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FIRE IN THE BELLY

BRUCE EDGELOW'S CAREER SPANNED ATB FINANCIAL'S TRANSITION INTO THE ENERGY BIG LEAGUES

PLUS

FACES OF INDUSTRY
FIVE LEADERS SHARE HOW THEY SURVIVED THE DOWNTURN AND POSITIONED THEIR COMPANIES FOR GROWTH

+

SPECIAL REPORT
OILSANDS COMPETITIVE OUTLOOK

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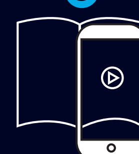

EXPLORE THE INTERACTIVE CONTENT

frontlines

Competing on price

First, the good news: whatever some wild forecasts claim, the oil age is far from over.

Despite new automotive fuel economy standards, the emergence of hybrid and electric cars, and increasing energy efficiency, demand for oil is expected to continue gradually rising for at least the next 25 years, according to almost all credible estimates.

Natural gas demand is expected to be even more bullish. Despite headlines about investment in renewable power generation surpassing fossil fuel investment in 2016, gas continues making inroads in this sector. And demand for heating and petrochemical products continues to grow.

Now, the bad news: supplies of both oil and gas have grown faster than demand and will continue to do so far into the future.

Global proved oil reserves have more than doubled over the past 35 years. For every barrel of oil consumed, more than two new barrels have been discovered, according to BP's latest outlook. Known resources today dwarf the world's likely consumption of oil out to 2050 and beyond.

Everyone is familiar with the decades of natural gas supplies made available through horizontal drilling and multistage fracking shale and tight gas plays.

The world is awash in petroleum.

With supply outstripping demand for the foreseeable future, it's the war of all against all in competition for market share. And, as ARC Financial's Peter Tertzakian recently put it: "the low-cost producer wins."

Right now, Canada isn't in that low-cost producer group. On the oil front, BP expects Middle East OPEC countries, Russia, Brazil and the U.S. to eat up most future demand. OPEC is assumed to account for nearly 70 per cent of global supply growth, increasing by nine million bbls/d to 48 million bbls/d by 2035. Non-OPEC supply grows by just over four million bbls/d by 2035 with growth from the U.S. (four million bbl//d), Brazil (two million bbls/d) and Russia (one million bbls/d) largely offset by declines in high-cost and mature regions elsewhere. Canada, with the third-largest oil reserves in the world, is expected to grow by only 500,000 bbls/d. Other outlooks show this growth happening within the next few years before production levels out.

The natural gas story is similar with U.S. shale production expected to more than double and other supply increases coming from low cost production in the Middle East and Russia. Canada, again with massive resources, is expected to see only a minimum uptick in production.

These predictions, of course, are based on business-as-usual scenarios. So what can Canada do to change this future?

In the oilsands, the industry needs a technological breakthrough to bring costs in line with competitors. But for the rest of the industry, the challenges are more complex. Any technological breakthrough will quickly spread to competing jurisdictions.

BP says for Canada and other high-cost countries to compete for market share, they may have to look at their royalty, regulatory and taxation systems. The days of the petroleum industry funding government growth may be coming to an end in Canada as the industry shifts from a demand-driven to supply-driven global market.

For the industry to survive and grow, governments are going to have to take less and learn to live with less. And that may be the biggest challenge facing the Canadian industry of all.

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jwn CONNECTED

Oilweek retools for the new energy future

For 75 years, *Oilweek* has told the story of Canadian energy—through an oil and gas lens.

Now, as Canada celebrates its 150th birthday, *Oilweek* is pivoting from a pure petroleum perspective to the broader energy landscape and, in the process, will significantly broaden its audience base.

The change recognizes that the country needs new and innovative ways of understanding the tensions—both positive and negative—between its energy heritage and its energy future.

Long a staple of upstream petroleum readers, *Oilweek* will broaden its target membership to include anyone with a stake in Canada's energy future, from First Nations and post-secondary campuses to policy makers and politicians. Simultaneously, *Oilweek* will broaden its coverage and context to include all the forms of energy that will shape the country over the next 150 years. That energy mix perspective is critical; all the systems are inter-related and often interdependent.

We're at a pivotal point in this country's energy evolution and to continue to be successful as a society and an economy, we need to find better ways of conversing about how our various energy options connect and relate to each other. Everyone should have at least a basic understanding of how it all ties together. With *Oilweek* readily available to anyone with an interest in Canadian energy matters, we hope to be an important part of how we constructively and collectively map our energy future.

Another central premise of *Oilweek*'s new focus will be to help Canadians understand, in the context of their everyday lives, how important their opinions are, such as in shaping future policy and regulation. That means helping people of all ages develop a better understanding of energy fundamentals.

Oilweek's position statement has for decades been "Canada's oil and gas authority."

With our September issue, the positioning will change to "Connecting Canadians to their energy," which we hope will be a clarion call to Canadians to embrace their role as part of the energy dialogue. With that issue, the *Oilweek* team will have completed a major push forward in broader audience development—the first in a series of additions. The new membership will include:

- All members of Parliament;
- All members of legislative assembly in B.C., Alberta, Saskatchewan, Manitoba, Ontario and Quebec;
- Deans and senior members of business, engineering and science faculties of major Canadian universities, polytechnical institutes and colleges;
- Students in those faculties;
- First Nations councils and businesses in Alberta and B.C.;
- The board and chair of the Canadian Chamber of Commerce;
- Mayors and city councils of the 20 largest cities in Canada;
- Boards and staff of the top 10 environmental non-governmental organizations, such as Pembina Institute, Greenpeace and the Sierra Club; and
- Boards and staff of other key energy associations in energy sectors, such as geothermal, solar and wind.

This is just the first wave of connecting to important groups. Very rapidly, we will bring on other provinces, business groups, communities and organizations—all those with a stake in where we go with Canadian energy.

While *Oilweek* will embrace and point to other forms of energy as important elements of the energy systems mix, it will remain committed to helping Canadians understand how the petroleum sector is evolving and responding to social and economic changes. This includes highlighting how innovation and technology originating from fossil fuel roots are shaping the next-generation low-carbon economy.

While *Oilweek*'s new members, plus existing members, will receive print copies of *Oilweek*, they will also have access to a range of digital tools that will bring to life key energy dynamics through data visualization and engagement technologies.

We hope between the combined power of the print and digital platforms, more and more Canadians will connect to, and be involved in, the energy dialogue.

One critical element of *Oilweek*'s pivot is that it will become a platform for other voices to contribute to the dialogue.

While our core content will still populate the pages, we will be reaching out to all these organizations and individuals to contribute to what we hope will be a dynamic and rich conversation that will constructively influence the way we approach our next 150 years as a country.

— BILL WHITELAW

PRESIDENT AND CHIEF EXECUTIVE OFFICER
JWN

Fracking company consolidation on the rise

In this low price environment, companies are partnering and consolidating fracking businesses, better positioning themselves to serve customers in this new world order.

In March, Trican Well Service announced its acquisition of Canyon Services in a stock-and-debt deal valued at $637 million, creating a larger and more prolific company. "It's the right time for the combination," Dale Dusterhoft, Trican's president and chief executive officer, told a conference call.

"We're seeing an improvement in our business. We're seeing a situation in our industry right now where horsepower-per-job is increasing rapidly, the sand-per-well is increasing rapidly, and these trends are putting a strain on both of our respective companies.

"This deal allows us to get to a scale that allows us to service our customers better, drive efficiencies in our business and really respond to the change to the market that we're seeing."

The combined company will boast 675,000 hydraulic horsepower of available fracking capacity, service bases spread across western Canada, and a suite of offered products and services across cementing, coiled tubing, nitrogen, industrial services and fluid management.

The time is right for the consolidation, and it will set the company up for the future, Dusterhoft says.

"Why do this?" he asks. "It significantly strengthens our core business, and before we want to diversify our revenue stream, we want to strengthen our core business.... We do want to diversify our revenue stream, but doing this deal gives us the financial flexibility with a very, very good balance sheet to be able to do those other things down the road."

Also in March, Weatherford and Schlumberger announced the creation of OneStim, a joint venture combining their North American land hydraulic fracturing pressure pumping assets, multistage completions and pump-down perforating businesses.

Weatherford will contribute its multistage completions portfolio, regional manufacturing capability and supply chain for 70 per cent of the joint venture. Schlumberger will scoop up the remaining 30 per cent; add access to its surface and downhole technologies, efficient operational processes and advanced geo-engineered workflows; and pay Weatherford a one-time sum of $535 million.

Both these partnerships follow Baker Hughes' announcement last November that it will be joining forces with CSL Capital Management and West Street Energy Partners (WSEP) to create a pure-play North American land pressure-pumping company.

The big three

Pressure pumping horsepower of Canada's major frackers

TRICAN WELL SERVICE
675,000

CALFRAC WELL SERVICES
410,000

STEP ENERGY SERVICES
290,000

Baker Hughes and CSL will mesh their North American land cementing and hydraulic fracturing businesses, including personnel, expertise, technology and infrastructure to form the new company. CSL and WSEP will together contribute $325 million in cash, of which $175 million will be used to strengthen the new company's balance sheet and position it for growth, and the other $150 million will go to Baker Hughes.

Headquartered in Tomball, Texas, the new company will operated as BJ Services. CSL and WSEP will together own 53.3 per cent, and Baker Hughes will have the remaining 46.7 per cent.

"With the combination of the Baker Hughes North American land cementing and hydraulic fracturing assets and our Allied Energy Services' fracturing and cementing businesses, we are excited to create a leader in the pressure pumping sector and to operate under the well-regarded BJ Services name, which for almost 150 years has stood for superior and timely service to its customers and to the market," says Charlie Leykum, founding partner of CSL.

PHOTO: TRICAN WELL SERVICE

PHOTO: JOEY PODLUBNY

Up-and-down energy markets create labour market uncertainty

Assuming average oil prices stabilize in 2017 and increase steadily to 2021, Canada's oil and gas industry will require 17,100 new workers during the five-year period, says a PetroLMI report from the end of March.

"The year has gotten off to a good start with activity and hiring picking up, particularly in the services sector," says Carol Howes, vice-president of communications and PetroLMI at Enform. "In fact, some of these companies are already experiencing a shortage of skilled workers with substantially more drilling rigs operating as compared to this time last year."

However, if prices slump and renewed activity slows, industry will shed additional jobs in 2017, and overall employment growth will slow. In this delayed-recovery scenario, the energy sector will create about 6,700 new jobs during the five-year forecast, according to Labour Market Outlook 2017 to 2021 for Canada's Oil and Gas Industry.

In the modest-recovery scenario, industry will experience hiring challenges beginning in 2017. In either scenario, PetroLMI still expects to see hiring challenges in 2018 and 2019 for occupations such as geologists, geophysicists, petroleum engineers and technologists, purchasing managers and agents, trades, oil and gas drilling and services operators, and labourers.

"There are a couple of things industry is looking at doing to try and address some of the shortages," Howes tells the Daily Oil Bulletin, Oilweek's sister publication. "They are obviously trying to move folks around within the companies themselves—'re-skilling.'"

Projected unemployment rates for the entire industry in 2017 are 5.4 per cent in a modest-recovery scenario and 6.6 per cent in a delayed-recovery scenario. Regardless of the scenario, by 2021 the projected unemployment rate across the industry is projected to be 5.9 per cent.

Basically, Howes says, the unemployment rate is low in either scenario because those who leave the industry for careers elsewhere would be no longer considered part of the oil and gas workforce. "If you have a smaller workforce in the industry, then the unemployment rate will be smaller because of that," she says.

One reason the industry's labour force is shrinking is that there are fewer anticipated new entrants to the industry with many being scared off by the layoffs over the last two years. Whether they are new graduates or those in mid-career transition, many potential entrants are not even considering being part of that labour force, perceiving the industry to still be in decline, according to Claudine Vidallo, PetroLMI team lead.

"One of the things industry could do overall is obviously communicate that there are jobs now," she says. She adds that a difficult, but important, task is attracting the same entrance level into the labour force as existed pre-downturn.

"The other thing is that there is obviously more internal workforce strategies that industry could do, which includes holding onto retiring workers longer, as well as workforce development to really focus on where the skill shortages will be, hopefully developing people internally to meet those needs as well," she says.

An aging workforce could add to industry's human resources challenges, says the report. About one in 10 workers is eligible to retire within the next five years, amounting to 4,000 potential retirements in 2017 alone. Companies surveyed noted not all job vacancies resulting from retirements will be filled—replacement will depend on the position, type of work and alternate options to accomplish the job.

Industry is concerned about the experience lost as long-time workers retire, says Howes. "What they are looking at is how some jobs may be addressed through technologies and innovation. For instance, some of these occupations with the introduction of technologies may not require that same level of expertise, because these technologies are taking over. There are also certainly considerations around keeping some of these potentially-retiring workers on contract."

According to Vidallo, 70 per cent of companies who responded to a PetroLMI survey were concerned about the loss of experienced workers. Strategies to address these concerns include recall, internal redeployment and professional development. "That is really a key consideration going forward. You have to have some strategies built around that," she says.

Projected labour demands are shifting, particularly in the oilsands, from construction-related occupations to operations and maintenance positions, says Howes. "That is where you see the real shift in occupations going forward."

Industry occupations with the greatest expansion demand from 2017 to 2021, in either a modest or delayed recovery scenario, include oil and gas drilling services supervisors and contractors, oil and gas well drillers, servicers, testers and related workers, heavy equipment operators, power engineers and power system operators, and oil and gas well drilling workers and service operators.

"In this year alone, the increase in drilling activity does dictate for more oil and gas services-types of roles," says Vidallo. "Really, we are talking about field workers—labourers, operators and those types of positions."

However, over the next five years, PetroLMI foresees a shift in industry spending, where there is really more dedication around operating expenditures and, to some degree, capital expenditures related to innovation and technology.

"There has been a shift in the types of roles as a result of those spending trends we are seeing. Any capex-driven role, like project management and that sort of stuff, would see less of a demand as opposed to more operations-driven roles," says Vidallo. "If you think about process operations and that sort of stuff, it is going to be in demand because production is not projected to decrease."

TOP 10 GROWING OCCUPATIONS

1. Supervisors and contractors, oil and gas drilling services
2. Oil and gas well drillers, servicers, testers and related workers
3. Heavy equipment operators (except crane)
4. Power engineers and power systems operators
5. Oil and gas well drilling workers and service operators
6. Purchasing agents and officers, including landmen
7. Managers in natural resources production, drilling and well servicing
8. Oil and gas drilling, servicing and related labourers
9. Geologists and geophysicists
10. Heavy-duty equipment mechanics

SOURCE: PETROLMI

Workforce demand is growing

Jobs are coming back. Despite the massive workforce reduction over the last couple years, service companies within the shale business are now starting to recruit again, says Rystad Energy, a Norway-based independent oil and gas consulting and business intelligence firm.

The North American shale industry in particular took a hard hit in 2014-16, Rystad says. Two of the largest land drillers—Nabors Industries and Helmerich & Payne—each announced staff reductions of more than 50 per cent.

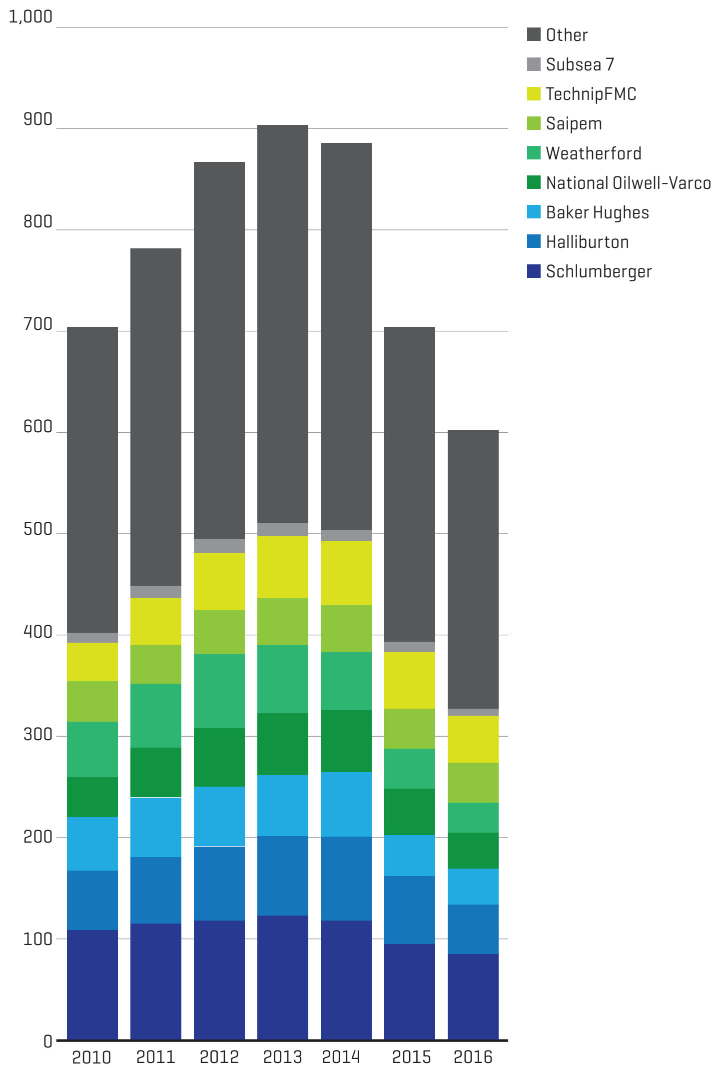
"Among the top 50 service companies, around 300,000 workers, or 35 per cent of the workforce, were laid off since 2014," says Audun Martinsen, vice-president of oilfield service research at Rystad Energy. "However, the negative trend is about to turn, and over the last few months, we have seen more job postings in North America from companies such as Weatherford, Nabors and Precision Drilling."

The offshore industry has been more resilient, but 2016 was still tough, Rystad says. FMC Technologies reduced its staff by 1,000, and Saipem cut 800 jobs in Europe, and they weren't the only ones.

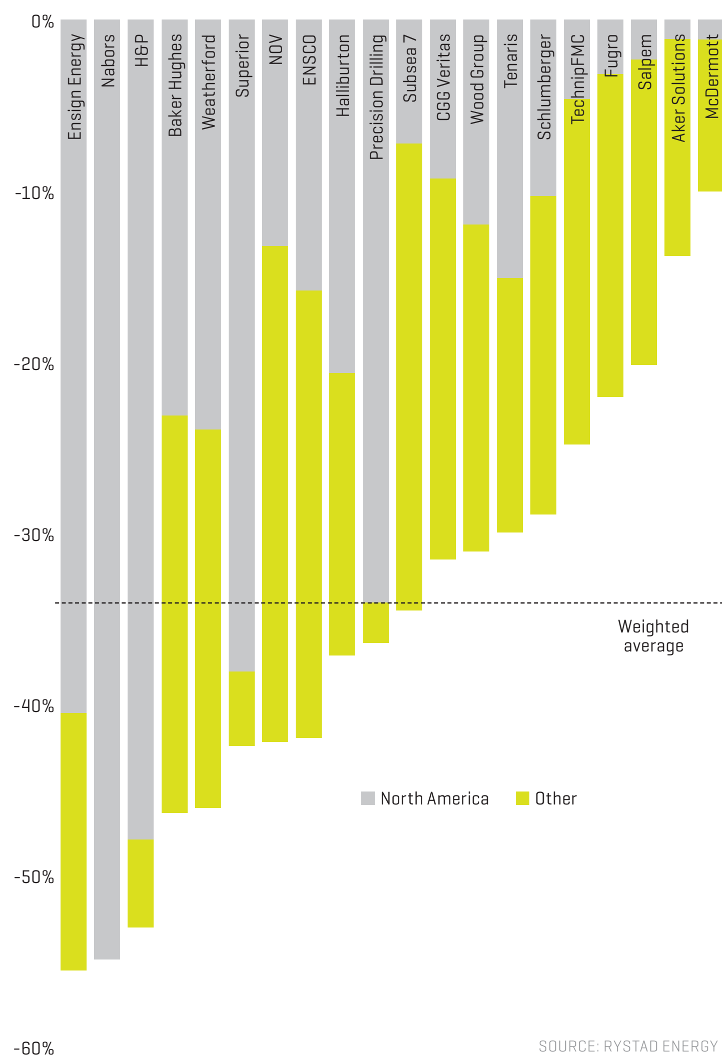
Things are beginning to look up, though. Recruitment is expected to increase once exploration and production spending increases, Rystad says. The firm expects shale-focused operators will increase their spending by 30 per cent in 2017, and offshore spending will grow in 2018.

"With more projects offshore being revived in 2017, we expect the offshore layoffs to stabilize and start to increase later in 2017. Already we see this trend in Norway, and it is only a question of time before it starts elsewhere," says Martinsen. "The race for the best hands and brains has started in the industry, and the companies that have laid off people in a responsible manner are likely to have a competitive edge going forward."

Permanent employees in oilfield services, top 50 service providers
Thousand full-time-equivalent employees



Workforce reduction in 2014-16
Split by revenue source in 2014



SOURCE: RYSTAD ENERGY

Mexico pitches bidding process

Mexico is encouraging Canadian exploration and production companies to look south for opportunities as it opens up its resource to outside investment. The Comisión Nacional de Hidrocarburos (CNH), Mexico's national hydrocarbon bureau, is pushing more than just a focus on the deep waters of the Gulf of Mexico, where most think of when they consider oil and gas in Mexico. Onshore opportunities also abound in Mexico.

"We have two main unconventional basins," Juan Carlos Zepeda, the president commissioner of the CNH, told Canadian executives in Calgary in March. "In northern Mexico, one of these is the extension of Texas's Eagle Ford Shale."

Another lesser-known unconventional basin is the Tampico-Misantla in central Mexico. "This is the most prospective play in Mexico for unconventional [resources]," Zepeda said. "This [is a] huge shale oil basin that's completely untapped. It's a first opportunity. Many in North America and Mexico have told me they've been waiting for this one."

The CNH estimates the Tampico-Misantla holds 35 million boe, and Zepeda believes approximately 88 per cent of that is light oil. While the state-owned Petróleos Mexicanos (Pemex) was active in some parts of the basin in the past, its work was conventional and did not exploit the unconventional plays that could interest Canadian companies. Luckily it did conveniently build up—and leave behind—local infrastructure, including crude pipelines.

After years of Pemex developing nearly all the country's oil and gas, Mexico is putting together a bidding process to open up its development to foreign companies. The CNH plans to release its bidding guidelines in June for the country's next land sale, which will be the first open, competitive bid on unconventional resources in Mexico's history. The upcoming rounds will include parts of the Tampico-Misantla.

Like in many other global oil and gas jurisdictions, the bid rounds will be a regular occurrence. They're planned for twice a year, in fact. In the first half of each year, the shallow water offshore and the onshore conventional categories will be up for grabs. The second half of the year will focus on deepwater offshore and onshore unconventional.

Land will be nominated by industry for bid and then posted by the government in a public, competitive tender process.

In the shallow water offshore, land should be nominated in parcels of 400 square kilometres; in the conventional onshore, 200 square kilometres; and in the deepwater offshore, 1,000 square kilometres.

Companies will have three months before each bid to nominate and review data on prospective lands, which the government will make available to producers—for a price.

CNH executives urge Canadian producers to nominate any land they are interested in.

To participate in upcoming land sales, companies must go through CNH's pre-qualification process, which will depend on which area—deep water, shallow water or onshore—the producer is interested in. Zepeda likened the process to getting a driver's licence. Once pre-qualified, producers are free to participate in Mexico's land sales for five years and must regularly update their financial information with the CNH.

At the same time as it's opening up its resources to foreign development, Mexico is making available its vast data resources, much of it accessible online. This includes decades of seismic data and other well data, such as well logs and well cores, again, at a cost. Data can be purchased either through a license or an annual subscription, but Zepeda also invited foreign producers to check out some of the data free of charge before committing to a purchase.

Ferus pushes LNG for Canadian north

LNG might be the key to unlocking the power sector in Canada's north, Ferus Natural Gas Fuels, a small-scale LNG developer, told a Calgary conference in March.

For decades, diesel has been the go-to for powering remote northern towns and villages, used for everything from vehicles and equipment to generators. LNG could change that. "We're not just coming up with ideas but actually building new LNG infrastructure in the U.S. and Canada," says Blaire Lancaster, vice-president of communications and government relations at Ferus.

Much of the work in the U.S. has focused on developing LNG as an alternative fuel for shipping, but in Canada it's been looking mostly at land applications.

Ferus calls its small-scale LNG plants "homegrown" and says their smaller scale makes them good candidates for fuelling local needs. Unlike the mammoth coastal terminals usually associated with LNG that can cost upwards of $5 billion, Ferus's plants can generate on a smaller scale for an accordingly smaller price.

Ferus built its first Canadian LNG plant in Elmworth near Grade Prairie, Alta., to supply the oil and gas industry, powering drilling rigs, pressure-pumping trucks and other heavy equipment. It's also shipping truckloads of LNG to Whitehorse and Inuvik and is "starting to develop a northern power market," says Travis Balaski, vice-president of natural gas fuels (Canada) at Ferus.

Designed to produce engine-grade LNG fuel, the plant is the first small-scale merchant LNG plant in Canada. It currently produces up to 50,000 gallons/day of LNG, but a second phase will double that.

Ferus believes LNG is the most economical choice and the best option in terms of reducing greenhouse gas emissions. Balaski says by switching to LNG from diesel, customers could see a 30 per cent decrease in CO_2, a 75 per cent decrease in nitrous oxide, a 90 per cent decrease in particular emissions and a 99 per cent decrease in sulphur oxide. Each plant similar to the one at Elmworth could cut CO_2 emissions by 100,000 tons over its lifetime, he says.

"About 90 per cent of the world is powered by fossil fuels," Balaski says. "We're seeing energy demand going up in the world, and we see natural gas starting to take up a lot of the demand and starting to take over some of the market share from coal and oil."

While Ferus's Elmworth plant currently ships its product by truck, the company is confident it can one day offer cross-water shipping for more remote places with fewer roads, like Nunavut and the eastern Arctic. It calls its method of using a sequence of different transport methods "virtual pipelines."

"Generally, it's not very economical to build oil pipelines in northern Canada, and we've developed virtual pipelines," Balaski says.

Price growth slow and fragile

Increased North American production and a milder-than-normal U.S. winter are once again putting pressure on oil and gas prices, according to Deloitte's Resource and Evaluation Advisory (REA) group. Pricing is on track to recovery, but it's shaky and might take a bit of balancing to keep it moving forward.

"Some of the initial optimism that OPEC production cuts would lead to higher oil prices has dampened as North American producers ramped up their own drilling activity, which could lead to a continuation of supply outstripping demand in 2017," says Andrew Botterill, a partner in the REA group. "This increased drilling will lead to increased production, [and coupled with the U.S.'s] record-high stockpile levels, will likely keep oil prices in the narrow window in the coming years."

Botterill says that total U.S. drilling activity has been increasing since last May, which has led to a 500,000-bbl/d increase since August 2016. Canadian production has been steadier, but rig activity has also been increasing into 2017 and is reaching levels last seen in early 2015.

Deloitte also notes that there could be increased volatility in the market later this year once the full effect of the U.S. drilling increases is known and OPEC decides whether to continue its production cuts.

Rory Johnston, a commodity economist at Scotiabank, is confident OPEC will extend its cap. "We believe that the combination of high OECD inventories, still-weak upstream investment outside the U.S. and recent oil price weakness will prompt OPEC to extend their production cap through the end of the year."

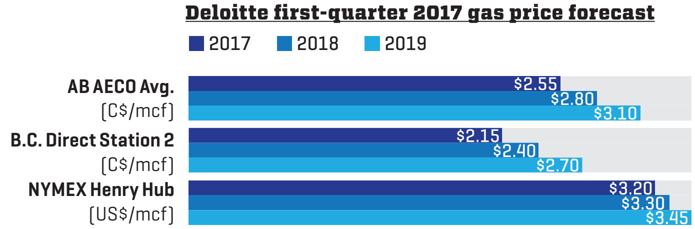
At least for now, though, Deloitte believes the North American market should be able to fill any gap in the supply-demand balance, which will help keep prices in check. For the rest of 2017, Deloitte is forecasting WTI to be US$52/bbl and Edmonton Light to be C$65/bbl. Scotiabank's forecast is similar with WTI averaging US$53/bbl in 2017 and $56/bbl in 2018.

Scotiabank believes there will be four key trends shaping the oil market for the rest of 2017: OPEC output discipline, the pace of the U.S. shale response, non-OPEC production declines outside the continental U.S. and the strength of consistently underestimated global demand growth.

Natural gas prices, which reached a high of US$3.42/mmBtu at Henry Hub in January, slipped in February to US$2.56/mmBtu as the winter remained relatively mild. The average heating days lagged well behind the previous two years, but production levels in the U.S. remained steady, which led to an unprecedented increase in natural gas storage levels in early 2017.

The weaker Henry Hub prices also drew down Canadian prices, and the AECO–Henry Hub differential widened as U.S. demand for Canadian gas dropped, affecting the price even further. For the rest of 2017, Deloitte is forecasting Henry Hub to be US$3.20/mcf and AECO to be C$2.55/mcf.

Deloitte first-quarter 2017 gas price forecast



Deloitte first-quarter 2017 oil price forecast

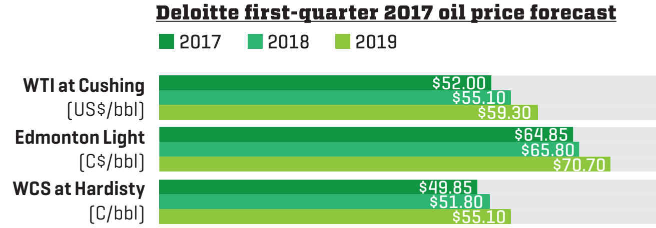


PHOTO: WIKI COMMONS

North Sea is thriving with 30 new projects

Despite the low price environment, the North Sea is booming: a total of 30 crude and natural gas projects are scheduled to start production there by 2020. The U.K. will lead with 20 projects, Norway will follow with nine and Denmark will round out the number with a single project, according to GlobalData, a U.K. research and consulting firm.

The downturn has actually been good for the North Sea, says GlobalData. Operating costs have nearly halved from approximately US$30/bbl to just over US$15/bbl, and projects being sanctioned now cost less than those sanctioned in 2013. The planned projects are expected to require a total capex of US$71.1 billion.

Norway plans to spend the most, approximately US$19.3 billion between now and 2020, US$13 billion of which will be spent on the Johan Sverdrup oilfield about 140 kilometres west of Stavanger, Norway. At the company level, Statoil tops the spending charts with a total of US$10.4 billion.

Another key factor to the North Sea experiencing an upswing is that production forecasts have climbed from what they were in 2016, and they are expected to continue to rise as new fields are brought on stream.

The total recoverable reserves for the 30 projects starting up in the near future is 5.2 billion boe. Statoil holds the most reserves at 1.6 billion boe, Lundin Petroleum follows with 635.9 million boe, Petoro with 610 million boe, Maersk with 414 million boe and Aker BP with 381.2 million boe.

"Of the 30 upcoming North Sea projects, 21 are crude oil projects and nine are gas projects," says Luis Pereira, an upstream analyst at GlobalData. "Norway will dominate oil production, while the U.K. will dominate gas production. The key planned projects in the North Sea are expected to contribute around 690 thousand bbls/d of oil to global crude production and about 1,255 mmcf/d to global gas production in 2020."

Pereira says 10 more fields are lined up to start production in the North Sea between 2021 and 2023, representing US$21.2 billion of further capex investment and 1.1 billion boe more recoverable reserves.

quotables

In late March, Cenovus Energy announced it was buying ConocoPhillips' 50 per cent share in the Foster Creek/Christina Lake (FCCLP) Partnership, giving Cenovus 100 per cent ownership of the assets, which are expected to produce an average 356,000 bbls/d of bitumen in 2017. In the same $17.7-billion deal, Cenovus also bought ConocoPhillips' Deep Basin assets, which are expected to produce around 120,000 boe/d.

Here is what **Brian Ferguson**, Cenovus's president and chief executive officer, had to say about the deal

"This transformational acquisition allows us to take full control of our best-in-class oilsands projects and to add a second growth platform across the prolific Deep Basin that provides complementary short-cycle development opportunities."

"With two recently completed expansion phases ramping up, construction resuming at Christina Lake Phase G, potential restarts at Foster Creek and Narrows Lake in 2018 and 2019, and full ownership of the FCCL asset base, we have a clear line of sight to five years of growth that should take our oilsands production capacity to over half a million bbls/d."

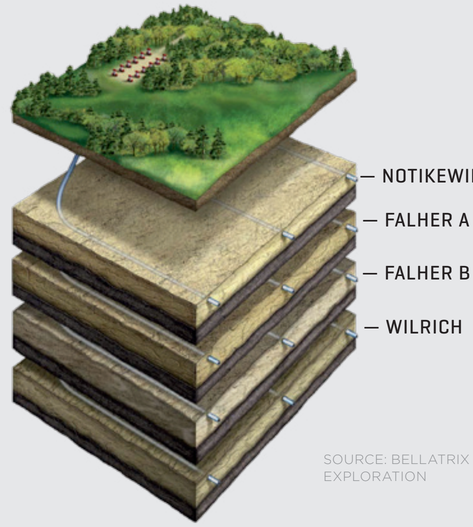
"In a low oil price environment, economies of scale are important. This deal about doubles the scale of the company and gives us a greater competitive edge."

"We also view this transaction as a strategic opportunity to establish an expansive presence in the Deep Basin, with more than three million net acres and an extensive inventory of short-cycle, high-return drilling opportunities. Capital investment into our long-life assets will be complemented by short-cycle capital in the development of the newly-acquired Deep Basin assets."

"Going forward, we plan to focus capital spending on these two value platforms. At the same time, we intend to divest a significant portion of our legacy conventional assets to help fund the transaction."

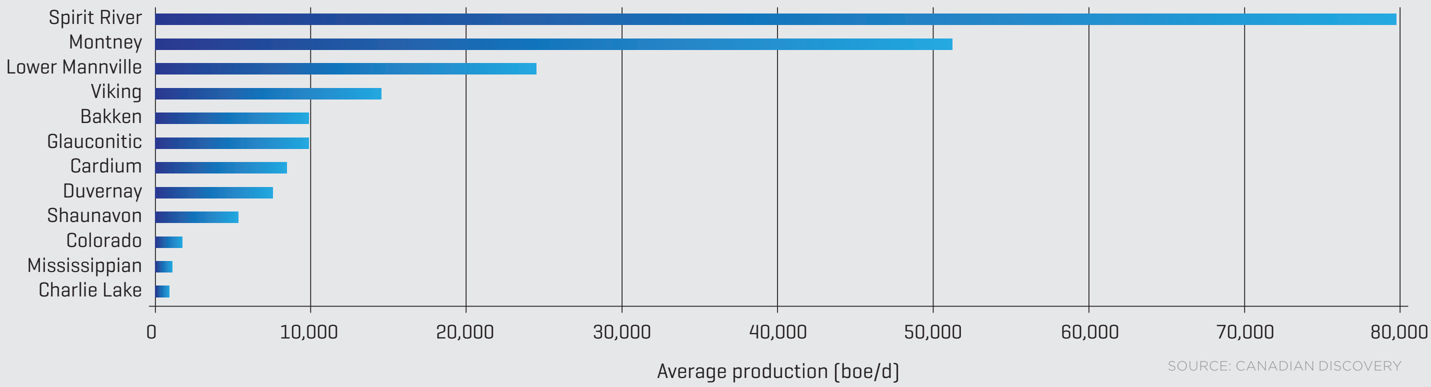
ALBERTA'S GAS TANK

The Spirit River Formation in Alberta's Deep Basin has proven a resilient target for natural gas-focused companies looking to make a buck in today's low-price gas market. With low costs and high productivity, the Notikewin, Falher A and B, and Wilrich zones of the Spirit River proved to be the most productive plays in the province in 2016.



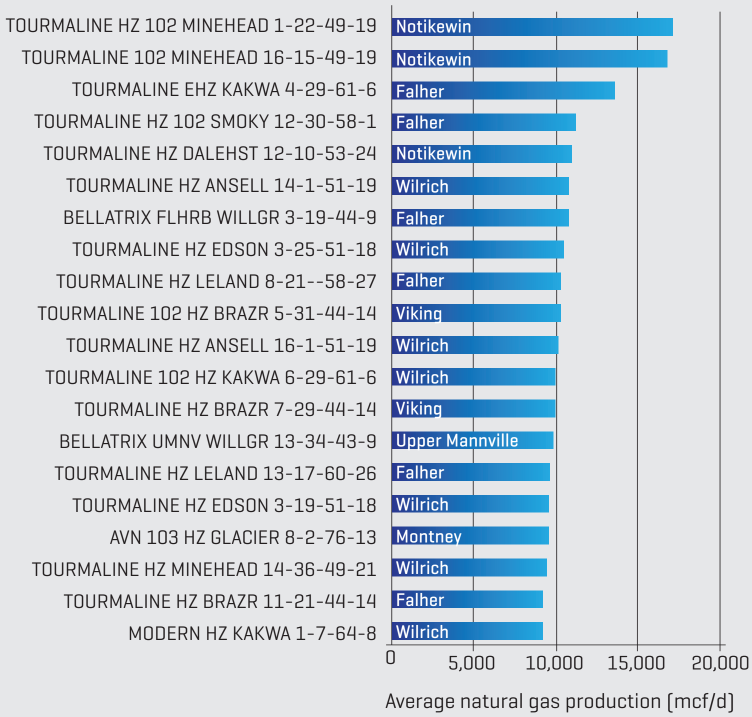
SOURCE: BELLATRIX EXPLORATION

NEW PRODUCTION ADDED IN 2016

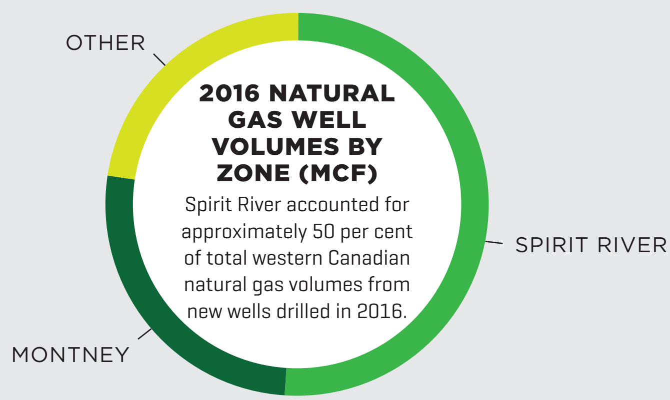


SOURCE: CANADIAN DISCOVERY

SPIRIT RIVER HAS BEEN THE TARGET FOR 19 OF THE 20 BIGGEST GAS WELLS DRILLED IN ALBERTA IN 2016, LED BY TOURMALINE OIL

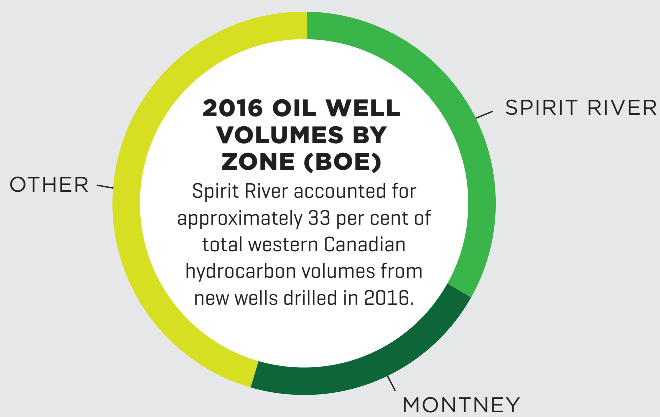


SOURCE: SCOTIA BANK



2016 NATURAL GAS WELL VOLUMES BY ZONE (MCF)

Spirit River accounted for approximately 50 per cent of total western Canadian natural gas volumes from new wells drilled in 2016.



2016 OIL WELL VOLUMES BY ZONE (BOE)

Spirit River accounted for approximately 33 per cent of total western Canadian hydrocarbon volumes from new wells drilled in 2016.

Note: Excludes oilsands and thermal oil wells and volumes.

SOURCE: CANADIAN DISCOVERY

BELLATRIX EXPLORATION IS FOCUSED ON THE SPIRIT RIVER, REPORTING LOW FULL-CYCLE SUPPLY COSTS

Full-cycle costs	$2.50/GJ	$3/GJ
Full-cycle finding and development costs ($/mcfe)	-0.85	-0.85
Cash costs ($/mcfe)	-2.07	-2.11
Sales price ($/mcfe)*	3.91	4.42
Profit ($/mcfe)	0.99	1.46
Profit margin (%)	25	33
Half-cycle internal rate of return (%)	35	62

Full-cycle finding and development costs ($ million)	
Drill	1.7
Complete	1.6
Equip and tie-in	0.7
Land, seismic and facilities	1.1
Total	**5.1**

Cash costs ($/mcfe)	$2.50/GJ	$3/GJ
Royalties**	0.31	0.35
Operating costs***	0.75	0.75
Transport****	0.16	0.16
General and administrative****	0.26	0.26
Interest and financing****	0.59	0.59

Note: Numbers may not add due to rounding.

* Assumes AECO at $2.85/mcf or $3.42/mcf as per scenario. Assumes ethane at $10/bbl, propane at $15/bbl, butane at $20/bbl and condensate at $60/bbl incorporating liquids extraction capabilities given mix of gas through third-party and BXE Alder Flats plant.

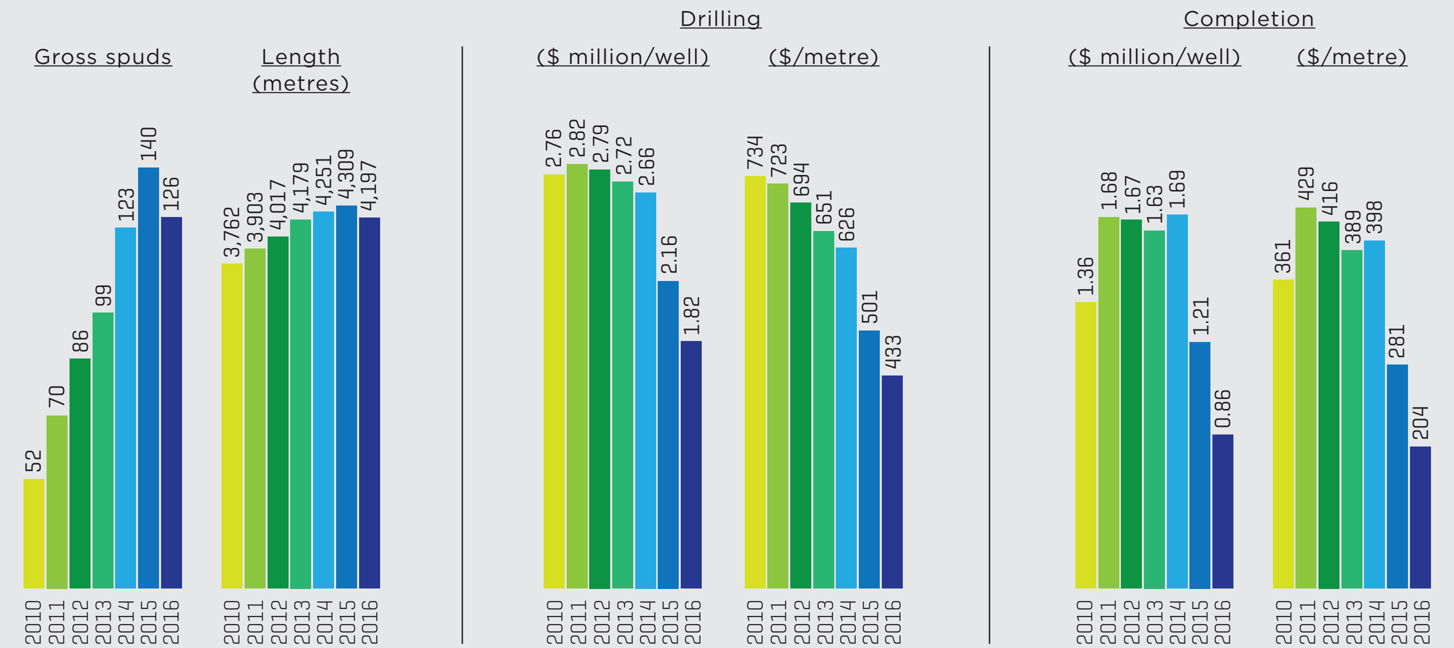
** Estimated at eight per cent.

*** Assumes natural gas through third-party plants at $0.56/mcf, for gas processing through BXE Alder Flats plants at $0.20/mcf and oil/condensate at $8/bbl. Assumes split is 80 per cent third-party and 20 per cent BXE. Includes estimated attributed operating cost impact from $75-million facilities disposition announced May 13, 2016.

**** Based on full-year average 2016 corporate costs.

SOURCE: BELLATRIX EXPLORATION

DRILLING AND COMPLETION COSTS CONTINUE TO DECLINE IN THE PLAY, LED BY PEYTO EXPLORATION & DEVELOPMENT



SOURCE: PEYTO EXPLORATION & DEVELOPMENT

technology

TWO IN ONE

Calfrac's new frac fluid system simplifies surface operations and improves production

BY **R.P. STASTNY**

PHOTOS: CALFRAC WELL SERVICES

In a downturn, new technologies can end up between a rock and hard place. Producers may need better production at lower costs, but they are often too risk-averse to commit hard-won cash flow to uncertain results. That Calfrac Well Services has found converts to its new CalVisc frac fluid system during the downturn is a testament to the demonstrable benefits of the technology and Calfrac's ability to minimize the risks of adoption.

CalVisc trades on two advantages: in the right reservoirs, it improves production compared to established fluid systems, and it simplifies surface operations.

In November 2016, an RBC Capital Markets report comparing 15 Montney wells positioned a Trilogy Energy well using the CalVisc system at the top of the list as the highest producer in the first 90 days.

Dustin Domres, Calfrac's lead on fracture optimization and division solutions, compared that well's initial oil production to offsetting Montney wells in a five-kilometre radius in 2013-16 and found a 67 per cent improvement over the next best producing well and a 193 per cent improvement over the average based on the first month of production.

Trilogy, a Montney- and Duvernay-focused oil and gas producer, tested a number of different fluid systems in two of its core areas and has since decided to use CalVisc fluid system "on a go-forward basis." ▶

"Switching to Calfrac's CalVisc fluid system has been an integral change to our completion design, which has led to superior production results compared to offset wells in the region," Trilogy's Corey Van Engelen, a drilling engineer, writes in an email.

Operational efficiencies at the surface also played into that decision.

"The fluid system has simplified the execution of our frac jobs, allowing us to increase pump rates with minimal impact on pumping pressures and decrease heating demand to effectively reduce costs," Van Engelen says.

Calfrac's in-house asset enhancement group of geoscientists, engineers and chemists helped Trilogy assess the suitability of CalVisc for specific jobs with detailed reservoir profiling and suggested optimal stimulation placements. This combination of mitigating upfront risks, delivering better results and simplifying operations has already proved itself in about 30 wells to date, by a conservative estimate.

"Everyone who has used this system so far continues to use it," says Chad Leier, Calfrac's vice-president of sales and marketing. By his estimate, the number of CalVisc jobs is closer to 60. With oil prices in the $50-plus range, he expects adoption rates to accelerate.

A team of geoscientists, engineers and chemists work together to assess the suitability of Calfrac's CalVisc fluid system for specific wells.

SLICK TO THICK

The idea behind CalVisc was to create a slickwater frac system that could also deliver high-molecular-weight polymers. Conventional wisdom believed this type of frac would damage the rock. But tests conducted by Stim-Lab, a research and testing service operated as a subsidiary of Core Laboratories, showed otherwise, and that "it should clean up better than a guar-based system," according to Tom McLoughlin, Calfrac's manager of technical services and division solutions.

Explaining CalVisc, McLoughlin first sorts frac systems into two broad groups: slickwater and crosslinked. A slickwater system uses a lot of water, high flow rates and a very thin fluid to propagate fractures deep in the reservoir. But the proppant-suspension capacity of slick water fluids is typically limited. So, in the last four or five years, producers have gone to a hybrid system that starts with slickwater and switches to crosslinked, which is a thicker, slower-moving fluid system loaded with proppant.

"The beauty of [CalVisc] is that it can operate as both," McLoughlin says. "You can pump it at a certain concentration, and it's essentially a slickwater system. As you feel the need for higher proppant concentrations, you can increase the loading. For the fellow in the van, it's just a matter of turning a dial, whereas before you would have to monitor pHs and temperatures and time and all this other stuff."

As the CalVisc system becomes thicker, it allows more sand to be carried into the wellbore.

"As you get away from the wellbore, your momentum and velocity slows down. This system has the unique property of getting thicker as it slows down, so essentially it starts to behave as a thicker system as you get farther away from the wellbore," McLoughlin says.

The improvements in production results and reduced fracking time on site are rounded out with associated health, safety and environmental benefits.

"You're saving water, time and logistics, less chemicals, fewer trucks on location and fluid losses," says Gord Milgate, director of operations in Calfrac's Canadian division. "But from an operations perspective, the biggest benefit is reduced complexity. A lot of systems right now are hybrid systems, where you're running slickwater and the guar—depending on the treatment. [CalVisc] is one system."

NEXT STEPS

CalVisc's biggest limitation is that it requires a potable-water source because of its total dissolved solids limit. Leier says Calfrac is working on making it compatible with produced-water to further improve its environmental profile.

Otherwise, CalVisc can be deployed in oil wells, gas wells, vertical, horizontal, plug and perf, ball drop, annular fracturing, zipper frac, on and on. "It all works," Leier says.

Calfrac's technical guidance in deploying CalVisc is part of the value proposition. About four years ago, Calfrac decided to bump up its reputation for service quality into a competitive advantage. So it created the asset enhancement group.

"The mandate of our asset management team is to go deeper," Leier says. "Deeper in the relationship with our customers; engage earlier in the conversation and understand our customers needs better and, therefore, formulate a solution that makes more sense or brings a more productive resolution."

Some customers lean heavily on Calfrac's expertise and collaboratively decide where to place laterals, how long laterals will be and which horizons to ultimately target.

"That's the most beneficial conversation because, yes, we can go in and frac at the back end, but that's just one solution at one point in time," Leier says. "If we can be involved throughout the life cycle, we can guarantee you that the final outcome, which is production, will be more meaningful and better."

PHOTO: CALFRAC WELL SERVICES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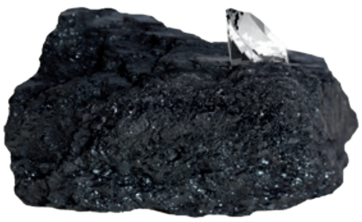


DIAMONDS IN THE ROUGH

Global initiative hopes to cool the planet by capturing carbon emissions and turning them into viable products. Canadians on the leading edge of technology revolution.

BY **DARRELL STONEHOUSE**

It's going to take more than windmills, solar panels and energy efficiency to slow global warming, according to Issam Dairanieh, chief executive officer of CO_2 Sciences, the research and development arm of the Global CO_2 Initiative (GCI). It's also going to take a major effort to tap industrial smokestacks, separate out the CO_2 and permanently remove it from the atmosphere. And if the industry is going to go through the expense, it might as well make some money off it by spinning that carbon into marketable products.

"Conventional wisdom favours strategies like decarbonization and adapting to the impacts of rising temperatures," says Dairanieh. "While these tactics are part of a necessary response, CO_2 Sciences believes carbon capture for reuse to be the complementary market-driven approach we need to keep temperature increases under two degrees Celsius."

In January 2016, GCI was launched to help develop the carbon product industry and commercialize new carbon products using recycled CO_2 as a key ingredient, such as cement, aggregates, chemicals, polymers and carbon fibres. CO_2 Sciences will award research and development funding to qualified research applicants creating innovative technologies. The GCI commercialization arm will work in parallel to accelerate the market for CO_2 products by investing in commercial-stage companies.

As a first step, GCI developed *A Roadmap for the Global Implementation of Carbon Utilization Technologies.* After assessing almost 180 global technology developers on the basis of their technology feasibility, readiness, markets and momentum, initial research has revealed significant progress in CO_2 utilization has been made in 2011-16. The report shows that, through broad scale commercialization of products derived from CO_2, there are sizable market opportunities while mitigating CO_2 emissions.

"Our findings illustrate just how feasible CO_2-utilization technology is for meeting both economic and environmental objectives," says Dairanieh. "Our roadmap identifies tangible actions we can take to further adopt these technologies on a global scale while expanding new opportunities among several markets and industries."

The roadmap says commercialization of CO_2-based products will help mitigate emissions and represents an annual revenue opportunity greater than $800 billion. It identifies four major markets that could potentially be scaled up and are already on the road to commercial production, including building materials, chemical intermediates, fuels and polymers. It adds that "some CO_2-based products are commercially viable today, and investment can be profitable without waiting for policy incentives."

Other technologies need investment, market development or policy support to reach their potential. Increased funding and incentives are necessary for some of the markets to accelerate development and achievement of full-scale capability.

Through carbon-based products, industry has the potential to use seven billion tonnes/year of CO_2 emissions by 2030—the equivalent of approximately 15 per cent of annual global CO_2 emissions, according to the roadmap.

CANADIAN COMPANIES ALREADY ON THE ROAD TO CARBON RICHES

Canadian companies in a variety of industries are already building the carbon products market, spurred on by competitions like the Emissions Reduction Alberta (ERA) Grand Challenge and the NRG COSIA Carbon XPRIZE. The ERA Grand Challenge recently announced its four finalists, while there are nine Canadian companies still in the running for the Carbon XPRIZE.

As a starting point, finding a cheap, efficient way to capture CO_2 from industrial sources is fundamental to creating carbon products. Conventional technology for the capture and production of pure CO_2 from industrial processes usually relies on chemical amine solvents, such as monoethanolamine and piperazine. These, however, require high-grade process heat for solvent regeneration and, therefore, are relatively inefficient and costly.

Quebec-based CO_2 Solutions is using enzyme-based CO_2 capture to attempt to address this issue.

"Our patented technology allows for the efficient capture of CO_2 from large stationary emissions sources such as power and steam generation plants, oil production and refining operations, and cement plants, while leveraging existing gas scrubbing equipment approaches already known to industry," says the company.

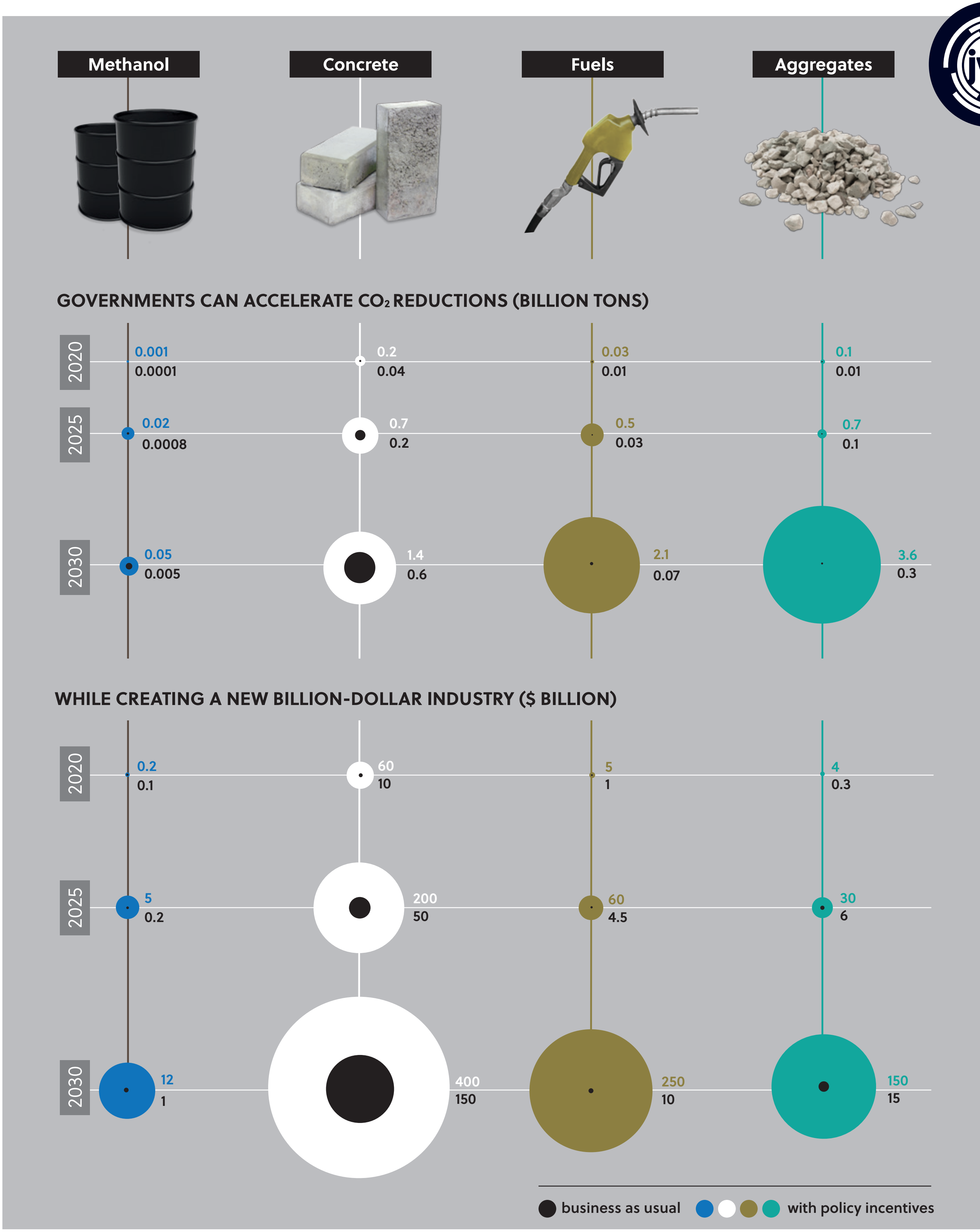
CO_2 Solutions' technology is built around the use of the carbonic anhydrase enzyme that efficiently manages CO_2 during respiration in humans and all other living organisms. Employing a salt-water solvent similar to seawater in combination with the enzyme, the result is what the company calls an "industrial lung" for carbon capture with low operating and capital costs using known equipment infrastructure.

The process captures and produces a highly pure stream of CO_2 that can be reused or geologically sequestrated.

TARGETING THE CEMENT AND CONCRETE INDUSTRIES

With the global cement market manufacturing around four billion tons/year and generating $300 billion in revenues, it is little surprise a number of Canadian companies are targeting this market. Add in the concrete market with 33 billion tons/year produced, and you have a $1.3-trillion industry. But that industry comes with a cost. ►

PHOTO: ©ISTOCK.COM/AYKUTSEVINC



SOURCE: THE GLOBAL CO2 INITIATIVE, CO2 SCIENCES

It produces around five to seven per cent of total global greenhouse gas emissions. The GCI roadmap estimates the market for carbon products in the concrete industry could reach between \$150 billion and \$400 billion by 2030, depending on whether it receives policy, market and technological support. The closely related aggregate business could add another \$15 billion to \$150 billion as technology in this market is not as advanced. If carbon products can meet maximum saturation, the two markets combined could eliminate around five billion tons of emissions.

Nova Scotia–based CarbonCure Technologies is targeting the cement market with a unique technology that reduces greenhouse gases, while also providing significant economic benefits to concrete producers. The technology is currently installed in nearly 50 concrete plants across North America.

The CarbonCure technology uses CO_2 captured from the emissions of local industrial polluters by gas suppliers across the country. This purified and liquified CO_2 is delivered to CarbonCure's concrete producer partner's plants in pressurized tanks where it is injected into wet concrete while it's being mixed. The technology is integrated with the producer's batching system and has no impact on normal operations.

When CO_2 is added to the concrete during mixing, it reacts with water to form carbonate ions. The carbonate then quickly reacts with calcium ions released from the cement to form solid nano-sized calcium carbonate (limestone) minerals, meaning the CO_2 has become permanently bound within the concrete and will never be released back into the atmosphere.

CarbonCure is currently competing in both the ERA and Carbon XPRIZE challenges. It recently advanced to the second round of the ERA competition, receiving \$3 million to continue advancing the commercialization if its technology. "We are grateful for this funding, but what this also means is that Canadian technologies can lead," says Robert Niven, CarbonCure's chief executive officer and founder. "This is an opportunity which is an open race right now, and Canadian companies are certainly leading the charge to be able to take advantage of this new market opportunity."

CarbonCure believes it can cut Alberta's emissions by one megatonne/year and save concrete companies more than \$700 million if its technology is widely accepted.

CHASING THE CHEMICALS MARKET

The GCI roadmap estimates the market for CO_2-based fuels, chemicals and polymers could reach anywhere from \$13 billion to \$290 billion by 2030, depending on development support. Over 2.1 billion tons of CO_2 emissions could be avoided if the market takes off.

Mangrove Water Technologies, a spin-off company from the University of British Columbia (UBC), wants a piece of that market. It is working to commercialize a technology that simultaneously converts CO_2 and saline waste water into value-added chemicals and reusable water. Its economic and environmental impacts could be considerable.

Formed by past and present members of professor David Wilkinson's research group in the UBC's department of chemical and biological engineering, Mangrove is another ERA second-round winner. Mangrove's technology targets CO_2 and saline waste water from oil and gas operations. The technology—an electrochemical reactor equipped with ion-selective membranes—desalinates the waste water and converts the CO_2 into carbonate salts and acids for on-site use by the oil and gas industry.

Easy to operate, transport and scale to industrial levels, the modular technology offers an economical alternative to conventional desalination and CO_2 removal processes.

When coupled with a waste-gas-to-power system, Mangrove's technology could annually remove more than one megatonne of CO_2, or about the annual carbon emissions from 210,000 cars, and conserve more than 11 million barrels of water, or about 770 Olympic-sized swimming pools, in Alberta alone.

While these projects focus on chemicals or chemical precursors, the holy grail of CO_2 products is the fuel market, where the roadmap estimates up to \$250 billion in revenues could be waiting by 2030.

Ontario-based Pond Technologies is chasing that market.

Pond has spent years developing the design, manufacturing and operating protocols for an LED-illuminated photo-bioreactor. The photo-bioreactor is an enclosed tank containing a continuous algae bloom, where rapid algae growth converts industrial greenhouse gas emissions into algae biomass. The algae biomass is then used as feedstock for biofuels in an accelerated replication of natural carbon cycles.

Pond sparges industrial flue gas directly into large photo-bioreactors, whereupon the CO_2 dissolves out of the sparging bubbles and into the aqueous growth medium. Industrial flue gas however, contains much more CO_2 (five to 20 per cent by mass) than the ambient air (0.04 per cent). To make algae grow fast enough to fix that much CO_2, Pond has designed the largest, most energy-efficient LEDs in the world, along with a unique passive cooling system and an associated light distribution system. As these LEDs provide the illumination to initiate and maintain rapid growth, its custom system harvests the algae as it grows, creating a continuous algae bloom.

Algae is one of the fastest-growing organisms in the world, consuming almost twice its weight in CO_2, making it an ideal medium to capture carbon.

The value of algal biomass is in its conversion rate into fuel: one tonne of algae can yield 100 litres or more of diesel. The residual biomass can also be used as a renewable coal substitute.

While the technology isn't yet commercial, in January, Pond and SNC-Lavalin entered into a strategic partnership to develop and deliver Pond's carbon-recycling technology worldwide, and the company hopes this will speed its progress. Together, Pond and SNC-Lavalin will design, propose and construct projects using the technology.

"We believe that the pairing of Pond's technology with SNC-Lavalin's global engineering and project management capabilities will accelerate the deployment of our algae growing platform worldwide," says Steve Martin, Pond's chief executive officer and chief scientist.

FACES OF THE INDUSTRY

Finding a way forward, whatever lies ahead

PHOTOS BY **JOEY PODLUBNY**

AFTER TWO YEARS OF LOW PRICES, political and regulatory uncertainty, and the resulting financial disaster, those that remain standing in Canada's oil and gas industry continue looking ahead, trying to find a way forward in what has become the new normal in the industry.

The five companies profiled in the following pages have each done more than just survive the worst commodity crash in a generation—they have also set the stage to grow no matter what the future holds.

They have done it through shrewd financial management, tight control over costs and managing risks to ensure they were in a position to take advantage of any opportunities that may present themselves.

Two operators profiled made significant acquisitions during the downturn, growing their opportunity base while spreading out fixed costs. All four operators honed their operations down to one or two assets matching their expertise and have focused on driving down costs on those assets.

The lone service company leveraged its access to capital to partner with operators to get its equipment in the field operating and generating revenues.

With higher prices early in 2017, many believe the worst is over for the industry. But the reality is oil prices aren't going back to 2014 levels any time soon, and gas prices, stalled out since 2009, will remain flat for the long term.

The five companies profiled represent the new face of the industry—those willing to find a way forward whatever lies ahead.

CLEAN SHEET

For Birchcliff Energy's **Jeffery Tonken**, success in the midst of a commodity collapse starts with strengthening the balance sheet

BY **DALE LUNAN**

There's a commonality running through Canada's exploration and production community as results from 2016—one of the worst years in the industry's 80-year history—begin trickling in: no matter how far the price of oil falls, a strong balance sheet is critical to weathering the trough.

Many companies still thriving learned this after the last collapse in 2008-09 and have been vigilant since in living within their means and their cash flow. At the other end of the spectrum are the free-spenders: those who spent like drunken sailors when oil was north of $100 and are now paying the piper—or their bankers—with oil hovering around $50.

And somewhere in the middle are a host of companies—many of them large juniors or small intermediates—who were cautious coming out of the 2008 recession but still found themselves in need of a balance sheet brushing-up as prices stayed lower for longer.

Birchcliff Energy is one of those. In the middle of the intermediate pack at around 50,000 boe/d of production in 2016, Birchcliff weathered 2016 by shutting down drilling early in the year, as WTI tanked below US$35/bbl, and returned cautiously to the field in the summer, as crude struggled back to around US$50/bbl. But it also kept its eyes open for worthy asset acquisitions, says JEFFERY TONKEN, president and chief executive officer, knowing that as times got tougher, bid-ask spreads would narrow and some gems might become available.

"Back in January and February of 2016, when the industry was in total collapse, we cut our capital budget, stayed focussed on just drilling Montney/Doig natural gas wells and took the opportunity to buy an asset from Encana," he says matter-of-factly. "Encana, like all the big oil and gas producers, saw its stock just cave, and suddenly they were carrying too much debt, so they had to sell some assets. They chose to sell the Gordondale asset, which happens to sit right between two of our major properties."

The $625-million all-cash transaction, which Birchcliff characterized as "transformational," was struck in June 2016 and brought with it 64 net sections of Montney rights in the heart of Birchcliff's core Pouce Coupe/Gordondale area north of Grande Prairie, Alta.

"They are acquiring an excellent complementary Montney asset base within the company's existing core area at very attractive metrics," Darrell Bishop, head of research at Haywood Securities, told the *Daily Oil Bulletin* when the deal was announced. "The synergies that exist between Birchcliff and the Encana Gordondale area are significant. They're basically identical assets side by side. Identical in terms of geographic area but also in terms of some of the horizons that are being developed there."

While Tonken recognized the excellent fit of the deal, he also recognized that Birchcliff itself was a bit over-extended on the debt side of its balance sheet, so it would have to structure the acquisition as a cash deal—meaning it had to raise new equity to support the bid. A syndicate comprised of National Bank, GMP Securities, Scotia Capital and Cormark Securities led an equity issue that ended up raising $690 million, enough to pay for the acquisition with some left over to pay down existing debt.

"It was incredible at $6.25, but the effect of it was that it took our production from roughly 40,000 to 63,000 bbls/d, but by raising that much equity, we totally de-levered our balance sheet because we added 23,000 bbls/d with no debt plus we raised an extra $65 million to reduce our debt," Tonken says. "When the smoke cleared, we had de-levered our balance sheet [and] increased the size of the company. And now the Gordondale property, which is an excellent property, gives us the ability to drill more Montney oil wells versus the Montney gas wells that we have at Pouce Coupe."

With a lot of new running room at Gordondale—more than 5,700 new drilling locations as of the end of last year—Birchcliff has more than doubled its capital program this year, to $355 million from about $167.5 million in 2015, and plans to drill and tie in 46 new horizontal wells, mostly at Pouce Coupe and Gordondale, and complete, equip and tie in another 10 wells drilled last year. Production is expected to average 80,000 boe/d in the fourth quarter this year, while current guidance suggests annual average production this year will be somewhere in the 70,000–74,000-boe/d range.

But none of it, Tonken says, would have been possible if Birchcliff hadn't been mindful of living within its means and strengthening its balance sheet whenever possible.

"If you are a low, low, low–cost producer and you have no debt, then it is just a question of how much money you're going to make when you have a repeatable business like the Montney/Doig natural gas play," he says. "Where everybody runs into trouble is they ramp up their production, way out-spend their cash flow, and then commodity prices tank or you get a new government or you get new taxes or some black swan event happens that you don't see coming, and all of a sudden that debt becomes a problem. Our goal is to take that away so our shareholders don't have that concern."

"WHERE EVERYBODY RUNS INTO TROUBLE IS THEY RAMP UP THEIR PRODUCTION, WAY OUT-SPEND THEIR CASH FLOW, AND THEN COMMODITY PRICES TANK OR YOU GET A NEW GOVERNMENT OR YOU GET NEW TAXES OR SOME BLACK SWAN EVENT HAPPENS THAT YOU DON'T SEE COMING, AND ALL OF A SUDDEN THAT DEBT BECOMES A PROBLEM."

— **Jeffery Tonken**, president and chief executive officer, Birchcliff Energy

"WE BOUGHT MOST OF OUR LAND AT AROUND $1,100/ACRE AS OPPOSED TO AS MUCH AS $5,000/ACRE FOR SOME OF THE OTHER ACQUISITIONS IN THE AREA. WE HAVE AN OPPORTUNITY TO REALLY GROW SHAREHOLDER VALUE OVER A LONG PERIOD OF TIME."

— **Stacy Knull**, president and chief executive officer, Saguaro Resources

BIGGER, FASTER

Not even five years in, **Saguaro Resources** is already testing the intermediate waters

BY **DALE LUNAN**

As far as first impressions are concerned, Saguaro Resources is considered a privately held, emerging producer, initially capitalized in late 2012 with annualized average production that has grown from 117 boe/day that year (just two months) to a bit under 7,100 boe/day last year.

But those are first impressions. Dig a little deeper, and you'll find an "emerging" producer that is now, in early 2017, a growing intermediate with production averaging more than 12,000 boe/day, 160 sections of 100 per cent working interest land in the liquids-rich fairway of the Montney in northeastern B.C. and enough de-risked drilling locations to reach 140,000 boe/day within the next 10 years.

According to **STACY KNULL**, Saguaro's president and chief executive officer, the company is fortunate in that it derives a large portion of its revenues—more than 40 per cent in the third quarter of 2016—from high-value condensate. Most of the rest is propane and butane, and dry gas and crude oil make up only seven per cent of its revenue stream.

"Condensate has been less volatile than oil—the lowest it ever fell to was about $38, and right now it's around $70, so we've always been able to generate good shareholder returns, and we've always been cautious with our capital program," Knull says. "We can stop and start pretty easily."

Saguaro acquired most of its B.C. Montney real estate in 2013, when Crown sales were deep in the tank, Knull says. This gave the company a running start on making money from modest drilling programs those first couple of years.

"We bought most of our land at around $1,100/acre as opposed to as much as $5,000/acre for some of the other acquisitions in the area," he says. "We have an opportunity to really grow shareholder value over a long period of time."

Serious drilling began in 2014, with a 13-well program that was part of a $187-million capital program that also saw the development of a 35 mmcf/d compression/dehydration facility. The company has since expanded the facility to 60 mmcf/day and procured the equipment to expand to 100 mmcf/day.

Drilling slowed a bit in 2015 as commodity prices cratered, and the company drilled only six wells, but activity picked up again in 2016 with 12 more wells drilled. Going forward, Saguaro's development plan is predicated on a six-bcf type curve characterized by 2,000-metre laterals on relatively shallow (1,400–1,900-metre) wells.

Because the wells are shallow and because Saguaro is constantly tweaking its completions program, drilling and completion costs have fallen steadily in the last couple years, from about $7.2 million per well prior to the start of the full development program in 2015 to a budgeted $4.8 million per well for the 28 wells contemplated in the 2017 capital plan. That should take production by the end of this year to around 16,000 boe/day, and because much of this year's drilling will take place late in the year, production by the end of 2018 could surge to around 26,000 boe/day, Knull says.

The 2017 capital program will likely be funded from additional borrowing facilities the company is hoping to nail down. In the past, Knull says, Saguaro's been "fairly allergic" to debt, but now with reserves climbing steadily, he feels its appropriate to gradually boost its reserves-based borrowing.

"Our reserves grew from about 108 million boe at the end of 2015 to 235 million boe in September last year and to about 270 million boe by the end of 2016," he says. "That underpins our value, which underpins our ability to take on a little bit more debt and still stay below a two times debt-to-cash-flow ratio."

Saguaro is currently running its production through any of three third-party processing facilities, where it has contracted firm service of 40 mmcf/day and where "substantial" interruptible capacity is also available. But it's also contemplating building its own full processing facility and is eyeing participation in various third-party infrastructure initiatives.

"We really have no concerns on infrastructure—we're not thinking five or 10 years out, we're thinking 40 years out," Knull says. "We're not big enough to drive the [TransCanada] Mainline to Ontario or the Spectra system all the way down to the west coast, but where we are at, we have access to possibly as many as five midstream plants, so we have a lot of flexibility."

Saguaro's full development plan contemplates running one rig for most of this year to drill 28 wells, but ramping activity steadily higher starting in 2018, when two rigs and more than 35 wells are planned, continuing in 2019 with three rigs and more than 50 wells and 2020 before levelling off in 2021, when five rigs will be used to drill more than 80 wells per year. By then, production should be around 75,000 boe/d and well on its way to more than 125,000 boe/d by 2025.

FLEXIBLE FINANCING

Bilal Hydrie's storage tank business prospers by creating opportunity

BY **R.P. STASTNY**

B

Buy low, sell high.

That's one philosophy **BILAL HYDRIE** has employed to grow equipment supplier Inclusive Energy through the oil industry downturn.

"This year we spent between $8 million and $10 million on equipment," says Hydrie, president and chief executive officer of Inclusive Energy. "On all that equipment, we paid 30–40 cents on the dollar. As soon as things start picking up, there will be a good return on our money."

Surplus storage tanks and equipment accounts for about 75 per cent of Inclusive Energy's revenues today. Hydrie says there's about $25 million of equipment sitting in three Inclusive Energy yards across Alberta. Good prices, great service and in-house financing—from rent-to-own-agreements to share-in-production joint-venture arrangements—keep things moving, even though revenues are half what they were in 2014.

So how do you make $10 million of equipment purchases and joint-venture investments during a downturn?

The answer is private equity. Hydrie comes from the family that controls the Habib Group, a 100-year-old enterprise with businesses in banking, insurance, manufacturing and trading of refined sugar, ethanol, CO_2, textiles and automotive products. It employs some 30,000 people around the world.

"So if a customer needs funding for their projects, we can also fund up to $10 million in a joint venture," Hydrie says. "We recently did that with one company in Lloydminster. It's a disposal facility. We supply all the equipment and take care of the [licensee liability rating], and once the company starts generating cash flow, we can start getting royalties and a return on our money."

Access to capital is Inclusive Energy's competitive advantage, but that shouldn't take anything away from Hydrie's business skills and hard work in building the company.

After graduating from SAIT Polytechnic with a chemical engineering diploma, he worked in Alberta's oil and gas industry for a few years. He heard talk of a growing market niche in western Canada for storing and transporting industrial fluids as the industry shifted to resource play production and saw first-hand the inefficiencies in storage tank fabrication—slow turnarounds on orders, inflated costs and financial inflexibility. So, in 2009, he decided he could do better.

Inclusive Energy's formula was to offer a one-stop shop. Design, custom fabrication, delivery, set up, repair and reconditioning of existing equipment, sales of new and used equipment—and, of course, financing if needed.

The company found its niche and business grew. Then oil prices collapsed in 2014, but Hydrie, a true businessman, refused to see the downturn as anything but another opportunity. Inclusive Energy cut its overhead, adapted to weather the storm and set itself on a path to prosper in the recovery.

"In 2008, people started panicking, went out of business. But by 2012, oil prices were back above $100. Those people who didn't explore opportunities are still out of business. People who took on the risk and hung on have done amazing," he says.

Each downturn plays out differently, and this one may still take a little longer, Hydrie concedes, but "you just have to have patience."

Patience. You don't always hear that advice from a young man looking to make his mark in the world. But there's more than money standing behind Hydrie. A *Business in Calgary* profile from September 2016 has Hydrie quoted as saying, "All the deals go through [Hasnain Habib, the chair of Inclusive Energy]…. He is my greatest mentor and has the greatest experience in the industry and international businesses, several of which he is managing himself."

That network of business mentors and associates are additional resources that have guided Hydrie to diversify into wider business interests. He is an independent director of Pennine Petroleum, a TSX-listed company planning to explore opportunities in Albania. As director of North American operations for the Habib Group, Hydrie has access to sophisticated private investors in the Middle East. Hence, Hydrie is also the executive director of Global Centurion Investments.

"We put together a very large fund for Alberta only that's $25 million. It's all private money. No public money involved. We're looking for great opportunities to invest that money. We're looking at all different sectors, whichever makes sense," he says.

"SO IF A CUSTOMER NEEDS FUNDING FOR THEIR PROJECTS, WE CAN ALSO FUND UP TO $10 MILLION IN A JOINT VENTURE. WE RECENTLY DID THAT WITH ONE COMPANY IN LLOYDMINSTER. IT'S A DISPOSAL FACILITY. WE SUPPLY ALL THE EQUIPMENT AND TAKE CARE OF THE LICENSEE LIABILITY RATING, AND ONCE THE COMPANY STARTS GENERATING CASH FLOW, WE CAN START GETTING ROYALTIES AND A RETURN ON OUR MONEY."

— **Bilal Hydrie**, president and chief executive officer, Inclusive Energy

EYES ON THE PRIZE

Black Swan does one thing—liquids-rich gas—and it wants to do it very well

BY **DALE LUNAN**

In just a few years, privately held Black Swan Energy has built a dominant position in the liquids-rich, over-pressured Upper Montney fairway in northeastern B.C., comprising some 341 sections of contiguous rights and an in-place resource estimated at some 78 tcf.

In the last two years, it has nearly quadrupled its production of high-value, liquids-rich gas to a 2016 exit rate of 16,500 boe/d from 4,300 boe/d in the fourth quarter of 2014. And, according to president and chief executive officer **DAVID MADDISON**, it has a clear line of sight to 100,000 boe/d in five years, as long as it keeps its eye firmly on the bottom line.

"We are a single-asset Montney producer with liquids-rich gas, and the liquids provide 40 per cent of the revenue for gas that goes through our own operated infrastructure," he says. "Our strategy is to be operationally excellent, so we're looking to be low cost on every area of the cost structure."

Driving Black Swan's growth is a robust asset that has, over the past couple dozen wells, delivered estimated ultimate recovery rates averaging nine bcf per well, with some as high as 11 bcf. At the same time, the company has consistently worked to reduce its drilling and completion costs to $4.1 million in 2016 from $6.4 million in 2014, adding 17,500 boe/d per rig while running one rig that drills 20 wells a year.

All of that, Maddison says, adds up to "pretty healthy" half-cycle economics yielding an internal rate of return—based on the nine bcf type curve—of nearly 80 per cent at US$50/bbl WTI and C$2.50/gigajoule AECO.

With a string of wells that exceeded expectations in 2016, Black Swan commissioned its first wholly owned gas plant at North Aitken Creek in January and expects to commission a 60-mmcf/d expansion in June that will bring capacity to 110 mmcf/d. A second plant—200 mmcf/d—is currently in the engineering stages, with the first phase expected to be commissioned late in 2018, depending on takeaway capacity developments between now and then, Maddison says.

"All three mainline systems—Spectra, Alliance and TransCanada—cut right through the heart of our acreage, and we already flow on both Spectra and Alliance," he says. Black Swan led an industry initiative to develop the Aitken East Pipeline, which would deliver 500 mmcf/d of capacity to the AECO hub, and has had discussions—cloaked in a confidentiality agreement—with TransCanada on other options.

"There is quite a bit of competition coming from the supply in that area, so that gives us the confidence that we will ultimately have a solution to get our gas to market," Maddison says. "The big question will be around timing."

In 2016, when many producers were shutting down capital programs in the face of sub-$40 oil, Black Swan maintained a presence in the field, spending $39 million (and another $50 million on infrastructure) to drill eight horizontal wells, complete eight more and tie in another 16.

This year, its capital spend will double to $180 million ($92 million on infrastructure), with a plan to drill 19, complete 16 and tie-in 16 horizontal wells. And it can easily sustain an even greater activity level, Maddison says, with more than 2,800 defined Montney drilling locations in its inventory.

Like many other producers in western Canada, Black Swan is continually tweaking the design of its wells, but it goes about the process a little more methodically than most. The company makes one change on each multi-well pad and then applies those changes to wells that are oriented in one direction but not the other.

"That really gives us the best possibility of understanding more precisely the impact of each particular change," Maddison notes. Most recently, Black Swan has moved to longer

"OUR STRATEGY IS TO BE OPERATIONALLY EXCELLENT, SO WE'RE LOOKING TO BE LOW COST ON EVERY AREA OF THE COST STRUCTURE."

— **David Maddison**, president and chief executive officer, Black Swan Energy

[Pictured: The Black Swan Energy team with Maddison third from left.]

laterals—2,500–2,600 metres—but it hasn't actually completed any of those yet, so the jury's out on whether the longer laterals will stick.

And the company has been equally innovative in managing its water requirements, spending $10 million on the water infrastructure required to remove and move water from the Beatton River, which bisects its Montney holdings, under what is believed the first licence awarded early last year under B.C.'s new Water Sustainability Act. The system gives Black Swan enough water to support up to 100 wells per year and production of 100,000 boe/day.

The infrastructure consists of 1.5 million barrels of fresh water storage, a permanent intake facility on the shores of the Beatton River and a network of temporary surface hoses to move the water from any of four storage pits to active well pads.

"That allows us to base our pad locations on economic factors, such as liquids yields, surface siting considerations and reservoir considerations, rather than being tied to specific sites because of any water infrastructure that you've put in," Maddison says. "It's a very cost-effective approach for us, and at this point in our evolution, we're able to recycle 100 per cent of our produced water as well."

LIGHTEN UP

With a strategic acquisition at the bottom of the crude price trough, **Gear Energy** spreads its risk by investing in a lighter barrel

BY **DALE LUNAN**

A Canadian oil and gas sector particularly scarred by the collapse in crude oil prices through 2015 and 2016 was the emerging producers, those tiny start-ups that could once get a toe-hold with a couple million dollars of capitalization but these days need 10 times that seed money, what with the expense of horizontal wells and hydraulic frac completions.

And among those emerging producers, one of the hardest hit was Gear Energy, a predominantly heavy oil producer active in the border area between Alberta and Saskatchewan that saw not just WTI collapse in 2015 and 2016, but the Western Canadian Select–WTI differential, on which most of its heavy crude output is priced, widen to as much as 50 per cent.

Early last year, as WTI drifted below US$30/bbl, Gear found that it was realizing just C$17/bbl for its heavy oil—a situation president and chief executive officer INGRAM GILLMORE says was certainly unsustainable.

"If it wasn't for some good hedging contracts, we would have had negative cash flow," he says.

In light of those economics, Gear did what many emerging and junior producers did—it halted drilling and dedicated what little cash flow it did have to reducing debt, essentially what it had done in 2015, when prices initially collapsed following Saudi Arabia's decision in the fall of 2014 to protect market share, raising production.

Net debt in the first quarter last year was in excess of $60 million, which for a company that had cash flow in the same period of less than $4 million was a scary proposition indeed—for the company's leadership team and for its bankers, Gillmore admits.

"Our banks—and a couple of them in particular—were getting very fidgety, which was pretty common in the junior energy space, so we were quite concerned in February of 2016 that we might be thrown into default by our banks," he says. "It was a super stressful time: we had already cut salaries, we cut staff [by one-third], we cut everything you could think of until we sat back one day and said the only thing that would ensure our survival was to get oil prices back up again."

Fortunately for Gear—and for many of its peers—global crude prices began to recover a bit in the second quarter of 2016, and by the summer, WTI was back up to around US$50/bbl, which for a company that has a few plays that are economic at US$40, was good news indeed.

"The good news is that oil stabilized a bit," Gillmore says. "We had raised some money in 2015 that helped us get through, and then coming into the spring, this transaction showed up, and I'm wondering why it showed up."

"This transaction" was the acquisition of Striker Exploration, a predominantly light oil producer active in west-central Alberta with what seemed to be "really decent assets" in the emerging Belly River light-oil resource play at Wilson Creek, but with a board of directors, Gillmore surmised, that lacked confidence in the existing management team to successfully monetize those assets.

The Striker assets—90 net sections of land and about 2,000 boe/day of 60 per cent light and medium oil production—were acquired via a share exchange valued at about $64 million. Concurrently, Gear entered a bought-deal financing with a syndicate led by Peters & Co. that provided about $20 million, which was used to pay down outstanding debt and free up future debt capacity to help fund the combined company's capital spending initiatives.

Taken together, the acquisition and the financing served to significantly alleviate the concerns of Gear's "fidgety bankers," Gillmore says.

"The good news is that, through the course of that, we had gotten our outstanding bank balance down to a much more appreciable level, and we actually ended up renegotiating a new lead bank," he says. "ATB had been our second; they took over the lead, and I think we were the first, if not the only, energy company that they took a lead on in 2016. We were able to convince them that we were the company to back—we had good downside production, and we had good upside potential."

Although the Striker deal brought 50 or so light oil drilling locations, Gear will continue this year to focus the majority of its $45-million capital budget on its heavy oil properties at Wildmere in Alberta and Paradise Hill and Hoosier in Saskatchewan. But the Wilson Creek prospects, Gillmore says, won't be ignored and will likely gain importance as Gear grows.

"We've had six years to develop inventory in heavy oil country and six months in the light oil assets," he says. "That being said, however, our light oil assets are nice and focused so we are going to spend about 35 per cent of our drilling budget on the light oil [seven wells] and about 65 per cent on the heavy [31 wells]."

And that, he says, will give Gear a lighter barrel by the end of this year, with heavy dropping to about 60 per cent of total production and light climbing to about 25 per cent.

"WE WERE ABLE TO CONVINCE [ATB] THAT WE WERE THE COMPANY TO BACK—WE HAD GOOD DOWNSIDE PROTECTION, AND WE HAD GOOD UPSIDE POTENTIAL."

— **Ingram Gillmore**, president and chief executive officer, Gear Energy

Fluor looks to dramatically drop oilsands facility costs with Zero Base Execution

By Deborah Jaremko

ZBE ensures the facility and the execution of the project is safe; meets all of the applicable regulations; and is operable, maintainable and reliable while delivering the most capital-efficient solution for owners.

Fluor flipped the paradigm on how major projects use modules with its award-winning 3rd Gen Modular Execution℠ approach, and now the company is using that experience—of how to effectively make such a step change—to flip the script once again.

Fluor's Zero Base Execution℠ or ZBE℠ is being used successfully all over the world to provide dramatic reductions to the cost of facilities while improving schedule certainty. In Alberta, that expertise is being applied to help enable future growth in the oilsands, says Bernie Moore, Fluor's Executive Technical Director – In Situ.

"We are finding in this low oil price market that business as usual, even when tweaked somewhat, is not getting our clients the project economics they need. More so, the capital efficiencies required in this market aren't being achieved through applying slight improvements or incremental changes—it requires something more," Moore says.

Fluor's ZBE enables that step change.

ZBE aligns the design and execution premise, project's drivers and economic needs before design work begins. Project teams assess and align with the client's business case before defining the project's minimum requirements and what a facility looks like that meets those minimum requirements. This offers much more in terms of overall capital efficiency gains than the current industry approach, where companies look to achieve big improvements through tweaking existing designs.

"When we define the minimum requirements, we ensure three things: the facility and the execution of the project has to be safe; it has to meet all of the applicable regulations; and it has to be operable, maintainable and reliable," Moore says.

Fluor's ZBE is not to be confused with industry value improvement practices. It is rather an ongoing holistic assessment of the execution of the complete project life cycle and is centred on four key concepts: *Minimum Kit Design*; *Reduced Quantities*; *Low-Cost Sourcing*; and *Better-Build Approaches* that leverage Fluor's worldwide network and suite of innovative tools for engineering, procurement, fabrication and construction.

During engineering, the minimum requirements are driven by *Minimum Kit Design* and *Reduction in Quantities* using various techniques such as process configuration and the application of 3rd Gen Modular Execution, while zero-base procurement is achieved through *Low-Cost Sourcing*. Fluor's application of its *Better-Build Approaches* allow its clients to realize the zero-base benefit during fabrication and construction; one such example is the use of Fluor's integrated scaffolding solution.

Moore reiterates, "Fluor looks at every opportunity throughout each phase to reduce project cost while ensuring that those minimum requirements are met, as well as any other non-negotiable commitments the client may have.

"Once we have identified the absolute minimum, then only do we evaluate and include value additions where they are justified and whether our clients have available capital to do so. So it's about starting with the absolute minimum and then adding on value components through a proper deliberate analysis.

"There is a cultural change that has to be implemented by both Fluor and our clients. Our people have learnt that the design approaches and execution concepts we used before have to change or improve to go forward, and their counterparts on the client side have to recognize and buy into the same thing," he says, which we are seeing, he adds.

But Moore says the most important component of the company's ZBE approach is not the "what" but the "how."

"It's one thing to say you need to flip the paradigm, but with the ZBE approach we've learned how to actually implement that new paradigm and, just as importantly, how to make sure that we don't default back to old paradigms when things get tough."

That step change through ZBE allows owners to deploy their capital in a way that meets project economics hurdles and maximizes their return on facility investments thus allowing continued growth in a low oil price market.

PHOTO: BP

SPECIAL REPORT

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PHOTO: JOEY PODLUBNY

RETHINKING OILSANDS MODELS

BY **DEBORAH JAREMKO, JWN OILSANDS EDITORIAL LEAD**

The oilsands industry entered its milestone fiftieth year of commercial operations challenged by global oil abundance, low prices and tightening environmental restrictions.

Just over two years ago, about one million bbls/d of oilsands production capacity was under construction. As the industry rolls toward 2018, capacity under construction will drop to just over 100,000 bbls/d.

While the installed base of capacity—which is now nearly three million bbls/d and larger than that of many countries—offers significant business opportunities and public benefits, the relative lack of new projects in the queue is a fundamental shift for an industry that has been in a near-constant state of build for almost 20 years.

While the world is undergoing a transition to lower carbon energy sources, projections are that demand for fossil fuels and specifically oil will continue for decades into the future. Analysts with McKinsey & Company recently forecast that by 2030 oil producers around the world will need to add 35 million bbls/d of new production capacity to meet demand.

The question is what role Canada's oilsands will play in that growth.

Dramatic changes are required in capital and operating costs as well as greenhouse gas emissions in order to enable oilsands projects to compete for new investment dollars with other shorter-cycle global plays like U.S. shale oil.

Technology is believed to be the answer, and a great deal of work is underway on developing and implementing the systems that will lead the oilsands into a new wave of build.

This special report details the challenges the oilsands industry is facing, the solutions it is chasing and their relative prospects for success.

STR

Following recent deals, three Calgary-based companies will operate all of the oilsands industry's mining projects as well as the majority of in situ facilities.

PHOTO: JOEY PODLUBNY

ENGTH to carry on

Canadian companies have the capacity to finance and execute oilsands projects, but a reduction in players could mute the industry's future

BY **CARTER HAYDU**

Around 410 AD, a weakened Roman Empire withdrew its forces from Britannia to preserve its own embattled homeland. As barbarian invaders encroached on the undefended territory, many Britons must have wondered just how their island could possibly survive without Rome's support.

Likewise, as contemporary global supermajors appear to be stepping back from oilsands ownership positions, many are wondering how the sector will proceed with less foreign investment and whether Canadian companies can finance oilsands developments on their own.

"We're definitely seeing a shift in investment in the oilsands whereby a lot of the multinationals are divesting of their oilsands assets, and Canadian oilsands producers are taking increased positions in the oilsands," says Ben Brunnen, vice-president, oilsands with the Canadian Association of Petroleum Producers.

The late March announcement that Cenovus Energy will spend $17.7 billion to take full ownership of SAGD assets from its former partner ConocoPhillips follows a number of recent major deals, including Canadian Natural's $12.7-billion acquisition of a majority stake in the Athabasca Oil Sands Project from Shell and Marathon and Statoil's sale of in situ assets to Athabasca Oil, valued up to $832 million.

Canadian companies appear to be doubling down in the oilsands as foreign multinationals pull away, Brunnen says. But while there is an economic shift, he believes there is continued financial interest in oilsands investments.

"The Canadian companies are raising their capital from the same types of markets as are the foreign companies, and so the capital is still interested because the oilsands generates returns. It's just these types of investment require a particular type of investor," he says.

"We're talking about upfront, significant capital costs, but not necessarily high sustaining costs. Over a long time period, there is a long-term payout. Each company is a bit different with its corporate strategy. In the Shell example, its corporate strategy is moving to a long position on gas."

Fifteen years ago, the world thought it was running out of oil; however, technology has changed the oil dynamic from scarcity to apparent abundance, notes Kevin Birn, senior director of North American crude oil markets at IHS Markit.

While abundance may wane as conventional reserves decline and oil demand grows, for now companies are tilting portfolios and ▶

shifting asset bases to match changing investment perspectives. This impacts the oilsands.

"If you have fewer players in the field, then there may be less capital as a whole," Birn says.

"You may set yourself up for more modest periods of growth than in the past. I think the exiting of the majors is maybe more a confirmation of what people saw happening already."

Fortunately, he adds, Canadian producers are now of a scale where they can finance oilsands projects on their own.

"It was always a story dominated by Canada, and it will continue to be one. Those companies are now much, much bigger than they were in the past as well. It's a different dynamic. They are more capable of executing on projects than they were 10 or even five years ago. They are more capable of growing organically from their base and through their cash flow than they were in the past."

In 2014, IHS published a report showing that firms headquartered in Canada already controlled 55 per cent of oilsands production in 2012, and Canadian interests held 30 per cent of equity. As for foreign investment equity, the report showed 54 per cent came from U.S. citizens, while U.S.-based corporations accounted for 29 per cent of production at the time.

"We had the U.S. dominating, whereas Asia and Europe, in terms of equity, were under 10 per cent individually each. The oilsands is really a story of North American investment, but during the boom you did see companies like Statoil, Total and Shell additionally enter the oilsands specifically," Birn says.

JWN analysis shows that, following the recent deals, Canadian-headquartered companies will own about 80 per cent of oilsands production.

Many global companies are refocusing mobile capital into core operating areas, such as Statoil to its backlog of deepwater projects, says Wood Mackenzie analyst Stephen Kallir. On the flip side, he adds, Canadian firms like Canadian Natural Resources, MEG Energy, Suncor Energy, Imperial Oil and Cenovus Energy are entrenching into core oilsands operating areas.

> **"IT WAS ALWAYS A STORY DOMINATED BY CANADA, AND IT WILL CONTINUE TO BE ONE. THOSE COMPANIES ARE NOW MUCH, MUCH BIGGER THAN THEY WERE IN THE PAST…. IT'S A DIFFERENT DYNAMIC."**
>
> — **Kevin Birn**, senior director of North American oil markets, IHS Markit

"A lot of things can change, and a lot of the foreign investment we saw through the early 2000s was part of a drive for reserves replacement. That's what the market wanted, and that's what a lot of these companies were trying to do—they were trying to bolster their reserves," Kallir says.

"Now the climate has changed somewhat. There is more focus on shorter-cycle-time, higher-return plays."

Clearly, some Canadian oilsands producers have the finances to develop major projects on their own, says Martha Hall Findlay, president and chief executive officer of the Canada West Foundation. However, the country's capital market is small, and there is an investment limit Canadian companies alone can achieve.

"This is not just oilsands; it's all across Canada. We've been a beneficiary of foreign investment throughout the last couple of hundred years because we aren't that big," Hall Findlay says.

Foreign investment brings cash, gains in technology and expertise, and reduced risk as companies assume some responsibility.

"If we see a significant decrease in foreign investment in the oilsands, then that is a problem," Hall Findlay says.

One of the regulatory uncertainties potentially dissuading foreign investment in the oilsands is carbon pricing and the rhetoric of those who oppose its implementation in Canada and Alberta, she adds.

"Whether or not you agree with carbon pricing, the worst thing from a foreign investment perspective is pendulum policies," she says, adding that it would damage foreign investment across the economy if the next governments tried to reverse such policies federally and provincially.

"Foreign investors need certainty. They would rather have [a carbon tax] in place and know what they are dealing with for the next while, rather than uncertainty."

While the oilsands is receiving less financial attention than it once had as shorter-cycle U.S. tight oil dominates the landscape, Canada's massive resource potential remains a strong investment target, Birn notes.

The industry is also reducing its costs and carbon emissions. Interesting to note: Shell is retaining a 10 per cent stake in the Athabasca Oil Sands Project and will continue to be operator of the Scotford Upgrader and associated Quest carbon capture and storage project.

Increased Canadian oilsands ownership can be an overall positive for Canada's energy sector as fewer returns leave the country, notes Kallir.

"What you have now is the bulk of [Canadian Natural's] portfolio and the bulk of their future growth based in Canada, and so there will be a lot of money initially used to develop plays elsewhere in the world now being reinvested back into Canada," he says, adding that, for example, Shell has used oilsands cash flow to finance growth opportunities elsewhere.

"It's an important point to remember—a lot more of that money will now stay within Canada, reinvested into Canadian resources, which provides an obvious benefit for the country."

As foreign supermajors reduce their oilsands exposure, Canadian companies can avail themselves of cost reductions through process streamlines and facility optimization, Brunnen says. "It's actually a great opportunity for oilsands companies to optimize, reduce their costs and find efficient ways to expand, which is exactly what they're doing."

To the extent increased Canadian oilsands ownership enables enhanced Canadian head-office capacity and head office-related functions, such as legal and financial services, more domestic ownership is a benefit carrying positive spinoffs for the economy, notes Hall Findlay.

"However, if it does limit overall investments because [Canada] just doesn't have a big enough capital market, and we end up with net less investment, then that is a downside," she says.

When a major company sells assets in a particular region, it is likely prioritizing investments elsewhere, says Birn. For Shell, a cultural shift to gas required divestment targets that included the oilsands.

"We're still going through a volatile period. I think there are still lots of things shifting around globally in the oil markets. We do see a lot of deferral to non-operators or reliance on Canadian-based companies to operate oilsands projects and to rely on that expertise and teams on the ground," he says.

According to Brunnen, future oilsands investment requires regulatory streamlining and effectiveness, as well as competitive financial terms and certainty. Recent federal and provincial policy changes add above-ground investor risk, he says, and policies must be firm and communicated well to foster investor confidence.

"When we see the U.S. move towards expanding and encouraging investment and deregulating their sector, Canada will not be immune to those changes," he says. "While we're proud of our responsible and highly effective regulated environment, we do need to make sure whatever we do here in Canada keeps us in competitiveness footing."

Not unlike medieval Britain, perhaps, which endured and survived after the fall of Rome, the oilsands must evolve with less foreign ownership from supermajors. However, as Britannia would eventually grow in power and influence until forming a mighty empire of its own, so too might a predominantly Canadian oilsands thrive for many, many years.

Canadian oilsands production ownership: The new landscape

This Alberta Energy Regulator-adjusted data envisions what production numbers and ownership would have been in December 2016 if the transactions were closed for Canadian Natural Resources' oilsands acquisitions from Shell and Cenovus Energy's acquisition from ConocoPhillips.

Athabasca Oil's purchase of Statoil's Leismer project is already closed and also reflected.

		DECEMBER 2016 (BBLS/D)	CANADIAN OWNERSHIP (%)	CANADIAN-OWNED PRODUCTION (BBLS/D)
Thermal in situ bitumen production				
Suncor Energy	Firebag	201,160.7	100	201,160.7
Imperial Oil	Cold Lake	159,114.0	100	159,114.0
Cenovus Energy	Christina Lake	184,648.1	100	184,648.1
Cenovus Energy	Foster Creek	166,151.0	100	166,151.0
Devon Canada	Jackfish	118,231.5	0	0
ConocoPhillips Canada	Surmont	108,257.1	0	0
MEG Energy	Christina Lake	78,933.4	100	78,933.4
Canadian Natural Resources	Primrose & Wolf Lake	90,039.3	100	90,039.3
Canadian Natural Resources	Kirby South	38,679.2	100	38,679.2
CNOOC	Long Lake	36,374.0	0	0
Suncor Energy	Mackay River	33,936.0	100	33,936.0
Husky Energy	Sunrise	34,868.8	50	17,434.4
Athabasca Oil	Leismer Demonstration	22,994.3	100	22,994.3
Husky Energy	Tucker	21,784.8	100	21,784.8
Pengrowth Energy	Lindbergh	15,189.3	100	15,189.3
Connacher Oil and Gas	Great Divide	10,388.9	100	10,388.9
Athabasca Oil	Hangingstone	8,675.5	100	8,675.5
Osum Oil Sands	Orion	7,968.6	100	7,968.6
Canadian Natural Resources	Peace River/Carmon Creek	5,170.2	100	5,170.2
BlackPearl Resources	Blackrod	520.8	100	520.8
Sunshine Oilsands	West Ells	710.7	100	710.7
Penn West Petroleum	Harmon Valley South Pilot	47.8	100	47.8
Japan Canada Oil Sands	Hangingstone*	---	---	---
TOTAL THERMAL IN SITU		1,343,844		1,063,547
Mined bitumen production				
Suncor Energy	Base Operations	258,635	100	258,635
Canadian Natural Resources	Horizon	211,733	100	211,733
Canadian Natural Resources	Athabasca Oil Sands Project	253,781	70	177,647
Imperial Oil	Kearl	159,022	71	112,906
Syncrude	Mildred Lake/Aurora	412,089	78.74	324,479
TOTAL MINED		1,295,260		1,085,399
TOTAL OILSANDS BITUMEN PRODUCTION		2,639,104	81.4	2,148,946

* The original Hangingstone project has been temporarily suspended, but Japan Canada Oil Sands recently started steam injection at the 20,000-bbl/d expansion.

SOURCE: ALBERTA ENERGY REGULATOR, MODIFIED BY JWN TO REFLECT NEW PROJECT OWNERSHIP OF CANADIAN NATURAL RESOURCES AND CENOVUS ENERGY

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Multibillions: The evolution of oilsands asset deals over the last decade

BY **DEBORAH JAREMKO**

In the last five years alone, there have been $38.6 billion in oilsands merger-and-acquisition transactions, according to CanOils. Here's a look at oilsands deals over the last decade with a value of more than $500 million.

DATE ANNOUNCED	ACQUIRER	TARGET COMPANY	BRIEF DESCRIPTION	TOTAL COST ($ THOUSAND)
April 27, 2007	Statoil	North American Oil Sands	StatoilHydro acquires private North American Oil Sands and the Kai Kos Dehseh SAGD project.	**2,234,000**
July 31, 2007	Marathon Oil	Western Oil Sands	Marathon acquires Western Oil Sands and its 20 per cent interest in the Athabasca Oil Sands Project.	**7,096,333**
Dec. 5, 2007	BP	Husky Energy	Husky and BP announce joint venture to create an integrated North American oilsands business; BP will acquire 50 per cent interest in Husky's Sunrise SAGD project, and Husky will acquire 50 per cent interest in BP's Toledo Refinery.	**1,755,036**
April 28, 2008	Total	Synenco Energy	Total subsidiary Total E&P Canada acquires Synenco Energy and its proposed Northern Lights oilsands mining project.	**541,000**
June 23, 2008	Occidental Petroleum	Enerplus	Occidental purchases Enerplus's 15 per cent working interest in the Joslyn oilsands project.	**510,000**
Dec. 17, 2008	Nexen	OPTI Canada	Nexen acquires 15 per cent interest in the Long Lake project and joint-venture lands.	**735,000**
March 23, 2009	Suncor Energy	Petro-Canada	Suncor acquires Petro-Canada, including operating MacKay River SAGD project and proposed Fort Hills assets.	**23,322,711**
Aug. 31, 2009	PetroChina	Athabasca Oil Sands	PetroChina acquire 60 per cent working interest in Athabasca Oil Sands' MacKay River and Dover SAGD projects.	**1,900,000**
March 10, 2010	Devon Energy	BP	Devon acquires 50 per cent of BP's interest in the Pike (formerly Kirby) oilsands leases and forms joint venture for the Pike (formerly Kirby) SAGD project.	**667,810**
March 15, 2010	BP	Value Creation	BP acquires majority stake and operatorship in the Terre de Grace project from Value Creation.	**916,830**
April 12, 2010	Sinopec	ConocoPhillips	Sinopec acquires 9.03 per cent stake in Syncrude from ConocoPhillips.	**4,658,835**
May 13, 2010	China Investment	Penn West Petroleum	China Investment Corporation forms joint venture with Penn West for the development of its Peace River–region bitumen assets. China Investment Corporation will hold a 45 per cent interest.	**817,000**
July 7, 2010	Total	UTS Energy	Total acquires UTS Energy.	**1,145,000**
Nov. 22, 2010	PTT Exploration and Production (PTTEP)	Statoil	PTTEP acquires 40 per cent interest in the Kai Kos Dehseh oilsands project from Statoil.	**2,317,620**
Dec. 17, 2010	Total	Suncor Energy	Total and Suncor form strategic oilsands alliance. Total acquires a 19.2 per cent interest in the Fort Hills project and a 49 per cent interest in the Voyageur Upgrader from Suncor. Suncor acquires a 36.75 per cent interest in the Joslyn project from Total.	**1,751,250**
July 20, 2011	China National Offshore Oil (CNOOC)	OPTI Canada	CNOOC acquires OPTI Canada and its interest in the Long Lake SAGD project.	**1,996,213**
Jan. 3, 2012	PetroChina	Athabasca Oil Sands	PetroChina subsidiary Cretaceous Oilsands Holdings acquires a 40 per cent interest in the MacKay River project from Athabasca Oil Sands. Athabasca exercised its option to divest its remaining interest in the project	**680,000**
March 21, 2013	PetroChina	Athabasca Oil Sands	PetroChina subsidiary Brion Energy acquires the remaining 40 per cent interest in the Dover project from Athabasca Oil Sands.	**1,184,000**
March 27, 2013	Suncor Energy	Total	Suncor Energy acquires Total's 49 per cent interest in the Voyageur Upgrader.	**515,000**
July 9, 2013	Unspecified	Canadian Oil Sands	Newmont Mining disposes of its 6.5 per cent stake in Canadian Oil Sands to a banking syndicate that will then offer the shares to various buyers.	**631,465**
Aug. 8, 2013	ExxonMobil Canada	ConocoPhillips	ExxonMobil Canada acquires 72.5 per cent interest in Clyden oilsands lease from ConocoPhillips.	**524,900**
Dec. 14, 2016	Athabasca Oil	Statoil	Athabasca Oil acquires Statoil's Canadian oilsands business, including operating Leismer SAGD project.	**578,000**
March 9, 2017	Canadian Natural Resources	Shell	Canadian Natural Resources acquires Shell's 60 per cent interest in the Athabasca Oil Sands Project (mining and upgrading operations); its 100 per cent interest in the Peace River Complex in situ assets, including Carmon Creek; and a number of undeveloped oilsands leases.	**11,100,000**
March 9, 2017	Canadian Natural Resources	Marathon Oil	Canadian Natural Resources acquires a 10 per cent interest in the Athabasca Oil Sands Project from Marathon Oil.	**1,638,713**
March 9, 2017	Shell	Marathon Oil	Shell acquires a 10 per cent non-operated interest in the Athabasca Oil Sands Project from Marathon Oil and will be the operator of the Scotford Upgrader.	**1,638,713**
March 29, 2017	Cenovus Energy	ConocoPhillips	Cenovus Energy acquires ConocoPhillips' 50 per cent non-operated interest in the Foster Creek Christina Lake oilsands partnership and the majority of its western Canada Deep Basin gas assets.	**17,710,880**

SOURCE: CANOILS

GROWTH BY OPTIMIZATION

Oilsands project investments to focus on improvement of existing assets and setting up for the future

BY **DEBORAH JAREMKO**

Cenovus Energy: Second project restart expected in June

In December Cenovus Energy announced it would restart construction of the 40,000-bbl/d Christina Lake Phase G expansion. Then in February—shortly before the announcement of its $17.7-billion buy of ConocoPhillips' SAGD and Deep Basin assets—the company hinted it would restart another thermal project in the near term.

In June Cenovus will release details on the timing and cost estimates for the 30,000-bbl/d Foster Creek Phase H and 45,000 bbl/d-Narrows Lake Phase A (a first commercial application of solvent co-injection).

"We could be in the position where we're reactivating one more phase in 2018 and then potentially one more phase in 2019, but stay tuned for details on that in June," chief executive officer Brian Ferguson says.

Canadian Natural Resources: SAGD restart and upgrader debottleneck

Even before its $12.74-billion acquisition of oilsands assets from Royal Dutch Shell and Marathon Oil, Canadian Natural Resources made it clear it is interested in oilsands growth.

In late 2016, the company restarted construction of its 40,000-bbl/d Kirby North SAGD project, and this year will also execute a major debottleneck at the Horizon upgrader that is expected to increase its mining project's production by up to 15,000 bbls/d.

Meanwhile, the company is nearing completion of the 80,000-bbl/d Horizon Phase 3 expansion.

Suncor Energy: Setting up for long-term SAGD

Suncor Energy may not be building new greenfield SAGD projects right now, but the company continues to advance them through the regulatory process.

In January Suncor initiated the environmental impact assessment for the proposed 40,000-bbl/d Meadow Creek East SAGD project. Suncor filed the regulatory application for the adjacent Meadow Creek West project in 2015.

Construction of Meadow Creek East is expected to begin in 2019-20, followed by first oil in 2023, while construction of Meadow Creek West is expected to begin in 2022 with first oil in 2026.

Osum Oil Sands: Bumping production through existing pads

Osum Oil Sands says it has found a way to increase production and improve efficiency at its Orion SAGD project without proceeding with a full project expansion.

While the company has regulatory approval to expand capacity from the current 10,000 bbls/d to 20,000 bbls/d, the expansion has been put on hold.

Meanwhile the company filed an application in April 2017 to increase Orion production from 8,000 to 13,500 bbls/d by drilling eight new SAGD well pairs on existing well pads, and adding central processing facility infrastructure including a third evaporator for water treatment.

Osum plans to start working on the project by November 2017, with commissioning and first steam by mid-2018, but the schedule is contingent on receiving regulatory approval by September of this year.

Husky Energy: SAGD production capacity increase

Husky Energy is seeking Alberta Energy Regulator (AER) approval to increase the capacity of its Sunrise SAGD project to 69,000 bbls/d from the current design capacity of 60,000 bbls/d.

In an application to the AER late last year, Husky said it believes it can boost the oilsands project's capacity by 9,000 bbls/d by optimizing existing infrastructure and by operating all 10 once-through steam generators at their full capacity of 100 megawatts.

The company said debottleneck studies concluded production capacity could be increased without additional equipment, infrastructure or surface footprint.

PHOTO: CENOVUS ENERGY

Pengrowth Energy: Optimizing and expanding SAGD

Pengrowth Energy divested of $272 million in Montney and Swan Hills assets in March as it continues its focus on the development of its core Lindbergh SAGD project.

The company plans to increase production by about 3,000 bbls/d this year through new well pairs, infill drilling and associated facilities.

Meanwhile, Pengrowth expects to be 70 per cent finished design for the 17,500-bbl/d Lindbergh Phase Two expansion by the end of the year; it's ready to execute as funds become available.

The company has also filed a regulatory application to increase approved Lindbergh capacity from 30,000 to 40,000 bbls/d without adding any additional steam generation capacity, thanks to strong performance at its existing operations.

Koch Oil Sands and Pengrowth Energy: New SAGD application

Koch Oil Sands has filed an application with the AER for a new 12,500-bbl/d SAGD project owned jointly with Pengrowth Energy.

The project, called Selina, would be near Pengrowth's high-performing Lindbergh SAGD project south of Bonnyville, Alta., within the Elizabeth Metis Settlement.

The application says construction is expected to take 12 months, starting in late 2018.

Koch also recently asked that the AER rescind its approvals for another SAGD project called Muskwa.

Japan Canada Oil Sands: SAGD production restart

Japan Canada Oil Sands (JACOS) has filed an application with the AER to restart production at its Hangingstone SAGD project, which it suspended in May 2016 due to market conditions. JACOS expected Hangingstone to be idle for 10–12 months.

"JACOS requires AER approval such that we are able to react quickly when market conditions support a restart of the demo project," JACOS regulatory director Enzo Pennacchioli wrote to the AER.

The company continued in its submission that bitumen prices have "recovered to the point where restarting the project is being considered." Timing on the restart is uncertain, JACOS said, but it would take about four months following regulatory and corporate approval to return to operations.

PHOTO: MEG ENERGY

Sunshine Oilsands: Finishing touches on capacity-doubling SAGD

Sunshine Oilsands has signed a memorandum of understanding with China Petroleum Engineering & Construction to explore completion of activities to increase production capacity at its new West Ells SAGD project from 5,000 to 10,000 bbls/d.

The expansion is expected to cost just $50 million, but that's because it is already nearly finished. The main surface facilities already exist, and all eight SAGD wells have already been drilled.

Sunshine commissioned West Ells Phase 1 in late 2015 after delaying start-up twice due to market conditions.

MEG Energy: Expansion, tech testing and new SAGD application

MEG Energy is proceeding with further roll out of its successful eMSAGP production enhancement system across its Christina Lake SAGD project this year, planning to increase production by 20,000 bbls/d. Volumes are expected to start coming online later this year.

Meanwhile, the company has filed the regulatory application for its planned May River SAGD project, a phased facility with total production capacity of 164,000 bbls/d. May River would use its eMSAGP technology "where applicable" to improve efficiency, MEG says. Construction on the first 40,000-bbl/d phase could begin in 2019.

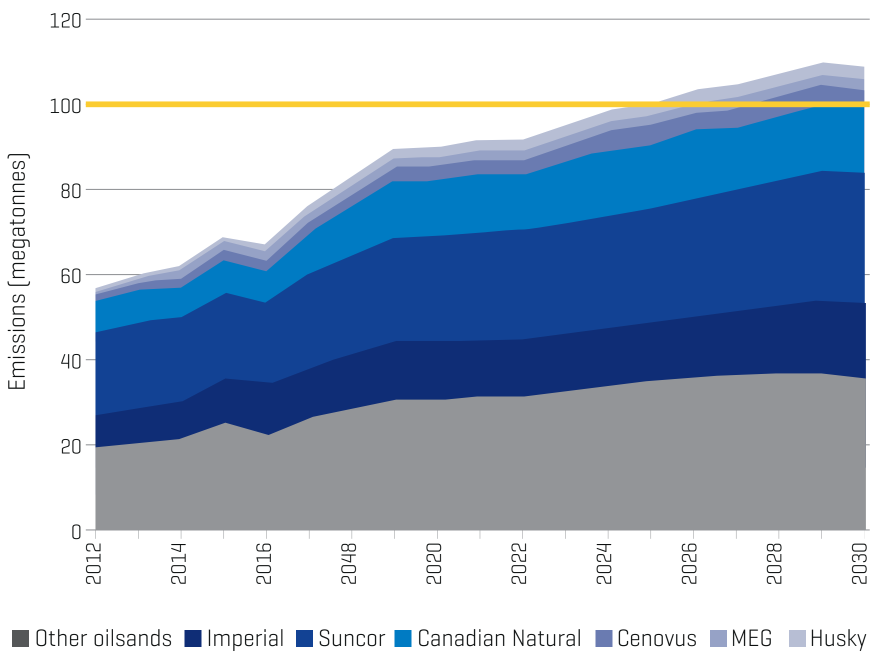
MEG also recently filed an application to expand its trial of eMVAPEX, which co-injects propane with steam with the goal of dramatically increasing efficiency.

NAVIGATING THE GHG GAP

Oilsands production likely less than a decade away from surpassing its 100-megatonne GHG ceiling

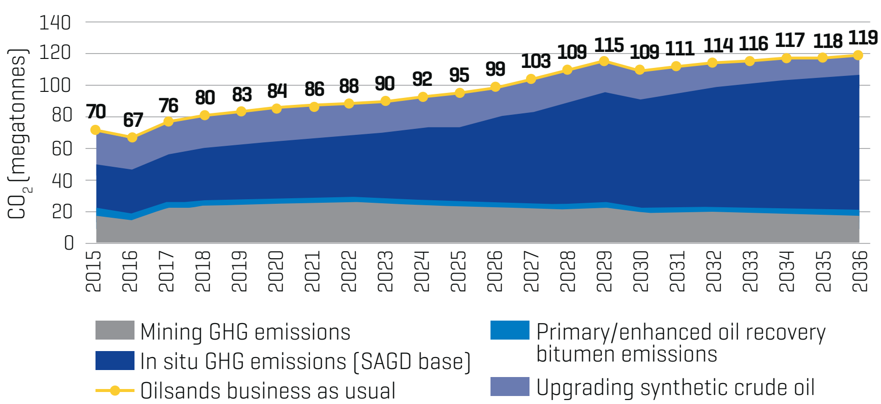
BY **DEBORAH JAREMKO**

Projected oilsands industry emissions versus 100 MT hard cap



SOURCES: BMO CAPITAL MARKETS, ALBERTA ENERGY REGULATOR, COMPANY REPORTS

Oilsands emissions by project type



SOURCE: CANADIAN ENERGY RESEARCH INSTITUTE

The oilsands industry is likely less than 10 years from exceeding the new emissions cap placed on it by the Alberta government, according to two recent reports on the future of the industry.

In November 2016, Alberta environment minister Shannon Phillips introduced the Oil Sands Emissions Limit Act, the legislation that will cap oilsands greenhouse gas (GHG) emissions to 100 megatonnes per year.

The GHG cap, which was announced in November 2015 with the support of several industry and environmental leaders, will take effect when passed in the legislature, but will not obligate oilsands producers until a regulatory system is designed and implemented, the government says.

"Our support for the oilsands emissions limit and climate policy leadership reflects the ongoing collective support for responsible development of the oilsands," reads a statement issued by the province from Canadian Natural Resources, Cenovus Energy, ConocoPhillips Canada, MEG Energy, Shell Canada, Statoil Canada and Suncor Energy.

Both BMO Capital Markets and the Canadian Energy Research Institute (CERI) predict that total oilsands production will reach about four million bbls/d in the 2025 time frame—up from an expected 2.8 million bbls/d this year—and around the same time, the sector will break through the 100-megatonne-per-year limit.

"Based on current emissions and our production outlook, we estimate the emission cap could be breached by 2025-26, and that emissions output peaks at roughly 110 [megatonnes] by 2030," BMO reports.

"The extent to which this either limits additional production growth or incentivizes emissions reduction is unclear, but may represent a risk to future oilsands growth potential."

CERI adds that "increasing production in this sector makes the meeting of international commitments increasingly difficult to meet, and thus there is interest in reducing the amount of GHGs emitted to extract bitumen from the oilsands and generate synthetic crude oil."

Another recent report, from CIBC World Markets, notes that the application of new technologies under development—such as solvent co-injection at thermal oilsands projects—could dramatically decrease carbon emissions intensity and allow growth despite the emissions cap.

"CO2-emission intensity has the potential to decrease by [about] 35 per cent with technology that has shown strong results on pilot application and potentially up to 70–80 per cent from higher risk recovery schemes," CIBC analysts write.

"There is considerable impetus by industry to improve the emission intensity of oilsands given the potential prize. Under the current technology, Alberta's emission cap of 100 megatonnes of CO2 would be reached in the second half of the next decade, but our analysis suggests there is the potential for this to be pushed out much further into time."

RACE TO THE BOTTOM

Oilsands operating costs are coming down, capital costs slowly following

BY **DEBORAH JAREMKO**

The oilsands is going through a period of transition, with producers and suppliers working to redesign systems to compete in a market of energy abundance where $50/bbl for WTI is relatively robust.

For Cenovus Energy chief executive officer Brian Ferguson, in situ oilsands production is being reborn through technology with a force similar to the impact that hydraulic fracturing has had on tight oil.

"You saw an incredible renaissance from 2010-2014 that has generated the success and the significance of the U.S. unconventionals," Ferguson told the company's fourth-quarter 2016 results call.

"It is my belief that, 2016 to 2020, the oilsands has that same opportunity for a renaissance. We need to be able to compete against the marginal barrel of supply, wherever it's coming from, both on a cost and carbon basis, and I absolutely believe that we can do that."

Mining and in situ producers have been wrestling down both capital and operating costs over the last 2.5 years as the oil price collapse raised the already-existing pressure to do so to a fever pitch.

In many cases, progress has been made, but there is still much work to be done both to reduce costs further and to maintain the decreases already achieved.

OPERATING COSTS

MINERS TARGET SUB-$20/BBL

Integrated oilsands mining companies are working toward a target of operating costs below $20/bbl, with both Suncor Energy and Canadian Natural Resources publicly stating the goal.

Suncor is getting closer, and while chief executive officer Steve Williams indicated that the bottom range of that target will likely remain elusive for some time, the reductions achieved to date are sustainable.

At its operated facilities, Suncor recorded cash costs of $22.55/bbl in the first quarter of 2017, down from its full-year 2016 average of $26.50/bbl, $27.85/bbl for 2015 and $33.80/bbl for 2014.

"The costs are sustainable. We're comfortable that we've permanently adjusted them down," Williams said in response to a shareholder's question at the company's annual meeting.

He added that the decreases over the last year have been achieved while absorbing a nearly 50 per cent increase in natural gas input costs.

Canadian Natural announced earlier this year that it expects to exit 2017 with operating costs at its Horizon project under $20/bbl, a milestone it previously expected to achieve by 2020. This is a result of production volumes exceeding plant capacity as the Horizon project is expanded.

"We're making great progress," said president Steve Laut during Canadian Natural's fourth-quarter 2016 results call.

"The effectiveness and efficiency that we're gaining at Horizon, combined with the increased reliability and utilization, have had a big impact on operating costs."

Canadian Natural's synthetic crude oil operating costs were $22.53/bbl in the fourth quarter of 2016 and $25.20/bbl for the year, down from $28.61/bbl in 2015.

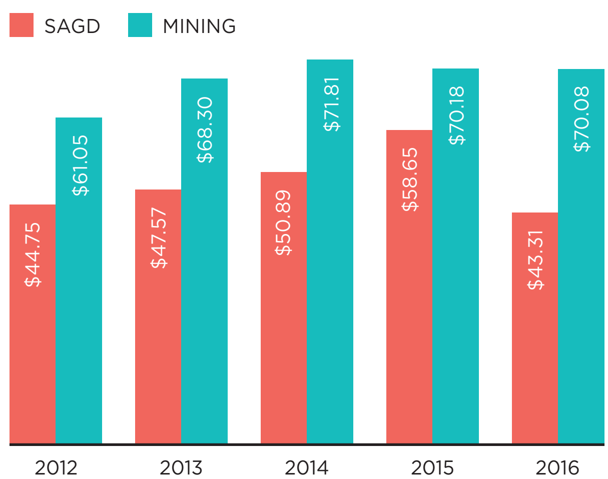
THERMAL PROJECTS PUSH UNDER $10/BBL

At thermal oilsands facilities, producers are also pushing down operating costs.

Between the first quarter of 2014 and the fourth quarter of 2016, the per-barrel operating cost of SAGD projects—based on publicly available information from six operators—dropped from an average of $20.40/bbl to $9.79/bbl.

In the first quarter of 2014, the highest SAGD cost reported was $28.44/bbl at Connacher Oil and Gas' Great Divide project, followed by $24.23/bbl at Husky Energy's Tucker facility. The lowest cost reported was $13.30/bbl at Cenovus Energy's Christina Lake project, followed by $17.48/bbl at MEG Energy's Christina Lake project.

Total field gate bitumen/synthetic crude oil supply costs (10% ROR)



SOURCE: CANADIAN ENERGY RESEARCH INSTITUTE

Fast forward to the fourth quarter of 2016, and the highest SAGD cost came from Suncor Energy, reporting $10.75/bbl at Firebag and MacKay River, followed by Cenovus Energy's $10.60/bbl at Foster Creek. Information for Connacher's fourth quarter was not available at press time.

The lowest SAGD cost per barrel reported in the fourth quarter of 2016 was again by Cenovus Energy, reporting $8.15/bbl at Christina Lake. This is followed by $9.11/bbl at MEG Energy Christina Lake.

"We've spent the last two years perfecting our game for the new business reality so that we can have a robust business model in the mid-$50-WTI range," said Drew Zieglgansberger, Cenovus's executive vice-president of oilsands manufacturing, in mid-2016. "This was a really big culture shift for people and our industry in order to remain competitive."

Even since before the downturn, Cenovus has been a leader in driving down operating costs, Zieglgansberger said most of the heavy lifting has been done since the end of 2014.

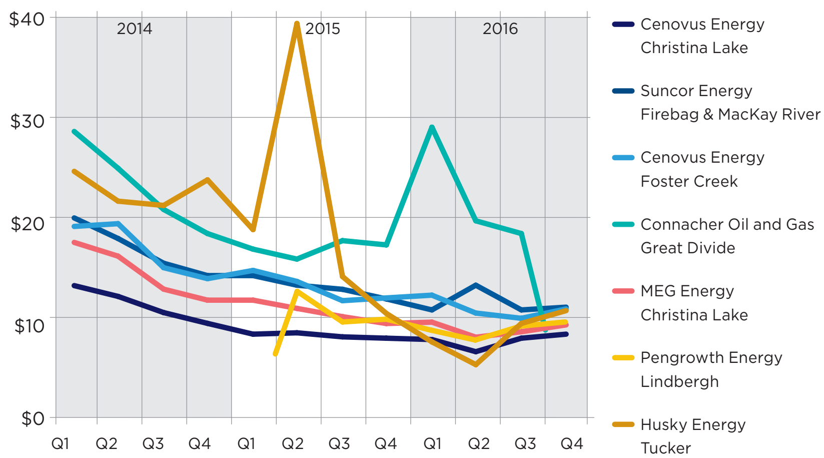
Like every other oil and gas company, Cenovus has had to slash its capital and general and administration costs, which included reducing its workforce by about 30 per cent from the end of 2014. It also asked for discounts from its suppliers. But some of the biggest efficiencies came from looking more closely at its production facility well pads.

"We've redesigned these to reduce the amount of equipment needed to move the steam into the wells and then take the production from the wells back to the main plant, reducing those costs in the order of 40–50 per cent," Zieglgansberger said.

Unlike the gains made in reducing staff and service costs, technology-driven operating cost reductions can progress more or less indefinitely. Zieglgansberger confirmed Cenovus's technology bias in its list of initiatives to potentially drive operating costs lower: continued improvements in wellbore conformance, reducing the number of well pads required in the future (due to wider well spacing and longer wells), continued improvements in drilling and completion efficiencies (further reducing the time it takes to drill and complete wells), and redesigned well pairs and pads.

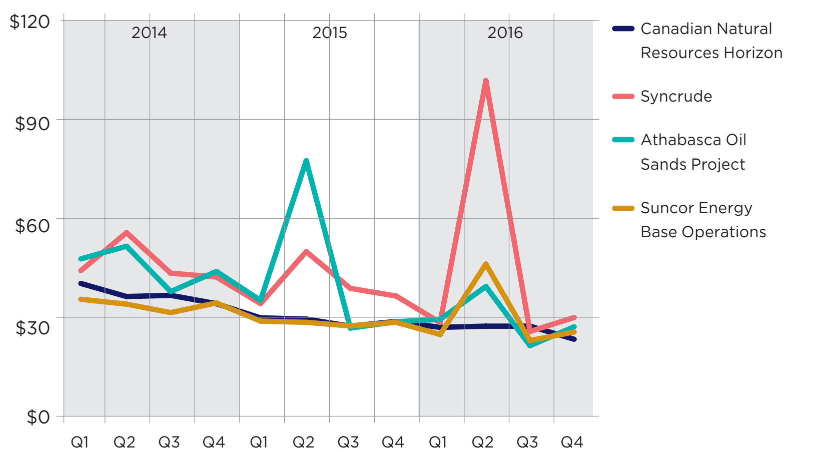
MEG Energy attributes cost reductions to its enhanced modified steam and gas push program, which involves non-condensable gas co-injection, infill well drilling and new well pairs. The company has also said that operating cost reductions were also helped by a decrease in the use and cost of natural gas as a source fuel for the company's SAGD facilities.

Quarterly total operating costs per barrel: In situ projects



SOURCE:CORPORATE FINANCIALS

Quarterly total operating costs per barrel: Upgrading projects



SOURCE:CORPORATE FINANCIALS

CAPITAL COSTS

The business case for a brand new SAGD project continues to be uneconomic, but it's getting closer as costs go down and prices rise.

The WTI equivalent supply cost required for a greenfield SAGD project to recover capital investment, operating costs, royalties, taxes and a 12 per cent return—while accounting for blending and transportation—is now US$60.52/bbl, according to a new report from the Canadian Energy Research Institute (CERI).

That is down 25 per cent from last year's CERI estimates, thanks to lower operating costs, changes in the U.S./Canadian dollar exchange rate and a lack of premium on diluent costs.

"At current WTI prices of just over US$50/bbl, one can assume that these greenfield projects are not economic or have to accept a lower rate of return," CERI says.

"However, as is observed in the industry, the relative position of oilsands projects against other crude oils is comparatively competitive, and as oil prices are expected to recover, so will the profitability of oilsands projects."

CERI notes that the average supply cost of U.S. tight oil is less than US$50/bbl, with new wells in the Permian, Bakken and Eagle Ford areas now profitable at US$40/bbl.

While CERI's outlook for SAGD is encouraging, its expectations for mining investment are not, although it notes that the supply cost for a stand-alone mine has dropped by 16 per cent from last year's report to US$75.73/bbl.

Suncor's Williams summed it up in the company's Q4 results call:

"Mining investments are coming to an end, not just for Suncor but for the industry I believe for a considerable period, probably in excess of 10 years. When we look at the absolute economics of Fort Hills, those are not projects we will be repeating in the foreseeable future. Some substantial things in the cycle would need to change."

Improved reliability and autonomous heavy hauling: Oilsands miners can find substantial savings with opportunities that exist today

BY **DEBORAH JAREMKO**

While the opportunities for in situ oilsands producers to improve efficiency and economics have a range of timelines from near to long term, for mining operators, many of the benefit enablers are available immediately.

Consider the improvements in reliability that have been achieved at Syncrude since Suncor Energy took over as majority owner in 2016. Suncor chief executive officer Steve Williams had stressed the opportunities for the company to help improve reliability and realize project synergies, and so far, the results have been better than expected.

"I promised that we would devote experienced personnel to work closely with the operating team from Imperial, Exxon and from Syncrude to drive major performance improvements and realize significant long-term added value for our shareholders," Williams said while discussing the company's fourth-quarter-2016 results.

"As it turned out, the performance improvements materialized more quickly than we had planned for. In the fourth quarter, Suncor's share of Syncrude production increased to just under 190,000 bbls/d with cash costs of $32.55/bbl, so that's down 19 per cent from the similar quarter in 2015."

For the full year 2016, with the exception of the second quarter when production was curtailed due to the Fort McMurray wildfires and planned maintenance downtime, Syncrude achieved average utilization rates of 97 per cent and cash costs of just over $30/bbl.

"In fact, the third and fourth quarters represented the best six months of production the Syncrude facility has ever achieved," he said.

"At this point last year we forecast immediate savings of about $25 million annually in reduced overhead, and as it turned out we actually captured more than twice that savings, and we generated $360 million free cash flow from our increased stake with an average WTI price for the year of just $43.36/bbl."

Suncor is also working with another immediately available cost-saving opportunity: driverless haulers.

Analysts with CIBC say that, on a scale of one to 10 of being able to help oilsands producers save costs today, autonomous hauling systems are a 10.

Suncor is currently operating a test fleet of autonomous haulers at its base oilsands mining project and has been testing the technology since 2013.

The company said it may proceed with progressive implementation this year, which is also the timing for the start-up of the new Fort Hills mining facility.

CIBC analysts noted in an oilsands technology update issued earlier this year that, already, every truck that Suncor is adding or replacing in its fleet has the ability to go fully autonomous.

"Suncor currently has about 100 trucks and could add about 10–20 more with contractors. With Fort Hills, it could add about 50 more trucks, bringing the total fleet to about 150," they wrote.

Suncor says every truck it adds or replaces, including the Fort Hills fleet, has the ability to go fully autonomous.

IMAGES: KOMATSU

"The decision to use the autonomous hauling system technology at Fort Hills has not been made at this time."

While deploying autonomous hauling has some hard costs including wireless networks and GPS systems, the main benefits come from efficiency gains by improving safety, minimizing downtime, lowering maintenance work and ultimately lowering the kilometres driven per tonne of material, CIBC notes.

According to Alberta Energy Regulator data, in 2016 Suncor hauled 128.3 million tonnes of oilsands ore at its Base Operations.

"Rio Tinto operates the largest autonomous hauling fleet in the world and reported in its 2015 annual report that, through the introduction of 71 autonomous hauling trucks, it has cut its load and haul operating costs by about 13 per cent and increased utilization by about 14 per cent," CIBC says.

"Suncor expects to start seeing some efficiency gains from the autonomous fleet with the goal of about five to ten percent cost improvement. In our view, there is upside to this estimate based on comments by Rio Tinto."

Reducing steel: Smaller facilities and well pads the starting point for major capex reductions, producers adding volumes without extra steam

BY **DEBORAH JAREMKO**

Not all opportunities to reduce oilsands capital costs and improve competitiveness involve implementing something entirely new.

As analysts with CIBC note, simply reducing the amount of steel and size of both thermal oilsands central-processing facilities (CPFs) and well pads can drop capital costs by up to 35 per cent and is implementable today.

Producers, including Suncor Energy, Cenovus Energy, ConocoPhillips and MEG Energy, are targeting well pad reductions between 40 and 50 per cent in part by incorporating a more advanced use of modularization.

In some cases, producers are also looking at better ways to execute infill drilling as project life progresses.

In MEG Energy's recent application for the proposed May River SAGD project, the company said it would implement a new well pad design that is 40 per cent smaller and "more technologically advanced."

MEG says the modularized well pads will have a staggered design that will allow for future infill drilling from the opposite side of the rack as SAGD well pairs so that no new disturbance is required.

ConocoPhillips, which continues to operate the 148,000-bbl/d Surmont SAGD project despite exiting its SAGD partnership with Cenovus, says that its new designs have dramatically reduced both the footprint and height of well pad facilities.

SAGD producers are seeking well pair size reductions of up to 50 per cent, while companies are identifying opportunities to add meaningful production capacity without additional steam generation.

Cenovus's new approach, which it started using in December 2016, is expected to result in overall cost savings of 35–50 per cent including 40 and 60 per cent reductions in materials and a five to 20 per cent drop in well pad surface footprint.

Because well pads are successively drilled throughout the life of a SAGD project to keep the plant full, incremental gains in new designs can be somewhat easier than with a CPF. But the same zero-base design principles that companies are taking to well pads—where every line item is fair game for review each time a project is executed—can be applied.

Fluor is now applying zero-base execution to SAGD facility designs, which it says incorporates cultural change for both project vendors and producers.

Fluor's new approach is to start facility designs at their minimum requirements and, while considering previous designs that a company may have used, to not be tied to the way designs have been done in the past.

Suncor says that its SAGD replication strategy—which will be the backbone of any new projects it builds post-2020—includes a new CPF design.

Suncor says the CPF will be 45 per cent smaller than recent industry builds and 20 per cent smaller than industry's "best announced."

Producers are also finding ways to increase production at existing facilities without much expansion of the CPF at all.

Pengrowth Energy, for example, recently applied to the Alberta Energy Regulator (AER) to increase approved production capacity at the Lindbergh SAGD project from 30,000 to 40,000 bbls/d without adding any additional steam generation capacity, thanks to strong performance at its existing operations.

Phase 1 of the project is currently operating at about 15,000 bbls/d (with nameplate capacity of 12,500 bbls/d), and approval is in place for the Phase 2 expansion, which would add capacity of 17,500 bbls/d.

Phase 1 has achieved a steam to oil ratio (SOR) of 2.5:1 compared to its design SOR of 3.62:1, although the SOR is expected to rise to its design rate as time passes. That means that in early stages of production, steam is available to be diverted to new wells.

At the Sunrise SAGD project, Husky Energy is seeking AER approval to increase capacity to 69,000 bbls/d from the current design capacity of 60,000 bbls/d by optimizing existing infrastructure and operating all 10 once-through steam generators at their full capacity.

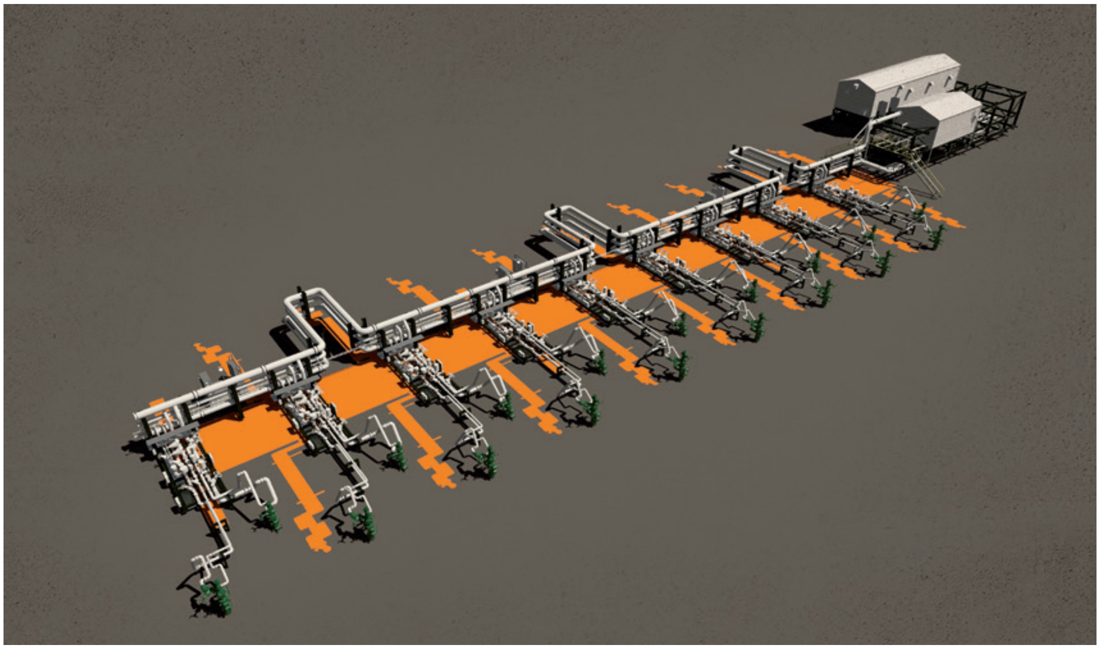


IMAGE: WOOD GROUP

Non-condensable gas co-injection: SAGD's insulating blanket could move the needle on economics

BY **PAT ROCHE** AND **DEBORAH JAREMKO**

While there is a good deal of talk about improving SAGD economics and environmental performance with solvent injection, in some cases producers are also seeing opportunities via co-injection of something else: a non-condensable gas (NCG), such as methane.

It's a system with roots that go back as far as SAGD itself.

The late Roger Butler, who patented the SAGD process for Imperial Oil, also came up with a process called steam and gas push. This involves co-injecting relatively small amounts of an NCG with steam.

The gas has several benefits. It replaces some of the steam, resulting in a lower steam to oil ratio. It helps maintain pressure: as steam condenses pressure drops in the reservoir, but methane doesn't condense, so the pressure needed to push the heated bitumen to producer wells is maintained.

The gas also forms an insulating blanket that reduces heat loss into the caprock, thereby improving energy efficiency. The methane layer at the top of the steam chamber also forces the steam to flow laterally. Instead of reaching the overburden, steam is diverted laterally, where it continues to mobilize bitumen.

The beauty of co-injecting NCG with steam is that it requires no new facilities and only small volumes of natural gas, which is already piped onto the site to fuel steam generators. In terms of capital spending, all that has to be added is the plumbing to mix the methane and steam before injection.

The technology has undergone widespread testing across the industry at different stages in SAGD operations by producers, including Cenovus Energy, Suncor Energy, ConocoPhillips, Nexen, Japan Canada Oil Sands, and Connacher Oil and Gas.

THE BEAUTY OF CO-INJECTING NCG IS THAT IT REQUIRES NO NEW FACILITIES AND ONLY SMALL VOLUMES OF NATURAL GAS, WHICH IS ALREADY PIPED TO SITE.

By far, the most public with its NCG success has been MEG Energy. NCG has driven MEG's recent efficiency gains and production increases—it's also at the heart of the company's growth plan.

NCG is part of the company's eMSAGP production enhancement system, which is going to be expanded at the company's Christina Lake oilsands project starting this year to the tune of $590 million and a 20,000-bbl/d production bump.

eMSAGP involves NCG, infill well drilling, new well pairs and facility debottlenecking, which increases production as well as reduces costs and greenhouse gas emissions.

"To date, we have applied eMSAGP to about 25 per cent of our production, which has increased volumes using less steam and cut the steam to oil ratio on those wells by half," says MEG chief executive officer Bill McCaffrey.

"This phase of eMSAGP growth offers some of the highest economic returns available to the company today…. When fully implemented, this growth is anticipated to bring MEG's total production to approximately 100,000 bbls/d, significantly improving the sustainability of the business by driving cash costs down by as much as $4–5/bbl."

While MEG deploys NCG on a commercial scale, other producers continue testing.

Earlier this year, Husky Energy received regulatory approval to initiate NCG on six wells at its Sunrise SAGD project.

And later this year, results are expected from an NCG test at ConocoPhillips' Surmont SAGD project, where a pilot was planned to start in late 2016.

ConocoPhillips executive vice-president Al Hirshberg says the technology is one of a number that are expected to move more of its Surmont 2 resources into a cost of supply less than $50/bbl.

He says, "Our modelling shows that this idea could reduce both steam to oil ratios and our greenhouse gas emissions intensity by up to 20 per cent."

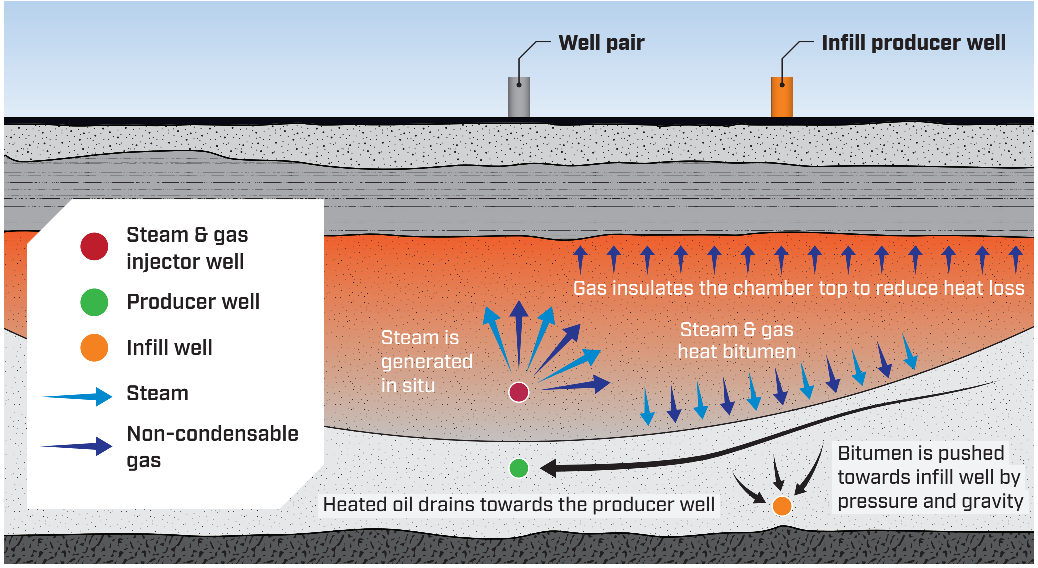


IMAGE: MEG ENERGY

Countdown to solvents: CAPP developing AOSTRA-like plan as commercialization remains elusive

BY **DEBORAH JAREMKO** AND **PAT ROCHE**

A recent study from the Canadian Energy Research Institute (CERI) identifies six technology configurations for in situ oilsands production that have the potential to reduce costs by 34–40 per cent and emissions by more than 80 per cent, consequently delaying the time until the 100-megatonne emissions cap is reached "by several decades."

Four of these technology configurations involve injecting or co-injecting solvents.

Any one of the six configurations would reduce to zero the chances of reaching the cap by 2036. (It is currently expected to be breached in 2028.)

CERI says the high supply cost of in situ oilsands projects, which is currently about $45/bbl, is intertwined with the industry's high emissions. Contrary to what one might expect, addressing one will address both.

"Reducing emissions usually comes with a cost penalty. Interestingly, the results of this study prove otherwise," CERI says. "They show that emissions and cost reduction objectives are not adversely related. This means the two objectives can be achieved simultaneously."

Solvent injection or co-injection has been tested at numerous in situ oilsands facilities and is now awaiting commercial deployment.

SOLVENT-ASSIST

Cenovus Energy's recent blockbuster oilsands deal with ConocoPhillips could help accelerate solvent-assisted SAGD commercialization.

The company's $17.7-billion acquisition of ConocoPhillips' 50 per cent interest in their shared Foster Creek/Christina Lake SAGD partnership also includes the Narrows Lake project, which may mark the industry's solvents milestone.

Narrows Lake is expected to be Cenovus's third oilsands project and the industry's first project to use solvent-aided process (SAP) on a commercial scale.

SAP adds a natural gas liquid, such as butane, to the steam injected into SAGD wells. The solvent goes into solution in the bitumen, enabling it to flow more easily. Thinning bitumen with solvent is intended to be more energy efficient than only using heat.

Construction of Narrows Lake Phase A, designed to produce 45,000 bbls/d of bitumen, was sanctioned in late 2012. The pioneering project was under construction in early 2015, when it was suspended following the collapse in world oil prices.

On a conference call with analysts and the media after announcing the ConocoPhillips deal, Cenovus chief executive officer Brian Ferguson re-affirmed the company's commitment to restarting the project.

"Resuming our two deferred oilsands expansions at Foster Creek Phase H and Narrows Lake Phase A remains our focus. We expect an improved free cash flow profile and liquidity position will enable us to invest in these projects," he said.

"Narrows Lake is an exciting opportunity to apply the learnings from our solvent pilot. The first phase at Narrows Lake is partially constructed, and we have full regulatory approval for 130,000 bbls/d of productive capacity."

Imperial Oil has also piloted a solvent-and-steam process, called solvent-assisted SAGD (SA-SAGD) and has applied for regulatory approval for commercial deployment at the proposed Cold Lake Expansion project.

But Cenovus's plan for commercial deployment of its solvent-and-steam process is further ahead than Imperial's because Narrows Lake has received regulatory approval and was internally sanctioned and under construction until it was deferred due to low oil prices.

Cenovus says it will update its plan for Narrows Lake Phase A at its investor day in June, including expectations for capital costs and timing.

PURE SOLVENTS

Meanwhile, oilsands solvent technology developer Nsolv is facing its biggest hurdle yet as it starts the process of shutting down its field pilot, says chief executive officer Joe Kuhach.

The pilot, which tests a solvent-only extraction process, has been operating on Suncor Energy's Dover lease since 2014. The company says it has proven "reliable and robust" and achieved all key performance indicators.

A recent report from CIBC World Markets notes the system as potentially commercial within five to seven years with many potential benefits, including due to its lack of water use, reduced capital and operating costs and lower greenhouse gas emissions.

PHOTO: CONOCOPHILLIPS

CIBC notes that Nsolv's lower operating pressures could also provide access to shallower formations and zones with thinner caprock that are not currently economic with SAGD.

"The ability for Nsolv to overcome these hurdles in shallow applications could potentially offer billions of barrels of incremental resource recovery for the industry," analysts write.

"Assuming US$50/bbl WTI, we see that a solvent-only project like Nsolv would have over a ~15.6 per cent internal rate of return as compared to ~5.2 per cent for a traditional SAGD development."

These figures, based on comparisons to a SAGD project in 2015, do not include the benefit of lower carbon costs. The key challenge, CIBC notes, is the amount of solvent that stays in the reservoir. Nsolv estimates a 95 per cent recycle rate.

The company has previously received funding from government agencies, including $10 million from Emissions Reduction Alberta (formerly the Climate Change and Emissions Management Corporation) and $15 million from Sustainable Development Technology Canada (SDTC). SDTC has also awarded Nsolv $13 million toward a commercial demonstration project. But the company is at a point where it needs much more.

"In the technology space, you need small amounts of money to test things in the lab, and as you move closer towards commercialization and to technically prove things out, the cost goes up," Kuhach says.

"We're now at the biggest chasm that there is. We're technically proven and ready to go from a commercial standpoint, but getting over that barrier to commercialization, that's the biggest cost investment, and that's arguably where you need the most help. That's where lots of technologies die. I don't think that's going to happen to us, but I think we're delaying a lot of the benefits that we could be reaping today by getting this technology going now…. At some point you've got to start betting on the winners."

In the mid-1980s the Government of Alberta invested $135 million (the first $80 million without industry funding) to construct the Underground Test Facility through the Alberta Oil Sands Technology and Research Authority (AOSTRA), noted former Alberta Innovates chief executive officer Eddy Isaacs in the Edmonton Journal in 2010.

This investment, which is not adjusted for inflation to reflect today's project costs, ultimately resulted in the commercialization of SAGD, which now accounts for more than one million bbls/d of oilsands production.

"The government made some huge investments in SAGD, and they paid off very well," Kuhach says. "To be honest, I think Nsolv is an opportunity like that. It's really taking things to the next step in what I believe would transform the industry into being more environmentally and economically sustainable."

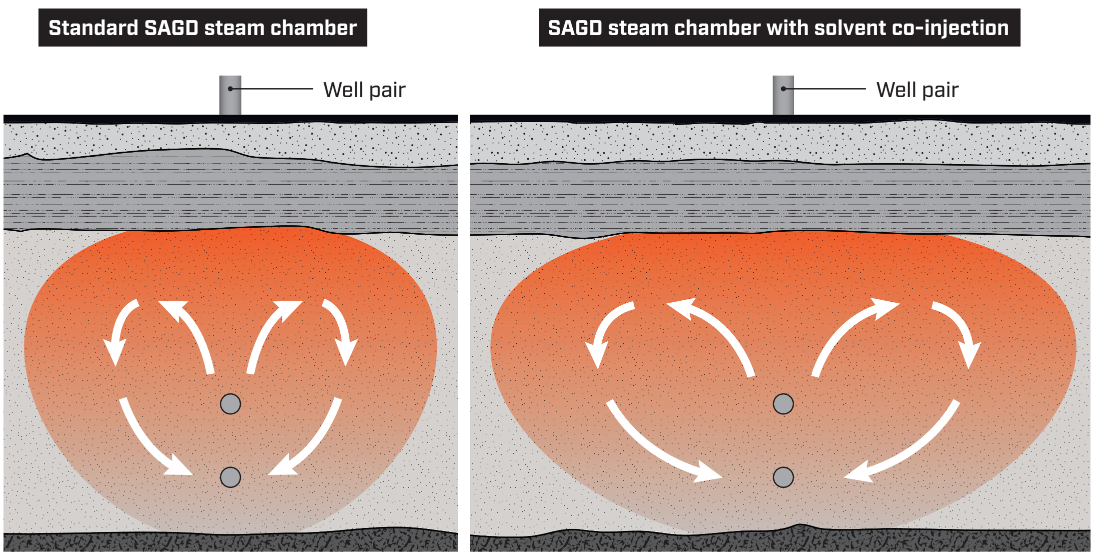


IMAGE: CONNACHER OIL AND GAS

SOLVENT AOSTRA

Speaking of AOSTRA, the Canadian Association of Petroleum Producers (CAPP) is exploring the idea of putting together a proposal for a joint industry-government consortium to do a large-scale commercial rollout of solvent-based bitumen extraction.

Nothing has been firmed up at this early stage, but the idea would be to prove up a solvent-based extraction process that would produce significantly less greenhouse gas emissions than conventional SAGD.

The project—possibly producing somewhere around 25,000–30,000 bbls/d of bitumen—would cost hundreds of millions of dollars. With sufficient industry and government buy-in, funding would come from the province and participating oilsands producers.

"We think it's absolutely necessary to see some type of joint arrangement like AOSTRA where both industry and government came to the table with sizable amounts of investment to share the risk and the reward of advancing oilsands development," says Ben Brunnen, CAPP's vice-president of oilsands.

"AOSTRA unlocked resource potential far in excess of what anyone has expected in terms of production for oilsands. And we're facing a very similar type of technological advancement…. And it's going to take that type of commitment from both sides to unlock…the next phase of oilsands development."

With the support of several major oilsands operators, Alberta last fall passed legislation capping the sector's emissions at 100 megatonnes a year. Oilsands operations currently emit roughly 70 megatonnes a year. When the limit might be reached is a matter of debate, but there's no doubt it would cap oilsands growth unless emissions could be lowered.

According to CAPP's calculations, if steam to oil ratios could be cut by five per cent, the province could add an additional 140,000 bbls/d of bitumen production within the emissions cap.

Based on consultations with its members and government in the coming months, CAPP will develop a strong position and recommendations before the end of June, Brunnen says.

SAGD flow control: For ConocoPhillips it's a win, for Suncor Energy it's not quite there

BY DEBORAH JAREMKO

Despite the great success of SAGD as a driver of oilsands growth, there are still many questions to be answered and improvements to be made.

The technology was commercialized in 2001 and now accounts for just over one million bbls/d of oilsands production, or close to half of total volumes of about 2.5 million bbls/d.

Having better control of steam in the reservoir could improve recovery and efficiency, resulting in better economics and a reduced environmental footprint, but operators aren't all convinced that the technology is quite there.

According to C-FER Technologies, which has completed two stages of a joint-industry project in an effort to advance the technology, potential benefits include rapid and uniform steam chamber growth, improved production rates, improved ultimate recovery and reduced steam to oil ratios.

C-FER says flow-control devices (FCDs) "can have a significant impact on the overall economics of a SAGD development."

ConocoPhillips invested the extra capital cost of installing FCDs in wells at the new Surmont 2 SAGD project and says this is paying off to the point that it is deploying the technology beyond its original plans.

About 30 per cent of the well pairs at Surmont 2 were originally equipped with FCDs when the 118,000-bbl/d SAGD expansion was commissioned in mid-2015.

Since achieving first oil in September 2015, ConocoPhillips says the devices have achieved impressive results.

"We now have over a year's experience with flow control devices in many of our wells at Surmont 2, and I really have to say it's not every day that you develop a single technology that can give you a 100 per cent increase in the cumulative oil production over 12 months time from your well pairs," ConocoPhillips executive vice-president Al Hirshberg told the audience at the company's 2016 analyst and investor meeting in New York.

"These FCDs have been so effective that we've even developed a way to retrofit them into wells that we drilled that didn't originally have them."

According to TOP Analysis, FCDs are designed to promote a more uniform distribution of steam along the injection well and fluid drawdown to the production well. They are also often used as a way of ensuring pump longevity by reducing the likelihood of steam interaction with artificial lift.

While ConocoPhillips is reporting success with its FCDs, Suncor Energy says the systems need more work in order to achieve their potential.

That's the view that Suncor Energy SAGD production engineer Jeremy D'Mello presented to the Alberta Energy Regulator (AER) in the company's latest performance update for its Firebag SAGD project.

According to its AER presentation, Suncor has seven FCDs installed in its production wells at Firebag and none in its steam injection wells.

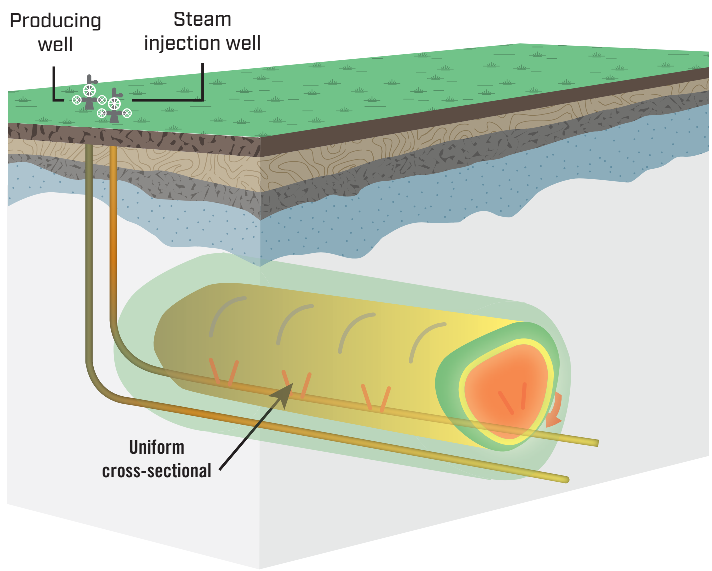
D'Mello said the company believes FCDs can help improve steam conformance when hotspots develop in a wellbore due to operating practices or heterogeneous geology.

However, the FCDs that are currently available to oilsands producers are not necessarily equipped to do the job.

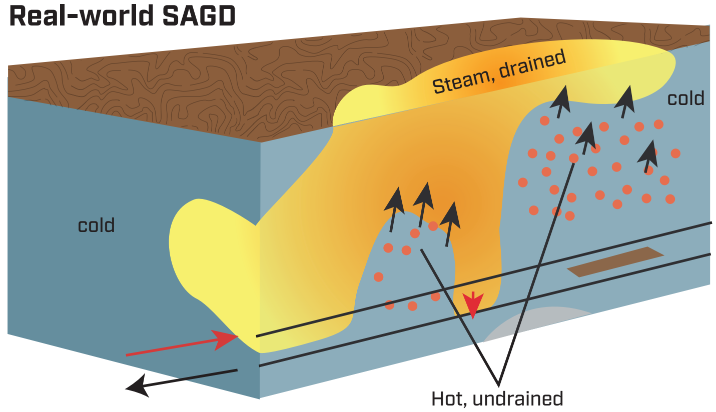
"Vendors are supplying FCDs developed for conventional wells," Suncor said in its presentation. "A purpose-built SAGD device could be a game changer if it blocked steam better."

According to C-FER, a number of questions remain, including the comparative costs of different FCD systems, how the devices and the associated well completions should be designed, how wells with FCDs should be operated, the performance and reliability of the tools over the SAGD project life cycle, and the capability of existing modelling tools to aid in FCD design and assessment.

Theoretical SAGD



Real-world SAGD



The reality of SAGD reservoirs is not uniform, so steam injection does not necessarily create the ideal steam chamber along a wellbore. This can create significant operational challenges and increase costs. Flow control devices can change the rate of steam injection along a well to create more uniformity.

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Direct-contact steam generation: Potential to drop in situ steam emissions to nearly zero

BY **PAT ROCHE**

New technology being developed by SAGD operators could effectively eliminate CO_2 emissions from the steam generation process, the largest source of greenhouse gases from in situ bitumen production.

Known as direct-contact steam generation (DCSG), the technology is thought to be about five years from commercial deployment. It could provide additional benefits including reduced water requirements and production of pure CO_2 that could be used for enhanced oil recovery.

Suncor Energy is leading the multi-year development project, backed by Canada's Oil Sands Innovation Alliance (COSIA).

"There are a lot of things to like about this technology, but there is a lot of development work that still needs to happen. If we can prove this out to be technically viable, there is potential to reduce direct greenhouse gases from steam generation almost to zero," Suncor's Todd Pugsley said in a speech at the Oil Sands Innovation Summit 2017 sponsored by COSIA, Alberta Innovates and Natural Resources Canada.

"It is a potential game changer," he said, noting DCSG has the added advantage of using existing infrastructure. This means "all our knowhow about thermal recovery of bitumen with steam still stands, and it also opens the opportunity for not just greenfield growth project applications but brownfield applications as well."

Today, huge quantities of steam are produced with once-through steam generators, which create heat on one side of a surface, in this case tubes, to heat water on the other side. To preserve the tubes, the water requires some degree of treatment.

DCSG does away with the heat transfer surface altogether to "directly contact the water with the flame, kind of the way you put out your campfire, except in this case, you don't want to put your fire out," Pugsley explained.

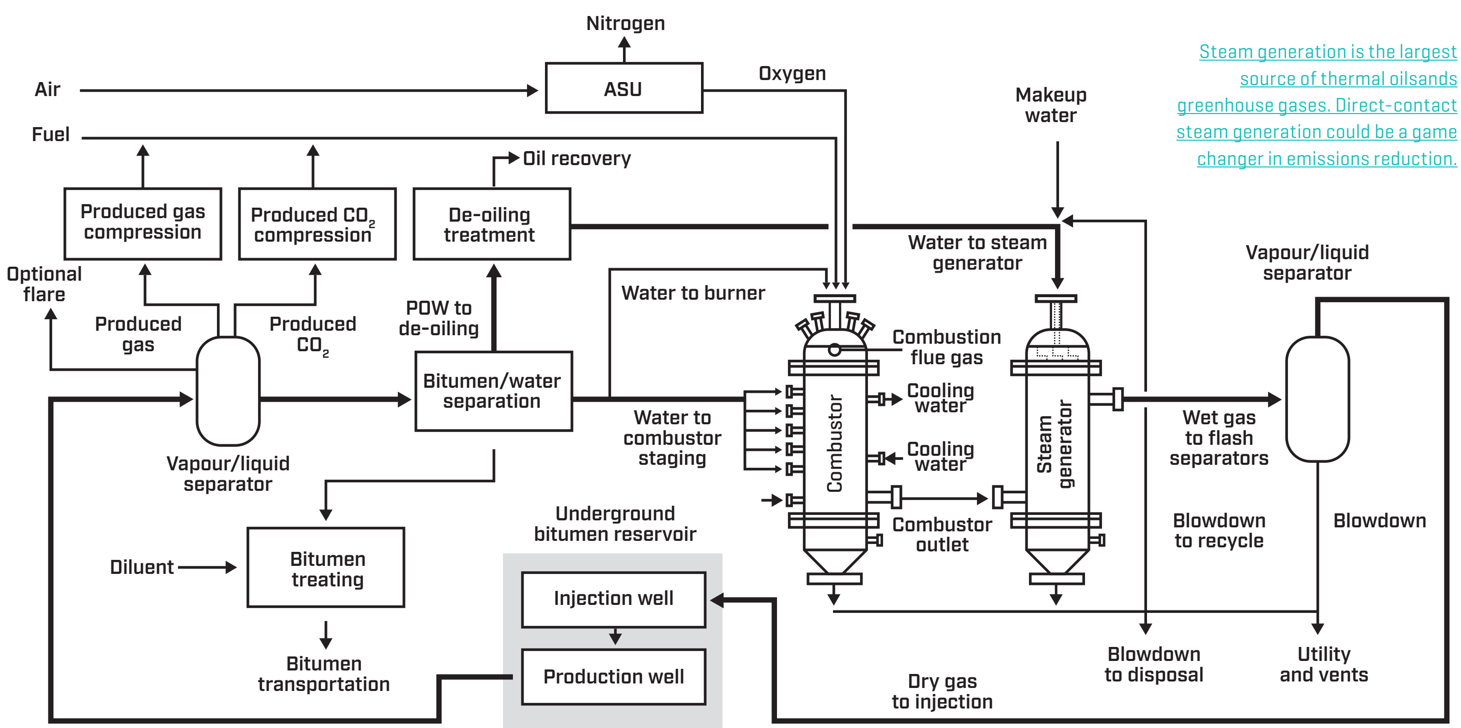
Its high-pressure, direct-contact design means the steam generator has a much smaller physical and environmental footprint. The process would enable companies to recycle about 90 per cent of the produced water and could also accommodate the use of oilsands tailings water at a time when oilsands mining companies are struggling to reduce those volumes.

DCSG would use oxygen-fuel combustion—burning natural gas with pure oxygen rather than air (which is about 78 per cent nitrogen and 21 per cent oxygen)—which adds to the cost. But the benefit is flue gas that is almost pure CO_2.

The CO_2 can either be sent downhole with the steam (in an approximately 90 per cent steam to 10 per cent CO_2 mixture), where it could enhance bitumen production and permanently sequester much of the greenhouse gas, or be separated out at surface for other uses.

Suncor has tested two versions of DCSG—one at California-based Clean Energy Systems and one at the federal government's CanmetENERGY research centre in Ottawa. CanmetENERGY recognized DCSG's potential as a transformative technology to address oilsands environmental issues about a decade ago when the first patent applications were filed, Pugsley said.

Further investigation is justified, he concluded. "Is the technology cost competitive? Yes. How long until DCSG is ready for full commercial deployment? It's probably four, five years away, depending how fast things can happen."



Steam generation is the largest source of thermal oilsands greenhouse gases. Direct-contact steam generation could be a game changer in emissions reduction.

IMAGE: UNIVERSITY OF OTTAWA

IoT: Tough market conditions driving uptake in digital technology for the oilsands

BY **MAURICE SMITH**

IMAGE: JOEY PODLUBNY

One of the quickest ways for oilsands producers to reduce costs is to digitize their processes.

The business management and analytics segment in particular, which is seen as a formidable accelerator of products and services in other sectors, offers great potential for the oilsands, according to the Canadian Energy Research Institute.

A recent IHS CERA report found that digitization improves productivity by two to eight per cent, with an operating expense reduction of five to 25 per cent and a capital expenditure reduction from one to 10 per cent depending on site localization.

Here's a look at digital technologies that promise to lower costs and improve the efficiency of oilsands operations.

- SAS has developed an asset optimization system for thermal oilsands producers that creates analytical models able to compute optimal steam distribution on a field-wide basis. It is designed to determine, for example, which wells to starve and which wells to feed more steam as availability dictates.

  Statistical models created by the program—developed from data collected from several SAGD operators—recognize process changes with time for each well pair while analytics evaluate and update models to provide performance predictions. The system is also designed to predict events such as steam breakthrough and process upsets before they occur, thereby minimizing costly unplanned events and maintenance costs.

  SAS estimates its technology can produce an additional 40 bbls/d per producing well, which on a 100-well-pair facility would translate into a production increase of about 1.4 million barrels annually or $24 million in increased pre-royalty cash flow with oil priced at $46/bbl.
- Calgary-based start-up Veerum is combining several recent advances—from asset tracking to digital twin technology and virtual reality—to enable cheaper, more efficient project delivery.

  Veerum uses robots and drones, lasers and photogrammetry to capture the layout of a physical site and create a digital twin to within a millimetre's accuracy, it says. The system allows users to pair the virtual digital twin with the project's plans in an effort to ensure the design and reality are a perfect match. The company is now adding virtual reality to the mix, allowing users to don headsets and take a virtual stroll through the project's digital representation.
- GE's Thermal Production Optimization software uses proprietary machine learning models to create a digital twin of a SAGD project in an effort to optimize operations like steam allocation across the field—which can have a material impact on production and save a company millions of dollars.

On a typical SAGD facility, there may be too many dynamic variables at play for any one reservoir engineer or team to solve. Advanced analytic and machine learning, however, can leverage the massive volumes of data the facility produces to provide well models that are used to run what-if scenarios and constraint-based optimizations. That could allow operators to establish ideal operating parameters on individual wells or across an entire field.

In one published case study of the Thermal Production Optimization software, GE said it produced a one to 1.5 per cent improvement to steady state operations and a three to five per cent improvement to non-steady state production across a SAGD producing field. Even a one per cent improvement in production can yield millions of dollars in additional revenue annually.

- Calgary-based Stream Systems has also developed a cloud-based software-as-a-service application that allows users to create, customize and test their projects in a virtual environment to extract maximum value from large capital investments. Stream Systems says it can trim the costs of capital projects 20 per cent by using simulations to mimic reality to test innovation in a risk-free, virtual environment.

By virtually replicating key elements of a business challenge, Stream Systems says it can run any number of variable inputs and outputs—for example, different economic scenarios, regulatory changes or the effect of equipment breakdowns or different routing options—and allow companies to experiment with design and operational strategies until the best approach to solving a problem is determined.

- While companies in the consumer auto market are racing to perfect driverless vehicle technology, oilsands producers are close to implementing the technology for some of the world's biggest vehicles—the heavy haulers used in oilsands mining operations.

Suncor Energy, which has a fleet of about 100 heavy haulers, is piloting the technology with 400-tonne Komatsu Front Runner autonomous haul trucks as part of a larger shift toward increased automation in mining. The Japanese company producing the Front Runner already uses the technology at large mines in Chile and Australia. Able to be remotely controlled and operated 24/7, GPS-assisted autonomous heavy haulers, which have also been developed by Caterpillar, are expected to cut costs five to 10 per cent.

- Engineering and procurement firm Vista Projects has created an integrated data portal designed to provide an open project database with real-time updating ability that can be shared by all parties participating in a major project. Full digitalization creates a layered and comprehensive online database that can be searched quickly and easily, Vista says.

Integrated engineering software is designed so changes made to one part of the design are automatically replicated or flagged in other layers of the database.

Vista says it recently completed one of the oilsands industry's largest and most comprehensive implementations of a digital engineering environment for a new project's front-end engineering and design (FEED). The technology allowed the operator to reduce costs through process simplification, plot plan compression, fit-for-purpose specifications, increased modularization and optimized execution, Vista says. The result was a collaborative effort with its client that led to FEED coming in 16 per cent under budget.

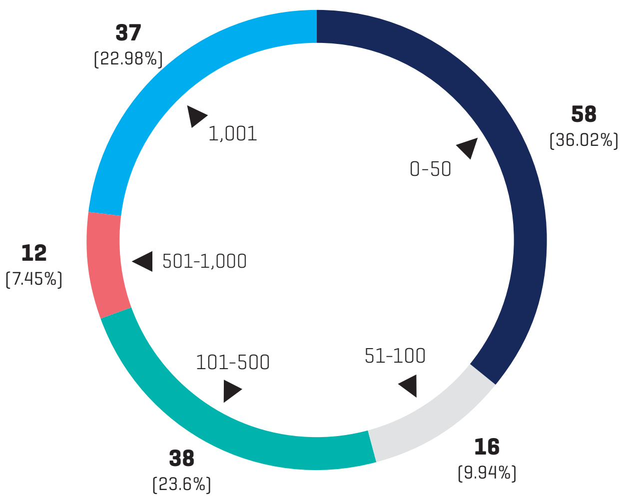
MEASURE TWICE, CUT ONCE

Alberta Projects Improvement Network survey shows better upfront planning could result in significant savings on project costs

BY DARRELL STONEHOUSE

DEMOGRAPHICS

How many employees (both permanent and contract) does your company currently have?



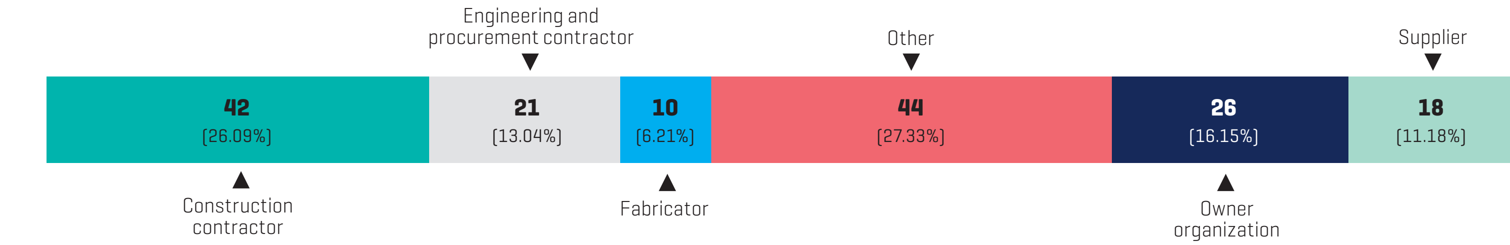
With ample oil supplies leading to longer-term lower prices, getting oilsands supply costs down is job number one across all sectors of the industry.

New engineering designs, technologies and business models are all being tested to make oilsands production competitive on the global market.

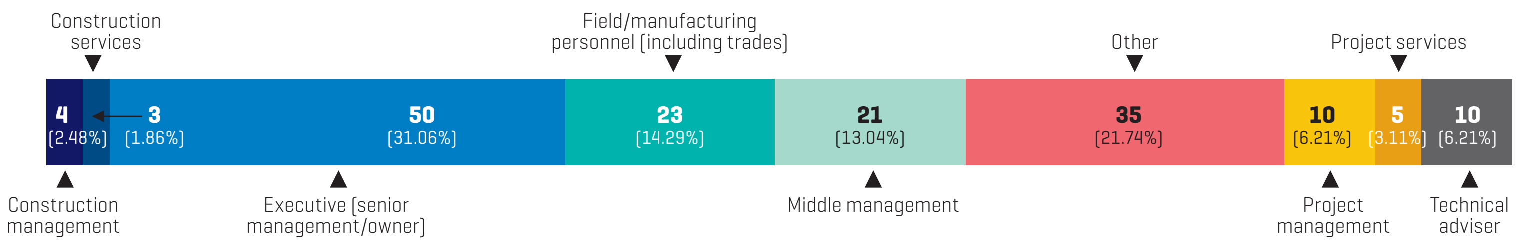
But another area with great potential to save costs is in project management. A study released by the Alberta Projects Improvement Network (APIN) in late 2016 shows using project management processes like stage-gating and advanced work packaging could result in major savings in capital costs in developing oilsands projects.

Stage-gating breaks a project into manageable pieces, with the project team having to meet specific criteria before moving on to the next stage in the project. By thinking in terms of staging, owners can closely monitor deliverables ►

What type of company do you work for?



What is your position within the organization?



and planning as the project moves through its life cycle.

Advanced work packaging is the extension of front-end planning across the project life cycle. It starts at the initial project set-up and, through interactive planning, guides the project through engineering and construction work packages.

APIN analysis shows when advanced work packages are implemented, there is a 25 per cent improvement in productivity and a 10 per cent reduction in total installed costs of a project.

Yet, despite the benefits of both project management practices, they have been slow to be implemented by industry in Alberta. In late 2016 APIN surveyed more than 160 leaders in the industrial construction sector ranging from executives at operator, engineering, procurement and construction management, and construction firms to members of project management teams.

What it found was an industry that knows it needs to change but has been slow to adopt project management best practices to spur that change.

Over 70 per cent of survey respondents agreed Alberta's project delivery and execution practices need improvement, while only two per cent said things are fine as they stand now **(Figure 1).**

The number one way to cut costs, they said, was to improve front-end and workforce planning.

The APIN study found that the biggest cause of poor project delivery is insufficient design completion before beginning construction. Alberta projects average 55 per cent design completion before starting construction compared with 75 per cent in the U.S.

APIN has been promoting the 80/100 rule: 80 per cent of

ALBERTA PROJECT IMPROVEMENT NETWORK (APIN) SURVEY RESULTS

FIGURE 1

Do you think Alberta's capital project delivery and execution needs to change?

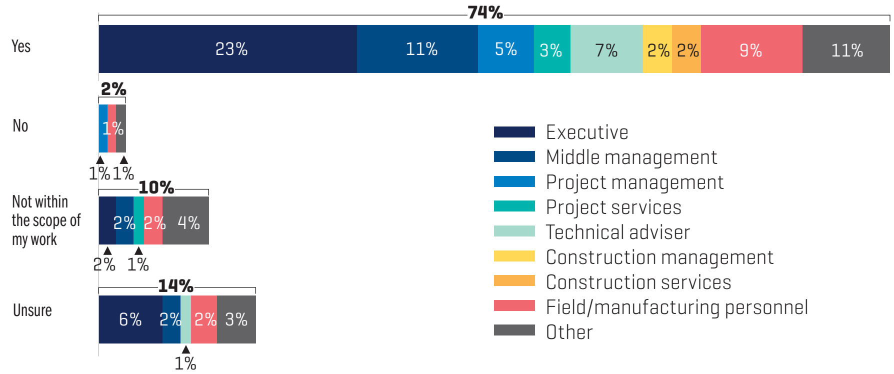


FIGURE 2

Are you aware of/implementing the 80-100 rule (complete 80 per cent of engineering before site mobilization, 100 per cent of Issued for Construction drawings, and specifications must be issued on time and completed prior to construction)?

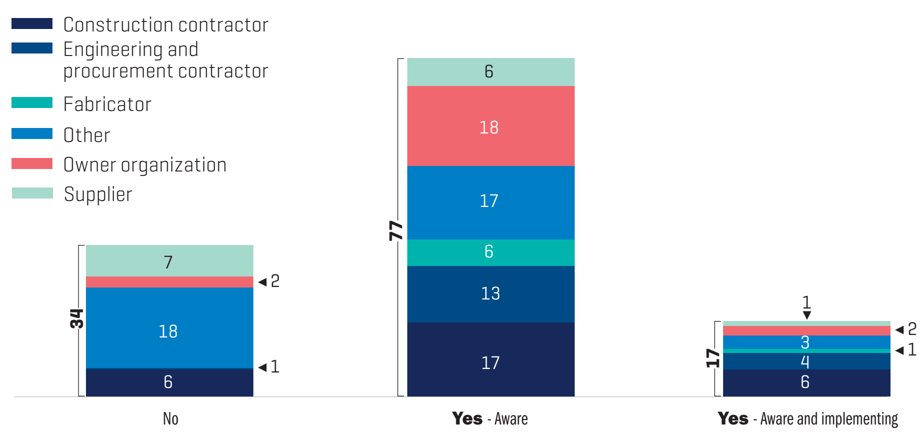


FIGURE 3

Does your company practice "fast-tracking" (sending designs to site or ordering materials before design is completed and reviewed by the construction and operation teams) on projects?

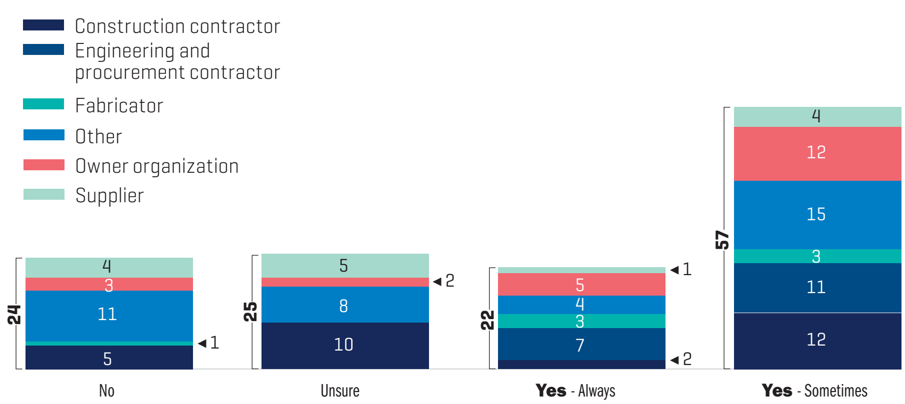


FIGURE 4

From your perspective, are the owners following their stage-gate process?

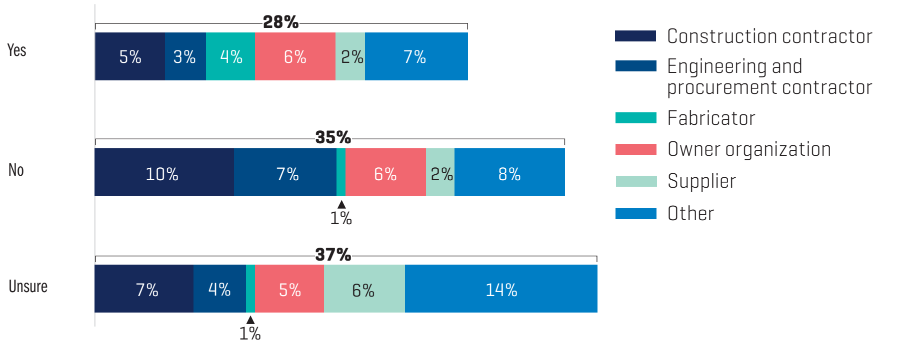


FIGURE 5

How effective is advanced work packaging and workface planning on projects you have worked on?

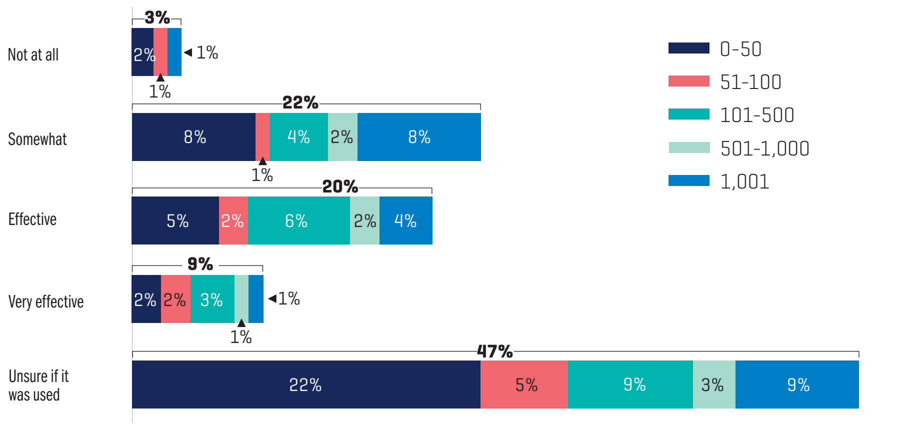
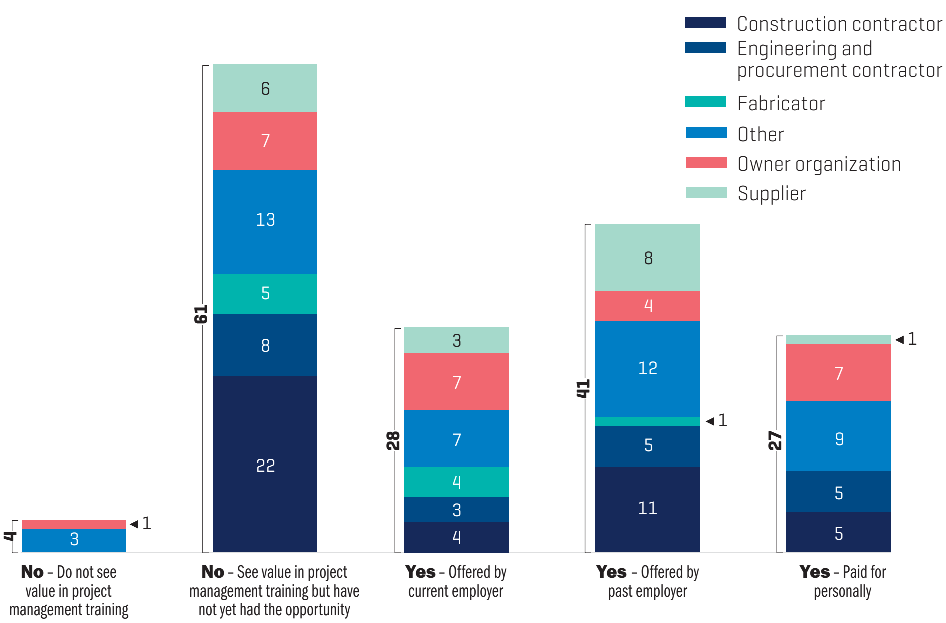


FIGURE 6

Have you ever had any formal project management training?



NOTE: NUMBERS MAY NOT ADD UP DUE TO ROUNDING.

engineering and 100 per cent of construction drawings and specifications completed prior to construction. Around 60 per cent of those surveyed said they were aware of the rule, but only one-fifth of this group had actually implemented the rule in their projects **(Figure 2)**.

Fast tracking—sending designs to site or ordering materials before the project design is completed and reviewed—continues to be common practice in the industry with 60 per cent of survey respondents reporting they sometimes or always fast-tracked projects **(Figure 3).**

Using stage-gating to break up projects and ensure work is completed before moving on to the next phase of the project has also been slow to become a best practice in the industry, with only 37 per cent of survey respondents reporting having applied the system.

Only 28 per cent of respondents said project owners actually follow the process where it does exist **(Figure 4).**

Around 75 per cent of respondents said they were somewhat or very familiar with advanced work packaging and workface planning, with half reporting they had been involved in a project using the practice.

On projects where the processes have been used, almost half of respondents said they were unsure whether they were effective **(Figure 5).**

One possible reason for the slow uptake of best practices in oilsands project management could be a lack of training for workers. Nearly 45 per cent of respondents said their company doesn't currently offer project management training.

Around 40 per cent of respondents said they had no training in project management **(Figure 6).**

Morning in America

U.S. tight oil players emerge from downturn with daylight to grow

BY **DARRELL STONEHOUSE**

PHOTO: ©ISTOCK.COM/ MILLRAW

With oil prices straddling the $100/bbl threshold and billions in investment money available for the taking, it was all too easy

From 2010 to 2015, U.S. unconventional resource developers drilled more than 60,000 wells, adding an incredible four million bbls/d of new production.

Then OPEC turned on the taps and flooded the market with oil. Prices began a downward spiral, sinking to $26/bbl in the first quarter of 2016. Many U.S. unconventional resource developers, burdened with high costs and high debt, began looking for an exit.

"Cut costs, borrow money or liquidate," Ali al-Naimi, then Saudi Arabia's minister of petroleum and mineral resources, told U.S. oil executives during a visit to Houston last March, when prices reached their nadir. He added that his country and other OPEC members had no intention of curtailing production to support oil prices.

U.S. shale and tight oil producers were already ahead of Naimi when it came to cutting costs. Through a combination of high-grading the best drilling prospects, productivity improvements through better technologies and lower service costs, supply costs were hammered ▶

down. From 2013 to 2016, wellhead break-even prices declined by 55 per cent on average, from $80/bbl to $35/bbl, according analysts at Rystad Energy.

Those that could raise capital did. Equity financings rose from a low of $500 million in the final quarter of 2015 to reach almost $9 billion in the third quarter of 2016.

Others simply exited the market: mergers and acquisitions doubled in 2016, reaching $69 billion as debt-ridden companies sold assets or their entire business to more financially stable competitors.

And then, less than a year after Naimi gave his warning, the Saudis and OPEC relented. A 1.1-million-bbl/d supply cut was agreed upon, buoying oil prices into the $50 range in early 2017.

With lower supply costs and higher prices, U.S. tight oil producers are back in the game with daylight to grow.

International energy consulting and intelligence firm Wood Mackenzie expects companies focused on shale oil and gas plays in the U.S. will increase capital upstream spending by 60 per cent, and production will increase by 800,000 boe/d in 2017.

"In the U.S., the Permian-based producers lead the charge," says Roy Martin, a corporate research analyst at Wood Mackenzie.

The forecast, based on an analysis of 2017 spending guidance issued during the fourth quarter reporting period, looks at 40 U.S.-focused producers, which Wood Mackenzie tracks on an ongoing basis.

The tight oil and gas–focused U.S. producers spent US$15 billion on capital expenditures in 2016, but Wood Mackenzie sees that rising to $24.5 billion this year. "That's much higher than we had expected," Martin says, adding that the analysts had been anticipating a 15–20 per cent rise in spending.

Much of this spending is being driven by supermajors like ExxonMobil, Chevron and Shell, which plan to spend a combined $10 billion in U.S. unconventional plays in 2017.

Longer term, the forecasts get even more optimistic. In its Annual Energy Outlook 2017, the U.S. Energy Information Administration forecasts U.S. tight oil production to climb to six million bbls/d by 2025 and level out at the range outward to 2040. Other forecasts are even more bullish, with one industry forecast claiming the Permian alone will be producing five million bbls/d by 2025.

But there remains a lot of uncertainty about whether operators will be able to maintain competitive supply costs as activity heats up and whether the supply in the ground will translate into long-term production growth above it.

ARE SUPPLY-COST CUTS SUSTAINABLE?

There is little question the huge decline in supply costs across U.S. tight oil plays has been an impressive feat, but the questions now are, where did those savings come from, and are they sustainable in the long term?

Rystad has attempted to answer these questions through a detailed analysis conducted throughout 2016 of the top tight oil and shale plays. It breaks down supply-cost savings as due to structural changes resulting from productivity improvements and cyclical changes resulting from cuts to service and supply pricing.

Bill Thomas, chief executive officer, EOG Resources, says his company is only drilling wells that are profitable at $40/bbl.

The analysis shows significant improvements in drilling, completion and well placement, resulting in better production performance and ultimately economic performance.

As newer high-performance rigs have replaced old ones and the use of pad drilling has increased as operators moved from exploration to development, drilling speeds have rapidly increased in the last two years, reports Rystad. Rigs in the largest tight oil plays are now averaging nearly 800 feet per day compared to less than 600 feet per day just two years ago.

Operators are drilling longer laterals and increasing fracture stimulation intensity across plays, opening up more rock to production and adding recoverable reserves, thus lowering supply costs per barrel. And they are high-grading drilling targets to the best acreage, further increasing recoverable reserves.

While these productivity gains have been impressive, Rystad calculates they only account for around 13 per cent of the 45 per cent decline in total supply costs since 2014. Cuts in service prices account for around 30 per cent of the decline, and Rystad believes these gains will be lost as activity heats up.

Operators, however, are optimistic continued productivity improvements and tighter cost management will mitigate service cost increases, at least in the short term.

Unconventional resource pioneer EOG Resources has undertaken a number of initiatives to keep supply costs in check across its unconventional holdings. The company has permanently high-graded its drilling inventory to focus only on what the company calls premium wells.

"Going forward, EOG's capital will be focused on wells that are profitable at $40, meaning with modest increases to oil price, our returns have the potential to soar," says Bill Thomas, EOG's chief executive officer.

EOG's focus on cost control and operational efficiencies delivered big time in 2016, says Gary Thomas, the company's president and chief operating officer. The company had originally planned to spend $2.5 billion drilling 200 wells and completing 270 wells in 2016, but by year-end had drilled 280 wells and completed 445 wells for a cost of $2.7 billion.

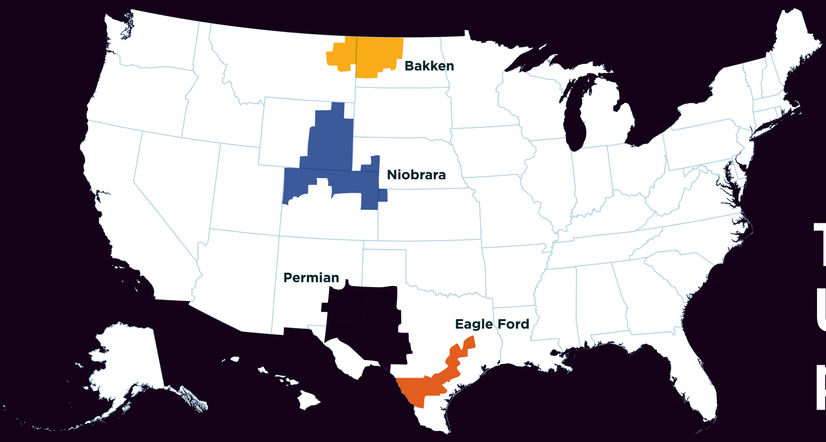
"That's a 40 per cent and 65 per cent increase in drilling and completing activity with only an eight per cent increase in capital," says Gary Thomas.

While EOG expects pressure on service prices to increase in 2017 as activity increases, it believes it can further bend the cost curve downward.

"Our average daily rig rates are down 25 per cent compared to last year. Fourteen of our drilling rigs, or 60 per cent of the total, are under long-term contracts, and nine of these rigs are at bottom-of-market rates," he says. "We've locked in three-quarters of ▶

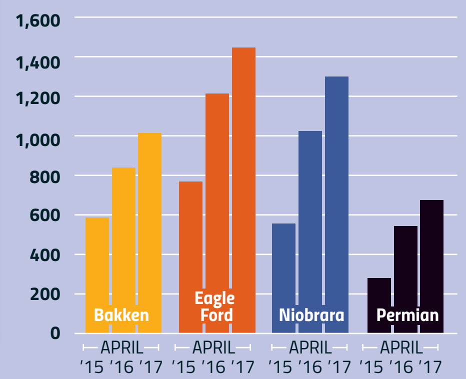
PHOTO: EOG RESOURCES

Tracking U.S. shale plays

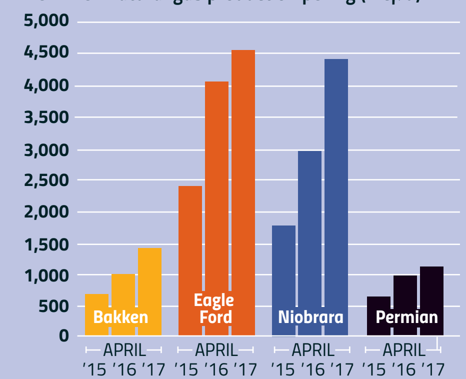


Rig productivity is climbing

New well oil production per rig (bbls/d)



New well natural gas production per rig (mcf/d)

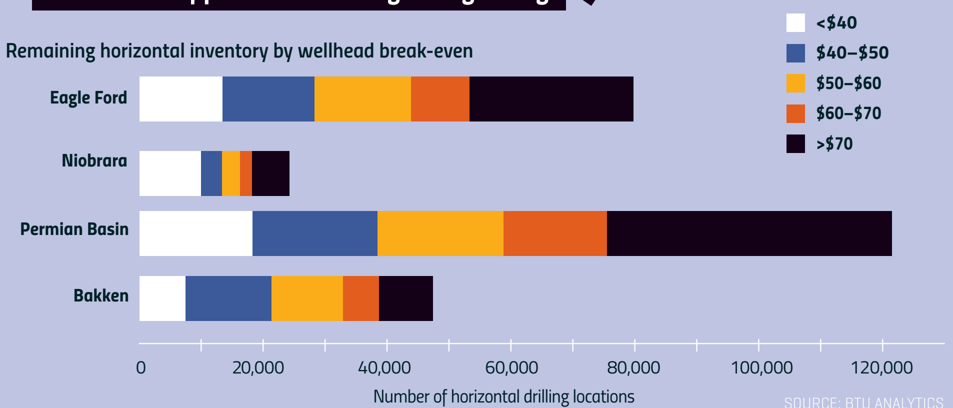


Note: measures the amount of production added by one rig in one month

SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION

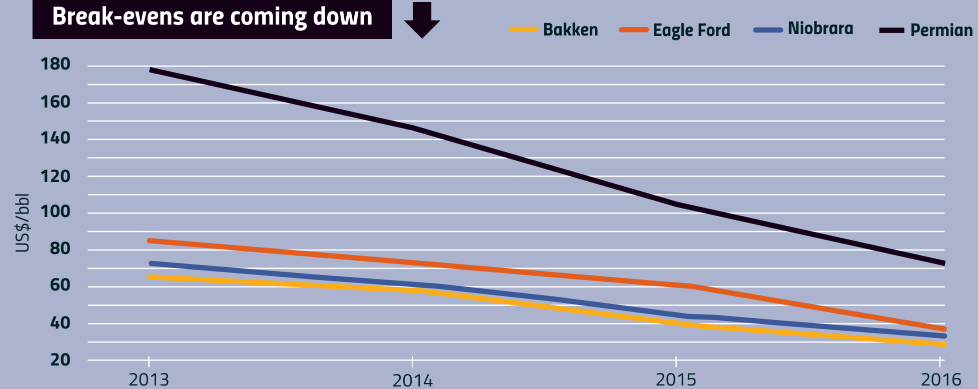
The number of premium well targets is growing

Remaining horizontal inventory by wellhead break-even



SOURCE: BTU ANALYTICS

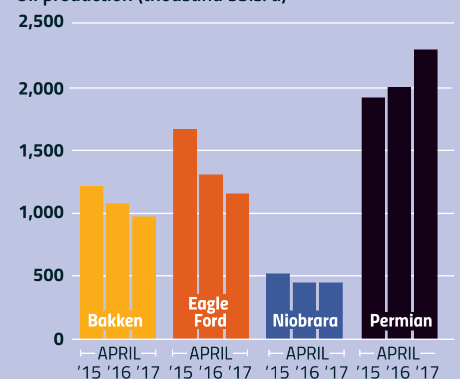
Break-evens are coming down



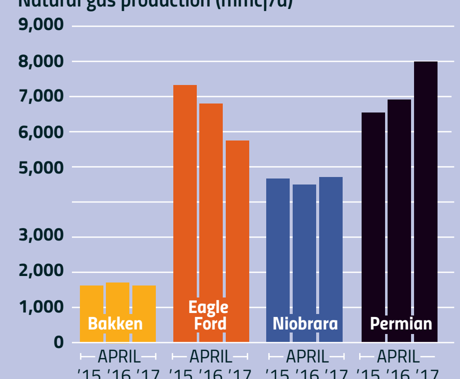
SOURCE: RYSTAD ENERGY

Production is on the rebound

Oil production (thousand bbls/d)



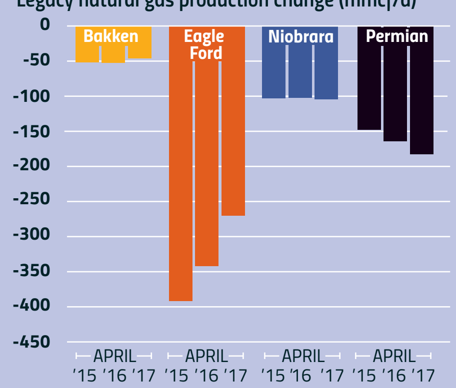
Natural gas production (mmcf/d)



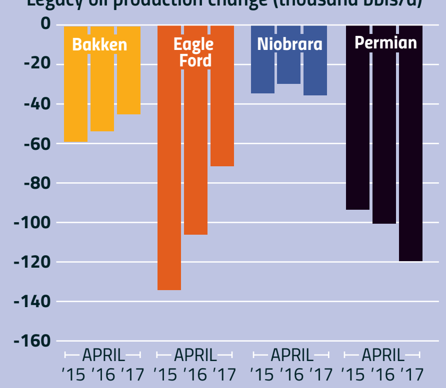
SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION

Decline rates remain a challenge

Legacy natural gas production change (mmcf/d)



Legacy oil production change (thousand bbls/d)



SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION

Darren Woods, ExxonMobil's new chief executive officer, says his company has cut unit development costs 72 per cent in the Permian Basin in the last two years.

PHOTO: EXXONMOBIL

our casing needs at prices 30 per cent below our 2016 costs."

EOG is also expecting to keep tight control of completion costs in 2017.

"To further control cost, we've also locked in 50 per cent of our frac fleets. And we have diverse sources of frac sand, and our aggregate sand costs are expected to decrease by 18 per cent year-over-year," says Gary Thomas. "Our expanded water infrastructure systems are expected to reduce our well cost by another $100,000 per well, and because of the combination of operational efficiencies, we expect to complete 15 per cent more wells per frac fleet this year."

Encana is also looking to lock in its supply-cost savings on its Permian Basin acreage in 2017, says Mike McAllister, executive vice-president and chief operating officer.

The company ramped up its 2017 drilling activity before the end of 2016 to take advantage of lower service costs. And the company remains focused on structural savings on drilling and completions.

"We continue to capture additional operating efficiencies with spud-to-rig-release times dropping below 10 days with our best being below nine days," he says. "We've also improved the efficiency of our completion operations. We have pushed our pumping times up to 20 hours per day.... This compares to more typical efficiencies of 12 hours to 15 hours per day. By making this improvement, we are creating value by lowering our completion costs and getting our wells on production faster."

Encana is focused on building out its pad-drilling program to cut costs. Last summer it brought on 14 wells from a pad in Midland County, Texas.

"We have now returned to this pad," says McAllister. "While those first 14 wells continue to produce, we are drilling an additional 19 wells. This will bring us to 33 wells from a single location. This is the largest multiple pad in the Permian to date. Above ground, this means improving drilling and completion efficiencies and increased utilization of existing facilities. Below ground, it's the first full-scale high-density development in the basin. These 33 wells are across multiple stack zones."

Aside from focusing on technology, Encana is leveraging its internal expertise to keep supply-cost savings as activity ramps up.

"In addition, our approach to innovation and supply chain management gives us a real advantage in offsetting service cost inflation," says McAllister. "We control 75 per cent of our capital spending through our centralized supply chain team. This small team is embedded in our operations organization and is staffed with expert professionals who have the commercial skills to understand markets and how to best procure goods and services. This means our drilling completions teams can focus on what they do best—drilling and completing wells.

"We also manage the supply chain by self-sourcing the key consumables in our drilling and completions operations, like sand, water, chemicals, casing and drilling mud. This gives us better pricing and improves our security of supply for those consumables."

McAllister says Encana has worked to identify "pinch points" for specific services in specific plays and plans ahead to avoid cost inflation. The company saw completions activity picking up in the Permian and responded by locking in a frac spread for 2017 with the option to lock in a second spread.

"We also have a pricing agreement for API sand that we negotiated in 2015 that extends out to 2020," he says. "With that agreement, and by driving efficiency in our logistics, we expect our all-in sand cost to go down this year. We've also had success with non-API or brown sand, which has the opportunity to further reduce our sand costs."

Encana is also looking at water management to cut costs.

"We're having success reducing our amount of consumables in our operations," says McAlister. “As an example, in the Permian, we’re also increasing the amount of produced water that we reuse in our frac jobs from 25 per cent up to 40 per cent. By recycling produced water, we’re also saving on operating costs because we don’t have to pay to dispose of the water. Our approach to sourcing our own water, transporting it by pipe and recycling our produced water in our frac jobs is saving us approximately $1/bbl in the Permian.”

While the large independent producers who pioneered the shale tight oil plays work to maintain their supply-cost gains, global supermajors like Chevron and ExxonMobil have invested heavily in tight oil acreage and are now working their way down the cost curve as well.

“In 2016, we delivered a 30 per cent reduction in our actual operated unit development and production costs and are competitive with our actual non-operated joint-venture partner costs and with some of the best operators in the basin,” says Jay Johnson, Chevron’s executive vice-president of upstream, commenting on Chevron’s more than two million acres in the Permian Basin. “With respect to recovery, we are increasing lateral lengths and continue to evolve our basis of design. Our Permian recoveries per foot have grown between 30 per cent and 40 per cent since 2015 and are expected to increase another 30–50 per cent in 2017. So we are competitive on costs, we are competitive on recoveries, and we are getting better every day.”

Chevron is leveraging a number of its advantages as a multinational company to help manage its supply costs.

“With advanced planning and our ability to leverage our global scale, we’ve secured the crews and materials necessary to execute our program,” says Johnson. “We source tubulars directly from a global supplier that maintains inventories and provides the pipe at global sourced prices.”

“Our rigs have staggered contract durations and competitive rates, and we secured key services with a variety of indexed or performance-based contracts,” he adds.

Chevron is also looking downstream to limit costs and add value to its production.

“We took advantage of the recent market downturn to secure pipeline capacity as well as [natural gas liquid–] and gas-processing and off-take at desirable rates,” Johnson explains. “We have access to multiple market centres to capture the highest realizations, and we’ve contracted capacity with options for expansion to support the majority of planned levels of production through the end of this decade.”

ExxonMobil entered the U.S. shale market with its $39-billion takeover of XTO Energy in 2010. Since then, it has continued to build acreage, most recently through a $6-billion acquisition of 227,000 acres in the Permian Basin. Darren Woods, ExxonMobil’s new chief executive officer, points to the Permian as an example of his company’s progress in driving down supply costs.

“Total unit development costs have been reduced 72 per cent in the last two years to less than $8 per oil-equivalent barrel. We have successfully reduced cash-field expenses by nearly 50 per cent since 2014 to approximately $5/bbl,” says Woods.

ExxonMobil is now leveraging this success and applying it across its unconventional fields.

“We’ve dedicated a team to research and develop techniques to maximize lateral lengths, support next generation well completions and optimize the development of unconventional fields,” he explains. “These combined efforts will improve recovery and reduce the total number of wells needed. While this data is specific to the Permian, we have achieved similar results in other unconventional areas by quickly transferring what we’ve learned and fully leveraging our experience.”

Jack Williams, ExxonMobil’s senior vice-president, says the integrated company brings more to the table than just expertise in developing its shale resource.

“We have that full value chain that goes from the acreage position all the way through to the market. So when you add on the development planning piece, the leveraging, the scale of our company, the research, the midstream, the refining infrastructure on top of our operating prowess and the acreage position, then I think you really have a winning combination,” he says.

OPERATORS PREDICTING HUGE PRODUCTION GROWTH GOING FORWARD

With supply costs now globally competitive, operators are predicting huge production growth across tight oil basins in the next decade.

Woods says ExxonMobil has nearly 5,500 drilling locations in the Permian and Bakken plays that are economic at $40/bbl to build on current production of approximately 230,000 boe/d.

“Through 2025, our total net production for these basins could grow to more than 750,000 oil-equivalent barrels per day, representing a 20 per cent compounded annual growth rate,” he says. “Pace will be driven by leasehold facility development, learning curve benefits and technology application.”

Chevron’s Johnson sees similar potential on its Permian acreage.

“Our current production forecast through 2020 is between 325,000 and 450,000 bbls/d, representing a compounded annual growth rate of 20–35 per cent,” he says. “We’re also evaluating cases where we continue to add rigs beyond 2018 and have several scenarios that would grow production of more than 700,000 boe/d within the next 10 years.”

If that sounds optimistic, consider Permian producer Pioneer Natural Resources’ vision for the next decade. Pioneer, currently producing around 235,000 boe/d, has set a target of one million boe/d by 2026.

An internal Pioneer forecast for the entire Permian Basin predicts liquids production could reach five million bbls/d, the equivalent of Canada’s current total production, in 2026. Associated gas production could reach 16 bcf/d, surpassing Canadian production.

But getting there won’t be easy.

With first-year decline rates on individual wells as high as 75 per cent, around 7,000 wells need to be drilled and completed each year just to maintain current production.

There is no shortage of potential targets, as analysts estimate there are 300,000 locations remaining in U.S shale plays. BTU Analytics estimates there are around 50,000 wells with break-evens below $40/bbl, and close to 100,000 wells with break-evens at $50/bbl or less. But those will rise if supply costs do.

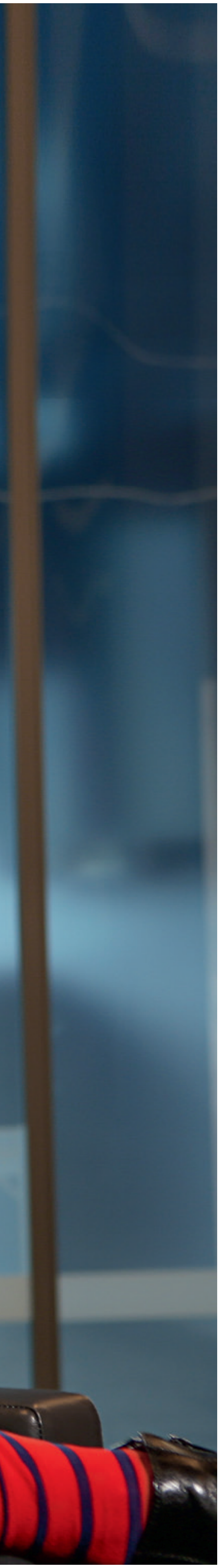
ExxonMobil’s Williams believes the U.S. is well situated to manage these costs.

“You have this unique environment in the U.S. with private mineral rights and the huge infrastructure we have and the service companies and the capital markets,” he explains. “And all that comes together to really underpin a lot of the development in the U.S. You don’t find those, all that combination of characteristics, elsewhere.”

profile

PHOTO: JOEY PODLUBNY

"We can celebrate our differences, but we also need to allow ourselves to come together for the common good."



FIRE IN THE BELLY

Bruce Edgelow's career spanned ATB Financial's transition into the energy big leagues

BY **R.P. STASTNY**

Here's the gist of what ATB Financial's former vice-president of strategic initiatives, Bruce Edgelow, had to say to the audience at his April 13th retirement do:

"The biggest issue that I see, and I talk about it all the time, is the notion that society, through a variety of dynamics—whether it's how we communicate with each other, social media or for other reasons—seems to be moving to the polar ends of issues. That's where we dig in our spears, and that's where we camp. Whether it's climate change or politics or faith, we seem to be celebrating the uniqueness of our disparities.

"But that's not how we can advance the issues. We can celebrate our differences, but we also need to allow ourselves to come together for the common good. The challenge for all of us is to move from the ends of the spectrum and find the way to the middle ground. It's from this middle that things get done."

Finding the middle ground is also what true leadership is about, Edgelow says. This middle ground is inclusive, yet doesn't pander to interests that lead away from the common good. Citing former prime minister Brian Mulroney speaking at an industry event, Edgelow says, "Sometimes, leaders have to be prepared to have tomatoes thrown at them."

By that, he means leaders need the wisdom and backbone to make decisions that may not be popular with some people but that are right decisions for the country, province, company or family.

No, this isn't Edgelow's opening bid for a life in politics after ATB. It's an expression of his personal beliefs, which happen to parallel those of the institution he served for 13 years. ATB today stands on level footing with its international competitors, such as RBC and CIBC, but its focus on western Canada and serving Albertans as a provincial Crown corporation sets it slightly apart from its peers.

One difference becomes apparent during the inevitable downturns in the Alberta economy. When people are in a state of panic, ATB tries to be the calming voice that says, "Just breathe."

"We have to lend through the cycles and be patient," Edgelow says. "We hire for that so that our people step into those situations and stand tall and make a difference and do the right thing. Think client first. Don't overreact. Have honest but earnest and respectful conversations with clients through the downturns."

Heading into year three of this oil and gas trough, those conversations are still taking place.

"But thankfully there are low interest rates in this downturn, and we're not hyperinflationary," Edgelow says. "There's also a fair amount of capital ready to come into the business. But that capital is anxious and still very wary to come in."

Commodity prices are double what they were last year, but the industry expanded recently on the back of much higher prices, so it's still difficult. There is also a more onerous regulatory environment today, with new rules around liability management ratios, licensee liability ratings and carbon constraints.

"So 2017 is still going to be very choppy," Edgelow says.

So financial institutions are treading carefully as oil and gas companies adapt to significantly new market realities. ATB faced similar challenges and opportunities in the early 2000s, when the oilsands came of age and people from all over Canada poured into Alberta.

Edgelow joined ATB in 2003. He was part of ATB's transformation from regional lender, hiding behind the province's triple-A credit rating, to full-service financial provider. The institution grew its capabilities to include a mergers-and-acquisitions advisory, gave its clients access to equity markets by taking a 30 per cent interest in AltaCorp Capital and expanded its syndication structure to handle much larger loans.

Today, it's not uncommon for ATB to lead on $900-million syndications. It's an institution that can grow with its clients through every stage of development. Provincial stalwarts, such as the mid-streamer Secure Energy Services, call ATB their agent bank.

"We've created the DNA of a shop that allows us to say to our customers, 'Bring us your talent and your passion'—or as my wonderful boss, Ian Wild, used to say, 'Bring us your fire in the belly,'—and let's see what we can do," Edgelow says. "The biggest legacy for me is to look back at the depth and breadth of the team at ATB now compared to what we started with. It's humbling."

GORDON JAREMKO is a former editor of *Oilweek* and a member of the Canadian Petroleum Hall of Fame.

POLICY

POPULIST CAPITALISM

Rebirth of a formula to enlist public support for industry

Albertans had pride in owning the oilsands when production began 50 years ago. Watch for an effort to revive personal connections to resource wealth—and popular acceptance of industry—on the political right.

Legitimate government roles still include fostering citizen stakes in development, Preston Manning told the 2017 annual meeting of the Canadian Petroleum History Society. The architect of the modern federal Conservative party added that his Manning Centre hopes to make the idea a plank in the platform for uniting Alberta's Wildrose and Progressive Conservative factions.

He described as "still relevant today" a populist investment policy, to broaden ownership of the private sector, that his father Ernest Manning used during his 1943-68 tenure as Alberta's longest-serving premier. The strategy helped lay two energy industry cornerstones.

The elder Manning built a 1960s Social Credit brand of people's capitalism into the pioneer bitumen mining and upgrading complex, Great Canadian Oil Sands (GCOS). His Fort McMurray foray into government-sponsored personal investment followed a 1950s success: Alberta Gas Trunk Line (AGTL), the ancestor of TransCanada's 24,000-kilometer supply collection grid, Nova Gas Transmission.

After much thought about Crown corporations versus conventional firms, "we finally came up with a third alternative," the retired premier recalled as a senator in 1981 in an oral history interview preserved by the University of Alberta.

AGTL's charter, enacted by the legislature in 1954, created a hybrid public-private enterprise with five ownership layers: personal investors, gas utilities, exporters, producers and processors, and two cabinet appointees on the seven-seat board of directors.

Alberta residents, granted first rights to buy, snapped up eight million non-voting shares for $5 each from the government-owned ancestor of ATB Financial. For a province that was just beginning to taste energy industry–driven affluence, the sale was a spectacular success. The $40-million total would be $368 million in 2017 purchasing power, according to the Bank of Canada's inflation calculator.

"The stock never looked back. It was up $10, $15 and away it went like a rocket. A lot of these people made a lot of money," the retired premier recalled.

When construction of GCOS began in 1965 after years of regulatory and financial ordeals, the Manning government again made a public share in the action a must: 125,000 Albertans—or nearly one in ten provincial residents at the time—paid $100 apiece ($781 today) for $12.5 million ($97.5 million today) in debentures convertible into ownership stock.

For the 10-year lifespan of the debentures, Manning acknowledged, "that deal didn't work out nearly as profitably for the [GCOS] investors as Alberta Gas Trunk." The first oilsands plant struggled for seven years before revenues exceeded operating costs for even one three-month financial quarter.

Most investors cashed in the GCOS debentures for their six per cent interest rate. But about 8,000 converted the debt paper into ownership shares and unsuccessfully fought Sun's complete takeover of the plant in 1979, saying the deal undervalued brightening oilsands prospects as prices and production methods improved.

The retired Socred premier stayed out of the takeover fight but suggested standard Canadian financial practice neglected much potential public participation in economic development.

Manning maintained government-supported share sales "demonstrated a conviction we had for a long time—and I still have this same conviction—that there are literally hundreds of millions of dollars of investment capital in the hands of the 'little people,' and it's not tapped for the simple reason that the whole structure that we have in Canada and elsewhere for financing industry is oriented to the larger investor."

The elder Manning was not alone in his faith. The founders of the Progressive Conservative dynasty that replaced his Socreds gave populist capitalism a big outing.

The Tories scored a landmark success by creating the Alberta Energy Company (AEC) with a legislature charter as a management team of private industry veterans, a control block of stock held by the provincial government as an investment and a 1975 Albertans-first share sale. The stock was snapped up by 60,000 personal investors.

Like the AGTL pipeline grid, the AEC production network swiftly grew into a business masterpiece that sired two economic pillars: Encana and Cenovus Energy. The original hybrid public-private ownership structure lasted until the government of the third Tory premier, Ralph Klein, sold its AEC shares to repay provincial debt and march in step with the 1980s and '90s international "privatization" vogue.

When GCOS redeemed the bonds in 197,5 investors received a medal stamped with a slogan "pioneering energy together" and images of a bucket wheel and dragline. "You have helped pioneer a very difficult venture that today stands as a milestone in realizing the potential of this unique Alberta resource," said the souvenir package. "Your role has been an important one—your participation historic."

DAVID YAGER is a former oilfield service executive who has written extensively about oil and gas since 1979 and was the PSAC chair in 2009-10.

SERVICE & SUPPLY

REAL OIL SERVICE RECOVERY STILL IN THE FUTURE

The good news is the battered oilfield service (OFS) industry is participating in the recovery. The bad news is how it is being done. When customers trumpet how they can earn acceptable returns at crude prices half of what they were three years ago it is primarily because OFS is denied the same opportunity. Think subsidy.

This means a real recovery—where clients and suppliers operate intelligent businesses that service the capital employed—remains in the future.

This is not to say activity hasn't improved. It has. According to the *Daily Oil Bulletin*, to the end of this year's first quarter there were 2,348 wells drilled on a "rig-released basis," up an impressive 115 per cent from only 1,091 wells drilled in the same period in 2016. OFS was scrambling for people, just like the good old days. You'd think there was something really good happening.

The problem is pricing. While oil companies recognized they had to pay more, it wasn't enough when the value of the capital assets being worn out on the job is taken into consideration. While service rates were up in the first quarter, a lot of the increased margin was consumed by higher wages, increased fuel costs and investments in getting equipment back in good working order. Mullen Group, one of the first companies to report 2016 results, indicated fuel was up 40 per cent in the first quarter of 2017 compared to 2016. Many of the experienced personnel released during the downturn either didn't want to come back or couldn't take the financial risk of leaving something steady for higher paying but short-term work of unknown duration. Therefore, OFS had to spend precious cash on recruiting and training. That hurt.

Some of the more revealing analysis comes from the U.S., which for the most part, operates the same way. An article on oilprice.com from April 10 by Arthur Berman, a petroleum geologist, reports that, while operators have indeed managed to figure out how to break even on new shale oil wells at US$40/bbl, most of the credit goes to reduced service prices, not oil company genius or more prolific reservoirs.

Public regulatory filings contain data that helped Berman calculate breakeven finding and development costs. Berman credits collapsed drilling and service costs as the major contributor. The Federal Reserve Bank of St. Louis publishes a producer price index for drilling oil, gas, dry or service wells dating back 30 years. After sitting at about 150 for the first five years of this century, the index went through the roof with rising oil prices and the shale boom. It peaked at 455.6 in March 2014, more than triple what it was ten years earlier. It then sank like a rock to 288.6 in January 2017. In March of this year, it was up slightly to 299.2 but was still 35 per cent lower than three years earlier.

In an earlier article, Berman figured the success operators were having putting oil on stream at lower prices was 90 per cent created by collapsed OFS rates and only 10 per cent by advanced technology or improved completion techniques. In the ten years from 2004 to 2014, Berman calculates the cost of drilling a well—including deep water offshore—rose by 400 per cent but now sits 45 per cent below peak levels. When it comes to making money at these prices, this certainly helps the customer. And only the customer.

The reward for higher service prices by some of the more mercenary clients has been intentionally extended payment terms to 90 days or longer. Thanks, buddy. OFS has been a de facto banker for customers since the early 1980s, when heavily-indebted Dome Petroleum advised its suppliers it could not pay them for 90 days due a cash shortage. To everyone's surprise, Dome's vendors went along with it. This emergency measure became accepted industry practice by too many operators, a phantom saving baked into prices that makes operating at low margins even more challenging.

But the biggest challenge is servicing invested capital. Examining annual reports for five top public drillers—Precision Drilling, Ensign Energy, Trinidad Drilling, Savanna Energy and Western Drilling—for six fiscal years, 2010-15, revealed these companies invested more than $8 billion in new equipment and upgrades, mostly new-generation rigs for extended-reach horizontals. The owners are currently wearing them out at margins unlikely to reflect replacement cost because OFS cannot extract anywhere near the cost reductions from its supply chain as clients are enjoying.

The new well market is elastic. Cut the price and more wells will be drilled. If the risks and rewards are shared, everybody benefits.

But they are not.

CHERYL CARDINAL is the president and chief executive officer of the Indigenous Centre of Energy

ENVIRONMENT

RIGHTING THE PAST

The Wiikwemkoong First Nation takes charge of an orphan wells remediation project in Ontario

The stories of Wiikwemkoong First Nation Elders helped locate undocumented oil wells drilled on Manitoulin Island, Ont., in the 1860s and 1950s as the community led a remediation project to remove the legacy of industrial development from its land.

Wiikwemkoong Unceded Territory #26 is the largest Anishnaabek community on the eastern peninsula of Manitoulin Island, between Georgian Bay and Lake Huron. Its 56,000 hectares of picturesque land is home to 8,000 band members whose leaders fought for decades to remove the pipes, structures and contamination left behind by oil and gas development.

This kind of impasse is not specific to this community but sadly is the reality for many First Nations communities across this country. In working toward a resolution, the Wiikwemkoong band members asked themselves how they wanted to be involved in the remediation of this project. Were they going to allow the government to come in and address the problem? Would the members stand on the sidelines while the oil and gas sector worked on the issue? Or would they ultimately roll up their sleeves and be the leaders on the project?

They decided the best path was to empower the community to control the project and train the necessary members to complete the work on the abandoned wells. The Wiikwemkoong leadership was clear about its goals and the direction it wanted to take to start this project in 2013.

Under the supervision of Patrick Fox as project manager and Jean Pitawanakwat as project coordinator, the Wiikwemkoong's department of lands and resources launched the Medi Kaaning Orphan Well Abandonment and Site Restoration project. The name of the project makes its own statement: "medi" means oil and "kaaning" means land in their language.

Fox was trained as the project manager and was given the proper mentorship to lead the project.

Pitawanakwat initially started as an environmental technician but gained the necessary skills to increase her involvement and knowledge to become the project coordinator. Her understanding and skills proved to be a great asset in showing project funders and partners that it is possible to bridge the gap between traditional knowledge and technical expertise.

"Eastern Oilfield Services Ltd. and Premier Environmental contractors trained band members to work with H_2S, oil rigs and environmental clean up," Pitawanakwat says.

Training new skills brought new competencies into the community, highlighting the abilities of First Nations people in the oil and gas sector when a community is properly supported.

Support from Indian Oil and Gas Canada, a special regulating agency under Indigenous and Northern Affairs Canada allowed the First Nation to move the orphan wells clean up through to completion.

"I'm really impressed with the growth this has delivered to [our community]—well work, prospecting, exploration and environmental clean up. They are now in demand by other companies," Fox

The First Nation would like to help other communities that face similar challenges by providing training and resources and sharing information.

PHOTO: WIIKWEMKOONG UNCEDED TERRITORY

Industry and the community worked together on the project.

says. "It has been a bit of learning curve, but we surrounded ourselves with the best."

Fox says his community now would like to help other First Nations that face similar land degradation and contamination challenges by providing training, resources and sharing information.

The Medi Kaaning Orphan Well Abandonment and Site Restoration project has not only built new capacity within the community but has turned its people toward the future rather having to battle with the past. But the project's greatest achievement is restoring the Wiikmemkoong's land back to its natural beauty.

"We get to use our land, water and air," Pitawanakwat says.

DUKE PELTIER, Ogimaa (chief) of Wiikwemkoong Anishnaabek, will speak on the "Connections to the Environment" panel at the upcoming Indigenous Conference on Energy and Mining on June 14–15, 2017, in Calgary in conjunction with the Global Petroleum Show.

For more information on the community of Wiikwemkoong Unceded Territory, please visit their website at wikwemikong.ca.

Members of the Wiikwemkoong Unceded Territory were trained by Eastern Oilfield Services and Premier Environmental to help reclaim and remediate abandoned wells on Manitoulin Island. Indian Oil and Gas Canada also supported the effort.

PHOTOS: WIIKWEMKOONG UNCEDED TERRITORY

Drilling a deep well near Fort St. John, B.C., in the early 1950s.

PHOTO: FORT ST. JOHN

Gasland

EARLY DEVELOPMENT IN NORTHEASTERN B.C. LAID THE FOUNDATION FOR TODAY'S SPOT IN THE HEART OF CANADA'S OIL AND GAS FUTURE

BY **JIM BENTEIN**

Geoff Morrison is a bit of an amateur historian and, as the manager of B.C. operations for the Canadian Association of Petroleum Producers, he has read extensively about the province's oil and gas history, one in line with the swashbuckling nature of resource development in Canada's westernmost province.

While B.C.'s tremendous reserves of liquids-rich natural gas in the Montney, Duvernay and other regions in its northeast are now viewed as central to the future of Canadian energy, explorers in the 1920s and 1930s were looking for oil.

"Back then we were reliant on the U.S. for our oil, and there wasn't a market for natural gas," Morrison says. "You only used natural gas if it was close to the place where you were living."

The search for oil and gas in B.C. didn't start in the northeast, Gerald Clare, the former president of the South Peace Historical Society, noted in 2003.

Clare traced the beginnings of B.C. oil and gas exploration to the Fraser Valley, where geologists thought there was a deep and productive sedimentary basin. But, aside from a few small gas discoveries, nothing of commercial value has ever been found there.

The search then shifted to Vancouver Island, where an area near Sooke attracted the Western Canada Prospecting Company.

"Beginning in 1910, three years of drilling produced nothing but disappointment for the company," Clare said.

Others attempted to find commercial oil and gas in Haida Gwaii (formerly the Queen Charlotte Islands) and in the Flathead River Valley, in the southwestern corner of the province. But once again the explorers found nothing.

It was then that the search spread to Peace Country in northeastern B.C. (a search that was also beginning in earnest on the Alberta side).

Evidence of hydrocarbons in Peace Country dates back decades to as early as 1914. That's when a young farmer named Blaine Pierce noticed a "black, oily seepage" discolouring the snow along the Pouce Coupe River, near Dawson Creek.

Once he took a specimen to a laboratory at the University of Alberta, Peace Country's early oil and gas rush was on.

The most notable explorer was Northwest Oil, a subsidiary of Imperial Oil, which drilled in the area in 1921. Using a cable rig, oil and gas were both discovered near the Pouce Coupe area—but more gas than oil.

In fact, they found so much gas that workers tapped the well for cooking, replacing firewood. But the gas line ruptured and caused an explosion that resulted in several injuries. Northwest capped and abandoned the well.

However, interest in the area continued, and in 1936, Imperial drilled a well at Pouce Coupe. It was set on fire by arsonists and burned for two months until finally being capped.

In 1937, the Guardian Oil Company began drilling nearby, close to the village of Bonanza, where it became so confident in a major oil find that it developed plans to build oil and gas pipelines to transport hydrocarbons to the Vancouver area.

Guardian's Bonanza No. 1 well was "standing full of oil," according to one observer at the time. A second rig was shipped to the area from Turner Valley.

Drilling continued throughout the Second World War, but there were no major finds until 1948-49, when drilling for gas began in earnest in the Pouce Coupe area on both sides of the border.

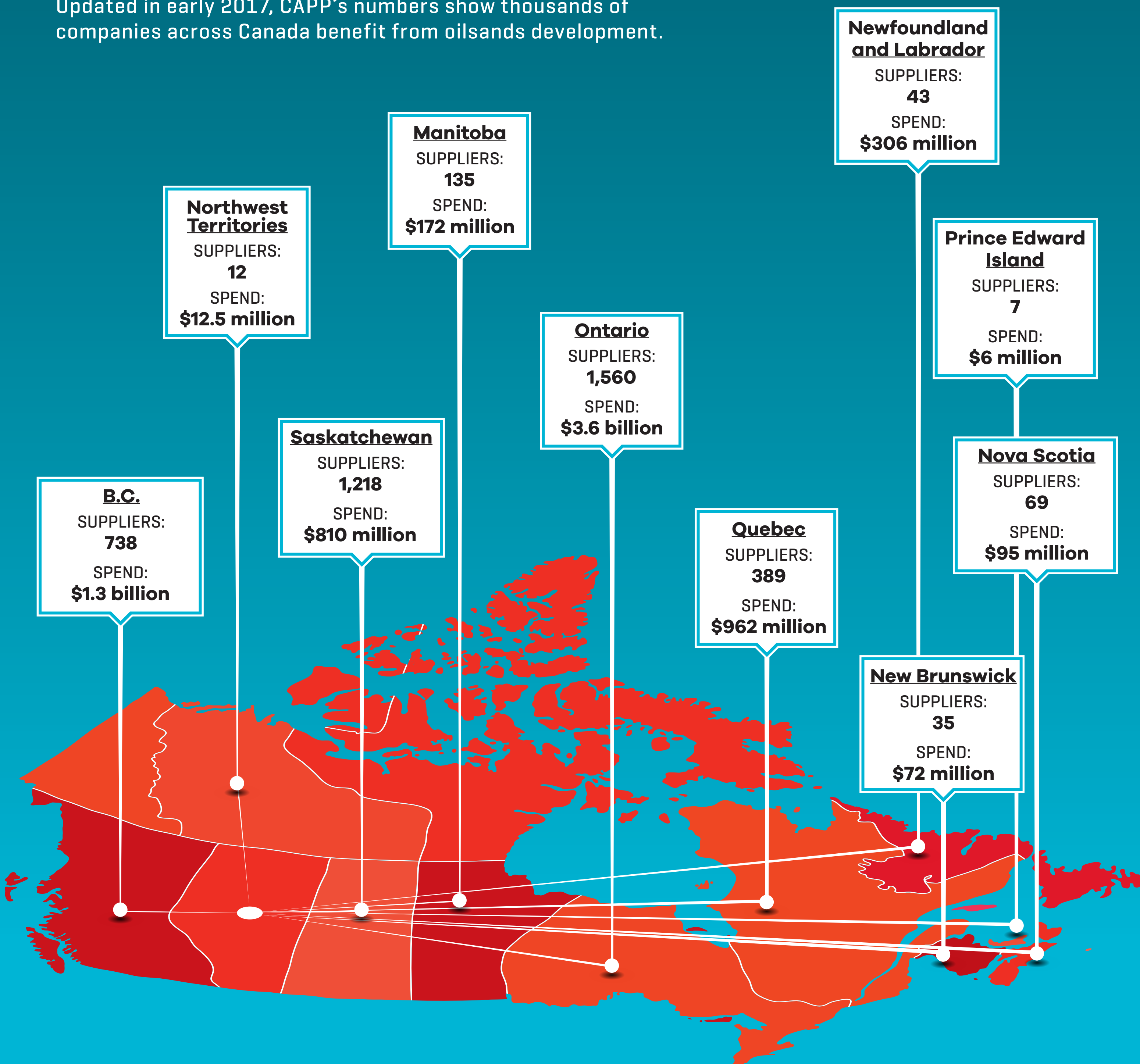
The General Petroleum Company, which had drilled four successful wells on the Alberta side, shifted to the Rolla, B.C., area 15 kilometres from Dawson Creek. By late 1948, production was reaching 70 mmcf/d.

The subsequent development of the province's first gas processing plant at Taylor, B.C., in 1955 and of Canada's first large-diametre pipeline, which transported gas from northeastern B.C. and Alberta to the Vancouver area, laid the foundation for the gas boom that continues today.

numbers

SPREADING THE WEALTH

Most Canadians think the oilsands are an Alberta story. But that is far from the truth, according to supply chain data from the Canadian Association of Petroleum Producers (CAPP). Updated in early 2017, CAPP's numbers show thousands of companies across Canada benefit from oilsands development.

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