Everything rises because of the heat in geothermal wells, therefore rigs need to be taller, said ThermaSource executive VP of operations Jim Hanson. Substructures on geothermal rigs are normally 22 ft to 30 ft tall.

GEOTHERMAL DRILLING MARKET HEATS UP

By Linda Hsieh, assistant managing editor

AS OIL PRICES reach unheard-of highs in the $140/bbl range, energy sources that have historically been considered too expensive to produce economically are getting new leases on life. Many such energy sources, like wind and solar, tend to reside far outside the realm of the oil and gas drilling industry. Geothermal energy, however, stands as one resource that holds potential opportunities for drilling contractors, especially as that industry continues to undergo a significant expansion.

Geothermal produces energy off of heated fluids that reside deep inside the Earth. Just as wells must be drilled to reach oil or natural gas, geothermal wells must be drilled to reach heated fluids. As it turns out, the rigs and equipment required to drill geothermal wells are nearly identical to what the oil and gas drilling industry uses.

California-based **ThermaSource** is one the largest geothermal-focused drilling contracting companies in the United States. It was founded in 1980, but for nearly three decades remained strictly an engineering and consulting firm. In 2006, as geothermal drilling amped up and drilling rigs became increasingly hard to find, ThermaSource decided to go into the rig-owning business, starting with one refurbished rig it bought from the oil/gas drilling market.

Since then, growth for the company has been tremendous, said **Jim Hanson**, ThermaSource executive vice president of operations. The company went from just three employees in 2006 to more than 235 employees in 2008. It also went from one rig to eight – plus two more on order as of August 2008. It also operates two other rigs not owned by ThermaSource.

This year, the company is even starting three service companies – **ThermaSource Cementing**, mud company **ChemTech** and a yet-to-be-finalized mud logging company, Mr Hanson said. All will focus on geothermal operations.

Geothermal drilling also is expanding rapidly geographically, he said. Within the United States, most operations so far have been concentrated in the West, mostly in California and Nevada. Now, ThermaSource is getting ready to move rigs into Utah and Idaho and plans to do drilling in Oregon and Washington in 2009. Outside the US, the company is drilling on the Caribbean island of Nevis and looking at potential projects in Australia, New Zealand, the Philippines, Panama, Chile and Peru. These are mostly new drilling projects, Mr Hanson said, and each would entail new drilling crews and another rig mobilization.

A survey released in August 2008 by the Geothermal Energy Association (GEA) confirms that geothermal is indeed becoming a high-growth, high-demand market. The GEA survey showed continued growth in the number of new geothermal power projects under development, with a total of 103 developing projects identified.

GEOTHERMAL RIGS

At the rate that geothermal operators are signing up drilling rigs, it appears unlikely that ThermaSource's units will run out of work anytime soon. Still, if that were to happen, the company can certainly shift markets relatively easily. For the most part, Mr Hanson explained, geothermal drilling rigs are just like oil/gas drilling rigs. In fact, all of his rigs could go to work on oil/gas drilling projects without any modifications, he said.

Probably the biggest difference between geothermal rig and oil/gas rigs is the height of the substructure required. Everything rises because of the heat in geothermal wells, therefore rigs need to be taller, even for drilling 7,000-ft to 11,000-ft wells. Substructures on geothermal rigs are normally 22 ft to 30 ft tall, he said.

The extra height required from rig floor to the ground often means a larger footprint for geothermal rigs, but Mr Hanson noted that ThermaSource has been working to make its rigs and operations as compact as possible. Its newest rig, a Thermal Single rig, was just delivered by **MD Cowan** in July 2008 and can move in 16 loads compared with 28 loads on older rigs.

ThermaSource has been working to make its rigs and operations as compact as possible and says it would like to be able to get in a 200-ft-by-300-ft location and still do multiple wells.

ThermaSource's 12,000-ft NCPA Rig 1 (left) is working in California, and its 9,000-ft Rig 101 (above) is working in Nevada. Though those two states traditionally encompass the bulk of geothermal drilling in the United States, new projects in other states have been identified that may soon start up. These include work in Utah, Idaho, Oregon, Washington and others. A recent survey by the Geothermal Energy Association cited 103 developing projects under way in the US.

"We'd like to be able to get in a 200-ft-by-300-ft location and still do multiple wells," he said.

Skidding is also a critical capability because most pads in geothermal drilling are multi-well, usually from three to six wells per pad. A skiddable rig can move from one well to the next in about three days, he said. Rigs that can't skid would require 7-10 days between wells at $200,000 to $300,000 per rig move.

"Our rigs also have an additional 175-200 ft of extra electric cabling and lines for pumps, bits and fluid lines that help us to skid," Mr Hanson added.

Additionally, due to environmental regulations in place in many of the locations where geothermal drilling is done, attention must be paid to the type of engines used on the rig. An air quality act in California, for example, dictates that all engines are late-Tier II's or Tier III's, "so a lot of the rigs that can operate in Oklahoma or Texas can't operate in California," he said.

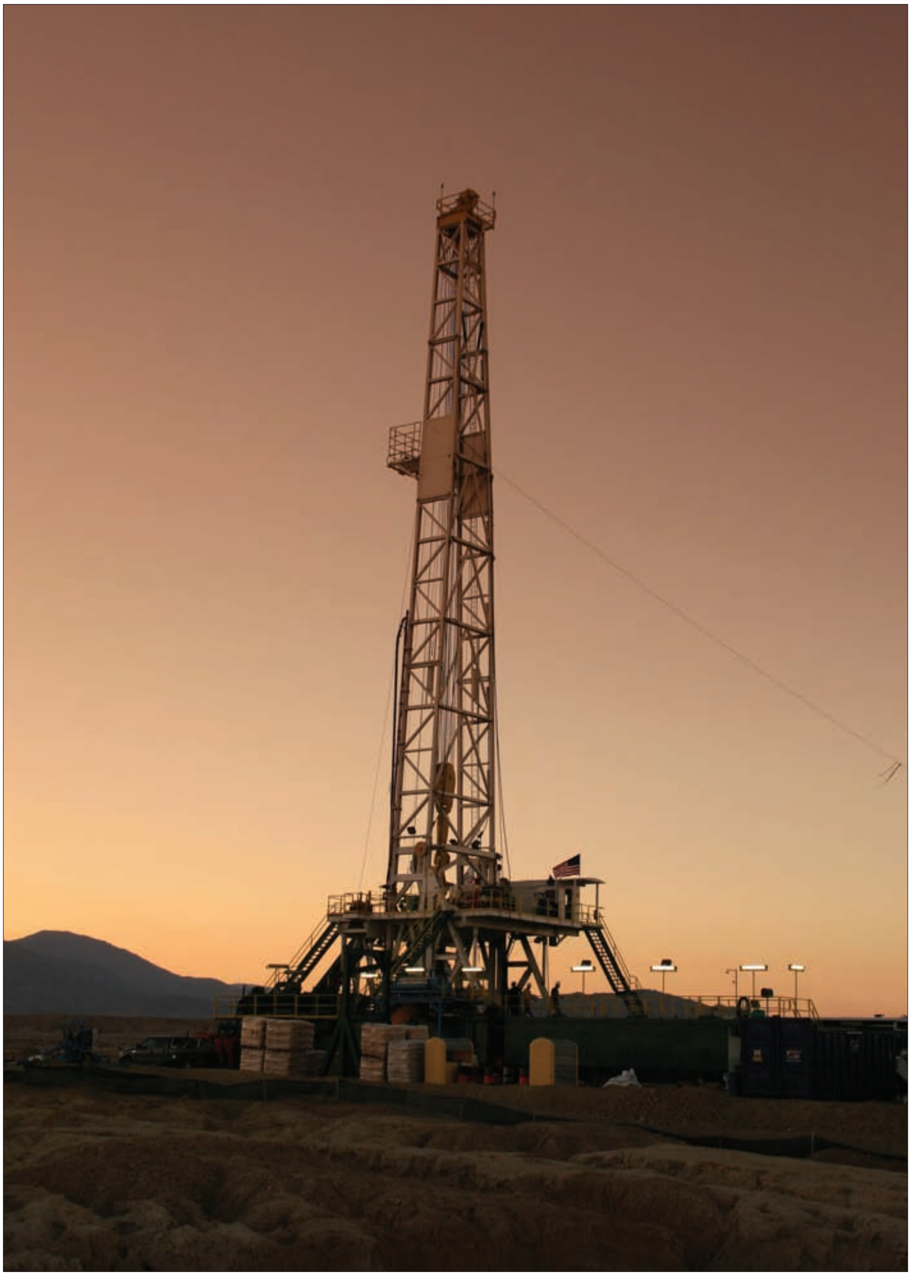
Pumps and mud capacity is another consideration for geothermal because drilling is usually switched from mud to air (or aerated fluids) in production zones. The geothermal resource is located in fractures in the reservoir, he explained, so drilling with mud can plug off the wellbore. If that happens, none of the sought-after geothermal fluid or steam may ever come up the wellbore.

In contrast, air is lighter and won't plug the fractures. As it flows up the well, it can even clean the upper fractures and increase production, Mr Hanson said.

NEW RIGS

Except for the very first rig ThermaSource bought in 2006, all other rigs in its fleet were built brand-new. The newest addition, Rig 105, is a Thermal Single rig built by Odessa, Texas-based MD Cowan. It is a variation of the manufacturer's Super Single rig and designed specifically for geothermal drilling. It is hydraulic-powered and features a telescoping, 22-ft substructure, two-piece mast and skid-mounted drawworks. The original Super Single's pipe-handling systems, mobility and safety features and minimal footprint remain, according to MD Cowan.

Rigs in the ThermaSource fleet range from 6,000-ft to 20,000-ft capability with 450-hp to 2,000-hp drawworks. The Thermal Single will sit in the middle of the range, capable of drilling to 12,000 ft with 1,000-hp drawworks.



When drilling rigs became increasingly hard to find in 2006, ThermaSource decided to go into the rig-owning business itself. It now owns eight rigs and is building two more.

Two more Thermal Singles are being built for ThermaSource, with deliveries expected later this year. Mr Hanson added that, due to strong market demand, the company is considering ordering two or three additional Thermal Singles in Q2 2009. Cost for the new rigs are averaging $10.5 million to $11 million.

EGS

Aside from conventional geothermal drilling exemplified by contractors like ThermaSource, the next generation of geothermal is also coming into sight with what's been called enhanced geothermal systems (EGS), sometimes also called engineered geothermal systems. The US Department of Energy (DOE) believes that EGS holds significant potential for expanding the use of geothermal energy. When the DOE announced in June 2008 a funding opportunity of $90 million over four years for advanced geothermal energy technology and research, EGS was pointed out as one specific technology that the DOE would like to push to commercial market.

Current geothermal reservoirs being exploited have a naturally occurring combination of high temperatures, permeability and fluids. EGS would target locations where there is high temperature but not necessarily fluids or permeability, and would use reservoir creation techniques to create a geothermal reservoir.

"(EGS) is manipulating reservoirs to make it do what you need it to do, not unlike what the oil and gas industry does," said **Doug Blankenship**, manager of the geothermal research department at Sandia National Laboratories. Sandia has been a long-time partner with the DOE on geothermal research.

While there's no real power being produced as of yet with EGS, Mr Blankenship said, the base equipment needed to make EGS happen is already there. What is still lacking is having equipment that are more suitable for operating in extremely high temperatures. Bottomhole temperatures can vary widely in geothermal wells, but 300°C (572°F) is not unheard of.

While geothermal drillers used to face the temperature challenge alone, the advent of deep and ultra-deep drilling in the oil and gas wells in recent years has created somewhat of a synergy between the two drilling segments. "Temperature is becoming an issue for everyone, including the oil and gas people," he said. This could become a significant driver to bring about research and field work needed to develop high-temperature equipment and tools.

High-temperature electronics is clearly one aspect, with MWD/LWD systems that can withstand even higher temperatures in order to detect fractures downhole and log or monitor temperature, pressure, flow rates and seismic events in wellbores. Current batteries and packers are also problematic at high temperatures and need further work, Mr Blankenship said.

HT logging tools and sensors was one of seven critical component R&D needs for EGS identified by the DOE. Others include:

- Downhole pumps to augment flow rates by using downhole pumps to add hydraulic head at depth.
- Fracture characterization to detect and characterize rock mass fracture systems.
- Image fluid flow to image fluid in created and/or pre-existing fractures so as to map flow through the reservoir.
- Stimulation prediction models to simulate a reservoir's response to stimulation.

Geothermal drilling rigs are largely similar to oil/gas drilling rigs. They need few, if any, modifications to go from drilling geothermal to drilling for oil or gas.

• Tracers and tracer interpretation to adapt or develop reservoir tracers and/or tracer interpretation techniques that provide information such as fracture surface area or fracture spacing.

• Zonal isolation to isolate wellbore zones in HPHT environments.

THE ECONOMICS OF IT

Theoretically, successful EGS would mean that geothermal energy can be tapped anywhere in the world. The emphasis is on "theoretically."

"But then you enter into issues of practicality," Mr Blankenship said. "Clearly, if you drill deep enough, you can tap geothermal energy – remember that the center of the Earth is about the same temperature as the surface of the sun. But it has to be economically feasible, and that's where a lot of the work is going."

Speaking of being economically feasible, Mr Blankenship believes that average geothermal well costs have decreased as drilling efficiency improved with a combination of more experience and technology advances. In comparison with oil and gas wells, too, geothermal costs have gone down, he said.

Still, cost per well is undoubtedly still higher for geothermal than for oil/gas. ThermaSource's Mr Hanson pointed out that in geothermal, larger wells must be drilled for production – often 8 ½ in. or 10 ¾ in. The bigger wellbores are needed in order to achieve high flow rates, which, in turn, are needed to make geothermal wells economical.

The high mass flow needed for geothermal wells also means that they are often produced through casing rather than tubing, Mr Blankenship added. And because downhole environments are sometimes highly corrosive because of high H_2S levels, expensive titanium casing materials may be needed, again driving up the cost per well.

Another potential financial disadvantage of geothermal hits operators specifically – they must wait longer for a return on investment. There are no profits from a geothermal well until it is hooked up to a power plant and actually making power, and that could be one to two years from the drilling of the well.

But once the well is tied to a power plant, Mr Hanson said, it runs 24/7 and, barring a collapse of casing, will run for the life of the power plant. Moreover, the geothermal energy itself can power the plant, eliminating any need for outside fuel.

To add to the economic viability of geothermal, the US government implemented a permanent investment tax credit in the early '90s and a production tax credit around 2005. A significant number of venture capitalists have found their way to the "green" industry in the last few years, Mr Hanson said, which should help to boost the geothermal drilling industry even further.

The US is already a leader in geothermal, with about 30% of the world total online geothermal capacity. According to the GEA, the US has a total installed capacity of 2,957.94 MW as of August 2008, with power generation occurring in seven states – Alaska, California, Hawaii, Nevada, New Mexico, Utah and Idaho. Oregon and Wyoming may soon be added to that list.

"There's nothing preventing us from drilling geothermal wells today other than cost, but we must drive down cost and improve the tools available for people developing geothermal," said Sandia's Mr Blankenship. "There are going to be a lot of opportunities in the future for drilling contractors."