New Technology magazine

• the first word on oilpatch innovation

November 2012

A CUT ABOVE

In the quest for oil and gas, those companies whose innovation stands above the rest are recognized as the industry's **Technology Stars**

Microbe Stampede?

An old EOR concept is being revived as interest grows and projects proliferate

PM40069240


Trust your pick?

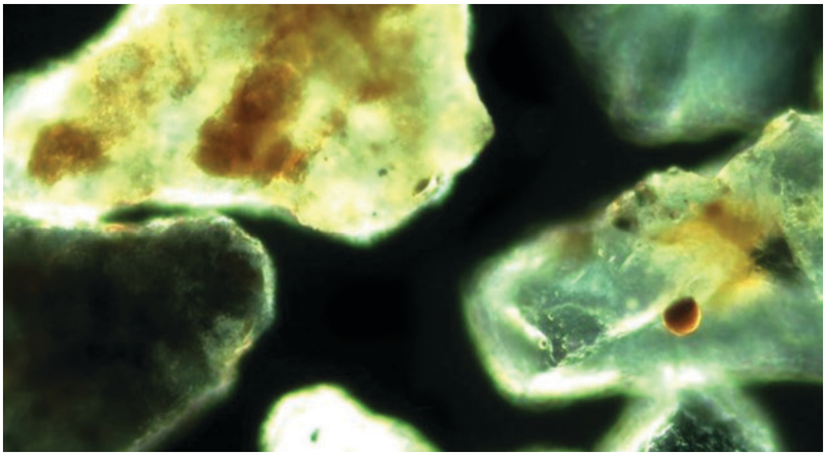
CONTENTS

NOVEMBER 2012 | VOL.18 | NO.09

FEATURES

Cover Feature

23 **A CUT ABOVE**
In the quest for oil and gas, those companies whose innovation stands above the rest are recognized as the industry's Technology Stars



18 **MICROBE STAMPEDE?**
An old EOR concept is being revived as interest grows and projects proliferate

DEPARTMENTS

EDITOR'S VIEW

6 Removing Barriers

VANGUARD

9 News. Trends. Innovators.

BYTES

15 Solution In Hand
Hand-held technologies cut costs, improve safety and enhance oilfield equipment reliability

NEW TECH

43 In The Zone
Ozone-based frac water treatment technology provider targets the oilsands

45 Breaking All The Rules
A new technology has the potential to eliminate hydraulic fracturing's biggest challenges

ADVERTISERS

Baker Hughes Canada Company .... IBC
Calfrac Well Services Ltd. 7
Canyon Technical Services Ltd. 29
ConocoPhillips Canada 41
Dragon Products 37
Entero Corporation 3
Extreme Engineering 21
Fluid Energy Group 22
geoLOGIC Systems Ltd. 14
Halliburton 42
Millennium Directional Service Ltd. 20
NCS Oilfield Services Canada Inc. 17
Packers Plus Energy Services Inc. ....IFC
Panasonic Canada Inc. 8
Schlumberger Canada Limited 5
Strad Energy-Matting 33
Tervita 13
Weatherford Canada Partnership .... OBC

EDITOR'S VIEW

REMOVING BARRIERS

THERE IS LITTLE doubt that what has been the most prominent advance in oil and gas technology in recent years—the commercial success of multistage hydraulic fracturing—has transformed the energy supply picture across North America and, increasingly, around the world.

The disruptive technology reversed the long-term decline in North American natural gas production and is now repeating that pattern in oil. The near-miraculous reversal in oil and gas production has reached the point where the unlikely state of North Dakota was recently reported to be on the verge of surpassing Organization of the Petroleum Exporting Countries member Qatar in oil output, having passed a record 700,000 barrels a day and climbing.

But sometimes more gradual, evolutionary technology development can have as big an impact. It may not have made as big a splash, but the technologies perfected over the last few decades that opened up the Alberta oilsands have also had big implications in turning around the North American hydrocarbon supply picture, converting what once couldn't be produced into the world's third-biggest reserve of crude oil.

That success, however, didn't come without particular complications. The environmental impact of oilsands extraction has become its Achilles heel, drawing opposition to its development on the grounds it stands out as the dirtiest source of oil on the planet. This is where technology once again enters the picture. Never satisfied to rest on its laurels and continue business as usual, the industry has invested heavily in improving its production methods, to the point some oilsands producers now say they can compete, emissions-wise, with conventional oil production.

Both Cenovus Energy Inc. and Imperial Oil Limited have recently boasted of technological advancements that have taken some of their operations to the stage that they may no longer need fear the outlawing of high-emission fuels, such as the low-carbon fuel standards proposed by California and the European Union.

Cenovus said in October that oil produced from some of its northern Alberta operations can already meet the emissions laws expected to soon be implemented in California. Independent analyses have shown the company's Christina Lake and Foster Lake operations to be among the most efficient in the oilsands sector.

In August, Imperial said new technologies implemented at its Kearl oilsands mining operations nearing start-up would enable it to emit the same level of greenhouse gases (GHGs) as the average barrel of oil used in North America. That level would actually give its output a smaller GHG footprint than heavy grades from Saudi Arabia and Venezuela.

And on the in situ oilsands production side—which is typically more GHG intensive and represents about 80 per cent of oilsands potential production—Imperial is investing $100 million to further advance lower-emission solvent—as opposed to steam—production technologies.

If they work as well in the field as they have in the laboratory, Imperial will be able to "reduce the overall greenhouse gas emissions intensity down very near to the level that conventional oils produce today," president and chief executive officer Bruce March said at an energy roundtable in Calgary in October. Quoted in the *Calgary Herald*, March added, "Think of what that could mean for the public perception of Canada's oilsands."

Indeed, it could mean new technologies could play as big a role in removing potential barriers to production as they have in the past to unlock the resource. If the sector can definitively remove the dirty oil label, it could go a long way toward maintaining its social licence to continue with ambitious expansion plans. Not all oilsands projects are near that stage of emissions parity with conventional production, but as the new methods—which almost always come with the added benefit of cutting costs—are perfected, their diffusion into the rest of the industry is only a matter of time.

As *New Technology Magazine* salutes its Technology Stars in this issue, it is the same spirit of constant technological improvement that has come to the fore. Some of the technologies originate in the oilsands, some relate to advances in multistage fracture technology driving the shale gas revolution forward, and some originate in the conventional oil and gas exploration, drilling and production side. Taken together, they represent an industry continuing to provide creative, innovative and sometimes groundbreaking solutions to today's industry challenges. ■

Maurice Smith

New Technology magazine

www.newtechmagazine.com

EDITORIAL

EDITOR
Maurice Smith | *msmith@junewarren-nickles.com*

STAFF WRITERS
Richard Macedo, Pat Roche, Elsie Ross

CONTRIBUTING WRITERS
Jim Bentein, Godfrey Budd, Gordon Cope, Jacqueline Louie

EDITORIAL ASSISTANCE MANAGER
Samantha Sterling | *ssterling@junewarren-nickles.com*

EDITORIAL ASSISTANCE
Kate Austin, Marisa Sawchuk

CREATIVE

PRINT, PREPRESS & PRODUCTION MANAGER
Michael Gaffney | *mgaffney@junewarren-nickles.com*

CREATIVE SERVICES MANAGER
Tamara Polloway-Webb | *tpwebb@junewarren-nickles.com*

CREATIVE LEAD
Cathy Ozubko | *cozubko@junewarren-nickles.com*

GRAPHIC DESIGNER
Jeremy Seeman

CREATIVE SERVICES
Christina Borowiecki, Joel Kadziolka, Jenna O'Flaherty

SALES

SALES MANAGER—ADVERTISING
Maurya Sokolon | *msokolon@junewarren-nickles.com*

SENIOR ACCOUNT EXECUTIVE
Tony Poblete

SALES
Nick Drinkwater, Rhonda Helmeczi, Mike Ivanik, Nicole Kiefuik, David Ng, Diana Signorile, Sheri Starko

For advertising inquiries please contact adrequests@junewarren-nickles.com

AD TRAFFIC COORDINATOR—MAGAZINES
Denise MacKay | *atc@junewarren-nickles.com*

DIRECTORS

PRESIDENT & CEO
Bill Whitelaw | *bwhitelaw@junewarren-nickles.com*

VICE-PRESIDENT & DIRECTOR OF SALES
Rob Pentney | *rpentney@junewarren-nickles.com*

DIRECTOR OF EVENTS & CONFERENCES
Ian MacGillivray | *imacgillivray@junewarren-nickles.com*

DIRECTOR OF THE DAILY OIL BULLETIN
Stephen Marsters | *smarsters@junewarren-nickles.com*

DIRECTOR OF DIGITAL STRATEGIES
Gord Lindenberg | *glindenberg@junewarren-nickles.com*

DIRECTOR OF CONTENT
Chaz Osburn | *cosburn@junewarren-nickles.com*

DIRECTOR OF PRODUCTION
Audrey Sprinkle | *asprinkle@junewarren-nickles.com*

DIRECTOR OF MARKETING
Kim Walker | *kwalker@junewarren-nickles.com*

DIRECTOR OF FINANCE
Ken Zacharias, CMA | *kzacharias@junewarren-nickles.com*

OFFICES

CALGARY
2nd Flr-816 55 Avenue NE | Calgary, Alberta T2E 6Y4
Tel: 403.209.3500 | Fax: 403.245.8666
Toll-Free: 1.800.387.2446

EDMONTON
220-9303 34 Avenue NW | Edmonton, Alberta T6E 5W8
Tel: 780.944.9333 | Fax: 780.944.9500
Toll-Free: 1.800.563.2946

SUBSCRIPTION INQUIRIES
Tel: 1.866.543.7888 | Email: circulation@junewarren-nickles.com
Online: junewarren-nickles.com

Printed in Canada by PrintWest. ISSN 1480-2147

You may also send information on address changes by email to NewTechnology@junewarren-nickles.com. Please quote the code that begins with the prefix NTM.

For members of the Society of Petroleum Engineers, please contact the SPE office directly with your address change.

New Technology Magazine is owned by JuneWarren-Nickle's Energy Group, a subsidiary of Glacier Media Inc., and is published 10 times per year. Printed in Canada by PrintWest. ISSN 1480-2147.

junewarren-nickle's energy group

Alberta Magazine Publishers Association

FSC Logo Placeholder

71 Per cent

Canadians overwhelmingly support oilsands development so long as continued efforts are made to limit the associated environmental impact, according to a Montreal Economic Institute (MEI)–commissioned Leger Marketing poll, which is part of a research paper, *Innovation and the greening of Alberta's oil sands*, published in October. When told about the latest technological advances in the field and how those advances limit environmental damage as well as reduce production costs, 71 per cent of those polled said they "think these efforts to protect the environment are significant," says Pierre Desrochers, MEI associate researcher.

"CONDENSATE HERE IS LIQUID GOLD. IT IS BETTER THAN OIL."

— Heather Christie-Burns, president and chief operating officer, Angle Energy Inc.

Alberta's booming oilsands sector is driving demand for condensate, a light hydrocarbon consisting primarily of pentanes and pentanes plus, which is mainly used to dilute bitumen for pipelining. Its demand could outstrip domestic supply far into the future. Speaking at a Peters & Co. Limited investor conference in Toronto, Christie-Burns said, "Condensate is very, very robust. It is always a premium on WTI [West Texas Intermediate]—anywhere from 105 up to 115 per cent premium."

"We must have, all of us, an unwavering dedication to zero leaks, an unwavering dedication to the goal of having zero incidents in the pipeline industry. Does that sound impossible? Maybe it does, but [it] must be our goal."

— Steve Wuori, president of liquids pipelines and major projects, Enbridge Inc.

Noting that pipelines have become a very deliberate and strategic target among opponents of fossil fuel and oilsands development, Wuori, in a luncheon speech during the International Pipeline Conference in Calgary in September, said the public "expects, and probably has the right to expect, that we know what is happening with our pipeline."

"WE THINK THE FUNDAMENTALS ARE NOW CONVINCINGLY POINTING TO A MAJOR TIGHTENING OF THE NORTH AMERICAN [GAS] MARKET."

— Martin King, vice-president of institutional research, FirstEnergy Capital Corp.

Minimal supply growth and robust demand for power generation will provide a much-needed boost to North American natural gas prices, King said in a presentation delivered at a JuneWarren-Nickle's Energy Group Speaker Series event in October. With the number of rigs drilling for gas in the United States at the lowest level since 1999—dipping to 422 after falling steadily from about 800 in January—King said the number has fallen below the tipping point needed to sustain production at current levels.

22.4%

The combined volume of flared and vented solution gas in Alberta last year totalled 27.86 billion cubic feet, or 76 million cubic feet a day, an increase of 22.4 per cent from 2010, according to the Alberta Energy Resources Conservation Board (ERCB). In its annual *Upstream Petroleum Industry Flaring and Venting Report*, the ERCB said production outside designated oilsands areas appears to be responsible for the lion's share of the increase in solution gas flaring with bitumen operations accounting for the balance.

IAMGE: PHOTOS.COM/RTIMAGES

COMPLETIONS

Frac Scrutiny Lacking

"Brute force" approach to fracture treatments may be wasteful, unsustainable

IMAGE: JOEY PODLUBNY

USING MASSIVE SLICKWATER frac treatments may be cheaper in the short run, but this assembly-line approach to completions is wasting horsepower, proppant and fresh water, says a veteran completions engineer.

"'Hit it with a bigger hammer' seems to be one of the approaches to optimizing our fracs," said Murray Reynolds, director of technical services at Calgary-based Ferus Inc., which supplies completion fluids such as nitrogen (N_2) and CO_2.

Brute force is easy because it requires no engineering and one-size-fits-all slickwater fracs may save money up front, but net present value—not cost—should drive frac design decisions, Reynolds said in a keynote address at the Canadian Society for Unconventional Resources' annual conference in Calgary in October.

For example, when excessive water and horsepower are used, frac networks are created that are much deeper than can be propped—and the un-propped part of the frac network contributes no production.

Reynolds said hydraulic fracturing accounts for 60–70 per cent of the total well cost, but frac treatments are the most poorly optimized aspect of developing unconventional reservoirs. He believes big gains in production can be made by improving frac designs.

"Has the assembly-line frac design concept completely blinded us to actually optimizing the frac treatment for value?" he asked rhetorically. "In the assembly-line approach…we have lost some of our ability to analyze and optimize fracs."

He said frac-fleet horsepower has grown ninefold since 2003, with most of the expansion capital spent on increased horsepower for pumping high-rate slickwater frac treatments.

Reynolds urged his audience to be wary of claims about the intrinsic superiority of "infinitely large" slickwater fracs.

The size and composition of frac treatments has evolved over the years. The first frac fluids, pumped in the 1940s, were kerosene and diesel. The volumes were very small—a few hundred or a few thousand gallons.

A big improvement in the development of hydraulic fracturing technology occurred around 1970. Reynolds said the first one-million-pound frac treatment was pumped in 1974 in the Wattenberg tight natural gas field near Denver. Some 500,000 gallons of poly-emulsion fluid (one-third water and two-thirds fuel condensate) were used to place that one million pounds of sand.

Further developments were the use of foams in the mid-1980s and visco-elastic surfactant (VES)–based fluids in the mid-1990s.

In the mid to late 1990s, the industry moved more to slickwater fracs, which use huge volumes of water. "Currently, the average volume used in a lot of the shale areas is actually five [million] to six million gallons of fluid," said Reynolds, who doubts this level of freshwater consumption is sustainable.

For example, he said about 270 rigs are working the Eagle Ford shale of southwestern Texas—a desert where 50,000 horizontal wells may ultimately be drilled. Meanwhile, he noted about 60 per cent of the continental United States was in a moderate to severe drought during the past summer.

FRAC MASTERY
In pursuing an assembly-line approach, the industry has impaired its ability to analyze and optimize hydraulic fracture treatments, according to Ferus Inc.'s Murray Reynolds.

In western Canada, Reynolds cited examples of water concerns making news amid large allocations of capital for water plants to supply frac fluid systems. In the Peace Country—which is in the second year of a severe drought—one producer allocated $35 million for a water pipeline. In northeastern British Columbia, the City of Dawson Creek put a moratorium on the industrial use of water production in September. "So not very good optics to use a lot of fresh water in a frac treatment."

While acknowledging that frac treatments account for only a tiny percentage of the total freshwater consumption, and that some areas use mainly saline water, Reynolds said it doesn't look good if the industry is pumping five million or six million gallons of fresh water per well when other users can't get enough.

"We know that assembly-line drilling contributes to lower costs, but we really need to take that to another level on the completions side," he said. "We need to do greater evaluation of the reservoir, more engineering effort, more application of [existing] frac diagnostic technologies [and to] reduce the amount of horsepower, fresh water and proppant per unit of production.

"We must have a sustainable industry," he said.

Without doing a cost comparison with slickwater, Reynolds listed several unconventional frac fluid systems. These include aqueous and non-aqueous fluids, polymer and non-polymer systems, N_2 and CO_2 foams, and hydrocarbon-based fluids.

N_2/CO_2 aqueous foams are probably the most technically versatile, he said, adding that VES surfactant gels are a huge advancement in clean frac fluid technology.

Non-aqueous frac fluids include pure liquid CO_2, a liquid CO_2/N_2 foam derivative, gelled methanol, CO_2 foam-gelled methanol and gelled LPG (liquefied petroleum gases), which may be a mixture of a number of hydrocarbons. Reynolds said the latter requires a specialized blender that may limit the job size and there are some "technical issues. But if there's a need to keep water off the formation, that's an option."

Another non-aqueous frac fluid system is miscible CO_2 gelled oil. CO_2 is highly miscible in oil and other reservoir fluids, and it comes out of solution quickly during cleanup.

As for future possibilities, Reynolds said a lot of research and development is being done to develop new frac fluid systems. Ferus is part of a joint industry project based at the University of Texas at Austin.

He said potential frac fluid developments include:

- Cellulose-based polymer that would reduce costs. (The cost of guar gum, which thickens some of today's existing frac fluids, has skyrocketed in recent years.)
- High-temperature VES fluids. The upper limit of existing VES is about 135 degrees Celsius.
- Produced-water gel systems that are tolerant of impurities.
- Gaseous CO_2 foams. Because CO_2 is generally pumped as a cold fluid at surface, if there are paraffins present in an oil reservoir, there may be problems with paraffins or asphaltenes dropping out. But if the CO_2 is heated to above the paraffin point, then an operator could take advantage of some of the CO_2 properties, such as full miscibility with the oil while placing the frac.
- Gelled CO_2 plus LPG. The original research done by Dow Chemical Company in 1971 used 50/50 CO_2 with LPG. In addition to technical advantages such as hydrostatic head, it removes a lot of the explosiveness and flammability, and it lowers the critical temperature significantly.
- Gelled liquefied natural gas. Right now there's no cheaper fluid than natural gas. So why not chill it to minus 162 degrees Celsius and pump it as a liquid?
- Nano-surfactants can reduce the CO_2/water interfacial tension significantly, which would be an advance in cleaning frac fluids out of the wellbore.
- Thermally induced fracturing, or "slick CO_2." Cold fluid hitting a hot dry gas reservoir would help enhance fracture systems, and there's the large expansion force of the CO_2 when it goes from liquid to a gas at reservoir conditions. ■

Pat Roche

DOWNSTREAM

Creating Natural Gas Demand

Oilpatch LNG engines make good economic sense; GTL also promising

FUELLING DEMAND FOR GAS
The oil industry itself could contribute to solving the natural gas supply overhang problem by switching from diesel to natural gas–powered trucks and equipment, according to a recent study.

IMAGE: JEREMY SEEMAN

CONVERTING LARGE ENGINES in the North American oilpatch from diesel to liquefied natural gas (LNG) fuel could create a billion cubic feet (bcf) a day of new natural gas demand, a conference heard in October.

One bcf a day is roughly 10 per cent of current Canadian gas production, said Robert Taylor, manager of the reservoir studies team at Halliburton in Calgary.

Citing data from two major gas producers, he said the potential market opportunity for LNG-powered engines in North America could be as much as 31 bcf a day. Hence the use of LNG fuel "could have a very significant immediate effect" on North American gas prices as consumption grows, Taylor added in a keynote presentation at the Canadian Society for Unconventional Resources' annual conference in Calgary.

Taylor's presentation discussed three potentially significant opportunities for western Canadian gas—gas-to-liquids (GTL) conversion, LNG exports and LNG engines. His co-authors are Mark Brown of Seven Generations Energy Ltd., Stewart Wilson and Kieran Ryan of Ferus Inc., and Peter Tertzakian of ARC Financial Corp. >

LNG as engine fuel shouldn't be confused with compressed natural gas, which powers most natural gas engines today. The difference is the natural gas for LNG engines is stored at a temperature of minus 162 degrees Celsius, which liquefies the fuel. This enables more gas to be stored, so vehicles can travel much farther without refuelling.

LNG fuelling infrastructure is already being put in place and vehicle conversions require relatively little expenditure of time and capital, Taylor said. Some companies in the western Canadian oilpatch are already running large engines on LNG. For example, frac fluid producer Ferus has LNG-powered trucks in its fleet.

Royal Dutch Shell plc plans to open three LNG fuelling stations in Alberta by the end of this year and some companies already have in-yard filling stations, said Taylor. In the United States, Clean Energy Fuels Corp. plans to open 150 LNG fuelling stations for trucks by the end of next year, he added.

The Achilles heel of vehicles powered by natural gas in its gaseous state is they need to refuel often. Chilling the clean-burning fuel to a liquid overcomes the limited-range handicap, Taylor said.

Of the potential North American market opportunity for LNG engine fuel of up to 31 bcf a day, the biggest potential consumer is estimated to be heavy-duty trucking at 15 bcf a day, he said. This is followed by mining and industrial (five bcf a day), medium-duty engines (four bcf a day), marine engines (four bcf a day), trains (two bcf a day), and the oil and gas industry (one bcf a day).

While oil and gas is the smallest of these estimated consumers, it is the market where LNG engines may first be adopted in North America, Taylor suggested.

Part of the reason is the oilpatch is geographically concentrated, it's a big consumer of diesel fuel and the sole producer of natural gas. "We do have a strong incentive—it's our own product," Taylor said.

Compared to truck and marine transport, the oil and gas industry would have the highest return on LNG conversion investments, he added. The payback period for converting a drilling rig to LNG from diesel is estimated at roughly 1.2 years versus 1.6 years for a frac pumper and 3.8 years for a transport tractor.

The energy equivalence of LNG to diesel fuel is 1.7 to one. In other words, 1.7 litres of LNG provides the same energy as a litre of diesel. However, LNG's lower price can mean significant savings over diesel in certain applications.

Fleet owners switching to LNG from diesel have two options. The first is a kit that converts engines to run 40–70 per cent on LNG with diesel making up the balance. The fuel is stored as a liquid, then vapourized to compressed natural gas using warm engine coolant before being fed into the engine with the intake air.

"The beauty of that is it's just a bolt-on addition and you're using the engine that you've already got. That's a very quick conversion," said Taylor.

The other option is a new dedicated LNG engine that burns about 95 per cent methane and five per cent diesel. It actually runs on methane; the five per cent diesel is just to get the engine running.

During storage or transportation, the LNG is held in double-walled stainless steel cryogenic tanks under a small amount of pressure.

LNG is already powering some drilling rigs. Taylor said this application is attractive because a rig operates on a fixed location, so the fuel storage tank can be separate from the rig.

Cautioning that the economic estimates are "extremely approximate," Taylor suggested LNG can be provided for 20–40 per cent less than the cost of diesel at current commodity prices. However, he said the saving depends heavily on factors such as the distance the fuel has to be transported from the supply source.

"But the point is there are some significant cost savings to be had," he said. "So this isn't just a case of being environmentally conscious. It's something that actually makes good business sense. Not to mention the fact we're in the gas industry, so we're creating an opportunity for our own product."

> "There is a very, very approximate 16-to-one rule for absolute minimum economics for a [gas-to-liquids conversion] plant like this to work. What that means is the price per barrel of crude oil needs to be at least 16 times the price for natural gas. Now that's a bare minimum. Twenty to one is a more comfortable number."
>
> ***— Robert Taylor, manager, reservoir studies team, Halliburton***

GAS-TO-LIQUIDS TECHNOLOGY

Another process that could increase gas consumption—and diversify demand—is GTL technology. South Africa's Sasol Limited, the world leader in GTL technology, is studying the possibility of building a GTL plant near Fort Saskatchewan, Alta. Encouraged by a feasibility study completed earlier this year, Sasol will decide before year's end whether to do a front-end engineering and design study. If the company makes a final investment decision, it says a plant could be built by the end of the decade.

Central to the economics of such a project is the spread between natural gas prices and crude oil prices. The higher the price of oil and the lower the price of natural gas, the better the GTL economics.

Using estimates from Seven Generations Energy, Taylor said, "There is a very, very approximate 16-to-one rule for absolute-minimum economics for a plant like this to work. What that means is the price per barrel of crude oil needs to be at least 16 times the price for natural gas. Now that's a bare minimum. Twenty to one is a more comfortable number. And as you get to 30 to one, you probably own the market."

Comparing the prices of AECO natural gas and Edmonton Par crude one day recently, Taylor calculated an approximate ratio of 26 to one. "So I think clearly the economics are looking good for us here."

However, he cautioned that even a 75,000-barrel-a-day GTL plant takes four to seven years to build and could cost anywhere from US$4 billion to US$6 billion.

For this reason, a potential GTL developer's long-term assumptions about oil and gas prices are crucial to its final investment decision. Taylor said one way to partially hedge the investment is for the company that will own the GTL plant to also own gas reserves. Sasol has done this by buying a 50 per cent stake in Talisman Energy Inc.'s Farrell Creek and Cypress A gas assets in the Montney play of northeastern British Columbia.

Converting natural gas to liquid fuels hasn't been done before in western Canada, but its commercial viability has long been established elsewhere. Sasol and Shell are the main operators of commercial projects.

The GTL process consists of two basic steps. First, natural gas is reacted with an oxygen source, which can be steam. This creates a carbon monoxide and hydrogen mixture called synthesis gas, or syngas.

The second step is the carbon monoxide and hydrogen are reacted in what's referred to as the Fischer-Tropsch process, which is at the heart of GTL technology. It converts the syngas to a synthetic crude oil. That synthetic crude can be refined to produce products such as diesel and naphtha.

A big environmental advantage of the GTL process is it creates a very clean diesel that is essentially free of sulphur and aromatics. ■

Pat Roche

For over 30 years, Tervita has worked to develop unique, industry-leading technologies that help oil sands producers overcome the challenges posed by unconventional oil and gas production.

We're a leader in developing new techniques for the processing of sludge, for instance, and are using that expertise to bring unique solutions to mine and tailings management. And working with academic, scientific and industry partners, we're helping to advance the research and development of practices which maximize oil sands extraction while minimizing environmental impact.

From coring services to well servicing to integrated onsite waste management solutions and specialized services like metal recycling, we support the industry by providing new technologies, more efficient processes and reduced costs. All while offering the utmost in environmental protection. Now that's unique. Visit tervita.com or call 1-855-TERVITA today.

TERVITA

EARTH MATTERS

FLUIDS SERVICES • SOLIDS SERVICES • PRODUCTION SERVICES • ENERGY MARKETING • RECLAMATION


geoLOGIC
SYSTEMS

PRODUCTION

Solution In Hand

Hand-held technologies cut costs, improve safety and enhance oilfield equipment reliability

STEVE JOBS, THE late chief executive officer and co-founder of computer, tablet and smartphone technology giant Apple Inc., used to talk about the need for his company's products to be elegant—a word that might not come to mind if he had learned that North America's largest hazardous waste disposal firm would end up using his company's iPads and smartphones in its operations.

But Norwell, Mass.–based Clean Harbors, Inc.—which is involved in such non-elegant businesses as garbage and recycling management, specialized hazardous materials cleanups, and high-pressure and chemical cleaning at refineries and energy production facilities—has embraced the iPad and hand-held technology world with a vengeance.

The company, which employs 8,300 people full-time in North America and about 2,000 part-timers, and generated US$2.1 billion in revenue last year, has adopted what it calls "disruptive technology"—hand-held devices like iPads, iPhones and on-board computers.

The company—which has launched a major push into Canada, where it now generates about half of its annual revenues, much of that in the oilpatch—has spent about $3 million to acquire the devices so far and is spending millions more annually on software support, training and implementation, according to David Parry, president, energy and industrial services.

"The technology is expensive," he says. "We're spending $500–$2,000 for each of the hand-held devices, and so far we've bought 4,000 of them," he says. "In addition, we're spending millions more on support and training."

But officials at the public company, which has seen its stock price move up steadily in the last few years as it was hired by the U.S. government and industry to do high-profile cleanups after Hurricane Katrina and the BP p.l.c. Gulf of Mexico oil spill, have no regrets.

"We're helping customers save money and we're able to provide them with better service," says Parry. "And we estimate there will be a three-year payout" with the investment in the technology having been fully recovered in that time.

The company has been on a buying binge in Canada recently, highlighted by the 2009 acquisition of Eveready Inc., which provided industrial maintenance and production, lodging and exploration services to the oil and gas, chemical, pulp and paper, manufacturing and power sectors. It paid US$174 million for that acquisition (also assuming $235 million in debt).

In April 2011, it announced it would purchase Calgary-based Peak Energy Services Ltd. for $196 million (cash and assumed debt). In doing so, it was purchasing a company that offered more than 6,000 pieces of rental equipment and related services to the oil and gas industry in North >

DISRUPTIVE TECHNOLOGY
Clean Harbors is investing in hand-held technology for its field staff in a big way, spending millions of dollars on the devices and the software support and training needed to implement the strategy.

PHOTO: CLEAN HARBORS, INC.

America through a network of 13 services facilities throughout the continent. The equipment includes centrifuges complete with related solids control tankage, wellsite accommodations, waste water treatment, tanks, drill camps and fluids hauling tankers.

Clean Harbors recently expanded its workforce housing division to include its own manufacturing division, through subsidiary BCT Structures Inc., which has a 140,000-square-foot plant in Lethbridge, Alta., where it employs 150 people.

Having become a major force in western Canada (it was already a major hazardous waste player in eastern Canada), the fast-growing company decided it needed to focus on the management and maintenance of its disparate assets, which is where the hand-helds entered the picture.

"That's why we're using technology to leverage our assets," says Parry. "We need to be an efficient service provider to ensure our customers get the data they need."

The company, which has more than 20,000 customers in North America, has an enterprise system group of five full-time employees who support the hand-held technology from offices in Massachusetts and Edmonton. The technology is backed by an Oracle-based enterprise system.

Parry says entering the iPad, smartphone and on-board computer world has given the company a competitive advantage. "Most of our larger customers [such as major oil and gas companies] don't want to push paper around any longer," he says.

Worksheets, invoices and other communication with customers are handled seamlessly via a cellular network. It beats the alternatives of the past. "The information is more accurate," Parry says. "We don't have to be concerned about humans [employees in the field] writing documents in minus-40-degree weather."

Drivers and other employees enter information such as fuel use and work locations into the internal system, which improves cost management and reduces mistakes. It also helps in managing equipment maintenance. "If a driver sees a need for equipment maintenance, he just enters that in our system," he says.

Paper worksheets are being eliminated, which means communication between Clean Harbors workers and customers moves faster and is more accurate. "We can email worksheets to the customers," he says.

Customers do have the option of receiving a printed copy, since the company has printers in all of its service vehicles, "but most customers don't want hard copies."

He says more than half of its customers prefer electronic communication, including invoices. "We can automatically upload billing information into their accounts receivable system."

The hand-held world has allowed the company to speed up its data management system, which lowers administrative costs, allows for the exchange of information more accurately, which improves customer service and improves cash flow, he says.

The iPads it uses—it has 1,000 of them in the field now—are protected by "rugged containers," since the workplace is more challenging than someone's living room. The company will be distributing another 1,000 iPads in the next few months. Training of staffers takes about two days.

Parry believes the adoption of hand-helds will also improve worker safety. For instance, he cites an example of a customer in northern British Columbia who requires a centrifuge servicing for a rig.

"Let's say the customer changes the protocol," he says. "Now our employees can access our training modules and procedures online. We see this as critical because we have hundreds of centrifuges in the field."

> "We're spending \$500–\$2,000 for each of the hand-held devices, and so far we've bought 4,000 of them. In addition, we're spending millions more on support and training."
>
> ***— David Parry, president, energy and industrial services, Clean Harbors, Inc.***

Parry says the use of iPads in such an application may not have been part of Steve Jobs's vision, but he thinks he'd feel fulfilled to see them making business more efficient and safer.

And Parry says the technology definitely gives his company a competitive advantage.

Cliff Wahlstrom, the company's Edmonton-based vice-president of technical services, who was formerly with Peak Energy Services and has 28 years of experience in the energy industry, says the hand-held technology has allowed him and his team of nine other employees to standardize its rental services business like never before.

"If we rent out a piece of equipment, we do a checklist before it goes out to the customer [to detail all aspects of the equipment's performance] and we do the same thing when it comes back from the customer," he says. "The hand-helds allow us to keep better track of the equipment and its history."

The hand-helds allow for the implementation of a more accurate "journey management" for equipment, he says. "It makes our operations more efficient and safer."

For instance, it was not uncommon in the past to have technicians go into the field to inspect a piece of equipment and determine that a belt needed to be changed. "Sometimes you'd have three different technicians change belts three times on the same piece of equipment and never determine what was actually wrong with it. Now they will see the history of that piece of equipment online."

Wahlstrom says it will also help to make the workplace safer, since equipment will receive the proper maintenance. And the hand-helds will allow for faster invoicing of customers, he says.

In total, the former Peak division has 6,000 pieces of equipment it rents out, ranging from centrifuges to generators to pumps and drilling equipment.

By next spring, its 300 field technicians, working out of nine offices in North America, will have iPads.

Wahlstrom says training of older employees may take more time since, unlike those in their 20s and 30s, they may not have entered the world of the tablet. "They're moving from paper to a paperless world," he says.

But he predicts they'll embrace the technology "because it will cut down on their workload" and improve safety.

Darin Hauck, senior vice-president at the company's Calgary office, says that division's 400 heavy trucks have already been equipped with Motorola personal computers and printers—similar to those used by couriers—and the 800 employees of the division have been trained to use them.

He says the technology has already improved customer billing and service, after only a few months of use (it started introducing the technology in January).

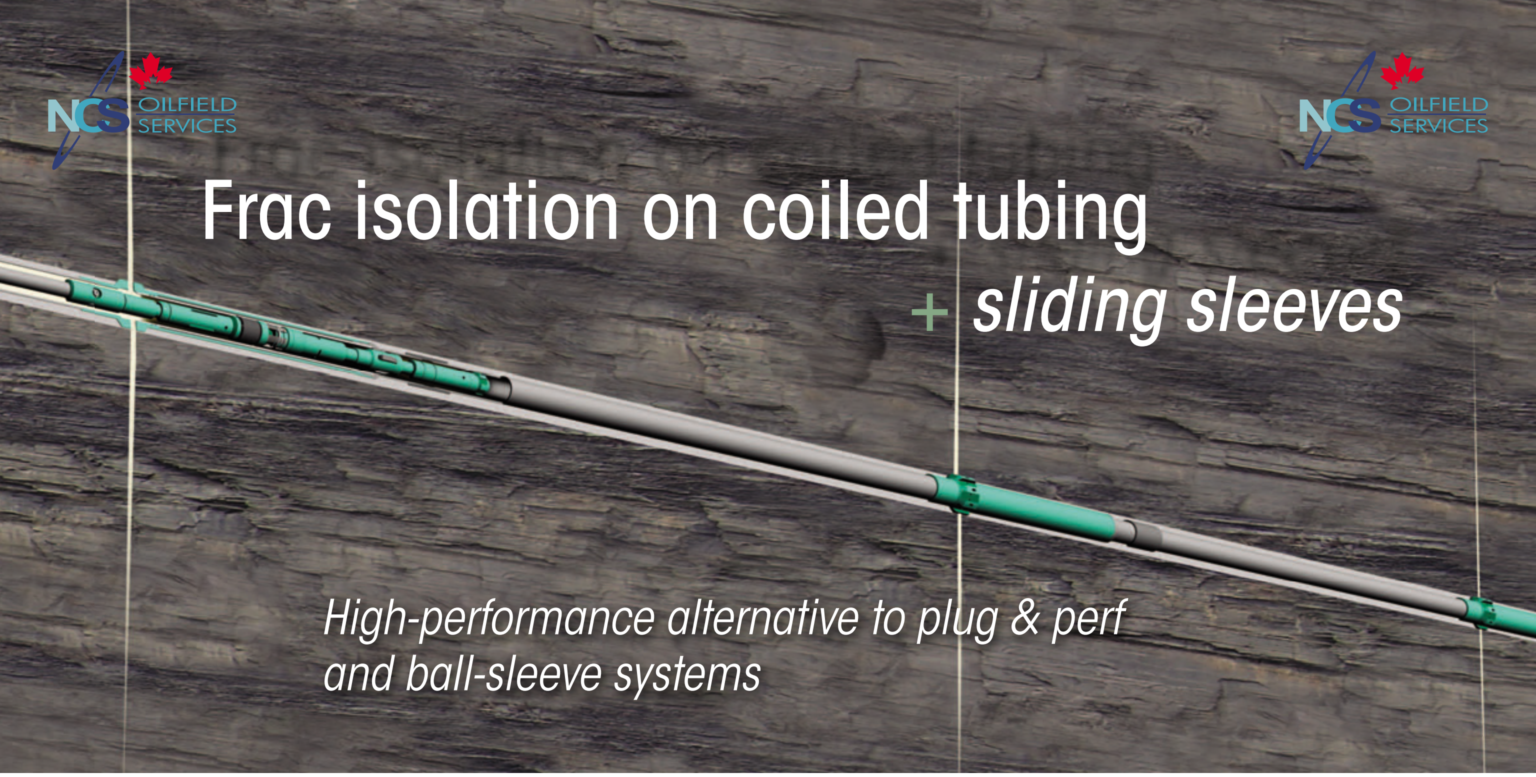
His division has 16 offices located throughout North America, which offer cleaning services at oil sites and refineries, among other locations. Its 400 trucks average two jobs a day, which previously produced "a huge volume of paperwork."

Now, thanks to the adoption of computer technology, there are fewer mistakes at work sites and jobs are performed more quickly and safely, he says.

Hauck has embraced the technology himself. "I'm a technology buff," he says, adding that he adopted the latest technologies before he joined Clean Harbors's predecessor Eveready (he had sold his own company to that firm).

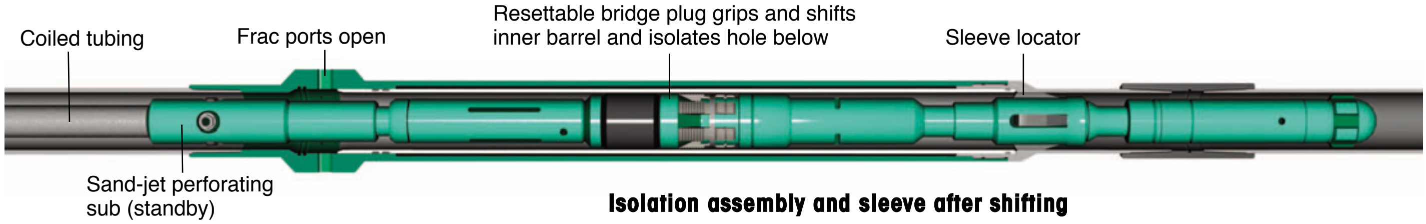
"The days of paper invoices [and paper in general] are behind us," says Hauck. ■

Jim Bentein



Frac isolation on coiled tubing + *sliding sleeves*

High-performance alternative to plug & perf and ball-sleeve systems



Isolation assembly and sleeve after shifting

Plug & perf and ball-sleeves and packers are basically brute-force techniques, with fluids and fracs bullheaded down the casing and into the formation, with no feedback about formation response at the frac zone, no recourse in the event of a screenout, and no way to conserve water and chemicals. Also, both methods can require extensive post-stimulation work to drill out plugs or ball seats.

With the Multistage Unlimited system, coiled tubing provides both a circulation path to the frac zone and a work string, giving this unique system a number of important advantages and none of the disadvantages of the other methods.

Fast frac isolation, mechanical sleeve shift

The coiled tubing running string permits the use of a remarkable, patented, dual-purpose tool that 1) isolates the target zone during the frac and 2) shifts the sliding sleeve open at each stage. This sand-friendly Multistage Unlimited resettable bridge plug eliminates the need for pump-down plugs and sleeve-shifting balls, cutting time between fracs to only 5 minutes. Fracs are pumped down the coiled tubing/casing annulus (smaller, low-rate fracs can be pumped through the coiled tubing).

Circulation path to the frac zone

The circulation path to the frac zone throughout the completion operation provides four important benefits:

- It is a means to monitor actual frac-zone pressure in real time for better control of sand placement
- It provides a way to manage fluids to reduce water and chemicals consumption up to 50%
- It provides quick recovery from screenouts by reverse circulating excess sand out of the well
- It enables the use of sand-jet perforating to add stages in blank casing, without tripping out of the hole.

It all adds up to better frac control, lower-cost completions, and lower environmental impact. Call us or visit our website for more information.

MULTISTAGE UNLIMITED

Leave nothing behind.

ncsfrac.com **409.925.7160 (US)** **403.862.0870 (Canada)** **info@ncsfrac.com**

microbe Stampede?

An old EOR concept is being revived as interest grows and projects proliferate

By Godfrey Budd

IT'S BEEN A long road to commercial application, but some experts believe that the perennial weak sister of enhanced oil recovery (EOR), the cultivation of production-boosting micro-organisms in the reservoir, is starting to show some strength.

Microbial activity in oil reservoirs is common and a general understanding of the role of some microbial processes in oil reservoirs has been around for decades. For instance, types of micro-organisms degrade oil to produce CO_2 and methane in the presence of water. Over geological time, such a process has resulted in Canada's oilsands. Some microbial byproducts can lower oil viscosity. Microbial activity can also produce a biomass that plugs up unwanted flow paths in a reservoir. These processes can be used to boost oil production and are known as microbial enhanced oil recovery (MEOR). While microbial-related corrosion prevention is a proven technology, harnessing microbial activity for MEOR has historically been a rather hit-and-miss affair over much of the last quarter century.

Recent laboratory work has accessed the latest measurement and analytic technologies and tools to improve the accuracy of its findings and still came up with some promising results. Growing numbers of field trials, pilots and, indeed, commercial projects are starting to show relatively consistent incremental production with MEOR, especially when compared to the spotty record of the past. A recent flurry of Society of Petroleum Engineers (SPE) papers, besides attesting to these successes, signals a general upswing of interest in MEOR. Oil and gas majors and some large intermediates have been hiring microbiologists recently, says Gerrit Voordouw, a professor and Natural Sciences and Engineering Research Council of Canada industrial research chair in petroleum microbiology at the University of Calgary.

The research indicates that reservoirs should be screened for MEOR, and a range of factors weighed first before deciding to go ahead with it. Still, MEOR could potentially have broad application across the global petroleum sector, resulting in billions of barrels of incremental production. According to an SPE paper (145054) by authors at two oil companies, Denver-based Venoco, Inc. and Calgary-based Husky Energy Inc., and Titan Oil Recovery, Inc. of California, a service company, "MEOR can be applied to a wide range of oil gravities. MEOR has been successfully applied to reservoirs with oil gravity as high as 41 degrees [API] and as low as 16 degrees API."

For oil companies, one part of the allure of successful MEOR—when it actually happens—is that it entails either negligible or no capital investment. It can usually rely almost entirely on existing infrastructure.

CUSTOMIZED NUTRIENTS

Some big chemical companies also appear to be taking MEOR seriously. In September, after a year or two of generalized optimism in the MEOR sector amidst what one expert called a proliferation of green shoots, and just ahead of the winter drilling season, DuPont unveiled its MATRx technology.

According to an October 5 announcement from DuPont Sustainable Solutions, the low-capital EOR technology, designed for fields under waterflood, "is distinguished from other microbial enhanced oil recovery technologies with a unique inoculation step."

DuPont's MATRx system uses customized nutrients to feed favoured microbes in the reservoir. "The DuPont proprietary injection system protocol ensures that nutrient effects are propagated far beyond the wellbore to prevent wellbore fouling. By moving nutrient effects deep into the reservoir, MATRx can effectively release more trapped oil from deep within the reservoir formation," according to a DuPont press release.

The targeted proliferation of selected downhole microbes is central to the MATRx concept and DuPont's MEOR process was operating commercially in Canada for several months prior to its October unveiling.

It is perhaps not so surprising that big outfits like DuPont are rolling out new products for MEOR or that the sector has been buoyed up as of late. "Microbiology know-how for isolating and identifying has improved a lot. We can now do things much faster, as in genomics technologies, which are helping," says John Fisher, business development manager at DuPont Canada and a co-author of several papers on MEOR.

As these technologies mature, companies, it seems, are warming up to the prospect of a giant bioreactor in the ground, which yields incremental crude oil when the appropriate microbial treatments and technologies are applied. Regarding MATRx, says Fisher, "We are getting intense interest in the technology from around the world and are in evaluation programs with majors."

An SPE paper by staff at DuPont presented at the SPE annual technical conference and exhibition in San Antonio, Texas, October 8-10 certainly points to some very promising lab and field data for the company's MEOR technology. In a field test described in the paper, a 15–20 per cent increase in production was seen. Prior to that, lab tests had shown similar promise. "In laboratory tests, we have observed in excess of 15 per cent increased recovery factor. This exceeded our expectations," state the authors.

Also, the field incremental production was matched by a corresponding drop in water cut.

Besides the good auguries from lab tests and field trials, the consistency of the two sets of data suggests that the lab science, protocols and measurements are growing more precise, and more predictive of field-trial and real-world results. It may indicate that MEOR is finally turning a corner away from being a last-ditch gamble to a viable EOR option.

ORGANISM IDENTIFICATION

Other developments in microbiology and MEOR should also help allay industry skepticism. "The biggest change in the last five to 10 years is our [improved] ability to tell which organisms are in the reservoir, so you can target the nutrient," says Mike McInerney, a professor of microbiology at the University of Oklahoma. "There are now lots of ways to determine how things are developing in the reservoir as a result. You can now track what organisms change and track what organisms or microbes do as a result of the introduced nutrients. That will give you a better ability to determine an approach [that's required] and determine its success."

The selective plugging of targeted flow paths is currently the more popular of the two main types of MEOR and has had a boost in recent years from the progress Fisher and McInerney point to. But the progress in microbiology, genomics and related disciplines could also boost the prospects of the other main approach. This involves altering the characteristics of reservoir crude by changing oil/water/rock interfacial properties, typically with the use of micro-organisms that produce biosurfactants.

"These can make the oil more mobile and move off the rock surface. Selective plugging is the most successful MEOR right now. Surfactants are more complicated. You want certain organisms to make a certain product," McInerney says.

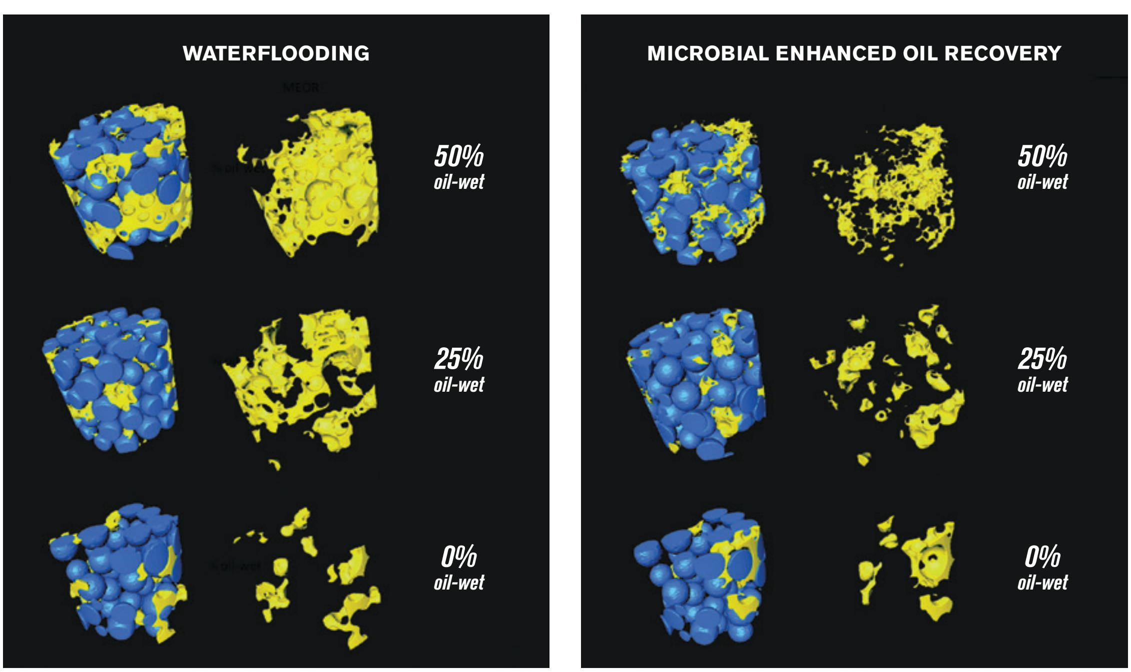
The U.S. Department of Energy has provided funding to the university for MEOR research and development, and McInerney's group recently completed a proof-of-concept project on biosurfactant-based MEOR with a small oil and gas company. The ultimate goal of the project, for which further stages are planned, is to move biosurfactant recovery from the lab to field commercialization.

In the work so far, approaches were developed and applied to detect and enumerate micro-organisms that produce biosurfactants in field brines. Seven different oil formations were surveyed, ranging in salinity from two to 15 per cent. Samples showed very low numbers of indigenous biosurfactant producers in the reservoirs. An effective biosurfactant producer was obtained for inoculation into reservoirs. A nutrient package was developed to trigger the growth of the biosurfactant-producing organism, which resulted in biosurfactant production in brine samples with salinity up to 11 per cent. "This made a lot of biosurfactant and there was some additional production," says McInerney.

Two wells received treatments. One that had been historically problematic performed poorly, but the microbial treatments worked in both, McInerney says.

As an indication of the spreading interest in microbial EOR, China's petroleum sector is conducting field trials and German chemical giant BASF is funding further research, he says.

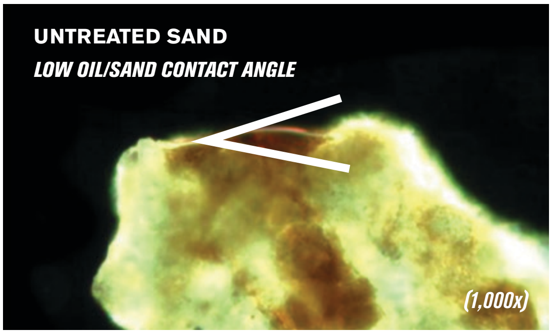
The development of MEOR technologies can involve protracted timelines. DuPont's press release mentioned eight years of research. But it's possible the timelines could be getting shorter. Besides the advances in sciences that can support MEOR, researchers have started to use X-ray computed microtomography (CMT) to better understand processes that might enable MEOR. According to a paper published in January, *Microbial Enhanced Oil Recovery in Fractional-Wet Systems: A Pore-Scale Investigation*, "MEOR is a large-scale >

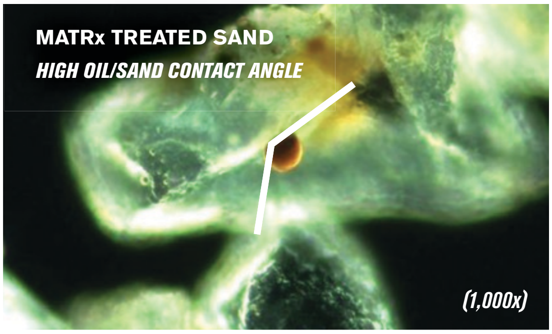


IMAGES: RYAN ARMSTRONG AND DORTHE WILDENSCHILD, OREGON STATE UNIVERSITY

CLEANER SWEEP
Residual oil blobs in three different glass bead porous media samples imaged with X-ray microtomography at the synchrotron facility at the Advanced Photon Source, Argonne National Lab. At left in both boxes, the blue regions are the glass beads, and the green areas are the residual oil blobs left after recovery. At right in both boxes, the green regions are the residual oil blobs left after recovery. It is clear substantially more oil is recovered using MEOR, as indicated by less of the green phase in the post-MEOR images. MEOR is also seen to be more efficient in the oil-wet system.

MICROBE INOCULATION
Unenhanced images at 1,000 magnification show oil/sand contact before and after treatment. DuPont's MATRx technology uses an inoculum of microbes in addition to nutrients to increase the bioplugging effects due to the larger population of desirable microbes present in the well after inoculation.





outcome driven by pore-scale processes. Therefore, to better understand the various MEOR mechanisms facilitating oil recovery, pore-scale investigations are needed."

The paper's authors say that although CMT has been around for more than three decades, and has been a powerful tool in studying multi-phase processes in porous media, "similar CMT analyses have not been applied to MEOR."

"If you use a particle accelerator like the synchrotron at the Argonne National Laboratory in Chicago, you obtain an image quickly and with very fine detail. This was [done in a research project] so that the amount of oil present in the experimental column, pre-MEOR and post-MEOR, was accurately measured and represented. It allows us to measure things we wouldn't otherwise and helps us understand EOR," says Dorthe Wildenschild, an associate professor in the school of chemical, biological and environmental engineering at Oregon State University (OSU) and the co-author of the paper.

Research into MEOR at OSU, which has been supported by funding from the Petroleum Research Fund of the American Chemical Society, indicates that more precisely targeted and effective MEOR is feasible, according to a paper in the September issue of the *Journal of Petroleum Science & Engineering*. One of the surprising findings reported in the paper, *Investigating the pore-scale mechanisms of microbial enhanced recovery*, also co-authored by Wildenschild, was that bacteria actually do their clogging better under stress than ideal conditions. This involved limiting their food source and treating the bacteria with antibiotics before allowing them to grow back.

In common with others, the co-author of several papers on MEOR research says the selective plugging approach is less difficult than trying to change the interfacial characteristics of downhole media. "We got the best results using both methods together, but [with selective plugging alone] the recovery is almost as good and much easier," Wildenschild says.

IMAGES: DUPONT

NEW LIFE FOR OLD FIELDS

The chief executive officer of Titan Oil Recovery, a service specialist that provides its proprietary MEOR process to onshore and offshore operators in the United States, Canada and overseas, sees little potential in biosurfactants for MEOR. “The microbial surfactant approach is uneconomic and a non-starter in our view,” says Brian Marcotte, who is the co-author of several SPE papers on MEOR.

Titan’s process targets fields under waterflood with a reservoir temperature less than 190 degrees Fahrenheit, an API gravity above 16 degrees and water salinity up to 100,000 parts per million. Water cut is typically between 50 and 98 per cent, Marcotte says.

After an analysis of indigenous organisms in a reservoir, a specific mix of nutrients is released into the reservoir in a series of periodic batches via the water injection system. The targeted microbes are stimulated to become interactive with the crude oil in the reservoir by locating at the water/oil interface, which reduces interfacial tension.

By treating the water injection in existing waterfloods, two production mechanisms are affected. “By activating specific species of bacteria, changes in the flow characteristics of the oil are affected and induce the reservoir system to release additional oil to the active flow channels. Stimulated microbes act at the interface of reservoir oil and water, altering the flow potential in the producing formation. In the higher-permeability portions of the reservoir, newly released oil, water and bacteria may interact to form a transient [temporary] micro-emulsion that may alter the sweep efficiency of the injected water as it moves through the reservoir,” states an SPE paper (145054), *What Has Been Learned From A Hundred MEOR Applications*, co-authored by Marcotte.

“The effect is to cause a physical change in the character of the oil. We’re trying to make micro-oil droplets that will flow through the rock more freely. We’re changing the apparent viscosity, not the absolute viscosity,” Marcotte says.

The nutrients used are biodegradable and no glucose nutrients are used, as they can stimulate growth of too many types of bacteria. Titan is currently treating over 250 wells in 25 fields in the United States and Canada. Incremental oil recovery varies widely over the short term with the Titan process, with production sometimes more than doubling. Over the long term, however, “This process can recover up to an additional 10 per cent of the original oil in place,” according to the SPE paper.

Experts like Bob Zahner, a reservoir engineer at Venoco, and the principal author of several SPE papers on MEOR, cautions that, although it can boost production, “You really have to understand a reservoir to optimize MEOR.”

In one instance, where the results of a treatment were not as expected, zones had to be isolated and then swabbed and a tracer survey injected to find out where the injected water was going. Without these procedures, “It’s possible you’re not treating what you thought you were treating,” he says.

MEOR has had some success in southwestern Saskatchewan, according to a 2009 SPE paper by staff at Husky Energy and Titan. Others have apparently caught a whiff of the region’s possible MEOR potential. The province’s Petroleum Technology Research Centre (PTRC) received $88,000 in federal and provincial funding in January to do preliminary research on local sources of nutrients that could be used in MEOR. The incremental potential is perhaps no small matter. “We’ve tens of thousands of heavy oil wells in the region. If 10–20 per cent are under waterflood, and microbes are there for plugging, MEOR could be applied to several thousand wells,” says Malcolm Wilson, the chief executive officer of PTRC.

With over 45 billion barrels of original oil in place, a further two per cent recovered translates into an incremental one billion barrels, he says. The governments funding the project could be getting a bargain. ■

A CUT ABOVE

In the quest for oil and gas, those companies whose innovation stands above the rest are recognized as the industry's **Technology Stars**

PRODUCTION

24 **WINNER:** Nexen Inc.

27 **RUNNER-UP (TIE):** NCS Oilfield Services Canada Inc.

28 **RUNNER-UP (TIE):** Cenovus Energy Inc.

DRILLING

30 **WINNER:** BOE Energy Systems

32 **RUNNER-UP:** Baker Hughes Incorporated

EXPLORATION

34 **WINNER:** Schlumberger Limited

36 **RUNNER-UP:** Adrok Ltd.

HEALTH, SAFETY & ENVIRONMENT

38 **WINNER:** Cenovus Inc.

40 **RUNNER-UP:** Adoil Inc.

WINNER
PRODUCTION

NEXEN INC.

PRODUCT: Pressurized frac on demand

SERVICE: Use of untreated subsurface non-potable water for hydraulic fracturing operations

ALTERNATIVE APPROACH
Nexen's Horn River fracturing operations in northeastern British Columbia. A closed-loop Debolt formation water supply system devised by Nexen allowed the company to avoid the expense of a water treatment plant to supply its frac water needs.

WATER-WISE FRACKING

New process uses sour brine and avoids the need for a treatment plant

By Godfrey Budd

When Nexen Inc. looked at options for a backup supply of water for its Horn River completion and fracking operations, it soon faced a choice between the tried and true or going the research and development route. Some alternative water supply is all but essential; otherwise, fracking has to rely entirely on surface or close-to-surface water supplies, much of which is subject to fluctuations in rainfall.

In common with some other Horn River shale gas operators, like Encana Corporation and Apache Canada Ltd., Nexen could access the Debolt aquifer, which is deeper than the freshwater zones and shallower than the shale gas, as a source of non-potable water. But the aquifer contains hydrogen sulphide (H_2S). Total dissolved solids (TDS) are around 22,000 milligrams per litre, less than the oceans, which have around 35,000 TDS. H_2S concentrations in the Debolt are about 80 parts per million in the liquid phase.

The amount of H_2S in the saline aquifer is a potential drawback, however. To be usable as a frac water source, H_2S concentrations must be below 45 parts per billion, according to a paper by Encana experts that was presented at an unconventional resources conference in Calgary in October 2010. If not, the H_2S in the frac water poses a hazard to field workers at the site and could damage equipment. The question then becomes: what is the best way to manage or treat this water so that it can be used to frac shale gas wells economically?

One response to an H_2S challenge of this sort is a water treatment plant, which, among other things, removes the gas. Encana and Apache took this approach. Operational since June 2010, their Debolt water treatment plant arose out of a 50/50 joint venture to develop part of the Horn River shale gas play. According to Encana, the plant has significantly reduced the companies' surface water use.

Nexen, too, considered essentially the same option. "Initially, we thought we'd need a water treatment plant to get rid of the H_2S in the Debolt water," says Dana Pettigrew, senior staff technical specialist at Nexen.

The Debolt brine, besides its quotient of H_2S, is not without its challenges. Once its entrained gases—H_2S, CO_2 and methane—are removed, the Debolt water becomes unstable. "On a table or in a lab environment, the water looks perfect—at first. It has dissolved [solids], but no suspended solids. Then, if you leave it sit, it gets darker and darker. In the field, the chemical reactions would lead to plugging of filters and other equipment. Left aside, it goes from looking like table water to very black in six days," Pettigrew says.

Two considerations, more than most others, must have stood out as Nexen management weighed the options. First was the cost of a water treatment plant—$50 million or more, plus an estimated annual operating cost of around $10 million. Secondly, if the Debolt remained under something close to the conditions that had prevailed over it for tens of millions of years, it would surely remain stable, so that perhaps it could be used for fracking—untreated.

PUMPING CHALLENGE

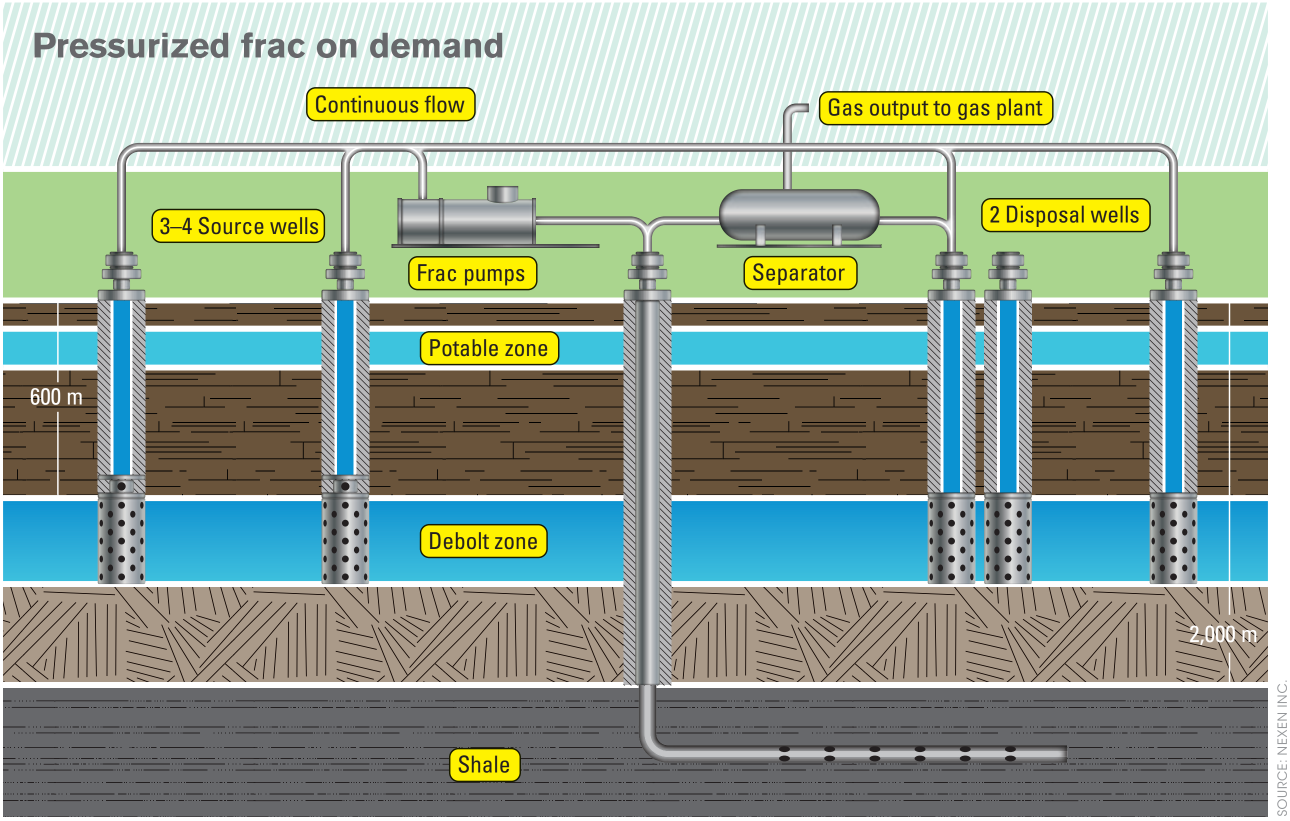
But if the water from the Debolt was to be used without first treating it to remove the gases and so on, it would have to be fed directly into the frac pump. And finding a pump that could do the job was a challenge. In part, that was because, in order to remain stable, the pressure of the Debolt had to be at a minimum of around 330 pounds per square inch (psi). At no time could it drop below its bubble point pressure.

"Typically, the suction feed side of a pump is around 100 psi, around 200 max, but we needed a pump that could handle sour water at around 600 psi. It would have to have a minimum 650 psi rating. No frac pump fits this requirement," says Pettigrew.

Manufacturers of positive displacement or reciprocating pumps were consulted, but to little avail. The development of a pump of this type that met the Debolt's required specifications would take years—too long for Pettigrew and his colleagues at Nexen.

Given such difficulties, the tried and true—water treatment—was not without its allure. "If you treat the water, you can use standard frac pumps. All you've done is >

PHOTO: NEXEN INC.



take out the gas. The fundamental basis of the design for treating this kind of water has been around for a very long time," says Pettigrew.

He points to a 1969 Society of Petroleum Engineers (SPE) paper from then Humble Oil & Refinery Co. that describes the design of a stripping plant for the removal of H_2S and CO_2 from produced water. But Nexen has opted for the research and development route, and now has done three seasons, beginning in 2010, of piloting a new system that, should it pan out, will sidestep the need for a costly water treatment plant altogether.

The system, it can be said, relies on two main components—a newly developed high-pressure horizontal pumping system (HPHPS), which, in turn, enables a pressurized frac on demand (PFOD) system to circulate untreated Debolt water in a closed loop. On demand, the PFOD withdraws water from the loop and sends it into a frac operation.

In the past, oilpatch centrifugal pumps for horizontal systems typically maxed out at around 6,000 psi capacity. But an Edmonton manufacturer, Canadian Advanced ESP Inc., working with Pettigrew, designed a new horizontal pumping system with a capacity of about 10,000 psi. "The whole job of development and testing was done in about six months," says Andy Limanowka, an engineer at Canadian Advanced.

The centrifugal pumps are less fuel efficient than reciprocating pumps, but have the advantage of being more robust, requiring less maintenance.

The pilot program has expanded each year, with more pumps and increased capacity, and each season has achieved the desired results.

Although the sour water flowing through the process loop is available on demand for fracking operations, a frac in the PFOD system does, in fact, begin with fresh water for safety reasons, but switches to sour if there are no leaks.

PUMPED UP

By developing a high-pressure horizontal pumping system, Nexen has been able to implement a unique pressurized frac-on-demand system able to divert under-pressure, untreated water directly from the Debolt aquifer to its frac operations.

Source water wells are a key part of the loop. Their downhole pumps circulate water around the loop and, on demand, divert some of the flow to the frac pumps for a frac job. "These high-pressure pumps can handle friction and elevation changes and could be running from just above 330 psi to 1,000 psi or so," Pettigrew says.

Also, because the entire loop always operates above the bubble point pressure, the water remains stable throughout the process.

There was a glitch during the first pilot season, however. The process section at the end of the loop and just before the disposal well was at a conventional low pressure. "The water became unstable and iron sulphides were precipitated and plugged filters. In mid-winter, three guys with H_2S [protective] self-contained breathing apparatus had to change the filters every 15 minutes," Pettigrew says. Now, of course, the entire loop is above the bubble point pressure.

Pettigrew and Limanowka prepared a paper, titled *Use of Untreated Subsurface Nonpotable Water for Frac Operations*, for a presentation at the SPE Canadian Unconventional Resources conference being held in Calgary from October 30 to November 1 this year.

Speaking of Nexen's pilots and the operational success of PFOD and HPHPS, Pettigrew says, "We think we might encourage others to see if they really do need an elaborate plant and look at the option of this type of water." ■

RUNNER-UP

PRODUCTION

NCS OILFIELD SERVICES CANADA INC.

PRODUCT: Half Straddle CT Frac System

SERVICE: A low-fluids multistage fracturing technique

CHEAPER, GREENER, FASTER

Half Straddle frac system cuts water use in half, trims costs ▪ *By Jacqueline Louie*

WATER MISER
NCS Oilfield Services' Half Straddle frac system has reduced water usage up to 50 per cent, leading to lower costs across the board.

For NCS Oilfield Services Canada Inc., conserving resources and saving money go handin hand.

NCS has designed its Half Straddle pad-less frac system with the goal of reducing frac water consumption and chemical use while lowering well completion costs at the same time.

Used in low-rate fracs in Alberta, Saskatchewan and Manitoba, the NCS frac completion system also allows faster operations and requires less equipment on locations.

"A lot of the big resource players have switched to this system and are having great success," says Lyle Laun, NCS executive accounts manager.

With the advent of horizontal multistage fracturing in recent years, fracturing treatments in conventional wells are now consuming up to 40 times as much fluid as the single-stage treatments of the past, while unconventional reservoirs can require fluid volumes of 200,000 barrels or more.

To help companies deal with this issue, NCS has developed the Half Straddle CT Frac System, a new method for delivering multistage hydraulic fractures. Combining the best of coiled tubing (CT) annular fracking with frac-through CT techniques, the Half Straddle system reduces or eliminates much of the wasted fluids associated with conventional methods. For example, for a 29-stage job with 29 different fracs, which used to require 800 cubic metres or approximately 5,000 barrels of water to pump, NCS is now pumping the same amount of sand, and doing the same number of fracs, with just 380 cubic metres of fluid.

"In less than two years, we have reduced water usage on a frac by 50 per cent on average," Laun says. "Customers are pretty excited that they can use less water."

And, not only are companies using less water, he adds, but it's far cheaper, with completion costs reduced anywhere from 15–25 per cent, and 35 per cent fewer chemicals used than in the past. "It's cheaper, greener and faster. It's an absolute win-win."

Developed by NCS nearly a year ago, the Half Straddle frac system is particularly suited for low-rate CT frac pumping. "There is less frac fluid to recover because you haven't put so much water down the well," notes Laun.

One customer, Crescent Point Energy Corp., has been using the NCS Half Straddle system in southeastern Saskatchewan for nearly a year. "It's been really good," says Crescent Point completions superintendent Curtis Swain. "One of the biggest things is that it's reduced our water volumes by more than 50 per cent on our fracs."

In 2012, from January through July, Crescent Point saved 34,000 cubic metres of fresh water. That amount of fluid equates to 1,130 fewer fully loaded tractor-trailer trips on the roads.

At the same time, "our frac times have been reduced by 60 per cent and it has decreased our completion costs by 20 per cent," he says. Through the use of the NCS Half Straddle frac system, Crescent Point has reduced its footprint on locations with lower water volumes and fewer storage tanks and trucks required.

Any company "with lower rates and doing horizontal fracking would benefit," Swain says. ■

PHOTO: NCS OILFIELD SERVICES CANADA INC.

RUNNER-UP

PRODUCTION

CENOVUS ENERGY INC.

PRODUCT: Steam dilation accelerated start-up

SERVICE: Technique to accelerate the start-up of SAGD well pairs

QUICK ON THE DRAW

Steam dilation accelerated start-up dramatically cuts in situ oilsands production initiation ▪ *By Maurice Smith*

FAST FLOW
By accelerating start-up time of its SAGD well pairs at its Christina Lake in situ oilsands operations, Cenovus wells reach their peak production rates quicker.

Unlike conventional oil well drilling, where penetration of the reservoir results in immediate flow of crude to surface, in the oilsands it may take months of coaxing—via the injection of steam to heat and "melt" the bitumen—before production begins.

The three to six months of pumping steam underground typically required to initiate flow in steam assisted gravity drainage (SAGD) operations is a costly investment in time and resources. It's an unwanted expense that Cenovus Energy Inc. is leading the industry in reducing.

Amid the approximately 140 technology development initiatives currently underway to improve its oilsands operations, an early success story has been its steam dilation accelerated start-up technique, which has slashed SAGD start-up times down to three weeks or less, some three to six times faster than the industry average.

Primarily, it's all about pressure. Conventionally, operators pump steam down the horizontal sections of both the upper steam injector well and the lower producing well (about five metres separate the two) and rely on heat conduction to establish "communication" between the two. At that point, a steam chamber has been created, injection into the producer can cease and extraction can begin.

Cenovus launched laboratory studies to find a way to quicken the process. The company found that by feeding steam down both wells at high pressure in a controlled manner, it could essentially rearrange the sand grains and thereby increase porosity and water mobility, resulting in early inter-well communications.

"In [conventional] circulation start-up, we just circulate steam down both wells. You are just slowly relying on heat conduction—there is no actual mobility, there is no flow that you can have between the wells," says Maliha Zaman, Cenovus reservoir engineer.

"If you increase the pressure, you roll the [sand] grains over, and that extra space that you are creating fills with water. What then happens is, instead of having no mobility, you get a bit of movement that you can start flowing between the wells, and that is what gives you the big speed-up."

The company says the process requires only minimal surface facility modifications. Additional benefits are a reduced steam circulation time and a decrease in cumulative steam to oil ratio—the amount of steam used per barrel of bitumen produced, an important economic indicator in SAGD production, says Jason Abbate, group lead, production engineering. "The steam that you save in the process is significant in comparison to our conventional circulation start-up method," he says. There have also been indications of improved overall production from the wells, Abbate adds.

He cautions, however, that the process is reservoir specific. "It's really dependent on what the reservoir looks like, what's above and below our SAGD well pairs. In some instances there is water below the well pairs, and in those cases we can't use dilation effectively the way we have got it set up currently. We are looking at ways to further innovate the technology and move dilation to the next level, so that we can utilize it on all of our reservoirs."

Cenovus began testing steam dilation accelerated start-up at its Christina Lake oilsands development in 2010 and by the end of 2011, it had been applied to approximately 13 wells. The technology contributed to the industry-leading start-up of the Phase C expansion phase, which reached production capacity within eight months of first production, between two and 12 months sooner than comparable projects, according to Cenovus. ■

PHOTO: CENOVUS ENERGY INC.


Careful development of a reservoir depends on far more than using predetermined formulas to crank out a "standard" program. At Canyon, every reservoir – from the Montney and Cardium to the Bakken and beyond – gets a customized fracturing solution driven by our knowledge of the geology, well control and chemistries. Our technology team is a multi-disciplinary group of scientists, technologists, chemists, geologists and engineers.
CUSTOMIZED FRACTURING SOLUTIONS
POWERED BY
CHAMPIONS
At Canyon, we go to great lengths to develop and apply fluids, additives and processes that avoid formation damage and maximize fluid recovery while delivering conductivity. We provide the full range of fluids: slickwater, linear and cross-linked gels and foams (including 100 percent N_2), hydrocarbon-based fluids, and poly-emulsion, plus acid fracturing of carbonates. We offer a complete line-up of effective, reservoir-friendly additives, including a number of proprietary blends.
While staying ahead of the curve on environmentally-friendly new chemistries, we've driven new processes that have helped advance fracturing technology. Our patented, ultra light-weight proppant is now being field-tested in deeper, unconventional applications.
CANYON
TECHNICAL SERVICES LTD.
www.canyontech.ca

WINNER

DRILLING

BOE ENERGY SYSTEMS

PRODUCT: SmartSite system

SERVICE: An advanced wellsite fluid-management system

LIQUID ASSETS
BOE Energy Systems, which depicts vintage Second World War artwork on its equipment, brings fluid-management systems up to date with modern drilling techniques.

SMARTER DRILLING

Going greener with intelligent fluid-management system

By Richard Macedo

With the spotlight glaring on the oil and gas industry's environmental perform-ance as much as it ever has, all sectors of the industry are focusing on greening their operations. At the same time, keeping operations efficient and cost effective is also vital.

In the service sector, Calgary-based BOE Energy Systems has been doing its part to combine these ingredients; the company is an innovator and leader in dewatering and wellsite fluid-management systems.

Its recently introduced SmartSite fluid-management system is an evolution of a couple of concepts Don Smith, president and chief executive officer, developed at his prior company, BOS Rentals Ltd.

In the oil and gas industry, there are two types of drilling fluids used to drill wells: water- and oil-based fluids. Smith notes that in western Canada through the 1980s and 1990s there was a shift away from sump technology and a move into closed-loop or above-ground, pit-type drilling applications. "The technology really wasn't that efficient," he says. "We went through several different methods for disposal of the fluids."

During this same period, drilling rigs went through an evolution, but nobody was examining the fluids management side, so the manner in which companies managed their drilling fluids remained static, which led to inefficiencies, he says.

"Drilling methods continued to evolve with more horizontal drilling replacing conventional vertical wells, and we began to migrate into more invert-based drilling applications in the latter part of the last decade," Smith notes. "There was a need for more efficient methods of capturing drilling fluids."

With a majority of horizontal wells being drilled using invert-based drilling fluid, improved fluid-management practices with increased environmental consciousness is a necessity.

"There's a need for an improved system, something that had the ability to manage the water-based phase, flip over to the oil-based phase and being able to go back to [the] water-based phase," he adds.

At the heart of BOE's business is its proprietary and patented SmartSite system, which the company says is the most sophisticated fluid-management system of its kind in the world. It includes a state-of-the-art control room and variable frequency drive recirculation system. "Managed on site in a safe, climate-controlled environment, the system allows significant operational, efficiency and safety benefits," Smith says.

The technology allows for more accurate control of the fluid density during drilling, allowing the operator to drill faster. This not only saves considerable time and drilling costs, but also means the wellsite will operate faster.

BUILDING ON EXPERIENCE

Smith began his career 30 years ago, working as a roughneck. He moved to a field supervisor position for a small independent oil and gas company before launching his career as an independent drilling and completions consultant.

In 2001, he formed his first service company, BOS. Smith developed the company's entire product line and was successful in registering four individual patents on various product-line ideas. BOS was sold in 2010 for $110 million.

Having already designed an integrated fluid-management system for water-based applications, he was seeking to adapt it to the new, evolving world of drilling.

Environmental benefits of the SmartSite system include a reduction in water usage of up to 70 per cent, the elimination of reserve pits, more oil recovered and less waste is transferred to landfills, the company says.

The system includes centrifuges, floc tanks, invert tanks and shale bins; it is a complete wellsite fluid-management system designed to allow operators to drill greener, faster, cleaner and safer by integrating advanced and extremely efficient fluid-management technologies into a complete end-to-end system.

The throughput capacity of the SmartSite system means it can handle the high demands of modern drilling techniques. "The fastest sustained drilling rates that I've ever witnessed in my career were about 45 metres an hour," Smith says. "We designed for three times that. The limiting factor of our process capacity is the centrifuge that is processing the slurry mixture that we feed into it.

"At 45 metres an hour, if I design [my system] for 150 metres an hour, I've got more than enough surplus capacity to handle it," he notes. "We're going to look at what's happening and we're going to continue to make sure we're at the front edge."

Smith says the company has been working with a major oil and gas producer in the Brazeau area of central Alberta using the SmartSite system. The operator recaptured about 43 cubic metres of oil over the course of the well. This resulted in a "cost recapture" of about $52,000 in oil that the SmartSite system saved from going to the landfill. When compared to a conventional dual centrifuge system without oil recapture, the net saving to the operator was in excess of $38,000 all-in. ■

PHOTO: BOE ENERGY SYSTEMS

RUNNER-UP

DRILLING

BAKER HUGHES INCORPORATED

PRODUCT: Kymera drill bit

SERVICE: A hybrid bit combining roller cone and fixed cutter systems

BEST OF BOTH WORLDS

Hybrid drill bit combines speed of PDC bits with toughness of tricones ▪ *By Maurice Smith*

TECHNOLOGY FUSION

By combining roller cone and PDC drill bit systems, Baker Hughes created a single bit able to outperform either predecessor technology.

As far back as the early 1900s, when the rudimentary fishtail drill bit was superseded by the roller cone bit—a marvel of engineering that was to revolutionize the oil industry—the limitations of the technology were well-known.

The two-cone bit introduced by Howard Hughes Sr. and Walter Sharp in 1909—to become the three-cone, or trademark tricone, bit in the 1930s—proved ideal for boring through medium- and hard-rock lithology. But in soft or plastically behaving formations like shale, roller cone bits lacked the performance and speed of fixed cutter bits such as today's polycrystalline diamond compact (PDC) bits.

Conversely, while the continuous shearing and scraping action of fixed-blade bits may be superior in malleable formations, they are prone to breakdown when encountering hard rock such as abrasive sandstone and cement stringers, where roller cones excel. Unfortunately, many wells penetrate both, alternating hard-soft-hard, making the choice of one or the other drill bit a compromise.

At least until now. After years of research and testing, Baker Hughes Incorporated—the company that traces its roots to Hughes' roller cone invention—introduced a hybrid drill bit in 2011 that synthesizes the best attributes of each. Its Hughes Christensen Kymera bit (named for chimera, a mythological creature with disparate parts derived from two or more animals) incorporates two to three roller cones—equipped with tungsten carbide inserts—and three or four arms of PDC cutters in a single unit, bringing together the rock-crushing strength and stability of a roller cone bit with the continuous shearing action and superior cutting of the PDC bit.

Combined, the two technologies create smoother drilling, improved torque management and precise steering capabilities, says Clair Holley, vice-president of wellbore construction, resulting in faster, more-consistent drilling than either roller cone or PDC can provide alone. "We believe the applications are widespread and anticipate continued growth with the entire Kymera offering as customers see the advantages of this hybrid bit," Holley says.

In either motor or rotary drilling applications, and on a variety of bottomhole assemblies, the hybrid Kymera bit has boosted drilling rates up to 62 per cent and extended single-bit run lengths more than 200 per cent in the United States. In applications in interbedded formations in western Canada, the bit has performed 60–100 per cent faster than competing bits.

NuVista Energy Ltd. was the first to use the bit in Canada. Drilling the build sections (turning from vertical to horizontal) of wells in the Wapiti Montney area in Alberta's Deep Basin, a liquids-rich natural gas play, the company estimates savings of $200,000 per well using the Kymera.

Seeking the steerability and reliability of a roller cone bit and the penetration of a PDC bit, NuVista first tried the Kymera last January, says Mark Thorne, NuVista drilling superintendent. The tough interbedded formations typically claim about four roller cone bits per well, meaning four time-consuming bit changes, or trips, per well. NuVista trimmed that to two trips using the Kymera, and given the experience of other operators in the area that have also switched to the Kymera, Thorne says that will likely drop to one trip per well.

"It has been proven to us and to other operators who are now using it that it is the fastest and most economic way to drill the build section," Thorne says. "In interbedded formations, or basically just hard rock, it's a real great application. We have used it on every well since [January], and our go-forward plan is to continue to use it on every Montney horizontal well that we drill." ■

PHOTO: BAKER HUGHES INCORPORATED

WINNER

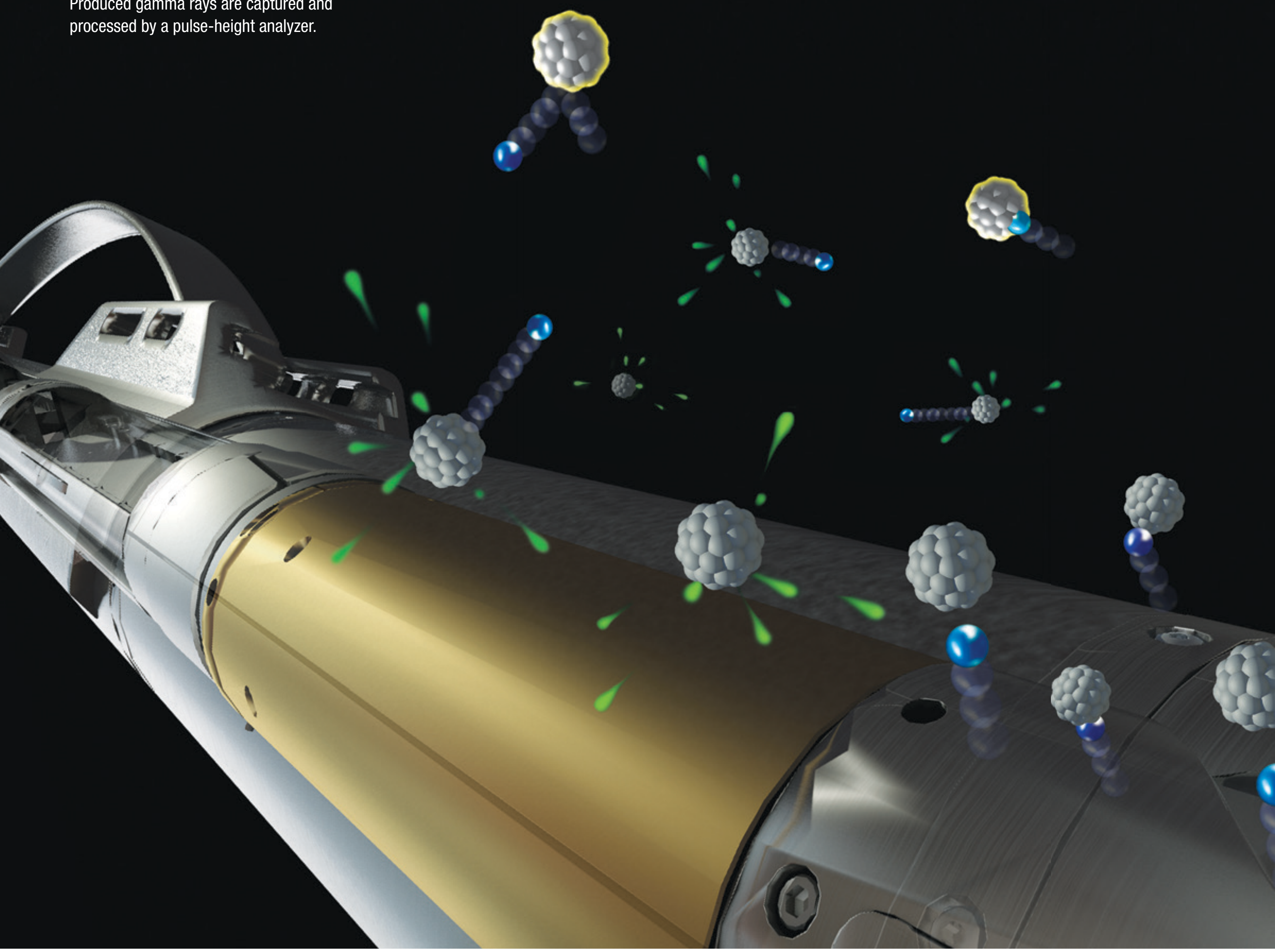
EXPLORATION

SCHLUMBERGER LIMITED

PRODUCT: Litho Scanner

SERVICE: High-definition spectroscopy measures mineralogy and total organic carbon

UNDERSTANDING THE FORMATION
Schlumberger's Litho Scanner incorporates a pulsed neutron generator that pulses neutrons in a controlled, measured amount. Produced gamma rays are captured and processed by a pulse-height analyzer.



RAY OF LIGHT

A new generation of gamma ray tools promises far greater reservoir resolution

By Gordon Cope

Unconventional plays create unconventional challenges. Not knowing the precise mineral makeup and concentration of hydrocarbons in a shale play, for instance, can have serious economic ramifications. Schlumberger Limited has just launched Litho Scanner high-definition spectroscopy service, a new gamma ray tool that allows explorers an unprecedented scale of precision and efficiency.

"It is one of the most important new technologies that wireline has launched in the past decade," says Maria Lorente, wireline product champion for Litho Scanner. "It is a new generation of spectroscopy tools that measures the elements in the formation to get an accurate mineralogy and total organic carbon [TOC]. This is very important in unconventional plays."

Traditional spectroscopy tools rely on bismuth germanate (BGO) gamma ray detector designs that have been around for several decades. While adequate for most uses, they can lead to insufficient spectral resolution and loss of sensitivity when exposed to downhole temperatures for an extended period of time.

Moving away from BGO generation tools, Schlumberger over the past few years set out to develop and incorporate state-of-the-art technology in Litho Scanner. "The improvements are due to several factors," says Lorente. "We moved away from a chemical source and incorporated a pulsed neutron generator [PNG] that delivers a high neutron output, which means higher precision and faster logging speed. Under ideal conditions, we are able to record up to 3,600 feet per hour, which is double the speed of previous generations."

What really makes the Litho Scanner tool stand out from others, however, is the cerium-doped lanthanum bromide detector. "The lanthanum bromide gamma ray detector provides the industry's most precise and accurate mineralogy computations, and the high-performance pulsed neutron generator eliminates the need for a chemical source," says Lorente.

The changes now allow the tool to operate at high temperatures for longer periods. "The previous-generation tools needed cooling systems, or the spectra would degrade over time," says Lorente. "Now, the PNG and the detector can operate over long intervals like those encountered in unconventional plays without deterioration of performance."

HOW IT WORKS

The downhole device is only 4.5 inches (114 millimetres) in diameter, so it can easily be conveyed on wireline through most wellbores at high speed. As the tool is drawn through the hole, the PNG pulses neutrons in a controlled, measured amount. According to Schlumberger, the gamma rays produced are then captured and processed by a pulse-height analyzer. Spectra are acquired during and after each neutron burst, which enables clear separation of the inelastic and capture gamma rays. Each spectrum is decomposed into a linear combination of standard spectra from individual elements.

The coefficients of the linear combination of the standard spectra are converted to elemental weight fractions via a modified geochemical oxides closure model or by using an inversion approach. The analyzer then generates mineralogy and lithology from the elemental concentration logs. By subtracting the amount of inorganic carbon associated with carbonate minerals from the total inelastic measurement of carbon, it can also determine TOC. Lithology and TOC output are then presented as a continuous well log.

Schlumberger has been field testing the tool for over a year, performing 80 jobs for more than 35 customers. "The Litho Scanner tool has performed very well in all complex lithologies," says Rob Badry, petrophysics domain champion in Canada. "The focus in Canada has been on shale oil and gas, heavy oil and bitumen-filled reservoirs, where TOC is especially important. We've had excellent results overall, including complex bitumen-saturated carbonates reservoirs."

Northern Cross (Yukon) Ltd. is one of the customers that tested out the new device. The Calgary-based company is conducting exploration of a series of unconventional Carboniferous and Devonian shales in a Canadian frontier basin. "We were primarily focused on understanding free-carbon weight percentages so that we could estimate TOCs," says Don Stachiw, vice-president, exploration, for Northern Cross.

"The estimated TOCs from this tool were used in conjunction with other open-hole logs, mud gas response, cutting descriptions and TerraTek HRA [heterogeneous rock analysis] modelling to choose sidewall core points. We chose the sidewall core points and successfully executed the coring program. We will now compare the measured TOC values to the Litho Scanner–estimated values to determine the quality of the prediction; this has yet to be completed."

THE FUTURE

After the commercial launch in October at the Society of Professional Engineers' Annual Technical Conference and Exhibition in San Antonio, Texas, Schlumberger will be looking at expanding the applications for the tool. "One application is called sCore lithofacies classification, which takes the mineralogy data and maps it into ternary diagrams together with reservoir and completion quality indicators to allow selecting the optimal completion intervals in unconventional reservoirs," says Lorente.

"In the future, we will continue to work with customers to answer their specific questions, and to generate applications for individual areas and particular cases," says Badry.

So far, Northern Cross has been impressed with the new tool. "The turnaround time from gathering the data, transmitting the data from a remote frontier-basin location and interpreting the data resulting in a TOC estimation was less than 24 hours, thus allowing real-time operational decisions to be made," says Stachiw. ■

RUNNER-UP

EXPLORATION

ADROK LTD.

PRODUCT: Adrok Scanner

SERVICE: Uses finely focused electromagnetic radiation to verify oil and gas reservoirs

THE VIRTUAL BOREHOLE

A new technology remotely identifies hydrocarbons

By Gordon Cope

LOW IMPACT
Adrok's exploration technology, seen here deployed in Northern Ireland, is compact enough to be mounted on an all-terrain vehicle.

When it comes to wildcatting, a petroleum company can spend hundreds of millions of dollars gathering data in order to create a suite of prospective targets. But until the drill bit hits the reservoir, there's no telling if that sweet spot is full of oil or salty water—until now, that is. "We can show if the prospect contains hydrocarbons prior to drilling," says Gordon Stove, managing director of Adrok Ltd. "We call this virtual borehole technology."

Adrok has devised the Adrok Scanner, an exploration system that uses finely focused electromagnetic (EM) radiation to penetrate up to four kilometres into the earth and analyze the rock properties of each formation. An Edinburgh, Scotland–based company, Adrok has captured the attention of Vancouver-based Teck Resources Limited, a diversified mining company with interests in the oilsands. Teck invested $5 million in the firm recently to help further develop the technology.

The invention has been several decades in the making, ever since Stove's father, Colin Stove, was conducting ground penetration experiments for the European Space Agency. Conventional wisdom had dictated that EM energy could only penetrate a few centimetres into the ground, but when Colin Stove directed radar waves into a Scottish beach, he managed to image the water table several metres down. Subsequent research led to the development of atomic dielectric resonance (ADR).

The Adrok Scanner emits highly focused beams of non-visible laser, microwaves and radar waves. The beams travel through the ground; each formation encountered emits a secondary resonant energy response. The resonant energy response is then recorded in terms of energy, frequency and phase, and compared to a comprehensive classification library in order to identify the chemical composition and fluids present in each rock.

The process is designed to be deployed in conjunction with other techniques. "We are a complementary part of an oil and gas exploration program," says Stove. "After a company conducts a seismic survey and pinpoints promising anomalies, we run a smaller survey over the bright spots."

Because the bandwidth is tightly focused and the amount of energy used extremely small, the Adrok Scanner is compact enough to be deployed on a suspended wire system or mounted on an all-terrain vehicle. A survey typically covers a few square kilometres and can be conducted and interpreted in five days.

In 2007, London, United Kingdom–based Caithness Petroleum Limited contracted Adrok to conduct a survey in Morocco. Adrok delineated a gas reservoir at a depth of 750 metres; subsequent drilling confirmed the discovery. Since then, the company has conducted surveys for Caithness in the United States. "Adrok carried out an ADR survey to a depth of 8,000 feet on an undrilled prospect in Oklahoma, which identified gas-bearing Ordovician sandstone at 7,500 feet," says Robert Kennedy, commercial director of Caithness.

"The well was then drilled and a commercial gas discovery was made at a depth within 0.3 per cent of the Adrok forecast," he says. "In my opinion, ADR has developed into an extremely powerful and effective hydrocarbon exploration and appraisal tool."

Adrok is also working with the mining sector. The company conducted a survey for Teck Resources in an underground mine in Washington State, independently identifying the water table and resources in a blind test. The company has subsequently searched for uranium deposits in the Athabasca Basin and for nickel around Sudbury.

Currently, Adrok conducts 25–30 projects each year. It plans to expand up to 40 per cent annually over the next several years, primarily by focusing on the North American market. Adrok is working on technology that would allow aerial surveys, expanding its capabilities into the realm of larger-scale seismic. Adrok is also looking to expand into downhole production monitoring, geothermal resource delineation and groundwater mapping. ■

PHOTO: ADROK LTD.

Frac water storage?
We've got Canada covered.

Every type, every size, every situation.

There are many challenges that you may face in frac water storage, but one thing is always constant – Dragon has the right solution. From 400-barrel uprights to insulated and non-insulated frac tanks to Water Corrals, we are the only company in Canada that offers the full range of water storage systems. Every product is severe-duty engineered to perform in the harshest production environments, and Dragon knows frac water storage and handling like no other company. We offer on-site needs assessment so our engineers can design solutions specific to each job site, including custom packages. Plus, we are fully committed to serving Canada, with a location in Red Deer and a Canadian sales force dedicated to providing exactly what you need. All solutions, all from one source. Make it happen.

www.dragonproductsltd.com — 1-403-340-3600

DRAGON
Make it happen.

U.S. owned and operated. Founded in 1963.

WINNER

HEALTH, SAFETY & ENVIRONMENT

CENOVUS ENERGY INC.

PRODUCT: Blowdown boiler

SERVICE: A process to allow leftover water to be boiled a second time without pre-treatment

PUSHING BOUNDARIES
In going off-spec from normal operating procedures, Cenovus was able to prove it could run leftover water through a secondary boiler untreated and significantly boost its recycle rate.

A CALCULATED RISK

Cenovus's blowdown boiler process reduces water usage, costs

By Elsie Ross

When Cenovus Energy Inc.'s technical team first proposed running waste water from its steam generators at its Foster Creek oilsands operations through a second boiler without treatment to increase the amount of water it was recycling, colleagues promptly organized a pool as to how long it would take before solids in the water plugged the tubes.

The results convinced the skeptics. Over a period of 166 days in 2007, a pilot project using a 50-million-British-thermal-unit-per-hour boiler—smaller than the boilers typically used to generate steam—generated more than 59,000 cubic metres of steam and produced nearly 150,000 barrels of bitumen using only untreated water. Following the pilot, Cenovus ran a successful commercial test for 100 days in late 2010 and early 2011 using a larger, standard 175-million-British-thermal-unit-per-hour boiler.

The boilers were inspected at the end of each testing stage and showed no significant wear, despite the higher component of solids, proving that a boiler could generate steam using untreated waste water, in contrast to standard industry belief.

"We wanted to recycle as much water as we reasonably could and to exceed the regulations, going beyond compliance," says Mark Bilozir, director, technology development, at Cenovus. Under the company's patented blowdown boiler process, up to 90 per cent of the original input water can now be converted to steam.

In a typical steam assisted gravity drainage operation, a steam generator converts about 80 per cent of the water it receives into steam, with the remaining 20 per cent usually disposed of due to the concentration of solids left behind in the water. "We could take that water out of our normal operations and spend a lot of money and chemicals and equipment and treat it so that it is back down to spec and run it again," he says. "But it's a lot more economical and simpler if we can just figure out how to go from one boiler right into another, and find out what the problems are and just solve the problems rather than just treating everything."

To accomplish that, those involved in the project had to go "off-spec" from what was considered normal boiler operation, something that Bilozir acknowledges caused a lot of debate within the operation. "We took a calculated risk and some people were thinking there is no way this could work, but we had good reason and solid evidence to say we think we could do this," he says.

WATER SAVINGS

A major benefit of the blowdown boiler process is a 50 per cent reduction in the demand for makeup water, which means that the company draws less water from natural saline aquifers, according to Bilozir. As a result, only two to five per cent of the original feedwater is disposed of in saltwater aquifers compared with the 20 per cent had the water not been run through the blowdown boiler.

The process also reduces capital and field costs. If Cenovus can get more steam from the same amount of water, fewer water wells will be needed to provide water and less water will have to be disposed of, he says.

"This is about as close as you can get [to a win-win] because we don't add any chemicals or do further treating," he says. "We just get more steam with less energy and less water required from the environment."

The water treatment plant, the largest single capital cost, can be a little smaller, resulting in an estimated saving of $100 million because now it will have to handle less than 10 per cent of the blowdown water compared to the previous 20 per cent. "We sort of joke that we run giant water treatment plants and produce a little bit of oil to pay for it," says Susan Sun, senior staff, water treatment engineer.

Based on the company's evaluation, the Cenovus-patented process will reduce operating costs by 15 cents per barrel, says Sun. For a 100,000-barrel-per-day operation, that would amount to about $15,000 per day. "It can improve the water recycling ratio above 90 per cent without using energy-intensive technologies like other people are using in the industry."

Additional benefits include reductions in natural gas requirements, CO_2 emissions, the waste disposal stream and the surface footprint due to the reduction in the makeup and water disposal systems, as well as the smaller water treatment plant.

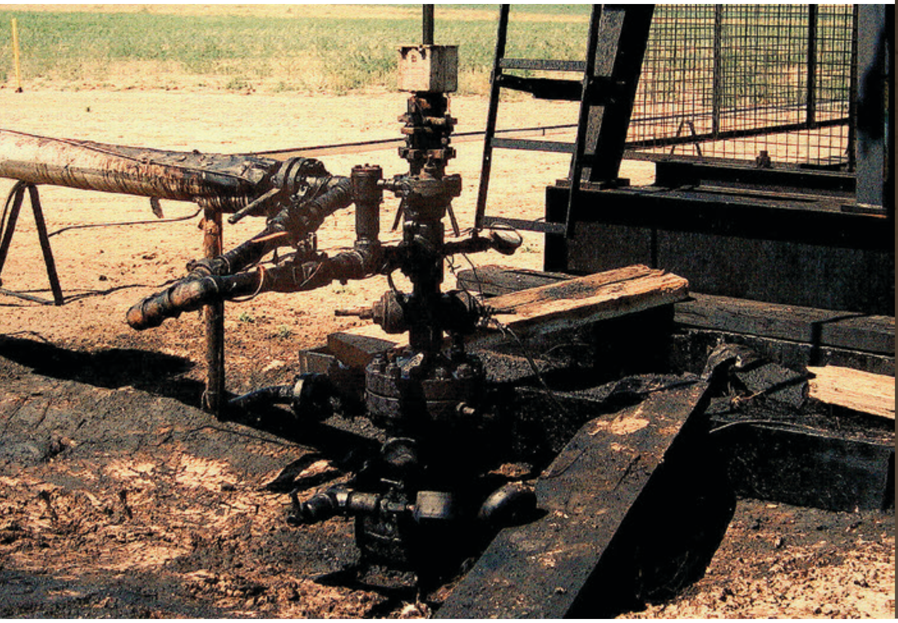
"This was tremendous work by Susan and we had a guy who is very well versed—Mike Wasylyk, a long-time boiler guy—[also] behind it," says Bilozir. "There are a lot of good people who did a lot of good work on this.

"Cenovus spends a lot of time making its plant more efficient, using less water and making the whole project smaller any way that it can," he says. "It's a big area of research for us."

The blowdown boiler process will be used in future expansion phases at its Foster Creek and Christina Lake in situ oilsands projects, as well as at future developments at Narrows Lake and Telephone Lake, says Sun. At Foster Creek, one of Phases F, G and H will be run off water from the two other phases, says Bilozir.

The blowdown boiler process could potentially be licensed by other oilsands operators who have shown interest in it. While Cenovus sees its patented process as a competitive advantage, it would be open to discussing the idea of licensing, though "the terms have to be defined," he says. ■

PHOTO: CENOVUS ENERGY INC.



RUNNER-UP

HEALTH, SAFETY & ENVIRONMENT

ADOIL INC.

PRODUCT: TITAN

SERVICE: Wellhead spill containment unit

NO MORE LEAKS

Operator-friendly spill containment system prevents soil and groundwater contamination ▪ *By Jacqueline Louie*

CONTINUOUS INNOVATION
Adoil's spill containment units were recently upgraded to include hydrogen sulphide and CO_2 detection capability.

Happy customers say it's one of the best investments they have for preventing wellhead leakage.

The TITAN is a wellhead containment device designed to protect the environment and lower the financial risks of wellhead leakage by preventing spilled oil, produced water and chlorides from contaminating the environment. It's designed, manufactured and distributed by Calgary-based Adoil Inc.

"If you respond to a leak, even if it's a small leak, chances are you are going to prevent a major problem," says Marty Matthews, Adoil founder and general manager, who established Adoil as an on-site training and wellsite inspection firm in 1986, conducting field equipment inspections of thousands and thousands of wellsites. "One recurring thing that was often found to be neglected was the leakage that was seen in anywhere from five to 10 per cent of the oil wells at that time," Matthews recalls.

In the early 1990s, after a major producer asked him to develop a containment system that would capture the produced water and oil that leaked when no one was around—"which is 99 per cent of the time"—Matthews designed and developed the TITAN. He worked with a number of oil companies and their lead operators to come up with a containment unit that was easy to install, required no bolts or screws, and would capture any leakage that occurred in oil wells and water-producing gas wells.

The TITAN is made using a high-end aluminum alloy containment system, stainless steel valving and hinges, and a shatterproof clear-view polycarbonate top. "The point of the clear-view top is that operators can drive by the well and see if it needs attention without having to get out of the truck," Matthews says. The TITAN also includes a shutdown switch to stop any leakage. Any leaked fluid "is returned to the battery and dealt with, and goes back into the system where it's supposed to be."

Adoil, which began production of the TITAN in 2002, has become Canada's largest wellhead containment manufacturer with sales in Canada and the United States, as well as in Colombia and Oman.

"We are constantly innovating," Matthews says, noting that Adoil has recently added features that include hydrogen sulphide (H_2S) and CO_2 detection to the TITAN's design. "With our containment system and a small detector with a built-in transmitter, a producer will instantly know which well needs attention to shut down the leak. H_2S, being highly dangerous gas, can be dealt with very quickly."

And, according to Matthews, the TITAN "helps the environment and lowers the cost of production because it eliminates an awful lot of the expensive services that have been used in the past, such as steam cleaning and gravel replacement."

Terry Chrisp, production superintendent at Winnipeg-based Tundra Oil & Gas Partnership, began using the TITAN devices about nine years ago on the company's wells in Manitoba.

"We really swear by them," says Chrisp, noting that Tundra now installs the TITAN on every new well. "It's great protection for the environment by controlling stuffing box spills in a very cost-effective way. We've had very good luck with Adoil's TITAN."

If companies "are concerned about wellhead spills, then definitely put them on. They are a very simple thing. They do a big job for a small investment," Chrisp says. ■

PHOTO: ADOIL INC.


JOBS ARE BETTER WHEN THEY'RE CALLED CAREERS.
You've had jobs. Now it's time to find a career. We're looking for people to build their careers at Surmont, our flagship oil sands facility located just outside Fort McMurray. With competitive benefits, a great rotator package and tons of room for advancement, Surmont can give you the future you've always wanted. So if you're looking for a career, then ConocoPhillips Canada is looking for you.
MakeYourWayUpHere.ca
ConocoPhillips
Canada Oil Sands


WE'VE MOVED
Please update your records.
As of August 27, 2012, the Edmonton office of JuneWarren-Nickle's Energy Group is located at:
220-9303 34 Avenue NW,
Edmonton, AB T6E 5W8
Our contact numbers will remain the same.
NewTechnology magazine
NEWTECHMAGAZINE.COM
junewarren-nickle's energy group

PHOTO: ECOSPHERE TECHNOLOGIES, INC.

COMPLETIONS

In The Zone

Ozone-based frac water treatment technology provider targets the oilsands

THE HEAD OF A FLORIDA-BASED company that has developed a chemical-free water treatment and recycling technology, now used extensively where fracking is deployed in the United States to produce natural gas and oil, says he believes the company's ozone-based method can also be applied to the oilsands industry in Canada.

Robert Cathey, chief executive officer and chief operating officer of Ecosphere Energy Services, LLC (EES), a division of Stuart, Fla.–based Ecosphere Technologies, Inc., which is a water engineering, technology licensing and environmental services firm that specializes in waste water treatment, says the energy services division he heads plans to focus on seeing its technology used in Canada.

"I believe we have an opportunity in the Canadian oilsands," he says. "We haven't piloted the process yet in the oilsands, but we've been working with environmental agencies in Canada and with Alberta Innovates," a government-funded agency focused on biotechnology, health care, and energy and environment. He says Ecosphere's technology would help oilsands producers recycle more of the water they use.

According to the Pembina Institute, annual water consumption in the oilsands industry reached 170 million cubic metres in 2011, equivalent to the residential water use of 1.7 million Canadians. Pembina claims water withdrawals from the Athabasca River threaten to undermine the ecosystem of the Athabasca delta.

However, oilsands producers counter by saying all existing and approved oilsands projects withdraw less than one per cent of the average annual flow of the river. Oilsands operators recycle 80–95 per cent of the water they use, with most making heavy use of deep brackish water. About 2.5 barrels of fresh water are used for each barrel of bitumen produced in mining projects and 0.5 barrels are used per barrel produced in in situ projects.

Ecosphere Technologies, which has been in existence for 12 years and is listed on the U.S. over-the-counter stock market, is growing rapidly, with revenue up 264 per cent in the second quarter of the year. Its annual revenue is about US$28 million.

It focuses on the development of water filtration technology for mobile delivery. One of its core products is a mobile water treatment system, which has been widely used following disasters such as Hurricane Katrina and tsunamis.

Ecosphere has exposure to several industries outside of the energy sector and the municipal infrastructure market, >

MOBILE TREATMENT
EES's Ozonix water treatment system has been used extensively in U.S. shale gas and oil plays to recycle waste water from fracking as well as flowback water from producing wells.

SEEING IS BELIEVING
Robert Cathey, EES chief executive officer, shows produced water before and after treatment using Ecosphere's ozone-based technology. Cathey believes the technology can also be applied to oilsands waste water.

including the agricultural, industrial, marine and mining sectors. It uses variations of its Ozonix technology to recycle and reuse contaminated water in all of those applications. Wholly owned EES is focused exclusively on solutions for the energy sector.

Its Ecosphere Ozonix water recovering and recycling process was first used in the fracking sector of the energy industry in 2007 and there are now 38 systems in use in the United States. It has contracts with subsidiary companies of Southwestern Energy Company and Newfield Exploration Company, both of which operate in the Fayetteville and Woodford shale areas of Oklahoma and Arkansas.

It's potentially a huge market. For example, Lux Research has predicted the market for treating hydraulic fracturing water will grow ninefold to $9 billion by 2020.

Fracking requires the use of an average of between 125,000 and 200,000 barrels of water per well, while producing a toxin-laced brine that can be more than six times as salty as the sea. Drillers pump large volumes of water mixed with sand and chemicals under high pressure into wells. The pressure cracks shale rocks and releases the gas and oil. However, the waste water mix produces a large challenge with it often being put into tailings ponds for evaporation and then trucked to a disposal site.

EES utilizes its Ozonix technology to recycle waste water produced during fracking, as well as flowback water from a producing well.

The Ozonix method involves a complex process of water oxidizing that kills bacteria and inhibits scale formation so that water can be reused. Ozonix oxidizes heavy metals and eliminates highly resistant bacteria, biofilms and the food source of micro-organisms. The process accomplishes this by combining ozone with proprietary hydrodynamic cavitation, acoustic cavitation and electro-oxidation technologies. Cavitation breaks up biological contaminants, which increases the efficiency of the ozone treatment. The company's process can reduce the amount of ozone required by up to 90 per cent.

The company says recycled water that isn't reused for fracking can be used in agriculture.

The company and its parent recently signed a deal with Hydrozonix LLC, which has offices in Texas and Florida and also specializes in environmentally friendly water treatment solutions for the oil and gas industry. That company now has the exclusive licence to market the Ecosphere ozone technology to the oil and gas industry in the United States.

"Ecosphere Energy owns the master licence for the technology globally," says Cathey.

Its initial target market is Canada, where it sees applications for its ozone-based technology in the fracking area, in the oilsands and even in power plants. "It's applicable anywhere water is being used to create energy," he says.

There's a track record for the technology. "We have processed over four billion gallons of water at 500 oil and gas wellsites since 2008," he says.

Cathey says operators can save up to $1 per barrel by using the Ozonix method. "We are very competitive with the cost of methods using chemicals," he says. "The cost of using the Ozonix method is about 50–75 cents a barrel. If the operator uses lower volumes, that may be higher."

The cost savings are in three areas. One area is in reduced water consumption—the company says operators can reuse up to 100 per cent of the flowback and produced water. The second is in the savings on the normal use of liquid chemical biocides and scale inhibitors. And finally, because waste water doesn't need to be hauled to sites and injected into disposal wells, there's a savings on the cost of waste separation, on trucking costs and on maintaining disposal wells.

Because the waste water doesn't need to be hauled to a distant site, there's an environmental benefit since there are fewer carbon emissions.

"As far as our application is concerned, there's no limitation on the number of times you can recycle your water," Cathey says.

Ecosphere's latest product, the Ozonix EF80, is a mobile water treatment system housed in a 53-foot trailer that travels from wellsite to wellsite and can process up to 80 barrels (3,360 gallons) of water per minute.

"We have gone from a 10-barrel-per-minute system to what we have now," he says.

Ecosphere licensee Hydrozonix, which took delivery of its ninth and 10th Ozonix EF80 units in the third quarter, with two more on order, recently deployed the technology in the Permian Basin and the Eagle Ford shale plays in the United States. The companies also recently signed a deal with the Blackfoot Nation to work with oil and gas companies for waste water treatment on the tribe's 1.5-million-acre reservation, located near the prolific Bakken shale play in North Dakota.

Cathey says in the United States it has captured less than two per cent of the potential fracking market with its technology.

He would not reveal the cost of the systems themselves, which are built by about 27 employees at its Florida plant. The units are not for sale. "We're selling a service to E&P [exploration and production] companies," he says.

However, he says the company might consider leasing a unit "depending on the value of the order."

He says his division plans to use the same method in Canada and elsewhere in the world to spread use of the technology as the parent company did in licensing the technology to Hydrozonix. "Our intention is to license our technology to other [oilfield service] companies."

Following a trip to Canada this past spring, including a visit to the Global Petroleum Show held in Calgary in June where it displayed the technology, there was a good deal of interest expressed by producers and the oilfield service sector, Cathey says. "There has been significant interest in our technology in Canada."

In addition to companies involved in fracking, he says oilsands-related firms have expressed interest and Ecosphere is in discussions with several oilfield service firms. ■

Jim Bentein

CONTACT FOR MORE INFORMATION
Corey McGuire, Ecosphere Technologies
Tel: 772-287-4846
Email: cmcguire@ecospheretech.com

PHOTO: ECOSPHERE TECHNOLOGIES, INC.

PHOTO: NEXT LEGACY TECHNOLOGIES INC.

CONCRETE SOLUTION
At a demonstration in Calgary recently, NEXT Legacy Technologies used a simple block of cement to show the effectiveness of its organic, low-water fracking solution.

COMPLETIONS

Breaking All The Rules

A new technology has the potential to eliminate hydraulic fracturing's biggest challenges

IT SEEMS LIKE A SIMPLE enough demonstration: a technician mixes some innocuous chemicals into a paste and inserts it into a hole that has been drilled into a large block of cement. But once the mixture heats up and expands, it crushes the cement block into fragments. John Harper, a former director of energy at the Geological Survey of Canada (GSC), was an observer of the demonstration. "I'm interested in innovation; if this technology meets everything we've seen, it's a game changer."

The technology in question is owned by NEXT Legacy Technologies Inc., an Alberta-based service company that believes it has created an evolutionary step in reservoir stimulation. "Our technology uses 100 per cent organic compounds and very little water," says Darren Wiltse, chief executive officer. "We can also do a major frac job in one day, versus several days for a hydraulic frac job."

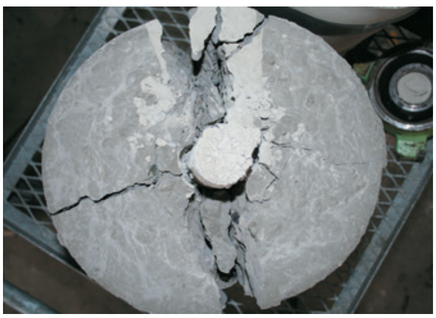
The technology has been many years in the making. Wiltse, a professional engineer, has been working in Canada's oil and gas (O&G) sector for several decades. During his work, he met the inventor of the system, an expert in perforating and other industrial activities. For the last 10 years, the inventor has been working to achieve controllable exothermic and kinetic reactions that can be used in place of hydraulic fracturing, as well as in other processes and materials creation.

NEXT (the name is an acronym for Non-hydraulic EXothermic/kinetic energy Technology) uses a single coiled tubing rig staffed by two crew members. Approximately one barrel of organic compound is mixed with 40 litres of water. The mix is then placed into the reservoir zone at low pressure. The compound reacts with the reservoir rock, increasing permeability through exothermic (heating) and kinetic (mechanical) action. According to the company, depending on the mix used, the product can experience expansion up to 14 times and the frac can radially penetrate farther than 200 metres into the reservoir.

The new technology could have many important ramifications for North America's O&G sector. Geoscientists have known for many decades that shale formations held trillions of cubic feet of gas and billions of barrels of oil, but their impermeable nature made them uneconomic to produce. Since the early 2000s, however, operators have been using two advanced technologies, horizontal drilling and hydraulic fracturing, to open up tremendous new unconventional resources. The Barnett shale of Texas now produces five billion cubic feet of natural gas per day, and the U.S. Energy Information Administration says that shale gas now accounts for 15 billion cubic feet per day, or 25 per cent, of all U.S. gas production.

The same potential holds true for tight oil–bearing formations. The Bakken formation in the Williston basin (located beneath North Dakota, Saskatchewan and Manitoba) produced 100,000 barrels per day in 2005; thanks to horizontal drilling and hydraulic fracturing, output now exceeds 700,000 barrels of oil per day. Production in the Eagle Ford shale in south Texas has grown to over 125,000 barrels per day from virtually nothing at the beginning of 2010.

Hydraulic fracturing, however, faces significant challenges. Millions of litres of fresh water are mixed with proprietary chemicals and then forced under pressure into the reservoir in order to fracture the rock. The work can take several days and generates significant blowback of water, chemical and sand proppant, which must be disposed of. The public, environmentalists >



EXOTHERMAL REACTION
A cement block is fractured after a mixture of NEXT Legacy Technologies' non-toxic, organic ingredients poured into its centre heats up and expands.

PHOTOS: NEXT LEGACY TECHNOLOGIES INC.

"It's not new science, as the effects of exothermic reactions have been known for decades, but it is a new application, and seems to be a major breakthrough. It doesn't use a significant amount of water, you don't need proppant and there are no toxic additives or waste water."

— John Harper, market director, EBA Engineering Consultants Ltd., a Tetra Tech Company

and politicians are concerned that the proprietary chemicals (some of which are known toxins) could leak into near-surface groundwater aquifers and contaminate drinking water supplies. Some U.S. states, as well as the province of Quebec and France, have imposed moratoriums on hydraulic fracturing until more is known. Should bans become widespread, future unconventional gas and oil production would be seriously compromised.

The exothermic/kinetic process circumvents most concerns. The process uses a tiny amount of water, so the needs of farmers and rural communities are not compromised. The materials are organic and non-toxic and, since it operates at low pressure, there is little potential for opening fissures that might connect to near-surface aquifers.

Just as importantly, the new technology helps to control spiralling well completion expenditures. Although frac costs per zone for the NEXT technology are similar to conventional hydraulic ones, the overall cost is much less because there is no need to contract a fleet of water and pump trucks or pay for blowback disposal.

In order to prove the technology worked, NEXT conducted over a dozen well tests. The results showed production increases from under 20 barrels per day to as much as 180 barrels per day. One of the test participants was sufficiently impressed with the process to agree to a multi-year, multi-billion dollar contract that will involve thousands of wells. NEXT recently constructed a compound-manufacturing plant in central Alberta and is in process of acquiring 10 coiled tubing rigs. "We expect to see around 30 rigs by next spring," says Wiltse.

It was at this manufacturing plant that NEXT recently held its demonstration, inviting several dozen participants from industry, government and the service sector, including Harper. In addition to being a former director of the GSC, Harper has participated in the Canadian O&G sector as an executive with exploration companies and as a petroleum geology professor at Memorial University in Newfoundland. He is currently market director for subsurface energy development at international engineering firm EBA Engineering Consultants Ltd., a Tetra Tech Company.

Harper was impressed by the technology on several levels. "It's not new science, as the effects of exothermic reactions have been known for decades, but it is a new application, and seems to be a major breakthrough. It doesn't use a significant amount of water, you don't need proppant and there are no toxic additives or waste water."

Harper noted another specific advantage. "To some small towns, unconventional resources can be like a gold rush, where the community experiences the arrival of a large number of individuals. Suddenly, people who are used to seeing two pickups a day on their road are experiencing 40 large trucks. The influx can be hard on local society and oil companies don't take that seriously. This technology has very little significant surface footprint and few employees, so there's less cultural impact. It not only has the potential to reduce costs, but to increase the social licence to operate."

THE FUTURE

NEXT is investigating other uses for the technology. Their compounds can be mixed to form a strong, lightweight, durable material that they are calling NEXT cement. "It can be used in well casing, but we are in discussion with major O&G companies for a host of uses," says Wiltse. (The housing and construction industry has also shown interest.)

The exothermic reaction can also be adapted to in situ oilsands extraction. Instead of injecting steam into a reservoir zone, the compound can be placed within the wellbore and it will provide enough steam to reduce viscosity in the bitumen for several days.

In producing wells, the wellbore can often get plugged by paraffin. Instead of using a hot oil or acid bath to clear the obstruction, the NEXT organic compound can be placed in the wellbore, where an exothermic reaction will heat the paraffin and melt it away.

In the meantime, NEXT intends to share its new technology with the service industry. "We understand that this is disruptive technology," says Wiltse. "But we intend to work with the existing frac sector by licensing our technology to those companies who wish to use it. NEXT has no intention of becoming a fracking company; it simply has a cutting-edge product to sell." ■

Gordon Cope

CONTACT FOR MORE INFORMATION

Darren Wiltse, NEXT Legacy Technologies
Tel: 403-968-5872
Email: darren@next-tech.ca