use wireline inside the coiled tubing. These can transmit directional data to surface at a higher rate than mud-pulse tools and hold the potential to provide electrical power to activate downhole tools. However, installation and maintenance of the cable increase drilling costs.

In case the bottomhole assembly gets stuck, a hydraulic or shear release tool allows the coiled tubing string to be discon- nected and recovered in one piece. A flap- per valve just above the disconnection point prevents any wellbore pressure from entering the CT string.

It would, however, be wrong to say that all the mechanical challenges of drilling have been met. For example, transmitting sufficient weight to the bit can be problematic. Since it is impossible to rotate the CT from surface, it is often difficult to overcome axial friction along the length of the CT, particularly in deviated wells. Because of this, the weight applied at surface frequently becomes “stacked up” against the borehole wall instead of reaching the bit. This phenomenon is well known for slide drilling, but is exacerbated by the flexibility of the CT and increases with the sidetrack angle.

Numerous solutions have been proposed, including hydraulically activated “crawlers” that grip the borehole wall and pull the CT into the hole, and hydraulic thrusters that apply weight by pushing on a slip joint or piston just above the bit. As yet, neither system offers a complete solution.

Another area under intense development centers on using CT techniques to mill a window in the existing casing and sidetrack out of the well. In 1992, ARCO Oil & Gas was involved in a West Texas well where coiled tubing was used to plug back the well, mill a window and drill new wellbore.

The challenge today is to achieve all this through tubing.

A conventional kick-off technique uses a whipstock plug—a long, inverted steel wedge that is set in the wellbore and diverts the drillstring toward the side of the hole to initiate a sidetrack. To achieve this through tubing on Prudhoe Bay wells requires a whipstock that will pass through the 3½-in. minimum restriction inside the tubing but sit firmly and reliably inside the casing below that has an inside diameter (ID) of more than 6 in. So far, this has proved difficult to achieve. Various solutions have been proposed and are being field tested. One system uses an articulated whipstock that unfolds once it has passed through the tubing, enabling it to reach across larger ID casing.

11. Externally upset equipment has its tool joints on the outside, irregularly increasing the outside diameter of the completion string.
Dowell is currently developing two other solutions:
- A hard and nonbrittle proprietary cement plug is set downhole so that a CT milling assembly is deflected against the casing wall to cut a window—two field tests have been carried out so far.
- The inside diameter of the casing is reduced to accommodate a normal but slim whipstock that passes easily through the production tubing.

In this second solution, a conventional cement plug is set in the liner below the tubing. With CT, an oriented 3 1/2-in. hole is drilled against the side of the casing through which the sidetrack must go. Then a 3 1/2-in. whipstock is run on coiled tubing. An MWD system and orienting tool ensure that the whipstock is set in the hole in the cement plug so that its face is adjacent to the casing wall. This is then drilled in the usual way to kick off the well (previous page).

Development of CT drilling is not exclusive to Alaska. For example, in the North Sea, the Danish Underground Consortium is turning to the technique as an alternative to its pioneering strategy based on long, conventionally drilled horizontal sections completed so that many individual zones may be separately fractured. Because these stimulation treatments and all the associated hardware can be expensive, operator Mærsk Olie og Gas believes that a network of slimhole wells drilled quickly and underbalanced with coiled tubing may be more cost-effective.

To evaluate this development strategy, Dowell and Anadrill drilled the first successful CT drilling offshore development well in the North Sea. The well was completed in May 1994 on Mærsk’s Gorm platform and initially produced some 3000 BOPD—up to four times the anticipated level (see “CT Drilling Offshore Denmark,” next page).

To date, CT drilling has not been used as a major exploration drilling tool. One factor that limits its usefulness for exploration drilling is the maximum openhole diameter possible. This is increasing as larger diameter coiled tubing becomes available. With 2 1/2-in. tubing, a vertical open hole of up to 8 1/2 in. may be drilled. Because it is stiffer and can extend farther before lock up, larger diameter CT also allows longer horizontal sections to be drilled. However, horizontal drilling necessitates more trips into the well and more cycling of the CT over the gooseneck. And the larger the CT diameter, the more it is liable to suffer from fatigue during horizontal drilling.

But another important parameter affects CT durability: the internal tubing pressure at the time of bending. The higher the pressure, the greater the fatigue. This, too, is related to the tubing diameter because internal pressure depends on the flow rate required to drive the downhole motor, which is a fixed value depending on the motor type and diameter. Larger diameter tubing can achieve the required flow rate at a lower internal pressure than its slimmer counterpart, thus reducing fatigue.

In short, there is an optimum tubing size for any flow rate, and therefore for any given motor. All these factors, and many others, are taken into consideration by Dowell’s design software when planning the drilling program and choosing the bottomhole assembly and CT type. To date, the reduced life expectancy of coiled tubing larger than 2 1/2 in. limits its use for CT drilling in horizontal wells.

Delivering Coiled Tubing Completions
The availability of larger CT—up to 3 1/2-in. diameter—has sparked interest in another major advance: underbalanced coiled tubing completion. Like CT drilling, this uses the coiled tubing unit’s well control capability to safely run the completion. There are two basic CT completion options.

One choice is externally upset completion strings, which incorporate traditional completion hardware like gas-lift mandrels, landing nipples, sliding sleeves and safety valves in the CT string. To safely run these strings into a live well, a window system may be employed. This window allows the BOPs and the injector head to be separated, giving enough room for the coiled tubing to be cut and the various completion devices installed. While this is happening, the annular and ram BOPs seal off any pressure from the well below (below).

A more rapidly deployable alternative is to use compact completion equipment that may be placed inside the tubing itself.

Externally upset completion rig up with an access window below the injector head and above the BOPs. With the BOPs closed to seal off the live well, components may be connected to the CT and moved into the wellbore. Then the window is closed, the BOPs opened and the components run in hole. When another piece of completion hardware is needed, the BOPs are closed and pressure bled off above. The window may then be reopened, the CT cut and the hardware connected. This process is repeated each time a completion component is added to the string.
This is the first of a number of wells to determine the usefulness of CT drilling for the Danish Underground Consortium’s North Sea wells. Some 3309 ft [1008 m] of horizontal 3\(1/2\)-inch wellbore was successfully drilled into the chalk formation using 2-inch coiled tubing at a maximum deviation of 89°. This was more horizontal length than was planned and the measured depth at the completion of the drilling was 11,000 ft [3352 m].

For this first attempt, the coiled tubing unit was located on the jackup rig Maersk Endeavour, which drilled to approximately 7690 ft [2344 m] measured depth where the 9\(5/8\)-in. casing was set and cemented. The casing shoe was drilled out and a 4\(1/2\)-in. completion string was run to just below the casing shoe.

Drilling was restarted using 2-in. coiled tubing (above). Although CT drilling took 19 days for the 3309-ft section, most of this time was spent in the first few hundred feet where unexpected, 

Danish drilling. The vertical (top left) and horizontal (bottom right) plans of the Gorm field CT-drilled well using the Dowell orienting tool in conjunction with Anadriil’s SLIM1 MWD system. Drilling using 2-in. coiled tubing commenced just below the completion, at 7690 ft. The angle was built to approximately 85°, which was then held until the bottom of the reservoir was approached when the inclination was increased to 89°. The total horizontal displacement from the rotary table was 4766 ft. The azimuth was built from 160° to a maximum of 203° before turning back to the left. 

The photograph (top right) shows the CT injector head in the rig’s drawworks. The photo at the bottom left is an aerial view of the CT equipment on the deck.
chert beds were encountered. Several bits were used in this formation including natural diamond and PDC bits, both of which were ineffective. Diamond speed mills and finally small tricone insert bits were used to drill the last feet of chert to get into the reservoir. While drilling through the softer formation in the reservoir, a PDC bit was used and it took just 7 days to drill the final 2600 ft [792 m].

The intention had been to drill the reservoir underbalanced. However, true underbalance proved difficult to maintain as the hole tended to slough, creating sticking problems. Therefore, most of the drilling took place with the gas lift creating a “just balanced” situation. This was aided by a surface read-out gauge that relayed the pressures at the bottom of the completion tubing. However, the final 1000 ft [300 m] of well were drilled underbalanced.

Reservoir fluids entering the mud were handled at surface using conventional surface test hardware—such as chokes, separators and heat exchangers. This is an element of the operation that operator Mærsk believes needs further development.

Both 2\(\frac{7}{8}\)-in. and 3\(\frac{1}{8}\)-in. motors were employed to good effect. Since it was necessary to steer along the entire 3300-ft section, several trips were made to adjust the motor angles.

As with the Alaskan wells described on pages 11 and 19, directional control was achieved using the Dowell orienting tool in conjunction with the SLIM 1 system. The orienting tool worked well, although it was sometimes time-consuming. When gas lift was used during drilling, the mud in the annulus became lighter than the mud inside the CT. Consequently, it took longer than usual to orient the tool face because each time the pumps were shut down, the heavier fluid flowed to equalize pressure with the lighter before down-hole hydrostatic pressure stabilized.

SPOOLABLE coiled tubing completion equipment developed by Camco Products & Services is flexible enough to bend over the CT reel (above). The whole completion string may be assembled and connected to the CT at the manufacturing plant or workshop, increasing operational efficiency and safety while reducing environmental hazards. Once on location, the CT and completion hardware are simply spooled off the reel over the gooseneck and run into a live well with standard equipment.12

As with other coiled tubing-related issues, ARCO is using CT in Prudhoe Bay to broaden its completion options. ARCO ran the first completion using 2-in. coiled tubing in 1990. Today, 3\(\frac{1}{2}\)-in. tubing is used (see “Combining CT Drilling and Reeled Completion,” page 19) and the company reports that running times for installing such completions are being cut with each job.13

For example, six Alaskan injector wells were recently completed using 3\(\frac{1}{2}\)-in. coiled tubing. All the wells were about 9000 ft [2740 m] deep and all the completions included a 10-ft [3-m] seal assembly, landing nipples and a tubing hanger. On-location time improved dramatically with each job. The first well took 40 hours, the last just 25 hours.

Logging and Perforating with Coiled Tubing

Like CT drilling, coiled tubing logging has come of age only in the 1990s. One of its key selling points revolves around the stiffness of the tubing, enabling penetration into horizontal and high-angle sections. Additionally, wireline inside coiled tubing offers the potential to pump fluids downhole and log at the same time.

Successful application of CT logging requires the reliable interface of the coiled tubing and logging units. Wireline log acquisition systems are driven by depth. To supply real-time depth data for CT logging, an encoder relays a depth signal from the injector head into the logging unit through a dedicated interface. This depth information is also used by the Dowell monitoring system that records coiled tubing and pumping parameters.

A newly designed coiled tubing head is now available to attach the logging tools to the CT. The modular head secures the cable in place, allows fluid to be circulated through a dual flapper valve during logging, and provides for electrical connection and mechanical release.

Fundamentally, a CT logging operation is not much different from its wireline counterpart. However, the tubing is stiffer than wireline so it tends not to stretch as much, and the injector head provides a stable speed. Coiled tubing may deploy most logging tools, as long as they are slim enough to fit inside the wellbore. The scope of slimhole logging—whether the wells were drilled using CT drilling or conventional techniques—has been limited by the availability of slimhole hardware. Now that scope is broadening.

Originally, slimhole logging tools were developed to gather petrophysical information in deep, usually hot, wells that required extra strings of casing, thereby reducing the final well diameter. Alternatively, they were needed to log through drillpipe under difficult hole conditions. These rigorous environments ensured that such tools were of necessity simple, reliable and rugged.

Today, CT drilling and slimhole wells are being used, or contemplated, for a broader

Combining CT Drilling and Reeled Completion

Well drilled overbalanced and completed using 2-in. and 3 1/2-in. coiled tubing, respectively.

Like the well described on page 11, Well 18-23A is operated by ARCO in the Prudhoe Bay field. This time, the well was not only sidetracked using CT drilling, but also completed using 3 1/2-in. coiled tubing (right).

A rig was used to pull the completion and sidetrack out of the old wellbore, drilling toward the new well location but stopping when a horizontal inclination was achieved in the target zone. CT drilling was then used to drill horizontally through the pay zone. Because the rig did not install any gas-lift hardware, the well was drilled overbalanced. The result was a horizontal section some 800-ft [240-m] long with a 4 3/4-in. diameter.

With 2-inch coiled tubing and conventional CT well control equipment, a 2 7/8-in. preperforated, plugged liner was run and hung off in a 3-in. by 5 1/2-in. packer inside the 5 1/2-in. liner. The completion assembly—which included an indexing mule shoe, a locator seal assembly, landing nipple, two gas-lift mandrels and a second landing nipple—was installed onto the 3 1/2-in. CT and then pressure tested. The assembly was then run in hole and stabbed into the completion packer.

The well was placed on production at 3900 BOPD and that rate subsequently increased to 4600 BOPD—compared to 1200 to 1500 BOPD from a nearby conventional well.

To date, coiled tubing is most often used for production logging, sometimes combined with CT-conveyed perforation. As usual, the production logging tool string measures a range of parameters, including spinner revolution, fluid density, pressure and temperature; a gamma ray tool and a casing-collar locator are also included.

Production logging of high-angle or horizontal wells presents a tremendous challenge. For example, there may be stationary fluid, back- or cross-flow—some zones may be accepting fluid produced by other zones. Only a fraction of the fluids “seen” by the tools may actually be moving. To overcome these difficulties, the production logging program must be sufficiently flexible to respond to changes in well behavior. A typical CT production logging job involves the following steps:

- Rig up and pressure test equipment.
- Run in hole stopping to check CT weight.
- Correlate depth with a reference log using casing-collar correlation and gamma ray logs—vital because the CT tends to form a helix in the well.
- Log the well while shut in.
- Log in both directions with typically four passes at say 40, 60, 80 and 100 ft/min.

range of well types that have more sophisticated needs. To meet these needs, many standard and new high-technology imaging tools have been reengineered to operate in more restricted boreholes. For example, the DLL Dual Laterolog Resistivity tool and the combinable Litho-Density tool have been repackaged with diameters of 2 3/4 in. and 3 1/2 in., respectively.

In addition, new instruments have been designed, such as the SRFT Slimhole Repeat Formation Tester tool for sampling the formation, the sourceless RST Reservoir Satur- ation Tool, and the Pivot Gun for slimhole perforation. Combining tools and coiled tubing logging capability are standard features.
[12, 18, 24 and 30 m/min] with the well flowing. The intervals between data collection may be decreased or the logging speed increased.

- Observe well anomalies, making some stationary log measurements to look for backflow.
- Pull out of hole.

Another production-related CT logging service employs pulsed neutron logs and borax solution. The borax is pumped into the CT-production tubing annulus at a pressure above that of the reservoir but below the fracturing pressure. Because borax is more effective than reservoir fluid at slowing neutrons, pulsed neutron logs can trace where it has gone and hence confirm the location of a suspected channel and indicate high-permeability zones. With additional openhole log data, initial reservoir saturation information may also be derived.

After the production profile of a well and potential hydrocarbon saturated zones have been identified, reperforation using CT-deployed guns may be necessary (see “CT Logging and Perforation in Alaska,” right).

**Matrix Treatment**

The most traditional of all coiled tubing services is the delivery of fluids downhole. No account of the practical uses of coiled tubing would be complete without describing at least one pumping application—a role that has become more important with the proliferation of horizontal wells.

As in other areas, increasingly sophisticated pumping services are available. For example, a relatively new matrix treatment tackles an old problem, diversion. Unless a stimulation fluid is successfully diverted into the areas that most need it, the fluid will channel into the high-porosity, high-permeability formation that least requires improvement. Horizontal wells generally have a much longer reservoir section than their vertical counterparts, so the problem of diversion is proportionally more difficult. To compound this, few horizontal wells are completed in a way that allows even rudimentary zonal isolation.

Traditionally, diverting materials—like calcium carbonate or rock salt—are introduced to temporarily plug the zones of the formation taking most fluid, redirecting flow to more needy parts of the wellbore. But the plugging must be reversible—by dissolution in acid or reservoir fluids—and leave the formation undamaged. Not an easy criterion to meet.

So far, ARCO’s sector of the Prudhoe Bay field has run 12 coiled tubing logging jobs in eight highly deviated or horizontal wells. The aims of these jobs were to obtain the production profile and verify the presence of channels using pulsed neutron logs. Where necessary, coiled tubing-deployed perforating guns were used to open up potentially productive zones.

Well 15-07A exemplifies the jobs performed in Alaska. It is a virtually horizontal well completed with a 4 1/2-inch slotted liner at a total vertical depth of 8761 ft and a measured depth of 13,545 ft.

Drilled as a sidetrack to a much older well and completed earlier this year (April 1994), the well...
Pulsed neutron logs made in conjunction with borax injection. Three logging passes were made during seawater injection as a base log and then three more after the injection of borax solution. Interpreting the result, ARCO located the gas-oil contact at 12,077 ft and a possible channel behind the 7-in. liner at 12,370 to 12,450 ft.

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A successful alternative employs stable foam that is generated in the “thief zones” as a diverter. Alternating stages of acid and the foam—made from water containing surfactant and nitrogen—are pumped. The diverter enters the formation that is taking fluid. Some 10 minutes or so are allowed for the foam to build up and, when pumping restarts with a new acid stage, a pressure increase is seen at surface as the foam ensures the acid enters some other part of the formation. Pressure gradually decreases until it is time to pump the next foam stage. Once production starts, the foam breaks down and flows out of the well leaving undamaged, acidized formation.

Coiled tubing is an ideal way of targeting the delivery of the treatment fluids to the formation, particularly in horizontal wells. Furthermore, because the volume inside CT is relatively small, a flexible treatment program may be employed, based on pressure responses observed during pumping (see “Matrix Treatment in Alberta,” right).

**Looking to the Future**

This tour of coiled tubing applications has concentrated on events in Alaska and the North Sea. But all over the world operators and service companies are using coiled tubing for a range of tasks that would have been inconceivable only a few years ago.

As larger diameter tubing and the availability of hardware needed to handle it become more widespread, even more services will be devised and current ones improved. For example, conventional directional CT drilling techniques will be replaced by geosteering. CT completion systems will be refined and costs reduced. Logging with CT will become more extensive. Rigless wellwork operations will become increasingly widespread.

If they weren’t so busy coping with the present, coiled tubing engineers could look forward to the future with excitement. —CF

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**Matrix Treatment in Alberta**

CT-conveyed FoamMAT treatment added an estimated deliverability of 2 to 6 million scf/D.

This case concerns a Suncor Inc. operated gas well, Pine Creek 10-1-56-19-WSM, in Alberta, Canada. It has a 2493-ft (760-m) horizontal section, drilled through the carbonate reservoir above the water leg to a measured depth of 14,935 ft (4552 m).

Unlike the usual situation, the best porosity of the horizontal section was believed to be at the toe of the well rather than the heel. However, it was also believed that these high-potential zones had been invaded by drilling mud filtrate. To enhance productivity, it was important to ensure that the acid was pumped into the toe of the well to open up fractures and allow the mud to flow out.

To create the required diversion, it was decided to pump a FoamMAT treatment. Foam is pumped into the formation, blocking further entry of the acid and diverting it to unstimulated reservoir. To minimize friction when pumping at the necessary rate, 2-in. coiled tubing was used to deliver the fluids. The relatively large CT diameter also helped avoid lock-up when running into the long horizontal section and offered more pulling potential if the string had become stuck.

The downhole assembly consisted of a nozzle, two memory gauges separated by a knuckle joint, and a check valve. The knuckle joint added flexibility to an otherwise stiff assembly. Data collected by the gauges were used after the job to analyze the buildup and breakdown of the formation as successive diversion and acid phases were pumped.

A number of factors complicated the choice of acid additives—which is crucial to the success of any matrix treatment. First, as already noted, Suncor suspected that the formation had been invaded by significant quantities of mud filtrate, which contained a strong emulsifier likely to form an emulsion with spent acid. Second, the presence of 25% hydrogen sulfide (H₂S) in the well necessitated the use of corrosion-control additives that may react with other chemicals in the fluid.

Consequently, extensive compatibility tests were run between the mud and proposed acid systems. The final treatment design included a number of stages:

- **tubing pickle**, which is used to clean up the inside of the coiled tubing—15% hydrochloric acid (HCl), inhibitor and surfactant
- **preflush**, to thin the mud in the wellbores—fracturing oil, antisludge agent and nitrogen, creating a foam with a quality of 50%¹
- **Mudclean OB solution**, to flush out any remaining mud in the well and water-wet the formation prior to the FoamMAT job—water, surfactant and solvent as a foam of 50% quality
- **diversion stages**—water and surfactant with nitrogen as a 65% quality foam
- **squeeze acid**—15% HCl, with inhibitor, surfactant, de-emulsifier, antisludge agent, miscible solvent and H₂S scavenger. The total volume of the acid, some 33,025 gal [125 m³], was determined by a rule of thumb and past experience of a FoamMAT job carried out on a nearby oil well.
- **postjob flush**—fracturing oil and nitrogen.

Having pickled the CT and negotiated some problems running in hole caused by a hydrate plug, the preflush was pumped with the CT on bottom—at the end of the toe. Once all the preflush had been displaced across the open hole, the well was shut in for about 15 minutes to allow it to soak and then flowed back to recover any mud filtrate. Next the Mudclean OB stage was pumped down-hole and displaced using nitrogen. The well was then allowed to flow to clean up and another stage was pumped.

When this had been displaced out of the well, the main treatment commenced. A series of 15 alternating acid—1585 gal [6 m³]—and diverter—400 gal [1.5 m³]—stages were pumped at 25 to 80 gal/min [0.1 to 0.3 m³/min]. At the same time,
The coiled tubing was gradually pulled out of the hole—at about 10 ft/min (3 meters/min)—from the toe to the heel of the well. After pumping a diverter stage, the pumps were shut down for 10 minutes before the next acid was pumped.

Midway through the job, the well went on a vacuum. To maintain a positive surface pressure and gain maximum information about the treatment, it was necessary to reduce the bottomhole hydrostatic pressure. The foam qualities of the two fluids were adjusted so that the diverter was 70% and the acid 25%.

Surface pressure was plotted throughout the job to assess the success of the diversion stages. Once all the acid was pumped, the CT was run back to the toe of the well and the postjob flush was pumped to break up the foam in the wellbore and hasten the cleanup.

The well was opened up to flow with the gauges still on bottom. During cleanup, the well flowed spent acid and an estimated 21,000 gal [80 m³] of mud filtrate. Suncor believes that this mud came out of the natural fractures of the formation. Once the well was cleaned up, the well pressure and temperature were logged using the memory gauges.

The well is currently waiting to be brought into production, but Suncor estimates that the acid treatment reduced the pressure drop across the reservoir by 435 to 725 psi. By comparing this to pretreatment pressure and rate information, additional gas deliverability due to the treatment is likely to be 2 to 6 million scf/D.

Log data from Suncor’s FoamMat stimulation job tied into a well profile. This shows a derivative of the temperature log while the well was flowing after the FoamMat stimulation. Interpretation is difficult, but the most likely explanation is that there was good production from the interval at 3760 to 3810 m, and possibly 3860 to 3880 m, 4000 to 4035 m, 4190 to 4210 m, 4265 to 4290 m and 4420 to 4450 m. However, during the initial flowback, significant quantities of mud filtrate also flowed and this may be masking effects of gas flow in the well.

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1. Foam quality is defined as the ratio of the volume of gas in the foam to the total volume of foam—expressed as a fraction or as a percentage. So a nitrogen-water foam of 75% quality contains 75% by volume nitrogen and 25% by volume water (at downhole conditions).