Rapid Deployment Drilling System for On-Site Inspections

Under a Comprehensive Test Ban

—Preliminary Engineering Design—

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**Rapid Deployment Drilling System for On-Site
Inspection under a Comprehensive Test Ban —
Preliminary System Design
Final Report
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1. Introduction

1.1 BACKGROUND

A Rapid Deployment Drilling System (RDDS) is needed that can be quickly deployed to drill postshot holes at the site of a suspected clandestine underground nuclear test. Evidence to confirm the event must be obtainable with the system. Confirming data are expected to take several forms, including radioactive gases at the surface, measuring gamma radiation levels in the borehole that are significantly above any known naturally occurring levels, and/or measuring a thermal environment with temperature levels and gradients characteristic of a nuclear event (Heuze, 1995).

The most probable drilling conditions for the RDDS are a hard-rock (mountainous) environment, with drilling depths not exceeding about 5000 ft. The capability to drill multiple laterals out of the parent borehole is an important component of a system to search for a nuclear “needle in a haystack” (Figure 1).

Figure 1. Rapid Deployment Drilling System

The ability to be rapidly deployed to the site, be as lightweight and mobile as possible, and to minimize the consumed materials and external support required, are fundamental design considerations for the RDDS. Personnel and environmental safety are also critical issues.

The unique requirements of the RDDS are best addressed by a coiled-tubing (CT) drilling system (Figure 2). CT is a continuous section of drilling pipe (up to several thousand feet in length) that is spooled onto a reel and can be rapidly run in and out of a well. CT drilling technology has been rapidly developed and embraced within the oil drilling industry for environments where high mobility, safety, and small surface impact are required (Sas-Jaworsky, 1991).

Figure 2. Coiled-Tubing Drilling System

While not a new drilling technology, CT drilling continues to undergo rapid development and expansion, with new equipment, tools and procedures developed almost daily. This project was undertaken to:

- Analyze available technological options for an RDDS CT drilling system
- Recommend specific technologies that best match the requirements for the RDDS
- Highlight any areas where adequate technological solutions are not currently available

Postshot drilling is a well established technique at the Nevada Test Site (NTS) (Butler, 1984). Drilling provides essential data on the results of underground tests including obtaining samples for the shot zone, information on cavity size, chimney dimensions, effects of the event on surrounding material, and distribution of radioactivity.

Rotary drilling, the technology used to drill the majority of oil wells, is also employed at the NTS. Two basic methods have been used (Figure 3): 1) directional drilling, where a standard vertical rotary rig is used to drill a vertical borehole to a medium depth, after which directional drilling techniques are used to curve the hole to the zone of interest, and 2) slant drilling, where a special slanted rig is used to drill a hole in a straight path directly to the zone of interest. Drilling depths, formation types and other factors are considered to determine which technique to apply at NTS.

Figure 3. Rotary Postshot Drilling at NTS (Butler, 1984)

While effective and routine, the rotary drilling systems used at NTS are not ideal for application with the RDDS. A rotary rig is considerably more massive than a CT rig, and the

requirement to screw/unscrew a new section of drill pipe every 30 to 40 ft when going into/coming out of the hole makes the operation much slower, more cumbersome, and potentially less safe to personnel on the rig floor. By contrast, there are no connections on a string of CT, and personnel on a CT rig come into contact with downhole equipment only when the drilling assembly is out of the hole. Telemetry data describing the environment down the hole are also constantly relayed to the surface on wireline inside the CT.

1.2 OBJECTIVES

The objective of this study is to define a Rapid Deployment Drilling System that can be quickly deployed to drill postshot holes at the site of a suspected clandestine underground nuclear test. The RDDS will be designed to meet the following criteria:

1. Highly mobile and able to be rapidly deployed
2. Drill to 5000 ft in hard rocks at rapid rates
3. Small environmental impact
4. Minimal external/infrastructure support
5. Minimize water requirements
6. Minimize waste
7. Be capable of accurately guiding multiple branch boreholes from a single well
8. Operate in high-temperature, high-gamma environment
9. Provide real-time measurement of temperature and gamma
10. Safely handle radioactive gases

1.3 COILED-TUBING DRILLING

Drilling with a continuous drill string provides a number of important advantages. The driving force behind the development of coiled-tubing (CT) drilling within the oil industry is the need to reduce drilling costs. The economic advantages of slim-hole operations are shared by CT drilling. Smaller rigs and surface locations result in less environmental impact and lower engineering costs. Lower mobilization costs and faster rig-up are also expected. Smaller scale operations lead to

savings in mud, casing, and other consumables. Fewer personnel and equipment can also decrease day-rate costs.

Drilling with CT requires different equipment than drilling with a conventional rig. Special equipment (Figure 4) is not limited to the surface equipment and the drill string, but extends to the bottom hole assembly (BHA). With vertical drilling, there are three primary differences between the BHA for conventional rotary drilling and CT drilling.

Figure 4. Coiled-Tubing Drilling Equipment

The first difference is in the rotation of the bit. CT, by the nature of the equipment presently used to convey the pipe, cannot be rotated from the surface. Therefore, to rotate the bit, a rotary power source is required downhole. This rotary power source most often takes the form of a positive-displacement mud motor. Other rotational power sources such as turbines and vane motors are becoming available in smaller sizes.

Secondly, CT also presents more challenges for fishing operations (retrieving tools, assemblies and pipe dropped or stuck in the hole) than conventional drill pipe due to the smaller diameter and higher flexibility of the CT string. Therefore, a release joint is included in the drill string for CT drilling. This tool allows release of the BHA and retrieval of the CT should the BHA become stuck.

The third difference between rotary and CT drilling is in the well control and safety for flow up the drill string. With conventional rotary drilling, when an influx into the wellbore occurs, a kelly cock or TIW valve is stabbed into the drill string at the surface and closed to prevent flow up the drill pipe. With no connections when drilling with CT, installing this kelly cock valve is not practical. Instead, a check valve is run in the BHA. Typical vertical hole BHAs for both conventional rotary drilling and CT drilling are illustrated in Figure 5.

Figure 5. Vertical Hole Drilling Assemblies

As illustrated above, stabilization requirements are less for CT drilling. Because of the nature of the small motors used, drilling energy is created by high rotary speed and low weight on bit with CT drilling. Conventional rotary drilling uses low rotary speeds and higher weights on bit due to pipe and rotational equipment limitations.

Directional drilling is accomplished by using a downhole motor with a bent housing to change the path of the well. Both conventional and CT directional drilling make use of a motor with a bent housing (Figure 6). To control the direction, the bent housing is oriented to the desired drilling direction.

To monitor the direction of the hole as drilling progresses, sensors are included downhole to provide inclination and direction. These sensors are referred to as “measurement while drilling” (MWD). In addition to the MWD sensors, other sensors can also be included in the BHA to measure formation characteristics. Steering systems with additional sensors, referred to as “logging while drilling” (LWD), typically include gamma ray and resistivity.

Important differences exist between the assemblies for directional drilling used with conventional jointed pipe and with CT. The two main differences are in the method of orienting the bent housing on the motor and the method of data transmission from the downhole MWD/LWD sensors.

In conventional rotary drilling, the pipe is twisted from the surface to orient the bent housing on the motor. To orient the bent housing on CT, an “orienting sub” is added to the BHA above the MWD/LWD package. This orienting sub rotates the BHA and is controlled through pressure pulses, hydraulics, or electrically.

For data transmission from the downhole sensors to the surface, conventional drilling relies on mud-pulse telemetry. Data are transmitted to surface by pressure pulses in the drilling fluid. These pressure pulses cannot be effectively transmitted through a drilling fluid containing gas. With CT drilling, other methods of communication with downhole sensors are also practical. The most common method in use today is an internally installed electric line. This wireline allows much higher data transfer rates than mud-pulse telemetry and will operate with a gaseous drilling fluid, such as air or foam.

Figure 6. BHA for Changing Hole Direction

2. Drilling Subsystems

Several subsystems comprise the RDDS drilling equipment and tools:

1. Drilling Rigs
2. Coiled Tubing
3. Bottom-Hole Assembly
4. Drill Bits
5. Mud System
6. Foam System
7. Air Compressor
8. Multilateral Tools

The design considerations for each of these subsystems is discussed in turn in the following sections.

2.1 DRILLING RIGS

A coiled-tubing (CT) rig consists of five integrated subsystems (Figure 7). These include the spool of CT, injector, blow-out preventers, control console, and hydraulic power pack.

Figure 7. CT Rig Components (Sas-Jaworsky, 1991)

These five systems are fitted onto a single trailer along with an on-board crane (Figure 8).

Figure 8. CT Rig Assembly (Halliburton)

At the well site, the on-board crane is used for lifting the injector over the well head (Figure 9). The injector is then rigged up to the wellhead or an adjustable-height platform is assembled under the injector. The crane can then be detached (or remain in position for added safety).

Figure 9. CT Rig Up

The general requirements for drilling with the RDDS do not present unusual criteria with respect to the CT rig. Designs and capacities of larger modern CT rigs becoming common in the oil industry will be more than adequate. A standard CT rig equipped with an 80k injector (80,000-lb pulling capacity) is recommended.

One operation for which additional equipment may be required is changing spools of CT after fatigue limits are reached in field operations. The CT crane can be upgraded with the additional capacity required for lifting the entire spool (30,000+ lb). This represents the most straightforward option.

Another alternative is to avoid the need to lift the spool by supplying a second trailer with a fresh spool of CT and an empty transfer spool. The used CT would first be spooled off to the empty reel using winding motors on both spools. New CT would then be tied in to the original spool and transferred over to the rig.

Using a mobile crane for handling tubing reels is a third option. It may be determined that a mobile crane is needed at the site for various lifting jobs. This approach, while requiring an additional piece of equipment to be transported, would provide greater flexibility on location than depending solely on the CT rig crane.

In the absence of a clear need for a mobile crane at the location, an upgraded crane on the CT rig is probably the best option for changing spools.

2.1.1 Drilling the Pilot Hole

The first step in drilling operations at the site of a suspected nuclear test is to drill the pilot hole. Pilot holes are needed to drill past soil and loose formations near the surface. A short length of large casing, called the conductor pipe, is typically set in the pilot hole. The conductor pipe provides support for drilling equipment and serves as a return conduit for the drilling fluids circulated down through the inside of the drill string (CT in this case).

A suitable support structure will be constructed at the RDDS site by setting and cementing one joint (about 40 ft) of 8½-in. conductor pipe (with a flange on the upper end). The CT injector is then rigged up on the flange. Snubbing (upward) loads on the injector will be well supported by the cemented conductor, especially if the conductor is set in a belled hole, i.e., with an enlarged-diameter section near the bottom of the hole.

If a second string of surface casing is required for some reason (a water-producing zone is encountered, significant hole sloughing is observed, etc.), 4½- or 5½-in. casing could be set using the crane and mechanical slips set at the conductor flange. The hole would be enlarged to about 6 in. prior to running the casing.

There are several potential approaches for drilling the pilot hole with the RDDS system. Each could be made to work in various situations. Approaches include:

1. Using a pile driver to drive in the casing
2. Using an auger machine to drill out the hole
3. Drilling the hole with a mud motor suspended from the crane

Pile drivers are readily available in the marketplace and are used daily to drive in piles for bridges. This process would be limited to soils and possibly some types of soft rocks. The principal drawback of this approach is that the casing cannot be cemented in place, so snubbing reaction forces are limited to the friction developed between the soil and the casing. (When normal

drilling commences, the CT injector will pull up on the conductor pipe while it pushes down on the bit.) For these reasons, using a pile driver is the least preferred approach.

Augering the surface hole is possible. Unlike pile driving, an augered hole could be made with a belled bottom. After the conductor pipe is lowered into the hole, cement could be poured in around the casing to form a very solid and strong base. Augering can be used in soils, mixed soils and some rock. Although augers do exist for rock drilling, they do not work in very hard rock like granite.

Figure 10. Auger System for Drilling Pilot Hole

An example auger operation is shown in Figure 10. The system in this figure is designed to be used with a large boom-type crane. Other auger systems are designed to be used with smaller mobile cranes referred to as “cherry pickers.” These cranes have a telescoping boom and are the type more often used in oil-well drilling. The auger method based on a mobile crane represents additional equipment that must be shipped to the site and, therefore, may be undesirable.

The auger approach could make more efficient use of available equipment if the auger were supported by the CT rig crane and anchored to the CT trailer. This represents a custom application, but will present no unusual problems for system design and fabrication. The primary concern will be whether sufficient crane capacity could be made available on the CT crane.

Expected crane loads should be carefully modeled to verify that the CT rig could safely perform this type of operation.

The third option for drilling the pilot hole would use a conventional mud motor and large bit. This would be accomplished by suspending a motor from the CT crane and lowering it as drilling progressed (Figure 11). The fluid to power the motor would be pumped to the inlet using a high-pressure hose. A torque reaction sub would be needed at the top to transfer torque into the crane boom along with a method to stabilize the drilling assembly before the bit is buried.

Figure 11. Drilling Pilot Hole with Mud Motor

Using a motor has advantages as compared to the other options. Most significantly, it requires minimal additional equipment. The motor could be used in soils and rock of all types. The hole size could be made large enough to allow cementing the casing. An underreamer could also be run on the motor to make a belled footing for extra support.

2.1.2 Drilling Below the Conductor

One joint (40 ft) of conductor pipe should be sufficient to support the CT injector and the reactive loads of drilling. The complete directional drilling assembly is about 40 ft long and can be hung off in the hole. A short lubricator can be used if additional rig-up height is required.

The RDDS exploratory holes will be drilled with 3⁷/₈-in. bits on 2-in. CT. The oil industry has had significant experience with this combination of sizes and found that ancillary tools (logging, fishing, etc.) are available and reliable.

If drilling is performed in a hard-rock geology, surface casing (a second length of casing inside the conductor pipe) will not be required. The initial plan will be to drill out of the conductor pipe with a 3⁷/₈-in. bit on CT.

If a significant water-producing zone is encountered or troubling hole sloughing is observed, the need to set surface casing may be justified. Prior to setting a string of 4¹/₂-in. or 5¹/₂-in. casing, the hole would be enlarged to about 6 inches. This is readily achievable with the CT drilling BHA, although a larger mud motor (3³/₄-in. or 4³/₄-in.) would probably be used than for the 3⁷/₈-in. hole (2⁷/₈-in. motor). The other important consideration, should surface casing need to be included in the well, is the added shipping weight of the casing. Representative casing string weights are compared in Table 1.

TABLE 1. Weight of Surface Casing

Casing OD (in.)	Weight (lb/ft)	200-ft String (lb)	500-ft String (lb)
4.5	9.5	1900	4750
5.5	11.5	2300	5750

2.2 COILED TUBING

Coiled tubing has been in use in the oil industry since the early 1960s. Its performance and reliability have been improved dramatically in recent years. While previously used only for light-duty workover operations (cleaning sand out of wells, nitrogen injection for unloading fluids), stronger and larger CT has paved the way for a variety of new applications, including drilling, production tubing and pipelines. CT is currently manufactured in diameters ranging from ³/₄ to 4¹/₂ inches.

The vast majority of CT sold commercially is manufactured from high-strength, low-alloy steel. Material yield strength is typically 80,000 psi, with 50,000-, 70,000- and 100,000-psi material available. All three manufacturers of steel CT are located in Houston, Texas.

A material strength of 80,000 psi is sufficient for the assumed drilling criteria for the RDDS. Although 100,000 psi CT would support greater loads and torques with no weight penalty, fatigue performance of the stronger CT is slightly degraded at lower internal pressures (less than about 3000 psi). The expected operational pressure range for the RDDS is less than 2000 psi. Therefore, 80,000-psi steel CT is recommended.

Based on load capacity and torsional strength (Table 2), 2-in. CT with a 0.156-in. wall is the recommended size for the RDDS. Industry's experience bears this out, as the majority of CT drilling operations are conducted with this size of pipe.

TABLE 2. Steel CT Specifications (QT-800, Quality Tubing)

QT-800[®] COILED TUBING TECHNICAL DATA — US UNITS						
Outside Diameter (inches)	Wall Thickness (inches)	Plain End Weight (lb/ft)	Yield Load (lb)	Burst Pressure (psi)	Collapse Pressure (psi)	Torsional Strength (lb/ft)
1.500	0.102	1.52	35,840	10,350	9,410	1,129
1.500	0.125	1.84	43,200	12,800	12,220	1,321
1.500	0.156	2.24	52,690	16,110	14,910	1,547
1.750	0.125	2.17	51,050	10,970	10,250	1,864
1.750	0.156	2.66	62,500	13,810	12,990	2,204
1.750	0.188	3.14	73,800	16,730	15,340	2,511
2.000	0.125	2.50	58,900	9,600	8,060	2,502
2.000	0.156	3.70	72,300	12,080	11,510	2,978
2.000	0.188	3.64	85,620	14,640	13,630	3,418
2.375	0.125	3.00	70,690	8,080	5,640	3,636
2.375	0.156	3.70	87,000	10,170	8,840	4,361
2.375	0.188	4.39	103,330	12,330	11,660	5,043

Other materials from which CT is manufactured include titanium and composites. Several spools of titanium CT have been sold over the last few years, primarily for offshore tubular applications (risers, umbilicals, etc.). Composite CT holds great promise with respect to superior weight, fatigue, and corrosion characteristics, but the product is still in the development stages.

The primary options for CT for the RDDS are steel and titanium. There are several factors to be considered when comparing titanium CT to steel CT. These are discussed with particular emphasis on the impact on the RDDS in the following paragraphs.

Titanium CT costs significantly more than steel CT: almost 8 times more for Grade 9 (70 ksi) titanium compared to 80-ksi steel. In most CT job-cost analyses, this cost differential would be an overriding concern. In the case of the RDDS, additional costs may be justifiable if the technical performance of titanium is demonstrably superior under the anticipated conditions (e.g., reduced loads for air transport and improved fatigue cycle life for extended drilling operations).

Density of titanium is significantly less than steel. Titanium weighs 42% less than steel. For the RDDS, titanium's reduced density is a benefit primarily with respect to ease of transportation and handling. For some oil-field applications, lower CT density will allow operations in deeper wells with the same injector capacities than could be attainable with steel CT. In deep wells, a large percentage of the total load borne by the injector is the CT itself. For example, the longest string of CT that can be hung vertically in a well before the string breaks under its own weight is about 23,500 ft for 80-ksi steel compared to over 45,000 ft for Grade 9 titanium. However, at depths of less than about 5000 ft anticipated for the RDDS, no significant problems while drilling would be expected with respect to CT weight.

Material strength for performing down-hole operations is similar for these two materials. Tension strength (for lifting loads), burst and collapse (internal and external pressure levels), and torsion strength (twisting forces on the string, which occur during drilling) are solely dependent on the material yield strength. Depending on which grade of material is chosen, yield strength can range from 70 to 100 ksi for steel and 50 to 70 ksi for titanium. For the RDDS, there are no significant improvements to be gained with respect to CT strength through choice of base material.

Fatigue cycle life has a critical impact on CT drilling and workover operations. CT operations are unusual from the standpoint of traditional engineering systems in that the material is intentionally plastically deformed during normal operations. Practical constraints on gooseneck and spool dimensions make this compromise a necessity. The result of these repetitive plastic deformations is rapid fatigue failure of the string.

Modeling results for 0.156-in. wall steel CT are compared in Figure 12. Two-inch tubing (the thickest trace) has a predicted fatigue life of about 240 strokes (a stroke is one cycle in and out of the well) with no pressure in the CT, 217 strokes at 1000 psi, and 168 at 2000 psi. Fatigue life declines significantly with increasing pressure, with a predicted life of only 54 strokes at 5000 psi for 2-in. CT.

Figure 12. Fatigue Life of Steel CT (0.156-in. wall)

As is shown in Figure 12, CT diameter also strongly impacts fatigue life. Two-inch steel with no pressure has 40% more life than 2 $\frac{3}{8}$ -in. steel and 23% less life than 1 $\frac{3}{4}$ -in. steel.

The fatigue life of titanium CT has been only sporadically investigated until recently. Limited early tests suggested only marginal improvement in fatigue life with titanium. These tests were, however, based on thin-wall CT. Interest in the use of titanium CT for standard workover operations has led one service company to recently sponsor an in-depth investigation of fatigue life. Results are just becoming available, and the detailed data were, unfortunately, considered proprietary at the time of this writing.

General trends for the fatigue of titanium were reported as greatly improved compared to steel, that is, about 3 to 4 times the fatigue life of steel. This is well within the range that might be expected based on mechanical properties. The level of plastic deformation for CT for a given bending radius (gooseneck or spool size) is proportional to Young's modulus. Young's modulus for titanium is about one-half that of steel. Consequently, for a given bending radius (spool size), titanium undergoes significantly less plastic bending than steel, which should result in many more strokes before fatigue failure.

The fatigue life of titanium CT should be considered again prior to final design of the RDDS. (The recent test results are expected to be published at a later date.) The benefits of greatly increased fatigue life would be two-fold. First, the CT drill string might not need to be replaced in the field even though many bending strokes will be required to drill multiple laterals while searching for the target area. Second, fewer strings should be required at the site, leading to a reduction in

transportation weight (fewer strings to ship as well as lighter strings). The logistics of changing spools in the field can be complicated if a suitable crane is not available.

Unforeseen circumstances may require *field welding of a CT string*. If the string is bumped or damaged in some way, a small section may need to be cut out and the CT butt-welded back together. Steel can be readily welded in the field. The primary disadvantage of welding steel is the formation of a heat-affected zone around the weld site. This zone is usually weaker than the parent material. As a consequence, the load capacity of a welded string must be derated.

Titanium welds do not produce a heat-affected zone. However, titanium welding must be performed in an argon environment to prevent oxygen embrittlement and significant weakening of the material. This procedure requires special training and equipment for success. Shielding the weld is difficult in the field since argon must be pumped through the coil to shield the interior of the weld.

CT deliverability is another significant difference between steel and titanium CT. A current typical deliverability for 2-in. steel CT is about 1 week; for titanium, a much less established product, deliverability is about 28 weeks. This time difference may decrease in the coming years if titanium CT becomes more accepted within the oil industry.

Industry usage/acceptance is another concern. Titanium CT is relatively novel compared to the routine usage of steel. Titanium has not yet been used as a work string in CT drilling operations. Most applications of titanium CT have been for offshore umbilicals and small pipelines where the corrosion resistance of titanium was a prime motivation.

The workover industry has only recently begun considering the cost/benefit of titanium for standard well operations. The primary concerns are in determining whether the increased cost of titanium can be justified by increased fatigue life in typical workover/drilling operations. The industry's lack of operational experience with titanium CT for drilling should be considered a disadvantage. Additional experience in the future may prove that the full benefits of increased fatigue and lighter weight are substantial and routinely achievable outside the laboratory.

In summary, titanium CT, while an interesting option for the RDDS, is not yet in routine usage for drilling or workovers. Unless more data are forthcoming which show that the potential of titanium is achievable, steel CT is recommended as an excellent solution for the RDDS.

2.3 BOTTOM-HOLE ASSEMBLY

The bottom-hole assembly (BHA) used for CT drilling is one of the most technologically complex elements of the entire drilling system. The mission of the RDDS will require that the hole be directionally guided as drilling progresses. Dynamic decisions regarding hole direction may be based on simple geometric considerations, the temperature gradient, the gamma gradient, or a combination of factors.

Operation of these complex BHA systems requires the participation of specially trained personnel. Within the oil industry, CT BHAs are normally leased as part of a complete directional service package by the major service providers. Companies active in this area include Schlumberger Anadrill, Sperry-Sun, Halliburton, Camco, and Transocean, among others.

An additional constraint on the BHA for the RDDS is the need to make provision for operation with gaseous drilling fluids including foam or air. Many CT drilling systems both are operated and communicate back to the surface using pressure variations of the drilling fluid. As a consequence, many of the CT drilling systems in common use in the oil industry will not operate in gaseous environments. Two suitable candidate systems that will operate in any drilling fluid were located and analyzed. These are the Transocean Dual-Capillary System and the Schlumberger Anadrill Viper System (Figure 13).

Figure 13. CT Drilling Assemblies

These systems are discussed in detail in the following sections. Either of these systems would effectively meet the requirements for the RDDS design. There are, however, basic differences

between the system designs, and a detailed comparison of advantages/disadvantages should precede the choice of either system for the RDDS.

2.3.1 Transocean Dual-Capillary System

The CT directional drilling assembly developed by Transocean provides steering, standard MWD sensors (inclination and azimuth) and gamma ray. The system uses two hydraulic control lines installed internally in the coiled tubing for orienting the bent housing on the motor. Data from the MWD and gamma-ray sensors are transmitted to surface via a monocable wireline. The directional tools are available either as traditional magnetic tools or a gyro.

This system has been used to drill five underbalanced wells with more planned in the UK. During these drilling operations, build rates of up to 43°/100 ft and penetrations rates of up to 95 ft/hr have been achieved in sandstone and limestone. The Transocean system has also be used for re-entry drilling in Argentina.

Figure 14. Transocean Dual-Capillary System

The Transocean CT directional assembly consists of the following components starting from the top:

- “Dual Capillary” CT
- CT Connector
- Orienting Tool
- Double Check Valves
- Emergency Release Tool
- Steering Tool
- Monel Flow Sub
- Motor with Bent Housing
- Bit

Dual Capillary System

The drill string for the Transocean CT drilling system is named the “Dual Capillary System” (Figure 14) and consists of 80,000 psi or 100,000 psi minimum yield strength CT with two 1/4-in. stainless-steel hydraulic control lines and a standard 7/32-in. mono conductor wireline cable installed internally in the CT. For drilling, the two hydraulic control lines are used to operate the orienting tool, and the monocable is used to transmit the signals from the MWD/LWD sensors.

Coiled-Tubing Connector

The BHA is attached to the CT with a special connector. The connector (Figure 15) provides a mechanical connection which will resist tension, compression, and torsion. With the connector installed, a thread is available on the lower end of the CT for connection of other tools. Both of the control lines and the mono-conductor wireline pass through the CT connector.

Figure 15. Coiled-Tubing Connector

Figure 16. Transocean Orienting Tool

Orienting Tool

The orienting tool is used to rotate the steering tool, motor and bit. This rotation ability is essential to controlled directional drilling. The orienting tool is hydraulically operated. This tool achieves rotation through linear motion of a helical floating piston engaged with a helical key (Figure 16). The tool will orient 360° clockwise by hydraulic fluid flow down one control line, and 360° counter-clockwise by hydraulic fluid flow down the other control line. The movement is infinite, i.e., not limited to indexing slots as is the case for previously developed orienters. The torque generated is sufficient to orient while drilling. The tool is hydraulically locked into position by isolating both control lines. The Transocean orienter is placed directly below the connector to allow termination of the hydraulic lines high in the assembly.

Emergency Release Tool

An emergency release tool (Figure 17) is installed in the string to allow controlled release of the downhole tool string in the event of hole collapse or other problems causing the BHA to stick. The release is operated by overpull. Should the bit, motor, or steering tool become stuck in the hole, overpull will shear the pins in the release tool, allowing retrieval of the orienting tool and CT drill string. The release is placed below the check valves to maintain safety at the surface if release is required. When the tool is released, the wireline pulls loose at the wireline head in the steering tool.

Figure 17. Emergency Release Tool

Figure 18. Steering Tool

Steering Tool

The steering tool is used to measure the direction of the borehole and to guide the directional driller in properly orienting the bent housing on the motor to achieve the desired wellpath. Because magnetic surveying tools rely on sensing the Earth's magnetic field and are sensitive to magnetic interference, the survey tools are housed in a non-magnetic collar (Figure 18).

The signals from the survey tool are transmitted to the surface through the mono-conductor wireline cable. The wireline cable terminates at the top of the tool using a standard wireline head. The weak point on this head is where the wireline cable parts in the event of an emergency release of the BHA.

The Scientific Drilling survey and gamma-ray tools used in the Transocean steering system are standard wireline tools modified for use in a drilling environment. The modifications

include addition of a shock-absorbing sub to reduce the shock loading to the electronics of the tools, and a heat shield to allow extended temperature operating range of the tools (up to 600°F). Directional information is usually acquired using inclination and magnetic azimuth sensors. For operations in areas where magnetic interference renders the azimuth readings unusable, a gyro survey tool can be used.

Pressure and temperature sensing devices are also available with this system. Pressure measurement can be taken from the inside of the string above the motor or in the annulus. Both pressure measurements can be combined.

Mud Motor

The mud motor provides rotation to the bit. For direction control, the motor contains a bent housing which deflects the direction of the bit. The motor commonly used by Transocean is built by VectorDrill. The usual size for smaller holes (3⁷/₈-in.) is 2⁷/₈-inches. The 2⁷/₈-in. motor is available in single or dual-power sections. To maximize penetration rate, dual motors should be used with the RDDS, if possible. The dual motors generate more torque, but are longer and therefore require more rig-up space. They also may be constrained to drill at lower build rates in curved wellbore sections than a conventional motor.

2.3.2 Schlumberger Anadrill Viper System

Schlumberger Anadrill has recently developed an innovative CT drilling BHA and has begun marketing the system under the name “Viper.” The multifunctional system integrates MWD, downhole motor, orienter and safety devices for use with CT as well as underbalanced drilling operations with rotary equipment. Viper is powered and controlled via wireline cable. Therefore, mud type does not influence system operation. The entire system consists of four assemblies (Figure 19):

- CT head module
- Logging assembly
- Orienting tool
- Mud motor

Figure 19. Schlumberger's Viper CT Drilling BHA

The physical specifications and measurement capabilities of the sensors are summarized in Table 3. The real-time display, log presentation and data base of all measurements are supported by Schlumberger Anadrill's standard surface directional equipment (e.g., the IDEAL system). All downhole measurements are transmitted on the 7-conductor wireline integral to the CT.

TABLE 3. Specifications and Capabilities of Viper

SPECIFICATIONS	
Pressure Rating	18,000 psi absolute, 5,000 psi differential
Temperature Rating	150°C
Flow	130 gpm
Drilling Fluid	Air, Foam, Mud
Max Sand Content	2.5%
Max Lost Circulation Material	40 lb/bbl medium nut plug or equivalent
Max Weight on Bit	11,500 lbs
Max Overpull	39,500 lbs
Inclination	0-125°, accuracy: $\pm 0.1^\circ$ (1 Sigma)
Azimuth	0-360°, accuracy: $\pm 0.1^\circ$ (1 Sigma) for inclination $> 5^\circ$
Tool Face	Magnetic or High Side, accuracy: $\pm 0.1^\circ$
Casing Collar Locator (CCL)	Detects magnetic anomalies generated by the casing joints. -X axis magnetometer.
Annular Pressure	0-18,000 psi, accuracy: ± 45 psi, res.: ± 1 psi
Internal Pressure	0-18,000 psi, accuracy: ± 45 psi, res.: ± 1 psi
Differential Pressure	0-2,000 psi, accuracy: ± 20 psi, res.: ± 2 psi
Temperature	1-150°C, accuracy: $\pm 1^\circ$
Gamma Ray	0-250 API, statistical precision: $\pm 5\%$ (100 API, 100 ft/hour, 1 Sigma)

The Viper system is rated for operations in temperatures up to 150°C (300°F). Gamma (gross, i.e., non-spectral) is measured continuously while drilling. The gamma measurement point is about 24.5 ft behind the bit (Figure 20). The standard system logging configuration allows measurement of gamma in the range of 0 to 250 API. There are several techniques to increase this measurement range for use in the RDDS environment. Additional discussion of gamma logging is presented in Section 3.1.

The orienting tool is the most innovative element of Viper. It consists of an electric motor geared down to turn at 1 rpm and powered via wireline. Orientation can be in either a clockwise or counter-clockwise direction. The torque rating is 900 ft-lb, allowing orientation with weight on bit. Unlike the Transocean orienter described in the previous section, the Viper orienter

can rotate continuously in either direction. (The Transocean Dual-Capillary System is constrained to one 360° rotation.) Continuous rotation is of benefit when drilling a straight section of the borehole, thereby decreasing hole rugosity and CT drag.

Current status of the Viper project is that prototype development and laboratory and field testing are complete. Six complete systems have been fabricated. Pairs of Viper systems (a back-up system is sent to each job) are scheduled to be used at three locations in the near future. In August 1996, one well will be drilled in the North Sea and one in Brazil. The third pair will be used in Oman in September. Several other customers (including some within the U.S.) are also requesting the system.

Figure 20. Viper Sensor Measurement Points

Based on the significant interest expressed by the industry and the excellent reputation and position of leadership of Schlumberger in CT technology, there is little doubt that Viper will be quickly and successfully introduced within the oil industry. MEI has no hesitation in recommending that Viper be considered for the RDDS. As stated, field experience will be soon be available for the purpose of final system evaluation.

2.4 DRILL BITS

The choice of bit type for the RDDS will be affected by rock type and other parameters. The fact that a mud motor will be required also has a significant impact on bit selection. For CT drilling, bits are usually small, with 3⁷/₈-in. a common final hole size. Potential bit types include roller cone (Figure 21), synthetic diamond (polycrystalline diamond compact (PDC) (Figure 22) or thermally stable polycrystalline (TSP)), natural diamond (Figure 23) and hammer bits.

Figure 21. Roller-Cone Bits: Tooth (left) and Button (right)

Figure 22. PDC Bits: Light-Set Drag-Type (left) and Heavy-Set (right)

Bits for the planned exploratory hole size of $3\frac{7}{8}$ in. are considered “slim” within the oil industry. Synthetic- and natural-diamond bits perform well in slim-hole sizes. Performance of slim roller-cone bits (both tooth and button bits) is limited by bearing performance. Until recently, premium bearings were not available in bits smaller than 6 inches. The significant increase in application of slim-hole technologies in the oil industry has resulted in the development and introduction of $3\frac{7}{8}$ -in. roller bits with premium bearings.

Figure 23. Natural-Diamond Bit

Bits used for drilling with CT are usually less aggressive than bits for conventional rotary drilling due to limitations in motor torque and

elasticity of the CT drill string. Less aggressive bits work well with high-speed/low-torque slim motors in harder rocks. Roller bits, which have low torque requirements, have also been successfully used for CT drilling.

Representative rates of penetration (ROP) for various rock hardness are summarized in Table 4. Each bit type can be used over a range of formation types by modifications to cutter design, density, placement, etc. Drilling very hard rock will be limited to carbide roller bits or diamond-impregnated bits.

TABLE 4. Representative ROPs and Rock Types

Rock Hardness	ROP (ft/hr)	Typical Bit Types
Very Hard	0-4	Roller (button), Diamond impregnated
Hard	4-10	Roller, PDC, Natural diamond
Medium	10-30	PDC
Soft	30-100	Roller, PDC (drag type)
Very Soft	> 100	Roller (tooth)

CT drilling usually has higher drilling rates than rotary drilling in smaller (slim) holes. This is because downhole motors must be used with CT, and motors can deliver more power to the bit than rotary drilling. The most important problem is placing sufficient weight on bit for efficient drilling. CT injectors have snubbing capabilities that can be used in conditions where gravity cannot supply the required bit weight, e.g., slanted or horizontal drilling. In some other applications, drill collars (heavy drill pipe) can be added to the drilling assembly.

Air hammers are another effective option for drilling hard and very hard rock. These systems cut rock using a chisel bit that is repetitively hammered against the bottom of the hole. However, the use of air hammers on CT is a novel application. Conventional air hammers require drill-string rotation so that each blow of the chisel bit makes a new cut into the rock face. Air hammers are normally rotated at slow rates—12 to 20 rpm. Since CT cannot be rotated, a mud motor is normally used to rotate downhole tools. Mud motors, however, rotate at rates too high for use with air hammers.

The use of Schlumberger's Viper orienter (see previous section), which can be continuously rotated at 1 rpm, is an option that may be worth considering. Two significant points would have to be addressed: the rotary speed (1 rpm) may not be sufficient for air-hammer operation and the

vibration loads may damage the orienter. High vibrations are a significant aspect of air-hammer use, and will strongly influence the life of any down-hole tools run as part of an air-hammer BHA.

Smith is developing an air hammer for directional drilling that could be run on CT. This effort is being funded by the DOE for application in Appalachian air-drilling operations. This new system can be used on a nonrotating drill string, and can be oriented with a bent sub. The bit is rotated by the tool itself. Smith's directional air hammer, called the Steerable Percussion Air Drilling System, is still in the development stage. They are hoping to have a commercial product by the end of 1996.

Most of the Smith team's efforts have been directed toward the development of systems in the diameter range of $7\frac{7}{8}$ to $8\frac{3}{4}$ inches. Smith is also designing a small $3\frac{3}{4}$ -in. hammer tool that could be run with a $4\frac{1}{4}$ to $4\frac{1}{2}$ -in. bit. This is the smallest tool that seems feasible. A $3\frac{7}{8}$ -in. bit would provide insufficient clearance.

If Smith's directional air hammer is successfully developed and implemented in the field, the $3\frac{3}{4}$ -in. tool should be seriously considered for the RDDS in hard-rock environments. Planned borehole size could be increased to $4\frac{1}{2}$ in. with only minimal impact on overall RDDS design.

2.5 MUD SYSTEM

The drilling fluid system for the RDDS will be designed to allow operations with standard muds, foam or air. Air and foam are the most effective drilling fluids (allowing the highest penetration rates) in hard-rock applications. Given that water may be an expensive consumable during the RDDS mission (low cooperation of host country, arid conditions, expense of trucking, etc.), equipment should be available to allow the use of gaseous drilling fluids. If water is plentiful, drilling mud may be preferred. Equipment required for handling drilling mud is described in this section. RDDS foam and air-compressor equipment are described in later sections in this chapter.

A basic mud system (Figure 24) includes mud tanks, mud pump and shale shaker for removal of cuttings. This schematic is based on a rotary-rig system, such as is used at NTS. Mud system components and functions are similar for the RDDS CT system. Drilling fluid is pumped out of the mud tanks, through the drill pipe (CT), out of the bit, up the annulus, across the shaker, and back to the mud tanks.

Figure 24. Components of Mud Circulation System

A mud skid sized for use with the RDDS is shown in Figure 25. The triplex mud pump, mud tanks (4 compartments, 180 bbl total capacity) and shaker are arranged on a standard trailer. Dimensions are approximately 44 ft long x 8.5 ft wide x 13 ft high. Trailer weight is near 50,000 lb.

Figure 25. RDDS Mud Trailer (Stewart & Stevenson)

The most significant concern for the RDDS beyond normal oil-well drilling operations is the potential for radioactive gases to be encountered and circulated to the surface. The closest analogies in the oil industry are closed underbalanced operations and hydrogen sulphide (H_2S) operations.

The primary defense against radioactive gases at the surface is a series of monitors placed in the flow loop. One early-warning monitor should be placed directly on the wellhead to monitor the returns in the annulus. Other monitors should be placed around the rig site (mud tanks, shaker, blooey line, control cabin, etc.). Alarm thresholds should be set low enough to allow shutting down drilling operations before any serious conditions develop. Drilling operational procedures adopted at the NTS (Butler, 1984) should be used to develop specific radiation threshold criteria for the RDDS.

To prevent any release of radioactive gases at the shale shaker or mud tanks, an enclosed separator (Figure 26) should be used to remove any entrained gases before the mud is pumped to the shaker.

Figure 26. Enclosed Gas Separator (Lunan and Boote, 1995)

Separated gases should be routed to the blowby line and vented safely some distance from personnel. Radiation monitors should also be installed on the blowby line.

There is no practical method routinely used to recycle gases from aerated drilling fluid. Gases separated from the returns will need to be vented as drilling proceeds. The operational philosophy to minimize radiation hazards will be to halt operations while radiation levels are still manageable. It is assumed that enough evidence (gamma logs, radiation monitor outputs, sampling of returns) will have been obtained at that point to confirm the nuclear event.

After radiation is detected in the returns, circulation should be stopped. Fluids in the annulus should be pumped back into the formation if possible by pressurizing the annulus. If the radiation levels are sufficient to contaminate the CT and tools in the hole, the drilling assembly can then be cemented in place in the hole and the CT cut off below the surface by an explosive cutter or by pulling the CT in two with the injector.

A typical closed mud system designed for underbalanced oil-well operations is shown in Figure 27. Another important difference between closed systems for the oil industry and the RDDS (the first being radiation hazard) is the use of nitrogen for gaseous drilling fluids. Nitrogen is used in the oil industry to avoid the danger of downhole fires when hydrocarbons are encountered. There is assumed to be no risk of hydrocarbons for RDDS operations. Consequently, air will be used when it is required to minimize water consumption.

Figure 27. Closed Mud System for Underbalanced Drilling (Lunan and Boote, 1995)

2.6 FOAM SYSTEM

Foam drilling equipment should be designed based on the use of drilling foam that can be recycled. This will satisfy the principal criteria for the RDDS, which include minimizing water consumption and waste generation. In typical foam operations, the foam is dumped into the pit and discarded after one circulation. Recycling the foam will result in a significant reduction in water requirements and waste generated while drilling.

Two basic methods exist for recycling foam fluids. The first involves breaking down the returning foam fluids mechanically. The other method involves breaking the foam and reconstituting it chemically.

Mechanical Recycling System for Foam

RWE-DEA AG, a German company, developed a system which used mechanical means to recycle foam fluids. Environmental regulations in Germany dictated that foam drilling fluid waste be injected into disposal wells. To minimize fluid volume and cost of disposal, a recirculation system was developed for foam by RWE-DEA and Oil Tools, International (Figure 28).

Figure 28. Foam Mechanical Recirculation System (Hanking and Rappuhn, 1996)

The foam is mechanically broken in the separators (Figure 29). The gas phase goes to the flare. The solid cuttings move from the separators with the liquid phase to the shale shaker and the conventional solids-control equipment for elimination from the system. The entire system is explosion-proof.

Figure 29. Mechanical Foam Separator (Hanking and Reppuhn, 1996)

Two of these separators are placed in series. Two are required to provide enough buffer capacity to handle fluctuations in the returns from the well. This also allows additional opportunity for the foam to be completely broken.

Once the solids have been removed from the liquid phase, the liquid is routed to additional storage tanks. There it is treated with proper chemicals to recondition it for use as a foaming agent. If acetic acid was used to break the foam, potassium hydroxide will be added in these tanks to raise the pH back to acceptable levels.

Chemical Recycling System for Foam

The chemical process of foam recycling is based on the concept of destabilizing foam by lowering the pH of the fluid. The process is shown in Figure 30.

Figure 30. Chemical Method for Foam Recirculation (Clearwater, Inc.)

As the foam returns to the surface through the bloomy line, treated water is added to the returning flow, much like the water added through a de-duster in air-drilling operations. However, this water may have additional acid added depending on the pH of the water. A pH meter automatically monitors the acidity of water to be added, and acid additions are based on this measurement. This treated water will eventually be reconstituted as foam and returned downhole.

The acid addition makes separation of the various phases of the foam much easier to accomplish in the separator, and only one is needed. The gas phase exiting the separator is sent to the flare stack. Only the liquid phase is recyclable.

After the solids have been removed from the liquid phase using the conventional solids-control equipment, the liquid is returned to the steel mud tanks. Some of the recycled liquid is used as the defoamer added to the blooey line. Since the pH may still be depressed, often no additional acid will be required.

After treatment with a centrifuge to remove small solids, the liquid pH is again measured automatically. If it is too low to prevent destabilization of the foam, lime is automatically added to raise the pH into an acceptable range. The liquid with acceptable pH is then re-injected into the gas or air stream to reconstitute the foam fluid for downhole requirements.

In summary, foams can be broken by mechanical or chemical means. As applied to the RDDS design, mechanical systems are less efficient and require more bulky equipment than chemical systems. For these reasons, mechanical foam breaking systems are not recommended for the RDDS. With a chemical recycling system, only a limited amount of water and chemicals has to be added to maintain the foam. The number of foam, defoam, and refoam cycles is virtually unlimited.

2.7 AIR COMPRESSOR

An air-compressor system will be needed for air or foam drilling with the RDDS. To estimate required capacity, calculations were performed for air drilling based on standard Angel criteria (i.e., 3000 ft/min in the annulus for effective hole cleaning). Results are summarized for a 3 $\frac{7}{8}$ -in. hole in Figure 31 and a 6 $\frac{1}{8}$ -in. hole in Figure 32. Air-volume requirements are dependent on both depth and penetration rate (which defines the amount of cuttings to be lifted to the surface).

The largest air flow rate would be required in a 6 $\frac{1}{8}$ -in. hole. This hole would be drilled if surface casing were required to some intermediate depth. At depths ranging to 1500 ft, the air flow rate required in a 6 $\frac{1}{8}$ -in. hole would range between 550 to 650 scfm. The inlet pressure to push this flow through the CT spool, through the BHA and up the annulus is about 550-600 psi, with the majority of the pressure drop expended within the drilling motor.

Figure 31. Air Volumes for 3⁷/₈-in. Hole

Figure 32. Air Volumes for 6¹/₈-in. Hole

In the 3⁷/₈-in. hole, air flow rates required to lift cuttings range from about 250 to 350 scfm depending on hole depth. The results shown in Figure 31 are based on the assumption of a vertical borehole. Since slanted boreholes are assumed highly likely with the RDDS and horizontal boreholes may be required, a safety-factor correction for horizontal operations should be applied to these results. Cardin (1991) suggested doubling recommended air-flow rates when drilling a horizontal well. Thus, flow rates of over 700 scfm may be needed for air drilling in a 3⁷/₈-in. horizontal borehole.

Air-volume and pressure requirements for foam drilling were also investigated with regard to sizing of equipment. Typical parameters were developed using Maurer Engineering's MUDLITE® foam-drilling model. This software is being developed as part of the DEA-101 joint-industry project to develop tools and systems for underbalanced drilling operations.

Several foam system designs were tested for the RDDS. Assumptions included Bingham plastic fluid flow, an average cuttings diameter of 0.08 in., choke pressure on the wellhead of 100 psi, and penetration rate of 100 ft/hr (best case). An air flow rate of 700 scfm was found to be adequate for effective hole cleaning to a depth of 5000 ft. A water injection rate of ½ bbl/min was found to be sufficient. (These values should be further optimized when drilling parameters can be better defined.)

The predicted pressure profile is shown in Figure 33. The foam enters the CT at 1350 psi (thin line at 0 ft depth). About 150 psi of pressure drop occurs in the CT on the spool. Maximum pressure (2080 psi) occurs just above the motor (thin horizontal line at 5000 ft depth).

Figure 33. Pressure Profile for Foam Drilling

Figure 34. Foam Quality for Foam Drilling

Foam quality (the ratio of air to liquid) is shown in Figure 34. The lowest quality (about 0.56) is predicted in the drill string just before the foam enters the motor. Foam quality in the annulus should be kept below 97%, which is the transition point to mist flow (less effective cuttings transport). A choke value of 100 psi accomplishes this.

Cuttings transport is especially critical if the inclination of the lateral branch approaches horizontal. General guidelines for hole cleaning suggest that a cuttings-transport ratio (velocity of cuttings divided by velocity of fluid) of 0.5 or greater is adequate for vertical boreholes. For horizontal sections, the cuttings-transport ratio should be greater than about 0.9 (Figure 35).

These modeling results for air and foam drilling suggest that a compressor package capable of more than 700 scfm should be sufficient for the RDDS. Inlet pressure to the CT at the surface may be as high as 1400 psi during foam drilling.

Contacts were made within the foam-drilling industry including foam-drilling operations in Kansas and West Texas by Weatherford. These operations have been conducted using rotary drilling

rigs, power swivels and CT rigs. Their standard foam-generation system is packaged on a 40-ft trailer and is rated for 900 scfm and 2000 psi. These design criteria were used for preliminary system sizing and pricing.

Figure 35. Cuttings-Transport Ratio for Foam Drilling

2.8 MULTILATERAL TOOLS

The RDDS must be capable of drilling multiple laterals (side branches) from the parent wellbore (or from a previously drilled lateral). The process of drilling out to the side of an existing wellbore and creating a new lateral is called “kicking off.” In soft formations, it is often possible to kick off by time drilling alone, whereby the bit is kept rotating against the side of the hole until a slot and a new ledge is formed from which to start the new lateral. In harder formations, it is unlikely that sufficient force will be available to push the bit sideways against the borehole and start the kick-off. Other mechanical means for starting the lateral will be required. Figure 36 shows some of the sidetracking methods used within the oil industry. These are described in the following paragraphs.

Figure 36. Sidetracking Techniques

Openhole sidetracking without any mechanical assistance (Figure 36-A). A motor, with a sufficiently large bent housing and kick pad to cause high contact loads between the bit and the formation, is run into the hole and oriented to the desired direction. The assembly is then slowly reciprocated for about 5 – 15 ft, allowing a groove to be cut into the formation. Once the groove is sufficiently deep, a ledge is formed at the bottom, reciprocation is stopped and a “time-drilling” procedure begins which allows the assembly to initiate the sidetrack. In areas where the formation is extremely hard and/or abrasive, this procedure may be ineffective.

Cement plug sidetracking (Figure 36-B). A cement plug containing some hard and/or abrasive material is pumped into the hole with the top of the cement slightly above the desired sidetrack depth. A motor, with a large bent housing and kick pad to generate moderate contact loads between the bit and the formation, is run into the hole and oriented to the desired direction. A time-drilling procedure is used to allow the assembly to initiate the sidetrack. In areas where the formation is extremely hard and/or abrasive, this procedure may be ineffective due to the relative hardness (drillability) differences between the formation and the cement.

Openhole sidetracking using a packer-type whipstock (Figure 36-C). A packer assembly with an orientation key is run into the hole and inflated. A survey tool is then run to determine the key’s orientation. The whipstock and anchor assembly are then aligned at the surface, run into the hole and latched into the packer. Various milling assemblies are run to initiate and extend the sidetrack hole. Both permanent and retrievable packers have been designed. The major limitation is the poor availability of packer assemblies for smaller hole sizes.

Small-diameter inflatable whipstocks for use in the open hole are not currently available commercially. Baker Hughes INTEQ is planning to develop several open-hole whipstocks including smaller diameter systems. However, these developments are contingent on the anticipated market demand, and no commercialization date has been set.

Openhole sidetracking using a bottom-trip whipstock (Figure 36-D). This whipstock can be set on any solid bottom, either the bottom of the hole or a false bottom formed by a bridge plug, packer, cement plug, cement retainer, liner hanger, junk, the top of a fish, or other obstruction (sand, fill, etc.). In most cases, the openhole is filled with either cement or sand to a few feet below the desired sidetrack depth. The whipstock is then run into position and set upon contact (pre-set amount of compression) with the sand or cement. Various milling assemblies are run to initiate and extend the sidetrack hole. Both permanent (typical) and retrievable packer types are available. Bottom-trip whipstocks are available in slim sizes, although they are more commonly run in large sizes. A system is available for setting in 4-in. casing (about 3.5-in. ID) and is compatible with the RDDS.

3. Logging and Diagnostics

Logging data are expected to serve an essential role in fulfilling the mission of the RDDS. Analysis of gamma-ray radiation along the borehole, and possibly of returns at the surface, will serve initially to guide the planned wellbore path, and later as definitive proof of an underground nuclear event.

The need for two separate downhole logging systems is anticipated. The first system will be incorporated into the drilling assembly. This sensor(s) will measure total (non-spectral) gamma while drilling is in progress. Gamma data relayed to the surface as drilling proceeds will be used to guide the borehole, along with other information (temperature changes, geometric data, geologic description, etc.).

The second gamma-ray logging system will be used to acquire more detailed measurements after drilling is complete. A spectral gamma tool would be run into the hole on a separate assembly, along with a formation sampling tool, if desired. Data recorded would be used to identify specific nuclear products and their proportions.

Design considerations for these logging tools are discussed in the following sections.

3.1 LOGGING WHILE DRILLING

Gamma-ray logging tools are widely used within the oil industry for differentiating between shale beds (which contain potassium (^{40}K) and other naturally occurring radioactive elements) and non-shales. The most common gamma-ray unit of measurement is the API unit. Standardized by the American Petroleum Institute, an API unit is defined by the difference in gamma levels between two test beds located and maintained at the University of Houston, with one bed assigned a value of 200 API and the other of 0 API. The 200-API bed contains 4% potassium, 24 ppm thorium and 12 ppm uranium. A simple standard such as the API unit is sufficient for most oil industry applications since small variations in total gamma are typically encountered. Absolute accuracy is not critical; beds are identified and characterized through relative fluctuations in gamma levels.

The nuclear industry uses a variety of logging units to characterize radiation hazards. Conversion factors relating API units to other standard units used within the nuclear industry include the following:

$$14 \mu\text{gram uranium/ton} = 1 \text{ API}$$

$$1 \text{ } \mu\text{roentgen/hr} = 15.5 \text{ API}$$

$$20 \text{ } \mu\text{curies @ 1 meter} = 120 \text{ API}$$

Confirmation of nuclear activity at the RDDS site may be obtained by recording gamma levels significantly in excess of naturally occurring levels around the world. Personnel familiar with oil-field and uranium logging were contacted to develop an estimate of the gamma range required for the RDDS.

Typical gamma levels encountered in oil exploration range up to about 200 API for massive beds and up to 400 API across stringers (thin zones), such as ash beds used as a geologic time reference marker over large geographic areas.

Discussions were held with personnel at the Department of Energy's (DOE) nuclear logging calibration facility in Grand Junction, Colorado. This facility is used primarily by the uranium mining industry. Gamma levels in typical mining conditions have been observed to range up to 4 times background levels. Background levels (in beds without uranium) should range up to about 200 API for massive beds. For a worst-case estimate, a gamma level of 4 times 400 API (in stringers) = 1600 API may serve as an estimate of the upper limit of naturally occurring levels. Gamma levels measured by the RDDS at two or more times this range may be sufficient evidence of an unauthorized test.

A typical oil-field gamma logging tool (e.g., the Viper system (see section 2.3.2)) measures total gamma in a range of 0 to 250 API units. The upper limit of the Viper system is defined by telemetry design rather than limitations in sensor response (see discussion below). This limit could be increased for the RDDS.

The upper limit of the gamma range required for effectively guiding the RDDS is not well defined, but is greater than normal oil-field and uranium-mining levels. Levels of 1 roentgen/hr, equivalent to over 15,000,000 API, are possible near the center of a nuclear event soon after detonation. However, the RDDS should not have to deal with gamma levels of this magnitude to fulfill its mission. A practical upper limit is more likely on the order of a few thousand API.

No standard total gamma logging tool currently available in the oil industry is set up and calibrated to measure radiation fields of several thousand API units. Discussions with industry suggest, however, that developing or configuring appropriate sensors and instrumentation will not be difficult.

There are at least three potential approaches to increase gamma measurement range for standard oil-field tools to levels required for postshot analyses:

1. *Adjust telemetry software and/or design.* The software that processes the logging data could be modified, more bits could be assigned to the output value (e.g., 8-bit words can relay values up to 256 API, 9 bits to 512, etc.), or a different scaling factor could be used (increasing range while decreasing precision). These types of software modifications would be relatively straightforward, but it is unknown whether this approach alone could extend the gamma range sufficiently without higher speed associated electronics, or changing sensor type.
2. *Shield the gamma sensor* to reduce response in a given gamma field by a factor of, for example, ten. This approach would probably be most effective if two sensors were run in the drilling assembly, one standard and one shielded. A sensor combination would provide both the necessary resolution at low levels and the extended range when approaching the target area.
3. *Use a smaller crystal* in the sensor. Gamma measurements are calibrated based on counts/sec striking the sensor, which are related to sensor volume. A smaller crystal is inherently less responsive in a given radiation field, and would measure higher gamma levels before becoming overloaded.

3.2 POST-DRILLING DIAGNOSTICS

After the postshot hole has been drilled, a separate diagnostic tool assembly may be run into the borehole. This assembly would include a spectral gamma-ray logging tool and an optional formation sampler for capturing samples of wellbore fluids for later analysis. Neutron tools are also available in slim sizes for use with the RDDS if desired.

Detailed discussions will be held with postshot nuclear logging experts from Lawrence Livermore and the DOE to develop specifications and operational procedures to provide logging data of greatest benefit to the mission of the RDDS.

Spectral Gamma Ray

Unlike total gamma-ray levels recorded while drilling, spectral gamma logs can be used to identify specific elements and their proportions along the wellbore. These data can form the basis of indisputable proof of man-made nuclear activity.

In discussions with Schlumberger, it was found that they have two spectral gamma tools. The Induced Gamma Ray Spectrometry Tool (GST) is a 3⁵/₈-in. OD tool that uses a sodium iodide detector to measure the relative amounts of carbon and oxygen in the formation by inelastic gamma-ray spectrometry.

The Reservoir Saturation Tool (RST) is configured as either a 1¹¹/₁₆- or 2¹/₂-in. OD tool and is more suitable for use with the RDDS. The RST is used in oil exploration to measure carbon and oxygen by analyzing the energy spectrum of gamma rays produced by neutrons from a pulsed neutron source. The on-board neutron source (called a minatron) can be remotely switched off. The RST is typically run at gamma-ray energies between 1 and 7 MeV, although thresholds can be set lower. Reportedly, laboratory versions of the RST have been set to accept count rates up to 200,000 API (Herron, 1996).

A typical RST configuration is shown in Figure 37. A total gamma-ray sensor can be placed at the top of the assembly (optional). The acquisition cartridge processes spectral gamma ray and time data from the detectors in the sonde. The accelerator cartridge contains the power supply and control circuitry for the neutron generator (not required for the RDDS).

The logging sonde is a dual-detector assembly (Figure 38). The detector crystal is cerium-doped gadolinium oxy-ortho silicate. The sensor has a fast decay constant, a significantly higher instantaneous counting rate than other detectors, and operates at temperatures up to 150°C without stabilization. The 2¹/₂-in. tool is designed for improved contrast and simultaneous determination of the borehole fluid and formation fluid compositions.

Figure 37. RST Spectral Gamma Tool String (Schlumberger)

Figure 38. RST Gamma Detectors (Schlumberger)

Specifications for both versions of the RST are compared in Table 5. Either size of tool could be run in the RDDS borehole.

TABLE 5. RST Specifications (Schlumberger)

RST Tool	1¹¹/₁₆ in.	2¹/₂ in.
Pressure rating	15 kpsi	15 kpsi
Temperature rating	300°F [150°C]	300°F [150°C]
Maximum tool diameter	1.710 in.	2.505 in.
Minimum tubing size	2 ³ / ₈ -in. API	3 ¹ / ₂ -in. API
Minimum restriction	1.813 in.	2.625 in.
Maximum recommended casing size	7 ⁵ / ₈ -in. API	9 ⁵ / ₈ -in. API
Maximum recommended borehole size	10 in.	12 ¹ / ₄ in.
Tool length	33.6 ft.	32.7 ft.
Tool weight	143 lbm	250 lbm

A spectral gamma-ray tool, such as Schlumberger's RST, should be able to be run with the RDDS with only minor modifications to the tool and/or operating procedures.

Formation Sampler

Formation samplers are also available within the oil industry. As an example, Schlumberger's Modular Formation Dynamics Tester (MDT) collects formation fluid through a probe placed hydraulically against the borehole wall. Multiple samples can be obtained on the same run (Figure 39), allowing testing of different zones on the same trip.

The standard MDT assembly has an OD of 4¾-in. and is designed to be run in holes larger than 6 inches. Simple borehole fluid samplers are available in much smaller diameters. Some tools lack some of the more sophisticated features of tools like the MDT, but may be adequate for the RDDS. Discussions with postshot logging experts will clarify these issues as RDDS development continues.

Figure 39. MDT for Multiple Samples (Schlumberger)

4. Mine Applications

A possible scenario for the clandestine test of a nuclear device is to use an existing mine to conceal the excavation and testing operations. In this case, drilling from inside the mine to locate the cavity formed by the device may be more practical than drilling a great distance from the surface. In some mines, rigging up the RDDS may be relatively straightforward because the mines have been constructed to allow the operation of large equipment. The entire coiled-tubing (CT) rig and associated equipment may be able to be taken down into the mine.

It is also possible that the mine entrance and shafts will not be large enough to house the RDDS equipment. Alternative techniques and approaches to drilling will be necessary. These types of conditions do not necessarily preclude the use of the CT system components, however.

There may be several situations where the proposed RDDS system can still be applied by modifying rig-up and operating procedures. One scenario is shown in Figure 40. In this case, a simple adit (horizontal access shaft) has been previously drilled into the side of a mountain. If the staging area at the entrance to the adit is large enough to support the CT rig, the injector can be placed at the face of the adit and anchored to the face and walls using roof bolts. The CT can then be run on the ground down the adit to the injector. Drilling can proceed as normal from this point.

Figure 40. Drilling Through Adit in Side of Mountain

A related scenario is illustrated in Figure 41. In this case, the adit is at the bottom of a vertical shaft. The CT can be pulled into the mine to the face where the injector has been attached. A guide arch would be used to guide the CT around corners. The limiting factor for either of these cases is

most likely the distance that hydraulic power for the injector can be pumped. If the power pack has to remain outside the mine, long hydraulic power lines will add significant frictional pressure drops to the hydraulic system.

Figure 41. Adit at Bottom of Mine Shaft

In cases where the distance from the mine opening to the drilling face is too great or the path too circuitous for routing the CT, an alternate drilling method will be required. In these cases, drilling equipment used in the coal industry can be adapted. The coal industry has used small drilling rigs and mud motors to drill holes for methane drainage and ore body delineation. These rigs accurately guide bores several thousands of feet (Figure 42).

Figure 42. Mining Boring Rig (Kravits et al., 1985)

Rigs of this type can be used in rotary mode or with motors. Guidance packages have also been developed for boring rigs. Figure 43 shows an example steering tool (GBS AccuNav) that is used to accurately guide utility boreholes up to 1000 ft in a wireless mode and 3000 to 5000 ft with a wireline. These rigs use 10-ft sections of drill pipe; the wire is spliced at each connection.

Figure 43. Utility Rig Guidance System

5. Manufacturer Contacts

A variety of equipment manufacturers and service providers were contacted during this phase of the RDDS Project. Technical performance, equipment limitations, cost estimates and many helpful insights were obtained through these contacts throughout the project.

Primary contacts for additional information regarding RDDS equipment and services are listed in Table 6.

TABLE 6. RDDS Equipment/Services Contacts

Equipment/Service	Company	Address	Contact
CT Rig	Stewart & Stevenson Petroleum Equip Div	P.O.Box 1637 Houston, TX 77251	Mike Dearing 713-923-0400
Mud System	Stewart & Stevenson		
Air Compressor Skid	Stewart & Stevenson		
Cement Batch Mixer	Stewart & Stevenson		
Steel CT	Quality Tubing	P.O.Box 9819 Houston, TX 77213	John Martin 713-456-0751
Titanium CT	RMI Titanium	P.O.Box 269 Niles, OH 44446	Harry Watkins 216-544-7619
Recyclable Foam	Clearwater Inc.	5605 Grand Avenue Pittsburgh, PA 15225	Ted Wilkes 412-264-1100
Drilling Motors	Phoenix Drilling Services	P.O.Box 40608 Houston, TX 77240	Fred Pittard 713-849-1990
Drill Bits	Reed Tool Company	P.O.Box 2119 Houston, TX 77252	Craig Ivie 713-924-5253
CT Drilling Services	Schlumberger Dowell	150 Gillingham Lane Sugar Land, TX 77478	Andy Rike 713-275-8643
Viper BHA	Schlumberger Anadrill	200 Gillingham Lane Sugar Land, TX 77478	Ike Nitis 713-275-8996
Transocean BHA	Transocean ASA	Platformveien 2-4 P.O.Box 65 N-4065 Tananger NORWAY	Larry Harford 44-1224-891 118 (Ph) 44-1224-891 266 (Fx)
Spectral Gamma Tools	Schlumberger	200 Gillingham Lane Sugar Land, TX 77478	Ivonna Albertin 713-275-4383
Formation Sampling Tool	Schlumberger Well Services	150 Gillingham Lane Sugar Land, TX 77478	Tom MacDougall 713-275-8872

6. Summary

A Rapid Deployment Drilling System (RDDS) is needed that can be quickly deployed to drill postshot holes at the site of a suspected clandestine underground nuclear test (Figure 44). The unique requirements of the RDDS are best addressed by a coiled-tubing (CT) drilling system. CT drilling technology has been rapidly developed and embraced within the oil drilling industry for environments where high mobility, safety, and small surface impact are required.

Figure 44. Rapid Deployment Drilling System

While not a new drilling technology, CT drilling continues to undergo rapid development and expansion, with new equipment, tools and procedures developed almost daily. This project was undertaken to:

- Analyze available technological options for an RDDS CT drilling system
- Recommend specific technologies that best match the requirements for the RDDS
- Highlight any areas where adequate technological solutions are not currently available

A summary of conclusions regarding the subsystems comprising the RDDS follows.

1. *Drilling Rigs.* Designs and capacities of modern larger CT rigs becoming common in the oil industry will be more than adequate for the RDDS. A CT injector with 80,000 lb pulling capacity is recommended.

The RDDS exploratory holes will be drilled with 3⁷/₈-in. bits on 2-in. CT. The oil industry has had significant experience with this combination of sizes and found that ancillary tools (logging, fishing, etc.) are available and reliable.

2. *Coiled Tubing.* Based on load capacity and torsional strength, 2- by 0.156-in. wall CT with 80,000-psi material yield strength is the recommended size for the RDDS. The primary options for CT material are steel and titanium. The factors to be considered when comparing titanium to steel CT include: titanium CT costs almost 8 times more than steel CT; titanium weighs 42% less than steel; plastic fatigue of titanium is reportedly 3 to 4 times less than steel; field welding procedures for titanium require special training and equipment; deliverability is significantly greater for titanium; and the use of titanium CT is relatively novel. Unless more data are forthcoming which show that the benefits of titanium are achievable, steel CT is recommended as an excellent solution for the RDDS.
3. *Bottom-Hole Assembly.* The bottom-hole assembly (BHA) used for CT drilling is one of the most technologically complex elements of the entire drilling system. The mission of the RDDS will require that the hole be directionally guided as drilling progresses. Two suitable candidate BHA systems that will meet performance specifications and operate with any type of drilling fluid were evaluated. These are the Transocean Dual-Capillary System and the Schlumberger Anadrill Viper System. Additional evaluation and comparison of these systems should be performed prior to choosing either system for the RDDS.
4. *Drill Bits.* The choice of bit type for the RDDS will be affected by rock type and other parameters. For CT drilling, bits are usually small, with 3⁷/₈-in. a common final hole size. PDC bits have been successfully used in many CT applications. Bits used for drilling with CT are usually less aggressive than bits for conventional rotary drilling. Less aggressive bits work well with high-speed/low-torque slim downhole motors. Roller bits have also been successfully used for CT drilling. A directional air hammer is also under development whose progress should be monitored in the future.
5. *Mud System.* The complete drilling fluid system for the RDDS will be designed to allow operations with standard drilling muds, foam or air. Air and foam are the most effective

drilling fluids (allowing the highest penetration rates) in hard-rock applications. If water is scarce and/or expensive, equipment should be available to allow the use of gaseous drilling fluids. If water is plentiful, drilling mud may be preferred. A trailer-mounted mud skid with a storage capacity of about 180 bbl is recommended. An enclosed separator should be used to remove any entrained gases before the mud is pumped to the shaker to prevent any release of radioactive gases. Separated gases should be routed to the blooey line and vented safely. Radiation monitors should be installed at several locations around the rig, including on the well head, blooey line, shale shaker, mud tanks, and control cabin.

6. *Foam System.* RDDS foam-drilling equipment should be designed for recyclable foam. This will satisfy the principal criteria for the RDDS, which include minimizing water consumption and waste generation. Recycling the foam will result in a significant reduction in water requirements and waste generated while drilling. Foams can be broken and recycled by mechanical or chemical means. Mechanical systems are less efficient and require more bulky equipment than chemical systems. A chemical recycling system is recommended for the RDDS. The number of foam, defoam, and refoam cycles is virtually unlimited.
7. *Air Compressor.* An air-compressor skid system will be needed for air or foam drilling with the RDDS. Preliminary modeling results suggest that a compressor package capable of more than 700 scfm will be required. Inlet pressure to the CT at the surface may be as high as 1400 psi during foam drilling.
8. *Multilateral Tools.* The RDDS must be capable of drilling multiple laterals (side branches) from the parent wellbore (or from a previously drilled lateral). Starting ("kicking off") a new lateral is the most challenging aspect. Several kick-off methods have been developed in the oil industry. If the formation is relatively soft, the procedure is relatively simple. Fewer options are available for kicking off in very hard rock, as might be the case for the RDDS. One recommended technique is to prepare a new bottom at the kick-off depth (with a cement plug, sand plug, etc.) and use an oriented bottom-trip whipstock (wedge-shaped tool) to force the bit out of the original hole. Another option is using a packer-type whipstock, which seals against the formation walls and does not need to be set against a plug. However, packer-type whipstocks are not yet available in slim sizes (but may be in the future).
9. *Logging and Diagnostics.* The need for two separate downhole logging systems is anticipated. The first system will be incorporated into the drilling assembly. Real-time

gamma data will be used to guide the borehole, along with other information (temperature changes, geometric data, geologic description, etc.). The second logging system will be used to acquire more detailed measurements after drilling is complete. A spectral gamma tool would be run into the hole on a separate assembly along with a formation sampling tool. These data would be used to identify specific nuclear products and their proportions.

Standard logging tools available in the oil industry are not set up and calibrated to measure radiation fields at the levels that are anticipated for the RDDS borehole (several thousand API units). However, developing or configuring appropriate sensors and instrumentation are not expected to be difficult. There are several approaches that may be pursued to increase gamma measurement range for standard oil-field tools to levels required for postshot analyses.

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