

Alberta Oil & Gas Quarterly

Winter 2020



Table of Contents

Cover Feature

Midstream: Inside the growing Alberta sector adding value to oil and gas

Investors drawn to midstream market as pipeline challenges drive demand 3

Spotlight

Keyera Corp. 4

Pembina Pipeline Corporation 6

Gibson Energy Inc. 7

Midstream data 8

Alberta Oil & Gas Price Forecasts 11

News

Alberta Indigenous Opportunities Corporation advancing toward funding projects 13

Applying ‘purposeful AI’ to your business 14

Painted Pony tests potential wellsite emissions elimination technology 16

Upstream 17

Midstream 19

Downstream 21

Mapping Alberta Oil and Gas

Connected to North America’s Critical Infrastructure

Oil 23

Natural Gas 24

Alberta Crude Oil Plays 25

Alberta Natural Gas Plays 26

Alberta pipeline safety record continues to improve: AER 27

Contacts 28



Investors drawn to midstream market as pipeline challenges drive demand

The midstream oil and gas assets in Alberta that transport, process and add value to the province's resources have become highly sought after as producers grapple with lack of export capacity out of the basin, creating a dynamic market for midstream operators.

"From a midstream operator's viewpoint, this situation has created significant demand for access to their assets," says Liam O'Brien, strategic advisor with Sproule.

This is particularly true for facilities and pipelines that produce and transport natural gas liquids (NGLs), as low natural gas prices have dramatically reduced the value of dry gas production.

Alberta AECO prices averaged US\$1.52/mmBtu in 2019, a full dollar lower than the U.S. Henry Hub benchmark at US\$2.54/mmBtu, according to Sproule data.

Production of NGLs like condensate, propane, butane and ethane increases value for producers, albeit still discounted compared to U.S. volumes.

"The midstream industry has been active over the past several years as NGLs, especially condensate for use in the heavy oil industry as diluent, are seen as the source of value in natural gas that continues to fund drilling programs," says Bill Rawlusk, IHS Markit's executive director of oil markets, midstream, downstream and chemicals.

Midstream operations are attractive for investors because they are driven by long-term agreements and not the drill bit, he says.

"You could almost view it like a utility in that they're kind of guaranteed returns on their investment capital, so it's not so risky as trying to go out and drill and be reliant on the price of a commodity," Rawlusk notes.

O'Brien says these attributes have led to dynamic merger and acquisition activity, including an influx of private equity groups and pension funds drawn to the reliable cash flows generated by the midstream model.

Midstream M&A activity is a "focal point" for investors, Torys LLP's Stephanie Stimpson and Derek Flaman wrote in the firm's Fall 2019 Canadian Sector Report.

They cite examples including KKR's partnership with SemGroup to create a new Canadian midstream company, AIMCo's acquisition of an 85 percent equity stake in the Northern Courier Pipeline, and Northleaf Capital Partners' acquisition of CSV Midstream Solutions.

In the public space, they note Pembina's agreement to purchase Kinder Morgan Canada, AltaGas exceeding its targeted asset sale program for 2019, and Husky Energy's sale of the Prince George Refinery in British Columbia to Tidewater Midstream and Infrastructure.

Midstream Spotlight: Keyera

One of Canada's largest midstream oil and gas operators is confident that the fundamentals for its business are improving, and that means additional opportunities for profitable growth.

Keyera, which operates 17 Alberta natural gas processing plants, five natural gas liquids (NGLs) fractionation facilities, about 15 million barrels of storage cavern capacity, rail and truck terminals, and over 4,000 kilometres of pipelines as well as product marketing, is already on a path of growth both in its asset portfolio and its financial returns.

Driven in part by a doubling of its fee-for-service business over the last five years, the company's net income increased from \$230 million in 2014 to \$406 million in the first nine months of 2019.

While Keyera has invested in U.S. assets such as the Wildhorse Crude Oil Terminal at Cushing, Okla., its focus going forward will continue to be in Canada, says CEO David Smith.

"We think Canada's oil and gas industry has a bright future," Smith told analysts during Keyera's inaugural investor day in December.

"We need to be cost competitive with other global sources of supply and we need to build out the infrastructure to access those global markets, but we are getting these things done – perhaps a little too slowly – but with the Trans Mountain Expansion, with LNG Canada, with the Coastal GasLink Pipeline, with TC Energy's debottlenecking of their system in Western Canada, we are more confident about the industry's future than we have been for a few years. I'm calling the bottom for Canadian oil and gas."

Keyera plans to invest \$700 million to \$800 million of growth capital in 2020, primarily on new natural gas processing capacity and

on the Key Access Pipeline System (KAPS), which will transport NGLs and condensate from the Montney and Duvernay plays to Keyera's fractionation and terminalling infrastructure in Fort Saskatchewan.

Montney gas plants

Keyera's gathering and processing business is currently focused on adding capacity to serve the liquids-rich Montney play in Northwest Alberta.

In May 2019, the company brought online the first phase of its \$1-billion Wapiti Gas Plant Complex, located about 60 kilometres southwest of Grande Prairie. Phase 1 has gas processing capacity of 150 mmcf/d and condensate handling capacity of 25,000 bbls/d. Phase 2, which will add an additional 150 mmcf/d of capacity, is currently under construction and expected to commence operations in mid-2020.

Also under construction is the \$600-million first phase of Keyera's Pipestone Gas Plant, located about 45 kilometres northwest of Grande Prairie, which will have 200 mmcf/d of sour gas processing capacity and 24,000 bbls/d of condensate handling capacity. Keyera acquired the Pipestone project along with the 14,000-bbl/d Pipestone Liquids hub in April 2018 in a fee-for-service agreement with Encana.

Keyera also completed a \$148-million expansion and enhancement project at its nearby Simonette Gas Plant in 2019.

"Once the Pipestone gas plant is completed in early 2021, Keyera will be one of the largest gas processing and condensate handling companies in this region," the company says.

Keyera has made a concerted effort to invest capital to build its Montney footprint, Smith



told investors. In areas where produced gas is sweet instead of sour and therefore easier to handle, he said producers will often build and operate their own processing capacity.

“We chose specifically to focus on the area of the Montney around Grande Prairie, where the gas has a significant amount of H₂S as well as water and condensate,” Smith said. “The complexities associated with building the infrastructure that can handle gas like that are considerable, and the footprint that we’ve created means that we do have competitive advantages relative to other alternatives in the area.”

In the first half of 2022, Keyera plans to connect its Northwest Alberta gas plants as well as other third-party facilities to KAPS, a partnership with SemCAMS ULC that was approved in May 2019.

Connecting with KAPS

The \$1.3-billion KAPS NGLs and condensate project is a centerpiece of Keyera’s growth

program. With it, Keyera will expand in Northwest Alberta what it did in West-Central Alberta with the smaller Keylink NGL Gathering System. Completed in April 2018, Keylink connects eight gas plants with Keyera’s Edmonton Terminal and Fort Saskatchewan fractionation and storage complex.

Based on the current scope, KAPS will consist of a 16-inch condensate pipeline and a 12-inch NGL mix pipeline, Keyera says.

“[KAPS] is running really right through the heart of the Duvernay and the Montney,” said vice-president Brian Martin.

“Condensate is the single biggest driver for our producers’ economics in this basin and KAPS will provide the most direct shot from the field to where the end users are and where the demand is, and that demand is within our condensate system largely in Edmonton [and] Fort Saskatchewan.... We love this project and we think it’s going to be a tremendous success story for us.”

Midstream Spotlight: Pembina Pipeline

Western Canada midstream heavyweight Pembina Pipeline Corporation is working to expand its value chain through projects including a propane dehydrogenation and polypropylene facility near Fort Saskatchewan, a liquefied petroleum gas export terminal at Prince Rupert, B.C., and a proposed LNG project in Oregon, all while investing in its core – pipelines and natural gas processing in Alberta.

The company has achieved significant growth in recent years, increasing its net income from \$1.47 billion in 2014 to \$2.28 billion in the first nine months of 2019.

Peace Pipeline expansions, new gas treatment facilities

Pembina has a planned 2020 capital program of \$2.3 billion, of which \$1.3 billion will be directed to its Peace Pipeline System. The company has four Peace Pipeline expansion projects under construction in Northwest Alberta, adding incremental capacity out of the Montney play including for delivery of ethane-plus, propane-plus, crude and

condensate into the Edmonton area for market delivery. Pembina plans to phase the new projects into service, starting in late 2019 through the fourth quarter of 2021.

A further \$400 million will be spent this year on facilities, which, in addition to the Prince Rupert LPG terminal, includes work on Duvernay III, a 100-mmcf/d sweet gas processing plant with 5,000 bbls/d of propane-plus liquids capacity that is expected to be in service by late 2020.

Pembina is also constructing sour gas treatment facilities at its Duvernay Complex, including a 150-mmcf/d sour gas sweetening system, which is expected to be in service in the first quarter of this year.

At Empress, in Southeast Alberta, Pembina is building new fractionation and terminalling facilities to add approximately 30,000 bbls/d of propane-plus capacity to its Empress East system. The new capacity is scheduled to be in service in late 2020.

'Pursuing multiple developments' for Montney NGLs

Pembina says that with the increasing amount of oil and condensate resource being developed along its pipeline systems and the anticipated startup of the LNG Canada project, it continues to receive customer requests for incremental fractionation services for natural gas liquids (NGLs).

"Increasingly, we are observing customer demand for incremental NGL barrels, particularly from the Montney play, to move westward for export," the company says.

Pembina is "pursuing multiple developments in parallel" to facilitate this movement, both within its Redwater fractionation complex near Edmonton and in Northeast B.C., it says.



Image: Pembina Pipeline

Midstream Spotlight: Gibson Energy



The oversupply of crude oil from Western Canada as a result of pipeline delays has created major hurdles and roadblocks for the industry as a whole, but it has also created opportunities for companies with the right assets.

One of these is Gibson Energy's Hardisty Terminal, and its sole-supplier connection to the nearby USD Partners unit train loading facility.

Over more than 60 years, the Hardisty Terminal has become an increasingly important piece of infrastructure in Western Canada's oil supply chain. Storage capacity at Hardisty has doubled in recent years, from approximately 5 million barrels in 2014 to 12 million barrels today. Another 1.5 million barrels of tannage is under construction and expected to be operational in 2020.

The company also owns about 1.7 million barrels of storage at its Edmonton Terminal and has four other smaller terminals within Alberta.

With Alberta's export pipelines running at capacity, customers are looking for increased storage optionality, said Gibson senior vice-president Sean Wilson.

"From a market access perspective, people lease our tanks in part for insurance. Our

province's current market access constraints are not good for our industry, it's not good for us, but, due to the current and continuing egress uncertainty, people need insurance," he said.

The opportunity to grow Hardisty has coincided with a major shift in focus for Gibson away from activity-based oilfield service businesses, Wilson said.

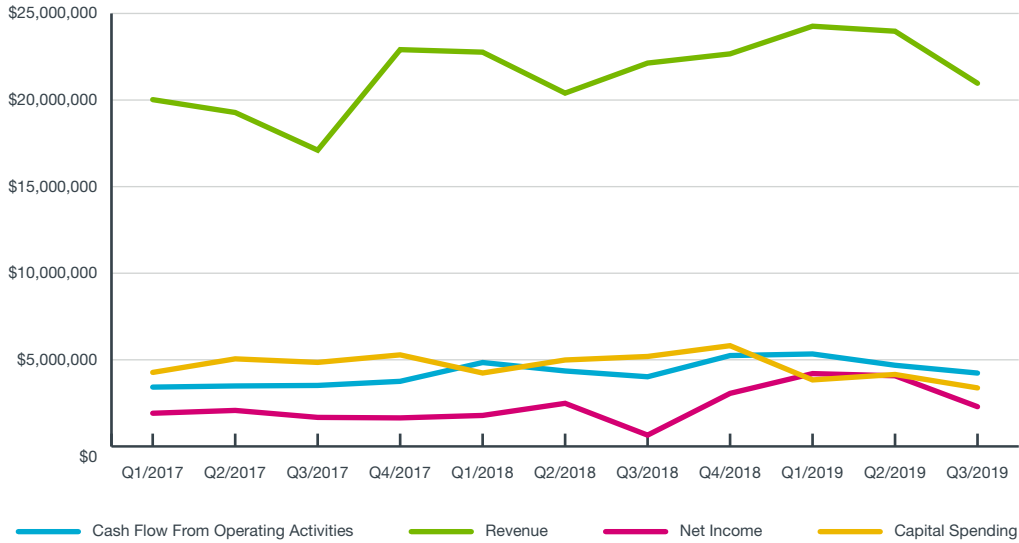
This includes the \$100-million sale of its trucking business in July 2019, as well as its wholesale propane business and U.S. energy services assets — including seismic and environmental services businesses — for approximately \$225 million in 2018.

Gibson is also adding a new line of business to its Hardisty Terminal. In December 2019 the company announced plans to build a 100,000-bbl/d diluent recovery unit (DRU) at Hardisty — 50,000 bbls/d of capacity contracted to ConocoPhillips Canada and 50,000 bbls/d to be negotiated with additional customers.

The DRU will separate out the diluent from diluted bitumen pipelined to the facility, creating a more viscous heavy crude designed specifically for rail transportation. This will satisfy demand for Canadian crude on the U.S. Gulf Coast, improving takeaway capacity out of Western Canada.

Midstream Data

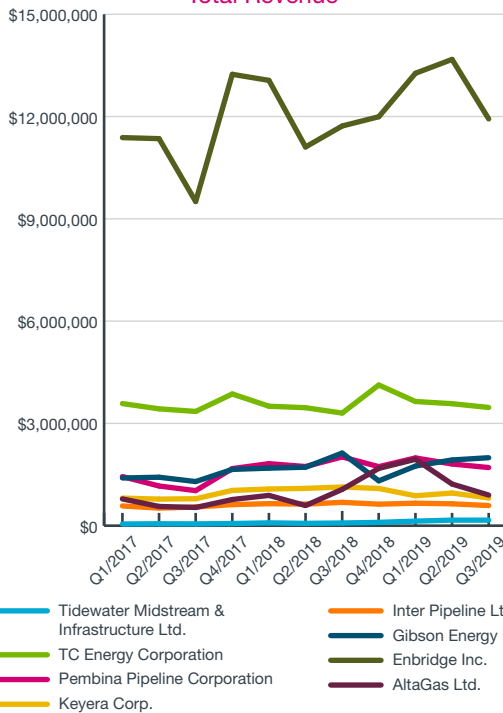
Health of the Midstream Sector



Aggregates figures for Tidewater Midstream & Infrastructure Ltd., TC Energy Corporation, Pembina Pipeline Corporation, Keyera Corp., Inter Pipeline Ltd., Gibson Energy Inc., Enbridge Inc. and AltaGas Ltd.

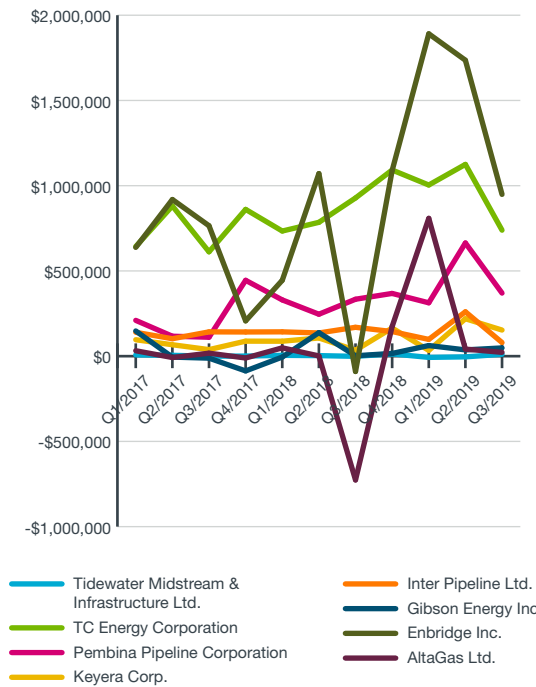
Source: CanOils

Total Revenue



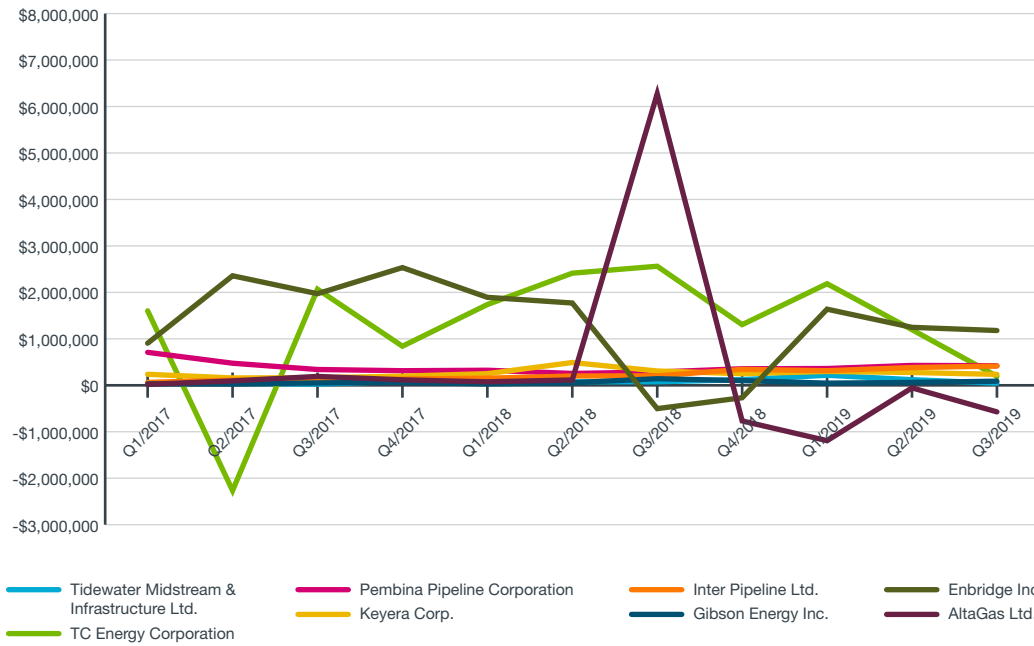
Source: CanOils

Net Income



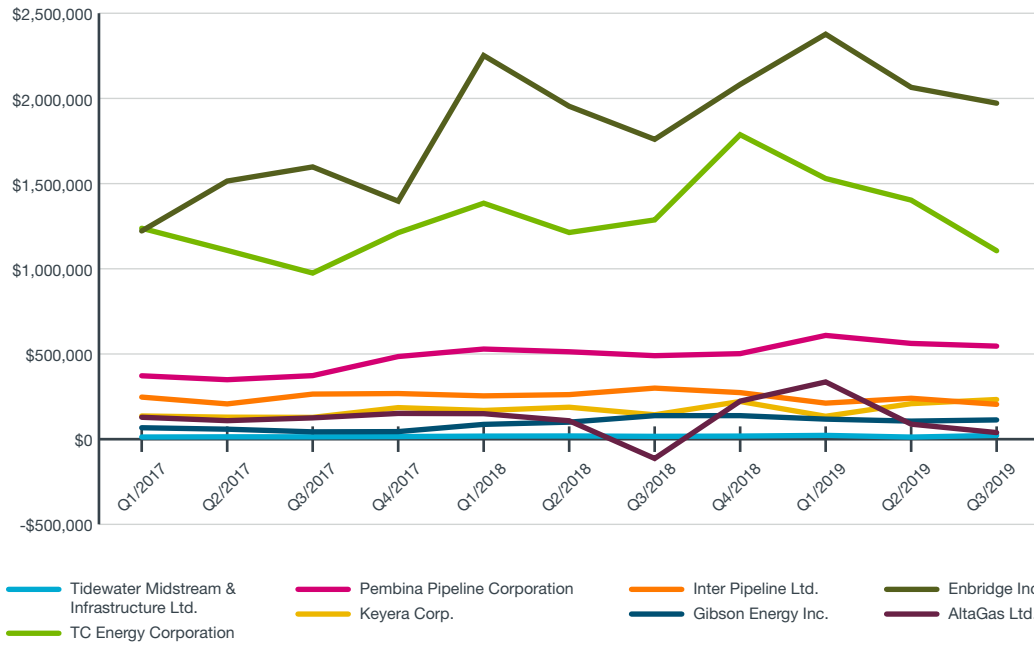
Source: CanOils

Total (Net) Capital Expenditure



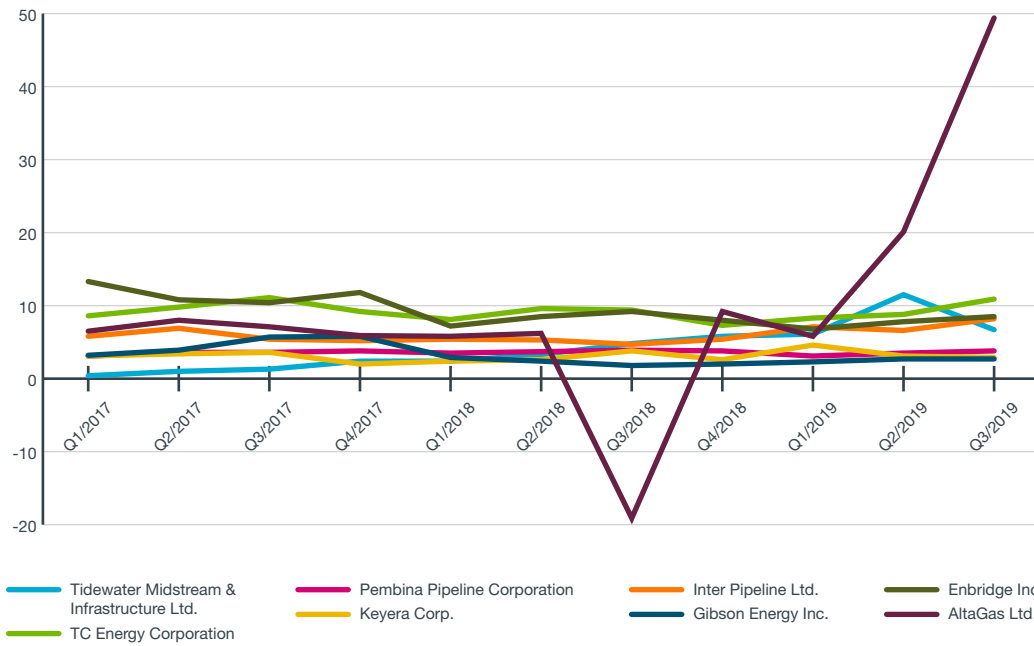
Source: CanOils

Cash Flow from Operations



Source: CanOils

Net Debt to Cash Flow



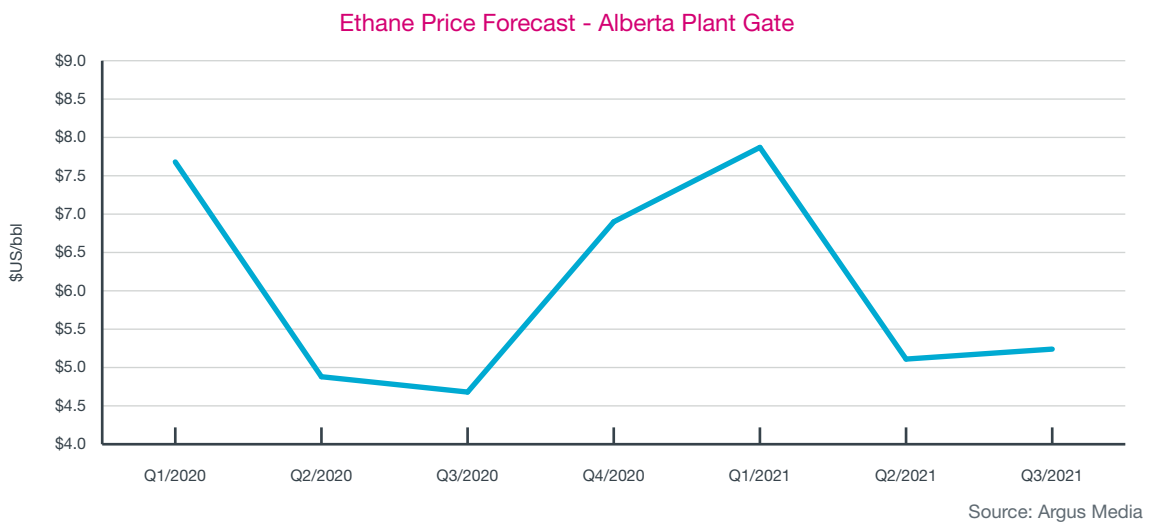
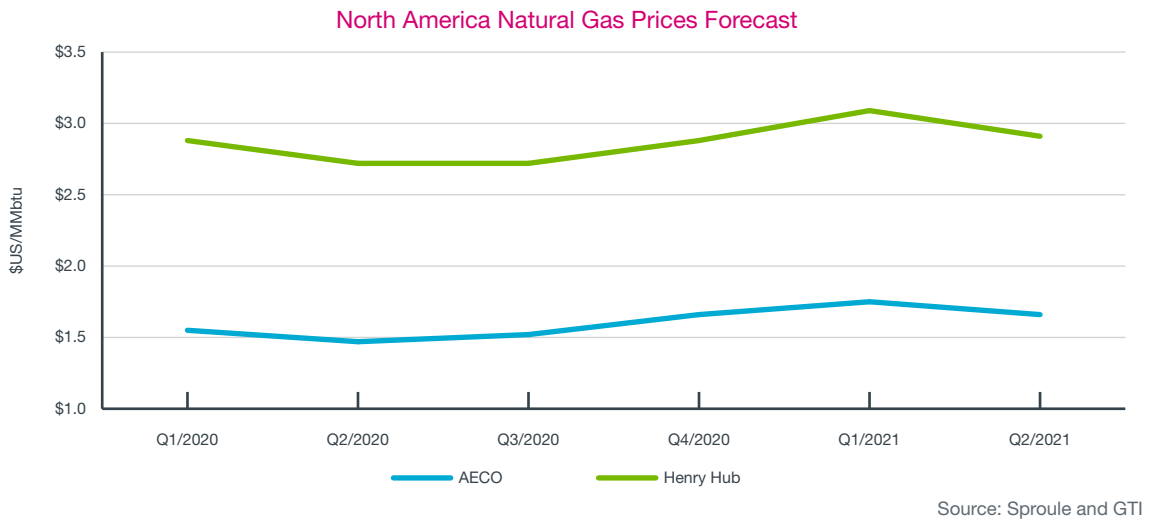
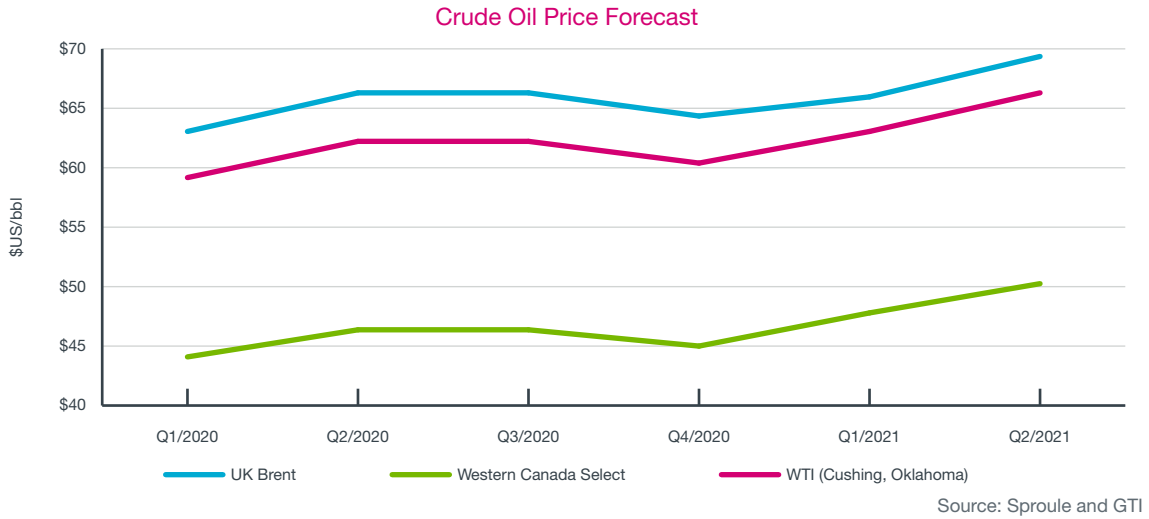
Source: CanOils

Return on Capital Employed

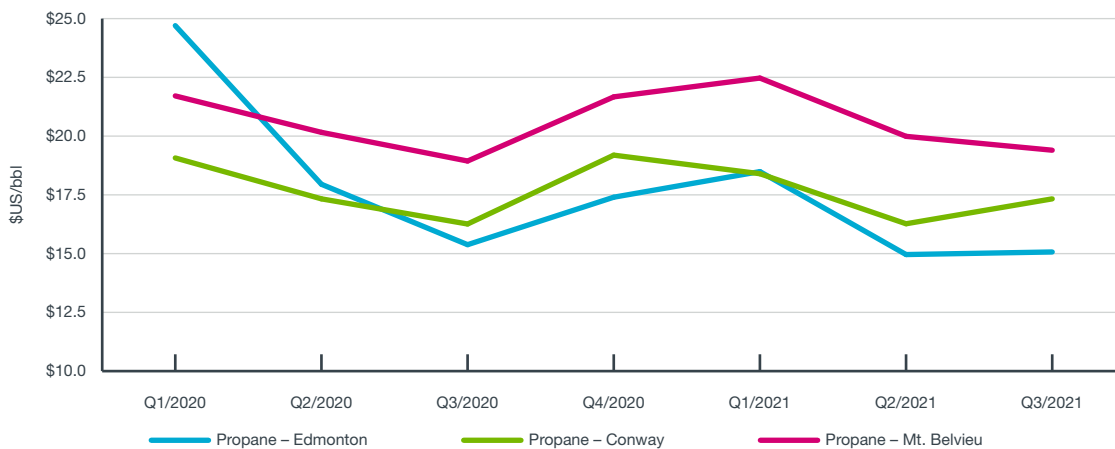


Source: CanOils

Alberta Oil & Gas Price Forecasts

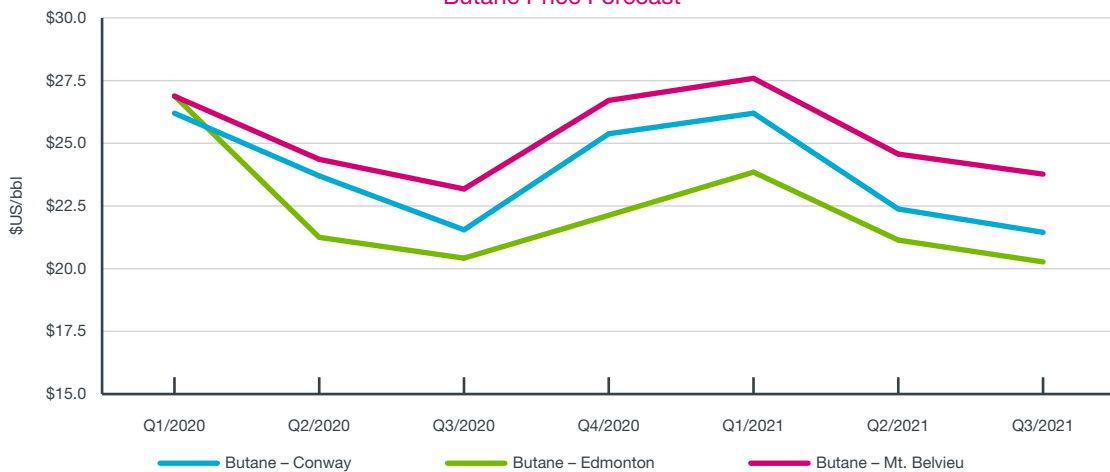


Propane Price Forecast



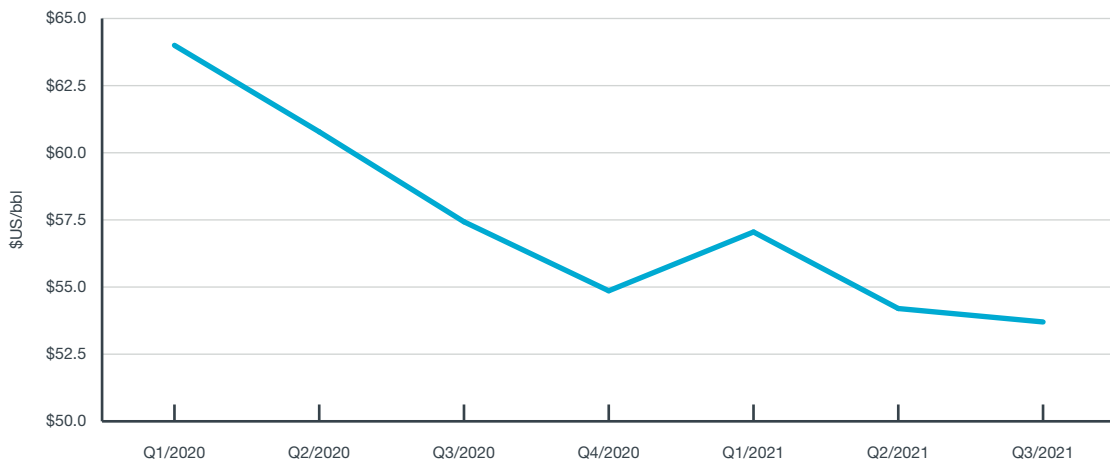
Source: Argus Media

Butane Price Forecast



Source: Argus Media

Condensate Price Forecast - Edmonton



Source: Argus Media

News

Alberta Indigenous Opportunities Corporation advancing toward funding projects

The first funding award by the new Alberta Indigenous Opportunities Corporation (AIOC) could come as early as the first quarter of 2020, says Matthew Machielse, its interim chief executive officer.

Machielse says that the \$1 billion in loan guarantees being offered by the province to support Indigenous participation in natural resource projects is the government's top two priority, "only behind takeaway capacity and market access."

Alberta's goal is to facilitate more deals like the 2017 agreement that saw the Fort McKay and Mikisew Cree First Nations take a \$545-million equity position in the East Tank Farm portion of the Fort Hills oilsands project.

"We've been using the Suncor initiative of the East Tank Farm as kind of the gold standard or a model that this initiative wants to replicate," Machielse says.

The AIOC is looking to fund projects in what Machielse calls "broad-based energy," including renewables and upstream through downstream oil and gas, as well as mining and forestry. Given the Alberta government's focus on midstream oil and gas development, he adds that midstream projects are likely to rise to the top of the list.

A minimum of \$20 million of Indigenous equity interest in a project will be required for eligibility.

"That sounds like a significant number, but we have to keep in mind that the objective of this initiative is to have revenues from the natural resources sector coming back to

communities and we want those revenues to be material, so that means we're looking for significant investment opportunities," he says.

Approximately \$4 million in capacity funding is being made available to help Indigenous communities evaluate business opportunities,

"We've been using the Suncor initiative of the East Tank Farm as a model that this initiative wants to replicate."

**– Matthew Machielse,
AIOC**

Machielse adds.

"This isn't about subsidizing; this is about making deals on commercial terms and making sure that Indigenous communities can engage in that exact conversation."

There is tremendous interest in the AIOC, with a number of potential projects starting to come forward, Machielse says. The next step is to establish the board of directors, which is expected to occur in the first quarter. After that, "we're probably looking at late into the quarter or into mid-2020 by the time everything is agreed to" for a funding award on a project of this complexity, he says.

Applying ‘purposeful AI’ to your business

More and more oil and gas businesses are adopting digital technologies like machine learning as part of their strategy, but companies should be careful where they focus their efforts and take the time to consider whether they really need to go down that route at all, experts told a recent breakfast event hosted by the Government of Alberta’s Ministry of Economic Development, Trade and Tourism. The panel of experts included representatives from Deloitte, Imperial Oil Limited and the Alberta Machine Intelligence Institute (Amii).

‘Rapid maturation’ of digital technologies in oil and gas

There are many examples of the “rapid maturation” of how oil and gas companies are approaching digital technologies, said Roland Labuhn, national digital energy and industrials leader with Deloitte. He pointed to the new “Suncor 4.0” approach launched by CEO Mark Little in spring 2019 as the biggest development along this path he has seen.

“When we started digital probably four or five years ago, we were looking at consumer trends and what was happening in the financial sector. When I look at it now, it has fundamentally changed. We’re seeing [oil and gas] firms commit to where digital is going, and seeing that intersection between technology and industrial strategy,” Labuhn said.

“In my 20-plus years in this industry, it’s the first time – when I think of that intersection between an oil and gas strategy and a digital strategy targeting billions a year of opportunity costs and savings and improvement of revenue – that we’re starting to see some of those global trends come here.”

Imperial Oil is another key example, announcing in September it is “taking action

to be a leader in advancing digital and AI technology across the value chain” with a new two-year agreement with the Alberta Machine Intelligence Institute.

Many people who do not work in the data science world can be afraid of AI, but it can serve to augment human intelligence rather than replace it, said Heather Wilcott, Imperial’s upstream digital strategy manager.

“I see the use of AI allowing us to make better and faster decisions. It’s not humanely possible to process trillions of rules, so therefore computers can help us with that and make us more efficient,” Wilcott said.

An example at Imperial is a steamflood optimization project at its Cold Lake oilsands operation. There are hundreds of producing wells at Cold Lake, Wilcott said, and to optimize which wells get what steam to get the most production is a very intensive exercise using spreadsheets and reservoir engineering subject matter experts.

“They spend several weeks a month with a low-cost centre in India doing some preparatory calculations, and then they get together once a month with all of the experts with many, many years of experience to say ‘this is the right place to send the steam in this amount to these wells,’” she said.

“There’s really no humanly possible way to run through all the possible combinations of scenarios and fully optimize that, which is where we use machine learning to build algorithms to model the reservoir and the well performance. It predicts the performance of the wells given a certain amount of steam, and on top of that we layer on mathematical optimization to run through all of the possible combinations that a human just couldn’t do, so now the steam schedulers and reservoir engineers use the model as a starting point. If they see something weird, they don’t have to follow the model but it drastically shortens



the amount of low value work that they're doing processing data and spreadsheets and enables them to make much better decisions to optimize production.”

Despite the benefits in that project example, Wilcott said that oil and gas businesses don't necessarily need AI to solve their problems.

“There might be a simple solution in many cases. If you can do it with a physical model or software engineering, then that should be your first approach before you just apply AI and machine learning to the problem.”

Machine learning should be the 'last resort'

Machine learning should not be the first choice, said Shak Parran, Deloitte's national AI insights leader.

“Start with your business problem, and machine learning should be your last resort because in 95 percent of the times there's a better, simpler, easier technique to solve that problem,” he said.

“If you come to a problem and say, ‘we actually can't solve the problem with anything else,’ then you should start talking about using machine learning or something of the

sort to solve the problem.”

Audrey Ancion, Deloitte's analytics experience lead, said the firm encourages organizations to think about what it calls “purposeful AI.”

“It's AI that has a clear-cut purpose; it's there to solve a business problem,” she said, adding that sometimes people take the opposite route, starting with the machine learning technique and then trying to find an application for it.

Ancion said there are two broad buckets where AI can be applied to help solve business problems: 1) reasoning, where AI can be used to predict and make recommendations for optimization; and 2) interacting capabilities, where AI interacts with something such as text or pictures, which can be particularly useful in predictive maintenance.

“For example, if you have videos or pictures, thousands or millions of them, AI is going to help process that much faster than a human being,” she said. “What it can really do super well is identify patterns in your data.... We would encourage you to start in places where you have lots of data.”

Painted Pony tests potential wellsite emissions elimination technology

The first unit of a new system designed to significantly reduce methane emissions from remote oil and gas wellsites is now operating in the field, and so far has performed “exactly in line with expectations,” according to operator Painted Pony Energy.

Painted Pony commissioned the sea-can package on a Montney well pad in Northeast B.C. in November. The system, called EPOD (engineered power on demand) was developed by Calgary-based Westgen Technologies founders Connor O’Shea and Ben Klepacki.

“...We actually believe we’re going to save money overall and have more reliable sites as a result.”

– **Tim Michaelis,**
Painted Pony

By enabling producers to use air compressors to power pneumatic systems that run wellsite valves and injection pumps instead of the common pneumatic systems powered by wellhead fuel gas, EPOD is designed to essentially eliminate methane venting.

Effective January 1, 2022, in Alberta, operators must control or prevent vent gas from at least 90 percent of pneumatic devices; while in B.C., effective January 1, 2021, greenfield oil and gas sites will no longer be allowed to use methane-emitting pneumatic devices.

But that presents a power problem. Existing substitute technologies can only cost-effectively provide one or two kilowatts to run site equipment, O’Shea said.

“We realized that in order to not vent methane, you actually need more power generated on site to be able to come up with an alternate solution.”

Westgen has adapted a line of mass market internal combustion engines capable of generating 6, 20 and 30 KW to run on wellhead fuel gas, and require maintenance once per year.

“EPOD takes our proprietary power generation technology and pairs it with an air compressor to provide high-pressure compressed air into the pneumatic devices on the wellsite,” O’Shea said.

“That way, instead of putting high-pressure gas into the devices and that gas venting into the atmosphere, we put high-pressure air into the devices and the air vents into the atmosphere. By making that simple switch, we basically eliminate the methane venting from these devices altogether.”

The innovation is enabled in part by Klepacki’s background working on cars. “There is still a lot of space where we can take technologies that have been done in other industries, and that’s really what we did here,” Klepacki said.

Painted Pony decided to try out the new system because it aligns with the company’s goal to reduce its overall emissions footprint, but that’s not the only expected benefit, said senior facilities engineer Tim Michaelis.

“As we build new sites it makes sense from our perspective to get ahead of the game and be proactive to comply with regulations, but honestly the real motivation is we actually believe we’re going to save money overall and have more reliable sites as a result.”

Upstream News

Capital Spending

▶ Canadian Natural Resources Limited plans to spend \$4.05 billion for 2020, up from a forecast of \$3.8 billion in 2019.

The 2020 capital budget is expected to deliver production of approximately 1.17 million boe/d, up from approximately 1.12 million boe/d expected in 2019, despite ongoing production curtailment. Canadian Natural has added approximately \$250 million to its 2020 capital budget compared to 2019 as a result of Alberta's elimination of curtailment for newly drilled conventional heavy oil wells and its reduction in income tax rates.

The company said the increased spend will add approximately 60 drilling locations across Alberta, put three additional drilling rigs to work and create an additional approximate 1,000 full-time equivalent jobs.

▶ Suncor Energy is

planning a 2020 capital program of \$5.4 billion to \$6 billion, up from \$4.9 billion to \$5.4 billion in 2019. While oil-related investment is expected to be flat compared to 2019, Suncor is increasing spending on projects associated with its target to increase annual free funds flow by \$2 billion by 2023.

This includes \$300 million for the new cogeneration facility Suncor sanctioned in September 2019, \$150 million for additional investment in digital technology initiatives, and \$50 million in connection with the completion of bi-directional pipelines connecting its oilsands Base Plant to Syncrude.

Upstream production is expected to be between 800,000 and 840,000 boe/d, an approximately five per cent production increase compared to 2019 guidance. This factors in expectations for Alberta's oil curtailment to extend through 2020, and special production

allowances for the utilization of crude-by-rail.

▶ Cenovus Energy plans to invest \$1.3 billion to \$1.5 billion in 2020, about 70 percent of which is sustaining capital primarily to maintain base production at its Foster Creek and Christina Lake oilsands operations.

The increase in total planned capital spending, compared to the company's 2019 forecast of \$1.1 billion to \$1.2 billion, is largely due to the mandatory production curtailment in Alberta, the company said.

Cenovus plans to spend \$705-\$820 million on its oilsands operations in 2020, of which \$625 million to \$675 million will be focused on maintaining base production at Foster Creek and Christina Lake as well as completing the ramp-up of the new Christina Lake phase G, thanks to utilization of Alberta's special production allowances for utilizing crude-by-rail.



Image: Cenovus

The balance of Cenovus's planned oilsands investment in 2020 will be focused on advancing the proposed phase H expansions at both Foster Creek and Christina Lake towards sanction-ready status by the second half of 2020, Cenovus said.

Meanwhile, Cenovus plans to spend \$80-\$95 million in the Deep Basin in 2020, a modest increase in total capital spending compared with the company's 2019 forecast, which reflected no drilling activity.

This capital investment plans the execution of a two-rig drilling program targeting high-return liquids-rich opportunities in the Clearwater and Edson areas, beginning in the second half of 2020.

► Tourmaline Oil is forecasting a 2020 capital spending program of \$925 million to develop its assets in Alberta and Northeast B.C.

Production is expected to average 315,000 to 320,000 boe/d, compared to 295,000 to 300,000 boe/d in 2019.

Tourmaline said its 2019 production exit target of 315,000 to 320,000 boe/d was achieved during the second week of December, with total corporate production reaching a record 317,000 boe/d.

International E&P Opportunities

► Canada's oil and gas

industry has a wealth of expertise that could be used by exploration and production companies to enter or diversify into international markets, according to a new report commissioned by the Canadian Global Exploration Forum (CGEF).

With 60,000 engineers, 4,000 geologists and 1,300 geophysicists, Calgary's downtown core has one of the highest populations of exploration and development professionals in the world. Thousands of other professionals ensure the industry has world-class health, safety and environmental standards. Still more professionals work bringing benefits to local communities where field development happens.

The report identifies four areas where Canadians have a competitive advantage to leverage this expertise: conventional oil and gas, unconventional resources, heavy oil, and enhanced oil recovery.

New oilsands project approved

The Alberta government, on the recommendation of the Alberta Energy Regulator, has issued approval for Grizzly Oil Sands ULC's proposed May River SAGD project south of Fort McMurray. The project would produce up to 12,000 bbls/d of bitumen from the Middle McMurray channel reservoir.

The province said its approval will enable the privately held company to advance the project to the next stages of development, including making a final investment decision and applying for other environmental licences and local area development permits.

Acquisitions and Divestitures

Pengrowth Energy says its shareholders and secured debt holders have approved its acquisition by Cona Resources, a portfolio company of Waterous Energy Fund, for five cents per share and the assumption of debt. The aggregate value of the transaction is approximately \$740 million.

Pengrowth operates two core asset areas: the 18,000-bbl/d Lindbergh SAGD project near Cold Lake, Alberta, and 19 sections in the Montney natural gas resource play in Northeast B.C.

► Paramount Resources has closed the sale of certain natural gas weighted properties in West Central Alberta for cash consideration of approximately \$55 million.

Paramount said the transaction significantly reduces the complexity of its operations, disposing of roughly 320,000 net acres and associated wells and facilities with average sales volumes of 8,500 boe/d (60 per cent natural gas) in the third quarter of 2019.

Midstream News

Diluent Recovery Units

► Oilsands operators are planning two large-scale diluent recovery units (DRUs) in order to enable shipping more oil out of Alberta.

In December, Cenovus Energy filed a regulatory application for a DRU at its Bruderheim Rail Terminal, and Gibson Energy announced plans for a DRU at its Hardisty Terminal, which is the sole-supplier to the nearby USD Partners unit train loading facility.

The Cenovus DRU would have capacity to separate up to 190,505 bbls/d of diluted bitumen, or dilbit, delivered by pipeline from the company's oilsands projects into undiluted "neatbit" and diluent components. It is expected to start operating in the fourth quarter of 2023.

Gibson announced its plans to build a 100,000-bbl/d DRU with 50,000 bbls/d

of capacity contracted to ConocoPhillips Canada and 50,000 bbls/d to be negotiated with additional customers. Gibson said the plant will create "DRUbit," a more viscous heavy crude designed specifically for rail transportation. It could be placed into service as early as 2021, the company said.

Oil Storage

► Gibson Energy says it has given the go-ahead to build two new 500,000-bbl oil tanks at its Hardisty Terminal, continuing ongoing expansion of the storage facility.

The company said it has also secured a new refining customer for the terminal, reflecting the importance of Hardisty to downstream players looking to secure heavy crude feedstocks from Western Canada.

One of the new tanks is contracted to the new refining customer, while the second tank will be leased to

Gibson's marketing segment under an inter-company agreement.

In November 2019, Gibson placed four new tanks with two million barrels of storage into service, ahead of schedule and within target capital costs, the company said.

Gibson said it now has three tanks representing 1.5 million barrels of storage capacity currently under construction at the Top of the Hill portion of the Hardisty Terminal.

The company expects to have approximately 13.5 million barrels of storage capacity in service in the fourth quarter of 2020, up from 5 million barrels in 2014.

LNG

► Pieridae Energy plans to invest to advance its proposed Nova Scotia LNG project to a final investment decision in 2020. The company announced a "pre-FID" capital budget of \$32



million, and a development expense of \$16 million for the Goldboro project.

Under a 20-year supply deal with German utility Uniper for 5 mtpa, or half of the capacity of the US\$10-billion project, Pieridae is facing a deadline of September 30, 2020, for FID.

The current timeline targets commercial deliveries starting November 30, 2024, and May 31, 2025.

Pieridae expects to realize net operating income of \$80 million to \$110 million in 2020, which otherwise would have been approximately \$10 million, were it not for the company's acquisition of Shell Canada's midstream and upstream assets in the Southern Alberta Foothills for \$190 million in October 2019.

License transfer approval for certain of the acquired Shell assets is pending from the Alberta Energy Regulator.

▶ Chevron says it is considering selling its 50 percent share in the proposed Kitimat LNG project, which received a new 40-year LNG export licence from the Canadian Energy Regulator in December 2019.

"I think it's important to note that ownership changes are not unusual in projects like this – large capital energy projects," said Bryan Cox, CEO of the BC LNG Alliance. "I think what's really important to note is that Chevron very clearly stated in

its remarks that they view this project as globally competitive."

A final investment decision on Kitimat LNG is not expected until around 2022 or 2023, with completion and commissioning timed for 2029.

Pipelines

▶ Enbridge executives told a recent investor day that the company's optimum goal is extending its integrated value chain all the way to the United States Gulf Coast.

"The focus of this Gulf Coast strategy is on securing the last mile connectivity to refiners, storage terminals and export opportunities while fully developing our heavy and light crude value chain," said Guy Jarvis, executive vice-president and president of liquids pipelines. A key link in the strategy is the potential to move additional heavy barrels from its Flanagan South and Seaway systems, he said, which connect to Alberta.

"We have been active for many years now building out our heavy crude value chain from the oilsands, to our Mainline, Flanagan South and the Seaway system to create a path that's unparalleled in industry," said Jarvis. "The next step is developing a strategically located terminal position on the Gulf and participating in the development of offshore VLCC (very large crude

carrier) loading facilities."

Rail Terminals

Cando Rail Services has started construction on a new terminal in Sturgeon County that will use a loop-track system to enable staging and storage of up to 1,900 rail cars.

The Cando Sturgeon Terminal is located nearby facilities including the \$4.5-billion petrochemical plant under construction by Canada Kuwait Petrochemical Corporation and Pembina Pipeline's Redwater Fractionator. It will be unit-train capable and serviced by the CN mainline.

"Access to cost-advantaged feedstock, world-class transportation and logistics infrastructure and readily available labour are allowing the Heartland to capitalize on the current petrochemical investment cycle," said Sturgeon County Mayor Alanna Hnatiw.

Early works and site mobilization have begun with completion expected in 2020.

Alberta Major Projects

View investment announcements across different sectors at www.majorprojects.alberta.ca. Click [here](#) for a list of pipeline, gas and storage projects in the midstream sector.

Downstream News

Refining

► The Sturgeon Refinery has completed a major maintenance shutdown that was scheduled to include a full test run of the gasifier unit that has held up its conversion to full commercial operations.

Refinery start-up is underway using synthetic crude oil (SCO) to produce low-sulphur diesel, according to a statement from operator North West Redwater Partnership.

Additional work is progressing to prep the gasifier unit for start up in early 2020 to enable the switch to bitumen feedstock, the company said.

The Sturgeon Refinery has been processing SCO into diesel since November 2017. The facility was originally expected to complete the switch to bitumen by the end of 2018. Ongoing diesel production is made possible because SCO is a partially

upgraded product and does not need all units operational, North West has said.

The gasifier is designed to process the heaviest portion of the bitumen barrel into hydrogen for the refinery, and produce pure CO₂ to be captured for enhanced oil recovery.

Issues with initial commissioning of the unit resulted in repairs and replacement of equipment.

An update from North West in November pushed out expected gasifier startup from the end of 2019 to early 2020, with the company saying that additional work was required.

A full test run of the gasifier was scheduled to coincide with the project's fall routine maintenance shutdown, which started in September.

The shutdown is now complete, logging over 390,000 total hours by skilled tradespeople, inspectors,

technical experts, planners and other job functions, North West said in late December. The refinery was expected to produce diesel from SCO again before the end of the year, followed by bitumen processing in 2020.

► China is breaking records for crude oil imports and isn't likely to stop soon as new refineries ramp up and hopes grow that the easing of trade tensions with the U.S. will bolster the economy, according to Bloomberg News.

Even as economic expansion has slowed, Bloomberg said the pace of growth still requires ever more oil. China imported an unprecedented 11.18 million barrels a day in November, which surpassed the U.S. high-water mark of 10.77 million set in June 2005. China's purchases will probably continue to rise into next year as new refineries in Zhejiang and Zhanjiang increase runs, and as a



Image: North West Redwater Partnership

widely anticipated tax rebate boosts domestic production of marine fuel, Bloomberg reported.

► Husky Energy has closed the sale of its 12,000-bbl/d Prince George refinery to Calgary-based Tidewater Midstream and Infrastructure Ltd. for \$215 million in cash, plus a closing adjustment of approximately \$53.5 million.

The transaction includes a contingent payment to Husky of up to \$60 million over two years. The company has entered into a five-year offtake agreement with Tidewater for refined products from the refinery, located in Prince George, B.C.

Petrochemicals

Fieldwork on two new propane-based petrochemical facilities in Alberta is advancing, with one project over the halfway spending mark and the other into early works and contracting.

As of the end of September, Inter Pipeline Ltd. says it has invested approximately \$1.9 billion of the estimated \$3.5-billion capital cost of the Heartland Petrochemical Complex, a propane dehydrogenation (PDH) and polypropylene (PP) facility under construction near Fort Saskatchewan.

The company reported

\$337.6 million in capital spending on the project for the third quarter, for the procurement of materials and construction services.

“Milestones for the third quarter include completing piling activities with approximately 6,500 pilings installed, commencing structural steel erection for the polypropylene plant, and installing the first major components of the central utility block,” Inter Pipeline said.

“The last major equipment lifts for the complex were also completed in the quarter with the installation of the propane dehydrogenation flare stack and the 300-tonne polypropylene purge bin.”

Construction of the complex began in early 2018 and is scheduled for completion in late 2021. Activities continue to advance according to cost and schedule targets, Inter Pipeline said.

Meanwhile, early works site preparation is underway for Pembina Pipeline Corporation’s PDH/PP project in the Fort Saskatchewan region, the company said earlier in its third quarter results.

Pembina and partner Canada Kuwait Petroleum Corporation gave the go-ahead to the \$4.5-billion project in February 2019. Engineering, procurement

and construction bids have been received and are currently being reviewed, Pembina said. Its spend to-date is tallied at \$90 million. The project is expected to be in service in mid-2023.

Both new PDH/PP projects have committed economic support through Alberta’s Petrochemicals Diversification Program in the form of future royalty credits.




















► Nearly 80 percent of Inter Pipeline’s planned 2020 capital program will be directed toward construction of the Heartland Petrochemical Complex, the company said in December.

The facility, under construction near Fort Saskatchewan, will be Canada’s first integrated PDH/PP plant, converting Alberta propane into pellets for plastic products.

The company said it expects to spend approximately \$935 million of its total \$1.195-billion capital budget in 2020 on the project, with a focus on advancing mechanical construction of the PP plant and completing the final stages of construction of the PDH facility.


Connected to North America's Critical Infrastructure: Oil



- | | | | |
|--|--|--|---|
|  CP Rail |  1 Trans Mountain |  6 TCPL Keystone |  11 Gulf Coast Project |
|  CN Rail |  2 Rangeland |  7 Alberta Clipper |  12 Seaway |
| Oil Pipelines |  3 Milk River |  8 Enbridge |  13 Portland P/L |
|  In Service |  4 Bow River |  9 Spearhead |  14 Trans Mountain Expansion |
|  Proposed |  5 Express Platte |  10 ExxonMobil USGC |  15 Keystone XL Northern Leg |

Connected to North America's Critical Infrastructure: Natural Gas



| | | | |
|--|---|--|--|
|  Natural Gas Pipelines | West Coast Exports <i>Under Construction/Operational</i> | <i>Proposed</i> | East Coast Exports <i>Proposed</i> |
| | <ul style="list-style-type: none"> 1 Ridley Island Export Terminal 2 LNG Canada 3 Prince Rupert Propane Export Terminal | <ul style="list-style-type: none"> 4 Kitimat LNG 5 Woodfibre LNG | <ul style="list-style-type: none"> 6 Goldboro LNG 7 Bear Head LNG 8 Energie Saguenay |

Crude Oil Plays

Oilsands Upgraders

Operating

- 1** Suncor Base & Millennium
- 2** Syncrude Mildred Lake
- 3** Athabasca Oil Sands Project Scotford
- 4** Canadian Natural Resources Horizon

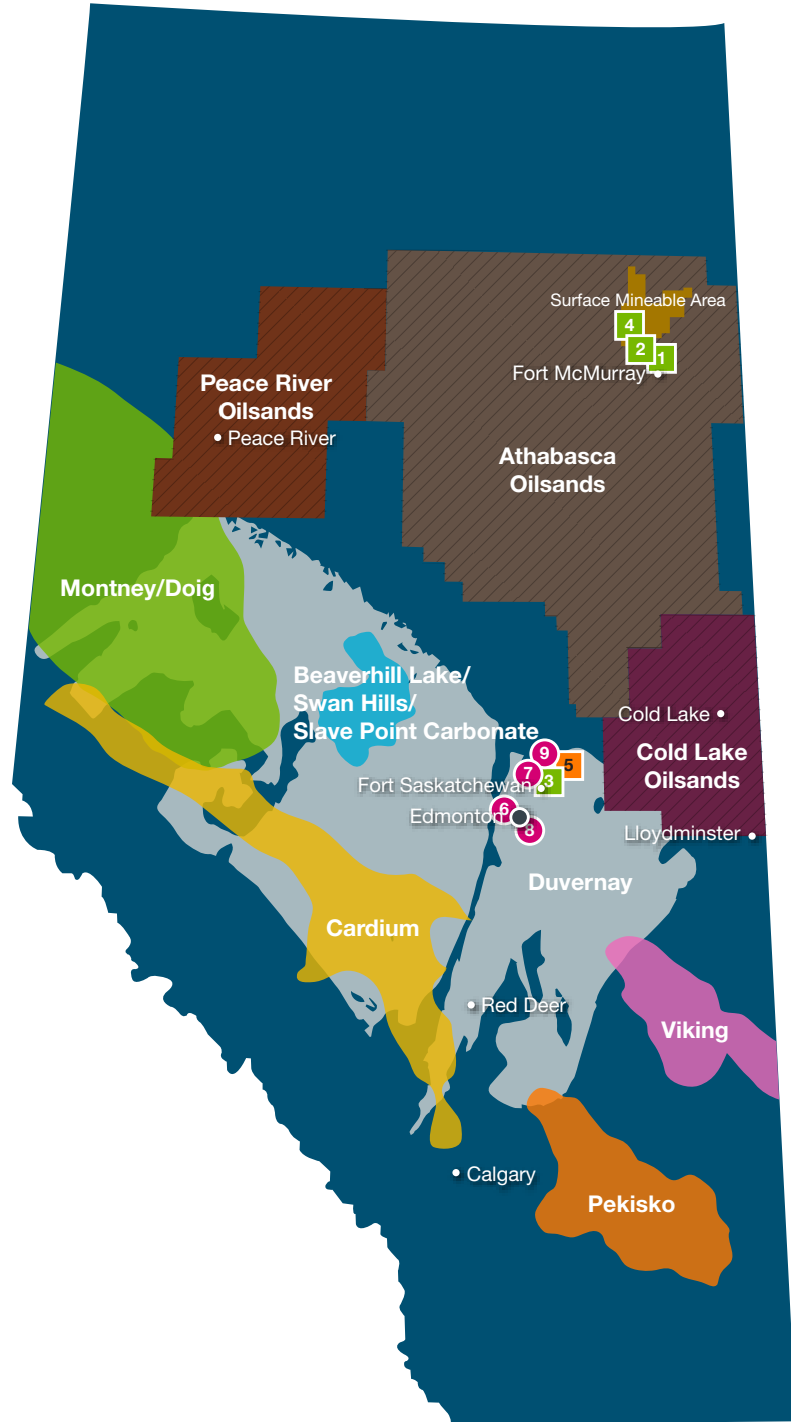
Proposed

- 5** Value Creation Heartland

Oil Refineries

Operating

- 6** Suncor Edmonton
- 7** Shell Scotford
- 8** Imperial Strathcona
- 9** North West Redwater Sturgeon



Natural Gas Plays

Straddle Plants

- 1 AltaGas Ellerslie
- 2 Inter Pipeline Cochrane
- 3 Alta Gas Joffre
- 4 Spectra Empress
- 5 Plains Midstream Empress
- 6 Atco Empress
- 7 1195714 Alberta Empress
- 8 Atco Fort Saskatchewan

Fractionators

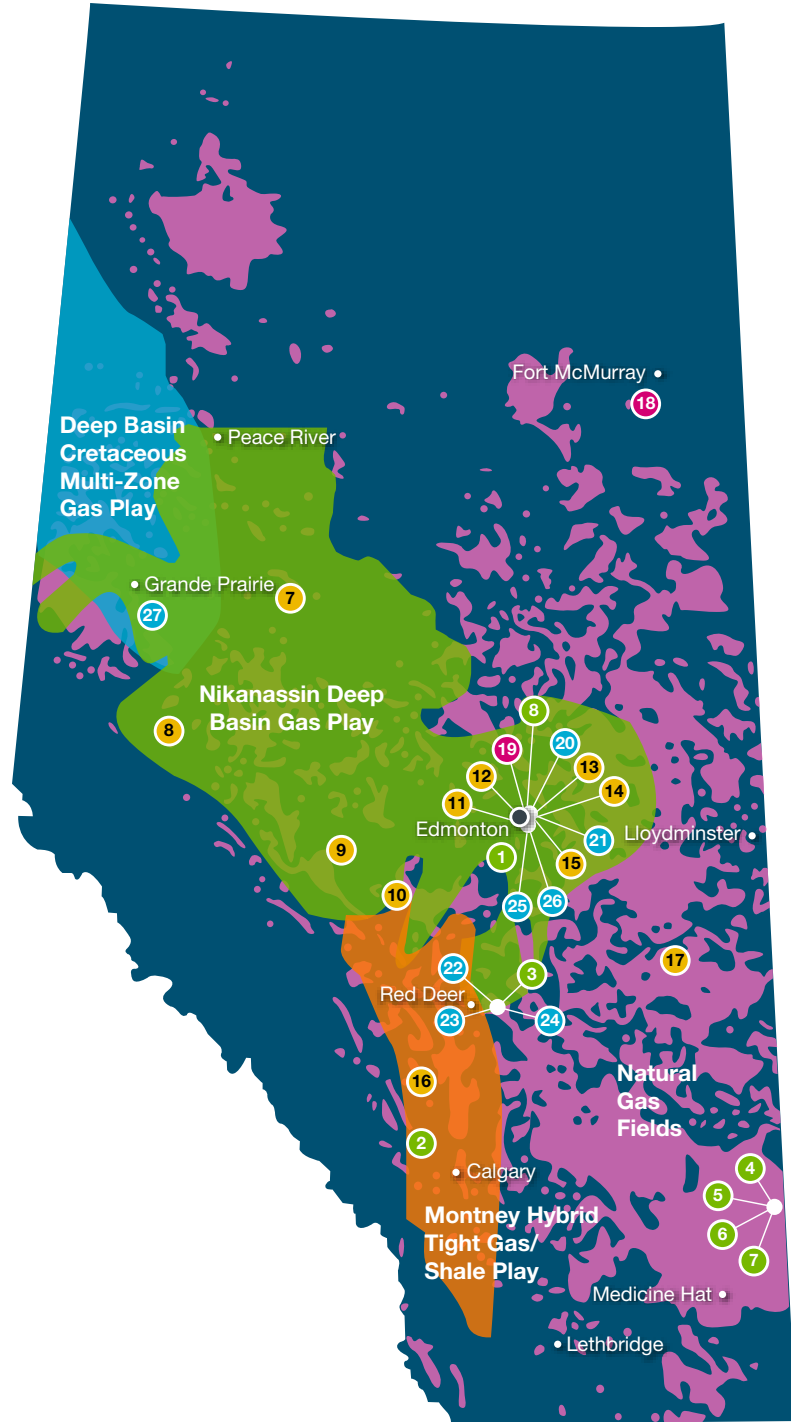
- 7 High Prairie Frac Plant
- 8 Kanata Simonette 13-11 Gas Plant
- 9 Tervita Granada Frac Plant
- 10 Buck Creek Frac Plant
- 11 DOW Fort Sask
- 12 Fort Sask Gas Plant
- 13 Keyera Fort Sask Frac Plant
- 14 Interpipeline ROF Facility
- 15 Pembina INFRA. & Logistics LP FRAC 1, 2 & 3
- 16 Harmattan Fractionation
- 17 Gibson Hardisty

Offgas Plants

- 18 Inter Pipeline Fort McMurray
- 19 Heartland Offgas Delivery (4917)

Petrochemical Facilities

- 20 Pembina PDH/PP (Under Construction)
- 21 Fort Sask: DOW
- 22 Joffre E1: NOVA
- 23 Joffre E2: NOVA
- 24 Joffre E3: DOW/NOVA
- 25 Inter Pipeline Heartland Petrochemical Complex (Under Construction)
- 26 Inter Pipeline Acrylic Acid & Derivatives Project (Proposed)
- 27 Nauticol Energy Methanol Facility (Proposed)



Alberta pipeline safety record continues to improve: AER

The latest data from the Alberta Energy Regulator (AER) shows a continued trend of improving pipeline safety performance in the province.

The number of high-consequence pipeline incidents, rated based on their impact on the public, land, environment, wildlife and livestock, decreased by approximately eight percent in 2018, the AER said in its third annual report on pipeline safety performance.

There were 24 high-consequence incidents in

2018, compared to 26 in 2017 and 29 in 2016. Over the last 10 years, the largest number of high consequence incidents occurred in 2014, at 52.

The total number of incidents was essentially flat year-over-year, the AER reported, at 416 in 2018 compared to 415 in 2017. Overall, the AER data shows that pipeline incidents are decreasing while the total length of pipeline operating in Alberta increases.

“We’re pleased with this trend, but we’re not letting up,” said David Helmer, the

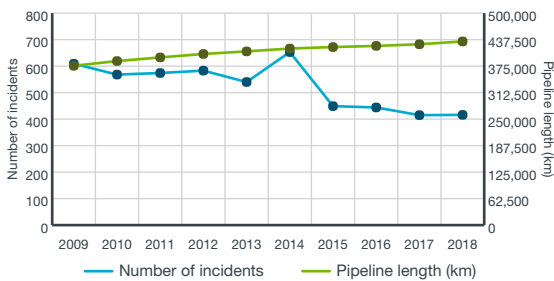
AER’s director of industry performance and analytics.

He added that the regulator is continuing with efforts to drive industry performance and further decrease the number of high consequence pipeline incidents.

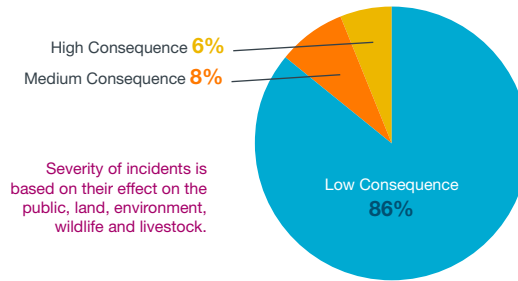
“The largest liquid release in 2018 was 335 cubic metres; just over two-thirds of the total number of pipeline releases were one cubic metre or less,” Helmer said.

“We would expect to see this sort of a trend where you’d see lots of very small ones and very few large ones.”

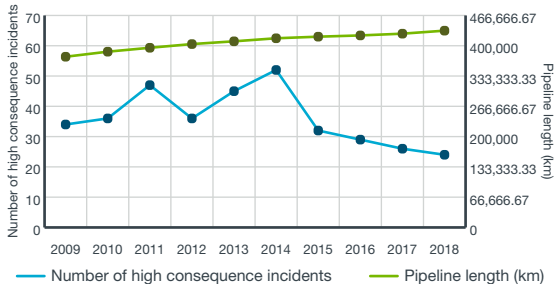
10-Year Trend: Total Accidents v. Total Pipeline Length



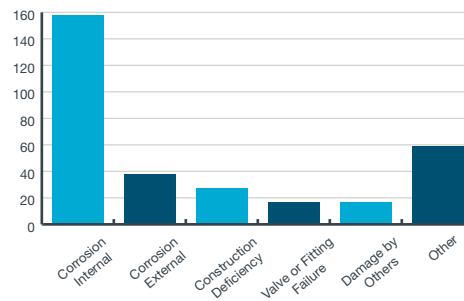
Severity of Incidents 2018



10-Year Trend: High Consequence Incidents v. Total Pipeline Length



Causes of Pipeline Incidents 2018



Source: AER 2018 Pipeline Performance Report

Contacts

Alberta Government

Alberta Advanced Education

www.alberta.ca/advanced-education

Alberta Energy

www.alberta.ca/energy

Alberta Energy Regulator

www.aer.ca

Alberta Environment and Parks

www.alberta.ca/environment-and-parks

Alberta Geological Survey

www.ags.aer.ca

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Alberta Surface Rights Board

www.surfacerights.alberta.ca

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Alberta Land Surveyors' Association

www.alsa.ab.ca

Canada's Natural Gas

www.canadasnaturalgas.ca

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www.capp.ca

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www.cepa.com

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Petroleum Technology Alliance Canada

www.ptac.org

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