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WASTE NOT, WANT NOT

Judging by recent headlines, one would be hard pressed to determine if methane emissions in the oil and gas sector—whether fugitive emissions or via venting or flaring—are a problem or not.


It is important to know the level of emissions because methane, the primary component of natural gas, is a powerful greenhouse gas—about 25 times more potent than CO₂, at trapping atmospheric heat over a 100-year time frame, or 72 times more potent over 20 years. And in any comparison of natural gas against coal, it loses its “green” advantage if methane leakage is too high—generally estimated at somewhere between one and two per cent.

Methane emissions occur at every stage of the natural gas life cycle, but since leaks from wells and the infrastructure that delivers it are not comprehensively measured, there remains a large degree of uncertainty and emissions remain the subject of ongoing study. NASA’s Carbon Monitoring System, for instance, is funding several projects testing new technologies and techniques. One recent project that used satellite observations found human methane emissions in eastern Texas were 50-100 per cent higher than previously estimated.

Petroleum Technology Alliance of Canada (PTAC) is in the process of collecting proposals for a new study, on behalf of Natural Resources Canada CanmetENERGY-Devon, the Upstream Air Issues Research Initiative, it hopes to have completed by March 2017.

“There is a current lack of understanding of short- and long-term environmental impacts from hydraulic fracturing, liquid hydrocarbon storage tanks and black carbon emissions from flaring in Canada, and little or no Canadian data are available,” says PTAC, resulting in critical knowledge gaps.

Emissions associated with fractured wells were until recently believed to mostly result during drilling and completions, and regulators have therefore assumed that requiring the “green completion” of wells would be sufficient to ensure environmental and social sustainability. “However, recent analysis of tight gas wells in the province of Alberta has indicated that over the production life of a well, operational flaring, venting and natural gas fuel use emissions play a dominant role relative to well drilling and well-completion activities,” states PTAC.

“In order to ensure environmental sustainability and obtain and maintain the necessary social licence to practice hydraulic fracturing, there is a requirement to understand the total per-unit-of-energy-production emissions of hydraulically fractured wells and to develop necessary and cost-effective technologies, practices, policies and regulations that effectively and verifiably minimize all emissions over the life of hydraulically fractured wells.”

Rapid development of tight oil and gas resources and increased heavy oil production has also led to a proliferation of fixed roof liquid storage tanks, it states, which represent “an especially important emission source in the Canadian upstream energy industry.” Less well known are issues relating to flare-generated black carbon, which create both climate forcing and health concerns. Impacts are exacerbated in northern regions where airborne transport leads to deposition in sensitive Arctic regions.

Recent studies have found that deposited black carbon on Arctic snow and ice is largely attributed to global gas flaring, but “there are essentially no quantitative data” of operating flares sufficient to predict black carbon emissions. “This severely hampers scientific understanding of potential emission rates and impedes ability to develop informed policy sufficient to control and mitigate these emissions,” says PTAC.

Clearly, there remains much we don’t know about the amount of, and impacts resulting from, methane emissions associated with oil and gas production. But we do know quite a lot about how to contain emissions. As we investigate in this issue, existing technologies are capable of locating and capturing much of these emissions—and forward-thinking companies and jurisdic- tions are moving to limit the squandering of this otherwise valuable resource.

Maurice Smith
Emissions from the oilsands and other oil and gas industry activities account for 46 per cent of all emissions across Alberta’s economic sectors, according to a document released in August by the provincial government. Alberta Premier Rachel Notley has committed to developing a strong climate change plan, which she says will improve Alberta’s international reputation and increase the likelihood of future project approvals.

A survey of Canadian oil and gas professionals found that respondents did not believe their organizations were ready to adopt any of 10 suggested digital oilfield use cases, all of which were or were close to being commercially ready. Respondents estimated that in 70 per cent of cases, it would take six months to get ready for their implementation, including the preparation of the people, processes and technologies required. The remaining 30 per cent of cases were estimated to be 18 months away from adoption.

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New technologies, including chemical treatments, robotics, super computers and the Internet of Things, have increased projected global proved fossil fuel resources from 2.9 trillion to 4.8 trillion boe by 2050. New technologies, including chemical treatments, robotics, super computers and the Internet of Things, have increased projected global proved fossil fuel resources from 2.9 trillion to 4.8 trillion boe by 2050. Global demand during this time is only projected to be 2.5 trillion boe. According to David Eyton, BP group head of technology, when all sources of energy are taken into account, the world will have access to 20 times more energy than will be needed over that period.

In 2015, Canada’s Oil Sands Innovation Alliance (COSIA) added 37 projects worth $23 million to its active portfolio, bringing the total to 219 active projects worth $490 million. Dan Wicklum, COSIA’s chief executive, says members are sharing 814 technologies that span COSIA’s four Environmental Priority Areas: land, water, tailings and greenhouse gases.
nanotechnology in the Canadian energy sector has the potential to advance efficiency, lower carbon emissions and provide access to what are currently considered unobtainable hydrocarbons—which is the case for much of the oilsands—according to a world-leading nanotechnology expert.

But Steven Bryant, Canada Excellence Research Chair in materials engineering for unconventional oil resources at the University of Calgary, told a joint technical conference of the Society for Petroleum Engineers and the Canadian Society For Unconventional Resources in October that human beings are not instinctually built to adopt new ideas.

People are inherently risk averse even when the calculated risk is rational—they dislike the idea of losing something more than they like potentially gaining something, he says.

“The fast-thinking part of your brain is influencing the slow-moving, rational part of your brain in ways that you are not conscious of.... We need to be aware of what is influencing our decision making and our assessment to risk when looking at innovation, because you have to at least be aware of it. I don’t think we can do anything about it, but we need to be aware of these things.”

Bryant looks to the 1960s moon shot as an example of how a society can push innovation beyond the comfort zone. By purposefully striving toward such an “impossible” goal, the U.S. proved it could be done, which led to further technological acceptance and inspired further innovation. He suggests setting a similar goal with nanotechnology could work for the Canadian energy sector.

“What if we got an industry based on producing energy in the form of hydrocarbon molecules, and what if you could produce different energy carriers in the petroleum industry, like methane, or something with no carbon in it, like hydrogen, like electron carriers—electricity?

“What if you could produce a different energy carrier out of that reservoir? What if microbes could merge chemical energy into electrical energy? What if microbes and nanoparticles could move those electrodes?”

The interesting thing, Bryant noted, is that nanotechnologies that could vastly benefit the oil and gas industry already exist.
Alice Batonyi, staff reservoir engineer at Enerplus, said nanotechnologies for enhanced oil recovery are extremely valuable in no small part because they can be natural and renewable, such as a solvent derived from citrus fruit that is among the most environmentally friendly options on the market.

Further, she added, nanodroplet dispersion leads to more extensive and uniform coating of a desired surface than one larger emulsion drop. Batonyi believes all this helps industry defend itself in the face of environmental scrutiny.

“What can we say to our society? Environmentally, we are trying to be less impactful. We potentially will have fewer facilities. Now, when we are doing the polymer floods, for example, we need big facilities, big volumes of water and big volumes of polymer, because we are trying to make the water more viscous. What if we used this product that made the water lighter?”

According to Batonyi, nanotechnology could potentially address concerns of induced seismicity at the fracturing stage of operations by potentially reducing the need for refractionation.

She said, “What if we don’t refrac as big as the last time? What if we don’t actually prop the fractures? What if we just inject below frac pressures using nanofluids to try and clean the old fractures and try to get the production that way?”

In the recompletions realm there is a lot of potential for nanotechnology to prove its worth, Bryant said. There is a lot of oil still in those reservoirs, and industry should be figuring out better ways to get it. “I think there might be other ways we have not thought of yet, and guess what, I think we have nanomaterial-enabled ways to do this.”

While he adheres to the principle of “no oil left behind,” Bryant also recognizes the increasing importance of environmental impacts when talking about unconventional production.

He believes that with innovation on its side, industry can respond to societal and governmental critics, showing it can produce more efficiently, using less energy to obtain the same amount of oil and gas to satisfy demand. Again, he noted, much potential lies with nanotechnology.

For academia, he noted, the move toward researching and developing the sorts of innovations that will best serve industry involves breaking through the silo structure of post-secondary institutions and changing the way universities do things so that chemists, biologists, petroleum engineers, structural engineers and representatives of other disciplines are all on the same team trying to solve common concerns, because the solutions will come from varied sources.

“We in the energy business and society are facing bigger and bigger challenges, and there is no longer going to be one cool thing—one technology—that solves it,” Bryant said.

“It is going to have to be a combination of things. I am convinced that is the only way we are going to solve these really big challenges that we have, and we are really terrible at that sort of thing in universitiy.”
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Thanks to advances in technology, the majority of oilsands production now comes from in situ thermal projects using steam assisted gravity drainage (SAGD), or cyclic steam stimulation. At the heart of most operations is the once through steam generator, a large industrial boiler that functions best when it is producing 80 per cent steam.

Unfortunately, it is difficult to know how close the boiler is to producing 80 per cent steam. “There is no way of testing the percentage in real time, so it is difficult to know what adjustments need to be made to a boiler to optimize output,” says Yonathan Dattner, the president of Luxmux.

The steam can be tested in a gas spectrometer, but the devices are large, expensive, fussy to operate and normally situated far from bitumen production facilities. What was needed was a robust spectrometer that could be installed on site.

Which is exactly what Luxmux has built. It recently launched the silicon nanophotonic Fourier transform near-infrared spectrometer-on-a-chip. “The core technology is the silicon photonics chip,” says Dattner. “We also developed a small, super bioluminescent light source. It is very innovative. It has been miniaturized so that it can be hand-held.”

The invention of the chip technology—which has the potential to significantly alter everything from the detection of skin cancer to the composition of the food you eat—has had a long and convoluted path. Dattner, a young Israeli scientist, came to Canada in the

**REAL-TIME MEASUREMENT**

Luxmux’s Broad Spectrum Tunable Superluminescent Diode (BeST-SLED) is the first miniature integrated spectrometer with a light source. The high optical throughput, polarization maintaining fibre coupled solution is measuring steam content in steam generators used in bitumen production.
mid-2000s to study electrical engineering at the University of Calgary and the University of British Columbia. He revelled in such esoteric disciplines as nanophotonics (the study of the behaviour of light on the nanometer scale), surface plasmon polaritons (light waves that travel along the metal-air interface) and Fourier transformations (which decompose a signal into the frequencies that make it up).

The various disciplines can be combined to suit a wide variety of uses. “The technology was originally developed in the telecommunications sector to optimize the interconnection between fibre optics and chips,” says Dattner. He and fellow researchers realized that it could be customized to create a device that could measure the molecular content of virtually anything.

In 2011, Dattner helped found Luxmux, with the goal of miniaturizing spectrometers. “Lux” is Latin for light, and “mux” is shorthand for multiplexing,” he notes.

One of the original investors was AGAR Corporation, which has been supplying multi-phase flow meters to the oil and gas sector for the last 35 years. Along with other investors, the company raised $5 million, with the purpose of developing a silicon chip that could be used with fibre optic technology to create a hand-held spectrometer capable of measuring steam content. AGAR subsequently licensed the technology and worked with Dattner to develop the first application, the Broad Spectrum Tunable Superluminescent Diode (BeST-SLED) spectrometer.

While the device itself is not expensive, the task of installing it in a boiler pass (where the steam is produced; each SAGD boiler has four passes) costs approximately $80,000. Once installed, the spectrometer emits a light source spanning the near-infrared spectrum of 1250–1750 nanometres. The light source travels down a fibre optic cable and contacts the steam–hot water mixture; subsequent electromagnetic wave emissions trace a return path along the fibre optic cable and are captured by the chip and analyzed to determine the steam/water ratio.

Luxmux, which won the Alberta Science and Technology Leadership Foundation award for Outstanding Science and Technology Start-Up in November for its one-of-a-kind device, anticipates the technology will find wider use. “We can also install at the pad sites; there are about 4,000,” he notes.

In addition to the oilsands, other parts of the oil and gas sector are intrigued by the spectrometer. “Pipeline companies are interested in the device as it can be designed to measure H₂S [hydrogen sulfide], water vapour, and gas chromatography [GC] in many points of their transportation system,” says Dattner. “We call it GC on a stick.”

Although the oil and gas sector holds great promise, Luxmux is setting its sights much higher. Its chip technology is compliant with complementary metal-oxide semiconductor (CMOS), a technology for constructing integrated circuits. Luxmux has the potential to mass produce the chip for pennies a unit and incorporate it into a device like a smartphone.

Luxmux’s optical distance sensor is incorporated into the head of glass tube variable area flow meters. It uses an invisible laser to send light pulses to the float and then picks up the reflected light to determine the float’s position inside the tube.

“The ultimate goal is to use it in the consumer market, where you would be able to tell what was in a food product, or whether there was bacteria,” says Dattner. “The sky is the limit.”

Luxmux is hoping to make a big splash with its steam spectrometer when it formally launches the unit in early 2016. In the meantime, it is busy proving its efficiency and value in the field. Currently, Cenovus Energy is pilot testing the device at its Foster Creek project. “With real-time measuring, a boiler could be adjusted to produce up to 86 per cent steam, which would greatly increase efficiency and lower GHG [greenhouse gas] emissions per barrel of produced bitumen,” says Dattner.

Gordon Cope

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There’s an app for almost everything these days, it seems.

What if there was a cloud-based application that allowed oil and gas companies, miners and others to assess the impact of their projects on surface waters in rivers, lakes and streams without the need to employ costly consultants?

It turns out there is such a product—and it was developed by one of those costly consultants.

“Rather than engaging a consultant, people can utilize our product,” says Ben Kerr, chief executive of Victoria-based Foundry Spatial, developer of NOLA Water, which provides real-time information on surface water resources through an online, map-based tool. “It won’t solve complicated problems, but it’s based on the 80-20 rule,” which deems that 80 per cent of surface water-related issues can be dealt with without consulting services.

Kerr, who presented his company’s NOLA Water tool in mid-October at a Petroleum Technology Alliance of Canada technology information session in Calgary, developed the product after several years of experience as a geographic information system (GIS) specialist.

GIS, a system designed to capture, store, manipulate, analyze, manage and present various types of spatial or geographical data, is at the heart of what Foundry Spatial does.

Kerr, a graduate of the University of Victoria (UVic), with a specialty in physical geography and applied GIS, worked for the British Columbia Ministry of Energy and Mines after graduating from UVic in 2002.

His role with the department involved conducting an assessment of aggregate (gravel) resources in the Horn River and Montney areas of northeastern B.C., where natural gas development had created a pressing need for more aggregates.

A WAY WITH WATER
Point-and-click software simplifies hydrology and watershed management

STREAMLINED MAPPING
Foundry Spatial specializes in presenting complicated data, such as those involving water resources over large areas, in clean and clear maps and graphs that are easily accessible and loaded with information.
While his work in assessing aggregate resources in the region was rewarding, he could see that managing that region’s water resources would become increasingly important.

“Water was becoming an issue, and I decided to go back into private business,” says Kerr, who had done some consulting before joining the government. In 2009, he launched Foundry Spatial, which had one employee then (himself). It now has five.

Kerr and his employees offer consultancy services, much of it for the provincial government as well as for private firms. They will continue to do that work, but he sees the company moving more into the area of offering its online management tools.

Those consist of the Northeast Water Tool (NEWT) and NOLA (named after Kerr’s oldest daughter), which were developed because the company was getting so much consultancy work—and had developed such a huge database—that the data started to overwhelm Kerr and his employees.

“We quickly found that so much data was hard to handle,” it says on the company website. “We needed to spend less time wrestling with data, and more time finding out what it meant. So we built tools that would make it easier for us to manage and understand the data and provide it to clients in a way that was accessible.” The company quickly discovered its clients were more impressed with the tools than with the “volumes of reports we had built for them.” Kerr calls this its “watershed moment.”

“We had to develop these tools to be more efficient,” says Kerr. And so was born the easy-to-use tools Foundry Spatial now markets as products.

The B.C. government was so impressed with NOLA and NEWT that it decided to pay Foundry Spatial to provide the tools to companies planning projects that will have an impact on watersheds. The company has developed management products for watersheds for northeastern, north-central and northwestern B.C.

It has also spread its wings to Alberta, with an initial focus on the Montney and Duvernay resource development areas of west-central Alberta. This includes large portions of the Smoky, Athabasca, North Saskatchewan and Red Deer river watersheds.

It had hoped to be able to offer clients the same government-supported product it does in B.C. It has now developed hydrology modelling and decision support tools for more than one million square kilometres of Western Canada. “However, in Alberta, the government decided it wasn’t willing to pay for it,” he says.

As a result, clients need to pay a service charge. Single reports on a watershed cost about $500. The company also has a subscription model that allows for virtually unlimited access to its data for a few thousand dollars per year. But that fee can save clients many thousands of dollars in consulting fees.

“There are 600,000 watersheds in northeast B.C.,” Kerr says. “With our product, you can click on a river and get all the information on that watershed we have gathered.”

The paid, client-based model Foundry Spatial is using in Alberta comes as it is planning to launch similar products in other areas of North America and even worldwide.

“We’re testing the business model,” he says. “Is it viable to sell these reports [to individual users]?” So far, the reception the company has received in Alberta tells him that is the case.

He says some of his competitors in the consultancy field have expressed their displeasure with his company’s move to sell a product that eliminates the need for their services. Kerr doesn’t buy that argument.

“Computers were going to put people out of work,” he says. “Instead, they replaced the repetitive work. It frees up the consultants for the more detailed work.”

For now, its tools are focused on hydrology and water management, but in the future the company plans to develop tools for environmental analytics—measuring air quality, pollution levels, vegetation, local wildlife habitats and a host of other environmental factors—as well as for land use.

Kerr is seeking investors to help him hire the skilled people he needs and to do the marketing required to expand the use of its hydrology and water management products throughout North America and to develop a suite of other products.

It’s a huge market.


And that doesn’t include other areas, such as environmental analytics and land use.

Kerr says real and potential users include government, those involved in agriculture and companies having to do air shed analysis. “We’ll definitely need more than five people to expand into other areas, which is why we’re staying focused on water for now,” he says.

Rob Bennett, chief executive officer of technology incubator VIATEC (Victoria Innovation, Advanced Technology and Entrepreneurship
Council), is a strong believer in Kerr’s company and its technology. “We can’t pick winners, but we do know the attributes that lead to companies winning, and Ben [Kerr] has them,” he says.

VIATEC, which was launched in 1989 to serve as a “one-stop hub that connects people, knowledge and resources to grow and promote the Greater Victoria technology sector,” holds an annual Showcase Showdown that sees the executives of some of the Greater Victoria area’s most promising technology start-ups offer a series of two minute pitches. This year, Kerr’s company came in second among some tough competitors, in what has become Canada’s mini Silicon Valley. High tech is now the area’s largest private sector player, exceeding tourism.

VIATEC is one of 13 regional bodies in the province that are part of the B.C. Acceleration Network, with the provincial government providing $6 million in seed funding, which is matched by private sector, federal government and other contributions. It has helped spawn companies in the last four years that have created almost 140 jobs.

Jim Bentein

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EMISSIONS

WIN-WIN

Low-cost methane emissions cuts offer green dividends

Tackling methane venting, flaring and fugitive emissions using existing technology could reduce the oil and gas industry’s greenhouse gas (GHG) emissions at a fraction of the cost of more high-profile methods like carbon capture and storage (CCS). But all too often, the technology is not being used, studies show.

A newly released analysis from ICF International suggests methane emissions from Canada’s oil and gas sector, which account for about six per cent of Canada’s GHG emissions, could be reduced by 45 per cent below projected 2020 levels at a net cost of just $2.76 per tonne of CO₂ equivalent (CO₂e) reduced. That equates to $1.33/mcf methane reduced, or less than one cent per mcf of gas produced nationwide, taking into account savings that accrue to companies that implement reduction measures.

The value of the gas recovered, at a price of $5/mcf, would amount to $251 million per year. Annual methane emissions from oil and gas activities are projected to remain stable to 2020 at around 60.2 million tonnes CO₂e (125 bcf of methane), says the study, which recommends regulations to nudge the industry to take action.

In an examination of venting among heavy oil and oilsands producers, which found some conserve a lot more than others, Bruce Peachey, president of New Paradigm Engineering, found the greatest differentiator was attitude. “Heavy oil resources and operations differ by region with different results, but the greatest difference is in attitude of producers towards reducing venting,” he told the Canadian Chemical Engineering Conference in Calgary in October.

In a presentation called Primary Heavy Oil and Oil Sands—Still Venting After All These Years, Peachey said “mitigation is a lot cheaper than carbon capture and storage. A five megatonne CO₂ equivalent per year GHG reduction would improve the industry image. We could probably do that over three to four years.”

Peachey looked at vent emissions in areas stretching from the Lloydminster region along the Alberta-Saskatchewan border to the Peace River area in northwestern Alberta and compared different approaches to venting among two producers in those areas.

In an initial focus on CHOPS (cold heavy oil production with sand) wells in the Bonnyville area—representative of the thousands of such vertical wells typically spaced eight to 16 wells per square mile, with a gas-to-oil ratio (GOR) averaging about 60 cubic metres of gas per cubic metre of oil—he found about 70 per cent of the gas was used...
for fuel, 29 per cent vented and one per cent flared.

In the Peace River area, where the GOR averages 107–175 m³/m³, there is more gas per well pad and odours are often present (which precludes venting), 35 per cent was used for fuel, 50 per cent went to sales, 13 per cent was flared and just two per cent was vented. Peachey found that one of the barriers to conservation of produced gas is the lack of measurement standards. He cited a number of problems with current measurement methods, such as operators changing pump rates and gas volumes not being matched to representative oil volumes, resulting in gas balances that are “extremely uncertain and open to potential ‘adjustments’ or ‘bias,’” he said.

“The errors are big enough to drive a Volkswagen van through, and that reference to Volkswagen is intentional. There is a lot of potential for the numbers to be biased, for the numbers to not be what is actually being vented, and there is a lot of incentive for them not to get to where they would have to do anything about it.

“The measurement is based on the estimation of fuel, produced gas and vent gas volumes, and everybody is using a different method,” said Peachey. “We did a [quantification project] and we showed a huge range in the numbers different companies were getting in the same pool that should have the same GOR, and different companies were getting two or three times the GOR of what others were getting.”

Another barrier is attitudes. In an examination of some 170 options for dealing with vented gas, flaring was one of them, he says, but that is resisted in the field. Methane has a climate-forcing impact 25 times greater on a 100-year basis than that of CO₂. Its impact is 72 times greater than CO₂ on a 20-year basis, which is how reductions could have real and tangible impacts on preventing climate change in the short term.

“Flaring methane is like running [natural gas] in your furnace. It can reduce greenhouse gas emissions by a factor of eight or nine, so you could get a big reduction just by flaring,” said Peachey. “But the environmental industry has done such a good job of scaring people about flares that no farmer wants a flare in their area. [Vented] gas is just coming out of a little rubber hose from the side of a building—it bothers nobody. There is no safety issue, no environmental issue besides greenhouse gas emissions and the loss of energy. But it is a big greenhouse gas impact, which impacts the impression on the whole industry.”

Alberta’s Directive 60 requires that all solution gas flares and vents releasing more than 900 cubic metres (31 mcf) per day of gas must be economically evaluated to see if gas conservation is viable. If the net present value of gas conservation at a crude battery is found to be greater than negative $55,000, the well or battery cannot be produced until the gas is conserved. But low natural gas prices and higher pipeline and compression costs challenge the economic viability of conservation under that formula.

And Peachey noted that by the time companies make an assessment, the evaluation period has already allowed much of the gas to escape. As a result, “40–50 per cent of gas is vented before conservation is implemented.”

Since retrofits miss much of the produced gas, the province should require installation of capture systems before operations begin, which would
also make it more economic. “We could standardize the oil and gas measurement, require installation [of capture systems] before operations begin. We know they are going to be venting [initially], why not require installation before they start and capture that 50 per cent right from the start,” he said. “Conserving gas should be an integral part of responsible oil production.”

COMPARE AND CONTRAST

Peachey contrasts a high vent town—ship—operated by Canadian Natural Resources Limited at Cold Lake—with a low vent field, Shell’s Clifldale operation. Canadian Natural’s township 63-9W4, containing 370 directional wells with two to 14 wells per pad and eight to 52 wells per section, was found to be venting about 32,000 cubic metres per day, or 11.7 million cubic metres annually. Some 70 per cent of gas was used for fuel (royalty free under provincial regulation) and 29 per cent vented.

“One of these sites, they are importing about 50,000 cubic metres per day of gas as fuel, and yet they are still venting—so they are not only still venting gas, they are still bringing in fuel.”

By contrast, when Shell acquired Clifldale and discovered vent volumes were higher than expected, it spent $40 million to capture casing vents, tank top vents and even truck loading vents, Peachey says. Most of the gas is now used in boilers to generate steam, with the excess stored in the Three Creeks reservoir.

“They first went to flare instead of venting, and then they went to gathering and storage. They said, ‘we are not going to produce if we have to vent.’ They integrated their primary terminal operations in Peace River that needs fuel, so they move the fuel from Clifldale to their terminal, and anything left over they put into storage. They are not venting anything.

“So if you have the motivation, you can do it—Shell has shown you can, and it didn’t cost them that much. So what does that mean? It really means that you have to include the vent gas capture as part of the total economics of the oil production. And that’s what Shell does. They say, ‘we are not going to produce oil unless we are cleaning up our mess at the same time.’ It’s not a matter of technology, it’s totally based on motivation.”

Peachey further contrasted methane capture with CCS. In November, Shell officially opened its Quest CCS facility that captures more than one million tonnes of CO₂ from its Edmonton-area bitumen upgrader and buries it in a saline aquifer.

“The cost of putting carbon capture and storage on their upgrader is about $1,000 a tonne of CO₂ equivalent. It only cost them $80 per tonne” of CO₂ emissions prevented at Clifldale. And Clifldale was self-funded, while Quest was 70 per cent funded by taxpayers, he said. “So it is a much cheaper way to get rid of greenhouse gas emissions than doing carbon capture and storage.”

FURTHER REDUCTIONS

According to Economic Analysis of Methane Emission Reduction Opportunities in the Canadian Oil and Natural Gas Industries, commissioned by the Environmental Defense Fund (EDF), achieving a 45 per cent reduction in methane emissions across Canada by 2020 would enable the recovery and potential sale of otherwise lost natural gas that equates to eliminating 27 million metric tonnes of CO₂e emissions.

Reductions would provide the same climate benefit as taking every passenger car off the road in B.C. and Alberta, assuming a cost of $2.76 per tonne of CO₂e. Analyzing reduction opportunities in both provinces, which together account for nearly 70 per cent of Canada’s total methane emissions, ICF determined Alberta could reduce its methane emissions by 45 per cent for $2.57 per tonne of CO₂e, while B.C. could reduce its emissions by 37 per cent at $1.69 per tonne.

“Even with the regulations on the book, and even with the voluntary actions, there are still a lot of reductions out there that could be achieved very cost effectively, and I think that is a very important point,” Drew Nelson, senior manager at EDF, notes. “This is kind of a no-brainer, because the reductions are so cheap. It is not going to solve the problem, but it is certainly going to go a long way towards reducing the impact and contribution of this sector.”

The $726-million initial investment needed to achieve the 45 per cent reduction in emissions represents about one per cent of industry’s annual capital expenditure, which is less than one cent per mcf of gas produced.

In order to get all companies to initiate these emission-reduction changes, Nelson says it requires “a bit of an external stimulus,” including government intervention through regulations. He notes EDF, which partnered with the Pembina Institute in developing and disseminating the ICF report, made its findings available to the climate change policy review panel currently composing recommendations to the Alberta government.

The largest abatement opportunities in the report include stranded gas venting from oil wells, which if tackled could see 78 per cent emissions reductions with installed flares. Tackling gathering and station fugitives through leak detection and repair (LDAR) could see 60 per cent emissions reductions. By replacing gas-driven pumps with a non-natural-gas-driven variety, industry could reduce chemical injection pump emissions by 60 per cent.

Industry could reduce emissions by 22 per cent on reciprocating compressor rod packing seals by replacing rod packing at a higher frequency, while LDAR implementation for fugitives from centrifugal compressors could reduce emissions by 60 per cent.

The ICF assessment does not account for all possible methane emissions from oilsands production, though, but only those related to flared and vented volumes and tank emissions from SAGD. Due to the limited data on other sources (e.g., mining, tailings ponds, bitumen production), other oilsands sources are excluded from the analysis.

“I think it is something that would require further study, and if it were included, then emissions would probably be going up, which means there would be more reductions that could be achieved. However, because we just didn’t have the good data to do it, we were not able to do so,” Nelson says.

The measures called for in the report are in line with the U.S. goal of a 40–45 per cent reduction and would align with regulations in jurisdictions such as Colorado, Ohio and Wyoming, the ICF notes. It says a recent analysis of Colorado and Wyoming found no negative impact from such regulations, with production and industry jobs up one year after implementation.

“Even during these challenging economic conditions, methane reductions are one of the lowest-cost, highest-value ways to tackle climate change in the energy business today,” Nelson says.
FINANCING INNOVATION

DESPITE INDUSTRY DOWNTURN, NEW TECHNOLOGIES FINDING VENTURE BACKING

BY GODFREY BUDD
Technologies for oil and gas applications are often capital-intensive to research and develop, with further infusions of cash, and perhaps extended timelines, needed to prove them out. But when executives at FlexGen Power Systems went looking for funding in January 2015, they were helped by the fact that one of the key criteria for attracting investors’ capital was in place.

A smaller version of the company’s hybrid power technology—which uses solid state generators (SSGs) that pair with diesel, dual fuel or natural gas gen sets—had already been deployed for military applications in remote areas of Afghanistan since 2010. Their use in the field meant significantly reduced fuel consumption for power generation, with less cost and risk to human life because of reduced fuel transportation requirements across dangerous and often hostile regions.

By last January, FlexGen had developed and tested a 1.2-megawatt SSG for the oilpatch. “It can plug into a lot of different power systems, with about a dozen or so power applications,” says Josh Prueher, founder and chief executive officer of FlexGen. Applications in oil and gas include drilling and artificial lift.

The SSG technology in its bigger iterations for oil and gas, among other things, is designed to handle the highly variable load profiles associated with drilling and tripping operations on big drilling rigs. “[It] integrates advanced energy storage, high-efficiency power conversion and dynamic software controls to automatically discharge at 100-millisecond response times to support rig power requirements, allowing traditional generators to ramp up smoothly and efficiently to match the stepped-up load requirements,” according to the FlexGen website.

After getting very promising results from initial testing and pilots of its scaled-up SSG technology, Houston-based FlexGen approached industrial venture firms and private equity outfits, many with a focus on the oilfield service sector, Prueher says.

Altira Group, a Denver, Colo.-based venture investment firm that has been investing in oil and gas technology since 1997, helped with financing. Last August, FlexGen announced a $25.5-million round of funding to accelerate deployment of its hybrid technology in the oil and gas sector and in power generation markets worldwide. Led by Altira, the round included investments from the venture arms of General Electric and Caterpillar.

FlexGen had already demonstrated the system with a pilot and had an order for a purchase. Pointing to one of the criteria for many investors these days, Prueher notes he had been able to tell prospective backers, “We’re on the cusp of commercialization.”

The capital is helping FlexGen scale up its product line for drilling and artificial lift. “We’re looking at additional applications in oil and gas, including offshore, as well as in industrial power markets,” Prueher says.

Apart from being highly scalable, ready for commercialization and suitable for a range of markets, FlexGen’s timing for oil and gas could hardly have been better. Industry’s demand for cost-cutting measures and technologies is intense right now, and the company’s SSG systems can reduce fuel consumption by 15–25 per cent and maintenance by 35–45 per cent. On a big rig, an operator can typically cut the number of gen sets from three to two.

“Customers and investors said our product was hitting the market at the right time. It’s a money-saving product, lining up in a favourable way for our story and the market,” Prueher says.

The investment money will help with commercialization and filling what has ballooned into a back order of about 60 units for drilling rigs, orders Prueher hopes to complete by the third quarter of 2016. “GE and Caterpillar bought into the global applicability of the technology,” he says.

FlexGen’s fortunate timing not withstanding, the adoption cycle in the oil and gas industry has been an issue for investors—including ones like Altira with an oilpatch technology focus. “Even the most compelling innovations take a long time to be adopted, in both Canada and the U.S. It’s industry, not the country. The concern is often, how rapidly is the technology going to be adopted by industry?” says Dirk McDermott, founder and managing partner at Altira.

Over its nearly two decades of operations, Altira has invested over $1 billion with partners in over 50 portfolio companies. Altira makes private investments in the $5 million to $20 million range, but often works with partners, both financial and strategic investors—GE and Caterpillar, for instance—who are active in oil and gas.

Altira has been working with some of the big independent oil and gas producers, also known as “super independents,” to back promising technologies for oil and gas. This is a way, McDermott says, to “shorten the adoption cycle by asking partners, ‘Would you consider using this technology?’ Companies know where the shales are. They want technology to help them get the most oil out for the least amount of money. So our thinking is, let’s engage the customers at the start.”

RigNet, a publicly traded company that provides communications and digital technology solutions to the oil and gas industry, was one of the early successes stemming from an Altira placement. “It was founded by a Norwegian. It facilitates a [communications] process that enables the digital oilfield,” McDermott says.

MicroSeismic is another company he points to whose first institutional investment funding was provided by Altira and its partners. “Our partners are looking for technologies that can be deployed today. FlexGen is an example. Its technology had proved successful with the military when the company built and was testing its first unit for oil and gas,” McDermott says.

He says investors are interested in technologies that are not very capital intensive.
ACCELERATING TECH GROWTH

BEHIND THE SCENES, AGENCIES ARE SPARKING THE RISE OF TECHNOLOGY INNOVATORS

The $6-million annual budget for B.C.'s program aimed at diversifying its economy away from a reliance on resource development is about equal to what it would cost to buy two or three houses in some of Vancouver's trendier neighbourhoods.

But despite the small budget, the program has created a great deal more permanent jobs and economic activity than if the same amount of money had been spent on three fixer-uppers in West Vancouver.

"It [the B.C. program] has been very successful," says Rob Bennett, chief executive officer of Victoria-based tech catalyst VIATEC (Victoria Innovation, Advanced Technology and Entrepreneurship Council), which is an initiative of the B.C. Venture Acceleration Program (BCVAP), a division of a program called the B.C. Innovation Council (BCIC).

Karen Spiers, a spokesperson for BCIC and BCVAP, the major initiative the BCIC has funded since 2011, says an assessment of the program completed this past fall showed it had helped create 408 businesses that generated $37.5 million in economic activity, attracted overall investment of $112 million and created more than 1,090 jobs in the province since BCVAP was launched.

The BCIC has other initiatives, including BC Tech Works, which helps match students with tech companies, and the New Venture Competition, in which start-ups compete for a prize that recognizes the potential of the technologies they have developed. BCVAP’s BC Acceleration Network and BCIC are definitely not top-down, overly bureaucratized programs. Based in Vancouver, they employ a total of 12–15 people.

BCIC leverages its clout by using other programs in the province, as well as federal ones. But its strength, says Spiers, is its locally based nature, with 13 different accelerator programs in various parts of the province. Four of those, including a program focused on wireless technologies and others focused on life sciences and clean tech, are technology-focused.

Aside from several successful start-ups the Victoria-based accelerator has spawned (such as Foundry Spatial, see page 13), there have been dozens of success stories that have led to new businesses created province-wide.

A similar agency in Alberta is called Alberta Innovates - Technology Futures (AITF). It is the technology-focused leg of a much more ambitious system called Alberta Innovates, which includes four agencies: Alberta Innovates - Technology Futures, Alberta Innovates - Bio Solutions, Alberta Innovates - Energy and Environment Solutions and Alberta Innovates - Health Solutions.

Cory Fries, vice-president, investments, for AITF says that division, which receives funding of about $90 million per year and employs 550, has been responsible for bringing dozens of new technologies to market.

Many are energy related, says Fries, who has been with the agency for four years and worked with entrepreneurs and small- and medium-sized companies most of his career.

For instance, AITF has funded work aimed at improving the effectiveness of SAGD technologies used in the oilsands in order to improve energy efficiencies and water use. In that respect, it’s a successor to the former Alberta Oil Sands Technology and Research Authority (AOSTRA), which pioneered dozens of success stories that have led to new businesses created province-wide.

Overall, he says the agencies operating under the Alberta Innovates umbrella have been responsible for many new technologies and products. He says it’s a story his agency has not effectively told in the past, but it is developing a new communications strategy aimed at doing so.

“We need to improve the telling of our story,” says Fries. “We’ve created billions of dollars in economic activity.”

Like the B.C. program, AITF has a geographical footprint throughout the province, with catalyst networks in Calgary, Edmonton, Red Deer, Lethbridge and Grande Prairie. Those local divisions work with economic development bodies in those areas to service entrepreneurs province-wide.

For more information on successful BCIC ventures, visit bcic.ca/success-stories.

Jim Bentein
Companies have a reputation for excellent ant time for technology in oil and gas, " she says. "There's never been a more import-
to raise money, but the right company with the right technology can raise money. The right level of innovation and business model are also important," says Ricardo Angel, managing director at GE Ventures.

Overall, the ups and downs of commodity price cycles don’t affect the company’s investment plans, he says. This year, it will invest about $200 million and, to date, has invested in "22 companies with breakthrough technologies or innovations. Of six that were for energy efficiency, two were for oil and gas. FlexGen was one of them."

"There has been a shift, Angel says, away from capital-intensive projects and companies. "In the past five years, companies are bringing innovation to market in a more capital-efficient way. Investors want new solutions that are very customer-focused to bring to the market. Investors are looking for solutions to customer issues; for example, system integrations that leverage existing technologies."

He says that GE Ventures takes a long-term-view approach to investing in technology. Also, its mix of technology types and other aspects of its approach to investment are fairly representative of the sector. When it comes to investing in oil and gas technology these days, the issue of efficiency is ever present, and the environment is often nearby. "Most [venture capital] companies on the energy side are looking for technologies that provide significant productivity gains, or environmental gains, by minimizing en-
vironmental footprint," says Trevor Conway, managing director and head of investment banking at Industrial Alliance Securities.

Financing horizons for innovation vary among oil-producing countries, says Altira’s McDermott. "The Norwegians have a lot of money allocated to technology. There’s a lot of government money for it, as well as money from oil companies. There’s quite a robust interest in new technology in Norway.

The U.S. is a contrast, he says. There is plenty of interest, but the approach is often laissez-faire, with relatively little government funding or support. But once an outfit launches a new product, there is lots of competition. "Other companies will right away make the same offer," he says.

Canada is somewhere in the middle, he says, adding, "There is good government support but less institutional private capital available."

Regarding capital requirements, this observation from McDermott seems to reflect a view shared by most of the people interviewed for this article. "The less capital-intensive something is, the easier it is to cross the Valley of Death from the lab to commercialization."

Technologies for the digital oilfield or enhanced reservoir characterization are of interest. Technologies for oil and gas that save money and have wide applicability have a decent shot at attracting investment capital, perhaps even better for some than during the days of $100 oil. "It’s a fairly good time. In 2014, some didn’t make investments much as costs were peaking. Now, we have lower costs, so there’s better potential. Operators are more likely to listen to you," McDermott says.

He points to some factors that got the right kind of attention for FlexGen. "Its hybridization technology starts saving costs at once. There are also long-term benefits in maintenance reduction and less downtime. The long-term ones are more important. It ad-
resses a very tangible need with immediate cost savings and efficiency gains."

Some markers, however, certainly indicate that the current low commodity price environ-
ment has its drawbacks. For instance, until Sept. 30, 2014, investment in energy service companies—which doesn’t designate a sub-
category of oil and gas technology or service companies needing money for technology commercialization—totalled $1.159 billion on the Toronto Stock Exchange. It is little surprise that investment in this sector fell off a cliff in the fourth quarter last year and the total for all 2014 was $1.6 billion. This year, the energy services sector had received $912 million up to September 30, much of it in private placements from accredited investors, as was the case last year.

There is, however, still money for new oil and gas technology, says Monica Rovers, head, business development, global energy, with the Toronto Stock Exchange and the TSX Venture Exchange. "There’s never been a more important time for technology in oil and gas," she says.

She adds that Canadian energy service companies have a reputation for excellent
SEEING THE UNSEEABLE

Downhole camera technology provides operators revealing worm’s-eye view

BY CARTER HAYDU
Downhole camera technology puts eyes underground, enhancing a company’s understanding of what is going on within the furthest depths of production and helping operators make important decisions that benefit from the all too valuable sense of sight.

“Today, thanks to EV’s telemetry, which can transmit up to 300 kilobits per second of data, we can send a full-colour video of 25 frames per second to surface in real time,” says Federico Casavantes, vice-president of marketing at EV, a U.K.-based company with a team of technical specialists and engineers at the technological development centre in Norwich, England.

“We see events as they happen—no gimmicks, no delays and, most importantly, no image degradation. We can send data on any logging cable, allowing our customers to see what’s happening downhole and, whenever possible, we also transmit the data in real time from the wellsite to the customer’s office, enabling even quicker decisions.”

He adds: “We do this a lot in Canada, mainly because of the sophistication and wide coverage of telecommunication systems in the country. Canada is a great example of how operators are adopting EV’s technology to arrive at better answers.”

The operating principle of his company’s downhole camera technology is not dissimilar to a typical smartphone camera. The difference is that EV cameras are purposely designed for the oilfield and regularly operate at temperatures of up to 150 degrees Celsius and pressures of 15,000 pounds per square inch (psi), whereas a smartphone would likely fail at around 60–80 degrees Celsius. According to Casavantes, EV’s technology trumps the competition, too.

“Right now, we are at field trial stage with our continuous 175 [degree Celsius] and 20,000 psi camera, and we have an EV team of 35 specialists working on this and other projects—nobody else has this capability.”

If running on coiled tubing or slickline, EV provides memory cameras that can record up to five hours of continuous video, with potential for segmented recording—up to 60 intervals—depending on operations. The data is then downloaded from memory as soon as the tool comes to surface.

“Our memory cameras are the best in the industry. Competitor memory options only provide still black-and-white pictures. Our memory cameras provide full-colour video at 30 frames per second, which is high-definition [HD] video.”

While Halliburton also offers HD colour for those who request it, Darren Walters, global champion for plugging and abandonment, says the black-and-white camera technology is just as effective at imaging beneath the earth, because colour is not a factor in that environment.

“We don’t paint the inside of a well with colours. Everything that you see downhole is black and white. It is like being out at night and there are no street lamps, and you usually just have grey vision. That is what you are getting downhole. For a crisp, clear picture, black and white usually works better than HD colour, although Halliburton offers both options for different operations.”

For mature wells with planned intervention or abandonment, running Halliburton cameras as part of the diagnostic provides key insight into the wells’ condition and can help optimize the operation, thus saving time and money. Walters says, “An operator’s specific goal will dictate how the proper camera is selected to ensure a complete and individualized solution.”

**GLIMPING THE UNDERWORLD**

With most applications, Halliburton’s downhole camera technology is geared toward mature wells or well intervention. For example, if the operator sends down a slickline that gets hung up at a certain depth, a “worm’s-eye view” can prove quite beneficial.

“At this point they have limited options,” Walters says.

“Operators don’t know what they have hung up on. They can go in with a lead impression block and hammer it hard to try and get an impression of what is in the hole, but that’s inefficient when finesse is required.”

A lead impression block is a tool containing soft lead in the bottom used to take an impression of an object (or fish) downhole to determine its size and shape, so that the appropriate fishing tools can be selected to remove the blockage during fishing operations.

He adds: “If you lost something in the well and don’t know how it is sitting, then hitting it with the lead impression block could manoeuvre it into a more difficult position for fishing. For example, if fishing for wire with a camera, operators have the ability to determine exactly how the wire is lying, reducing potential risks.”

“If there is a tool string in the well and no wire, operators will be able to identify how the fish is lying in order to use the most appropriate overshot or recovery tool to recover the fish from the well. Downhole cameras bring an added advantage to see potential hazards which could result in a longer, more expensive job.”

Halliburton offers three cameras—two of them are deployed on electric line (e-line) and one on slickline. The e-line cameras offer a downward and sideways view, providing information about what obstructions are in the way for a wireline fish or what problems an operator might be having downhole.

“You’ll run in hole to up to 30,000 feet on 7/32 line that will provide video frames back to the surface,” Walters says. “So it is a live feed, although there is a slight delay as you might expect, as it transmits through the conductor, which is 1.25 images per second going up the hole on mono cable. We can run on fibre optics, which is also live feed.”

When running a tool with down- and side-view cameras, Halliburton can detect and investigate potential downhole issues with greater precision. For example, if the down-view camera sees gas bubbles coming from a sidewall of the tubing, switching to side view at that depth allows a 360-degree turn to help determine what is occurring in that area.

“You may find that there is a crack in the pipe, or you could learn that when the well was constructed the thread itself was not fully tightened, causing a leak path,” Walters says. “This has been seen downhole with the e-line cameras.”

The e-line cameras can be conveyed on the vast majority of electric line cable used in the energy sector, whether single- or multi-conductor wireline. According to Walters, downhole camera technology once implied a lot of accompanying surface equipment—panels for communicating with the cameras, recording the data and changing it to video. Today, though, Halliburton cameras only require a laptop and a small communications panel at surface—a bonus for offshore operations.
“What makes Halliburton different than others is our complete solution. We can conduct the camera service and perform the fishing operation as an integrated solution. Halliburton wireline specializes in intervention, so we can enter the well, conduct and survey the problem, and then offer a solution directed at the detected problem, whether fishing, perforating, mandrel replacement or other invention.”

With more than 120 people in 26 locations around the world, EV is a truly global diagnosis company that must routinely innovate and stretch technical boundaries to meet the challenges encountered by its global customer base in some of the most extreme environments, says Casavantes.

EV’s downhole camera technology has a wide range of applications, from identifying unknown objects stuck downhole to diagnosing well-integrity issues on land and offshore, such as corrosion or valve conditions. EV also provides measurements in conjunction with video images.

“Thanks to our powerful telemetry, we can combine pressure, temperature, gamma ray, casing-collar locator and log as we acquire the video, and this is also unique to EV.”

EV’s combination of video with sensors—whether to look at sand screens, sand entry, mineral deposits, frac efficiency, or a wide range of other situations encountered downhole—makes for a more powerful, clearer understanding of the condition being evaluated, Casavantes says.

**FRAC ASSESSMENT**

“In the U.S., we are undertaking a lot of frac efficiency diagnostics. We are called in to multistage wells to measure the perforations before and after the fracturing operation and provide the customer [with] a perforation variance evaluation. This ultimately provides the operator with an understanding of fracture efficiency. [Companies] have been able to save millions of dollars by tailoring subsequent fracturing operations based on the information provided by EV.

“By combining both visual and physical measurement data in the same run, EV provides significant cost efficiencies. Not only do operators get a better answer, they get it in less time.”

The advantage of downhole camera technology is that it actually cuts down on non-productive time by eliminating guesswork and minimizing interpretation time. Video-based solutions provide a clear, unequivocal understanding of the issues at hand so customers can decide exactly what actions to take in the shortest time frame possible, says Casavantes.

For example, he adds, while recently trying to complete a well intervention, an operator lost a nozzle assembly in the well, and it was causing an obstruction across the downhole packer. The operator had been working unsuccessfully to resolve the problem for several days. “When they finally called EV, they had a clear diagnostic within 24 hours and were able to resolve the issue expediently.”

In this particular case, costs were in the order of $650,000 per day. The operator spent over $5 million before deciding to engage EV. “They would have saved a lot of money if they had done so sooner,” notes Casavantes.

“On the positive side, operators are increasingly relying on EV to provide reliable solutions. More and more, we are being pulled into and considered at the planning stage of operations, and less and less as a last resort call-out. It is great to know that people are starting to understand the unique advantages offered by EV.

“In Canada, for example, we have been very successful with our Integrated Video Caliper (IVC), which not only was field tested in the country, but is now utilized regularly by many of our customers.”

While many companies provide multi-finger caliper tools, he adds, only EV does so with a camera—on its IVC. “The benefits include considerable time savings and an unequivocal diagnosis. We run into the well and perform a preliminary visual inspection and, by the time we get to bottom, we have a fairly good idea of where the key issues are.

“We then log the caliper across the area of interest, and finally inspect close up with a side-view camera. A multi-finger caliper is a mechanical device, so you need to interpret it. When you combine it with a video, the interpretation becomes a lot more robust supported with visual evidence.”

**OPAQUENESS OBSCURES EFFECTIVENESS**

Sometimes when trying to use camera technology to answer questions downhole, the answers—along with the environment—are not always clear.

According to Casavantes, the biggest advantage of a downhole video is also its greatest disadvantage: the technology works within the visual spectrum. “If your environment is predominantly oil, or just dirty water with mud, then cameras won’t work unless there is adequate well preparation,” he says, adding that EV typically achieves 95 percent efficiency in acquiring video-based diagnostics in a wide range of environments around the world.

“Out of more than 100 jobs we run in any given month, at least on 95 of those we capture the necessary video images to provide our customers with answers. Even in the cases where we are challenged beyond the physical capability of the technology, thanks to our vast global experience we are able to provide guidance for appropriate well preparation to get the best picture possible.”

The downhole environment has to be suitable for camera operations. If the operator cannot see through the fluid with his or her own eyes, then the camera images are going to be less effective. According to Walters, because Halliburton uses a light source behind its visual device, too many suspended solids in the well fluid adds to reflectiveness, which degrades picture quality.

He says: “The key to an effective camera operation is knowing how to work within the well itself, which includes proper fluid usage and management. This knowledge, coupled with special surfactants applied to the lens to stop heavy oils from sticking to it, requires detailed pre-job planning rather than just running in the hole and hoping for the best.”
Deeper. Hotter. Lower cost. That’s what Alberta-based CJS Production Technologies is offering as it begins to commercialize its ArmorPak umbilical that it describes as “next generation artificial lift deployment technology.”

“We wanted to get deeper, we wanted to get hotter and we wanted to bring down the cost,” says Scott Kiser, president of the privately held company. “We are running pumps less expensively which increase production so as not only to increase revenue but to reduce costs.”

Patent pending under international application, the new technology is the next generation of CJS’s FlatPak umbilical, a multiple-tube umbilical surrounded by thermoplastic resin that the company rolled out in 2008. That technology is now patented in the U.S. and patent pending in Canada.

The ArmorPak’s all-metal banded umbilical coiled tubing (UCT) is designed to facilitate the installation of low-maintenance hydraulic and electric submersible pumps at greater true vertical depths and higher reservoir pressure and temperature in challenging horizontal and deviated wells.

Conveyed with a coiled tubing unit, it contains tubes to deploy, actuate and receive production from the downhole pumps. Additional items associated with the ArmorPak include a specialized stripper and blowout prevention system to facilitate its installation in live wells.

For hydraulic service, CJS installs a third tube into one side of the ArmorPak to permit injection and receipt of hydraulic fluid through the concentric side to power the pump.

For electric drive pumps, including electric submersible pumps (ESPs), the 1.5-inch dual banded coiled tubing is loaded with an encapsulated three-phase copper cable and includes braided aircraft cable for support. This combination is preloaded into one side...
of the ArmorPak, leaving the other side open to carry production fluids from the downhole pump to surface.

The custom power cable used in the ArmorPak ESP is manufactured and installed into the power side of the ArmorPak by company partner Petrospec Engineering of Sherwood Park, Alta.

“We have been working with Petrospec for years, and this relationship has facilitated CJS’s ability to create products like ArmorPak ESP while also facilitating other unique ArmorPak-supported well services which require components installed inside coiled tubing, such as well pump off automation,” Kiser says.

CJS relies heavily on Petrospec’s expertise due to its in-depth engineering, optimization system design and manufacturing capabilities, he adds. “Petrospec is a master at installation of pretty much any smart technology into coiled tubing, having performed this service for years at its assembly facility in Edmonton,” he says. “When it comes to designing and installing custom ESP power cable, capillary tube, thermocouple, fibre optic for distributed temperature, pressure and acoustic measurement, data conductors or pretty much anything to support CT-conveyed smart technology, Petrospec is a Canadian leader.”

CJS has developed all the custom running equipment including injector assemblies, stripper heads and blowout preventers to allow most industry-available coiled tubing units to run UCT products. It also carries a line of sub-surface hydraulic equipment specifically designed to work in connection with the umbilical technology to power hydraulic progressive cavity pumps. These UCT-deployed systems support ESPs, hydraulic reciprocating piston pumps and hydraulic progressive cavity pumps.

“We wanted the whole suite,” says Kiser of his company’s technology, noting that ESP, reciprocating and progressive cavity pumps account for 90 per cent of the market by units. “Light, heavy, oil, gas—it hits all areas of the spectrum,” he says. “That’s why it took us eight years.

“We have relevant pumps that will fit in all areas: Canada, the U.S., parts of South America, Middle East, China and Australia,” Kiser adds.

The ArmorPak technology has a number of benefits, he says. Those include rigless “live well” operations in which a coiled tubing unit replaces a service or workover rig and rodless technology that reduces well downtime, service frequency and the costs associated with tubing and rod failure.

Conveying the artificial lift via coiled tubing eliminates the need for a workover rig, saving money for the operator and relying on fewer persons on location, reducing the environmental footprint and increasing safety, says Kiser.

“Our operation is very smooth,” he says. “We show up with a truck and three guys.” That enables CJS to do in a day a job that in some other areas might take a service rig up to three or four days.

The lower cost is a major reason why customers prefer a rigless technology, Kiser suggests.

The ArmorPak can also help to increase production in a horizontal well as a result of optimum pump placement at the true vertical depth of the producing reservoir, says Kiser. “Otherwise, the hydrostatic weight of the fluid column below the pump intake is pushing against the formation and can restrict production, often in lower pressure wells,” he says. “Generally, in more mature wells you will get the benefit of optimal pump placement.”

In 2014, CJS initiated and completed development of the first ArmorPak deployed electric submersible pump, the ArmorPak ESP, for higher production wells (more than 200 bbls/d). The system was installed for an Alaskan operator in the summer of 2015.

Although the company can sell its system with an ESP provided by any vendor, it plans to partner with Summit ESP based in Tulsa, Okla., enabling CJS to offer a combined package. “We have the rigless deployment system; they have the ESP,” says Kiser.

Over the past four years, Summit has installed more than 5,000 ESPs, becoming the second largest ESP manufacturer in the U.S., providing superior technology and exemplary customer service, he says. Summit offers a wide range of products and services including application engineering, equipment design, reliability engineering and equipment service, testing and repair.

“Because Summit’s mandate parallels CJS’s regarding customer well optimization and operating cost reductions, the two companies are a perfect fit,” says Kiser. “This partnership brings CJS the professional support it requires to deliver a fully integrated riglessly conveyed ESP solution. It’s with relationships like Petrospec Engineering and Summit that CJS is confident in its ability to tackle the company’s fully vertically integrated business mandate.”

Kiser also believes that this is a good time for the ArmorPak to be coming on the market. “Even though it’s tough times in the oil industry, those [operators] who still have a budget are looking to be saving money wherever they possibly can in a low [commodity] priced market, and our technology is exactly what they are looking for.”

In Alberta, the FlatPak has been used to deploy artificial lift systems in both coalbed methane and heavy oil wells. Ember Energy has 25 hydraulic submersible pumps in place in central Alberta, using them as permanent dewatering solutions for Belly River coalbed methane, says Duke Laye, superintendent of optimization and maintenance. It is run on the FlatPak triple string coiled tubing, which he says makes it easier to deploy.

“The best part that I like about it is the reliability,” says Laye. “We have had many in the ground for close to 10 years.” While the CJS pumps are more expensive, they are less costly over the long term because Ember hasn’t had to spend money on costly repairs and pulling out pumps, he says. “Longevity for us is key—and the low maintenance costs.”

In the Lloydminster, Alta., area, CJS installed its first two hydraulic progressive cavity pumps in Husky Energy horizontal heavy oil wells where the company was worried about rod and tubing wear, says Dustin Newman, a production engineer there at the time.

With the FlatPak, Husky was able to do a couple of things it couldn’t do on traditional set-ups, he says. It ran a pressure sensor downhole and also ran a bubble tube so that it could inject chemical downhole at the pump. “It just gave us some options you really can’t do in traditional setups,” according to Newman.

The FlatPak was used in two wells, and the company had success with both of them, although in the first well CJS had to go back and make some modifications when there were problems with the driver.

Laye also appreciated the time-saving with the coiled tubing. “The set-up and pull-out and run back in was a lot quicker with coil compared to a service rig, because coil can set up way quicker,” he says.

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