U.S. Department of Energy

Microhole Initiative

Workshop Summary

Prepared by

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June 19, 2003

Executive Summary

- The US Department of Energy is continuing a major R&D initiative to develop microhole technology (MHT) using a coiled tubing drilling platform. This report documents the results of a meeting with potential users and suppliers held in Albuquerque April 29-30, 2003.

- 63 people from the petroleum industry, government and laboratories met to identify the primary potential applications for MHT in order to guide future investments in the development of related systems and tools.

- The group highlighted four primary applications:

  1) Drilling shallow development wells - 20,000/year now
  2) Drilling reservoir data monitoring holes - 100/year now
  3) Drilling shallow re-entry wells - 3,000/ year now
  4) Drilling deep exploration holes - 100/ year now

- Independent producers preferred using microhole for shallow development drilling, large producers leaned toward exploration holes and service companies preferred drilling holes for data.

- The group highlighted 5 critical technologies:

  - Downhole drilling systems
  - Downhole logging systems
  - Completion equipment
  - Solids control
  - Coiled tubing units

- As with most technologies, users insist that MHT must evolve from current applications rather than seek to revolutionize the industry.

- Without government assistance, MHT will be slow in developing. Current coiled tubing-based drilling technology and use has plateaued.

- With DOE financially supporting its development, majors and independents will employ MHT, which will spur service companies to invest in technology development.

- Targeted cost savings compared with existing technology: 40-50%.

- For all applications, microhole technology must first be able to drill a very small hole (≤3-1/2”) using coiled tubing. For example, shallow development wells and reservoir data monitoring holes – called “Drilling Shallow Holes” in the table below – will first require the creation of drilling technologies such as bottomhole assemblies (MWD, LWD, motors, bits, sensors), special drilling fluids (including analysis of the hydraulics) and fluids cleaning equipment (solids control):

Primary Applications

	Drilling Shallow Holes	Drilling Re-Entry Holes	Drilling Deep Exploration
Drilling Technologies			
Bottomhole assemblies	◆	◆	◆
Drilling fluids / hydraulics	◆	◆	◆
Solids control	◆	◆	◆
Production Technologies			
Completion systems	◆	◆	
Artificial lift systems	◆	◆	
Maintenance options	◆	◆	
Data Sampling			
Fluid sampling	◆		◆
Temperature & pressure	◆		◆
Lithology logging	◆		◆
Vertical seismic profiling	◆		◆

- DOE and industry will need to determine the order in which the specific technologies are developed. The engineering team that understands the strengths and weaknesses in current systems is best suited to make this road mapping decision.

- Spears & Associates was selected by DOE to help frame the discussions about MHT, record participant input and summarize the findings. SAI is solely responsible for this report.

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Objectives

The U.S. Department of Energy (DOE) is continuing a major research and development initiative to create a small, fast, inexpensive and environmentally friendly rig for drilling 5000' microholes to investigate potential oil and gas reservoirs. In order to prioritize the next series of investments, DOE desired input from petroleum industry operators, service companies and equipment suppliers on the operation and application of this coiled-tubing-based technology.

Specific Study Requirements

In order to fulfill the primary objective, SAI was commissioned to:

- **Evaluate the history, status and future of demand for very small bore-hole drilling.**
- **Measure the market for coiled tubing drilling and describe the state-of-the-art.**
- **Identify companies and individuals who should have an interest in micro drilling and invite them to the DOE workshop.**
- **Participate in 3 concurrent workshop sessions, record and evaluate participant comments and report workshop conclusions.**

Spears & Associates, Inc. (SAI) has written this report after preparing for and attending a DOE-sponsored project-scoping workshop in Albuquerque April 29-30, 2003.

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Research Method

DOE has field-tested microhole technology (MHT) and has distributed throughout industry and government an analysis of the current state-of-the-technology and the perceived hurdles remaining in product development.

In order to gather additional industry input and quantify the possible demand for these tools, Spears & Associates, in partnership with DOE, took the following steps:

1) Develop a 19-page **report on the state of the coiled tubing drilling market**, including size of the market, profile of suppliers, cost of drilling and the number of coiled tubing drilled holes per year. This report was provided to all parties interested in attending the microhole technology workshop.

2) For a workshop in Albuquerque, **identify and invite industry personnel** who might be interested in advancing microhole technologies.

3) **Survey workshop participants** regarding the merits of microhole, possible applications and critical related technologies. Immediately report findings to participants.

4) **Attend three concurrent breakout sessions** moderated by DOE-appointed facilitators and record participants' comments. Additionally, conduct private interviews with participants to flesh out or clarify statements made during public sessions.

5) **Summarize the findings** of the workshop and prepare a document that ranks the best applications for microhole technology and helps guide future investment in the concept.

To write the 19-page report in step 1, SAI married in-house market data[1] with recent interviews conducted with service companies and operators drilling wells throughout the US. SAI's conclusions were reviewed and, in some cases, modified by the coiled tubing services companies prior to publishing the report.

This report is the completion of step 5 and includes input from over 60 workshop participants and from about 30 other industry professionals SAI interviewed during the project.

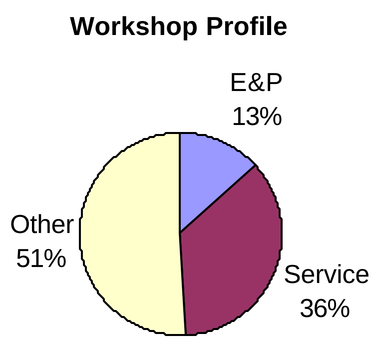
[1] To support the firm's two subscriber services, the *Drilling and Production Outlook* and the *Oilfield Market Report*, SAI maintains a library of 700 oilfield data series and a system that can retrieve market data from thousands of our proprietary interviews with industry leaders and public sources.

Description of the Workshop

DOE hosted a two-day workshop in Albuquerque to talk about potential applications for microhole technology and to identify and roadmap near-term and long-term goals for the project. DOE invited people from industry, government and research who all have an interest in coiled tubing, small bore hole drilling and the advancement of technology. 63 people attended, of which 40 were from industry and 23 were from government, a national lab or some other sponsoring organization.

The workshop agenda was designed to teach attendees the current state of microhole technology and coiled tubing drilling and to solicit ideas and comments on possible development and applications of the technology.

As attendees entered the meeting they were handed a short questionnaire designed to quickly determine if participants thought microhole technology had merit, where it might be applied, what the critical technologies are and how much the service should cost to be attractive to industry. **45 people answered the questionnaire** – half from industry, half from government and research organizations:



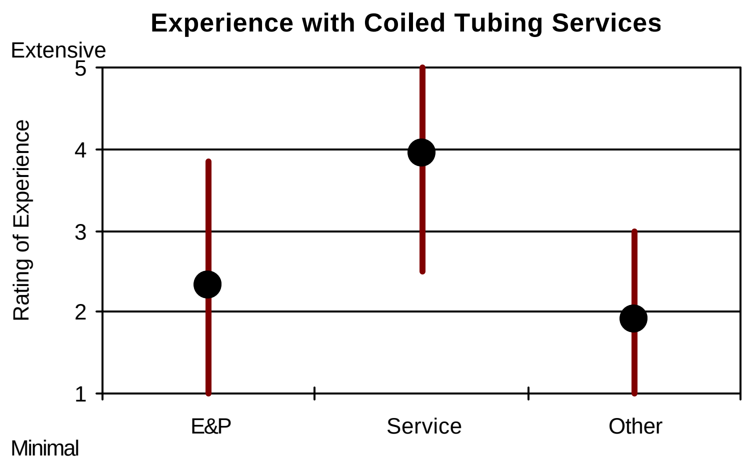
While the opinions of all attendees were sought, **Spears & Associates has considered the opinions of the E&P companies and the service companies to be of greatest value** because these are the companies who will commercialize the technology and employ the technology. Conclusions found throughout this report reflect this emphasis on industry's opinions.

Agenda

Day 1 Lunch / Answer questionnaire
Introduce microhole technology
Instruct attendees on objectives of breakout sessions
Review of questionnaire responses
Breakout sessions – 3 concurrent

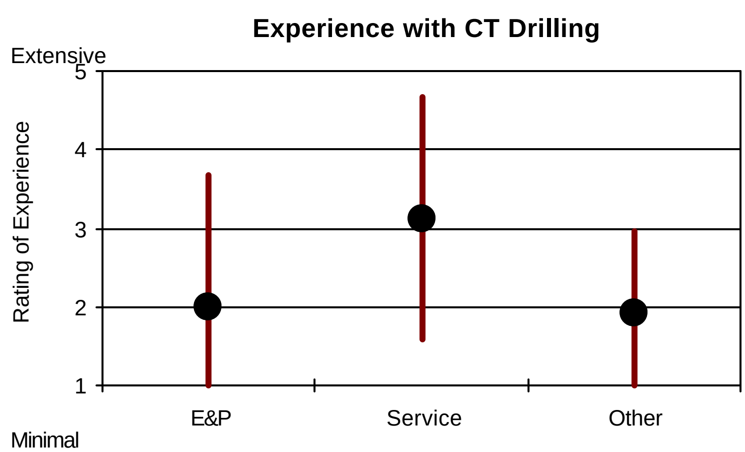
Day 2 Summary of the prior day's concurrent breakout sessions
Identification of priority applications for microhole technology
Group discussion of ranked applications
Adjourn

The breakout sessions were concurrent 2.5-hour periods where 15-20 people met in an open forum, led by a facilitator, to discuss and debate the merits and applications of microhole technology. Some entered the forum with years of experience in both coiled tubing drilling and microhole technologies; others had no experience with either, but were involved in the petroleum industry in a related capacity. As the following chart indicates, representatives from service companies had the most experience with coiled tubing[2]:



Source: DOE Microhole technologies workshop participant survey

Attendees did not have a great deal of experience with coiled tubing drilling. Again, it was the service companies who brought field experience to the meeting:

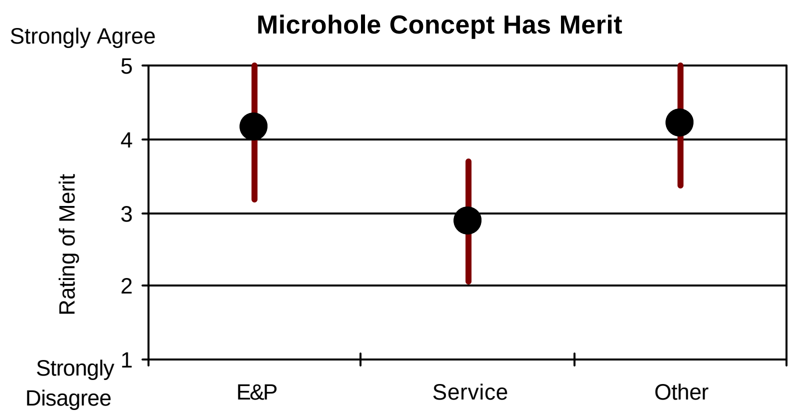


Source: DOE Microhole technologies workshop participant survey

[2] Each of the following charts plots the average response and a line representing one standard deviation from all related companies.

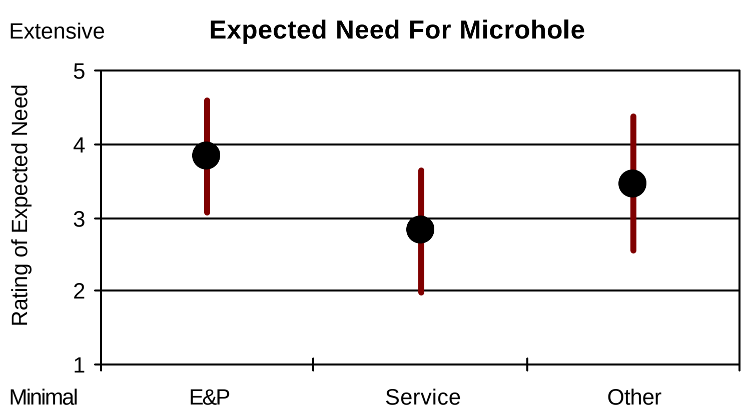
Initial Survey Results

E&P representatives thought that the microhole drilling technology had merit, agreeing with people from the government and from the national lab[3]. Service companies took the middle ground:



Source: DOE Microhole technologies workshop participant survey

Attendees responded similarly to the question: "How would you rate the expected need for this type drilling concept in the US?"

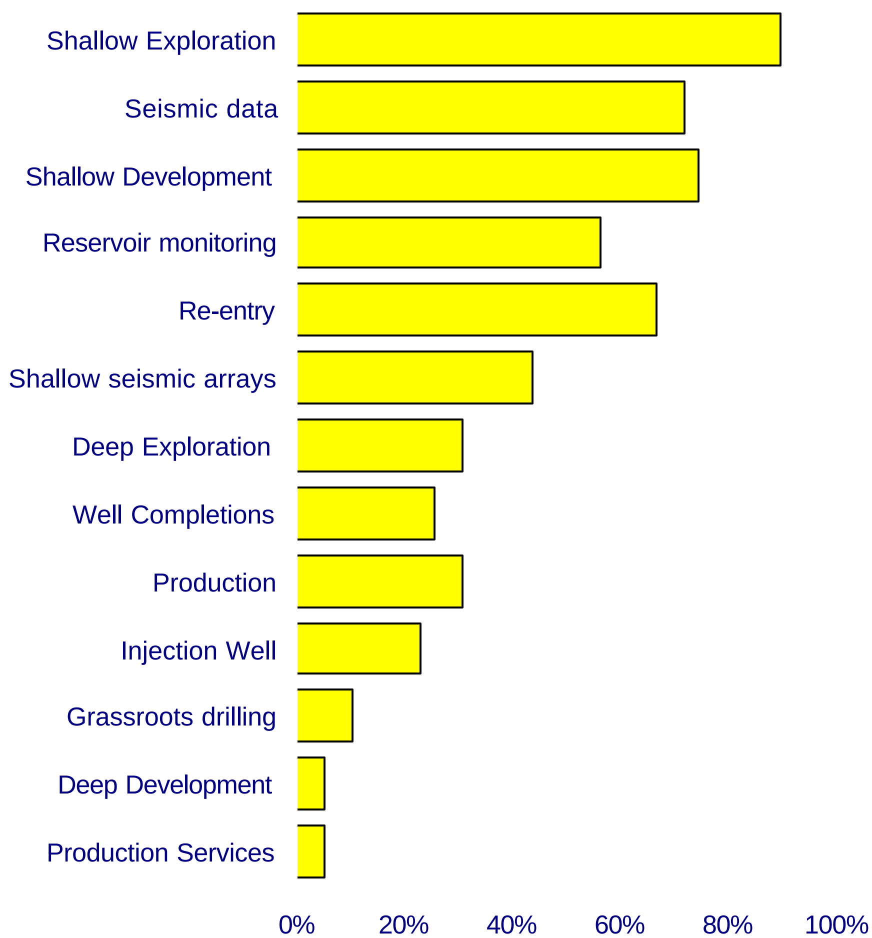


Source: DOE Microhole technologies workshop participant survey

[3] Participants were asked to rate, on a scale of one to five, their reaction to this question: "*The microhole concept has merit*."

From the initial questionnaire – and before the workshop started – attendees indicated that shallow exploration and seismic data types of holes were the most attractive applications for microhole drilling technologies, as shown on the graph below. As the workshop progressed, however, this ranking was modified to reflect the strongly stated opinions of the E&P sector and to group a few related applications:

Microdrilling Application Focus



Source: DOE Microhole technologies workshop participant survey

In the next section we have gone into greater detail about the applications most likely to be near term and medium term uses for microhole drilling technology. This new ranking is based on comments and discussions conducted during the conference. The new ranking:

1) Drilling shallow development wells
2) Drilling shallow reservoir and seismic data holes
3) Drilling re-entry wells
4) Drilling deep exploration holes

Primary Applications

#1: DRILLING SHALLOW DEVELOPMENT WELLS

Description of application

Drilling from surface to total depth (TD) small diameter (≤3-1/2"), vertical holes that, if oil or gas is encountered, are able to produce using artificial lift equipment, if necessary. Maximum depth is 6000'.

Current demand for the service

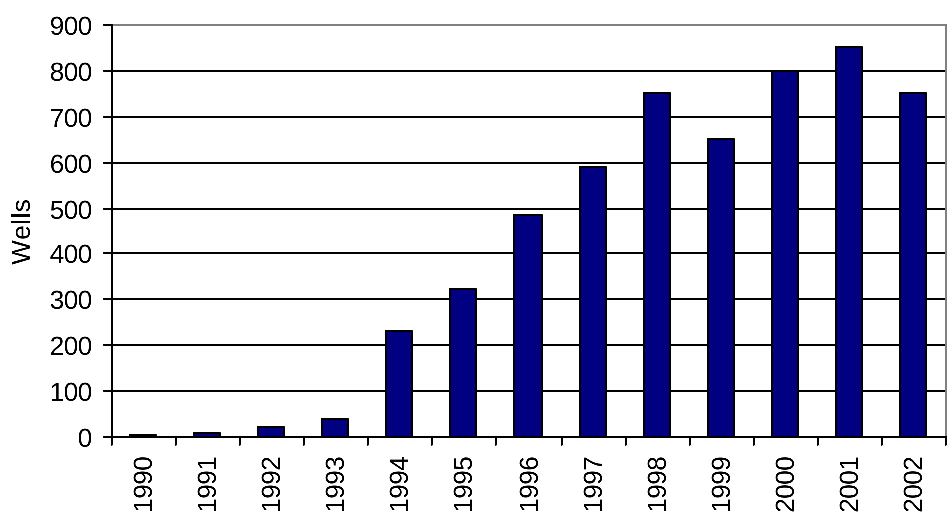
CURRENT ALTERNATIVES:

Oil and gas producers use standard rotary drilling and, occasionally, drilling with casing. Operators in Canada often use coiled tubing to drill standard sized holes[4].

NUMBER OF EVENTS PER YEAR:

In the US in 2003, 18,000-20,000 wells will be drilled to about 5,000' using conventional drilling methods. This level of drilling has been fairly stable in recent years. Only a handful – 25? – are drilled each year using coiled tubing. To our north, Canada drills 10,000-20,000 shallow wells each year, of which hundreds are drilled with coiled tubing. In fact, by the end of 2003, about 7000 wells will have been drilled with coil, with about 750-850 being added each year. In all, Canada accounts for over 90% of worldwide coiled tubing drilling. As the next chart indicates, CTD plateaued a few years ago:

Annual Coiled Tubing Drilled Wells Worldwide



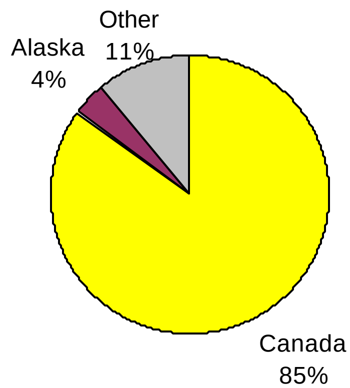
Source: Spears & Associates interviews with service providers and operators

[4] A chart on page 28 shows hole size distribution in the US. SAI research shows that ~97% of all US holes are 4" and larger.

LOCATIONS:

Most coiled tubing drilled wells are in Canada, which are simple vertical, non-steered holes. Higher cost reentries are performed in Alaska and the North Sea. The continental US has seen about 300 CTD wells to date[5]:

Location of CTD wells in North America



The real growth in shallow drilling in the US has come from coalbed methane plays in Wyoming, Kansas, Oklahoma, New Mexico and a variety of other locations.

> *Coalbed methane seems to be a viable market for microhole. – Engineering company*

Almost every basin on land in the US has mature shallow oil and gas reservoirs. Therefore, we believe that locations for microhole development drilling technology can be found nationwide.

CUSTOMER DESCRIPTION:

Independent oil & gas producers were particularly interested in using microhole drilling to reduce the initial capital cost of a shallow development well.

> *Cost of drilling a conventional 5000' well: $13-17/foot in West Texas. Completed cost is $250,000-$350,000. $150,000 is a really attractive price at which we'd drill wells all day long. If microhole would do that, great, but it must be reliable and repeatable. – Independent producer*

But the majors and large independents also have properties scattered throughout the US:

> *All types of companies drill shallow wells. – Large producer*

Therefore, it is reasonable to assume that **all types of producers in the US could be potential customers for MHT**. There are over 10,000 active oil and gas operators in the US currently.

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[5] A primary source of this data is Alex Sas-Jaworski via a survey his firm, SAS, takes annually. Spears has supplemented SAS data with recent drilling activity information.

DOLLARS SPENT ANNUALLY:

Producers will spend about $2.1 billion in 2003 to conventionally drill and complete about 18,000 wells from 0-5000' in the US. About $700 million of this goes to the drilling contractor and $250 million is for casing and tubing.

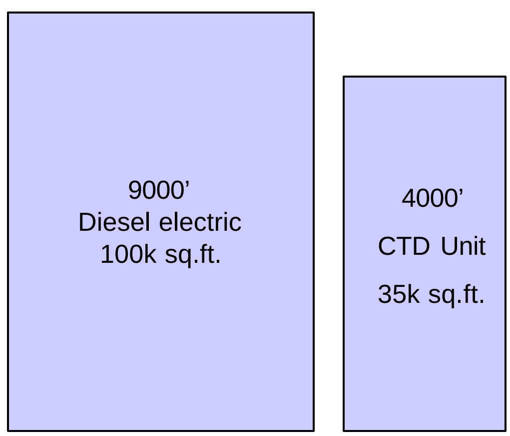
SAI believes that total spending on shallow drilling will not rise if MHT is developed; rather, spending will shift away from the rotary drilling contractor and toward service companies with MHT. This shift has always occurred with the advance of technology[6].

Perceived advantages of coiled tubing-based microhole technology

US operators tend to agree with the well-documented fact that drilling with coil saves space, simplifies logistics and can improve well performance. For example, based on discussions with Canadian producers and service companies, to drill a 4000' grassroots well in Canada with **coil requires about one-third the space and one-third the number of loads when compared with a conventional SCR drilling rig**.

The most active coiled tubing drilling contractor is Precision Drilling in Canada. With 11 units pursuing work, Precision Drilling can punch about 500-1000 holes each year. Comparing minimum location size of Precision Drilling's coiled tubing units with Precision's small conventional drilling rigs, coiled tubing clearly has the size advantage – well sites are only one-quarter to one-third the size of a conventionally drilled pad:

Minimum Location Size
Precision Drilling Co.
Conventional SCR Rig vs. Large CTD Unit



Along with smaller location size, fewer loads are required to deliver equipment to location. The **conventional drilling rig requires 27 loads in the winter and the coiled tubing unit requires only 9 in the winter**[7].

[6] For example, in the Texas Panhandle a drilling contractor's typical number of days over a hole has been cut by 30-50% over the last 5 years due to faster drilling speeds. The primary culprit is the operators' shift toward using PDC bits rather than re-tipped roller cone bits. The total well cost has gone down only slightly, but mainly money has shifted away from the drilling contractor and toward the drill bit suppliers.

[7] Winter drilling in Canada requires extra heating equipment to prevent freeze up.

The previous information comes from Precision Drilling. Technicoil, also of Calgary, through a new rig design, has further reduced the number of trips required to haul equipment to location and has possibly reduced the minimum location size as well.

Key Canadian grassroots drilling metrics are as follows:

Average measured well depth:	3200'
Penetration rate:	220 feet per hour
Days to drill:	2-2.5
Casing program:	5-1/2" surface casing 2-7/8" production casing
Deviation:	<3 degrees
Pad size:	115' x 215'
CTD contractor invoice:	USD 30-40,000
Total completed well cost:	USD 80-100,000

Perceived disadvantages of microhole

In every potential application of microhole drilling, people expressed concern about the hydraulics of drilling very small diameter holes. Even in shallow wells, hydraulics must be considered:

Are hydraulics a problem in shallow holes? No, not less than 5000'. There is not a consensus about this, but this is less of a concern. But it should be evaluated. Hole size and tubing size all must be considered. The hydraulics must match. – Service company

Once the well is drilled and producing, regular maintenance should be expected. For example, producers who deal with downhole problems like scale and paraffin insist that there must be ways to treat these problems in small holes:

If you go with a microhole, you have to be prepared to deal with production problems down the road. Scale, paraffin. - Independent producer

Therefore, perceived disadvantages included limited options to produce wells and maintenance problems.

Critical technologies

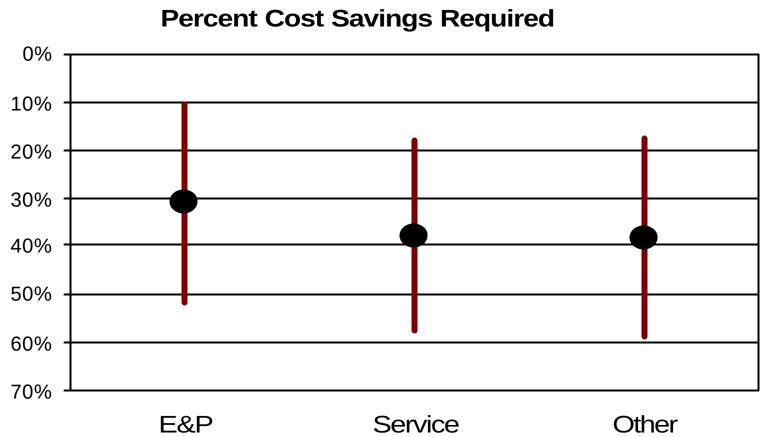
WHAT MUST THE TECHNOLOGY DO?

First and foremost, **MHT must drill a very small diameter hole from ground level to targeted depth quickly and cheaply** with a minimum footprint in a manner that is reliable and repeatable.

Producers are very comfortable with the familiar process of rotary drilling shallow development wells around the US. Advances in PDC bits and rotary steerable systems have made the time required to drill high quality holes drop sharply in many regions. Therefore, for a coiled tubing-based microhole technology to be attractive, the cost differential must be substantial. One producer echoed the industry's attitude:

It costs $300,000 to drill and complete a West Texas well, but if I could drill it for $150,000, I'd drill them all day long. – Independent producer

Therefore, for microhole to be attractive enough to cause operators to change, costs must be about 50% lower than the cost of current alternatives. This conclusion falls generally in line with the expectations of the group as they entered the workshop. As the chart below indicates, workshop participants – E&P, service companies and other organizations – thought that microhole technologies would need to save 30-40% to be attractive to potential customers[8]:



WHAT ARE THE APPARENT TECHNICAL HURDLES?

The primary technical hurdle is being able to drill a small diameter hole vertically from the surface in a manner that is safe, quick, inexpensive and repeatable.

Once the primary hurdle of drilling is overcome, some workshop participants were worried that artificial lift equipment would be hard to use in microholes. Others thought that artificial lift was already available:

> *Producing technology exists now for small wellbores. You can move a lot of fluid in a 2-7/8" hole, not 2-3000 bpd, but you can get a good test. If there is a way, we can figure out how to use it. – Independent producer*

> *For sucker rod pumps and plunger lift, 1-1/4" is about the smallest practical size for current industry use. I suspect there is very little demand for smaller pumps. I've heard that somebody has a 7/8" rod pump. - Independent producer*

Obviously, completing wells correctly is critical to the success of this project. Some people have mentioned that innovation will be required to develop reliable tools for zone isolation, perforation, stimulation and packer systems.

[8] Workshop participants were asked the question, "*Assuming the microhole concept worked, at what percent below current costs of conventional drilling would you consider employing microhole?*"

Impact if successful

A cheaper hole logically extends the attractive economic life of a producing property, increasing the ultimate recovery from a reservoir and extending the US' ability to sustain its oil and gas production.

On the other hand, for this technology to be commercialized, operators will need to insist and demand that the service be made available. Service firms are not enthusiastic about the idea of charging less for a service without boosting volume since this cuts into revenues and hurts return on assets. Therefore, we do not expect service companies to be the initial, strong advocates for MHT.

#2. DRILLING RESERVOIR & SEISMIC DATA HOLES

Description of application

Using a coiled tubing-based drilling system to punch vertical holes from surface to 6000' and using those holes to gather any of the following four data series:

- Seismic data / vertical seismic profiling (VSP)
- Reservoir pressure & temperature data
- Rock samples
- Fluid samples

The hole would be similar to the hole intended for production (≤3-1/2"), but production issues would not be of concern. Data sampling technologies would need to be developed.

In the initial workshop survey, participants were given 4 choices regarding data-type holes: Shallow exploration wells, shallow data gathering holes, reservoir monitoring holes and shallow holes for vertical seismic profiling. All 4 choices ranked near the top of the list. After discussing these applications with workshop participants, we have decided that they should be grouped together since in all cases a shallow, small diameter hole must be punched from which a sample or a data series must be extracted. The question is, what tool is to be tripped into the hole?

Current demand for the service

CURRENT ALTERNATIVES:

There exist three primary ways of gathering this data:

- Using an existing well to install measurement tools
- Drilling a standard-sized well
- Using a coring/slimhole rig to drill a small diameter hole

Each alternative has a benefit and a cost:

Existing wells obviously provide ready access to a reservoir, but doing so can require shutting in production, which is rarely an attractive alternative to a production engineer. Additionally, the well may not be in the place you would prefer to take the measurement.

Drilling standard-sized wells allows the data sample to be taken exactly where the geoscientist would like, but the cost of constructing the hole can be quite high.

Using a coring rig to drill a small hole is less expensive than a standard hole, but hole depth is limited and speed may be an issue.

NUMBER OF EVENTS PER YEAR:

We do not have a way to measure the number of times these events occur each year. It appears, however, that the number is relatively small since the cost of gaining access to a subsurface location can be quite high.

LOCATIONS:

Nationwide.

CUSTOMER DESCRIPTION:

Independent producers at the DOE-sponsored workshop insisted that:

> *Independents don't have the money to drill reservoir-monitoring holes. The majors do, but not the owners of the majority of US's wells. - Independent producer*

This is one reason why we ranked this application behind drilling shallow production wells; there is not a loud, clamored need for data-gathering holes. There is agreement among reservoir engineers and geoscientists that being able to gather and process large amounts of information about a reservoir or a field greatly aids the production team both in producing a field and placing wellbores.

> *I think microhole should be used for sensor placement and reservoir monitoring. This information would improve the placement of producing wellbores. – Sensor supplier*

We believe that the initial customer for data gathering holes will be the larger oil and gas producers and, once costs decline and the technology is proved up, smaller and smaller independents will see the value of improved reservoir information.

DOLLARS SPENT ANNUALLY:

We do not have a way of measuring the amount of money spent on these type wells each year. One manufacturer pointed out that the cost of the hole is not the main concern of customers; it is the cost of lost production:

> *I think the target cost for this service – micro holes for data gathering – should be comparable to the cost of a well test of an existing producing well where you would have to pull the production tubing and stop production for several days on a well. A major stopping point for VSP is the (value) of lost production when you shut down to put a monitor in the well. – Sensor manufacturer*

Therefore, to measure the value of this requires calculating lost or delayed production, which goes beyond the scope of this market-sizing project.

Perceived advantages of microhole

Workshop participants listed a variety of ways microhole technology could benefit the industry in data gathering:

- Wellbore in the exact location[9]
- Less expensive than traditional rotary drilling
- Smaller footprint leaves minimal surface damage during exploration
- No lost production

[9] One option available to VSP has been to place a sensor in an existing well. The problem is, wells are never in the ideal location for the seismic survey.

Participants asked, for reservoir monitoring, how deep would a hole need to be to gather high quality data? If holes are limited to 5000' and an actual sample must be taken, then MHT is better for oil reservoirs[10]. On the other hand, sondes in shallow holes can probe deep into the earth:

> *With a seismic array, tools in a well down to 5000' can look at 10,000'. Even offshore, being able to put the geophones below the surface would reduce the liability of putting permanent monitoring systems in. – Service company*

In summary, the advantage of MHT is delivering a low cost hole in the right location to gather the best information possible.

Perceived disadvantages of microhole

Small producers at the workshop were not excited by this application for microhole drilling technology:

> *I have to be able to produce if I find anything, otherwise I can't afford to drill a hole that just gets me information. I can't waste a hole. – Independent producer*

Rather than being a disadvantage, many small producers simply place no value on a hole that can only gather information. Why is this? Small operators rarely operate a unitized field. The value of information is realized when the operator owns all or a big part of a field early in the development cycle. Then is when information pays off significantly by making smart production decisions. Late in the life of a field – with wells producing <10 BOPD – there is little value in data.

Since well depths for this application are shallow, major technical hurdles for downhole measurement tools are minimal. In a different application – deep exploration holes – the technical hurdles and perceived disadvantages are much greater.

Critical technologies

WHAT MUST THE TECHNOLOGY DO?

MHT must, in the first place, drill a hole quickly and inexpensively to 5-6000' – the same primary objective as shallow production wells. Missing this primary objective will limit the value of any data-gathering technology that is installed in the hole.

Once the hole is drilled, the particular technologies required will depend on the survey being taken. For example, seismic surveys will require tools that can measure acoustic waves while reservoir surveys may require tools that can take a fluid sample while measuring temperature and pressure.

> *I think a good application is reservoir monitoring, planting geophysical arrays for surveillance. These are 3D arrays below the weathering zone, which is the first 500 to 1000'. And they are safe from theft. Plus, you eliminate some surface noise. It would be used where there are high profile assets, assets that can handle big installations that would drive the unit cost down. These are onshore and offshore fields operated by the majors, but not mature reservoirs. - anonymous*

The prize here is the ability to drill a small hole quickly and cheaply.

[10] Oil reservoirs tend to be shallower than gas reservoirs in the US.

WHAT ARE THE APPARENT TECHNICAL HURDLES?

We believe that microelectromechanical system (MEMS) technology makes the data gathering part of this application fairly easy to achieve. It is the drilling component which appears to be the greatest challenge and these drilling challenges are similar to the hurdles seen in the prior section about shallow producing wells.

Impact if successful

Producers and service companies believe that few data sampling wells are drilled in the US each year due to high costs. If the cost of constructing these holes can be significantly reduced, **the number of data sampling holes will rise sharply** once producers become comfortable with the technique of drilling with coil.

> *If one is doing monitoring (conventionally), the well access costs quickly outweigh the survey costs. By having a cheap well ($50k) and multilevel sensor strings ($50k, reusable) the well costs would be dramatically lowered as well as the acquisition costs, thus for a single VSP the cost would be lowered 50 to 75 percent overall, and even more as one does time lapse and multi-offsets. This would open up whole new opportunities for reservoir imaging and fluid imaging.*

The net result is, a **reservoir is managed more correctly**, thereby extending its useful, productive life and boosting ultimate recovery.

#3. DRILLING SHALLOW RE-ENTRY WELLS

Description of application

Entering an existing well and drilling laterally from the wellbore, primarily from land wells in marginally economic fields. This may include a single lateral or multiple laterals. Additionally, re-entry may involve simply drilling straight down through the bottom of the casing and continuing the hole vertically.

Shallow is defined as 6000' or less and the hole size is less than 3-1/2".

Current demand for the service

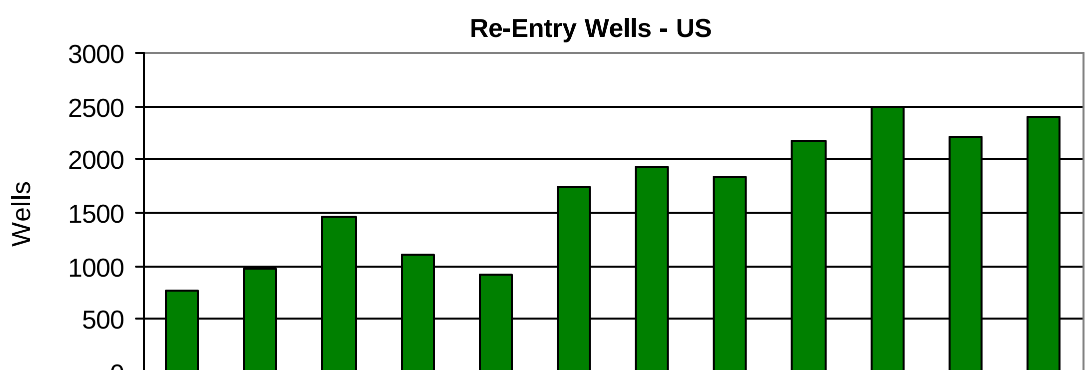
CURRENT ALTERNATIVES:

Re-entry drilling has become quite popular in recent years throughout the US. The standard technique includes a drilling rig or large workover rig which hoists a drill string, bottomhole assembly with bit, window cutting tools and a kick-off system which sends the bit at some angle from the hole. On any day, 50-100 of these rotary operations are going on in the US.

The producers in Alaska always have two coiled tubing-based re-entry operations going on at the same time year round.

NUMBER OF EVENTS PER YEAR:

According to our research, re-entry drilling has been climbing since the mid-'Nineties, standing now at almost 2200 wells per year:



	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Re-Entry	778	971	1469	1097	918	1744	1939	1831	2176	2486	2220	2397

We expect the re-entry number to peak in 2004 as standard drilling tops out, falling in 2005 before re-entry activity resumes its growth[11].

[11] Full documentation of this forecast can be found in Spears' *Drilling and Production Outlook*.

LOCATIONS:

Drilling with coil is fairly mature. Alaskan fields have seen drilling with coil for over 10 years already and, although many predicted it, a significant offshore market never did develop. Industry experts say that many coiled tubing service companies have drilled with coil, especially in Canada and Alaska, but that most drill only one or two holes per year. Nevertheless, **fields across the US are candidates** for coiled tubing re-entry drilling.

CUSTOMER DESCRIPTION:

Re-entry drilling is so commonplace now that all types of operators are using the technique to develop untapped reserves of oil and gas.

> *I think exiting existing cased holes is the best target. The US has 400,000 wellbores that are candidates. To contact new parts of the reservoir, you can test a deep perforating concept. If you find something, you can produce it. You can get quite a bit out of a 2" hole. If the hole produces too much – what a problem to have, huh? – you can drill a regular hole. The current cost to kick off and drill out starts at $150,000. – Independent producer*

Therefore, **all operators with small cased wellbores could be candidates of this technology**; small operators, however, are the most likely candidates.

DOLLARS SPENT ANNUALLY:

Producers will spend at least $7.5 billion in 2003 re-entering existing wellbores[12]. This includes the cost of re-entering the wellbore, drilling a new lateral and completing the well.

Perceived advantages of microhole

The primary stated advantage of a microhole option for re-entry drilling is a significantly reduced cost and the ability to re-entry wells that have 4-1/2" casing and smaller.

> *Must be able to afford directional drilling with coiled tubing. This would open up many potential drilling opportunities. Going to air drilling would further reduce the problems. Deepening wells cased with 4.5" casing is a good market to begin with. – Coiled tubing service company*

Potential customers believe that moving in smaller equipment to drill a smaller hole should result in lower drilling costs.

[12] This assumes about 1,600 land wells costing a total of $2 billion and 600 offshore wells costing a total of $5.5 billion.

Perceived disadvantages of microhole

No disadvantages were stated during the workshop sessions, although some of the disadvantages will carry over from microhole producers: Artificial lift issues, scale and paraffin buildup and remediation options[13].

Critical technologies

WHAT MUST THE TECHNOLOGY DO?

MHT must first and foremost drill out from an existing cased wellbore and drill a lateral 1000' or more. This lateral may go perpendicular to the exited wellbore or may continue the wellbore straight down.

Reentry holds opportunities in oil and gas, if it could drop the cost significantly. Of course, there would be hydraulics problems. – Service company

WHAT ARE THE APPARENT TECHNICAL HURDLES?

CTD is employed every day to exit cased wellbores, but none are the size of microhole technology. The bottomhole assemblies, logging tools and, in fact, the entire drilling operation has been set up to drill conventionally sized holes. Therefore, workshop participants suggested that all systems – motors, MWD, logging, whipstocks, bits – must be developed before reliable microhole drilling can be performed in the US.

Additionally, completion and production equipment for new hole sizes should be studied to determine which additional equipment/service has yet to be developed.

Impact if successful

The amount of oil and gas left in place after a field ceases to be profitable is legendary – 60-70-80% of the original oil. Poking cheap laterals in shallow holes, drilling extended "perforations" with coiled tubing, will possibly return some of these fields to a profitable operation, bringing additional oil and gas on the market from domestic sources.

[13] Quite a bit of time was spent discussing if a very small diameter hole would significantly constrain the amount of oil and gas leaving a reservoir. DOE will need to evaluate this matter to determine if this is an economic method for a drilling and completing wells.

#4. DRILLING DEEP EXPLORATION "TAILS"

Description of application

Drilling a very small diameter hole out the bottom of a conventionally drilled exploration hole in order to evaluate an additional 2000' of rock prior to plugging and abandoning a test hole. Primary application would be offshore in extremely high cost areas, such as deep water, where the total measured depth of the hole is around 20,000 feet.

Current demand for the service

CURRENT ALTERNATIVES:

The only option today is a conventionally drilled exploration hole with a borehole diameter that shrinks with each casing run. Expanding casing may minimize this loss of hole size as time goes by, but the standard setup currently requires a large offshore drilling with the attendant systems and services.

NUMBER OF EVENTS PER YEAR:

About 50 deepwater exploration holes are drilled in the Gulf of Mexico each year. This number does not fluctuate greatly with time.

LOCATIONS:

Gulf of Mexico, in the US. Other locations around the world include West Africa, North Sea, Southeast Asia and offshore Brazil.

CUSTOMER DESCRIPTION:

This suggested application was brought to the workshop by a major oil and gas producer and was confirmed after the workshop by another major. Only about 20 producers drill these types of wells and they tend to be the largest 20, such as ExxonMobil, Shell, BP, Total, ChevronTexaco and ConocoPhillips.

DOLLARS SPENT ANNUALLY:

Deepwater exploration holes are the most expensive wells drilled. Assuming an average cost of $50 million per hole and 50 holes per year, **annual spending on deepwater exploration holes is about $2.6 billion per year**.

If the average per foot cost of these holes is about $2000, then **one 2000' exploration tail is worth about $4 million**.

Perceived advantages of microhole

Operators comment, "we run out of hole" with the last casing run and can't investigate further[14]. The desire is to have an option to drill a tiny investigative hole out the bottom of the last casing string to take samples, measure pressure and temperature and evaluate zones just below the targeted zone of interest. Ideally this would be an inexpensive option to the geologist.

[14] Geologists have always wanted to drill another one-hundred or one-thousand feet just to see what is there.

I want a very inexpensive way to drill another 2-3000' out the bottom of an exploration hole. An exploration tail. This CT unit could sit off to the side of a rig to finish a hole offshore while the big rig drills something else. – Major operator

Perceived disadvantages of microhole

Although the equipment and personnel required to run a microdrill operation may be small, the rest of the drilling vessel is required to provide a platform from which to work. The **cost of this vessel is extremely high**; therefore, the cost of drilling a microhole may be just as high as the cost of a standard sized hole.

Deepwater issues are more to do with the ship and not the drilling system. The biggest percentage of the cost is positioning the ship. Still, deepwater companies would love a cheap hole to evaluate a deepwater block. – Service company

Critical technologies

WHAT MUST THE TECHNOLOGY DO?

As with the other applications, MHT must first be able to **drill a small diameter hole** quickly and reliably. Second, the system must be able to **sample data in the hole and transmit that information to the surface** somehow:

I must be able to test the last 2000' of exploration hole; otherwise I can't sell it to management. – Large independent

Drilling and sampling. In deep wells these are not insignificant issues. See below.

WHAT ARE THE APPARENT TECHNICAL HURDLES?

Greater depths generally mean **high temperature and high pressure**:

I can't imagine a 1" tool that can withstand the pressures of a 15,000' hole. Temperatures are secondary issues now; pressure is the primary issue. I can't believe it is feasible to develop systems and hydraulics for deep applications and high pressures. – sensor supplier

In a 6" hole, 175 degrees C is okay, but in a 2-3/4" hole, 150 degrees C begins to be a problem because you can't use flasks and other techniques. In deep applications, reliability becomes more of an issue than cost. And integrity. What is the risk of losing a system in the hole? – Large independent

Secondly, **how to transmit power to the drill bit** at those depths? Two choices exist: Hydraulic and electric:

A major barrier to deep microhole drilling is how much power you can get to the bottom of the string. Hydraulic power. I think DOE has to make a critical development decision: Do we go electric or hydraulic? Electric has benefits, but hydraulic is still required for cutting transport. – Service company

> *Any type of wired system would work best with coil rather than jointed pipe. And any type of underbalanced drilling project leans toward coil, not jointed. - Independent producer*

> *Cable systems are much better for data capture. – Service company*

> *Data transmission through cable hits a limit at 16,000' – Service company*

Thirdly, if hydraulic power is used, are the motors up to the task? As the comments below indicate, companies do not agree about the state of the art at these depths:

> *For new exploration wells, a 2-1/2" hole sizes means a 1-1/2" coil size. The motors are there, but the memory tools are questionable. – Sensor manufacturer*

> *The state of the art in the 2-1/2" hole market: The small motors are service motors, not drilling motors, so they won't last long. – Service company*

In reality, all of these issues go hand in hand. The solution to one will effect the others:

> *In deep, exploration tails, power, pressure and temperature are all critical issues to work through. We could be extending a new hole that found nothing or you could extend an existing well. – Large independent*

Impact if successful

Geologists would have another tool in their toolbox for evaluating deep zones. If successful in the high cost regions, the technology may move onshore as a cheap way to test zones below the casing shoe.

Other Applications

Workshop participants proposed a few other applications for MHT. These are listed below:

Seafloor Drilling Rig

The concept involves placing a coiled tubing drilling operation on the ocean floor and remotely – from a vessel – controlling the operation.

Subsurface Monitoring at the South Pole

As one participant proposed:

For reservoir monitoring or subsurface monitoring at the South Pole. A permanent sensor, a hot wireline. It needs to be super reliable, so it needs a different design, different parameters. I think 1" diameter tools are feasible and cheap. – Government

Coalbed Methane in Alaska

Remote locations are attractive to any technology that is small and easily transportable. One service company proposed using MHT for coalbed methane in Alaskan villages, which would be a spin off application to drilling development wells:

Let's think about where we could go that we don't go now. CBM in Alaska, for example. 5000' limitation is okay. And up there technology changes are needed – smaller rigs to field the system that has been envisioned by Los Alamos. And Alaska exploratory wells. Remote locations. Current rigs for slim hole drilling are still too big. – Service company

Alaska is an example of a good application for any type of coiled tubing drilling. The first Canadian wells were in environmentally sensitive areas.

Remote/sensitive location wells or wells you can only get into in seasonal situations. Exploratory holes. – Service company

If CBM experience in Eastern Kansas is a sound model for potential in Alaska, then several hundred wells could be drilled each year with this tool[15].

[15] Many towns in Eastern Kansas have contracts with local CBM producers to buy natural gas. This direct supplier/consumer relationship has worked well for years and drives a thriving oilfield service and equipment market in the region.

Current State of Coiled Tubing Technology

Coiled tubing drilling is maturing

One of the facilitators at the workshop summarized the state of the art for small bore holes like this:

> *It sounds like technology for shallow development drilling with coil exists, but what we need is demonstrated successes. So, what are the enhancements we need? The barriers look like learning curves, economics, and demonstration projects. – Facilitator*

From Spears' past work we see that coiled tubing (CT) services can be broken into two categories: **Production services and drilling services** CT drilling appears to be maturing, particularly in Canada where shallow, directional wells are used to produce oil, and in Alaska, where the technique has been used to reenter wells for many years.

Coiled tubing expands its applications by a few percent each year, so its overall market is growing. The improving quality of the tube itself and the predictability of its performance has won it this increasing demand in new applications. Credibility is improving and Canada is leading the world in innovative use of coiled tubing.

During the 2000-2001 uptick in the oilfield services market, conventional CT services, which represent 75% of CT spending, were growing about 10-12% per year while frac and drilling were growing 30%. This move toward drilling and stimulation has been driving demand for larger diameter pipe.

About 800 units are in the current coiled tubing fleet:

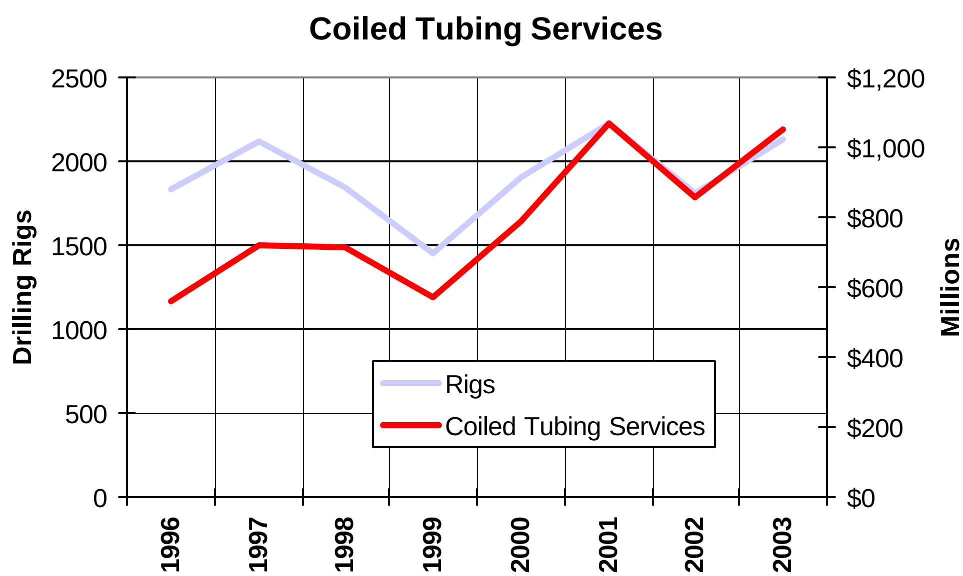
UNITS	SERVICE COMPANY
200	Schlumberger
165	BJ Services
105	Halliburton
38	Superior Energy Services
23	Cudd Pressure Control
11	Precision Drilling
6	Technicoil
5	Tucker Energy Services
5	Saber Energy Services
4	Advanced Coiled Tubing
3	Baker Hughes Inteq
210	Others
775	**TOTAL**

Source: Spears & Associates, Inc.

It is possible that the "Others" category could be larger and may add as many as 200 to this list. Russia and China are not included.

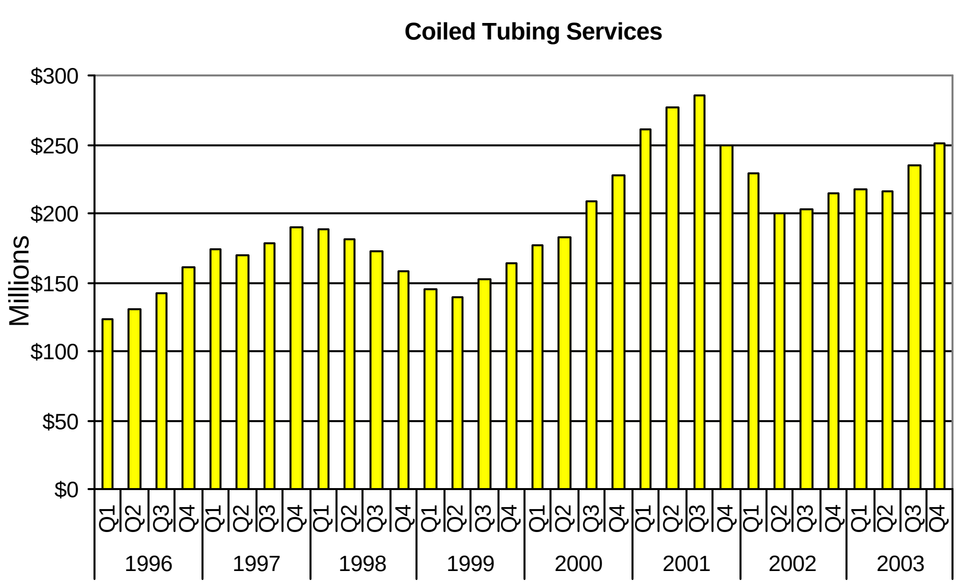
Coiled tubing services doubled from 1999 to 2001 as the US moved toward gas well drilling and as a result of a trend toward completing wells under pressure. Conventional well servicing rigs were also booked up during the 2001 period. With a recovery in drilling in 2003, sales are expected to increase.

When coiled tubing services revenues are plotted against active US drilling rig count, we see that sales of CT services are growing at a rate faster than rig count. As the following chart clearly indicates, coiled tubing is a growth market:



Source: Spears & Associates

This is a cyclic business. Viewed quarterly, sales fell abruptly at the end of the last "boom" in mid-2001, but have been slowly increasing since mid 2002:



Coiled Tubing Services
Global

	Revenues (Millions)			
	2000	2001	2002	Share
Schlumberger, Ltd.	$240	$310	$265	31%
BJ Services	$172	$260	$190	22%
Halliburton Corp.	$135	$155	$135	16%
Superior Energy Services, Inc.	$43	$65	$45	5%
Cudd Pressure Control	$35	$50	$35	4%
Sangel Cementers Ltd.	$25	$31	$25	3%
Trican Well Service Co., Ltd.	$22	$32	$25	3%
Precision Drilling Corp.	$21	$30	$24	3%
Technicoil Corporation, Inc.	$4	$17	$15	2%
Pride International, Inc.	$13	$18	$14	2%
Ensign Resource Service	$7	$5	$4	0%
Others	$71	$96	$83	10%
Total Market	$788	$1,069	$859	100%

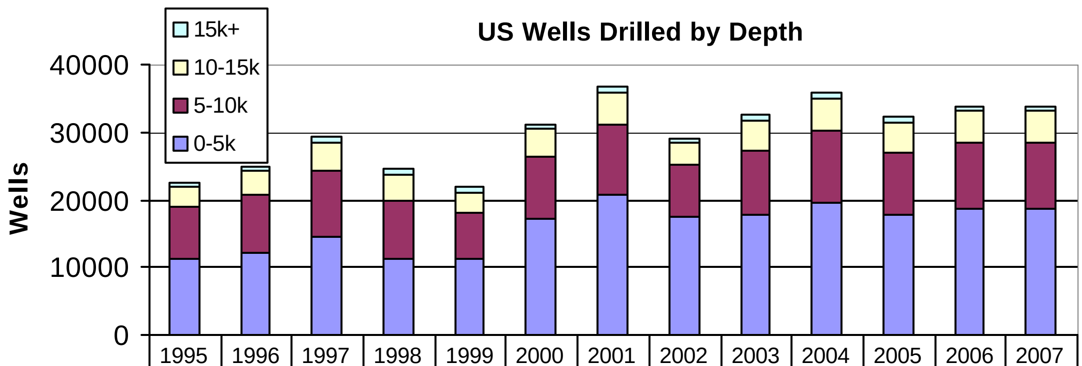
Source: Spears & Associates

Although coiled tubing's past growth has been more robust than the general oilfield, from this analysis we conclude that **coiled tubing services is no longer a high growth market**, given how technology development has slowed in recent years. Without an enhancement to the technology – be it MHT or something else – coiled tubing services will grow slowly, subject to the usual cyclic market forces.

US Drilling Forecast

Summary

2003 is a recovery year for the US petroleum industry, with drilling expected to climb about 12% from the prior year. 2004's totals should also be higher by another 10% before cycling down:



	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
15k+	544	681	813	875	689	700	850	677	825	905	815	857	857
10-15k	3003	3387	4191	3957	3086	4020	4832	3209	4397	4793	4312	4543	4543
5-10k	7826	8560	9772	8478	6777	9070	10453	7615	9459	10466	9424	9898	9898
0-5k	11196	12224	14457	11378	11273	17323	20675	17560	17910	19652	17680	18623	18623

*Source: Spears & Associates, Inc.'s **Drilling and Production Outlook**, March 2003*

Spears & Associates expects drilling shallower than 5000' to be higher during this decade than during the prior decade as operators invest in coal seam gas developments. This focus on coal gas has made shallow drilling rise by about 35% when compared with the 1995-1999 period.

The following table estimates current exploration drilling, which is a subset of the table above:

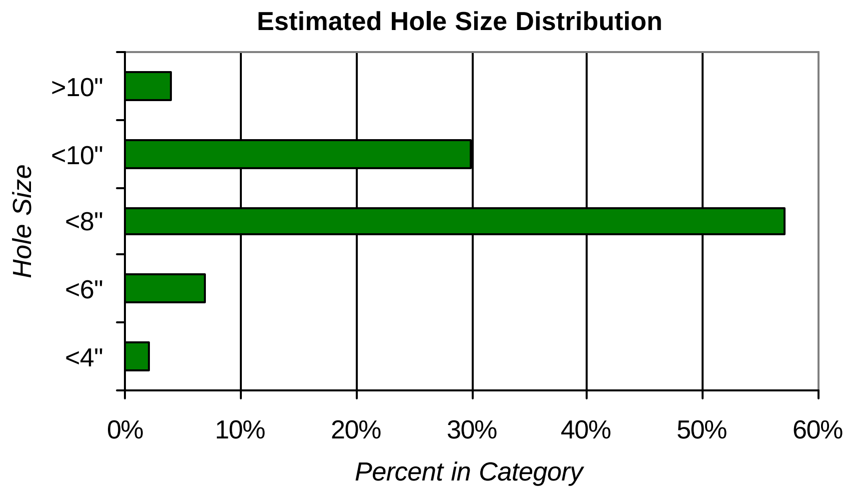
Exploration Drilling - US

	2003 Estimated Activity									
	0-5000 ft		5000-10000 ft		10000-15000 ft		15000+ ft		Total	
Region	Average Depth	Cost/ Foot	Average Depth	Cost/ Foot	Average Depth	Cost/ Foot	Average Depth	Cost/ Foot	Average Depth	Cost/ Foot
Land Explo Conventional	2,833	$43	6,941	$69	12,023	$130	16,624	$274	6,445	$105
Land Explo Sidetrack	4,300	$50	5,610	$160	4,867	$159	4,200	$344	4,931	$180

	2003 Estimated Activity														
	0-5000 ft			5000-10000 ft			10000-15000 ft			15000+ ft			Total		
Region	Wells	Footage (000)	Cost ($mil)	Wells	Footage (000)	Cost ($mil)	Wells	Footage (000)	Cost ($mil)	Wells	Footage (000)	Cost ($mil)	Wells	Footage (000)	Cost ($mil)
Land Explo Conventional	1,061	3,007	$128	851	5,905	$407	442	5,309	$691	93	1,546	$424	2,447	15,767	$1,649
Land Explo Sidetrack	2	8	$0	10	55	$9	18	86	$14	6	25	$8	35	174	$31
Total	1063	3,015	$128	860.5	5,960	$415	459.2	5,394	$705	99	1,571	$432	2,482	15,940	$1,681

Hole Size

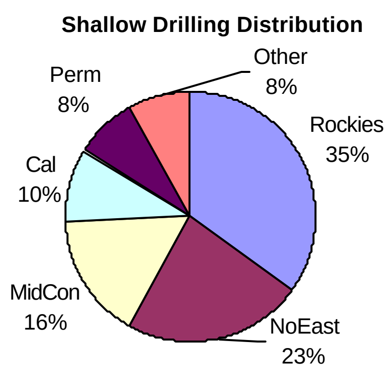
It is very difficult to accurately determine the footage drilled each year by hole size or bit size. The chart below is our rough estimate of this hole size distribution based on analysis of casing runs and on sales of drill bits over the past few years. For a more precise analysis, we recommend that a large drill bit manufacturer – Smith Bits, for example – be asked to evaluate these measures using their extensive drill bit database.



The smallest common bit size appears to be 3-1/2", although smaller sizes are available through specialty bit manufacturers. We believe that only 1-2% of the footage drilled is 3" and smaller[16].

Regional Drilling

Details on regional drilling activity can be found in the next section under "*Regional Drilling Costs*". For drilling shallower than 5000', the Rockies and the Northeast represent about 60% of the market in the US:

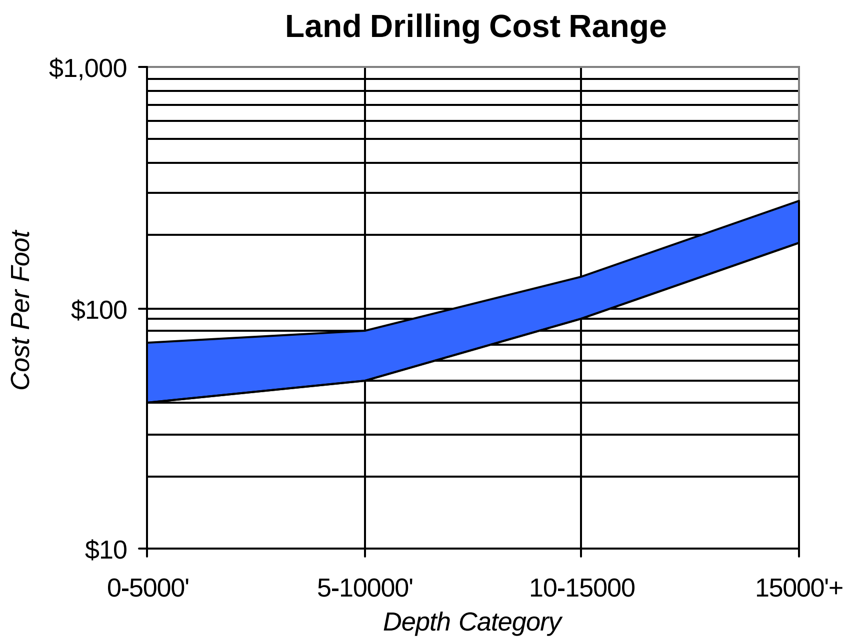


[16] The main point here is that the drilling industry is geared for larger hole sizes since the majority of holes are development wells requiring production tubing and downhole lift systems in many cases.

Cost of Drilling

Summary – Land Wells

As a rule of thumb, as well depth increases, the per foot cost of drilling rises logarithmically. The following chart indicates the range in drilling costs for all land wells drilled in the US – for example, wells drilled in the US between the depths of 5000' and 10,000' cost between $50 per foot and $80 per foot to drill and complete:

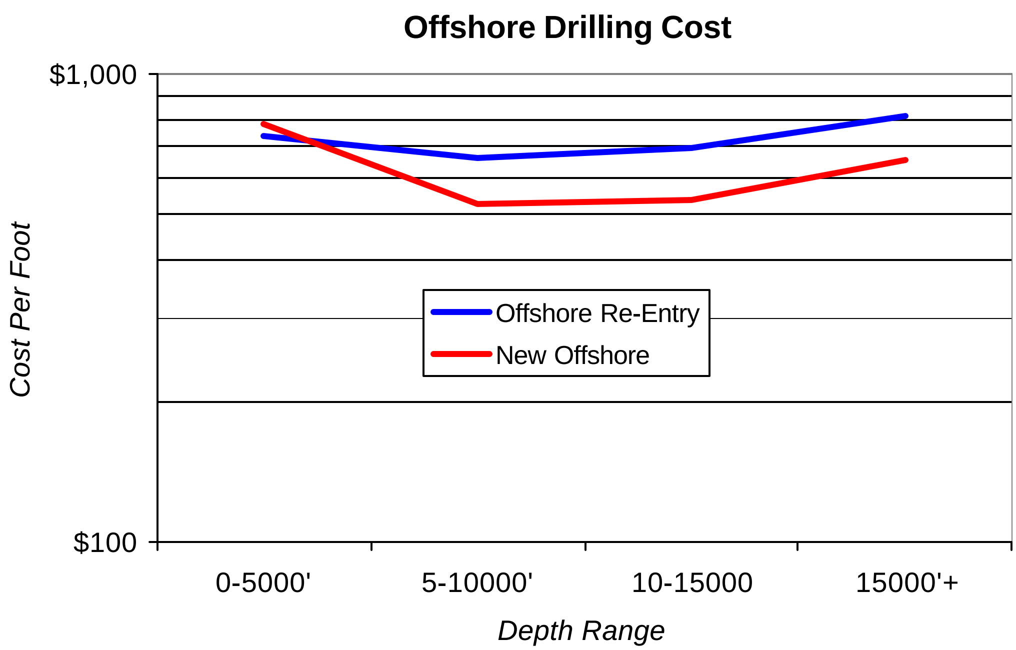


Source: Joint Association Survey and Spears & Associates

Please note that the average per foot cost of drilling a shallow hole is about the same as the average per foot cost to drill a 5-10,000' hole. Rig mobilization charges for a 2000' hole are about the same as for a 7500' hole, but the shallower hole has fewer feet to distribute the costs over. As a result, the cost per foot for a shallow hole is about the same as for a medium depth well in the US.

Summary – Offshore Wells

Close to 1200 wells will be drilled offshore this year, about half of which will be reentry drilling and the other half new. These offshore wells show almost no change in per foot drilling costs as wells get deeper because fixed costs are extremely high and Gulf of Mexico drilling is fairly uniform at all depths:



Source: Joint Association Survey and Spears & Associates

Comparing the Costs of Conventional Drilling and Coiled Tubing Drilling

Other than re-entry wells in Alaska and other places, few new wells have been drilled in the US with coil, so data is scare. On the other hand, thousands of wells have been drilled with coil in Canada. Although the comparison is not exactly "apples to apples", below we have estimated the per foot costs of drilling a MidContinent well with a conventional rig and a Canadian well with a coiled tubing drilling rig.

3000' well per foot cost

REGION	CONTRACTOR	PIPE[17]	OTHER[18]	TOTAL
MidCont Rotary	$15	$5	$23	$43
Canada CTD	$15	$4	$14	$33

Source: Spears & Associates

[17] Both wells have surface pipe set at 300'. The MidContinent well's production string is 4.5" and the Canadian production string is 2-7/8".
[18] Cement, drilling fluids, logging, site preparation and damages, logistics, fuel, production tubing, etc.

Regional Drilling Costs

Spears & Associates has assembled from Joint Association Survey (JAS) data the following table of regional drilling cost information. These per foot average costs have been married with the projected number of wells in each region for 2003 to yield the amount of money to be spent this year on drilling and completing wells in the US. Obviously these averages mask a wide range of actual costs, but these tables give strong guidance regarding the money spent on drilling:

	2003 Estimated Activity									
	0-5000 ft		5000-10000 ft		10000-15000 ft		15000+ ft		Total	
Region	Average Depth	Cost/ Foot	Average Depth	Cost/ Foot	Average Depth	Cost/ Foot	Average Depth	Cost/ Foot	Average Depth	Cost/ Foot
Onshore Re-entry	2,198	$129	3,056	$156	5,139	$212	8,185	$277	4,478	$207
Offshore Re-Entry	2,352	$736	6,439	$660	9,671	$693	15,569	$814	9,303	$723
New Offshore	3,706	$779	8,017	$529	12,420	$536	18,170	$652	11,552	$572
Mid Continent	2,549	$43	7,273	$59	12,011	$102	16,940	$185	5,466	$69
Permian	3,516	$48	7,187	$59	11,529	$89	16,932	$259	6,616	$71
Rockies	1,292	$72	7,323	$83	11,738	$106	15,868	$231	3,197	$87
California	2,116	$40	6,986	$167	11,698	$285	18,643	$459	2,974	$104
South Texas	3,364	$44	7,278	$75	11,687	$132	16,447	$281	8,502	$120
Ark-La-Tex	2,391	$43	8,359	$67	11,812	$104	15,980	$209	8,654	$89
Gulfcoast	2,641	$97	7,555	$89	12,254	$164	17,061	$243	8,083	$156
Northeast	2,790	$41	5,737	$33	11,233	$101	0	$0	3,366	$39

	2003 Estimated Activity														
	0-5000 ft			5000-10000 ft			10000-15000 ft			15000+ ft			Total		
Region	Wells	Footage (000)	Cost ($mil)	Wells	Footage (000)	Cost ($mil)	Wells	Footage (000)	Cost ($mil)	Wells	Footage (000)	Cost ($mil)	Wells	Footage (000)	Cost ($mil)
Onshore Re-entry	96	211	$27	359	1,098	$171	499	2,566	$543	108	881	$244	1,062	4,756	$986
Offshore Re-Entry	26	62	$46	202	1,299	$857	253	2,443	$1,694	107	1,661	$1,352	587	5,465	$3,948
New Offshore	31	116	$90	231	1,852	$979	276	3,429	$1,840	124	2,259	$1,474	663	7,656	$4,383
Mid Continent	2,794	7,123	$306	2,105	15,309	$910	552	6,632	$674	64	1,078	$200	5,515	30,142	$2,090
Permian	1,422	5,002	$240	2,145	15,416	$909	521	6,005	$531	61	1,028	$266	4,149	27,450	$1,948
Rockies	6,103	7,884	$568	1,615	11,829	$982	544	6,389	$676	24	388	$90	8,287	26,491	$2,317
California	1,716	3,631	$143	181	1,265	$212	51	596	$170	7	128	$59	1,955	5,619	$584
South Texas	342	1,149	$50	722	5,251	$395	601	7,025	$929	91	1,497	$420	1,755	14,923	$1,795
Ark-La-Tex	392	936	$40	723	6,040	$404	799	9,436	$980	20	313	$65	1,933	16,725	$1,489
Gulfcoast	592	1,564	$151	427	3,225	$286	431	5,279	$867	184	3,140	$762	1,634	13,208	$2,066
Northeast	4,066	11,342	$463	968	5,555	$185	6	66	$7	0	0	$0	5,040	16,963	$655
Total	17581	39,021	$2,127	9677	68,138	$6,290	4533	49,865	$8,911	789	12,374	$4,933	32,580	169,398	$22,261

Source: Joint Association Survey and Spears & Associates

Additional Workshop Comments

DRILLING PRODUCTION HOLES

I think exiting existing cased holes is the best target. The US has 400,000 wellbores that are candidates. To contact new parts of the reservoir, you can test a deep perforating concept. If you find something, you can produce it. You can get quite a bit out of a 2" hole. If the hole produces too much – what a problem to have, huh? – you can drill a regular hole. The current cost to kick off and drill out starts at $150,000. – Independent producer

It costs $300,000 to drill and complete a West Texas well, but if I could drill it for $150,000, I'd drill them all day long. – Independent producer

I have to be able to produce if I find anything, otherwise I can't afford to drill a hole that just gets me information. I can't waste a hole. – Independent producer

All types of companies drill shallow wells. – Large producer

Cost of drilling a conventional 5000' well: $13-17/foot in West Texas. Completed cost is $250,000-$350,000. $150,000 is a really attractive price at which we'd drill wells all day long. If microhole would do that, great, but it must be reliable and repeatable. – Independent producer

Reservoirs are heterogeneous and we don't know where the remaining oil is. But the cost of drilling can't exceed the value of the oil in place. - Independent producer

What is shallow? 5000' is pretty good. I can think of a lot of applications I've looked at over the last several years that this would fit in. In Canada we are drilling 2-800' wells a day with coil and it is economic. So I don't agree that a waterwell rig will always be more economic at that depth. These are not environmental issues or remote issues. It is simply economic. Weight on the road is the true limit to depth of well in Canada and the rest of the US land. – Large producer

I don't think coiled tubing drilling will ever beat waterwell rigs. They are just too cheap now. - Independent producer

I've got 200 6000' wells in West Texas if microhole works. - Independent producer

Coalbed methane seems to be a viable market for microhole. – Engineering company

How many extra wells can be drilled by MHT that we won't be drilling conventionally? – Sensor manufacturer

Microholes will have watering problems if less than 2-3/8" diameter. – Service company

Reentry holds opportunities in oil and gas, if it could drop the cost significantly. Of course, there would be hydraulics problems. – Service company

Wade Dickens did research for drilling a 1" x 1000' perforation, especially in the Rockies. The Madden in the Wind River Basin at 17,000'. Up there, massive fracs didn't work and many small fracs didn't work either. – Service company

A coiled tubing unit costs about $10,000 per day. – Service company

Southern Alberta has perfect geology for CTD. Pan Canadian paid to move a CTD drilling rig out of California. We had to drop our rates 20-50% before the drilling program took off. Montana has some similar geology. – Coiled tubing service company

(One key conclusion of the meeting was,) independents can't afford to drill non-producers. If an independent has only enough money to drill one well to replenish capital funds and make a profit, it has to be a producer. One would have to be planning a lot of wells in a short period of time and have a huge benefit from an exploration well for this paradigm to change. For example, for a two well program and one year to drill the exploration well and benefit from it, one would have to be willing to wait three years and double the return on investment (assuming a one year budgetary cycle and nominal two year return on investment). – National Laboratory

(A second key conclusion of the meeting was,) it would have to cost 50% less. The AFE would have to be 50% less. Risk is handled separately by contingency funds. Expecting the risk would be higher, the AFE would have to be 50% less because I am going to have to put aside an extra 50% to cover the risk that the first time will probably be a learning experience. Alternatively, the overhead or management costs will be a lot higher to pull off something we are not familiar with, so we need to set aside an extra 50%. – National Laboratory

Must be able to afford directional drilling with coiled tubing. This would open up many potential drilling opportunities. Going to air drilling would further reduce the problems. Deepening wells cased with 4.5" casing is a good market to begin with. – Coiled tubing service company

DRILLING EXPLORATION OR DATA HOLES

If you are going to drill an exploration hole, you want both logging data and rock samples, plus the ability to run a drill stem test. You want to get fluid samples. – Engineering consultant

I want a very inexpensive way to drill another 2-3000' out the bottom of an exploration hole. An exploration tail. This CT unit could sit off to the side of a rig to finish a hole offshore while the big rid drills something else. – Major operators

Another application is deepening from an existing well. Use PDC bits. Motors are still the weakest point. – Coiled tubing service company

I must be able to test the last 2000' of exploration hole, otherwise I can't sell it to management. – Large independent

Independents don't have the money to drill reservoir-monitoring holes. The majors do, but not the owners of the majority of US's wells. - Independent producer

But if you could drill a hole cheaply enough, if you don't find anything, you cut it off and move on. Like disposable hole. - Independent producer

The survey told us we all wanted to use it for shallow exploration, but how much shallow exploration is going on at <5000'? – Service company

People refuse to spend money for data and information, but will spend more to drill a well. So, information holes also need to be used as production holes. – Technology transfer manager

The first well we drilled with coiled tubing in California was to put geophones downhole. There is some demand for this. There may be some market for this. – Coiled tubing service company

Deepwater issues are more to do with the ship and not the drilling system. The biggest percentage of the cost is positioning the ship. Still, deepwater companies would love a cheap hole to evaluate a deepwater block. – Service company

I consider seismic data collection to be a type of reservoir monitoring. I'd be putting permanent geophones under the surface for monitoring. I could see that growing onshore and offshore. – Service company

I don't understand the fascination with 1" pipe. I can do everything I want in 2-7/8". – Service company

We only develop technologies we can use across the board. Products with niches don't succeed. – Service company

I can see dropping a drill package off a ship to the sea floor that can drill and evaluate a well. We have deployed coiled tubing before to help lift a Japanese boat that sank. – Service company

For reservoir monitoring, how deep would you need to be? If you are limited to 5000', then this is better for oil reservoirs. But with a seismic array, tools in a well down to 5000' can look at 10,000'. Even offshore, being able to put the geophones below the surface would reduce the liability of putting permanent monitoring systems in. – Service company

I think a good application is reservoir monitoring, planting geophysical arrays for surveillance. These are 3D arrays below the weathering zone, which is the first 500 to 1000'. And they are safe from theft. Plus, you eliminate some surface noise. It would be used where there are high profile assets, assets that can handle big installations that would drive the unit cost down. These are onshore and offshore fields operated by the majors, but not mature reservoirs.

How about monitoring EOR fields for CO2 injection sweeps? – Technology exchange manager

We need a new hole for reservoir monitoring because majors don't want to use an existing borehole. VSP isn't accepted because it interrupts a well.

The barriers to VSP are cost and instrumentation. A typical cost is $100,000, plus the time lost on the well. So, the alternative cost must beat $100,000 significantly.

VSP currently suffers from too high a cost to benefit ratio. Typical costs for VSP range from $75K for a single offset to $250K for a full 3-D in a 6000 foot well. This does not count the access costs of the well, which can be from $50K to $150K per VSP. If one is doing monitoring, the well access costs quickly outweigh the survey costs. By having a cheap well ($50k) and multilevel sensor strings ($50k, reusable) the well costs would be dramatically lowered as well as the acquisition costs, thus for a single VSP the cost would be lowered 50 to 75 percent overall, and even more as one does time lapse and multi-offsets. This would open up whole new opportunities for reservoir imaging and fluid imaging. Specific areas of application would be fractured reservoirs, compartmentalized reservoirs (one could now afford to dissect these areas with cheap wells) areas where 3-d surface seismic is not possible (rough terrain, fields with surface infrastructure, pipelines, wells in urban areas), environmentally sensitive areas) and, last but not least, offshore areas. Surface seismic is so labor intensive and expensive in many instances it would replace 3-D surface seismic, especially on land. The increased resolution would also offer a much better understanding of the subsurface. Going to multi-component would offer the use of direct fluid detection in addition to structural imaging. Thus, applications such as CO2 monitoring, steam and water flood prediction and monitoring, in-fill drilling would all benefit. – National Lab

Microholes could revive (crosswell seismic), which is just a niche service now. It suffers from the same symptoms of cost benefit ratio as VSP, but twice as badly. The great promise of crosswell has not been realized due mainly to cost. In one way it may benefit the most. If one could put cheap hole down one could strategically place the holes to optimize information and investigate problem areas in the reservoir. In addition selected crosswells in individual fields would determine the nature and amount of complexity of the field, such that the operator could manage the whole field in a much (better fashion). An example is flood monitoring. EnCana and LBNL recently did a two panel crosswell in vertical wells to determine why no increase in production was coming from a portion of the reservoir due to CO2 injection (the Weyburn field), total costs were $375K US, $200K were for well bore access!! We also did a time-lapse crosswell in two horizontal injector wells, the first survey was $500K, the second was $1,200,000 US and, to add insult to injury, we did not get the second data set all due to well bore problems and costs. If dedicated cheap wells were available, you can see the difference it would make. – National Lab

(With surface seismic) it may make an impact by being able to supplement the surface seismic with VSP and check shot information (zero offset VSP to validate the surface seismic) this would be especially useful in complex areas. The sources for VSP are already doing the surface seismic; why not use them to do VSP at the same time, now it is a cost issue with the holes and instrumentation. In addition, as the technology developed (microhole) one could see emplacing arrays in the shallow (100 to 200 feet) subsurface to replace the surface arrays, especially in 2-D seismic applications, thus enhancing resolution and increasing the signal to noise ratio. Also, thinking far ahead, in subsalt environments the need for information below the subsalt is critical, cheap drilling to these areas would be of great benefit.

As was pointed out, logging, fluid sampling and other geophysical methods could be used, especially if the hole size accommodated the current tools (many of which are 2" now). By having cheap holes one can afford to sample then subsurface at a denser spacing and thus reducing the need in many ways for very sophisticated logging. Electrical methods such as resistivity, SP and

EM would greatly benefit. This would provide the impetus for integration of methods and thus information improvement overall. – National Lab

Are deep, high-pressure applications an opportunity? A much longer-term opportunity. Still lots of problems with the standard 4.5" tools. Huge barriers to overcome if you are to use CTD for deep, high-pressure wells. – Coiled tubing supplier

For the shallow, development wells, drilling for information appears to be a non-starter. Information wells are for majors looking for big markets. Is it a cultural thing that we don't want to drill for information, or is it a smart thing to do if we can get past the hurdle of drilling for information. Is it smart to drill these wells, and should the DOE sponsor this type of activity? Maybe. Maybe not. Is it a cost or an investment. Avoid costs, make investments. – Coiled tubing supplier

DRILLING SMALL FOOTPRINT HOLES

Remote locations or places with limited access to services. – Large independent

Urban areas ought to be an application. You'd have a small footprint and excellent well control that the city fathers would love. This application probably happens if we can make microhole coiled tubing drilling work. – Small independent

Does the rig size change a lot when you go from 1" tubing to 2-1/2" tubing? Yes, the 1" has a smaller footprint. The 2-1/2" unit is not helicopter transportable. – Service company

The Canadians bring out 4 trailers to drill the wells. Technicoil in Canada. But they couldn't do it in the US. I don't know why; maybe because of the hard rock formations or maybe because of the environment. It was the San Juan Basin. – Service company

What we did not hear was coiled tubing drilling is important for access to public lands where minimum foot print requirements make it the only way to do the job. Yes, that idea was laid on the table initially, but had not been on participants' radar screen before they came. The discussions were guided, but the rules of the game were not "foremost we must discuss what has to be done for national energy security," instead everyone was speaking from the perspective of "represent your segment of the industry." – National Laboratory

TECHNOLOGY ISSUES

I can't imagine a 1" tool that can withstand the pressures of a 15,000' hole. Temperatures are secondary issues now; pressure is the primary issue. I can't believe it is feasible to develop systems and hydraulics for deep applications and high pressures. – sensor supplier

A major barrier to deep microhole drilling is how much power you can get to the bottom of the string. Hydraulic power. I think DOE has to make a critical development decision: Do we go electric or hydraulic? Electric has benefits, but hydraulic is still required for cutting transport. – Service company

Producing technology exists now for small wellbores. You can move a lot of fluid in a 2-7/8" hole, not 2-3000 bpd, but you can get a good test. If there is a way, we can figure out how to use it. – Independent producer

When the existing shallow rig fleet finally fails, this coiled tubing unit might be the new rig fleet. – Independent

Size of the hole is a barrier. Smaller than 3.5" is a breakover point where you have to start using specialty tools, special bottomhole pumps, special bits… - Independent producer

I think microhole should be used for sensor placement and reservoir monitoring. This information would improve the placement of producing wellbores. – Sensor supplier

Any type of wired system would work best with coil rather than jointed pipe. And any type of underbalanced drilling project leans toward coil, not jointed. - Independent producer

We drilled with coil near Farmington and the unit drilled so fast that the shale shaker could not keep up. ROP was not an issue. And we used 2.5" coiled tubing, which is real stiff under pressure. – Large producer

Cable systems are much better for data capture. – Service company

We did tests with electric motors years ago. XL has a totally different concept. – Service company

It sounds like technology for shallow development drilling exists, but what we need is demonstrated successes. So, what are the enhancements we need? The barriers look like learning curves, economics, and demonstration projects. – Facilitator

Data transmission through cable hits a limit at 16,000' – Service company

Is 1" way too small? Shouldn't we do a nodal analysis to determine optimum hole size? It depends on a lot of factors that are reservoir specific. – University

A 2-3/8" hole does fine. - Independent producer

Are hydraulics a problem in shallow holes? No, not less than 5000'. There is not a consensus about this, but this is less of a concern. But it should be evaluated. Hole size and tubing size all must be considered. The hydraulics must match. – Service company

For sucker rod pumps and plunger lift, 1-1/4" is about the smallest practical size for current industry use. I suspect there is very little demand for smaller pumps. I've heard that somebody has a 7/8" rod pump. - Independent producer

If you go with a microhole, you have to be prepared to deal with production problems down the road. Scale, paraffin. - Independent producer

If a well wasn't drilled right next door to our well into the same reservoir, a new technology doesn't count. - Independent producer

In deep, exploration tails, power, pressure and temperature are all critical issues to work through. We could be extending a new hole that found nothing or you could extend an existing well. – Large independent

In a 6" hole, 175 degrees C is okay, but in a 2-3/4" hole, 150 degrees C begins to be a problem because you can't use flasks and other techniques. – Sensor supplier

In deep applications, reliability becomes more of an issue than cost. And integrity. What is the risk of losing a system in the hole? – Large independent

The DOE wants fields where data is vast and where reservoir characterization is possible. Otherwise how can be determine if a technology succeeded or not? – DOE

The service company executing the project must be willing to fully support it with the best people. - Independent producer

We have worked with GRI/GTI for a long time. When we work in a consortium, it must have further economic benefit to us that is easily definable. We are picky about releasing our private data, especially in exploration areas. This is too sensitive to share. Producing areas in secure lease areas are much easier to do. – Large producer

If there is a big enough market, irrespective of location, service companies will invest in new technologies. – Service company

We need to define the market. We need to find out who the customer is, who will pay us to develop this. The LANL report shows need for several technologies to develop or be improved, but who will build new small bits and motors to replace the ones people don't like now? – Engineering company

We can drill a 4-3/4" hole cheaper than a 2-3/8" well. I can't imagine why you left out 4-3/4". The infrastructure is already there for 4-3/4". The industry now needs an instrumented mud motor. Now the mud motor fails way too often. In the mining industry Amoco would core all the way down. Why drill a hole that can't be produced? The minimum producible well is 4-3/4", Amoco says. What is practicable versus feasible? For production we need to focus on 4-3/4", whether it is in Alaska or coalbed methane. – Service company

Let's find a place where this would work. Let that operator sponsor a test. – Service company

Slimhole has been talked about for 10 years. What has slowed it? Green River had problems with 4-3/4" motors, bits had short lives. Small motors failed and little bits don't work long. And small motors didn't drill very fast. Since then, DOE and Terratek have done good work with hammer drilling in overbalanced wells. – Service company

Is it possible that CBM fields have low production rates and might need a cheap way to drill a lot of cheap small wells to produce low volumes? A log of beds are 1' thick. In Alaska fields are remote, so they can only be developed if microhole technology can be developed. Conventional rigs can't be moved in. – Service company

I see two issues: How to significantly lower the cost of producing oil and gas, or here is a neat new technology – what can it be used for? – Service company

What kind of information can we get that E&P guys can use? – Sensor manufacturer

What would I like to do cheaper than I do now? Offshore exploration, at a cost of half of current cost. Measuring points in reservoirs, to drill quick and cheap. Or drill shallow infill wells in fields that have not been sufficiently swept. – Independent producer

CBM in the Power River basin to 500' – drilling is cheap, so drilling with microhole technology too shallow may not be an application for MHT. Besides, CBM needs a bigger wellbore to pull water out. But maybe you have a conventional diameter primary producer in the middle with MHT around the perimeter to get drilling costs down. – Independent producer.

We need a new market to support MHT investment. It can't just cannibalize from existing market by doing it cheaper, because it would have to write off the existing equipment. – Sensor manufacturer.

That is why we need to find another industry that has developed this and transfer that technology to us. – Technology manager

I have great concerns about the amount of technology that needs to be developed. Even if 80% of the technology can be developed, if 20% can't be developed, then the money for the R&D is wasted. – Service company

Let's think about where we could go that we don't go now. CBM in Alaska, for example. 5000' limitation is okay. And up there technology changes are needed – smaller rigs to field the system that has been envisioned by Los Alamos. And Alaska exploratory wells. Remote locations. Current rigs for slim hole drilling are still too big. – Service company

In California we tried drilling with coil. 1" was too small. 1-1/4" or 1-1/2" may be feasible with a hole size of 2-1/4" – Tubing manufacturer

In order to get a lower cost, we need to have memory logging while drilling, so we can drill in 12 hours and pull out of the hole and plug. The smallest tools are 2-3/4" now. And they must have a solid drilling fluid. – Service company

With real time acquisition of data, a 1" tool can't get there yet. We need a bigger tool, maybe 2-1/2" is more likely feasible. – Service company

Remote/sensitive location wells or wells you can only get into in seasonal situations. Exploratory holes. – Service company

For reservoir monitoring or subsurface monitoring at the South Pole. A permanent sensor, a hot wireline. It needs to be super reliable, so it needs a different design, different parameters. I think 1" diameter tools are feasible and cheap. – Government

We're still going to need formation isolation – cementing – and perforating. – Service company

My idea is to put the sensors and motors in one place. You drill a 2-1/2" to 3" hole and then cement the whole unit in place. Leave it in the hole. It is a disposable motor. – Coiled tubing manufacturer

For new exploration wells, a 2-1/2" hole sizes means a 1-1/2" coil size. The motors are there, but the memory tools are questionable. – Sensor manufacturer

The state of the art in the 2-1/2" hole market: The small motors are service motors, not drilling motors, so they won't last long. – Service company

I don't think operators could save on infrastructure on smaller hole sizes using conventional slimhole drilling, so the savings are marginal. With coiled tubing the operator could realize infrastructure savings. – Government

I think we need good lithology information in a small diameter hole. We need to protect water sensitive, lost circulation, etc. That one is hard to control with this size rig. If we don't have good lithology, the coiled tubing unit won't work well. If we start with a CT rig in 3-3/4" range and then worked down in size as experience is gained, that is what we ought to do. – Coiled tubing service company

A 2-3/8" coiled tubing unit can go to 8000' through 4-1/2" production tubing and it can drill underbalanced. For a production well, you can get a frac job done. – Coiled tubing service company

For horizontal drilling with coiled tubing, I'm not sure if steering is affordable. If steering for horizontal CT were developed, it would take off. – Coiled tubing service company

A 4-3/4" hole with 2-38" coiled tubing is easy to do. I love it. – Coiled tubing service company

Most Canadian coiled tubing drilling is 2-7/8" tubing in a 6-3/4" hole. But the reels are too big beyond this point. They can't be roaded. But if you put on a smaller reel, the coiled tubing life is too short.

I want to try to expand the market and then lower the cost. This is a new value, it is information about the reservoir. We need geophones, temperature profiles, pressure profiles, etc., to be able to manage the reservoir better. – Sensor manufacturer

Titanium tubing is real – it is half the weight and 10 times the cost. – Coiled tubing manufacturer

An operator will drill a monitoring hole at "X" cost. We need to know what "X" equals. – Engineering company

I think there is a general consensus that the critical technologies that are in the Los Alamos report are the ones to be addressed. And there is general consensus of the 5000' depth limitation. – facilitator

Cuttings transport is a huge problem for coiled tubing drilling. The effective circulating density stinks. The closer the hole size is to the coil size, the worse the problems get. It doesn't take much to get stuck with coiled tubing. You don't have much pull capacity with coil before the material will yield. The fundamental problem with 1" is, how could you transport anything in the inside? – Service company

This microhole technology counters the push by majors for 9-5/8" casing down to TD. The "bigger straw" for international wells. – Service company

For any service to be commercial and profitable for us, we must have utilization of equipment of >60%. It must be out of the yard more than 20 days a month. That is why most of our equipment is supersized – it improves its usefulness and therefore its utilization. – Service company

Expandable coiled tubing is possible and would help our completion goal. The smallest expandable now is 2-3/8" because of hoop stress. There are also problems being able to expand with pressure on the ball. Not much will stretch and keep threaded. – Coiled tubing supplier

Fishing with coil is a problem. Solids build up and you can't rotate. – Service company

ID flash cutting is possible in 1½ tubing, but you end up with weld beads to deal with. Laser welding can avoid the flash problem, but it costs tremendously more. – Coiled tubing supplier

Canadian wells are being drilled with 2-7/8" tubing and Alaska's wells are drilled with 2-3/8". – Coiled tubing supplier

Most work strings are getting larger, compared with conventional well size growth. 3-4" is the sweet spot for coiled tubing because of the hydraulics going down and coming up. – Service company.

Coiled tubing loses its roundness when it is spooled. It becomes oval. Ovality is an indicator of near failure. – Coiled tubing supplier

I don't see the advantage of 1" coiled tubing. – Service company

The system needs to be engineered so wells are punched in one day. Rig mobilization should be improved. We could use a fit for purpose rig to cut mob time. – Service company

Coiled tubing is a lot more expensive than standard casing. CT is $3000/ton and standard OCTG is $600/ton. – Service company

I think we should start with a 4-3/4" hole and move slowing to microhole. – Service company

It will take a DOE-type entity to bring the technology from Alaska down to the lower –48 and prove it up.

How deep can you see with a 5000' hole for VSP? 20,000', because the signal is cleaner. Therefore you can monitor a deep reservoir with a shallow hole.

What we did not hear that might be critical is, "One only uses coiled tubing when there is no other way to do the job!" Of course that statement must be interpreted especially since we heard they are drilling wells with coiled tubing. The context of my quote is when we have proposed solutions to drilling problems using coiled tubing. For example, when we proposed and drilled slim-hole exploration wells, coiled tubing always lost out to core rig drilling with small tricone bits. My (point is,) one would have to be planning a lot of wells in a short period of time for this paradigm to change. – National Laboratory

Reduced costs for subsurface access will open up a whole new means and industry for reservoir monitoring and characterization. It could have the impact that 3-D seismic has had and be the catalyst for the next generation of subsurface imaging. On the technical side, one of the greatest obstacles to extracting more oil and gas out of the ground is how one scales information from the core/well log scale to the reservoir scale. I firmly believe that if one can achieve cheap access to the subsurface, quantum leaps in understanding scaling issues can be made and we will be a long way towards achieving the long elusive goal of maximum oil and gas recovery, and that would have great impact for years to come! – National Lab

The obvious first need is to demonstrate such holes can be drilled, first vertical, then deviated and horizontal. Once this is demonstrated there will be a stampede to develop complementary technology, this includes completion technology for open and instrumented holes. Get the independents involved now. Show them that, in the long run, this will be to their advantage. When I say independents I mean commercial vendors as well as oil and gas producers. The Schlumbergers, Halliburtons etc., will not jump in until they see that they can replace their cash flow with this technology. Do not get discouraged if they are cool at first - that is a good sign!! They have no incentive to develop a technology that will replace them. Any thing new makes them nervous. You may get lucky (with the larger service companies), but it may be the smaller guys who make this go at first. – National Lab

It's more than cost reduction holding this back. There are "glass Ceiling" technical issues to face. There are many reasons that coiled tubing drilling has not taken off. There are very little alternatives available if you get in trouble with CTD. – Coiled tubing supplier

Building something for a non-existing market is very dangerous. – Major service company

What can we do to encourage the E&P companies to find and produce more oil? Lower their costs dramatically. – Coiled tubing service company