New Technology magazine

JANUARY/FEBRUARY 2016

THE FIRST WORD ON OILPATCH INNOVATION

VOICES OF THE FUTURE

WITH CANADA'S ENERGY INDUSTRY AT A CROSSROADS, WE PONDER THE WAY FORWARD

CONTENTS

FEATURES

DEPARTMENTS

New Technology magazine

www.newtechmagazine.com

EDITORIAL

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

STAFF WRITERS
Lynda Harrison, Carter Haydu, Pat Roche

CONTRIBUTING WRITERS
Jim Bentein, Godfrey Budd, Gordon Cope, Sarah Miller

EDITORIAL ASSISTANCE MANAGER
Tracey Comeau | *tcomeau@junewarren-nickles.com*

EDITORIAL ASSISTANCE
Sarah Miller

CREATIVE

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

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

PRINT COORDINATOR
Janelle Johnson | *jjohnson@junewarren-nickles.com*

GRAPHIC DESIGNER
Teagan Zwierink

CREATIVE SERVICES
Paige Pennifold, Jeremy Seeman

SALES

SENIOR ACCOUNT EXECUTIVE
Diana Signorile

SALES
Rhonda Helmeczi, Mike Ivanik, Tony Poblete, Paul Sheane, Brian Tamke, Blair Van Camp, Patrick Yee

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

AD TRAFFIC COORDINATOR, MAGAZINES
Lorraine Ostapovich | *atc@junewarren-nickles.com*

DIRECTORS

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

SENIOR VICE-PRESIDENT, ENERGY INTELLIGENCE
Bemal Mehta | *bmehta@junewarren-nickles.com*

VICE-PRESIDENT, SALES OPERATIONS
Donovan Volk | *dvolk@junewarren-nickles.com*

VICE-PRESIDENT, GLACIER BUSINESS DEVELOPMENT & EVENTS
Ian MacGillivray | *imacgillivray@junewarren-nickles.com*

VICE-PRESIDENT, DIGITAL STRATEGIES
Gord Lindenberg | *glindenberg@junewarren-nickles.com*

DIRECTOR, THE *DAILY OIL BULLETIN* & EDITORIAL PRODUCTS
Stephen Marsters | *smarsters@junewarren-nickles.com*

DIRECTOR, GOVERNMENT RELATIONS
Chaz Osburn | *cosburn@junewarren-nickles.com*

DIRECTOR, PRODUCTION
Audrey Sprinkle | *asprinkle@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

MEMBERSHIP INQUIRIES
Tel: 1.800.387.2446 | Email: circulation@junewarren-nickles.com
Online: junewarren-nickles.com

GST Registration Number 8265 26554RT.

 Publications mail agreement No. 40069240. Return undeliverable Canadian addresses to our circulation department, 2nd Flr-816 55 Avenue NE, Calgary, AB, T2E 6Y4.

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 6 times per year. Made in Canada. ISSN 1480-2147.

junewarren-nickle's energy group

AMPA Alberta Magazine Publishers Association

AT A CROSSROADS

What a difference two years can make. As we enter 2016, the landscape facing the oil and gas sector is unrecognizable from that of a mere two years ago. Oil prices have collapsed, while natural gas prices remain in the cellar; new governments in Alberta and Canada are promising big changes to the energy sector; and, against all odds, the international community unanimously agreed in Paris last December to largely decarbonize the world economy within the lifetime of someone born today.

While it may be debatable how quickly prices will recover and economies will actually move off fossil fuels, less debatable is the fact the status quo is no longer an option. A very basic change in mindset is occurring, one in which oil and gas as we know it today does not have a long term future, and one in which decisions—about investment, infrastructure, economic development—will increasingly reflect that new reality.

Which doesn't, of course, spell the demise of the oil and gas industry any time soon. But it does mean it will have to change to thrive, and those who prosper will be those who view the new reality as an opportunity rather than a threat.

And the biggest opportunities will come through new technology. As we put an escalating price on greenhouse gases (GHGs), we will need to look at new ways to produce oil and gas—a particularly important task in the high-emitting oilsands. There are already a variety of technologies in development capable of dramatically reducing GHG emissions. A carbon tax and the Paris deal could be the impetus to bring them to commercialization sooner.

Many creative and innovative solutions are out there. Some oil companies are already moving to capitalize on the drive to decarbonize production with innovative new technology adoption. For example, GlassPoint Solar and Petroleum Development Oman (Royal Dutch Shell owns chunks of both companies) are constructing one of the world's largest solar farms to produce steam for heavy oil production in Oman. At its peak, Miraah will be able to generate in excess of one gigawatt of solar thermal energy, save 5.6 trillion BTUs of natural gas and trim CO_2 emissions by over 300,000 tonnes annually.

Other companies are getting directly involved in renewables. Statoil has announced construction of the world's first floating wind farm off the U.K., leveraging its offshore oil and gas production expertise, while Dong Energy recently announced it will construct the world's biggest offshore wind farm in the Irish Sea. In Canada, pipeline companies Enbridge and TransCanada have both invested heavily in low-carbon power projects, from wind and solar to geothermal and nuclear.

Alberta has tremendous potential for renewable energy development, including some of Canada's best wind and solar resources, which could be tapped as coal power is phased out. Carbon capture (CCS) with enhanced oil recovery (EOR), such as NW Refining and Enhance Energy's CO_2 EOR project, or sequestration, such as Shell's Quest project to sequester CO_2 from its upgrader, are in the forefront of CCS technology deployment. Enhanced geothermal system development could leverage our expertise in drilling and fracturing technology and create an entirely new industry with potentially large export opportunities.

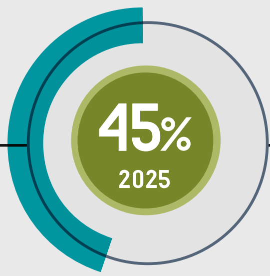
Certainly, many other opportunities exist, and there are many directions the energy industry could take as we transition to a lower-carbon economy. In this issue, we asked a selection of thought leaders for their input on our energy future. Their views vary—ranging from improved, lower-emissions oil and gas production to carbon capture and developing new uses for carbon, to renewables, to fusion power—but two of the themes to emerge most prominently were collaboration and innovation.

And maybe that's the biggest takeaway of all. Certainly the opportunities are immense, and the oil and gas sector's spirit of innovation—the same spirit that made the oilsands viable to produce and created the shale gas and tight oil revolution—and its growing culture of collaboration—as exemplified by organizations like Petroleum Technology Alliance Canada and Canada's Oil Sands Innovation Alliance—will serve it well as we transition to a low-carbon future.

Maurice Smith

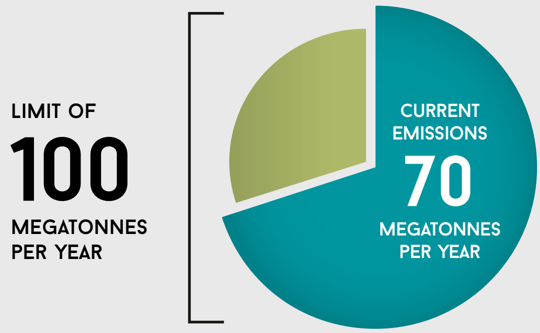
In the summer of 2015, a five-person Climate Change Advisory Panel was formed to help the Government of Alberta develop a new strategy on climate change. After receiving feedback from industry representatives, farmers, indigenous communities, academia, think-tanks and the public, the panel made recommendations that lead to the development of a Climate Leadership Plan that focuses on four key areas.

1. DEVELOPING MORE RENEWABLE ENERGY PROJECTS WHILE PHASING OUT COAL-GENERATED ELECTRICITY
2. IMPLEMENTING A PRICE ON CARBON EMISSIONS
3. LEGISLATING A LIMIT ON EMISSIONS FROM THE OILSANDS
4. PUTTING INTO EFFECT A METHANE EMISSIONS REDUCTION PLAN



As part of Alberta's climate change policy, the provincial government plans to reduce oil and gas industry methane emissions by 45 per cent by 2025. In 2013, 70 per cent—30.4 megatonnes—of provincial methane emissions were from the oil and gas sector. Of those emissions, more than half were from venting, one-third from fugitive emissions and the remainder from flaring.

Alberta's new climate change policy will see the price of carbon emissions rise to $20/tonne in January 2017 and to $30/tonne in January 2018; thereafter, the price will increase every year in real terms. At $30/tonne, the carbon price is expected to generate around $3 billion annually. Premier Rachel Notley says that a large part of the revenue raised from the carbon tax will support industry innovation and research into technologies that can reduce the amount of carbon produced in the oilsands.



A limit of 100 megatonnes per year, with provisions, will be legislated for Alberta oilsands emissions. With current emissions levels at 70 megatonnes per year, the new limit gives the oilsands industry 30 megatonnes to play with while new technologies are developed that will ensure an increase in the number of barrels produced and a decrease in emissions.

The Alberta government plans to phase out pollution from coal-fired electricity generation by 2030 through a combination of accelerated retirement of coal-fired plants that exceed regulations, carbon pricing and incentives for renewable electricity generation. Up to 30 per cent of electricity generation will be from renewable sources such as wind and solar. The remainder will largely come from natural gas–fired plants, though there is some room for other sources that use technology to eliminate pollution.

EMISSIONS

SEARCH FOR GREEN TECH

Oilsands producer seeks coalition for study to tackle climate change concerns

Cenovus Energy wants to put together a coalition of companies—and possibly government—to do a FEED study on climate change mitigation.

The goal is to find technologies to address the public's concern over climate change, which has been increasingly evident in Cenovus's monitoring of Canadian public opinion since the company was founded about six years ago.

"We've been doing public opinion research ever since we started, and we have seen it change over time," said Alan Reid, the oilsands producer's executive vice-president of environment, corporate affairs and legal.

Since it spun off from Encana in December 2009, Cenovus has been sampling Canadian public opinion across the country through polling, workshops, social media monitoring and face-to-face meetings.

"So we feel we've got a pretty good handle on where things are now and how things have changed," Reid told an Economic Club of Canada energy conference in Calgary last November.

CENOVUS'S RESEARCH FINDINGS

While it found Canadians understand the economic impact of the oilsands and appreciate the work that has been done to reduce local environmental impacts, Cenovus's continual research has also revealed growing public concern about climate change.

"I think five years ago, climate change was something that really wasn't part of the public discourse. It was more something that was occasionally talked about in boardrooms. It was talked about certainly in academic circles. But it wasn't part of the pubic discourse," Reid recalled.

"What we're seeing now is that Canadians are concerned about climate change and they're concerned about their role in climate change," he said. "So our polling indicates that the concerns are more around end use of oil as a product than it is necessarily around the environmental impacts of upstream production."

One finding is that a significant number of Canadians now believe the world may stop using oil within the next 10 years, while others believe that shift could happen in 10–20 years, he added.

In other words, many Canadians don't see oil as part of humanity's energy future, and they expect the change to occur surprisingly soon.

Although widely held, this expectation of such a rapid transition isn't supported by any forecasts or experts, Reid pointed out.

He suggested this misconception may be the result of talk about the "green economy" and vehicle manufacturers investing in electric, battery-powered cars.

"So I think despite the fact that most experts don't see a big move away from oil, that's not necessarily how the public is looking at it," Reid said, noting this would increase support for policies that could hasten the transition away from oil.

FEED STUDY

So if the public sees climate change as a problem, how should the industry tackle it?

"I think the first thing we need to do is...acknowledge that there is the concern," Reid said, adding, "If end users are concerned about your product...you have to address your customers' concerns."

He said that means taking a broader view "of what responsible development looks like."

Cenovus has been holding "very, very preliminary conversations" with some other upstream players in Calgary. "We have talked to some people in the Alberta government—not at the leadership level—about it. And resoundingly we're getting a very positive response," Reid said.

SO WHAT'S THE NEXT STEP?

"If you build projects, one of the things you do is identify a business case. So then you do a FEED—a front-end engineering and design," he said.

> "I THINK THE FIRST THING WE NEED TO DO IS... ACKNOWLEDGE THAT THERE IS THE CONCERN. IF END USERS ARE CONCERNED ABOUT YOUR PRODUCT...YOU HAVE TO ADDRESS YOUR CUSTOMERS' CONCERNS."
>
> *— Alan Reid, executive vice-president of environment, corporate affairs and legal, Cenovus Energy*

Speaking to reporters afterwards, Reid elaborated: "A FEED study is something that you do early on. Once you have a concept, you do a FEED study to understand potentially what that project would look like—how much it would cost, how long it would take, and those kinds of things."

So Cenovus wants to build a coalition of companies to do the FEED study. That could also involve government, Reid said.

"We need to understand what the problem looks like: What are potential solutions? How do we fund research and development into potential solutions? How do we bring innovation to bear... not just on our upstream use—because I think there's been a lot of great work done there. But how do we also resolve the concerns with end-use emissions?"

It would start with an inventory of existing technologies and trying to get a handle on the research and development costs involved, and then it would put together a timeframe.

"I think those are the likely next steps," Reid said. "It's to build a coalition of the willing, if you will, and to get started."

Pat Roche

ENHANCED OIL RECOVERY

REACTIVATING SUSPENDED WELLS—FOR FREE

Multi-phase pumping solution comes at no cost to producer

Almost 400,000 wells had been drilled in Alberta to the end of 2012, of which about 150,000 were abandoned and, of these, approximately 50,000 have yet to be certified as reclaimed, according to Petroleum Technology Alliance Canada (PTAC).

Prior to abandonment, wells may be suspended, which could have financial implications for operating companies through the Licensee Liability Rating (LLR). In an environment of low oil and gas prices, more wells are being suspended, increasing the financial strain on many producers.

Innovative technology solutions are needed to alleviate the situation, says PTAC, and a Swiss company believes it has one. Globotics Industries wants to bring its Low Pressure Pumping System (LPPS) to Canada. And one particularly attractive aspect of the system in today's crude oil bust economy is that while it will bring new revenue to the operator, it comes at no additional cost.

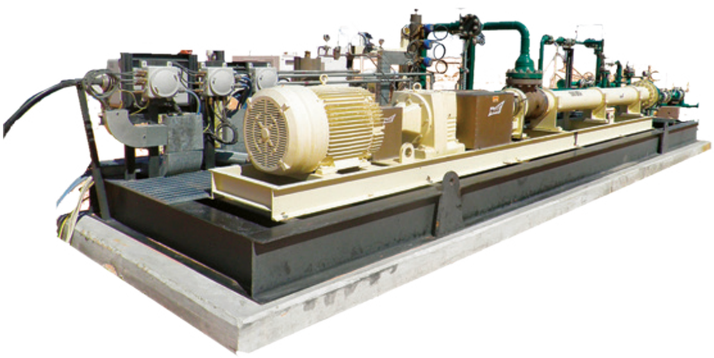
The system is used to recover significant quantities of fluid from wells that would otherwise be unusable, both by boosting the flow with a thrust action and by reducing the wellhead pressure, thus improving the normal productivity of the well.

Massimo Bianchini, Globotics chief executive officer, says that where it is found to be applicable, the company will pay all the upfront cost to establish the LPPS system, and operate it with only a daily fee and royalty paid by the operator.

"We propose our LPPS system in a full-service formula. That means that all investment cost is paid by us—the oil company has no capital expenditure [capex], just operating expenditure [opex]. And then I would say that still, opex expenditure is not really expenditure because…that will start only when actual recovery at the GOSP [gas-oil separation plant] will start," he says. >

AVOIDING SUSPENSION With the number of abandoned and suspended wells on the rise, companies are seeking new technologies to extend the productive lives of their wells.

PHOTO: ©ISTOCK.COM/HUYANGSHU



> TURNKEY SOLUTION
Globotics' multi-phase pump skid houses the pump, motor and control valves on a steel baseplate for ready field application.

Once producing, the operator pays a daily fee that includes hire costs and operating expenses, and a royalty on recovered oil and gas, which allows Globotics to recover its investment over time. "So I could say really that, for the oil company, there is no operating expenditure, because the oil company will give a small part of its income to us only when the system will be operating."

The contract is normally a fixed initial period that depends on an estimate of the remaining life of the well using the system, but it can be renewed as long as production continues. It is also flexible in that the configuration of the system can be changed to continue to maximize production.

Operations management activities are carried out by Globotics, and routine maintenance and unscheduled interventions are paid for by Globotics, he adds. At the end of the contract, all demobilization charges are also paid by Globotics.

Based in Lugano, Switzerland, Globotics Industries SA is a consulting services and industrial production company that operates in the manufacturing and automation sectors. It operates divisions in Loughborough, U.K., and in Edmonton, where Globotics Industries Inc. carries out engineering activities, quality services and construction.

In a PTAC-sponsored presentation to a Calgary oilpatch audience in November, Bianchini explained the wellhead pressure, or blowout pressure, determines the actual possibility of exploiting the flow and therefore well productivity. Also important is the position of the wells with respect to the first gathering centre and the pressure of the flowline to which the well is connected.

There can be several reasons for non-productive flow. In normally productive wells, the blowout pressure is sufficient to get the fluid into the flowline, and the well could produce more with a lower wellhead pressure, but this pressure would not allow the fluid to reach the first gathering point.

Wells with a blowout pressure theoretically sufficient to guarantee flow to the flowline but with values of a few pounds per square inch difference can generate bottlenecks with considerable lowering of production, he says.

In other cases, the blowout pressure is considerable but not enough, with regard to the distance to the first gathering point, to allow outflow of fluid into the flowline, and the wells are therefore not connected to the flowline. And in the case of depleted wells, the pressure has fallen below the minimum necessary to allow the outflow into the flowline to which the wells are connected.

In all these cases, "the blowout pressure is the critical element that prevents the well's productivity or reduces it, maybe even drastically," Bianchini says.

And in these cases, Globotics' turnkey LPPS can restore wells that are not operative and increase productivity of operative wells. "The multi-phase pumping technology implemented in the LPPS allows boosting of the fluid, which guarantees its transfer from the well to the GOSP," he says.

Due to the pressure drop (Delta P) generated by the LPPS, the discharge pressure is high enough to compensate the head losses and is enough to ensure the fluid has the necessary pressure at the arrival point of the GOSP, but this is lower than the maximum service pressure of the flowline, says Bianchini.

The LPPS can handle multi-phase fluids with variable gas volume fraction up to a maximum of 98 per cent. It makes the presence of gas separation systems, compressors, gas transportation pipes and flaring systems unnecessary.

Many different configurations are possible, Bianchini adds. Installation in tie-in on the flowline, for example, where several normally productive wells are present, allows their respective wellhead pressure to be reduced, increasing the productivity of reduced pressure wells.

Installation in tie-in on the flowline can also resolve bottlenecks due to the presence of multiple wells with wellhead pressure values very close to each other. "Elimination of the bottleneck increases production for all the wells connected upstream of the LPPS and allows the blowout pressures to be reduced and so optimizes productivity."

Installation immediately downstream of the manifold allows the wells with insufficient pressure to be connected to the flowline and their productivity to be restored, while increasing productivity to already operating wells where wellhead pressure can be reduced.

And where there are several wells with a wellhead pressure too low, installation of the LPPS can be done immediately downstream of the manifold even when productive wells are present, and reduced pressure wells can then be restored.

Thanks to its Delta P, he says, the LPPS compensates the reduction in pressure carried out on the well and guarantees outflow of the fluid toward

PHOTOS: GLOBOTICS INDUSTRIES

the gathering point or its introduction into the flowline.

If the minimum conditions exist—configuration of the oilfield gathering system, suction pressure and maximum gas volume fraction of the fluid—the system can easily be adapted to a wide variety of existing system configurations.

The pumps are supported by a sophisticated control system that controls the pump operation based on feedback describing the well's functional parameter trends, thus continuously adapting the suction methods to the optimal operating conditions of the fluid extraction process.

And thanks to the experience gained by Globotics engineers over many years, collaboration with the pump supplier has allowed it to increase the capacity of the pumps and gain greater adaptability under the most extreme and unfavourable conditions, he says.

The company's involvement begins with a preliminary feasibility study, Bianchini says. "We request to have a lot of data. We need geological data of the fluid and on the reservoir; we need a full specification of the well; we need to have the historical situation, the picture [of] what happened to the well in the past; we need to have the well testing data in order to verify the IPR [initial production rate] relation in order to understand how pressure and therefore productivity can be tuned.

"We also need the geographical data of the complex because there are several possibilities of implementation of the system.... Having all this specification, we can proceed with an idea of the design process and design and size the system with all [necessary components] to implement the system.

"And then you have more traditional engineering activities—the procurement, transportation, implementation, construction, all these activities are done by us. This is a really turnkey system—the oil company has nothing to do, they just make available the oilfield and wells."

Thanks to installation of most of the components on a containerized multi-phase pump skid, assembly, disassembly and reuse can be carried out in a short time frame. A remote control system allows centralization of the operations management of several units distributed in a field or in diverse locations.

Compared to other artificial lift systems, its 70 per cent efficiency rate is the highest of the various systems available, Bianchini notes. "Its ability to adapt to the pressure variations of the well guarantees its optimum operativeness and therefore maximum well exploitation."

According to Bianchini, in one project Globotics installed seven LPPS systems starting in 2006 on 32 wells in North Africa for Algerian national oil company Sonatrach. Up to last year, it created US$118 million in profit per year from the 32 wells, he says. "There is a lot of interest" in Canada for the technology, he adds.

Maurice Smith

CONTACT FOR MORE INFORMATION

Massimo Bianchini, Globotics Industries SA
Tel: +41 91 921 21 57
Email: m.bianchini@globotics.ch

< KEEP IT SIMPLE Seven Lakes' software can extract data from various platforms and source systems and consolidate it in one easy to read and digest view.

PRODUCTION

ON THE DASH

Software delivers the right information to the right personnel at any time, any location

You are driving down a highway, wondering if your engine is going to overheat. Now imagine that instead of having one gauge on your dashboard where you can see your engine's temperature, you have to look at four screens, and one of them is in the back seat while another is in the trunk.

"You can imagine how hard it would be to keep tabs on your engine," says Bret Wiener, chief technology officer at Seven Lakes Technologies.

Instead, cars are made so that readings are taken from sensors whose information is piped to one little gauge that's easy to look at, and with just a glance you know exactly the temperature of your motor and if you're in good shape or not.

"We provide the same sort of thing at the enterprise scale, drawing data from a bunch of different sources within [an] organization and then presenting that data in a consolidated, very easy to read and digest view, and we enable different users to set up different preferences or filters, so that if you're a user in one business unit, for example, or a field supervisor, when you log in, your personalized dashboard gives you almost instant access to exactly the data that you need to see, which may be slightly different [from that of] somebody in a different business unit," says Wiener.

Seven Lakes' software can extract data out of all the various platforms or source systems companies are already using and consolidate that data under one "hood" for consistent and consolidated insight, he says.

And the user interface of its applications is incredibly easy to use, he adds. "There's nearly no training required with our solution, which means that user adoption is usually just excellent with our products. It's obvious after literally a glance from across the room at the screen you can see these look like the kinds of applications that people are accustomed to from their phones and their tablets and their PCs in their daily personal lives."

With 70 employees and offices in Los Angeles, Houston and Bangalore, India, Seven Technologies provides oil and gas enterprise software that enables data analytics, enterprise mobility, collaborative workflows and field data capture for production operations, drilling and completions, accounting and environmental health and safety.

In market conditions like these, this is a great time for companies to refocus on making their operations more efficient so that when, hopefully, the market rebounds, they'll be in a better position to grow their operations and take some additional market share, says Wiener.

Willson Beebe, lead financial analyst with Concho Resources' Texas basins asset group, has been using Seven Lakes' dashboards for about a year. "I love them. They're really easy to use," he says.

Beebe also likes that he can connect to raw data using Excel spreadsheets. "In my job, I do a lot of analysis so I utilize that probably more than the dashboards because I'm more interested in the raw data, so the ability to use that native in Excel is really good because everybody around here uses Excel and is comfortable with that and understands it, so that's a big plus."

Midland, Texas–based Concho, whose assets are all in the Permian Basin, has grown through acquisitions from about 500 wells to about 5,000 wells in five years and from about 300

PHOTO: SEVEN LAKES TECHNOLOGIES

employees to around 1,100 employees. Beebe estimates 250 of them are using Seven Lakes' software. Integrating data and wells from many different companies has been a challenge, but Seven Lakes' dashboards have helped, he says.

Al Abeyta, senior business systems analyst for Vanguard Natural Resources of Houston, has been using Data Cube, LOS dashboard and AFE workflow for two and a half years, and the company is still "getting its feet wet" with the production portal after eight months.

"They built our data warehouse and infrastructure that allows us to manage our data from all business applications," says Abeyta. "We love them. We couldn't do what we do without them. We're a big oil and gas acquisition company. We run lean as it is; we're constantly looking for ways improve processes, and reporting is a big deal, so I couldn't imagine us surviving without AFE workflow and LOS dashboard, for sure. There's just no way we could function without those two applications."

He, too, appreciates the software's ease of use, and says the LOS dashboard is laid out exactly how Vanguard, a company with about 10,000 operated wells, wanted it. "It's not just a generic LOS dashboard that the company rolls out to everybody and you just have to change and get used to it," says Abeyta. "We were able to work with them to configure it the way we want it based on how we see our business."

The software enables him to identify potential issues within a matter of seconds and then get results and additional analytics using other tools within a minute or two, he says, adding this is a huge time saver.

"Before, we were massaging data from all over the place," he says. "It would take us a day, sometimes two or three days to get to [where we could] ask certain questions, so now we're able to make smarter decisions, ask more relevant questions and dig down to the lowest level of detail, all within a few seconds."

Based in Westlake Village, Calif., Seven Lakes has about 30 customers with as few as 40 or 50 wells and as many as 40,000 or 50,000 wells.

"In terms of market penetration that doesn't sound like a terribly impressive number," admits Wiener. "I will say, though, that about 10 per cent of all the wells in North America are managed or represented within Seven Lakes' solutions."

Seven Lakes has three broad categories of products: business intelligence (BI), workflows and general business applications. Its most popular dashboards are within its BI unit, and they include production, downtime and expense dashboards like general and administrative, vendor spending and related sorts of things, he says.

The workflows category is designed to help drive higher-quality data so that the analytics and the BI products can be optimized. "We've learned over the years that no matter how good our dashboard products are, they're always at the mercy of the online data," Wiener adds.

Its well life cycle manager application affords workflow enforcement throughout the lifespan of a well. Another product, AFE Workflow, helps businesses control costs by collecting all the data necessary for an authority-for-expenditure and going through an approval workflow.

General business applications are designed to improve analytics. "That really is our value proposition," says Wiener.

One of the best-selling products in that category is called Field Data Gathering (FDG), a product that effectively replaces the grease sheets used by pumpers, he says.

"These organizations all have pumpers who go out and visit wells each day to take different measurements and readings from all the equipment in the field, and the industry for the most part unfortunately is still [using] paper, called grease sheets. Our FDG application replaces that with a mobile application that can run on any sort of a tablet or ruggedized laptop.

"[Pumpers] can take all their measurements and readings within our product with a lot of data validation and cross-check to make sure that all the information they're collecting makes sense. It will run in offline mode because in many cases when they are out in the field, there is no Internet connectivity, but then as soon as they're back in a 3G or 4G area or they've got WiFi access, the application automatically uploads that data back to the computer system and then the information can feed into our production dashboard or other system the organization is using."

One of the problems with using paper is it can take days for data to get into the computer system. Sometimes an operation will stop because something is broken, and the company may not even know about it for days. "Our FDG product helps them collect much better data in a much more timely fashion," says Wiener. "Detecting or even predicting downtime events is definitely one of the things that people tend to rave about with the Seven Lakes technologies."

Often, companies without Seven Lakes' technology in place will continue to run unprofitable wells for a long time before they realize they are unprofitable, says Wiener. "Our production and profitability dashboards can assist with the well-review process, so maybe instead of waiting six months or a year after a well becomes unprofitable, they can either shut it in or sell it off. That's definitely a way they can save a lot of money. Just that alone can typically pay for the cost of our dashboard product several times over."

Recently Seven Lakes and Houston-based Noah Consulting, which has an office in Calgary, joined forces so that Noah is now the exclusive partner for delivering Seven Lakes' well life cycle manager application. "We are information management consultants, so we have a great deal of expertise in the oil and gas domain. They bring the tools and the applications, and we bring the process and the domain expertise," says Amber Charboneau, Noah's marketing manager.

■ ***Lynda Harrison***

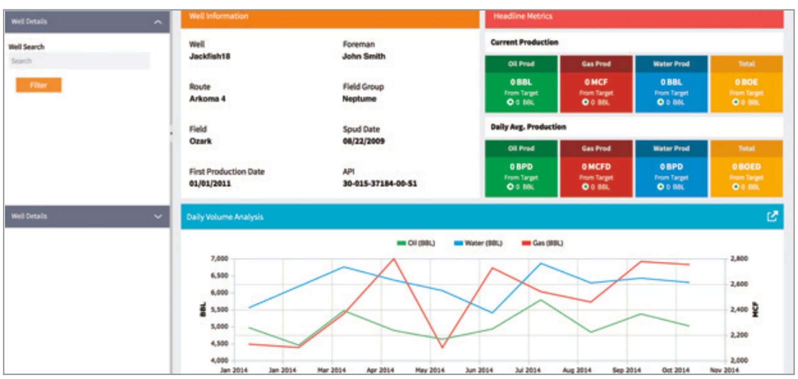


IMAGE: SEVEN LAKES TECHNOLOGIES

CONTACT FOR MORE INFORMATION

Sowmya Murthy, Seven Lakes Technologies
Tel: 805-242-4288
Email: sowmya.murthy@sevenlakes.com

Amber Charboneau, Noah Consulting LLC
Tel: 832-689-8600
Email: amber.charboneau@Noah-Consulting.com


RIG Locator
Close deals before your competitors.
GET TODAY'S RIG LOCATIONS AND RIG COUNTS
• Via email alert, map or Excel download.
• View current and accurate information about western Canada's drilling rig fleet.
Search by status
Map it
Build a list of prospects
Download to Excel
Set up email activity alerts
START A FREE TRIAL ON RIGLOCATOR.CA
RIG LOCATION INFORMATION PROVIDED BY:
CAODC
RIGLOCATOR.CA
junewarren-nickle's energy group

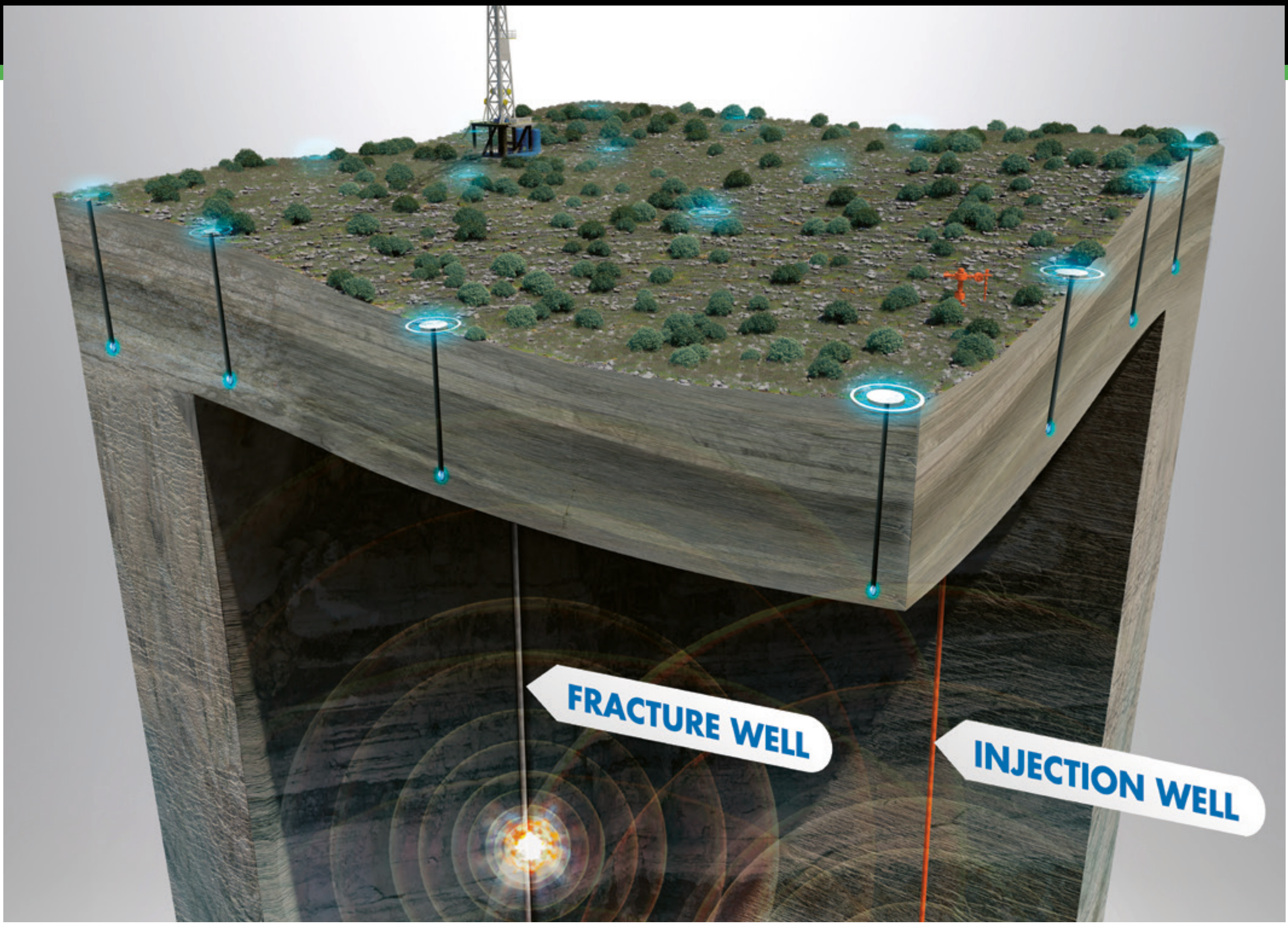


IMAGE: MICROSEISMIC

PRODUCTION

MITIGATING THE SHAKING

Seismic technology key to reducing induced seismicity

Between 2005 and 2008, there were eight earthquakes registering magnitude 3.0 or greater in Oklahoma. In 2013, that number climbed to 109, and in 2014, to 584. By late November 2015, there were 802 recorded by the Oklahoma Geological Survey—more each day than were recorded each year in the earlier period—and the once quiet state had surpassed California as the most seismically active continental U.S. state. Increasingly, authorities have ordered a cessation or reduction in injection rates of waste water in nearby wells as a result.

Similarly, the area around Fox Creek, Alta., northwest of Edmonton, typically recorded one or two small quakes per year until recently, when increasing frequent and intense seismic events have risen in tandem with hydraulic fracturing in the Duvernay Formation. There have been more than 160 earthquakes since 2013, including two in 2015 of magnitude 4.4 that the Alberta Energy Regulator (AER) has attributed to hydraulic fracturing, making them among the strongest ever to be connected to fracking.

And the B.C. Oil and Gas Commission in 2014 positively linked 231 seismic events over 14 months to the shale gas sector, with some causing damage to horizontal wellbores. In August 2014, a 4.4 magnitude earthquake was recorded in northeastern B.C. that the commission found was "triggered by fluid injection during hydraulic fracturing." A year later, on Aug. 17, 2015, Progress Energy temporarily shut down multistage fracturing operations in the Montney shale when a magnitude 4.6 quake struck three kilometres from their well, in an area about 100 kilometres northwest of Fort St. John, B.C.

In most cases, the increased seismic activity has coincided with the rise in shale gas and tight oil production, which require massive hydraulic fracturing to release the hydrocarbons. But while hydraulic fracturing has sometimes been blamed, it is usually the large-scale injection of waste water—both the return to >

^ SEISMIC ALERT ARRAY
MicroSeismic's seismicity monitoring system allows operators to establish a baseline for naturally occurring seismicity prior to the start-up of injection activities. Monitoring over the life of the asset helps to demonstrate proactive stewardship of field operations.

surface of water pumped for the frac and highly saline formation water—into deep formations that has been associated with induced seismicity.

SMALL NUMBERS

While waste-water-injection-related earthquakes may appear alarming, Peter Duncan, founder and co-chair of MicroSeismic, a Houston-based company specializing in hydraulic fracture stimulation surveillance and evaluation, points out that they still represent only a tiny fraction of wells in operation and that the technology exists to mitigate the risk—where it is used.

"Of some 150,000 wells injecting a couple of million barrels a day [of waste water] all over the U.S., you have only a handful of instances where there are earthquakes or induced seismicity that have been large enough to be felt," he notes. "And if you are monitoring and you sense that the events are larger, you can shut the whole system down very readily. It is a pretty well understood engineering process in that we can mitigate that risk by simply flowing back the well. And I would emphasize that regulations are coming in places that make sense [to enact them], and those have been fairly successful at mitigating the risks."

Last February, the AER introduced seismic monitoring and reporting requirements for operators in response to concerns over induced seismicity in the Fox Creek area. Similar to that enacted earlier in B.C., the AER adopted a traffic light protocol that sets thresholds for reporting seismic activity. Any events measuring a magnitude of 2.0 to 3.9 must be reported, and companies must modify their operations to help prevent future events. Any event that measures 4.0, the magnitude at which the quake is likely to be felt at the surface, prompts a shutdown of operations within a five-kilometre radius, regardless of whether or not they are considered the cause, until mitigation measures are agreed upon.

In Oklahoma, which remains largely unregulated, deep well disposal of waste water has been occurring for decades, and until recently, there was a reluctance to blame the booming unconventional oil and gas industry for the surge in earthquakes.

Companies that specialize in seismic technology, like MicroSeismic, which mostly monitors fracking operations to help companies improve their effectiveness, and Weir-Jones Group in Vancouver, which has specialized in monitoring natural earthquakes for decades, now offer induced seismicity monitoring specific to fracturing and water injection.

There are generally four factors that need to be in place for a large seismic event to be induced, says Duncan. "There has to be a pre-existing fault under a certain amount of stress; the fault has to be orientated in the right direction; it has to be deep enough that it can slip over a large area; and there has to be a sufficient amount of fluid under sufficient pressure going in but not escaping fast enough—if the fluid leaks off, the pressure goes away and the fault is not lubricated.

MicroSeismic's passive seismic system, which can be incorporated in its BuriedArray system or used as a standalone sparse array for real-time seismicity monitoring, will detect an increase in magnitude of events early on so that action can be taken to forestall larger events. "We always see build-up of smaller events first, and when you see smaller events are getting larger, then if you reverse the pumping process you are going to remove the fluid from the fault and the tectonic forces shut it down again."

Highly sensitive frac monitoring systems typically pick up events at around minus two on the Richter scale—roughly equivalent to the shock created by dropping a can of pop on a cement floor from waist level, says Duncan. (Since modern seismographs can detect seismic waves smaller than those originally chosen for zero magnitude, the scale now measures earthquakes having negative magnitudes. Each number represents a tenfold difference in magnitude.)

Because felt seismic events are exponentially stronger, systems to monitor them require fewer ground stations and less data processing, and are therefore much cheaper to install and operate. "To put it into perspective, if we are putting in a BuriedArray [hydraulic fracture monitoring system] we will typically have two or three stations per square kilometre, whereas if you were putting in an array simply to look for the larger events, you can get away with one station every four or five kilometres."

SEISMIC MONITORING EVOLUTION

In Canada, there may not be any company better suited to have come up with a cost-effective technology to monitor seismic events caused by fracking than Weir-Jones Group. That's because the privately owned company, founded in 1971 by Iain Weir-Jones, who remains its president, is widely known for its expertise in monitoring seismic events ranging from possible earthquakes to rockfalls to monitoring the integrity of nuclear power plants where seismic events might occur.

The origin of the company's suite of technologies is systems developed to provide a warning system before a quake strikes and another that measures the structural integrity of buildings, bridges and other structures after a quake has hit.

A newer product, which it has started marketing in the last few months, is its QuakeMonitor system developed specifically for induced seismicity monitoring, working within the ranges of magnitudes applicable for frac monitoring and regulatory compliance of 0.5 magnitude and larger. Given the controversy over seismic events caused by fracking, Weir-Jones says the new technology offers a cost-effective approach for producers to conduct ongoing monitoring of their wells.

He says QuakeMonitor is a low-cost and highly effective solution for companies concerned about seismicity at their sites. The capital cost of installing one device is $8,500, while continuous monitoring, either by satellite or cellular technology, costs about $1,000 monthly. That compares to fracture mapping microseismic systems that often run from $250,000 to $400,000, he says. "We can install the system in two hours or less," he said. "Some of the other [competitive] systems cost 10 times that to install and they amount to overkill."

He said there was a time in the past when surface-based systems were not as reliable as higher cost technology installed inside a reservoir, "but the software and hardware [of his company's surface-based system] has improved dramatically."

The last few decades have seen a huge evolution in the technology that, with state-of-the-art digital recorders, triaxial downhole sensor packages and real-time data rendering, has created the ability to monitor geo-mechanical events to depths greater than 10,000 feet. A single station can now provide seismic magnitudes, event distance from the well and seismicity rates and report it to the operator in seconds, he says, while three or more stations can add location to reporting and reduce the chance of false alarms.

Jim Bentein and Maurice Smith

OPEN-HOLE OR CEMENTED LINER?

QUEST FOR THE BEST TECHNOLOGICAL FIT CONTINUES—WITH PLENTY OF EXPERIMENTATION

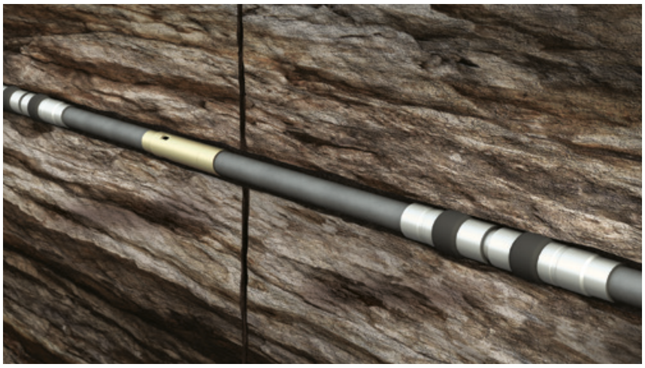
BY GODFREY BUDD

THE choice of which multistage fracturing techniques—such as using an open-hole or cased cemented completion—to apply to shale gas and tight oil wells has been contested for years. Indeed, as a paper presented at the SPE Annual Technical Conference and Exhibition in Houston in September noted, "Debate continues regarding the advantages of open-hole versus cemented liner completions."

While each system will no doubt continue to have its committed adherents, such factors as economics, formation characteristics and completion strategy are likely to affect an operator's choice as well. The influence of such considerations is increasing as technologies advance, along with bigger accumulations of historical data and a better understanding of shale plays. Over the years, a more finely tuned and educated decision making process has supplanted much of the guesswork of the early days of horizontal completions.

Completions across North America are typically more complex than they were just a few years ago, as wells get deeper, laterals get longer and the number of stages continues to climb. The average depth of wells drilled in western Canada, at 2,529 metres for the >

PHOTO: PACKERS PLUS ENERGY SERVICES



< WELL-CHOSEN
Economics, formation characteristics and completion strategy are increasingly deciding whether to choose an open-hole or cemented liner completion.

first 10 months of 2015, is 13 per cent higher than the average of 2,247 metres a year ago, according to the Daily Oil Bulletin. In 2006, the average well depth in western Canada was just 1,199 metres. The number of stages is also way up, with the average in the Saskatchewan Bakken, for instance, which was just under seven in 2007, hitting 25 stages per well in 2014, according to Canadian Discovery.

Companies providing tools and services for multistage fracture completions are offering a widening range of options to accommodate the sector's growing complexity. Some service outfits that are mostly associated with one type of completion are applying their technologies to the other.

NCS Multistage, for example, long identified with cemented liner completions, has applied its coiled tubing, sliding sleeve–based Multistage Unlimited system to open-hole completions.

Packers Plus, which pioneered open-hole completions in western Canada, has also applied its StackFRAC ball-drop technology, first designed for open-hole completions, to plug and perforation (plug and perf) with a cemented liner. The company now provides coiled tubing–supported completions and ball-drop technology for cemented wells as part of its product and service offering.

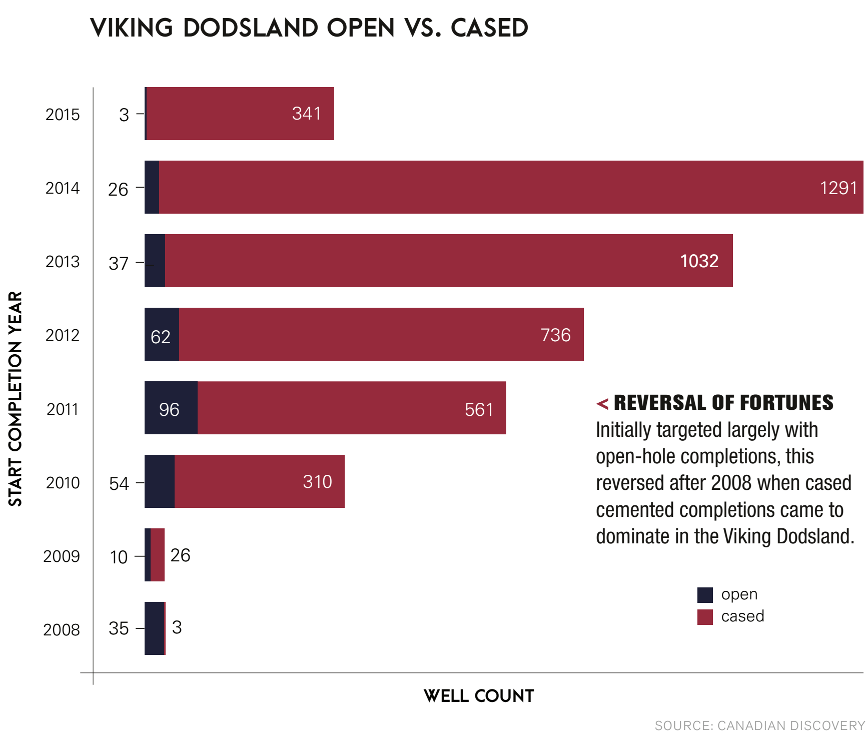
Operators today are sometimes opting for hybrid techniques or slightly unorthodox blends of technologies in their completions, says Tim Leshchyshyn, president of FracKnowledge Solutions. He identifies three main types of completion systems. Two of them, plug and perf and coiled tubing (CT), are associated with cemented wellbores. The third is with an open-hole liner and packer-sleeve system. "Each system has its advantages. Each will have some disadvantages," Leshchyshyn says.

Plug and perf, he notes, is based on conventional technology for which some improvements have been made, and is an option for high-pressure fracturing in deeper zones that require high rates of pumping—10–12 cubic metres per minute or more. Open-hole liner with a packer-sleeve system is a faster method for fracturing medium to deep zones and can offer maximum reservoir exposure by taking advantage of natural fractures. It is best when no post-frac re-entry activity is planned, as ball seats will probably have to be drilled out first. "If you want to do a very technical frac, you go for CT," Leshchyshyn says.

CT systems are typically used at shallow to medium depths, he says, and the technical attributes of these systems enable easier monitoring of downhole events, "which helps you to do a good technical job." The system requires full-bore internal diameter (ID) to operate, so it has the advantage of no preliminary drill-out requirement if post-frac re-entry activity is planned. Leshchyshyn adds that CT completion systems handle screen-outs well and can maintain circulation, should they occur.

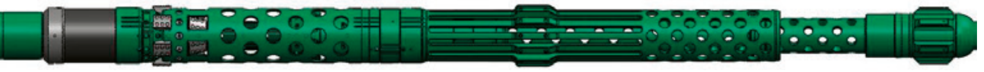
Leshchyshyn estimates that in 2012, in the U.S., where about half of all wells are drilled in Texas and the rest of oilpatch activity is spread across another 23 states, about 90 per cent of completions were plug and perf with cemented liners, leaving about 10 per cent done with an open-hole system. In Canada, on the other hand, in the period 2009-10, the ratios were reversed, with 90 per cent of completions open-hole and about 10 per cent cemented.

What accounts for the difference? On both sides of the border, for much of the last 100 years, wells were vertical with a cemented casing in place prior to completion. (Today, still, Leshchyshyn says, 99 per cent of vertical



< REVERSAL OF FORTUNES
Initially targeted largely with open-hole completions, this reversed after 2008 when cased cemented completions came to dominate in the Viking Dodsland.

IMAGE: PACKERS PLUS ENERGY SERVICES



wells are cemented.) Then, as the focus on unconventional resources intensified, in deep, hot, high-pressure wells in Texas, plug-and-perf completions were performed on laterals that were seen as extensions of vertical wellbores.

But in Canada, the mindset at the start of the shale revolution was, "We're stuck with some of the lowest permeability, so we have to innovate," Leshchyshyn says.

Canadian service companies, among them Packers Plus, NCS and Trican, soon emerged with a range of solutions for successfully improving fracturing operations. One of the earliest innovations was the Packers Plus open-hole ball-drop system, which enabled operators to increase the number of stages on a cost-effective basis. "It was the downhole tool market that got the U.S. industry to look at Canada," Leshchyshyn says.

The early lead in innovation of Packers Plus prompted many western Canada–based operators to opt for the company's open-hole approach, and the company's system soon had its competitors. In the Canadian Bakken, Packers' open-hole completions helped unlock a technically challenging resource. The result was that in 2008, of 698 completions, 696 were open-hole, according to a chart from Canadian Discovery. In 2007, there had been a total of eight open-hole completions in the Canadian Bakken.

Besides the Canadian Bakken, the following years saw increased multistage horizontal completions in other western plays, including the Cardium and the Viking Dodsland. Although operators in all three plays first did multistage horizontal completions using the Packers Plus open-hole ball-drop, the quest for the ideal technological fit for play-specific conditions continued.

In 2008, of 38 completions in the Viking Dodsland, 35 were open-hole. But this largely reversed itself in 2009, and of 36 completions, only 10 were open-hole. Activity took off in the Viking play in 2010, when 364 completions were done, 310 with cased cemented wells. Cemented hole completions continued to predominate in the Viking Dodsland where, in 2014, the play's busiest year, 1,291 completions were done with cemented liners and only 26 open-hole.

The shift from open-hole to cemented liner completions was more gradual in the

^ APPLICATION FLEXIBILITY
NCS Multistage's Mongoose SFC tool. Long identified with cemented liner completions, the company has applied its coiled tubing sliding sleeve–based Multistage Unlimited system to open-hole completions.

IMAGE: NCS MULTISTAGE

Bakken, but by 2014, of 343 completions, only 23 were open-hole. The Canadian Bakken had its activity peak in 2010 with 513 open-hole completions and 320 cemented liner ones.

Referring to plays like the Bakken and Viking, Leshchyshyn says, "Shallow formations can be very cost-sensitive, so a cemented liner tool and CT were a choice. CT cemented had a cost advantage over open-hole for these types of well. CT more accurately places the frac, uses less fluid and proppant."

Cemented liner completions can also make adding extra stages simpler and less costly on a unit basis, as there's no need to add packers. "With cemented liner, all your isolation is already there and your frac is punched through the cemented liner," says Eric Schmelzl, vice-president, strategic business at NCS.

He adds, "With a BHA [bottomhole assembly] equipped with memory gauges, it allows us to identify when there is a lack of isolation between the frac stages." With open-hole, he says, it can be harder to identify the problem with a frac.

In the Cardium, however, open-hole completion has remained the choice of most operators, while the number of cemented liner completions has fluctuated slightly. For each of the years 2011-14, the play saw over 600 completions. Numbers of cemented completions for those years were, respectively, 38, 10, 20 and 50.

"It's a balance of cost and production," says Mike Seifert, a geologist and senior account executive at Canadian Discovery. "There has been some growth of cased but not much. With open-hole ball seat, a frac with 20 stages is done in a day."

Yangarra Resources is one company operating in the Cardium that is moving away from open-hole completions. "We found that there was no incremental production after 18 stages on a lateral," says Jim Evaskevich, Yangarra president and chief executive officer.

The company opted for an NCS CT system with cemented liner. "We found we didn't need as much horsepower, and it's less cost although it takes a little longer. It's easier to run the casing as there's less jewelry in the hole. It's less complex than ball-drop," Evaskevich says.

With respect to open-hole versus cemented, some of the operators in the Montney seem headed in the opposite direction. "In 2013, we started experimenting with a Packers Plus system on individual wells and found production was much better," says Pat Ward, president and chief executive officer of Painted Pony Petroleum. "Then in 2014, we started doing parallel wells beside each other. We fracked one well with 18 stages then did the next well right away. We got better results from each well than from doing them singly. The key is spacing, back-to-back fracs and keeping pressure."

He says the company has seen costs drop from $8 million per well to $5.9 million per well at the same time as the company has boosted production and optimized its fracturing operations. "For us, slick water with a high pump rate works best. We picked slick water based on studies," he says.

"The best wells in the Cardium are open-hole, according to the data, and we would advise open-hole even though we have a CT cemented cased system in Quadrant," says Dan Themig, president and chief executive officer of Packers Plus.

He points to the paper presented at the recent SPE Annual Technical Conference and Exhibition that referred to the open-hole versus cemented debate. The paper is based on a study comparing the performance of the two systems across 30 single-lateral horizontal wells by an operator in the northern Montney gas play.

"Our data demonstrates that the benefits of open-hole completions relative to cemented liner completions include an average 25 per cent increase in IP 30 rates [initial production 30-day average], an average increase from seven to 10 bcf in expected ultimate raw gas recovery per well, an average 13 per cent decrease in stimulation period costs, plus an average 36 per cent decrease in stimulation operating time [days], all on an unadjusted basis," states the paper.

"Each technology has its applications," Themig says. "The jury's still out on the best place for each technology. There's a lot experimentation in a lot of different plays." ■

VOICES OF THE FUTURE

With Canada's energy industry at a crossroads, we ponder the way forward

MIKE HANNA,

Managing director, Synergy Canada

Hanna has 35 years' experience behind the scenes facilitating and training leaders, organizations and communities to grow strategies for working on complex interdisciplinary issues. He believes balancing the social, economic and environmental elements of situations often requires examining new and existing information from a different perspective to gain breakthrough insights.

CHAD PARK,

Executive director, The Natural Step Canada and director, the Energy Futures Lab

Park writes and delivers presentations on a wide range of sustainability and social innovation topics, including collaborating for systems change, sustainability-driven innovation, organizational change and sustainability leadership. In addition to leading the Sustainability Transition Lab, he plays key roles with the Future Fit Business Benchmark, Housing Action Lab and Natural Capital Lab.

SOHEIL ASGARPOUR,

President, Petroleum Technology Alliance Canada

Asgarpour leads PTAC's efforts to promote innovation and collaboration in the hydrocarbon energy industry. He previously served as president of Innovative Oil & Gas Inc. and business leader of Oil Sands Development for the Alberta Department of Energy. He has published over 40 articles in technology and business journals.

RICHARD ADAMSON,

President, CMC Research Institutes

Adamson has facilitated the commercialization of innovative technologies for three decades. He has overseen the transition of CMC (formerly Carbon Management Canada) from an early-stage research network to a not-for-profit accelerating the movement of technologies into industry-ready solutions. He assembled the national team that wrote the Canadian chapter of the international Deep Decarbonization Pathways Project.

DAN WICKLUM,

Chief executive, Canada's Oil Sands Innovation Alliance

Wicklum oversees COSIA's efforts to enable responsible and sustainable growth of the oilsands while delivering accelerated improvement in environmental performance through collaborative action and innovation. He has held senior positions for Environment Canada and Natural Resources Canada, and was a senior policy adviser to the federal minister of Natural Resources and the Government House Leader.

ROBERT FEDOSEJEVS,

Professor of engineering, University of Alberta

Fedosejevs has over 40 years' experience in the development of laser systems and their applications in fusion energy research, the generation of XUV and soft x-ray radiation for lithography applications, micromachining, thin film coatings and studies in ultrafast phenomena. He is a member of the Alberta Council of Technologies and the Alberta/Canada Fusion Energy Alliance.

PLEDGES MADE BY NEW GOVERNMENTS IN OTTAWA AND ALBERTA TO REDUCE THE PROVINCE'S AND CANADA'S GREENHOUSE GAS (GHG) EMISSIONS FOOTPRINT WILL SHIFT THE DIRECTION OF THE ENERGY INDUSTRY OVER THE NEXT 15 YEARS. THE WORLD WILL BE WATCHING AS THE INDUSTRY AND THE COUNTRY TRANSITION TO A CARBON-CONSTRAINED FUTURE. *NEW TECHNOLOGY MAGAZINE* ASKED SIX ENERGY THOUGHT LEADERS FOR THEIR RESPONSES TO THREE QUESTIONS ABOUT OUR ENERGY FUTURE. >

Q&A

1 What is the biggest change in the energy industry that will come about in the next 10–15 years in order to meet federal and provincial emissions targets? How will they affect the oil and gas sector in particular?

SOHEIL ASGARPOUR: Canada has the largest hydrocarbon deposits in the world, and over 90 per cent of these are unconventional. They are among the most expensive to develop and produce globally. In addition, they have higher environmental impacts that add to their cost and have been an impediment to increasing access to the U.S. market. So what is the solution?

We need to use collaborative innovation to reduce development and production costs and also reduce the environmental footprint. At PTAC, we have defied the conventional wisdom of economics that states there is a trade-off between financial and environmental performance. We have proven that we can reduce costs while reducing GHG emissions. I believe that in the next 15 years, we will see an increase in the development of collaborative technologies that will ultimately result in significant reductions in both costs and GHG emissions.

CHAD PARK: The biggest challenge in the energy industry will be the changing market conditions being brought about by radical advances in new, low-carbon energy technology and infrastructure worldwide. To compete and remain relevant, Alberta's oil and gas sector will need to make a big push on "decarbonizing" production, ideally making the new 100-megatonne emissions cap for the oilsands almost inconsequential. Every dollar spent on innovation to reduce emissions will pay off in continued viability of assets and resources.

DAN WICKLUM: The biggest change in the energy industry is already under way: collaboration. In the oilsands sector, producers know that operating in Canada requires a high standard of environmental care. They are committed to meeting that expectation through the development of new and innovative technologies. Now, through COSIA, they are innovating together.

COSIA's member companies are competitors when it comes to attracting capital, staffing and developing energy products. But when it comes to accelerating environmental performance improvement, they recognize that they can all make better progress by sharing technology, information and ideas. You might be able to go more quickly over the very short term alone, but you can go much further together.

MIKE HANNA: Confronting the brutal facts, we as a species cannot afford to burn all known fossil fuel reserves. So optimizing which fossil fuel reserves are developed and where will likely become a dynamic geopolitical issue in the next 15 years. This process will be played out through economic and political brinkmanship. Alberta's oil and gas sector internationally and at home rightly or wrongly has had its social licence threatened with suspension. Getting the oil and gas industry's social licence back domestically is the first hurdle. Alberta's oil and gas sector needs to be a valued partner, not a liability, in the effort to reduce GHGs.

RICHARD ADAMSON: Major investment in variable renewables such as solar and wind (which is necessary under all scenarios) as well as increasing use of CO_2 capture technologies from both power and other industrial sectors will both be in the cards. Capture is one of the few technologies that can bolt on to existing industrial processes and that is proven at full scale today. While the race is on toward cost reduction, technical feasibility is no longer in question. This will be the preferred path to extending the life of existing high-value legacy projects.

At the same time, enhanced oil recovery, or injection of CO_2 to produce oil from old plays, will become more desirable as the value of long-term storage of CO_2 helps compensate for depressed oil prices.

On the oilsands front, the drive will be toward smaller-scale, low-emissions modular production technologies as the risk associated with large capital/long payback projects is no longer acceptable.

ROBERT FEDOSEJEVS: One of the biggest changes in the next 15 years will be a relentless, increasing pressure to move away from carbon-based energy systems. This will stimulate rapid deployment of alternative energy sources, such as renewables, and increased scrutiny of emissions from all energy sources. Oil sources with the largest GHG footprint and that are furthest from the markets, such as those of Alberta, will be at risk of being the first to see reduced demand.

At the same time, one forefront technology, fusion energy, will likely make breakthrough demonstrations of significant net energy production, both in the laser fusion experiments currently underway at the Lawrence Livermore National Laboratory in California and in the international magnetic

“SOME OF THE GREATEST NEAR-TERM OPPORTUNITIES FOR ALBERTA WILL COME FROM SEIZING THE CHALLENGE OF METHANE EMISSIONS MONITORING....”

— Richard Adamson, president, CMC Research Institutes

fusion project, ITER, being built in Cadarache, France. Once demonstrated scientifically, these will be followed by the rapid development of demo reactors, with planning already under way today, and we could see the first fusion power to the grid in the period of 2040-50 or sooner, especially if more resources are applied.

2 Are there areas where Alberta has a natural advantage or could aim to become a world leader in the development of new technology solutions?

RICHARD ADAMSON: Some of the greatest near-term opportunities for Alberta will come from seizing the challenge of methane emissions monitoring, detection and mitigation. There is a great deal of opportunity for development in this area, especially with understanding fugitive emissions methane from production or abandoned wells, but also of volatiles from coal and oilsands mine faces.

Solutions to these challenges have global markets. Many of the worst culprits for venting and fugitive emissions are in countries that have less rigorous regulatory regimes than ours. That will have to change, so by immediately addressing these issues Canada has an opportunity to supply solutions to developing areas of the world.

DAN WICKLUM: The COSIA model is a world first, both in terms of structure and the amount of innovation it has enabled. Collaboration works. It speeds innovation and accelerates technology development. Demonstrating that very large companies can collaborate together and with third parties is a contribution to global knowledge on how to speed innovation. We are leading the world in understanding how collaboration works and using it to speed innovation. This will serve us very well over time.

The reality is that Alberta is already leading in developing new technology—we are strong in energy efficiency, water treatment, minimizing land disturbance and speeding reclamation. At COSIA, we have staked out ground in the solution space to global climate change by launching the Carbon XPrize with a co-funder. This XPrize is synergistic with the Climate Change and Emissions Management Corporation (CCEMC) Grand Challenge, and offers a cash prize to innovators that can best change carbon, which is now seen as waste, into a valuable product. I find it very exciting to see Alberta leading the planet in this area of carbon conversion.

MIKE HANNA: Alberta has highly productive wind, solar and biofuels sources—among the top ten in the world. We need to make these opportunities viable economically and accommodate them within the regulatory structures, particularly the electrical energy system. Implementing feed-in tariffs that provide new energy sources access and stable prices for power sold into the electrical grid and removing regulatory barriers to distributed micro grids are essential first steps. If hydrocarbons could be separated into hydrogen for fuel and carbon for building materials such as carbon-fibre materials, our fossil fuels would become sustainable assets.

ROBERT FEDOSEJEVS: Alberta has a large-scale need for clean thermal energy to extract underground oil reserves to make it competitive with world oil producers, particularly for moving from carbon-based fuels to carbon chemistry and other value-added applications. Fusion power plants could provide such heat, reducing the GHG footprint of Alberta oil. Another natural advantage is the knowledge base in our research institutions in the many areas required to pursue the development of fusion energy. These include advanced materials (from nano to macro), lasers and photonics, plasmas, large-scale modelling, controls, robotics and power systems. The strong connections to other fusion energy research groups around the world can be leveraged in order to launch an accelerated program of research and development within Alberta. Once a significant program is established to build a critical mass of expertise, the province could then position itself to be the home of the next generation laser fusion demo reactor engaging the significant engineering skills that already exist in the province. >

CHAD PARK: One of my favorite quotes amidst all the applicants to the Energy Futures Lab Fellowship was on this topic and came from Justin Smith of the Calgary Chamber of Commerce. Justin said, "Alberta should be the place where the world's energy future comes to audition." I agree. A very wide range of new technology solutions could and should be developed and tested in Alberta.

With our tremendous renewable energy resources and the commitment to transition our electricity system off coal, Alberta should become a hot market for renewables. Our lack of provincial energy efficiency programs historically means there is a lot of low-hanging fruit on energy savings. A major push now on energy efficiency should create many opportunities for new business models in commercial, industrial and residential markets and ample export opportunities.

Perhaps most significantly, with Alberta's rich endowment of hydrocarbon resources, we have a clear economic interest in finding innovations that will allow these resources to be developed and used in a low-emission future. I think Alberta should make a major focus on developing new technologies to convert CO_2 into valuable products, as in the COSIA Carbon XPrize and CCEMC's Grand Challenge. These technologies are exciting to me, partly because they challenge the notion that hydrocarbons are inherently unsustainable.

The way we produce and use hydrocarbons today clearly presents major sustainability challenges. But hydrogen and carbon molecules surely will have an important role to play in a sustainable future. Alberta should lead the way in developing the technologies that eliminate emissions from the use of hydrocarbons and allow them to play a role in a circular economy. It may seem like a moonshot, but breakthrough on these technologies would be transformational for Alberta.

SOHEIL ASGARPOUR: Alberta has a strong infrastructure to provide solutions through innovation. While innovation without collaboration is possible, it is often a bumpy, costly and difficult road. An example of an existing infrastructure for developing collaborative technology is PTAC. Over the past two decades, we at PTAC have developed a unique innovation ecosystem with over 190 diverse organizations: producers, federal and provincial governments, regulatory bodies, technology providers, academic institutions, service and supply companies, inventors and transporters. We have formed numerous networks to articulate challenges and identify technology solutions and have launched hundreds of consortia that have taken conceptual technology solutions all the way to field demonstration and commercialization.

An example of such a project that has addressed environmental issues while increasing corporate profitability is REMVue Slipstream Technology, which captures vented light hydrocarbons from oil tanks, condensate tanks and other instrumentation and uses it as fuel in the field. Hundreds of Slipstream units are currently operational, generating $15 million/year from the engine fuel displaced. At the same time, the carbon offset of the technology thus far is equal to taking 150,000 cars off the road annually. Should these units be fully implemented across industry operations, the carbon offset would be equal to taking 1.6 million cars off the road annually while generating $160 million/year from engine fuel displacement. This is simply one of over 450 PTAC projects completed to date.

3 What are the biggest barriers to innovation? How can they be overcome?

CHAD PARK: Price signals were certainly a very big one. The new provincial climate policies will help create more financial incentive for innovation.

I also think that the structure of Alberta's innovation system is a barrier. Innovation is not a linear process, as our institutions seem to suggest—where research and development happens at one end and commercialized products come out the other. Instead, innovation comes from the unpredictable blending of people, ideas and resources. We have pockets of this kind of ecosystem approach to innovation in the province, but I think we must be far more deliberate in building an innovation ecosystem where researchers and innovators in a range of fields interact with more intention, "backcasting" from a clear set of desired principle-based breakthrough outcomes.

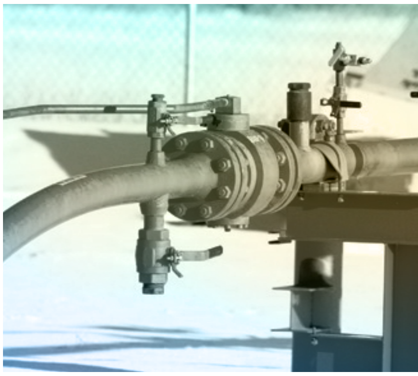
Social innovation is often the missing piece. The cultural landscape shapes and reflects the public imagination and creates the boundary conditions for innovation. Other jurisdictions have done a far better job of linking social, technological and financial innovation, and there is great potential in this for Alberta.

RICHARD ADAMSON: At present we frame issues in terms of renewables versus non-renewables. That is using language from an earlier crisis—oil shortages of the 1970s—to address the much different issue of climate change mitigation.

Language matters. It will shape the solutions we consider and may cause bias against useful, innovative and cost-effective options.

To build policy that supports innovation we should take care to frame it in terms of the desired outcomes: How do we reduce GHG emissions? When we frame policy in terms of renewable portfolio standards, which are quite popular in the U.S., then we create a barrier to, for example, a new device that may convert natural gas to electricity and produce carbon-based building blocks rather than GHGs.

ROBERT FEDOSEJEVS: One major barrier to innovation is the lack of a realistic assessment of the mix of total energy sources



> **“INNOVATION COMES FROM THE UNPREDICTABLE BLENDING OF PEOPLE, IDEAS AND RESOURCES.”**
>
> *— Chad Park, executive director, The Natural Step Canada and director, the Energy Futures Lab*

that will be required in order to achieve a net zero carbon energy economy this century. This has led to complacency in the development of really innovative energy technologies. While renewable sources can serve a significant role and be deployed in less densely populated regions of the world, there will still be a large need for central base-station power plants for heavy industry, for production of transportation fuel, for desalination and to power the hundred megacities of population 10 million to 100 million in the future.

Fusion energy offers one of the only sustainable, environmentally acceptable sources to fill this need. The other barrier is a lack of the high level of investment required to support the development of innovative rather than incremental energy solutions. The power industry falls way behind other technology sectors in terms of fraction of net profits reinvested in innovative research and development. Ideas, such as laser fusion energy, which already have a number of potentially viable options to pursue, are advancing at a limited pace today but could be accelerated significantly if funding were increased dramatically. If Alberta wants to be an energy leader in the future, it should start investing significantly in such future game-changing technologies.

PHOTO:©ISTOCK.COM/PETERARLENE

SOHEIL ASGARPOUR: Small- and medium-sized enterprises (SMEs) play a major role in innovation and technology development in our industry; however, they face major challenges in terms of securing funding and sites for field testing technologies. PTAC provides up to 15 per cent of the cost of each project in seed money, with no expectation on IP ownership or future revenue from the project. This approach has enabled us to act as a neutral facilitator to negotiate IP ownership between funders and SMEs. Currently, we are also working with Venture Capitals to provide additional sources of funding to our SME partners. Since PTAC’s projects go through extensive review prior to producers agreeing to provide funding and test sites, Venture Capitals believe that by providing funding to PTAC projects, they can reduce their investment risk.

MIKE HANNA: From IBM research (2010) of 1,000 leading transnational chief executive officers, corporate culture and changing mindsets and attitudes were by far the top two challenges. Three challenges were closely grouped in ranked order: complexity is underestimated, shortage of resources and lack of higher management commitment. How are these overcome? The right investment for the right impact, real insights and actions, better skills and change, and solid methods and benefits were the key elements for success.

There are no technical silver bullets to save the day. Just the high cost of doing nothing or business as usual. Leadership, employee engagement and honest timely communication are prerequisites for successful change. How do we become price setters that sell value-added renewable energy solutions in a world addicted to fossil fuels?

DAN WICKLUM: The world is changing quickly. There is more information available than ever before. A big challenge is wading through information and understanding what is important and what is not. Doing this with other people or organizations in a collaborative way makes it even more complex. So I would say a barrier—or maybe more a great opportunity—is to continue to develop and refine mechanisms where people and organizations can work together. The more people you have working on an innovation problem the better, but getting them to work efficiently together and to focus is the difficult part. A key part of the solution is to articulate as clearly as possible what you are trying to accomplish. It takes time, but the more clearly you can define the problems you are trying to solve, the greater the chance of success.

COSIA’s members have begun to share their innovation needs publicly through our 13 Challenges. The COSIA Challenges were developed to provide focused, actionable descriptions of the innovation gaps as well as the desired outcomes without prescribing the means for reaching the outcomes, so as not to limit potential solutions. One of the most innovative aspects of the Challenges is that they have been written in such a way that innovators without any knowledge of the oilsands industry can understand them. Better collaboration mechanisms and better technical problem definitions are ways we can speed innovation. ■

Online exclusive

For their responses to a fourth question, and the responses from Zhihong (John) Zhou, chief technical officer, Alberta Innovates - Energy and Environment Solutions, go to the *New Technology Magazine* website, **newtechmagazine.com**. The fourth question is: The Energy Futures Lab asked, “How can Alberta’s strengths in today’s energy system serve as a platform for the transition to the energy system that the future requires of us?” How would you answer that question?

NO STONE UNTURNED

Low-price environment prompts development of advanced proppants

BY GORDON COPE

Canada's oilpatch is taking it on the chin. Recently, the Canadian Association of Oilwell Drilling Contractors (CAODC) announced that it expects only 4,728 wells to be completed in 2016, less than half the long-term average. Not surprisingly, oil companies that are still drilling want to get maximum bang for the buck and are asking service companies to not only lower their day rates, but also to deliver wells faster, more efficiently and with greater profitability. "The big value is in increasing the net present value [NPV] and estimated ultimate recovery [EUR]," says David Browne, director, marketing and community relations, for Calgary-based Trican Well Service.

Ironically, the downturn has had a positive effect on the adoption of innovative technologies. "In the last several years, many operators have been too busy to stop and look at ways to enhance their hydraulic fracturing methods; if something worked for them, they didn't have time to examine alternatives," says Browne. "Now, they have more opportunities to look at other technologies and examine ways of improving their entire process. Rigs are now more adapted to horizontal wells, and drillers are becoming better and better; what used to take three weeks now takes one week. Completion technologies, such as ball drops, are much more effective."

But some of the simplest components of fracture stimulation, proppants (the material used to prop open the spaces created by hydraulic fracturing) and the fluids that carry them to their destination may offer some of the best bargains. "The innovations we are seeing in proppant technologies are also saving money and adding value," says Browne.

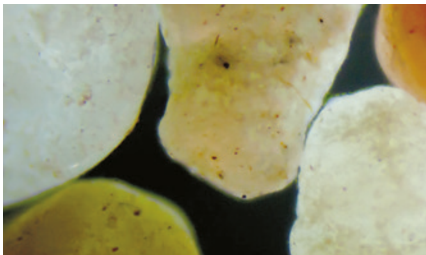
Although some proppants are man-made from ceramics, the vast majority are natural silica, sculpted by glacial erosion into tiny, smooth spheres. Service companies mix the proppant with liquids and inject it at high pressure into a tight formation, overpowering the internal pressure and causing the reservoir to shatter into a highly permeable network of cracks. The proppant settles into the cracks and prevents them from reclosing. Once the stimulation is complete, the frac fluid is flushed out so that oil and gas can flow in large quantities into the wellbore and thus to surface.

In the first generation of hydraulic fracturing employed in the Barnett shales of Texas, the liquid was primarily water (with some viscosity-reducing additives), and the proppant was finely sieved silica sand. Operators worked closely with service companies to find the optimal mix of proppant, pressure, fluids and additives to produce sufficient oil and gas to earn a profit. Each subsequent shale or tight sand reservoir, from the Bakken and Marcellus to the Montney, Cardium and Duvernary, had its own special needs, and those companies that found the best blend tended to keep it under close guard.

The basic system has significant drawbacks, however, including the use of high volumes of fresh water, relatively little control over the pattern and direction of the crack networks, and clogging of the reservoir as the proppant and additives chemically decompose. In addition, early generation frac technology was hit-and-miss; typically, only 25–33 per cent of fracture stages were as productive as designed, meaning that a minority of the reservoir was being effectively drained. "Most unconventional shale in North America has an estimated ultimate recovery of less than 10 per cent," says Michael O'Neill, founder and chief executive officer of Preferred Sands.

Last, but not least, was the expense: the hydraulic fracturing phase could easily surpass the cost of drilling the hole. As long as the price of oil and gas remained sufficiently high, such imperfections could be ignored. No longer. As well completions drop, explorers are struggling to maintain production levels in the face of massive declines (initial production in a shale well can tail

PHOTOS: ©ISTOCK.COM/3QUARKS



off by 70 per cent in the first year). Not only are horizontal drilling expenses being slashed through an array of advanced technologies (like automated drilling and pad drilling), completion specialists are seeking out a variety of ways to reduce costs, increase production and improve NPV and EUR for each well.

FRAC FLUIDS

The volume of frac fluid used in a major stimulation can easily exceed five million litres. Most of the fluid is fresh water, which amounts to about 90 per cent of the frac fluid. If an operator wishes to create large dominant fractures in the reservoir, they use a high-viscosity frac fluid. Materials such as guar gum and other thickeners are mixed at surface to create a thick fluid capable of suspending large volumes of proppant at lower pump rates. Other chemicals are added to break down the gel and allow it to flow back to surface after the frac is completed.

If an operator is looking to create a pattern of very small fractures in the reservoir, then viscosity-reduction compounds such as polyacrylamide are added to create slick water. The lower-viscosity fluid can be pumped at higher rates—100 bbls/min versus 60 bbls/min—and carry more of the proppant much farther into the fracture zone. Generally, slick water uses fewer chemicals and is less expensive, so engineers strive to incorporate it as much as possible.

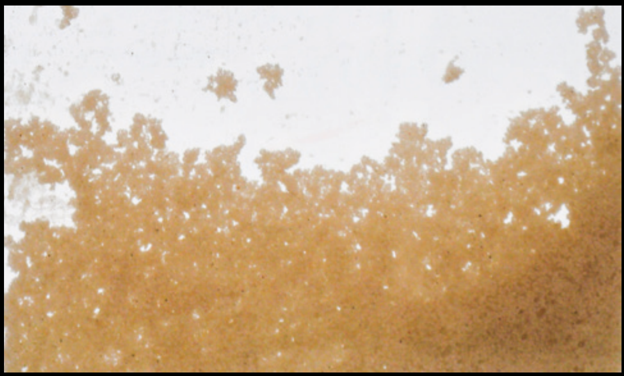
PROPPANTS

Proppants are typically made of spherical silica sand grains or tiny ceramic beads approximately one-half millimetre in diameter. They comprise about nine per cent of the frac fluid and can exceed 500,000 pounds per well. There are several key factors to keep in mind when choosing a proppant. The smaller the size, the longer the proppant stays in suspension, thus assuring it reaches the very limits of the fracture. Larger-sized proppants allow greater conductivity (the ability of gas and oil to flow freely), as does higher sphericity (roundness). The material must be strong enough to resist crushing by the surrounding rock.

Carbo Ceramics offers KRYPTOSPHERE, a high-density proppant. The engineered material, made of ceramic, was originally designed to meet the extremely high pressures encountered in deep wells in the Gulf of Mexico. Each grain is highly spherical and mono-sized and features a smooth surface. Capable of withstanding pressures up to 20,000 pounds per square inch, the proppant creates uniform pore throats that maximize available flow space and minimize fines trapping. It is less corrosive to well equipment, reducing failures in downhole tools. The company notes that the material offers more long-term conductivity, more production and increased EUR and superior internal rate of return.

Sand is about one-quarter the price of ceramics, however, and is used in about 90 per cent of fracs. Several service companies are using proppant coatings to increase its effectiveness. Preferred Sands has extensive experience in Canada in the Montney, Viking and Horn River plays. The company has developed FloPro PTT (PTT stands for proppant transport technology) for use in gel fracs. Sand is coated with a hydrophobic material prior to mixing. The coating significantly reduces pumping time and increases flowback, allowing for greater fracture permeability.

In field tests in the Mississippi Lime Formation, operators reduced pumping time by approximately 20 per cent. According to the company, third-party testing has shown that, compared to untreated white sand, FloPRO PTT maximized frac volume by improving proppant transport by approximately 40 per cent and increased hydrocarbon flow rate by approximately 75 per cent.



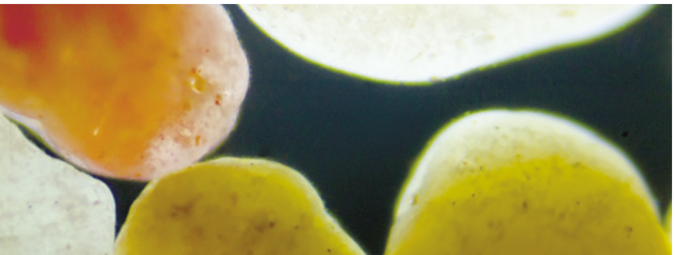
BUOYANCY BOOST
Trican's MVP Frac proppant incorporates a gasphilic coating that attracts gaseous phases in the fluid, giving each grain the buoyancy it needs to be distributed more effectively into the fracture network.

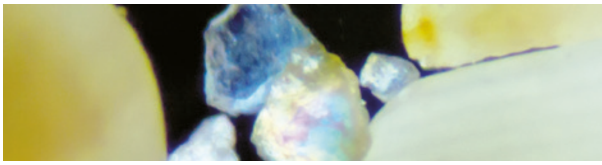
MINING SAND
Most proppant sand is mined in quarries at near-surface deposits.

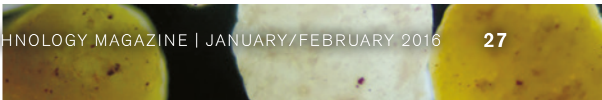
Fairmount Santrol has devised Propel SSP, a self-suspended proppant that is touted to maximize fracture penetration. A sand grain is pre-coated with a polymer prior to mixing. When the grain comes in contact with water, the polymer swells into a hydrogel layer three times the size of the grain, effectively reducing the specific gravity by half and lowering the grain's surface friction. This allows the grain to "float" much farther into the fracture network. The process eliminates the need for water sweeps, significantly reducing water needs and pumping time. The company notes that some operators in initial field trials are recording hydrocarbon production increases of greater than 50 per cent within six months.

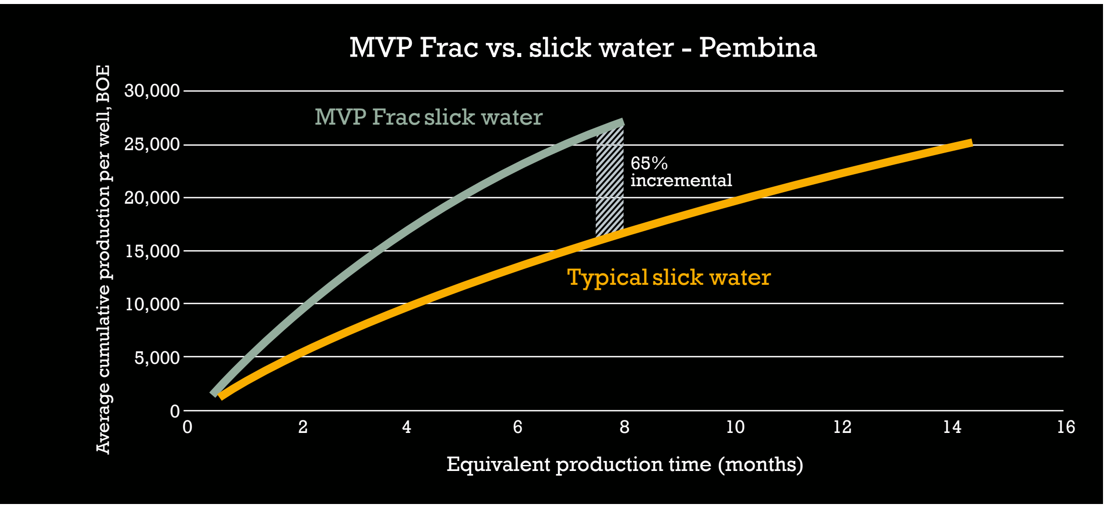
Trican Well Service recently introduced a new process into their MVP Frac treatment (MVP stands for maximum volumes placed). MVP Frac modifies natural frac sand, creating a gasphilic coating that attracts gaseous phases in the fluid. A thin layer of nitrogen or >

PHOTOS: (TOP) TRICAN WELL SERVICE; (BOTTOM) PREFERRED SANDS









SOURCE: TRICAN WELL SERVICE

air attaches itself to the proppant, giving each grain the buoyancy it needs for superior transportation and distribution in the fracture.

"We used to add it to the frac water in the sand blender tub, and since it has an affinity for sand, it sticks to it," says Browne. "What is new is that we are now spraying the chemical on when the proppant is dry. The advantage to the latter method is that you use a lot less chemical; it sticks better. The sprayed-on chemical is also compatible with other additives, and isn't neutralized by them."

To date, the new MVP Frac coating method has been deployed in more than 530 stages in Canada and over 140 stages in the U.S. Clients are coy about discussing its effectiveness, but Trican has compared Cardium wells using information gleaned from public sources and has calculated that over an eight month period, MVP Frac'd wells returned an average cumulative production per well of 27,209 barrels of oil equivalent, compared to 16,459 with conventional slick water—an increase of 65 per cent.

MONITORING

The performance of hydraulic fracturing can be improved through various means, including more comprehensive monitoring. Traditionally, hydraulic fracturing has been scrutinized at surface. Pressure and flow rates during various stages of the process can tell engineers the approximate length, width and conductivity of a frac.

But earlier-generation monitoring still missed a great deal of information. Newer monitoring technologies include fibre optics (the cable is installed outside the casing and measures temperature, revealing how much fluid is entering which stage of the frac), microseismic (geophones are installed in nearby wellbores and gauge the advance of a frac through associated microvibration), and radioactive tracing.

In the latter technique, isotopes such as Iridium-192 are bonded to proppants and mixed into the frac fluid. Their displacement into the frac can be monitored using a gamma log.

Carbo Ceramics markets the CARBONRT ULTRA inert tracer technology to monitor near-wellbore proppant location and quantity. The proprietary tracer component is mixed with sand proppant prior to injection. The tracer is then directly detected during a standard neutron log run. By varying perforation clusters and stage spacing, the operator can use the gathered data to determine the optimum stimulation process.

If a reservoir section is underperforming, the operator can determine whether the poor output is due to a barren section or a poor stimulation. Finally, since the tracer does not deteriorate, subsequent logs can be run years later in order to identify restimulation prospects.

In order for operators to optimize production, the large amounts of data generated by various monitoring technologies need to be integrated and analyzed. Several companies offer interpretation software; Carbo Ceramics has developed the WELLWORX suite of applications.

The application uses multi-well, data-driven linear and neural network analysis techniques to optimize the critical drilling, fracturing and completion parameters. The software creates a unique index of key completion indicators for each reservoir that allows simulation of fracture, completion and production profiles for each well. The operator can then establish cause-and-effect relationships. Although the software can be used on any tight reservoir, Carbo has developed customized packages for the Bakken and Eagle Ford formations. The company notes that the software lowers costs, increases completion efficiency, identifies cost-effective design modifications and increases return on investment.

THE FUTURE

There are several trends that are shaping both current and future hydraulic fracturing practices. Fluid additives, some of which are carcinogenic, have been supplanted by benign organic compounds. The use of large volumes of water is being replaced by a variety of gases, foams and solvents. Flowback water is increasingly being recycled and reused.

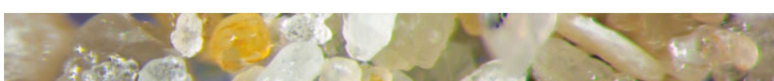
Worker safety is also being addressed. Tiny particles of silica generated during the handling of sand can settle in the lungs and cause respiratory complications. Working with Dow Chemical, Preferred Sand has developed DustPRO, a patented chemical that alleviates the creation of silica flour at all transfer points.

"In addition to employee health and safety benefits, DustPRO provides significant cost savings through a reduction in non-productive time and less wear and tear on frac equipment," says O'Neill. "Operators have reported average savings of about $45,000 per pad."

Proppants will also see changes. "The goal in a frac is to place the proppant as high and deep as possible, and traditionally, that's been done by modifying the fluid for greater viscosity and carrying power," says Browne. "We are the first to modify the proppant instead of the fluid, and I predict that will become a trend. We are already seeing competitors trying to copy us."

And, as always, operators will test boundaries. Companies are discovering that by simply increasing the amount of sand used as proppant, well productivity can be significantly enhanced. WPX Energy, based in Oklahoma, started increasing the amount of sand used in a well from an industry standard of 500,000 pounds to six million pounds.

Because the cost of sand is a minor component, WPX was still able to reduce overall well costs by 30 per cent while increasing EURs. They are now testing 10-million-pound fracs. "Increasing the stimulation size is about pursuing additional upside for our EURs," said Rick Muncrief, WPX president and chief executive officer. "The collaboration we're seeing from service providers makes this the perfect time to proceed." ■



ENHANCED OIL RECOVERY

SHINING A LIGHT ON PLASMA PULSE

Joint venture takes Russian technology into Canadian oilfield

Plasma is the most common state of ordinary matter in the universe, observable in neon lamps, welding arcs, St. Elmo's fire and, perhaps most notably, the sun, which shines due to intense heat and pressure that ionizes gas to a point at which the energy frees electrons from hydrogen and helium atoms. Energizing gas into plasma is also part of a new and environmentally friendly technology used to obtain sustained higher productivity for oil and gas producers.

"It is a high-energy electrical discharge of capacitated, stored energy in the tool, in which the power is achieved from the surface into the tool through wireline or e-line delivery," says Ken Stankievech, president and chief executive officer at Technovita Technologies. "It does not require a lot of power on surface. In fact, while the energy delivered at the source of pulse creation is very high, it is only for a nanosecond."

Plasma pulse technology creates an electric arc between two electrodes, which very briefly discharges approximately 20,000 volts within the formation, emitting a high-speed hydraulic impulse wave strong enough to remove any clogged sedimentation from the perforation zone, and moving far into the formation without causing damage to downhole infrastructure.

The resonance vibrations can clean filtration channels and even create new ones within a 1,500-metre radius of the initial pulse, clearing away paraffins, asphaltene, scales and other materials. Placed opposite the perforated interval, crews initiate a metallic conductor discharge that forms the plasma pulse and accompanying compression wave. A well can be treated and put back into service within 24 hours.

Stankievech says: "If it is on surface, you can actually see a flash. But when done in the fluid of the >

^ SHOCK TREATMENT
Novas Energy's plasma pulse technology uses a high-energy electrical discharge of capacitated, stored energy to emit a high-speed hydraulic impulse wave into the formation to increase oil recovery.

PHOTO: NOVAS ENERGY NORTH AMERICA

wellbore, then a gas bubble is created at a very intense pressure level—about 1.5 gigajoules for an instant—regulated at the absolute perfect location that we measure through logging to be in alignment with the perforation zone."

As the plasma cools, the formation pressure forces sedimentation to flow into the well's sump, and the shockwave can be altered into flexible volume oscillations from the surface. With proper conveyance techniques, the technology is applicable to vertical, deviated and horizontal wells. "We have managed extensive laboratory testing to show that we are far below any threshold of destructive damage to any component of a well completion."

In October, Propell Technologies Group, the U.S. provider of this Russian enhanced oil recovery method, launched its joint venture between wholly-owned subsidiary Novas Energy USA, along with Calgary-based Technovita, the Canadian provider, to form Novas Energy North America, for which Stankievech serves as chief executive officer, and which has the exclusive rights to deliver well treatment for North America using the patented plasma pulse technology.

"We now have a large inventory of tools in Canada and the [U.S.]. Novas Energy already has customers under contract for Canada and the [U.S. and] we are very excited with our planned treatment programs throughout Alberta and Saskatchewan," he says. "This next year, 2016, will be a very busy year for us."

NOVAS TECHNOLOGY COMES TO CANADA

With over 35 years experience in materials engineering and testing in Calgary, Stankievech spent about a decade in Russia working with Gazprom, where he was introduced to the plasma pulse technology via Skolkovo, a large research and development group focused on energy. In 2013, he invested in Novas Moscow to attain part ownership in its intellectual property.

"There are so many great areas of science which have been developed in Russia, but the problem is [the Russians] have struggled in the commercialization of their world-class technologies," Stankievech says, adding North America's oilpatch by contrast is very well equipped to manufacture and roll out new technologies domestically and abroad.

"My goal with my colleagues in Moscow is to use the Canadian [entity] as the springboard to take this technology beyond the excellent early development that has been done in Russia, the Middle East, China and South America."

The joint venture recently treated its first Canadian well with the proprietary plasma pulse technology—a Petromin production well in the Grand Rapids Formation near Cold Lake, Alta.

"We believe the technology has incredible potential, and we are now engaging Novas Energy in the treatment of additional Canadian assets," says Ross Gorell, president and chief executive officer at Petromin. He adds the excellent results of this new technology demonstrate both its economics and the professional services provided by Novas.

Completed in 2005, the Petromin well's production levels initially averaged 11 cubic metres per day, but had fallen to less than half a cubic metre per day over the past decade. On October 29, after less than six hours of treatment, the well immediately increased its flow and bottomhole pressure levels and improved its production level to between 12 and 13 cubic metres per day.

On December 1, production levels stabilized to what they were at the time of initial completion 10 years prior. Stankievech says: "A year ago, I would have said that we are not ready to provide our treatments with heavy oil in the unconsolidated sands.

"If we had a 'sweet spot' area it would have been in the tighter permeability geologies of the dolomite, carbonate and potentially the very tight shale formations. However, after our recent successes in the Cold Lake area we have now broadened that to include a big part of Alberta and Saskatchewan's oil assets. This pilot work was challenging for the company, but I felt it was worthy of risk."

He adds: "If we are going to do work in western Canada, then we better be able to treat or have some sort of impact in the heavy oil and in the unconsolidated sands."

While still fairly new to Canada, crews have thus far treated about 60 U.S. wells with plasma pulse, and the Society of Petroleum Engineers recently published a study demonstrating how the technology improved productivity on a Middle Eastern Kuwait Oil Company well.

"In some of our own experiments, through microseismic activity we have seen that we have actually had stimulation taking place in neighbouring wells 1.5 kilometres away from the well being treated," Stankievech says.

PLASMA PULSE NEEDS SOME PRESSURE

Plasma pulse technology "cannot resurrect the dead," according to Stankievech. For it to work there must be at least some bottomhole pressure in the reservoir.

"If there is no back pressure, then the well is not a candidate for treatment. We have had some results when we treated a well with low bottomhole pressure, because we opened up some new zones, but that is a rarity. Therefore, we look for minimum pressure levels in the well so that there is positive pressure to assist in the reduction of the skin factor and improvement in the overall stimulation of the selected pay zone."

In Canada and the U.S. over the past 12 months, Novas Energy has trained over 20 geologists and petroleum engineers, along with data management experts, who can look at customers' assets and recommend which wells are optimal candidates for plasma pulse treatments. "In Canada, with the use of AccuMap and GeoSCOUT, we can zero in on the clients' assets that are best suited for our technology," Stankievech says.

The current generation of plasma pulse tools has treated over 400 wells, Stankievech adds, but there are a number of features the company is developing in its next generation tools. Scientists and engineers are working on real-time feedback features that will provide Novas Energy valuable additional information downhole with the various impacts of the technology.

"We are adding intelligence into our tools specific to real-time feedback of the treatment area such as pressure, temperature and precise location, without having to rely on typical downhole logging tools today that need to be run prior to our treatments."

Novas Energy recently opened a service centre in Calgary and is working with an Edmonton-area partner to roll out a plasma pulse manufacturing facility in 2016. According to Stankievech, the joint venture is also finalizing its Canadian patents, which will accompany those already held in the U.S. and internationally, bringing to the world this Russian-designed technology and harnessing the power of plasma creation to enhance oil recovery.

Carter Haydu

CONTACT FOR MORE INFORMATION

Lee Primeau, Novas Energy
Tel: 587-955-6802
Email: lprimeau@novasenergy.ca