December 2010

# New Technology magazine

• the first word on oilpatch innovation

## TECHNOLOGY STARS 2010

★ Best Exploration Technology ★ Best Drilling Technology ★ Best Production Technology ★ Best HSE Technology

page 19

PUBLICATIONS MAIL AGREEMENT NO. 40069240

# in this issue

December 2010 | vol.16 | no.10


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## hail the early adopter

THE LAUNCH IN THIS ISSUE OF OUR FIRST TECHNOLOGY STARS FEATURE, produced in co-operation with sister publication *Oil & Gas Inquirer*, was a valuable learning experience in many ways. For us at JuneWarren-Nickle's Energy Group, we have gained the experience necessary to improve on and expand the awards process next year.

More importantly, we learned about many of the new and, in many cases, lesser-known techniques and technologies percolating into the industry, originating across the spectrum from major international corporations right down to essentially one-person operations, confirming once again that the spirit of innovation remains alive and well in the industry.

But we also learned that behind just about every Technology Star nominee worth considering was an often unsung user willing to stick his or her neck out to help bring the new concept to reality — something whose importance can hardly be overstated.

It is a commonly heard refrain among those attempting to break into the industry with a new and improved tool or concept that producers in Canada are extremely conservative when it comes to testing new technologies. Some say oil company executives are too busy to be bothered to even let them in the door and hear them out, or that many decision-makers seem to have the impression that if a new process did not originate from within, it must not be very good.

Or, in many cases, they would rather let a competitor trial the latest technique, safely sitting on the sidelines until there is irrefutable evidence it works before jumping on the bandwagon. It is the easier path, after all, to stick to the tried and true than to put one's career or reputation on the line to promote something new and improved — but unproven. This, despite the fact that many of the advances, if and when they do pan out, could prove enormously beneficial to the company's bottom line — particularly to the early adopter, who gets a big head start on the competition.

Thus, while they may not be explicitly recognized in our feature, the early adopters ought to be acknowledged for opening the door a crack to some truly innovative ideas and taking a chance with them. One company in particular, Suncor Energy Inc., was a notable standout in this regard, featuring in no less than three of the six winning entries as the company that was willing to give new technologies a try and even to assist, as was the case with Weatherford Canada, in jointly develop a new and winning technology.

Pradeep Dass, president of Can-K Group (Best Production Technology award winner) singled out Suncor for the break it gave his startup new tech company. "Suncor's willingness to test our pumps gave us a lot of field experience in SAGD applications," he offered. "We are now ready to land ESTSP [Can-K's new pump technology] in SAGD wells."

With such openness to trying new things, then, it is perhaps not too surprising that Suncor took home an award of its own, for its TRO (tailings reduction operations) reclamation solution — a game-changing technology the judges agreed was a shoe-in for our HSE award this year.

Sometimes it is only through high-risk that companies find high-reward. There are bound to be failures along the way. But sooner or later, there will be reward. And that can go as much for those willing to give new inventions and technologies a try as it does for the inventors and innovators themselves.

## milestone

This issue also marks a milestone for New Technology Magazine as we celebrate 15 years of publishing history. The upstream oil and gas industry has witnessed enormous change over that period of time, not without a few booms and busts along the way. As we look forward today, the outlook is as bright as it has ever been in those 15 years, due to a healthy and growing oilsands sector and the emergence of unconventional gas production — both of which could not have materialized without new technologies. Needless to say, we at New Technology Magazine will continue to bring our readers the latest in technology development as the industry continues to expand and thrive in the years ahead. • **Maurice Smith**

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Toll Free 1-800-387-2446

ISSN 1480-2147

New Technology Magazine is published 10 times a year by JuneWarren-Nickle's Energy Group, a subsidiary of Glacier Media Inc., a leading Canadian information company with interests in daily and community newspapers and business-to-business information services.

junewarren-nickle's energy group

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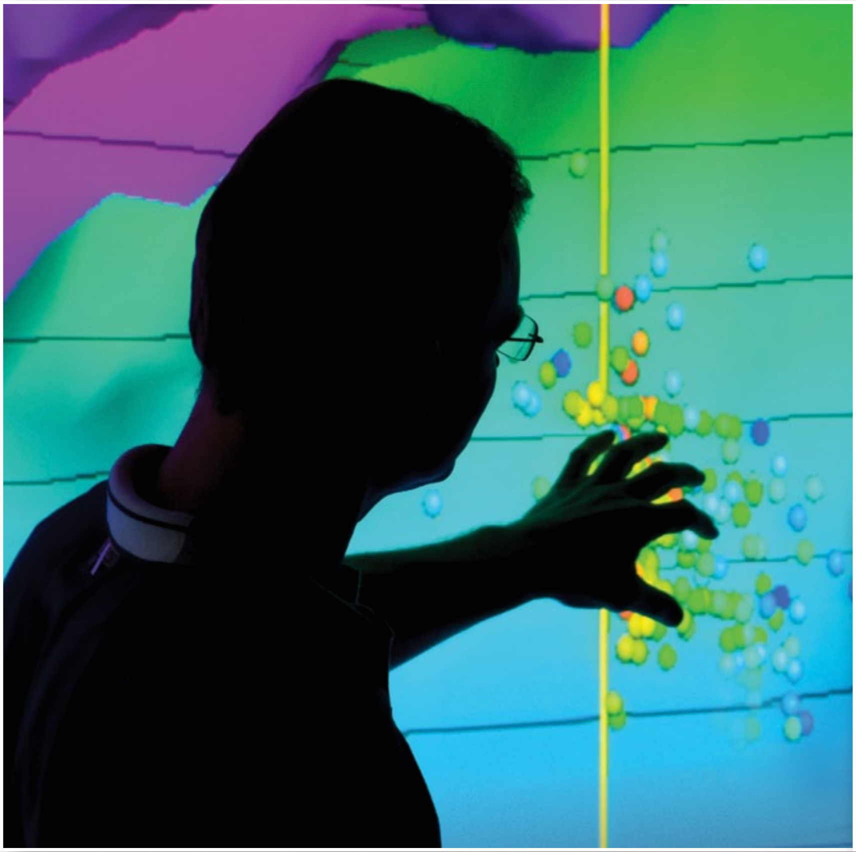



Photo: Cenovus Energy

PRODUCTION

# Gaining Ground

*As $CO_2$ EOR stalls, polymer floods ramp up*

A FEW YEARS AGO THERE WAS MUCH talk about the large-scale use of carbon dioxide to boost Alberta's oil recovery, but polymer flooding has actually made the greatest commercial inroads.

Today Alberta has two large-scale polymer floods while the province's first large-scale $CO_2$ enhanced oil recovery (EOR) project has yet to materialize.

Polymer flooding is typically used in heavy oil while $CO_2$ EOR — which has enjoyed commercial success in Saskatchewan and the United States — has generally been done in lighter crudes.

Though several producers did pilots, most plans for large-scale $CO_2$ EOR developments hit a brick wall: lack of an adequate $CO_2$ supply at an affordable price.

And while only nine polymer floods, or various combinations of alkaline surfactant polymer (ASP) injection schemes, have been approved to date in Alberta, there doesn't seem to be any significant roadblock to wider adoption of the technology, pending reservoir suitability.

Polymer's edge over $CO_2$ is its relative simplicity. It's just a matter of adding a thickening agent to injected water. Instead of building $CO_2$ pipelines, the relatively small quantities of chemicals can be trucked in.

"As you go through EOR, water is the cheapest. Then adding polymer to water is the next cheapest. And then it's a big jump to get to any sort of tertiary [recovery] — like a gas recovery process," says Bruce Peachey, an Edmonton consulting engineer and EOR advocate.

Upgrading a straight waterflood to a polymer flood involves the relatively modest capital cost of extra surface equipment and the additional operating cost of purchased chemicals. In contrast, a commercial $CO_2$ flood typically involves the significant cost and complexity of third-party $CO_2$ sources and pipelines.

So it isn't surprising that next to waterflooding, polymer flooding is gaining the most ground commercially in Alberta.

**POLYMER ASCENDANCY**
Despite all the attention given to $CO_2$ enhanced oil recovery in recent years, polymer flooding projects, such as this one at Pelican Lake, remain the EOR method of choice among Alberta producers.

The mechanics of polymer flooding are fairly simple. Because of the difference between the viscosities of water and heavy oil, injected water tends to channel around the oil, leaving much of it in the reservoir. The polymer fluid roughly matches the mobility of the heavy oil and is better able to push it out of the pores.

Started around the middle of the last decade, pilots operated by Canadian Natural Resources Limited and Cenovus Energy Inc. at Pelican Lake in northeast Alberta were among the first to establish the success of polymer flooding in Canada. Both companies have since embarked on large commercial developments they hope will recover hundreds of millions of barrels of heavy oil at a fraction of the cost of steam-assisted recovery methods.

At Pelican Lake, Cenovus produces about 23,000 barrels of heavy oil a day from about 425 wells. About 137 wells are on primary production, 163 on waterflood and 125 on polymer flood.

Cenovus says its Pelican wells on primary production average about 13 barrels a day while those under polymer treatment yield 63 to 94 barrels a day.

At its Suffield heavy oil property in southeast Alberta, Cenovus has declared its ASP pilot a success, and is moving toward commercial ASP development.

In the wake of CNRL's and Cenovus's successes, several other producers are doing straight polymer or ASP floods.

More than a year ago Harvest Operations Corp. upgraded a successful waterflood to a polymer flood at its Wainwright property in east-central Alberta. Harvest termed the results encouraging. The company, a unit of Korea National Oil Corporation, believes it can also do polymer or ASP floods at its nearby Bellshill Lake property, at Suffield and eventually at Hay River in northeast British Columbia.

Husky Energy Inc. has ASP projects underway at Warner and Crowsnest in southern Alberta and at Gull Lake, Saskatchewan. Others are slated for Fosterton and Bone Creek, Saskatchewan. Construction for the Fosterton ASP facility is to start in 2011 and Bone Creek is in the design phase.

In the Lloydminster heavy oil belt straddling the Alberta/Saskatchewan border, Pengrowth Energy Trust has been running two small ASP pilots for about two years at its Bodo and Cosine heavy oil properties. At East Bodo, production jumped to 500 from 110 barrels per day. A decision on whether to proceed to commercial development may be made when Pengrowth prepares its 2011 budget.

BlackPearl Resources Inc. just received regulatory approval to proceed with development of the $25 million to $30 million first commercial phase of an ASP flood at Mooney in north-central Alberta.

The Mooney field produces 16-degree API oil from the Bluesky sands. Primary production is expected to recover only three to five per cent of what BlackPearl estimates is 150 million barrels of original oil in place.

The company figures the ASP flood will boost recovery to 20-30 per cent. A three-well pilot recovered 18 per cent of the oil in place over 18 months, BlackPearl says.

Engineering and design of the chemical and water-handling facilities began earlier and the company plans to immediately begin field preparation and construction.

Half of the 44 producing wells will be converted to injectors. Chemical injection is expected to start in the first quarter of 2011 and BlackPearl expects the oil production response will occur six to 12 months later. •

**Pat Roche**

# Number Crunching

## 65%

Delegates of Alberta’s ruling Conservative party approved a motion in late October asking the government to proceed on an "urgent basis" to put policies, programs, incentives and, if necessary, legislation in place to ensure that 65 per cent of bitumen is upgraded in the province. "It's not about upgrading 100 per cent but it is about the potential loss of hundreds of billions of dollars to Treasury and various [levels] of government over the next decade," said MLA Jeff Johnson, the author of a discussion paper on the topic, who emphasized he was not speaking on behalf of the party.

## 12,250

**The Petroleum Services Association of Canada's 2011 Canadian drilling forecast released Nov. 1 predicts 12,250 wells will be drilled (rig released) across Canada next year, which is eight per cent higher than the expected final tally for 2010. "Drilling activity levels are increasing," Roger Soucy, outgoing president of PSAC, stated in a news release. "This past year has been a turnaround year for the industry. We are anticipating a 35 per cent increase in wells drilled over 2009 to 11,350. Although still a long way from the almost 25,000 wells of 2005, it represents a new beginning on a number of fronts."**

## 50 YEARS

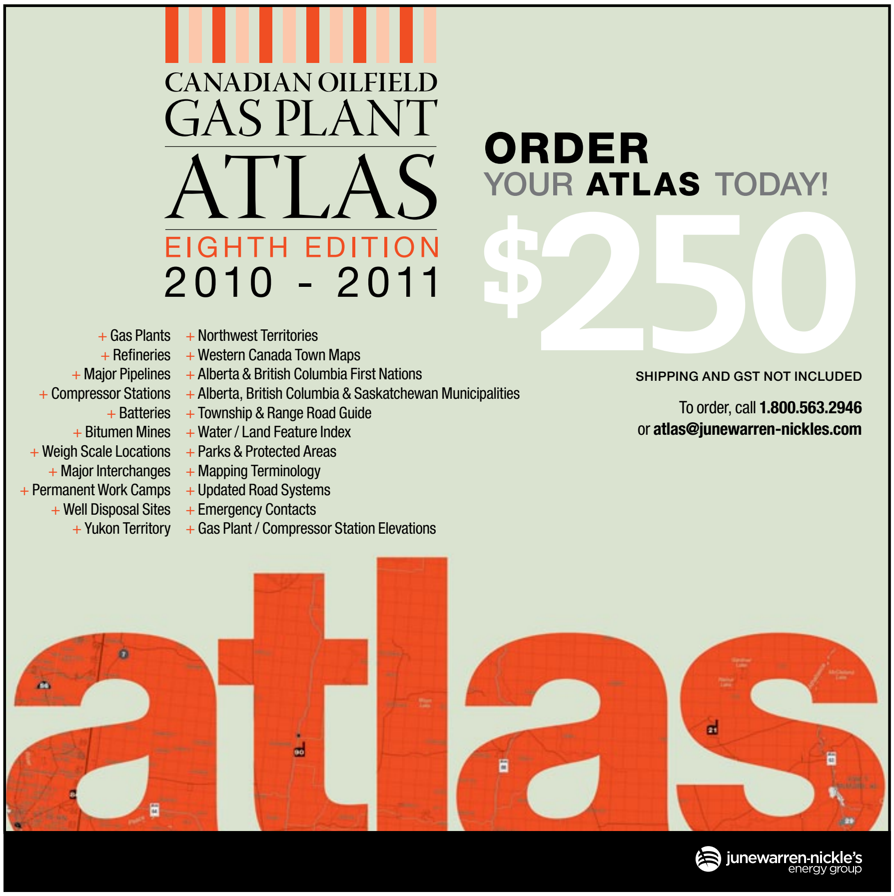
The United States was set to supply gas to Britain for the first time in 50 years in late November, with a liquefied natural gas tanker steaming across the Atlantic from Louisiana. The U.S. also started re-exporting LNG to Asia and South America earlier this year, while another shipment was headed to Kuwait. Surging North American gas production, driven primarily by new technologies that allow exploitation of numerous shale gas plays, has transformed the demand-supply outlook from that anticipated earlier in the decade, when permanent declines were predicted.

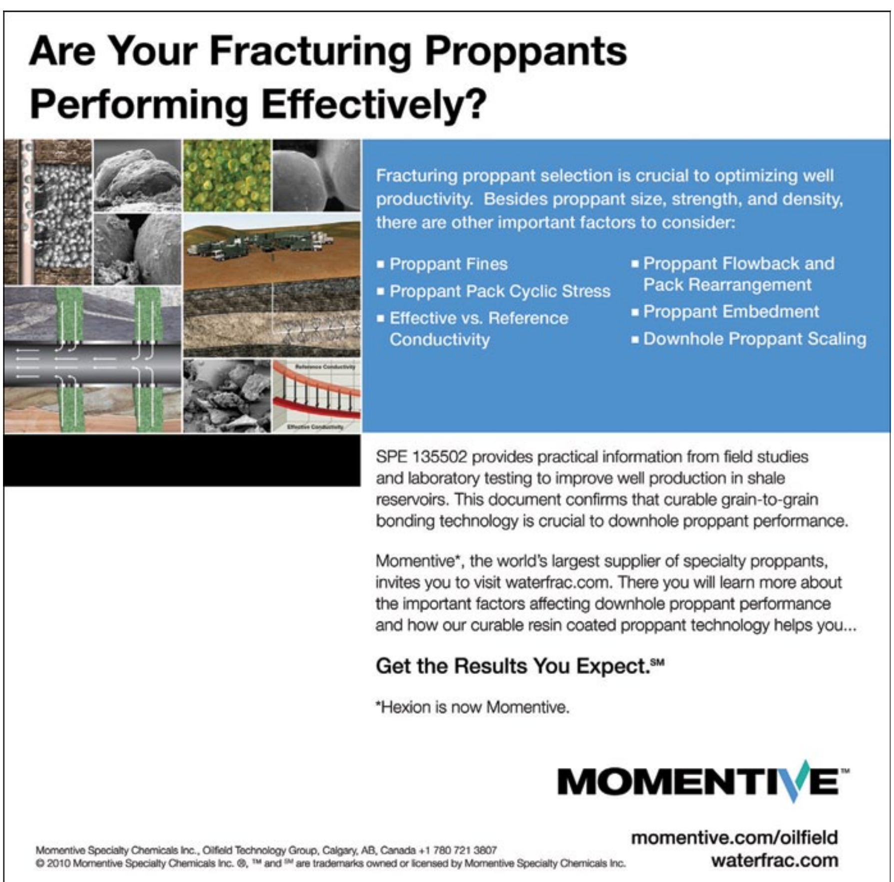
## 76%

**A survey found a noticeable drop in the number of Canadians who believe Canada can meet its future energy needs — from 82 per cent in 2009 to 76 per cent in 2010. At the same time, Canadians increasingly believe it is important for the country to be a global energy leader — from 82 per cent in 2009 to 89 per cent in 2010. “There may be many reasons for seeing a drop in confidence at the same time as an increase in global aspiration,” said Steven Bright, senior adviser, Canadian Centre for Energy Information. “In our view, increased energy literacy can bridge the gaps between confidence and aspiration.”**

## $40 billion

BP raised its estimate of the likely cost of its Gulf of Mexico oil spill to $40 billion in November, up $7.7 billion from previous estimates. Even so, its underlying third-quarter performance beat expectations on higher refining margins and a lower tax rate. Delays in finally capping the well raised the estimate, which included costs of the cleanup and compensation. The final cost is unknown, as uncertainty remains over whether BP’s partners will be required to contribute and whether BP will face further federal fines. BP’s loss in market capitalization surpassed $60 billion since the blowout last April.




# News Briefs

**Harvest Operations Corp.** plans to create and operate a Global Technology & Research Centre (GTRC) funded by its Korean parent.

Harvest (formerly Harvest Energy Trust) was acquired on Dec. 22, 2009, by KNOC Canada Ltd., which was incorporated on Oct. 9, 2009, as a wholly owned subsidiary of Korean-government-owned Korea National Oil Corporation (KNOC).

"The GTRC is intended to be an industry-leading research and development organization that will benefit KNOC as well as Harvest," the latter said in a press release announcing its third quarter results.

KNOC has agreed to fund the research centre's creation and operation with the injection of $7.1 million of equity and then through ongoing payments to Harvest for services provided by the GTRC, said Harvest. No other details were announced regarding the facility, which Harvest will own and operate.

**Synodon Inc.** has received an introductory survey contract from **Terasen Gas Canada** to provide remote airborne methane leak detection services within their network.

"We are pleased to welcome Terasen Gas as a customer for our realSens gas sensing services," said Adrian Banica, chief executive officer of Synodon.

"We are also very pleased with the response we received so far from the market, both from an adoption point of view as well as pricing. The vast majority of the contracts signed were within the range of commercial rates that our business plan called for."

The flights for Terasen Gas are scheduled to be completed before the end of the year.

**Baker Hughes** has announced the launch of its Reservoir Navigation Services (RNS), which is intended to optimize wellbore placement through the combination of reservoir modelling, a real-time drilling evaluation toolkit and 3D/4D visualization software with interpretation experts.

The service is designed to optimize production and increase overall asset recovery by reducing uncertainty during drilling and delivering maximum reservoir contact in the targeted zone. •

PRODUCTION

# Live Long And Prosper

*Alberta government, industry seek ways to strengthen conventional oil*

WITH PRODUCTION DECLINING for years, conventional oil has long been eclipsed by the growth sectors — such as the oilsands — of Western Canada's oilpatch.

"What was missing was a group [to] focus specifically on conventional oil development," says Don Wood, vice-president of engineering and enhanced recovery at Penn West Energy Trust and chair of a new CAPP working group called the Mature Oilfield Review.

Started informally last winter, the Mature Oilfield Review is focused on improving the viability of conventional oil development in Alberta.


Though Alberta's conventional oil production has been declining for about a quarter century, the sector is still an important contributor to local economies across the province. And with about 70% of discovered conventional oil still in the ground, proponents believe it can still have a future.

The Mature Oilfield Review is looking at whether Alberta's fiscal and regulatory framework could be tweaked to help spur activities that would increase recovery from conventional oilfields.

At the same time the province is conducting a technical review to identify targets for enhanced oil recovery (EOR). The technical study is being funded by the Alberta Department of Energy and will be done by Energy Resources Conservation Board (ERCB) staff. The study will use ERCB reserves data as well as other information.

A detailed work plan is currently being finalized, but the study is envisioned to involve the services of an oil and gas engineering firm to provide the required technical analysis, consult with industry experts and prepare the necessary reports, according to the Alberta Department of Energy.

The province expects two reports will be prepared with the first due by March 31, 2011, to highlight initial observations from readily available information.

A final report — expected by March 31, 2012 — would identify likely candidates for EOR and examine the potential incremental oil recovery that may be realized using the latest technology, the energy department said.

EOR is part of the focus of the industry's Mature Oilfield Review, but the scope isn't limited to conventional EOR activities such as waterflooding or tertiary recovery techniques, says Wood.

"In addition, it is really trying to increase the sustainability and longevity and contribution of the conventional oil industry to Alberta," he says.

So the scope includes technologies such as horizontal wells, which are expanding the boundaries of long-established oilfields into tight portions that were previously uneconomic.

Wood says the question of whether more incentives are needed to increase recovery is a significant part of the review. Alberta does have some limited royalty treatment for certain types of EOR such as carbon dioxide floods, but it excludes waterfloods, which account for about 99 per cent of the province's existing EOR schemes. The Enhanced Oil Recovery Royalty Relief (EORRR) program allows the extra costs of EOR to be written off against the incremental oil recovered from the scheme.

The Mature Oilfield Review will look at the EORRR to evaluate whether this program remains current and effective, says Tim Markle, an energy department spokesman.

Wood says the review is considering factors that reflect "how enhanced recovery should be viewed today in a broader sense than it was viewed when the enhanced oil recovery royalty relief program was implemented."

That program began in the late 1970s and reached its peak in the 1980s. "A lot has changed since then," Wood says.

Among the changes that have raised the economic bar are higher operating costs, investor expectations of higher returns and a costlier regulatory process. "[So] it's probably the right time to be looking at revamping those programs" that date back to the 1970s, he says. • **Pat Roche**

# Savanna: Setting New Standards

## The Next Generation of Service Rig Technology

**SAVANNA ENERGY SERVICES** is setting new standards in service rig technology, with its two new workover rigs featuring automated controls, safety, monitoring and communications systems for a client in Australia.

Designed to meet the rigours of the Australian climate, rigs 64 and 65 — Savanna's most technologically advanced workover rigs to date — are built-for-purpose equipment designed with detailed input from their client. Savanna Energy Services Pty Ltd. began operating in Queensland, Australia, in mid-November, under a five-year contract with Origin Energy, a leading Australian integrated energy company and Australia's largest producer of coal seam gas (CSG).

"Our commitment to Origin is to help them drill and complete coal seam gas wells right up to the pipeline stage. Then their joint venture takes it from there," says Savanna Well Servicing Vice President and General Manager, Brad Kingston.

The latest workover rigs in the Savanna Well Servicing fleet incorporate some of the latest technology available, making the Calgary-headquartered company a technological leader in the service rig industry.

Advanced features on these units include:

**Doghouse monitors –** allow real-time viewing of rig and pump operational parameters for both the company representative and rig manager via wireless communication.

**Working floor HMI (Human Machine Interface) –** allows the operator to view and set operational parameters, as well as provide an efficient means of troubleshooting. It also incorporates transmission shifting functions. This is an industry first, allowing the operator to electronically change transmission gears from the driller's console.

**Autodrill –** allows the operator to set weight on bit (WOB) and rate of penetration (ROP) on the rig floor HMI, which the programmable logic controller (PLC) will then maintain — another industry first.

**Joystick operation –** One joystick controls the clutch, engine RPM and brake functions, allowing a new worker to quickly become familiar with rig operation. If the joystick is ever let go, the brakes will rapidly apply.

Ease of operation is a key benefit. Operating the rigs by means of a joystick is easier and safer for workers, Kingston notes. "The learning curve isn't so steep, never mind the fact the rigs are more appealing to the new generation who are used to playing video games."

**Operational limits –** The operator can set both upper and lower limits, so that blocks will not travel beyond these limits without holding down an override button. The blocks will safely come to a smooth stop, regardless of weight and speed when approaching these limits.

**Governed block speed –** will not allow blocks to fall any faster than a programmable speed, allowing a new operator ample opportunity to become familiar with joystick response.

**Redundant safety –** Dual encoders (used to determine the blocks' speed, position and other factors) and maxi (emergency stop) valves are used as self checks to ensure the part is working properly. Also, combining the upper operational limit with a mechanical crown saver switch, located at the top of the mast, ensures that a crown-out will not occur. Four proportional valves control the main drum brake application pressure and provide feedback to the PLC to ensure that all are performing to expectations.

**Advanced safety interlocks –** The rig and pumping unit PLC programs incorporate numerous safety features to ensure the units will operate in the safest, most effective manner possible.

**Hazardous area compliant –** All electronics and controls meet or exceed hazardous area requirements, ensuring worker safety.

**Pump Display –** Several sensors are located throughout the pump unit, whose information is displayed on the HMI, eliminating the need for personnel to put themselves at risk (for instance, at the top of the tank). This information is transmitted wirelessly to the rig floor and both doghouse HMIs.

**Remote access –** A satellite uplink allows technicians to troubleshoot problems on the rig and pump from anywhere in the world, resulting in decreased downtime.

**Wireless remote shut down –** One central emergency stop button will shut down every engine on location if an incident occurs.

For Savanna, a premiere contract drilling and well servicing company operating in the U.S. and Canada, its Australian contract is a significant step in moving further onto the international stage. "The important thing is that this is just our first step into the international market," Kingston says. "Our intention is to make more built-for-purpose equipment, with operator input, to facilitate our expansion. That's something we pride ourselves on: working with our clients to bring them what they need for specific operations. As resource plays get more and more technical, operators will require more technical equipment to complete them."

Savanna is Western Canada's largest operator of programmable logic controller (PLC) workover rigs. With its newest generation of service rigs, the company has incorporated the latest technology to set a benchmark for others to follow. In all that it does, Savanna focuses on "Defining leadership in global energy services through people, innovation and technology — the path for others to follow."

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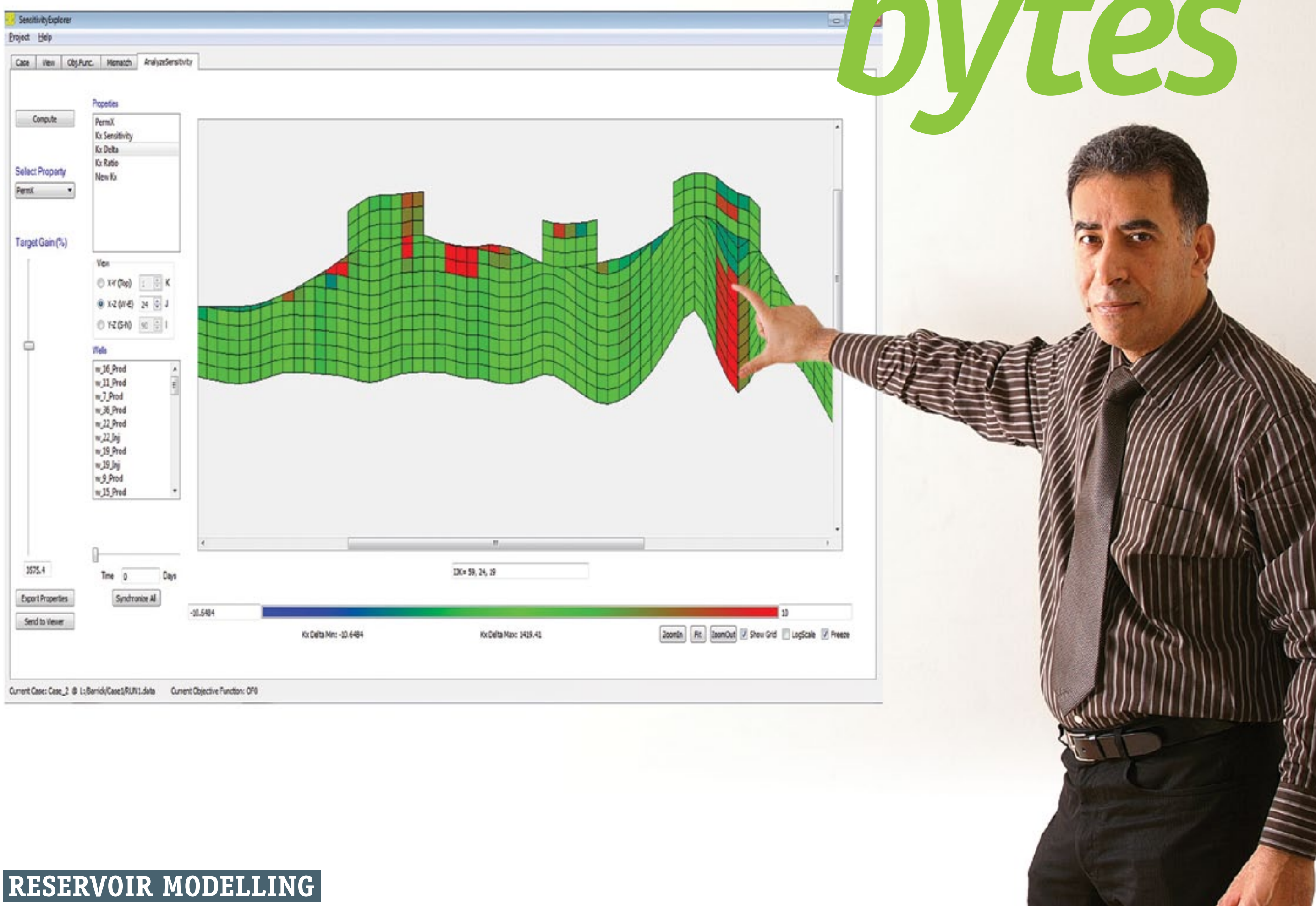

RESERVOIR MODELLING

# Matching History In Reservoirs

*As reservoirs mature and become more complex, producers are reaping the benefits of applying cutting-edge software to increase output and maintain pressure*

THERE IS LITTLE IN COMMON BETWEEN Calgary, Tokyo, Oregon and Dhahran (the oil capital of Saudi Arabia). But, for Hussein Almuallim — founder and director of Calgary-based FirmSoft Technologies Inc. — all four places are close to his heart and have each contributed in some form or another to his current achievements.

From an academic perspective, he received his PhD in computer science from Oregon State University. Prior to that, he completed masters and bachelor degree courses in electronics engineering at the Tokyo Institute of Technology.

On the work front, he was a professor at the King Fahd University of Petroleum and Minerals in Dhahran. He also has several years of industry experience in companies like Japan's NTT and RC Squared, acquired by Veritas DGC, Inc., in the U.S., in addition to consulting contracts with the national oil company of Saudi Arabia, Saudi Aramco.

"Teaching was a major part of my work at the King Fahd University, but all along I had an interest in research," Almuallim says. "I was keen on doing theoretical work and, living in the heart of the world's biggest oil producer, got interested in the energy industry."

There was probably every reason for that, as the prime purpose for setting up King Fahd University in 1963 was to train the next generation of Saudi petroleum engineers and geophysicists to reduce dependence on foreign knowledge.

While Dhahran was his work station for a 14-year period that started in 1992, in his mind Almuallim

**MAKING HISTORY**
FirmSoft Technologies' Hussein Almuallim explains his company's SenEx software, which significantly reduces the time normally required for history matching of complex reservoir models.

had a dream of establishing his own start-up software firm to serve the oil and gas industry.

“FirmSoft Technologies was registered as a business in Alberta in October 2009. It is specialized in developing innovative software to aid petroleum engineers in reservoir simulation and modelling,” he says. “There was a reason behind the nomenclature of my company. ‘Firm’ stands for fully integrated reservoir modelling.”

Commenting on the driving force behind the launch of his firm, Almuallim says petroleum engineers in reservoir modelling departments spend a great deal of resource and effort in modifying models aimed at matching available historical data collected over years of operating an oil or gas field.

“This task is usually called ‘history matching’ and I came up with a new algorithm that helps in easing it significantly. FirmSoft Technologies was established to commercialize this innovative and easy-to-use software package,” he points out. “Our main interest is to develop a system integrating geology, seismic and engineering data in the most seamless and efficient manner. Yet another task is also to minimize both computational and human-time costs.”

**SenEx, FIRM**

Within a short period, FirmSoft commercially launched its first product — SenEx, which cuts down substantially the time it takes for history matching of complex reservoir models.

“What earlier would take weeks or months is now achieved in days using the new software product. Also, final reservoir models based on SenEx technology enjoy more accuracy when compared to those generated through conventional means,” Almuallim says.

The product carries a price tag of $15,000 to $19,000 for a one-year lease. Almuallim is currently offering SenEx on a lease basis, although he is open to the idea of a permanent licence.

His efforts have borne fruit with upstream operators Cenovus Energy Inc. and Husky Energy Inc. leasing SenEx and certain consulting firms — Fekete Associates Inc. and Sproule Associates Limited — employing the product in real-world consulting projects.

**“Our main interest is to develop a system integrating geology, seismic and engineering data in the most seamless and efficient manner.”**

“SenEx has helped us efficiently improve our history match quality in a very heterogeneous and fractured carbonate reservoir with a long production and injection history,” comments Tarun Kashib, a reservoir engineer at Cenovus.

According to Chris Galas, manager for reservoir simulation with Sproule, the new product assisted in the history-matching of oil and water production under primary depletion from a field with 92 wells and over 200 identified sandstone layers. “The time required to achieve an acceptable history match was greatly reduced,” he says.

Almuallim’s achievements have not been without challenges, however. Top on the list was establishing the credibility and reliability of the product.

“The only way to prove the validity of a new theoretical idea like the SenEx algorithm is to demonstrate its success on a real-world domain. Convincing reservoir modelling engineers at oil and gas companies to devote time and effort is challenging. Typically, a busy engineer is working under a tight deadline to come up with a history-matched model and would prefer to use conventional and familiar methodologies. Thus, switching to a new and not-yet-known technology involves risk that not many people are willing to take," he says.

As part of his efforts to gain a footing, Almuallim adopted an approach to offer his history-matching service for free and one that runs parallel to conventional work done by the engineers. The results were positive, with SenEx offering faster, more accurate and consistent models.

Looking ahead, Almuallim plans to launch his next product — FIRM. "Our target is to commercialize the more advanced FIRM technology in one to two years. It will use the technology of SenEx internally," he says.

In the meantime Almuallim is taking his product to international markets. "We are targeting Middle East clients with SenEx and are working on their data to demonstrate the benefits. If our attempts go through, it will be a major success for FirmSoft Technologies," he says, without divulging any details.

Few will deny that software is set to play an increasing role in the global oil and gas industry. However, two significant factors will be cost and effectiveness of the new tool in increasing recovery rates of hydrocarbon.

"Reservoir simulation and modelling software are crucial to successful and efficient operations and this is being increasingly realized by the industry. However, the cost of software usage is still tiny compared with the volume of savings it offers and the risk levels it eliminates. The cost of drilling a single wrong well far exceeds that of buying and maintaining sophisticated software packages for decades," Almuallim comments.

### Lack of investment

A recent study conducted by U.S. software giant IBM indicates that historically the oil and gas industry has not invested sufficiently in research and development (R&D). The scenario is quite acute when compared to other sectors.

"International oil companies spend 0.3-0.5 per cent of their revenue on R&D," says the global leader of IBM's chemical and petroleum unit, Steve Edwards. "Contrast that with aerospace and defence or biotechnology, which will be spending something nearly 50-100 times that. There needs to be significant step-changes in this."

The IBM study was based on a survey it conducted on technological progress as being one of the most important factors set to change. This included small-scale advances, such as improved safety devices in the subsea to opening up new frontiers, such as offshore Arctic areas.

"The recent blooming of shale gas — and its unconventional cohorts — will continue. But, the development of technologies and interest in these new resources will have an impact. There is a basket of things that people are now looking at, beyond conventional oil and gas resources."

The scenario is not any different in Alberta. Over the coming few years demand for software products is expected to rise considerably to deal with depleting and complex oil and gas reservoirs.

"In many ways, Calgary offers a great opportunity for software companies. Unlike national oil companies in other major producing regions, in Alberta there are several firms that I can approach as a vendor and get business," Almuallim says. •

**Ashok Dutta**

**CONTACT FOR MORE INFORMATION**
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Tel: (403) 770-9219,
Email: Hussein@firmsofttech.com


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# THE JUDGES

The technologies selected as winners by these judges span the breadth of the oil and gas sector — large and small, Canadian and multinational. Their achievements, however, do reflect several common denominators: ingenuity, leadership and unrelenting perseverance.

**Arthur Dumont**
CEO, Retired
Technicoil Corp.

**Grant Shomody**
President and Founder,
Grantech Engineering

**Roger Soucy**
CEO, Retired
PSAC

To learn more about the judges, visit us online.

more online
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# TECHNOLOGY STARS 2010

Best Exploration Technology ★ Best Drilling Technology ★ Best Production Technology ★ Best HSE Technology

# A great resource can be found in the minds of those who champion new ideas.

**In this issue, we recognize six of the most innovative technologies as our inaugural Technology Stars. It is also a recognition of those individuals who pushed the boundaries to rise to the top and of the creative and entrepreneurial spirit that remains alive and well throughout the oil and gas sector — a spirit that above all else ensures the industry will continue to prosper in the years ahead.** >

TECHNOLOGY STARS
2010
WINNER

MicroSeismic maps hydraulic fracturing results in real time

**by Maurice Smith**

Horizontal drilling and multi-stage hydraulic fracturing form the indispensable duo that's driving shale gas plays across North America. That innovative revolution has transformed a sunset industry into a thriving sector that's apparently capable of supplying the continental gas market for the next century. But as the technology spreads, operators have found what works in one

**BEST EXPLORATION TECHNOLOGY:**

MicroSeismic, Inc.

**PRODUCT:**
FracStar and Buried Array monitoring systems

**SERVICE:**
Real-time mapping of hydraulic fracturing

# LISTENING TO THE FRACING GROUND


MicroSeismic president Peter Duncan says Encana Corp. pioneered the use of his firm's surface and buried monitoring systems in the Haynesville shale gas play.

Photo: MicroSeismic, Inc.

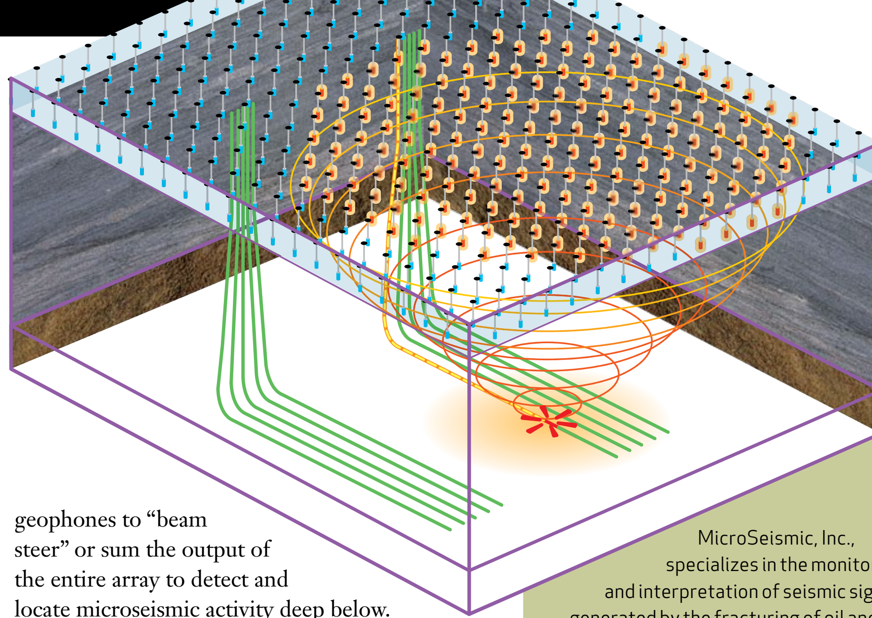
Illustration: Andrew Brien

MicroSeismic, Inc., specializes in the monitoring and interpretation of seismic signals generated by the fracturing of oil and gas reservoirs over time. The company uses FracStar surface-based data acquisition or a Buried Array permanent network of geophones buried in shallow ground to gather low level acoustic energy emissions. Its Passive Seismic Emission Tomography system sums the output of the entire array to detect and locate microseismic activity.

play doesn’t necessarily translate to the next. Each geological prospect has to be “solved” before large-scale commercial production can be a success.

An important tool for helping operators crack new plays quickly has been derived from technology used to monitor earthquakes and geothermal activity. Houston-based MicroSeismic, Inc. (MSI) has developed the capability to monitor hydrological fracturing of gas-bearing shales. From the surface or near-surface, an operator can monitor and interpret the tiny vibrations triggered when tonnes of frac fluids and proppants are pumped at high pressure into reservoirs some 5,000 to 15,000 feet underground.

The technology creates high-definition imagery that indicates the direction and penetration of the fracs, with results reportedly superior to the more costly method of drilling adjacent monitoring wells to reservoir depth. Further, MSI’s product performs that task in real time. Operators can adjust and tweak the fracing procedure as it advances stage by stage down the length of the horizontal wellbore. In addition, future horizontal wells and frac stages can be more effectively placed across a shale gas play.

The technology is being used not only to help solve new shale plays, but to optimize production within plays. “The variability of the shales from well to well is driving more and more operators to monitor 30 to 40 per cent of their wells, and in some plays 100 per cent,” says Canadian-born Peter Duncan, MSI’s founder and president. “It is a matter of value proposition. As the unit price comes down, operators are able to employ the monitoring on more and more wells. At some price point it will make sense to do it on every well.”

MSI uses either its FracStar surface-based data acquisition or its Buried Array permanent network of geophones (guaranteed for at least 10 years), buried from 100 to 500 feet underground — to avoid near-surface noise — to gather very low-level acoustic energy emissions. The process relies on the small seismic events, or micro-earthquakes, created at depth by the frac procedure. There’s no need for an active source of vibration, such as dynamite or vibroseis vehicles.

Fracing data is wirelessly communicated to MSI’s Passive Seismic Emission Tomography (PSET) system for interpretation. Signal attenuation by the overburden makes conventional seismological earthquake location techniques ineffective. In contrast, PSET allows MSI to use the dense array of geophones to “beam steer” or sum the output of the entire array to detect and locate microseismic activity deep below.

The technology has been taken up by some of the continent’s biggest producers, Duncan says. It’s now in use in tight gas plays from the Marcellus and Haynesville in the United States to British Columbia’s Montney and Horn River Basin, along with the Bakken tight oil play in Saskatchewan.

Duncan, a geophysicist who founded MSI in 2003, describes himself as “more like the midwife than the inventor” in this case. A Colorado University professor developed earlier versions for hydrothermal exploration in Russia. MSI, purchasing the technology, advanced and adapted it for oil and gas applications.

“What it has become is a tool for putting large-aperture arrays over entire oilfields, turning them on and listening to all the production activity in the oilfield, whether it's frac monitoring or injection of fluids or production of fluids, in order to hear those sensitive sounds, pinpoint their location and their nature, and really allow the reservoir engineer to know something about the dynamics of what is going on in his oilfield,” Duncan says.

Encana Corporation, an early user, tested the surface-based FracStar in 2007 and installed the first permanent Buried Array in 2008. Both systems were applied at its Haynesville shale gas play in northern Louisiana. The Calgary-headquartered producer went on to install another three permanent Buried Arrays in the Haynesville.

MSI has now installed about 20 Buried Arrays, almost all to monitor frac operations. But the rapidly growing company also sees potential in monitoring everything from steam injection in the oilsands to carbon sequestration and enhanced geothermal systems. “We have only begun to scratch the surface,” Duncan says. •

Read Peter Duncan's bio online.

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TECHNOLOGY STARS

2010 RUNNER-UP

## geoLOGIC systems ltd.

Knowledge equals profit. Geologists, geophysicists, engineers and accountants from no less than 19 producers notified JuneWarren-Nickle’s Energy Group that they rely on geoSCOUT, a product of Calgary-based **geoLOGIC systems ltd.** This comprehensive software package generates a range of sophisticated reports, integrating data sources that cover the life cycle of an oil and gas project.

TECHNOLOGY STARS
2010
WINNER

Weatherford's Multiphase Performance Drilling system increases penetration rates in hard, abrasive formations

**by Maurice Smith**

Any time a driller can double, triple or even quadruple its rate of penetration (ROP) in a well, it must be doing something right. Particularly for producers dealing with hard, abrasive formations, a dramatically improved ROP can open up many opportunities. When Weatherford Canada and Suncor Energy Inc. achieved a drilling breakthrough of that magnitude in the Alberta foothills,

## BEST DRILLING TECHNOLOGY:

for a company with 100 employees or more

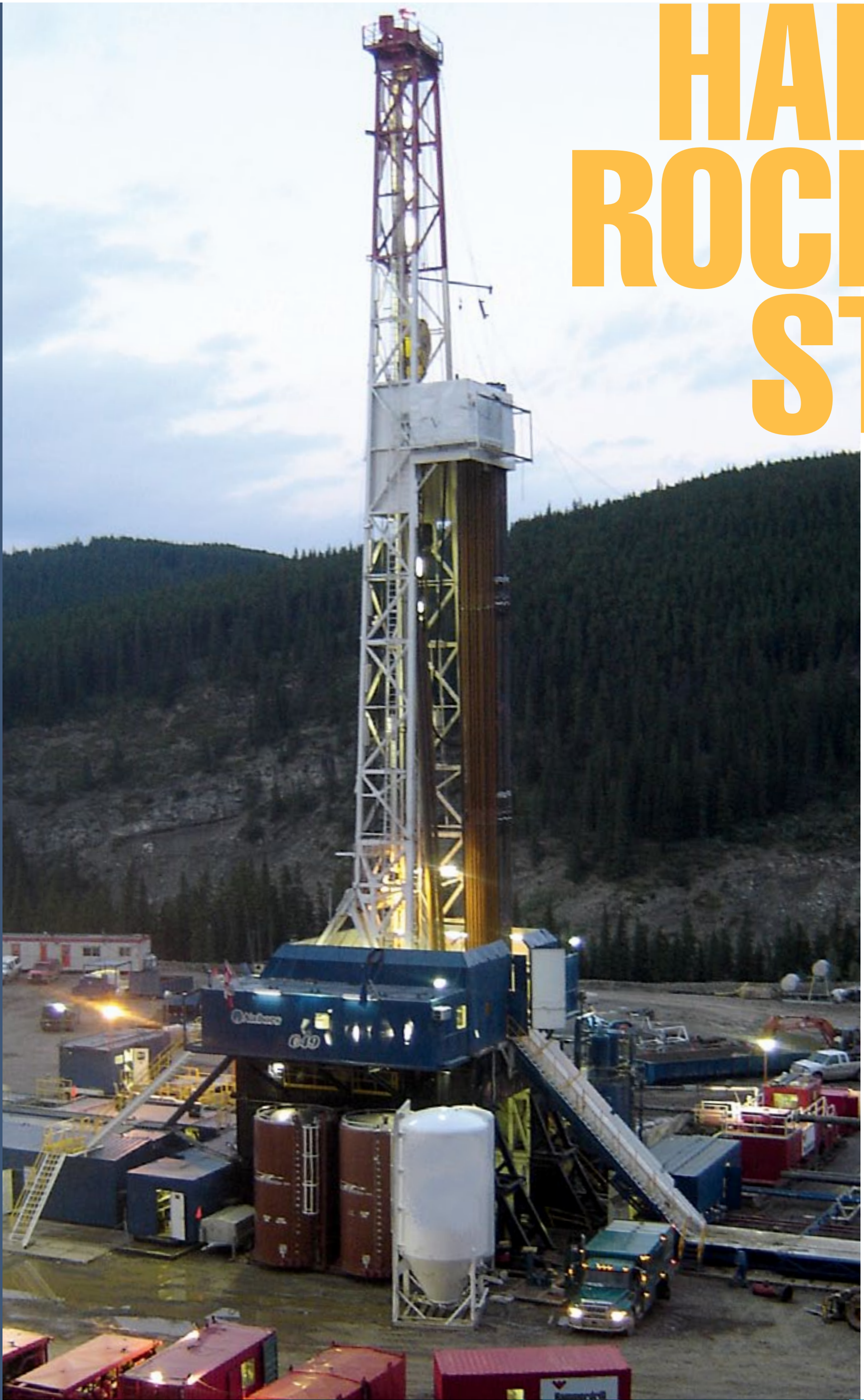
**Weatherford International Ltd.**

**with Suncor Energy Inc.**

**PRODUCT:**
Multiphase Performance Drilling (MPPD) system

**SERVICE:**
Enhances drilling rate of penetration

# HARD ROCK STAR



Multiphase Performance Drilling was originally developed for the slow drilling formations encountered in the Panther field near Sundre, Alta.

the innovative technology soon began spreading elsewhere.

After developing the patent-pending Multiphase Performance Drilling (MPPD) system in the Panther field, the two companies have expanded its use to Suncor's Kelly Lake and Gwillim plays in British Columbia. Now Weatherford is poised to take the new technology worldwide.

"We see potential anywhere where there is large meterage of hard formations to drill. As long as it is consolidated rock that has good hole stability while you are drilling it, it can be a candidate, so it has global application," says Rich Norton, Weatherford Secure Drilling Services operations manager. "We have had several different countries looking at it. It's one of those things that has only been done in Canada, but it's time to open it up and push it out further. The potential market is huge."

The technique is optimal for drilling in harsh, abrasive formations like the Nikanassin or Cadomin. MPPD is changing the game for operators in these challenging conditions, the companies say. The marked increase in ROP using nitrified-invert MPPD has allowed Suncor to save as much as $1.5 million per well. At Kelly Lake, distances drilled per day through hard formations were about three times greater with MPPD, saving four to seven days of drilling time for intermediate sections and seven to 10 days for horizontal sections of a well.

Drilling the Nikanassin formation in the Gwillim field also netted significant improvements, when ROP went from two to nine metres per hour. "Time is money when drilling. When you go from 35 days to nine days drilling, you can see the economics are significant," says Bob Staysko, contract drilling specialist with Suncor.

Key to the process is the controlled use of nitrogen to lighten mud weight. The amount used can be adjusted depending on the type of rock being drilled. And because it's an inert gas, it renders drilling low-risk. "We like to drill with maximum nitrogen to get the lightest weight that we can," Staysko says. "Membrane nitrogen generated on site is compressed and injected, along with the drilling fluid down the drill string through the bit, resulting in a lighter mud weight and that has a direct relationship to the rate of penetration, so you're able to drill faster."

In order to handle the increased cuttings coming to surface because of the higher ROP, specific operating procedures have been implemented and strictly followed by both Weatherford and rig contractor employees. Annular effluent is safely handled by Weatherford's specialized surface equipment, processes and engineering.

Weatherford uses its model 7000 rotating control device (RCD) to provide precise control of the wellbore pressure profile. At Kelly Lake, Weatherford was able to reduce equivalent circulating density to less than 600 kilograms per cubic metre mud weight compared to 950 kilograms per cubic metre during conventional operations.

MPPD is used in applications that meet a set of criteria before a project is approved. Complex wells of this kind need proper planning to ensure flawless execution, says Alek Ozegovic, engineering manager of Weatherford's Secure Drilling Services group. Weatherford creates a custom-engineered drilling program for all MPPD projects to complement the operator's well program. "Extra equipment is needed in a multiphase application, but despite the extra up-front costs, savings in the end justify the means," Ozegovic says. •


Photo: Aaron Parker

Weatherford's Secure Drilling Services group includes (from left) Dwight Affleck, Rich Norton and Larry Lavigne.

## A producer-service partnership generates a step-change in technology

**WEATHERFORD HAS HIGH PRAISE** for its partner in developing the Multiphase Performance Drilling (MPPD) system since the concept was raised with Suncor in 2004. The multinational services firm says few client companies have the patience and the willingness to make sometimes costly long-term investment necessary to perfect such systems.

"Suncor was committed to making a change in their drilling process versus doing it the traditional way," says Keith Corb, a technical support consultant with Weatherford. "It was a real commitment on their part in helping develop the process, not just trying it once and walking away."

Corb and four other specialists from Weatherford and Suncor were involved as the system was tested, modified and, at times through mere trial and error and an abiding willingness to try less conventional concepts, perfected.

"Initially, we really weren't sure how this was going to work," concedes Alek Ozegovic, engineering manager of Weatherford's Secure Drilling Services group. "Every hole that we did was an improvement on the previous one, but I would say between the first and the second one was the biggest step-change. After that it was just tweaks and modifications that we incorporated, pushing the envelope a little bit more each time." Weatherford, with some 35 MPPD projects now under its belt, continues to improve on the technique.

TECHNOLOGY STARS
2010
WINNER

# HIGH-TECH HAMMER

BBJ Tools transforms the traditional fluid hammer into a revolutionary drilling tool

**by Mike Byfield**

**BEST DRILLING TECHNOLOGY:**
for a company with fewer than 100 employees

**BBJ Tools Inc.**

**PRODUCT:**
Fluid hammer

**SERVICE:**
Enhances drilling rate of penetration

In the spring of 2010, Suncor Energy Inc. drilled a foothills horizontal wellbore to 6,500 metres using a fluid hammer from top to bottom. That feat had never been achieved previously with this type of tool. "ROP [rate of penetration] was improved by 30 to 50 per cent," explains Brad Cote, president of Calgary-based BBJ Tools Inc. "Our fluid hammer represents a revolutionary improvement in

Photo: Aaron Parker

BBJ founder Brad Cote says his firm's proprietary fluid hammer works with PDC bits as well as traditional roller cones.

terms of maintaining drill bit integrity, steering ability, operating flexibility and other critical performance factors."

BBJ carries fluid hammers for all standard hole applications. Its patent-pending proprietary hammer maintains the drill bit in constant contact with the rock face, creating axial percussion force directly above the bit and exerting tremendous percussive force at hundreds of cycles per minute. BBJ's fluid hammer incorporates a positive displacement motor (PDM) and adjustable housing, which enables the driller to steer the drill bit, unlike conventional fluid hammers, which cannot be steered.

The recent foothills well was drilled with tri-cone insert rock bits. Today, however, most wells are drilled with polycrystalline diamond compact (PDC) bits. "The synthetic diamond cutters are much more delicate than roller cones, so we had to undertake focused research and development to tailor the fluid hammer to PDC applications," Cote says. The fluid hammer has been proven viable for a number of PDC applications. BBJ credits Tourmaline Oil Corp. as a tremendously helpful customer for its PDC development.

The percussion force is developed in the lower housing directly above the bit box. When weight is applied to the bit, the fluid hammer engages while keeping the bit in compression, delivering axial movement to the outer housing. "This design provides efficient weight-to-bit transfer for centre percussion force," Cote says. "This design allows for diversified percussion control as rock formation compressibility variations are encountered. For example, when the driller needs more force, he simply puts more weight on the bit. If all weight is removed from the bit, the hammer cycle stops, which is unique to BBJ's fluid hammer design."

The BBJ fluid hammer is integrated with major components of the mud motor. "Not only can our tool compete in every application where a mud motor is used, it outperforms them," Cote says. "Mud flow and type are not restricted or diverted. Our technology eliminates flow issues for LCMs [lost circulation materials like sawdust], high solids content and torque beads. In addition, there are no interruptions to the MWD [measurement-while-drilling] signal. With the cycling of the hammer, it develops movement to the outer housing which acts like an agitator tool, eliminating drag to the bit and increasing ROP."

The BBJ fluid hammer's percussion mechanism transmits powerful left-hand reactive torque to the housing. "Reactive torque was our most difficult engineering hurdle," Cote comments. "We came up with an anti-backoff connection that in itself is a breakthrough. This concept has other possibilities that we'll work with in the future with respect to mud motors." •


Traditional fluid hammers exert continuous percussive force whether the rig is drilling ahead or not, an action that cannot be controlled from surface. The BBJ hammer is operator-controlled through the weight placed on the drill bit. The patent-pending mechanism stops hammering when drilling halts.

## From hockey enforcer to Technology Star

**BRAD COTE SPENT MUCH** of his boyhood in North Battleford, Sask., on the ice. While still in high school, he competed at a major-junior level in the Western Hockey League (WHL), playing for the Portland Winterhawks and later the Moose Jaw Warriors. However, "to save my hands," the hard-hitting left-winger quit hockey and entered the oilpatch.

"I've always wanted to know how things worked," recalls the president of BBJ Tools Inc. The mechanically inclined youth was soon roughnecking for a major drilling contractor. "From the moment I first set foot on a rig, I developed a passion for the industry and technology," Cote recalls. Eventually, he became toolpush of one of Canada's deepest-rated rigs and a senior troubleshooter. "The inspiration for BBJ Tools' technology originated from a desire to improve project efficiencies in the oilsands and foothills," the company co-founder comments.

BBJ was launched in 2004, making its first mark with the slotted liner assist tool and cuttings bed removal tool. Combined, these two devices broke new ground for drilling modern extended-reach and steam-assisted gravity drainage wells. The fluid hammer followed, outclassing any competitive device from a major company. "Luis Guzman [a co-owner of BBJ] and I produced this tool in less than two years," Cote says. "I'm still amazed at what our small team has been able to achieve in a short time."

TECHNOLOGY STARS
2010
WINNER

Baker Hughes' latest electrical submersible pump system raises the SAGD operating bar to 250 C

**by Mike Byfield**

Baker Hughes Canada sees its latest ultra-temperature electrical submersible pumping (ESP) systems as a big step forward for steam-assisted gravity drainage (SAGD) technology. "In subsurface bitumen reservoirs, higher heat creates a larger steam chamber and makes the oil more missive, which translates into higher production," says Kelvin Wonitoy, project manager for Baker

## BEST PRODUCTION TECHNOLOGY:
for a company with 100 employees or more

### Baker Hughes Inc.

**PRODUCT:**
Ultra-temperature electrical submersible pumping systems

**SERVICE:**
Operates in steam assisted gravity drainage wellbores up to 250 C


Photo: Aaron Parker

# BEATING THE HEAT

Kelvin Wonitoy at Baker Hughes' Centrilift plant in Leduc.

Hughes artificial lift systems. "We're the first company to deploy ESPs capable of operating reliably at downhole temperatures as high as 250 C. This generation of ESPs is also designed to be more robust in operation, which will result in longer run-life, less downtime, less pulling costs and, as a result, will provide a greater return on the client's investment.

The specialist, based in Leduc, Alta., has been Baker Hughes' Canadian lead for ESP applications in SAGD since the company first entered the sector in 2003. "Conventional oil reservoirs rarely rise above 100 C. We've continuously adapted our core product ESPs [used for conventional crude] for this new operating environment," Wonitoy says. Initially, SAGD wells operated at bottomhole temperatures of about 180 C. In 2005, the heat limit had risen to 200 C, then 220 C by 2008. In Wonitoy's view, raising the bar to 250 C required more extensive improvements in manufacturing materials and design than did previous stages.

Baker Hughes began research into ESP deployment at higher temperatures for use in geothermal power generation during the 1980s. At Claremore, Okla., the multinational services firm constructed a vertical test well that remains unique in the industry. That research and development facility was upgraded in 2003 for SAGD applications with a hot loop, gas loop and slurry loop. In 2009, Baker Hughes added a second hot loop at its testing facility at Claremore, designed to rigorously stress ESP systems at temperatures as high as 300 C. Provision was also made for the horizontal pump placement used in SAGD bitumen wells.

An ESP system includes a pump, motor and downhole power connection, with the entire assembly fitting inside casing that's 9 ⅝ inches in diameter. "There were two key hurdles to overcome when designing an ultra-temperature ESP system," Wonitoy says. "First, we required better insulation materials for the stator, cable and motor lead extension. Second, we had to develop metallic materials that would enable all parts to remain within appropriate mechanical tolerances despite the dimensional changes caused by higher temperatures."

Besides more heat, ESPs in SAGD applications must cope with temperature cycling (due to shutdown, steam optimization and other field operations), slugs of gas and steam in the bitumen flow, and the fine abrasives that inevitably slip through screening systems. The Claremore test facility (shown at right) puts all materials through more aggressive stress conditions than would ever be encountered under real-life operating conditions.

To protect the magnet wire used in the stator (a component of AC electric motors), Baker Hughes' chemists helped create a high-purity polyamide film along with a proprietary outer Perfluoroalkoxy (PFA) insulation. Half a dozen metallurgies were addressed. The pump shaft, for example, is manufactured with a space-age material called Inconel, and bearings are hardened. A multi-vane pump stage was developed to eliminate gas lock, along with a new intake design that operates well in a horizontal application. Chemists also ran tests to identify motor oils capable of standing up under SAGD operations.

Since April 2010, Baker Hughes has installed 12 pumping systems capable of operating at 250 C. "We're working with four producers in northeastern Alberta," Wonitoy reports. Although results remain confidential at this point, he is confident of success. "We've invested $5 [million] or $6 million in our testing facilities alone, a greater commitment to SAGD than any other ESP manufacturer has been willing to make. That R&D investment is really paying off for producers now." •


Photo: Baker Hughes Inc.

Baker Hughes tests with a hot loop at its Claremore research facility.

"In subsurface bitumen reservoirs, higher heat creates a larger steam chamber and makes the oil more missive, which translates into higher production."

— Kelvin Wonitoy, Project Manager, Baker Hughes

## Kelvin Wonitoy has worked from 65 C below to 54 C above

AS BAKER HUGHES CANADA'S project lead for ultra-temperature SAGD electric submersible pumps, Kelvin Wonitoy liaises between research and manufacturing teams in Alberta and Oklahoma as well as Canadian bitumen producers. "I've worked in some pretty extreme temperatures myself," he notes with a smile. "It hit 65 below in the Arctic when I was a rig hand with Commonwealth Hi-Tower. When I worked in southern Libya, the temperature in the Sahara [Desert] reached 54 C. It felt like walking into a furnace."

Raised on a dairy farm near Camrose, Alta., Wonitoy roughnecked before taking an electrician's apprenticeship through the Northern Alberta Institute of Technology (NAIT). Almost 26 years ago, he joined Baker Hughes as a field technician. Since then, he's received intensive in-house training in mechanical engineering, risen to senior supervisory positions and authored several papers.

His oil and gas work has taken him to Europe, Africa and Asia, operating on and offshore. "We're the only company that manufactures all major components of electrical submersible pumping systems," Wonitoy comments. "That way, we can ensure consistent quality at the highest level, we provide consistent compatibility across the full ESP system and we provide one customer point of contact for effective management. The technical breadth of Baker Hughes is a constant challenge. However, I'm still vertical and kicking — it's been a very satisfying career."

TECHNOLOGY STARS
2010
WINNER

Can-K's electric submersible twin screw pump is designed to handle the nastiest crudes

**by Mike Byfield**

Can-K Group of Companies is about two-thirds of the way through building an electric submersible twin screw pump (ESTSP) for Kuwait Oil Company (KOC). The unique downhole pump, coupled to a suitable electric motor and related equipment, is scheduled for service in a complex oilwell characterized by high asphaltene, hydrogen sulphide and very high wax content. Can-K won the large

## BEST PRODUCTION TECHNOLOGY:

for a company with fewer than 100 employees

### Can-K Group of Companies

**PRODUCT:**
Electric submersible twin screw pump

**SERVICE:**
Pumping heavy crudes heavily laced with asphaltenes, hydrogen sulphide, wax, methane and more

# DOUBLE TWIST

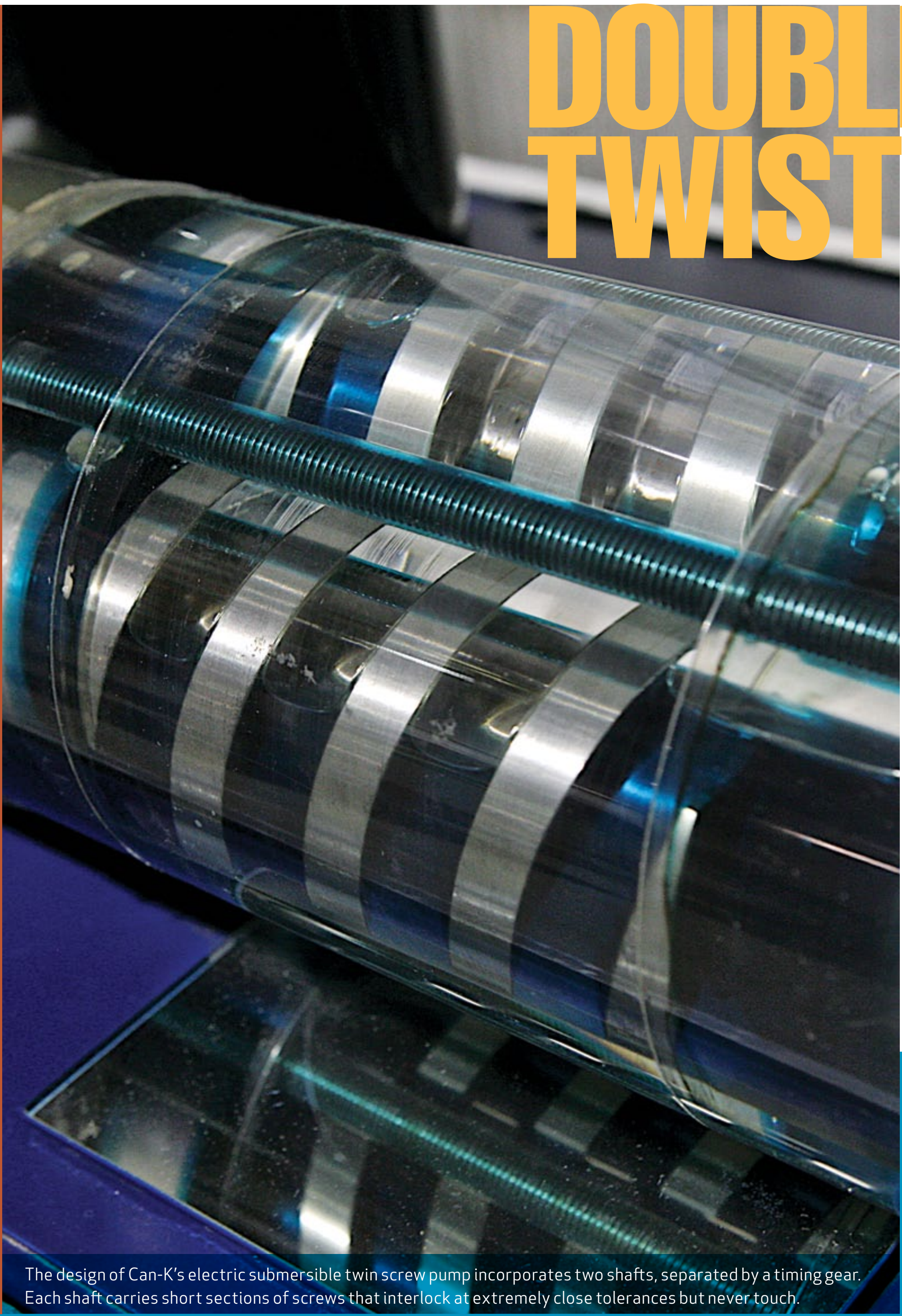


Photo: Aaron Parker

The design of Can-K's electric submersible twin screw pump incorporates two shafts, separated by a timing gear. Each shaft carries short sections of screws that interlock at extremely close tolerances but never touch.

turnkey project because no other artificial lift technology can handle such a well at depths in excess of 12,500 feet deep.

"Suncor [Energy Inc.] gave us an opportunity during the initial Firebag installations to test our pumps in their SAGD [steam-assisted gravity drainage] wells at 225 degrees Celsius," says Pradeep Dass, who founded Can-K in 1991. "Suncor's willingness to test our pumps gave us a lot of field experience in SAGD applications. We are now ready to land ESTSP in SAGD wells. We are also developing rigless ESTSP at this time with permanent magnet motors. We hope to be ready by sometime in 2011 with field trial capabilities.

"Twin screw technology has been around for ages," Dass acknowledges. "It's a very efficient volumetric design type of pump with many advantages for petroleum production. However, it's very difficult to manufacture an ESTSP small enough to fit within well casing while generating the high pressures needed to move large volumes of heavy oil. There are other design challenges as well — our company has climbed a steep learning curve over the years."

The traditional rod pump is relatively inexpensive, but is typically limited to wells producing daily volumes under 2,000 barrels. Progressing cavity pumps (PCPs), also quite affordable, handle sand and heavy crude well but are even more restricted with respect to daily volumes. Can-K claims that its ESTSP models can be adapted to pump 150 to 56,000 barrels per day and directly compete against electric submersible pumps (ESPs), gas lift and some PCP designs.

Its patented design incorporates two shafts, separated by a timing gear. Each shaft carries short sections of screws that interlock at extremely close tolerances but never touch. Because the screws don't touch, there is less friction and less torque is needed, resulting in lower electricity consumption. It is very efficient when compared to ESP systems, especially in more viscous and high gas-to-oil ratio mediums.

"Because it is a positive displacement pump, it is always volumetric. Pressures remain the same with varying speed," Dass explains. "The pump does not distinguish between gas and liquid because it interprets volume only. Unlike a centrifugal pump, the twin screw unit has no best efficiency point, and it can draw down to vacuum conditions." Gas content can be as high as 97 per cent, with three per cent liquids required for motor cooling and lubrication.

The Can-K president says the ESTSP works well for asphaltene and waxy wells because it has low shear, which minimizes breakout. "Residual asphaltene improves efficiency because it increases viscosity, a fact that has been clearly noted during field applications," he comments. "Although an ESTSP is not a sand pump, it can handle more sand than a conventional ESP. That's because the twin screw pump does not have a centrifugal component so it does not throw the sand around." The company has also come up with a patented screw design that impedes pump seizure due to sand and other solids. Everything that comes out of the well goes into the pump.

The ESTSP uses downhole electric motors from other manufacturers. Bottom-hole temperature can be as high as 280 C as far as the pump is concerned. Besides ESTSP, the company offers a top-drive twin screw pump that is sucker-rod driven or coiled-tubing driven. It also has a rigless top-drive twin screw pump that can be installed using coiled tubing, slick line or a sucker rod.

"The inherent efficiencies of the twin screw pump give it the potential to replace conventional ESPs," Dass says. "However, a lot of lessons could only be learned the hard way, through trial and error. KOC has more than 48 similar wells, so we're looking at an exciting opportunity. Can-K just moved into a larger manufacturing facility in Edmonton, and we are ramping up our manufacturing capability for major production by 2011 or 2012." •

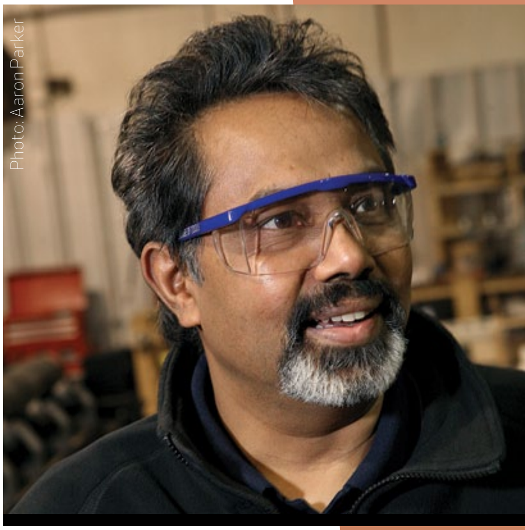


Photo: Aaron Parker

Can-K president Pradeep Dass has invested years in adapting twin screw pump technology.

"Suncor's willingness to test our pumps gave us a lot of field experience in SAGD applications. We are now ready to land ESTSP in SAGD wells."

— Pradeep Dass, Founder, Can-K

## Pradeep Dass tackled a steep learning curve

**BORN IN SINGAPORE,** Pradeep Dass studied mechanical engineering at Bangalore University in southern India. His family owns a high-tech company in India that manufactures space- and mining-related products. "The truth is that I've never worked for anyone else [as a salaried employee], and I doubt that I could hold a job," says the 53-year-old Edmontonian.

As a youth, he chafed in Singapore, a city state in southeast Asia whose exceptional prosperity is tempered with limited freedom of speech. "I came to Canada in 1991 as a business-class immigrant and looked for opportunities in engineering and manufacturing. Most of our sales are international, but SAGD represents an opportunity for us on our own doorstep."

TECHNOLOGY STARS
2010 WINNER

## BEST HSE TECHNOLOGY:

### Suncor Energy Inc.

**PRODUCT:**
Tailings Reduction Operations (TRO) system

**SERVICE:**
Greatly reduces reclamation time for tailings

# TAILINGS TRIUMPH

Suncor's TRO technology slashes the time to reclaim oilsands tailings by two-thirds

**by Mike Byfield**

Suncor Energy Inc. estimates that its tailings reduction operations (TRO) technology will slash the time required to reclaim oilsands tailings from 30 years to 10 years or less. "Thanks to this development, we've eliminated the need to construct new tailings ponds at our bitumen mining operation," says Bradley Wamboldt, TRO director for Suncor in Fort McMurray, Alta. "In addition, we plan to


The TRO process is based on clay particles clinging to a polymer material. After flocculation, the MFT/polymer flocs are dried in thin layers over gently sloped sand banks, then left in place or moved to another location. Here, Suncor TRO director Bradley Wamboldt examines a bed of drying tailings.

reduce the eight existing ponds to just one over time."

Oilsands producers use hot water to separate bitumen from sand and clay. The clay is then stored in shallow ponds, which currently cover a total area of 170 square kilometres. (This figure, equivalent to an area 13 by 13 kilometres, includes all oilsands mining companies.) The clay particles are suspended in water with traces of hydrocarbon, forming a thick soup that requires centuries to consolidate on its own. Consolidated Tails (CT), a process pioneered by Suncor in the 1990s, accelerates consolidation by adding sand and gypsum.

As oilsands bitumen output continues to increase, however, the CT time frame wasn't fast enough to halt the expansion of the huge slurry ponds. Suncor began experimentation with drying out tailings in 2003. The TRO process, first field tested in 2008, is based on clay particles clinging to a polymer material. The resulting flocs readily come out of suspension in water. (The chemical term is flocculation.) "Mature fine tailings [MFT] and polymer solution are both viscous materials. They must be mixed but not too much. Over the past two years, we've worked out operating parameters which we can now pretty much just dial in," Wamboldt explains.

After flocculation, the MFT/polymer flocs are dried in thin layers over gently sloped sand banks, then left in place or moved to another location for final reclamation. From time to time, the flocculent beds are ploughed, exposing more wet material to the air. The entire drying process occurs within weeks. The TRO process can only take place in months without a firm freeze-up. During that period, Suncor's project work force rises to the range of 200.

Suncor currently processes 180 million tonnes of oilsands annually, ingesting 50,000 tonnes per day of fine clays. Half of these fines are captured in the tailings beaching operation as they are pumped into the big ponds. The remaining 25,000 tonnes per day eventually settle into MFT and will be treated by the TRO process. "In 2009, our team processed MFT at a rate of 1,500 dry tonnes per month, utilizing 30 hectares of land," Wamboldt says. "This year was our big ramp-up. We now have four drying sites totalling 350 hectares, capable of handling 25,000 to 30,000 tonnes per month. Remember, though, that we can't dry in winter. So we plan to add 90 hectares annually for the next three years — it's mostly a matter of clearing the land."

Last year, the Alberta government introduced regulations that impose annual targets for reducing MFT. "We are in a position to meet or beat those targets," Wamboldt says. The company has spent "in the low hundreds of millions" of dollars developing the TRO method, he says, with a further billion dollars budgeted for MFT processing in the years ahead. The patented process remains confidential. Suncor is willing to share its innovative methodology with other oilsands miners — if they help pay some of the TRO technology research and development cost. •

## Suncor's tailings breakthrough will save money

**BRADLEY WAMBOLDT** categorically rejects the notion that Greenpeace and other enviro-lobby groups bullied Suncor Energy Inc. into cleaning up its tailings act. "Tailings management has always been integral to this industry's planning, long before it became a high-profile issue beyond Alberta," says the chemical engineer, a graduate of McGill University in Montreal. "Any oilsands operator is legally obliged to restore its leases back to their original condition or a comparable state. Nothing new there."

The key question was never if, but how. "Producers have been chasing a solution for MFT [mature fine tailings] for a long time," admits Wamboldt, who's worked overseas as well as in Canada. He came to the oilsands in 1997, helping with initial development of Shell Canada's Muskeg River Mine project. "Technically, tailings have proven to be a challenge, as they are for many other mining industries," says Suncor's TRO director. "Now we have the necessary technology to address the problem."

Before TRO technology was developed, Suncor planned to construct five more tailings ponds. "Dikes aren't cheap to build, and these would have been large structures," Wamboldt says. "Suncor will also generate a significant cost saving by shortening the distance that mine waste material has to be transported. We crunched the numbers and TRO came up the winner both economically and environmentally. That's not really surprising. New technology that's environmentally sound often makes financial sense as well."

Photo: Suncor Energy Inc.

Suncor pumps a slurry of mature fine tailings and polymer flocculant over a gently tilted slope for drying. The TRO process works only during seasons without freezing weather.

TECHNOLOGY STARS

2010 RUNNERS-UP

*Two nominees were selected for honourable mention in the HSE category:*

**Environmental Refuelling Systems Inc.** of Edmonton would have won a 2010 Technology Star if safety were a separate category (an option that will be considered carefully next year). Its FracShack is a stand-alone modular unit that provides a low-pressure fuelling system for a fleet of frac pumpers and other heavy vehicles while they're completing wells on closely packed drilling pads.

**Questor Technology Inc.** designs and manufactures state-of-the-art incinerators, providing up to 99.99 per cent combustion efficiency without any particulate matter, polynuclear aromatic hydrocarbons or unburned hydrocarbons. Our judges ranked this product as the best in the environment category from a small firm.

**Could hybrid SAGD/in-situ combustion programs provide a magic bullet?**

*By Godfrey Budd*

# the heat is on

Although the complexities and challenges of in-situ combustion (ISC) are widely viewed as greater than those for other high-impact production technologies like thermal or $CO_2$ flood, ISC — either alone or combined with other technologies — is attracting growing interest among producers. Dubert Gutierrez, a reservoir engineer with Computer Modelling Group Ltd., a reservoir simulation software vendor and consulting firm, says he received three or four enquiries about ISC "in just the last three days," during one recent week.

"The fact that some ISC projects have been working for years should tell you something," says Gutierrez, who recently co-wrote an SPE paper, *30 Years of Successful High Pressure Air Injection: Performance Evaluation of Buffalo Field, South Dakota*.

The Buffalo field, part of a group of eight Red River units operated by Continental Resources, Inc., is the oldest active air injection project in the U.S., according to the paper, which was presented at the SPE Annual Technical Conference and Exhibition in Florence this last September. The field, which produces 32 degrees API oil from a carbonate formation at an average depth of about 8,500 feet, was discovered in 1954, but was soon troubled by steep declines. Koch Oil acquired an interest in the field in 1974 and, in 1978, began commercial ISC or, as it is often known in light oil applications, high pressure air injection (HPAI).

In 1995, Continental acquired Koch's Buffalo Red River Unit, which included 73 vertical producing and 38 injection wellbores. Continental subsequently re-entered 48 existing vertical wells and drilled horizontal laterals to increase production and sweep efficiency. The company announced plans to spend $16.7 million in 2010, "for drilling, capital workovers and facilities" on Buffalo Red River.

Waterflooding was ruled out for Buffalo and other units early on, because of "wetting" issues that are common to carbonates, says Archie Taylor, manager for reservoir engineering applications with Continental. At one of the newer Red River units, where air injection began six or seven years ago, the company initially considered a carbon dioxide flood, as the anticipated incremental oil, at an estimated 15 to 20 per cent, was better than the one for ISC, at around 10 per cent. "The economics of $CO_2$ didn't work when we started in 2003, 2004. At the time, $CO_2$ would have cost three or four times the cost for air injection," says Taylor.

**TEST TUBE**
Researchers at the University of Calgary use a combustion tube to test field samples at reservoir pressure to determine if they are suitable candidates for in-situ combustion oil recovery.

Photo courtesy: In Situ Combustion Research Group

## ISC potential

The total production from Continental's eight units, located in South and North Dakota, was a healthy 14,249 barrels of oil equivalent (BOE) per day in the fourth quarter of 2009. The potential promise of ISC in Western Canada's heavy oil and bituminous oilsands sectors could be far greater than at the Red River units, however. With four-fifths of the oilsands, or about 136 billion recoverable barrels of oil that can't be surface mined and are only recoverable through some kind of in-situ process, there should be plenty of scope for other bitumen-heating technologies besides steam-assisted gravity drainage (SAGD).

Unfortunately, although ISC has chalked up heavy oil successes in Romania, Venezuela and India, with recovery factors in the 39 to 50 per cent range, it has had a spotty record in the sandy bituminous deposits of Western Canada. "There have been 30 to 40 air injection projects in Western Canada — and about 95 per cent have failed," says Robert Bailey, who was vice-president of engineering and chief

Buffalo field, South Dakota

operating officer at Excelsior Energy Limited until a deal closed in early November for Athabasca Oil Sands Corp. (AOSC) to acquire Excelsior.

"There've been operational problems. Hot, corrosive gas damaging tubulars and pumping equipment. Sands, propelled by hot gases, plug tubulars downhole and damage pumps. There was also concern about hot gases migrating and the potential for gas blow-outs at the wellhead."

Researchers have attributed ISC failures and operational problems to channelling of injected air, insufficient oil mobility at the start of injection, unfavourable air-to-oil ratios, and poor gravity segregation of gases and liquids.

Despite a seemingly jaundiced view of ISC's track record in Western Canada, Bailey is a proponent. During his time at Excelsior, he spearheaded development of a proprietary in-situ combustion process called COGD — combustion overhead gravity drainage. "COGD has been designed with these historic problems in mind. COGD and other combustion overhead applications overcome them. It segregates the oil and gas and keeps the gas at the top of the reservoir away from the producer. Fluids in the reservoir move slowly, so sand is not mobilized and does not enter the producer well," he says.

Developed with the help of consulting advice from the In Situ Combustion Research Group at the University of Calgary's Schulich School of Engineering, the COGD system deploys a series of vertical air injector wells above a horizontal production well located at the base of the bitumen pay zone. But, with COGD, the vertical ignition/injectors don't start the fireflood process. Instead, a multi-step pre-ignition cycle using steam heats up the bitumen, prepares it for ignition and improves its mobility. On ignition, a combustion chamber develops above and along the length of the horizontal well. Combustion gases are segregated within the upper part of the chamber, with the hot bitumen flowing by gravity into the horizontal producer. Gases are collected in vertical vent wells positioned at the flank of the exploitation pattern and sent to a facility for processing. The process would include the application of "maintenance" steam to protect tubulars from excessive heat.

Besides far lower water and natural gas requirements, as compressors could be electrically powered from the grid, partial upgrading of the bitumen within the reservoir via thermal cracking is one potential advantage of the process. But perhaps its biggest potential advantage over SAGD is a five- to seven-fold increase in energy efficiency. With SAGD, when one unit of energy in the form of steam leaves a boiler, part of it has been lost by the time it has reached the pay zone — it's now less than one. By contrast, says Bailey, a unit of energy in the form of compressed air increases up to seven-fold in the downhole combustion process. "This is the critical efficiency metric," he says.

At the time of the AOSC purchase, which includes the COGD intellectual property, Excelsior was awaiting regulatory approval for a COGD pilot of up to 1,000 BOE per day at its Hangingstone property, and was seeking a partner to help with funding the $50-million project.

The AOSC purchase also included Excelsior's oilsands properties at Hangingstone and West Surmont and, the day the purchase deal closed, the new owner announced plans to file an application for a SAGD pilot at Hangingstone. "We plan to have our experts review COGD and decisions will be made later on it," says Heather Douglas, AOSC's vice-president of communications. She says there was no timeline for when a decision on COGD would be made.

Although COGD technology appears iced for the time being, concerns around SAGD's water usage — despite improved recycling — and natural gas costs could still favour ISC technologies in future. Bailey argues that a 10,000-BOE-per-day SAGD operation requires about 4,000 barrels per day of fresh water even if the operation is recycling 40,000 barrels per day. Also, he is not convinced that the deliverability of North American shale gas is as certain as some believe. There are smart people on both sides of the issue, he says, and recalls that deliverability of coalbed methane has not matched the promise of that resource.

Unless the energy that is locked in the bitumen is used for fuel, current SAGD technologies indicate that about 136 trillion cubic feet (tcf) of gas — or equivalence in energy source — will be required to produce all the recoverable in-situ bitumen in the Athabasca oilsands. (True, the OPTI-Nexen Long Lake project is using gasification of on-site bitumen but, so far, output has fallen short, producing 28,500 BOE per day as of July 2010, instead of the anticipated 55,000 BOE per day.)

## Uptick in interest

It is perhaps because some of the young engineers who participated in the failed ISC pilots of a dozen or more years ago are now decision-makers that ISC proponents like Gordon Moore and Raj Mehta, University of Calgary petroleum engineering professors and both part of the In Situ Combustion Research Group, have encountered resistance to ISC.

But cracks are appearing in the wall of resistance, and Moore and other ISC researchers are seeing an uptick in interest from producers. (Besides the recent consulting for Excelsior on COGD, Moore and his group are working with other industry clients.) For one thing, oilsands experts have long anticipated that, as the better SAGD prospects are exploited and used up, remaining in-situ plays could prove problematic for SAGD. Also, it is both tradition and considered good practice in the oil industry to hedge your bets.

Indeed, if the results of some recent lab work are successfully piloted in the field, ISC, supported by SAGD or another thermal in-situ technology, could one day prove to be the sector's closest thing to a magic bullet, solving a host of problems.

As one might expect, Moore believes a blended or hybrid approach that includes both steam injection and fireflood is best suited for oilsands conditions. "Combustion can't be the first process used in the oilsands," he says, citing the heavy viscosity of the bitumen.

The In Situ Combustion Research Group is located at the University of Calgary's Schulich School of Engineering.

Photo courtesy: In Situ Combustion Research Group

Cold temperatures and low API gravity combine to make a fireflood impractical without first applying heat to mobilize the oil. "Venezuela's oilsands are similar, but temperatures are high enough for mobility," says Mehta.

A recent SPE paper, *Experimental Evaluation of SAGD-ISC Hybrid Recovery Method*, which was co-written by Moore, Mehta and two other petroleum engineers, described an experiment in which SAGD was operated in the model for a period of time before starting combustion by switching to air injection. Core samples were extracted from the model to evaluate coke formation and asphaltenes. "It was concluded that it is possible to recover almost 70 per cent of the original oil in place with a special kind of well arrangement," stated the paper, which was presented at the Canadian Unconventional Resources & International Petroleum Conference in Calgary in October.

The work described in the paper and other tests and experiments done by the In Situ Combustion Research Group target a range of issues. "We are aiming to find out at what point do you bring in ISC for a specific situation. What's the optimal way to inject air? What does the gravity flow look like? Where's best to locate the flame?" says Moore. The research team that he co-supervises has performed over 274 in-situ combustion tube tests on 35 reservoirs in eight countries, with gravities ranging from six to 40 degrees API. About 60 of these tests have involved 95 per cent oxygen-enriched air. Extensive kinetics measurements have enabled the development of models that describe the thermal cracking, low and high temperature oxidation of Athabasca bitumen.

Another SPE paper from the same group and also presented at the Calgary conference in October titled *Feasibility of In-Situ Combustion in the Mature SAGD Chamber* looks at potential optimization with ISC during or approaching the blow-down phase. Based on lab experiments and other studies, the paper proposes an ISC solution to an operational problem that's encountered in SAGD, where steam chambers typically don't grow at the same rate. Instead, steam can leak from an "immature" chamber, where pressures are likely higher, into a lower pressure "mature" chamber. This can result in efficiency losses with higher steam-to-oil ratios.

The research so far has been promising. The paper reports that not only was oil recovery increased by more than 20 per cent over the SAGD operation, but that a coke layer formed around the perimeter of the mature chamber, isolating it from the rest of the reservoir. "Perhaps this can increase net present value from a company point of view while increasing the ultimate recovery from the well. The process could benefit from the energy stored in the well from years of steam injection," says Moore.

Clearly, SAGD has limitations. "It's proven for some reservoirs, but you can't implement it everywhere [in the oilsands]," says Soheil Asgarpour, president of Petroleum Technology Alliance Canada (PTAC). But, noting the operational problems associated with ISC, he considers firefloods as yet commercially unproven for oilsands applications. Nonetheless, he says, "ISC can work better in a very thin reservoir that is homogeneous."

But another ISC process, which would use dual horizontal wells for air injection and heavy oil production, might work successfully in thicker reservoirs, according to researchers at Texas A & M University. An SPE paper titled *Combustion Assisted Gravity Drainage (CAGD) Appears Promising*, also presented at the Calgary conference, says detailed reservoir simulations were conducted to compare the performance of CAGD with SAGD and toe-to-heel air injection (THAI). "The results reveal that CAGD process has the lower cumulative energy-to-oil ratio in comparison to the other two methods and its oil production is comparable to SAGD," states the paper.

A patent for CAGD has been applied for. "In a thin zone, ISC with vertical wells can work, but CAGD should work better in a thicker zone," says Daulat Mamora, a professor and one of the authors of the paper.

The issue of predicting ISC outcomes — either alone or in tandem with another thermal technology like SAGD — via reliable reservoir simulations is likely to shadow the prospects for firefloods for some time. But, as Gutierrez points out, early simulations for SAGD were hobbled by a lack of historical data.

Despite the complexities of ISC processes, he says good simulations are possible provided two key conditions are met: first, that extensive, detailed testing, sampling and data gathering is performed as there are many critical variables and, second, that the engineers doing the modelling have an excellent grasp of oxidation processes and can model the relevant oxidation behaviours of the reservoir being studied. "We have the basic physics understanding," he says, adding that simulations will improve as more data is gathered from labs — and pilots in the field.

A recent paper he co-authored, and published in the April 2009 issue of the Journal of Canadian Petroleum Technology (JCPT), examined some of the challenges of predicting field performance ISC based on lab and numerical modelling.

Gutierrez, who is studying the data and literature on existing ISC projects, says, "The lab work results are correlating well with data from the field." •

# NEW RIG technology

"The market is looking for a smaller footprint and easier moves, but lots of power and capacity. And that's really what this rig was designed for."


Savanna's TDS-3000

Photo courtesy: Savanna Energy Services Corp.

# what's old is new again

## Savanna's 're-invention' of its hybrid fleet creates new medium-depth rig opportunities

Born out of the bottom line necessity of maximizing utilization, Savanna Energy Services Corp. is in the process of revitalizing its hybrid drilling fleet. With the need for shallow gas wells in decline, Savanna is reacting to the changing demands of its customers with the type of creative thinking that has placed the company as a leader in Canada's energy services industry.

In a move that will re-engage its mainly idle and under-utilized hybrid fleet, Savanna has created the TDS-3000 drilling platform that uses many key components and ancillary systems currently part of its hybrid CT-1500 platform. And according to the company, customer response to the new design "has been very positive."

That said, Ken Mullen, Savanna Energy Services' chief executive officer, is quick to note that the company's latest drilling platform "isn't as much an innovation as it is a re-invention.

"We have a large fleet of hybrid rigs which were ideal when we were drilling lots of vertical shallow wells, which we haven't done for a couple of years now and it doesn't look like we're going to be doing many of them in the near term. We have 38 shallow hybrid rigs that are in our fleet and the clear indications are that those rigs, as they sit, are not going to get good utilization for a number of years," Mullen says.

"Our strategy really was to say, 'We've got this platform, how can we re-invent it to make it attractive to the industry and to make it not just a rig that will hopefully go to work, but a rig that actually fits the needs of what industry is looking for.'"

So Savanna's operational and design teams got to work. And much like some of the plays

Photo courtesy: Savanna Energy Services Corp.

they were targeting — such as the Cardium and Viking — they were determined to make what was once considered old and dated, new again.

"When the operational and design guys embarked on it, it was really about looking at all the pieces of equipment we've got, looking at the layout we've got and looking at the market needs and trying to build to that," Mullen says.

"The market is looking for a smaller footprint and easier moves, but lots of power and capacity. And that's really what this rig was designed for. It's got the platform virtually of a hybrid with a few added loads obviously because of pipe and some additional pumps — we doubled the pumps up. The key thing is it's a very small, very easy-to-move rig. It's got quite a narrow centrepiece on it, which makes it ideal for minimal disturbance and quick moving."

Mullen notes that when a hybrid rig is built, one of the dynamics of drilling with coiled tubing is it's a smaller pipe than drill pipe, which means in order to drill it is necessary to get more volume down a smaller pipe. "This also means you need bigger engines, bigger pumps, bigger capacity in all your ancillary equipment than the depth rating of the rig would otherwise warrant."

But if you take away the coil, take away the centrepiece and all of the components that surround it, the mud pumps, engines and other components, the hybrid rigs are built for a 3,600-metre capacity while the existing units had only a 1,500-metre capacity. And that's essentially what Savanna did in creating the TDS-3000 platform.

"Once we take the coil attributes off that rig and slide in a conventional centrepiece, all of the other equipment fits in. So there was some reconfiguration, obviously, to make it work, but not really that much," Mullen says, noting that while Savanna already has a strong presence in the deep double market and the shallow market, the refurbished hybrids will allow the company to start shifting rigs into the medium depth market.

"The TDS-3000s are a really good fit in the Viking play, the Cardium, the Shaunavon as well as in portions of the Bakken, though some of the Bakken is too deep. The biggest advantage of these rigs is they've got pretty significant depth capacity — 3,000 metres vertical, 3,600 metres horizontal — off a very small platform."

The TDS rig is equipped with an integrated 150T top drive capable of 23,000 foot-pounds of torque. It also has a hook load of 300,000 pounds with 630 horsepower drawworks. The rig still incorporates many of the efficiencies that are seen on the hybrid, such as automated catwalk and iron roughneck, and the ability to quickly tear down and rig up.

Mullen says the first two TDS-3000 rigs have been contracted by Cenovus Energy Inc. and will begin operations during the fourth quarter.

"I think one will be going to Saskatchewan, probably the Shaunavon play, and the other is going farther north to the Pelican Lake play," Mullen says. "I think that as we get the first two rigs out and people see what they can do — we still have to prove it in the field — but if people see it's a successful platform then that will generate additional work."

Based on anticipated additional demand for these rigs Savanna has committed to the manufacture of six additional TDS-3000 rigs in 2011. The company has also committed to the retrofit of two additional hybrid drilling rigs for Australia. • **Paul Wells**

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# going deep

### Xtreme's XTC 500 rig has broad application for horizontal wells in shale plays

Xtreme Coil Drilling Corp. has set its sights on the deeper horizontal drilling market, and is building larger rigs to meet the needs of that market, worldwide.

Recently, the Houston-headquartered drilling contractor signed a multi-year contract with a new customer for its newest drilling rig model, the XTC 500 Coil Over Top Drive (COTD), a fit-for-purpose, variable frequency drive electric rig designed for deep horizontal resource plays. It will be Xtreme's second XTC 500 contracted to work in North Dakota's Bakken formation, and when completed in the second quarter of 2011, will bring the company's advanced technology drilling fleet to 17 rigs.

"This rig has a broad application in the horizontal shale plays," says Rod Uchytil, Xtreme Coil's president and chief executive officer. "The other aspect is that it will have the capacity to be a dual-purpose rig, to utilize coiled tubing if desired. With our rigs, we can go deeper than any other coiled tubing rig in the world, by a long way."

Featuring two 1,600 horsepower mud pumps, which meet the need of most horizontal wells for more pumping capacity, the XTC 500 is an alternating current (AC) rig with a 500,000-pound hook load capable of drilling to 21,500 feet (6,553 metres). Its highly automated pipe handling system is designed to drill with and rack 45-foot joints of drill pipe in double stands, with the ability to rack all of the drill pipe in the derrick — a significant technical improvement, according to Xtreme Coil, over conventional rigs that drill with 30-foot joints of drill pipe in triple stands.

"Having that extra capacity speeds up the operation a little bit more with one-third fewer connections required," Uchytil says, noting that it takes approximately 24 hours or less to move the rig from one location to the next. "It's all focused on time savings. Our rigs are very mobile and fast moving." To this end, the XTC 500 includes a skidding system for multi-well pad drilling.

Xtreme's technology, which has been on the market for the past four years, provides operators with an alternative not just to drill the well, but also to do post-completion work. "We have dual-purpose rigs that allow you to drill with a top drive or perform other services with coiled tubing," Uchytil explains. "That's part of

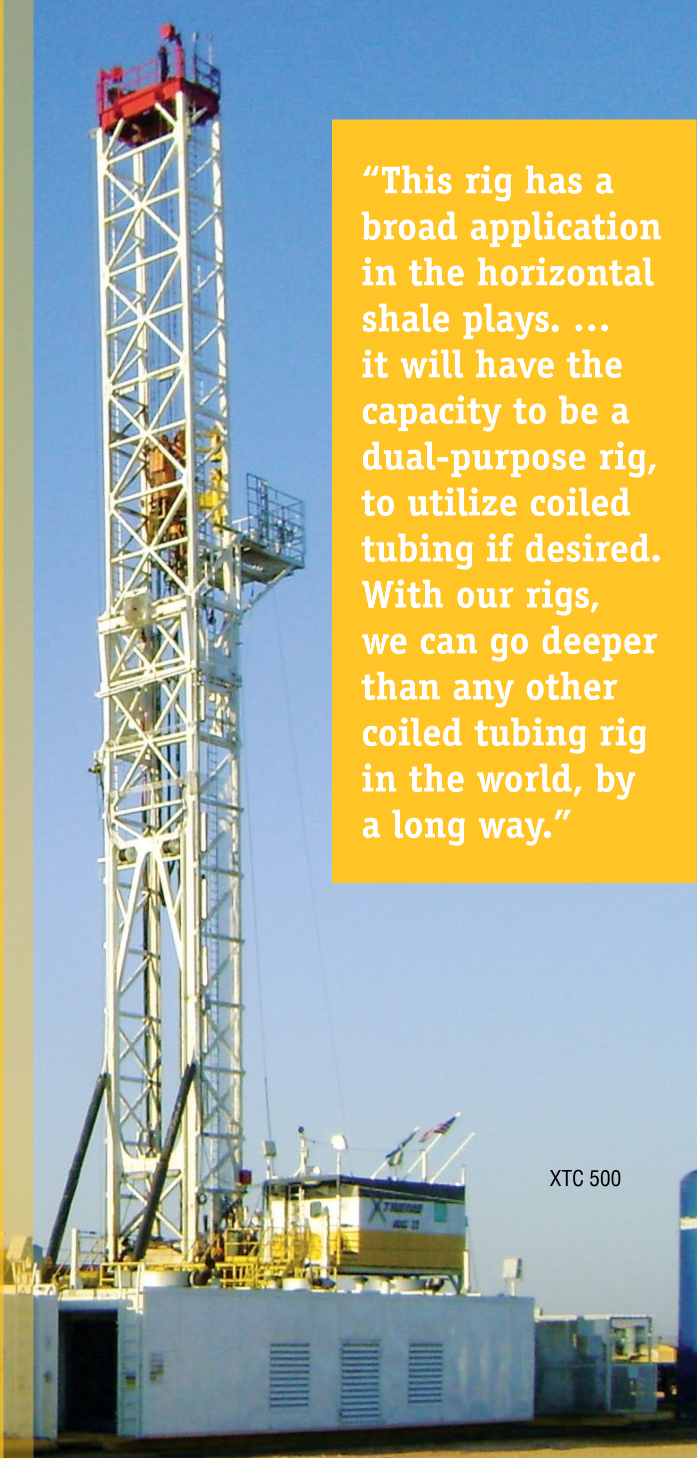

Photo courtesy: Xtreme Coil Drilling

XTC 500

**"This rig has a broad application in the horizontal shale plays. ... it will have the capacity to be a dual-purpose rig, to utilize coiled tubing if desired. With our rigs, we can go deeper than any other coiled tubing rig in the world, by a long way."**

the design. You always have that dual capability."

Xtreme Coil says it can do what any of the other high-tech Tier 1 rigs can do, with coiled tubing as an add-on that can be used for drilling or servicing wells.

Xtreme also expects to take advantage of a new requirement by Pennsylvania's Department of Environmental Protection that companies use a snubbing unit or coiled tubing rig for all post-completion work, in order to more effectively manage blowout risk.

"This is a trend that could move to other plays as well and if it does, Xtreme Coil has a unique product to meet that need," Uchytil says. "We have a feature that nobody else has: to go with deep, large diameter [2 ⅞-inch] coil to depths of 21,500 feet." In comparison, other coiled tubing providers are limited to approximately 18,000 feet of two-inch pipe.

While now headquartered in Houston, Xtreme Coil remains a Canadian public company with a corporate office and engineering and design team in Calgary. It also has offices in Al Khobar, Saudi Arabia, and Veracruz, Mexico. The company provides full-cycle service by designing, building and operating dual-purpose rigs for customers, using technology that can be applied anywhere in the world.

"The focus of our company is advancing drilling technology and innovation," Uchytil says, noting that Xtreme has 23 patents already granted and another 60-plus patent-related applications in progress around the world.

For Xtreme, the next step beyond the XTC 500 is the XTC 750, which the company is designing to meet the needs of the long horizontal wells typically drilled in shale plays. The XTC 750 is also suitable for wells in the Middle East and even Mexico, Uchytil says, noting that the 750's sub-structure is its key differentiator from the XTC 500, with a three-piece instead of a one-piece design.

"When you're getting into that larger size, it usually brings more requirements," he explains. "With the design we're building, we want to be able to move it around in Pennsylvania, in particular in the Marcellus shale and in other areas where there are more restrictions on logistics, such as smaller roads and bridges that can't handle large weights."

Xtreme still has another four to five months of detailed engineering work to do in order to complete the XTC 750 design. "We believe there is a need, and will work toward securing contracts for that rig before we start to build," Uchytil says. • **Jacqueline Louie**

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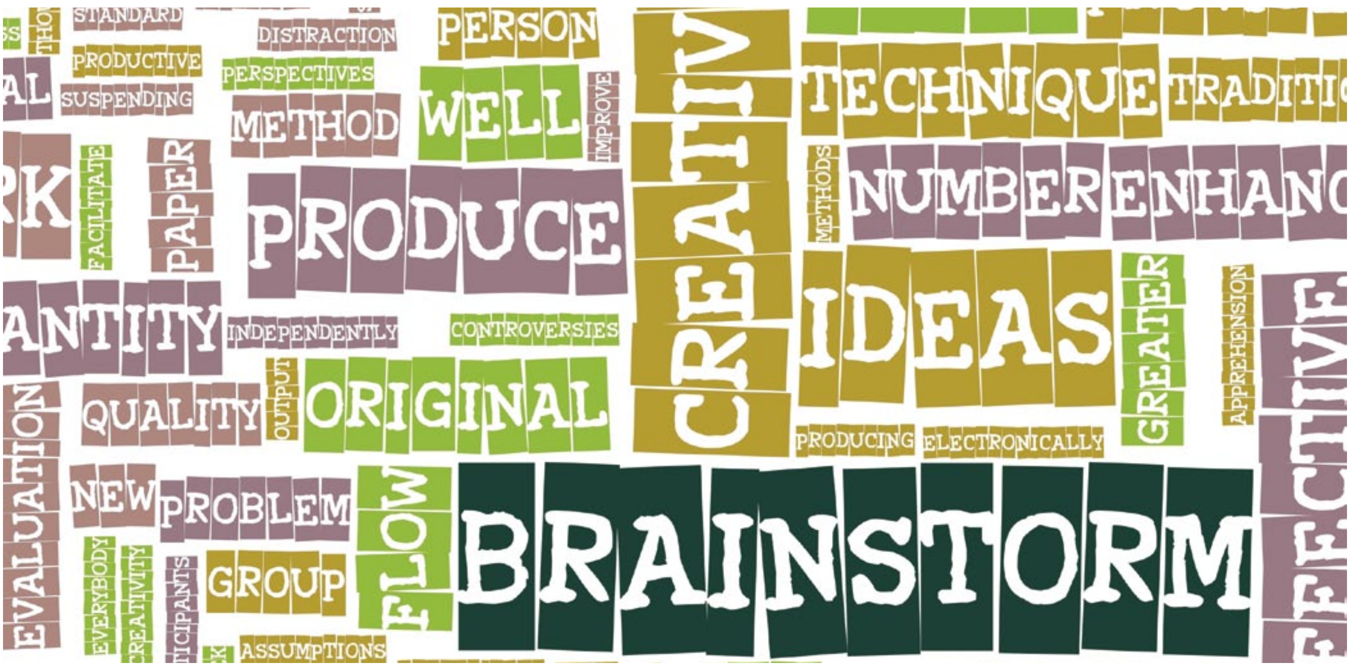
TOOLS AND TECHNIQUES

# new tech




DRILLING

## United We Stand

*Collaborative approach helps improve drilling performance*

DUE TO FIERCE COMPETITION, CO-operation in the oil and gas industry has tended to be fleeting.

Because of this environment, companies tend to be acquisitive by nature. They gather land, for example, through brokers in Canada so competitors are none the wiser as a rival gobbles up prime real estate. This mentality has pervaded other key areas of the industry, including technology development.

But that sort of thinking has been turned on its head in several ways at the Horn River Basin shale play in northeast British Columbia. A high-profile example is the Horn River Basin Producers Group, a collection of major producers that has banded together to facilitate a streamlined approach to dealing with various issues that are inherent as industry attempts to exploit an area that has been relatively void of petroleum industry activity.

This sort of co-operation recently spilled over to the relationship between producers and service providers in the play as well. The benefits of ongoing collaboration was highlighted in a recent paper co-authored by Steve Barton, Andrew MacLeod and Russ Lockley of NOV (National Oilwell Varco) Downhole.

The paper details how a major operator, working with the drill bit supplier, made "radical improvements" in drilling performance in the area, leading to significant cost reductions. The team approach allowed for bit design improvements implemented in a controlled, continuous and closely monitored program. A key was the development of a unique flexible bit design developed specifically for directional applications.

The bits contain features that allow rapid design modifications to be performed locally, reducing response time and allowing the program to proceed at a much faster rate than was previously possible.

The systematic co-operative approach allowed the operator to achieve the initial objective of drilling the interval in three bit runs but also the subsequent goal of drilling the interval in just two

**QUICK BITS**

The NOV Downhole drill bit created for faster drilling in the Horn River Basin features torque control components (TCC) that help prevent the bit from damaging the formation. The TCCs, which can be easily modified to suit the specific application, are the "buttons" seen on the face of the bit as well as at the gauge.

bit runs. Days to drill this section were drastically reduced from over 40 to less than 12 days.

The savings produced by this huge improvement in performance has helped the economic viability of continued Horn River development, according to Barton, vice-president, drilling tools, with NOV Downhole in Houston. The major difference using this approach is the fact the company worked in conjunction with the customer to achieve clearly defined targets that both had agreed were attainable.

**"When I looked at the before and after numbers for the drill out, build and lateral, we had substantially improved metres drilled and ROP."**

"This had the benefit of setting clear goals and also ensured that the customer was aware that each new bit iteration that was developed was an attempt to reach these goals, thereby removing any objection they might otherwise have had to constantly trialing different bit designs," he says. "Also, the fact that both the initial and subsequent goals were set very high meant that this was to be a longer-term project, with rewards for both parties."

For NOV, this led to increased sales because more wells were being drilled economically, while for the operator it meant lower costs, ergo the ability to drill more wells.

The main technology employed in this example was the SystemMatched Motor Series (MS). Managing the fluctuations in bit torque is the key to success in directional motor drilling, Barton says. The MS technology consists of a number of proprietary features, which include a relieved gauge geometry that reduces friction when sliding and torque control components (TCCs) that prevent the bit from taking an excessive bite into the formation.

Positioning of these components can be adjusted to minimize torque fluctuations, improve tool face control and maximize rate of penetration (ROP). The TCCs can be easily modified to suit the specific application and this approach was exploited in this project to quickly fine-tune the characteristics of the drill bit to meet the drilling demands in the vertical, curve and lateral sections of these wells, the authors say.

"Historically in Canada, the customers' objectives had been defined entirely from their point of view and not necessarily agreed upon with the bit suppliers," says Lockley, formerly Canadian sales manager, but now in a technical position in Brazil. "In addition, there was always a reluctance to be the first to try anything new … which made it almost impossible to achieve the desired results."

The fact the team included the field personnel made the project work even better, "as they believed in what we were trying to do and did their best to make it successful and supply feedback if we were not," he adds.

"When I looked at the before and after numbers for the drill out, build and lateral, we had substantially improved metres drilled and ROP," says MacLeod, regional evaluation engineer manager for Canada based in Calgary. "We more than tripled the metres drilled in the drill-out phase compared to the offsets, more than quadrupled the metres drilled in the build section, while nearly tripling the average ROP, tripled the metres drilled in the lateral section, all while increasing the ROP in the drill-out and lateral section."

The benefits of this strategy are being used by the majority of other operators in the Horn River, who saw how much quicker this operator was drilling the wells and wanted to emulate its performance, Lockley adds.

"This strategy is being used to some [extent] in other shale gas plays within the U.S., where a new drilling challenge is providing opportunities for significant savings to be made by combining resources to develop a solution," Barton says. "Another phase of this project is to employ other drilling tool technologies that are complementary to each other, to further enhance performance, thus delivering time and cost savings to the operators.

"Aside from drill bit technology, this includes matching the bit with specific downhole motors, addition of a downhole agitator tool, and utilization of dynamic recording data to optimize the [bottom hole assembly] and parameters."

These will be outlined in a separate paper that will be presented at a drilling conference in Amsterdam in February 2011. •

**Richard Macedo**

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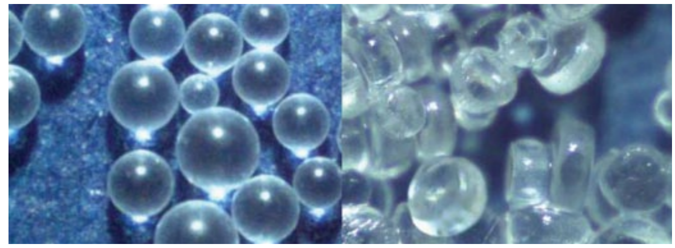
FRACING

# Deep Impact

*Fracing process for shallow wells now being used for deeper wells*



**GOING DEEPER**
Canyon's polymer-based proppant compresses to a neutral point due to its elastic properties and does not crush or embed like sand.

A PATENTED HYDRAULIC fracing process — which was developed about five years ago and, with nitrogen as a transfer medium, was mainly geared for shallow coalbed methane, sand and shale formations that typically respond poorly to fluid fracturing — is now being applied to hotter formations at greater depths, using water.

Canyon Services Group Inc.'s patent is for a process, using either gas or liquid, of placing a partial mono-layer of a light-weight deformable proppant (LWP) into a formation. Called the Grand Canyon process, as it initially targeted Horseshoe Canyon CBM, it has been applied successfully on hundreds of shallow gas wells in Western Canada, in a range of formations. According to a January investor update, Canyon had by then applied over 3,500 high-rate nitrogen fracing treatments, and "completed over 800 wells using the Grand Canyon process."

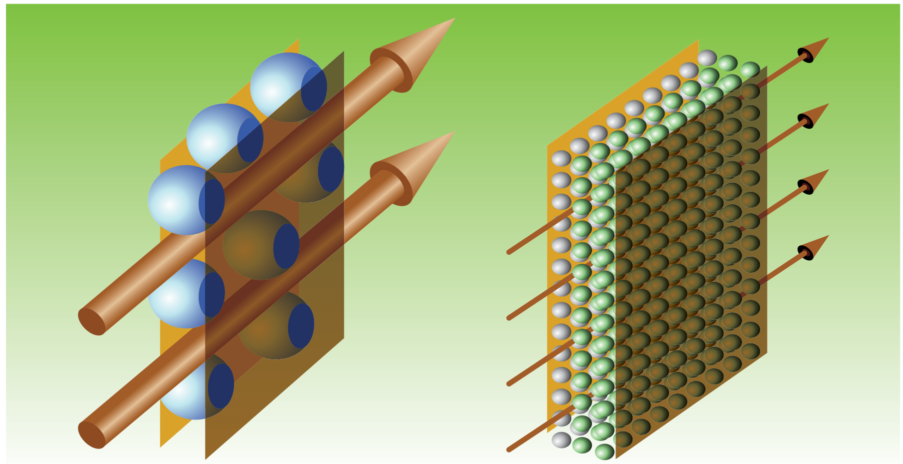
The polymer-based proppant, once placed in the formation, can compress to a neutral point because of its elastic properties and does not crush or embed like sand. The partial mono-layer is up to 100 times more permeable than a conventional, multi-layer sand pack.

Furthermore, placing a heavy proppant like sand with a transfer medium like nitrogen was a challenge best avoided, if possible. So Canyon developed a light-weight proppant, working with a third party. With its specific gravity of 1.05, compared to sand with a specific gravity of 2.65, the LWP travels more easily and about three times farther than a conventional proppant like sand.

Using a deformable proppant has the further advantage of reducing erosion on coiled tubing and downhole tools. Also, sand has a grinding effect, creating "fines" or minute particles that can plug some wellbores.

Canyon's track record with nitrogen fracing for its Grand Canyon process bodes well for upcoming field trials using water. "We think LWP and high-rate nitrogen pumping was something unique and novel. LWP has great load-bearing and placing power. It's technology like this that helps us crack open new plays," says Derek Krivak, president and CEO of Stealth Ventures Ltd.

The Calgary-based junior exploration and production company is focused on unconventional gas plays in CBM, shale and tight sands and first used nitrogen-based Grand Canyon fracing in 2007. "It was geared for Horseshoe CBM, but



**LWP VS SAND**
Partial monolayer of lightweight deformable proppant (left) versus conventional sand pack (right). The partial monolayer floats into hydraulic fracs, allowing up to five times longer effective frac length. The partial monolayer is up to 100 times more permeable.

we've also used it for Colorado shales near Vermilion [Alberta]," says Krivak. He adds that Canyon was "always willing to adapt and spend money on R&D to make the product better."

The Grand Canyon fracing process with nitrogen has also been used on shallow gas wells near Medicine Hat, Alberta, says Brian Lowen, senior completions superintendent at Direct Energy Marketing Ltd. "Our primary reason for using it was to get away from using water. This was to prevent damage to the formation and avoid water clean-out issues. Also, there are no winter freezing issues. The results are as good as completing with water. It means completions are done more quickly and are less complicated. All this saves money at the end of the day."

Petroleum Technology Alliance Canada (PTAC) is helping to co-ordinate a series of field trials with about five producers for Canyon's patented process using water on deeper wells. "We're hoping for less water use," says Marc Godin, a consultant for PTAC.

There are several reasons for switching to water on deeper wells, notes Joe Peskunowicz, executive vice-president, corporate, at Canyon. At greater depths, gas starts to compress and it becomes more difficult to maintain sufficient width to bring the proppant to the formation. "At shallow depths, the nitrogen can keep enough width to ferry the proppant into the formation," he says.

Canyon has been working with 3M on polymers for a range of temperatures and depths. Peskunowicz says that LWPs used for shallow wells are unsuitable for some depths as they could melt or deform too much at the higher temperatures. A new polymer has been developed to handle higher temperatures. "The proppant deforms as it is flexible, but this specific polymer for greater depths deforms to a specific extent in lockstep with specific temperatures and closure stresses," he says.

A mid-size producer has begun using Grand Canyon with water, but has a non-disclosure agreement. "They want a competitive edge to prove a particular play. All that can be said is that they are planning more treatments," says Peskunowicz.

Fluid-based fracing with the Grand Canyon process should be less water-intensive than conventional fracing with sand, as the lightweight proppant has a specific gravity only marginally greater than fresh water and about the same as some produced brines. "The nitrogen treatments proved that the partial mono-layer theory worked in the field. So it's not a big stretch for it to work in deeper, hotter wells if they're not water sensitive. Usually, deeper wells are not water-sensitive," says Peskunowicz.

As with nitrogen, by using a lightweight deformable proppant the fracing process with water sidesteps the problems associated with sand — namely its tendency to either fall out, not reaching the formation, or become crushed or embedded. On the other hand, Peskunowicz says, "You don't have the thickness or width you have with nitrogen, so you have to rely more on the speed of injection."

He anticipates the learning curve for orienting the Grand Canyon process to more water-based fracing will be about the same as it was for nitrogen. •

**Godfrey Budd**

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