CUTTING-EDGE OIL RECOVERY

Oil-recovery technologies are enjoying a fresh look from many operators.

ARTICLE BY
PEGGY WILLIAMS

Excerpted from

Oil and Gas Investor

December 2005

4545 Post Oak Place
Suite 210
Houston, TX 77027
(713) 993-9320

Popularity is surging for all sorts of oil-recovery projects, due to today's robust commodity prices. While much attention currently swirls around thermal projects in Canada's heavy oil sands, and miscible CO_2 floods in various mature U.S. oil fields, other oil-recovery technologies are also benefiting from a fresh look. Some have long histories and are now being rejuvenated, while some are new or are being applied in different areas.

Chemical romance

Chemical-recovery processes have been around for decades, but have not been heavily used in North America. Of daily production of 660,000 barrels of oil from enhanced oil-recovery (EOR) projects in the United States, chemical projects contribute minimal barrels at present.

That's likely to change, however. Chemical projects have proven effective in several major fields around the globe, most particularly in China. Now, proponents of these methods are working on a variety of projects in the U.S., where abundant declining oil fields offer fertile ground.

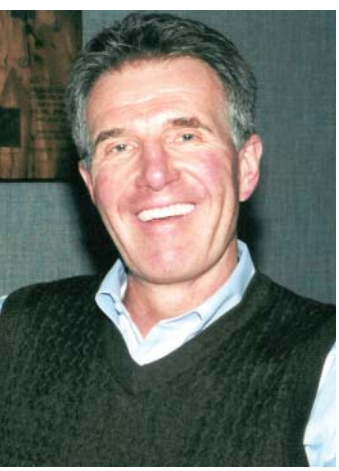
Englewood, Colorado-based Tiorco Inc. has been involved in the design and application of polymer-gel treatments since 1977. "During the past year, we have seen a lot more interest in chemical technologies to improve oil recovery," says Jim C. Mack, president of the private firm. Every week, Tiorco has been fielding more inquiries from operators who are looking at the total reservoir picture and how they can recover more oil out of the entire reservoir.

The surging interest is not from any breakthrough change in the technology, but rather stems from a growth in knowledge and experience with polymers, he says.

Tiorco's main focus is on the application of polymer-gel technology for sweep improvement in waterfloods. "The gels allow water to contact more of the rock and sweep more of the oil out."

Most of the company's work involves finding ways to improve or revive existing waterfloods. Some waterfloods are being launched, but new projects are quite limited, says Mack. "There hasn't been much drilling for oil in the U.S. during the last 10 to 15 years, so oil fields just haven't been found. Today, our business is in waterfloods that are very mature."

In addition, the company has built an extremely popular sideline in the use of polymer gels to reduce water volumes in producing wells. The gel treatments can make wells more economical to produce, and can also ex-



Jim C. Mack, president of Englewood, Colorado-based Tiorco Inc. says polymer-gel treatments are growing in popularity throughout the world. Right, a Tiorco unit treats a well in Argentina.

"Interest in chemical flooding is worldwide, and it is very high."
Harry Surkalo, Surtek Inc.

tend the well lives and the volume of reserves.

Tiorco pioneered the use of Marathon's trademarked-service Marcit polymer-gel treatment in the Arbuckle formation in Kansas. The process reduces water production and significantly improves oil rates by allowing greater drawdown on the producing wells.

Tiorco's clients are mainly mid- to small-size independents, and the treatments are usually performed on existing producers. Over time, the oil rates decline and water production begins to rise. Recently, Tiorco clients have treated a number of wells for a second time with the polymer gels. "Responses to these treatments are very encouraging. We've only done a few so far, but we're optimistic," Mack says.

The success has spawned drilling activity, because now that operators know the gel technology will reduce water production, they are becoming more aggressive with their drilling programs. Additionally, operators are sufficiently confident in their ability to reduce water that they are drilling deeper into the Arbuckle section.

Although the Arbuckle has been the highest-profile success story for chemical production treatments, work is ongoing in the Permian Basin in the Ellenburger formation, and in the Big Horn Basin in the Phosphoria and Tensleep formations.

"There's certainly a lot of opportunity for this technology today," says Mack.

An operator's perspective

Denver-based Whiting Petroleum Corp.'s experiences with polymer-gel treatments in Wyoming's Big Horn Basin have been positive.

"We're using the Marcit technology on producing wells. The polymer plugs off the fractures, which plugs off the water, and allows the matrix to produce more oil," says Jim Brown, vice president of operations.

Whiting acquired its Big Horn properties in July 2004 when it acquired Equity Oil; Equity had launched the polymer-gel program and Whiting has carried it forward. During the summer of 2004, it performed four treatments, and added two treatments this past summer.

A total of 18 wells have been injected with polymer gels to date, mainly in Torchlight Field in Big Horn County. Torchlight, discovered in the 1940s, produces from the Mississippian Madison, a fractured carbonate at a depth of 3,700 feet.

The first well Whiting treated this year was producing one barrel of oil and 900 barrels of water per day. The fluid level was 842 feet from the surface. "We had a very high fluid level, and a small pumping unit on the well," says Tom Smith, engineer. Whiting could have installed a high-capacity submersible pump, with an accompanying electrical cost of around $6,000 per month.

Instead, it opted to try to shut off the water production and continue to pump the well with the existing beam pump. The polymer treatment, supplied by Tiorco, was spectacularly successful: water production was reduced to 40 barrels per day, and oil production rose to 9.4 barrels per day.

"I've done these treatments for years, and I've never seen a producing well respond like this. It worked very well," says Smith.

Whiting's second treatment was performed on a nearby well that had been shut in. The company reactivated the well and tested it with a submersible pump at the rate of 15 barrels of oil and 5,000 barrels of water per day. The fluid level was 1,475 feet from surface.

The chemical treatment reduced water production to 936 barrels per day, and oil jumped to 23 barrels per day. And, Whiting was able to install a beam unit on the well. "We're moving much less water and more oil per day, and we're saving a lot of money on electricity," Smith says.

The company figures the cost of a polymer-gel treatment, including chemicals and associated rig costs, tubing and pumps, at about $60,000. A job can pay out in four to six months, depending on prevailing oil prices.

"We have budgeted three or four additional treatments for 2006, and we may do one or two more before the end of this year," says Brown. "The Marcit treatment preferentially shuts off water-bearing fractures without hurting matrix bleed-in, and no other method attacks this problem as effectively."

Obviously, nothing in the oil patch is a panacea. Whiting has attempted the technology in other places, but without as much success as it's had in the Big Horn Basin, he says. "We suspect that's due to higher reservoir temperatures—our experience is that there is an upper temperature limitation of about 200˚ Fahrenheit." Within the proper temperature window, Whiting considers fractured, water-drive reservoirs and waterflooded reservoirs with conformance issues to be good candidates for the process.

ASP process

Enthusiasm is building in another area of chemical recovery, the alkaline-surfactant-polymer (ASP) process. Surtek Inc., a Golden, Colorado-based firm headed by Harry Surkalo, developed the ASP chemical-recovery method. The company provides laboratory analysis, reservoir engineering, geological studies, and project planning and design for chemical flooding.

"Interest in chemical flooding is worldwide, and it is very high," says Surkalo.

Surtek developed the process in the early 1980s as an alternative to micellar polymer technology. "We wanted to lower chemical costs and still have good oil-displacement characteristics to the slug."

The ingredients of an ASP flood mobilize oil and improve its flow in reservoirs. The alkalis,

surfactants and polymers have specific functions that work synergistically.

Popularity of the process, like many other EOR technologies, suffered greatly in oil-price swings of the past two decades. However, ASP has been successfully used in several Minnelusa oil fields in Wyoming's Powder River Basin.

"The West Kiehl and Cambridge field projects have been commercially successful and papers have been published on the results; a few other projects have not been written up but are also successful," says Surkalo. Additionally, Husky Energy has a large project in Etzikom Field in Alberta that is a success.

"ASP is in its infancy in the U.S. Any field that has been waterflooded successfully may be technically suitable for ASP technology," he says.

The technology might be simple in concept, however, it is very complicated in design and application. The chemistry of the rock, and its reaction to chemicals that are injected, are the keys.

If an operator interested in ASP starts with a field with a reasonably good waterflood history, the laboratory work to design a chemical system takes about six months, he says. Surtek works with oil and water from the reservoir, injection water and reservoir rock. The interplay between these materials and chemicals is intricate, and requires both patience and high-level skills to assess accurately.

Once the formula is set, chemicals can be added to the waterflood. It's not necessary for the field to have already been under waterflood; an ASP project can be started immediately as a secondary-recovery procedure. In these cases, operators can recover much more oil in a shorter period of time. That was the situation with both West Kiehl and Cambridge fields, which went directly from primary to ASP waterfloods.

Naturally, not every field is a good candidate. Sometimes, a proper mixture just can't be designed to achieve good displacement in the reservoir rock. For those fields with amenable chemistry, an additional 15% to 30% of the orig-

CONVERSION TECHNOLOGY

Vancouver-based Ivanhoe Energy Inc. operates a 1,000-barrel-a-day demonstration plant in Aera Energy LLC's South Belridge Field in Kern County, California. The plant is using the rapid thermal process (RTP), an exciting proprietary technology, to convert heavy oil into light oil very quickly.

"RTP is a unique process," says David Martin, chairman of Ivanhoe. "Basically it's a flowing sandbed, in which sand circulates in a loop through a tower and back to a reheater. The heavy ends of the barrel are converted to lighter products and carbon is rejected as coke in a very thin film on the sand grains. When the coke-covered sand circulates through the reheater, the coke is totally consumed and releases a significant amount of excess energy."

Ivanhoe acquired the technology when it purchased private firm Ensyn Group Inc. earlier this year. The idea came out of the field of biomass conversion, but Ivanhoe saw tremendous potential in the petroleum industry.

The technology does not require an outside fuel source, as its byproducts of coke and gas are used for on-site energy. The feedstock can be raised about 10° in API gravity, and viscosity is substantially reduced. Commercial-scale plants are expected to be in the range of 15,000 to 20,000 barrels per day, making them much smaller than the gigantic upgraders used on most heavy-oil projects today.

"Our capital costs and operating costs are substantially less than in traditional upgraders," says Martin. The RTP process does not require natural gas; the product does not have to be mixed with diluent; and there is no disposal of waste coke.

"Our objective is to partner with major heavy-oil operators in joint ventures, to tie the plant and its ability to upgrade crude, produce energy and reduce environmental problems, as an integral part of the field development."

Vancouver-based Ivanhoe Energy Inc.'s demonstration plant in South Belridge Field, Kern County, California, can convert heavy oil to light oil at the rate of 1,000 barrels per day.

Cano Petroleum Inc. recently acquired Desdemona Field, in Erath, Eastland and Comanche counties, Texas, says Jeff Johnson, chief executive officer. The company plans to rejuvenate the old field, above, through water- and chemical-flood processes.

inal oil in place can be recovered, says Surkalo.

"But, I can't emphasize enough that if a company doesn't do proper design on a project, it will fail." And, the operator must carefully and prudently implement the design to ensure an auspicious outcome.

"Oil prices have obviously changed the economics of everything in the oil field, and we are seeing a tremendous amount of interest in ASP technology."

A field success

The Dakota Gas Co., located in Spearfish, South Dakota, started investigating the possibilities of chemical flooding a few years ago.

Privately held Dakota acquired Thompson Creek Unit in Crook County, Wyoming, in 1998. The field's 13 producing wells were making 55 barrels of oil a day from a Muddy sand at about 1,700 feet. The high-quality reservoir sand had porosities of 25% to 30% and permeabilities of up to 1.5 Darcies, but less than 4% of the original oil in place had been produced. The poor primary recovery was due to low reservoir pressure of about 230 pounds, and viscous, 20-degree-gravity oil.

"We bought the field with the idea of waterflooding," says Ted Williams, president. "But the more we studied it, the more we realized that it would take a lot of water and a lot of time to accomplish what we wanted."

Williams started researching chemical flooding, and soon hooked up with Surtek. During the following year, Surtek designed an alkaline-polymer fluid, performed linear and radial core floods to confirm injection characteristics and efficiencies of the sweep, and conducted a reservoir simulation.

"All the news was encouraging." Too, Dakota's field was about 15 miles north of Cambridge Field, a marquee ASP flood that recovered nearly 70% of the original oil in place in less than 10 years. "Our objectives are not quite that high, but we hope to recover 35% to 40% of the original oil in place," he says.

During 2003, Dakota drilled 40 new wells, including 20 injection wells, and installed a polymer injection plant for a 720-acre flood. It began injecting alkaline and polymer fluid in March 2004. (Surtek's studies indicated that a surfactant was not necessary.)

Production has jumped from 70 to 535 barrels of oil a day at present. "The rate is still building, and has every month since we started the flood."

Dakota is currently injecting about 1,500 barrels of alkaline water and polymer and producing 160 barrels of water per day. Over the life of the chemical flood, it expects to inject about 25 million barrels of fluid; a waterflood would have taken nearly three times as much water and recovered half as much oil.

A few operational problems have been successfully solved. "It took us about three months to get the bugs worked out of the plant," he says. The fluid must be kept within tight quality specifications, and Dakota regulates the polymer and alkaline additives down to parts per million. Make-up water is also softened to close specifications. "The plant was complicated for us initially, but it works well and doesn't seem so complicated now."

Another feature of a polymer flood that was new to Dakota was the change in injection pump requirements. Because polymer molecules are fairly fragile and cannot be sheared, to limit flow rates to individual injection wells polymer floods require a separate pump for each injector.

"So far, the chemical flood has been very effective and is working quite closely to the projections made by Surtek," says Williams. "We are optimistic about the project."

EOR business model

Among companies that have staked a future on pulling leftover oil from mature fields is Cano Petroleum Inc. The Fort Worth-based firm acquires properties that are at the end of their primary production cycle, and are amenable to secondary and tertiary recovery techniques. Cano specifically hunts for fields that are too small and too aged to attract much notice from large industry players.

"At the end of the day, we are buying assets that have a very high probable-to-proved reserve ratio," says Jeff Johnson, chief executive officer. At present, Cano owns five properties containing 5.5 million barrels of proved and 42 million barrels of probable reserves for which it has paid a total of $12 million.

The company plans to move its probable reserves into the proved category through waterflood and ASP projects. Cano estimates the recovery efficiencies of its ASP floods will be around 17% of original oil in place.

The time is right for a dramatic leap for ASP technology, the company believes. The economic floor for an ASP project is a commodity price of $25 per barrel, and Cano is confident that oil prices will stay well north of $30 per barrel.

At present, the costs per incremental barrel in an ASP project are estimated at $2 to $8, and that's on top of typical lifting costs of $15 to $20 per barrel. "A key for this process is lowering the cost of incremental barrels by growing the volumes," says Johnson. "As we develop it and move it into the space of the smaller independents, the technology will only get better and cheaper."

A shallow field with a clean sandstone reservoir filled with light oil makes an ideal ASP candidate, the company says. It has acquired several target properties in Oklahoma and Texas.

Its Nowata Field, in Nowata County, Oklahoma, is a shallow Bartlesville sand accumulation at about 650 feet. The 2,601-acre field, discovered in the early 1900s, currently has 228 producing wells and 180 injectors that are drilled on five-spot patterns on 2.5-acre spacing. Original oil in place was 58 million barrels.

Current production is about 240 barrels of oil per day, out of 77,000 barrels of fluid per day. "Our oil cut is only one-third of 1%," says Johnson. Cano plans to add a small amount of chemical to the waterflood, and expects to raise the cut to 5%. Its goal is to raise production to 4,000 barrels of oil per day.

"We have received final lab results and are preparing to execute a pilot project in the field. This will be our first surfactant-polymer flood, and we expect to be injecting by early to mid-2006."

Another Cano property is Davenport Field, in Lincoln County, Oklahoma. It was discovered in 1924 and produced about 22 million barrels of 38-degree oil from both primary and secondary recovery projects, from a Prue Sand at 3,300 feet. Davenport's original oil in place was also 58 million barrels.

The company is currently evaluating the 2,178-acre field, which produces 50 barrels of oil and 5,000 barrels of water per day, for its suitability for chemical recovery.

Cano's latest and largest acquisition is Desdemona Field, in Erath, Eastland and Comanche counties, Texas. The field lies within the Barnett Shale play, and Cano plans to market the Barnett Shale rights to another operator.

"We're going to focus on the EOR opportunity in the field," he says. That potential is heady: Desdemona has produced nearly 24 million barrels of oil on primary recovery, but has never been waterflooded. It was unitized for waterflooding, infrastructure was built and a flood was started by a previous operator, but the project was shut down in the mid-1980s after oil prices crashed.

"We have inherited a tremendous amount of infrastructure that was left behind," Johnson says. At present, Desdemona produces about 50 barrels of oil per day from the Duke sandstone at about 4,500 feet. The company has started injection into a single well, and is awaiting state permits to ramp the project up to as much as 12,000 barrels per day.

"As soon as we start to see response to the waterflood, we will start to evaluate the introduction of surfactants and polymers."

From these three assets, Cano plans to raise current production from 300 barrels of oil to almost 20,000 per day within 3.5 to four years.

"We are always continuing to look for additional opportunities as well," says Johnson.

Modified SAGD

A firm that has taken another slant on oil-recovery technologies is Vancouver-based Ivanhoe Energy Inc. The publicly held company is operating an EOR project on the eastern flank of the Powder River Basin in Weston County, Wyoming. It has partnered with Derek Oil & Gas, also of Vancouver, on the LAK Ranch project.

This is a cold oil deposit in the Lower Cretaceous Newcastle sandstone, just downdip of the outcrop of the Newcastle on the basin's edge. The oil is 19-degree-gravity but extremely viscous, making it difficult to produce.

Minor amounts of oil have been produced from the 7,500-acre property since the 1920s, and several attempts were made to apply tertiary recovery processes to the accumulation. In the 1950s, one firm injected petroleum liquids and gasoline in a solvent flood pilot; in the 1960s, a major attempted a huff-and-puff project; and in the late 1980s, an ASP project was started. These efforts were all abandoned due to various legal, economic or technical problems, however.

Now, Ivanhoe and its partner think that a variation of the Canadian in-situ steam-assisted gravity drainage (SAGD) process might work. A modified SAGD process could reduce the oil viscosity enough to allow commercial production.

Ivanhoe and Derek have two horizontal wells in the ground. Initially, the partners operated a huff-and-puff test on one well, which provided data for the design of a continuous injection program. Next, they drilled three shallow, vertical wells in a line over the horizontal producer. Ivanhoe recently started continuous steam injection into the vertical wells, and in a little more than a week saw oil production jump from 10 to 60 barrels a day.

The company is optimistic about this approach at LAK Ranch, says David Martin, chairman of Ivanhoe.

"There is a lot of oil in place, but it's in steeply dipping beds in different fault blocks. We found that because of the faulting it was hard to control the steam when we injected it into the horizontal well, and think that these shallow injectors will solve that problem."

Industry-wide, interest in cutting-edge oil-recovery technologies will continue to be strong. The best of these methods offer both the potential to increase the number of barrels that can be recovered and to reduce the costs of that recovery. M

David Martin, chairman of Ivanhoe Energy, says the company is trying a variation of the steam-assisted gravity drainage process on its LAK Ranch project in Weston County, Wyoming.