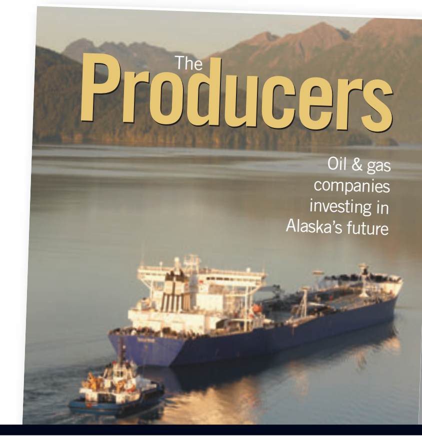
Petroleum news



page 5 Amaroq doubles Nicolai Creek production with well work focus

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Wulff, Oil Search snag Balash; Walsh becomes partner at PRA

CHANTAL WALSH, EX-DIRECTOR of Alaska's Division of Oil and Gas, and Joe Balash, former Interior assistant secretary for land and minerals management, recently secured elevated positions in private industry in Alaska.

Walsh, who resigned her position with the division in February to return to Petrotechnical Resources of Alaska, an Anchorage-based integrated oil and gas consulting firm she and her husband Tom Walsh co-founded in 1997, has once again become a managing partner/owner in PRA.

see **INSIDER** *page 12*

Jade postpones Sourdough well; couldn't get barge, rig into pier


ERIK OPSTAD

Based on results from a bathymetric survey conducted on July 31, Jade Energy executive Erik Opstad told Petroleum News Aug. 30 that the barge carrying the drilling rig for the eastern North Slope Sourdough prospect was not able to get into the Point Thomson unit's service pier this summer, so the appraisal well planned for this coming winter will have to be deferred until the first quarter of 2021.

"It's going to require some light dredging," he said, to remove the silt.

The Alaska-based independent had everything lined up to drill

see **WELL POSTPONED** *page 12*

State terminates small Beechey Point unit north of Prudhoe Bay

The Beechey Point unit is no more.

Brooks Range Petroleum Corp. has been working this area — north of Prudhoe Bay — for more than 10 years, but the unit approved by the Alaska Department of Natural Resources' Division of Oil and Gas in August 2009 has been terminated. The company had asked for reconsideration of a September 2014 decision, by then DNR Commissioner Joe Balash, that the unit had automatically terminated.

DNR Commissioner Corri Feige said in a decision issued this May that while BRPC requested a hearing in addition to a reconsideration of the 2014 decision, "BRPC never contacted the DNR about such a meeting." The commissioner's office inquired in 2016 if the company was still interested in the hearing and BRPC

see **UNIT TERMINATED** *page 10*

EPA proposes rollback on Obama administration O&G emissions rule

On Aug. 28 the Environmental Protection Agency announced a proposal to roll back some of the provisions in regulations introduced by the Obama administration for the limitation of air emissions from oil and gas operations. The regulations had been introduced as part of a series of administrative moves to limit U.S. methane and carbon dioxide emissions.

The regulations in question were introduced in 2012 to limit emissions of volatile organic compounds, and in 2016 to limit methane emissions. The EPA says that, by removing regulatory duplication, its proposed rule change will save the oil industry millions of dollars per year in compliance costs. There is a 60 day public comment period following publication of the proposed changes in the Federal Register.

see **EMISSIONS RULE** *page 11*

EXPLORATION & PRODUCTION

Prudhoe operator?

ConocoPhillips, 36% owner, and Hilcorp, 26%, in talks about operatorship

By KAY CASHMAN
Petroleum News

It's official: ConocoPhillips, with a 36% interest in the Prudhoe Bay unit, and Hilcorp, in the process of buying BP's 26%, are in talks about operatorship.

When asked whether Conoco will operate any part of the Prudhoe Bay unit, Conoco spokeswoman Patty Sullivan told Petroleum News Aug. 30: "BP is the operator until the transaction closes. In the meantime, we will be having conversations with Hilcorp regarding operatorship."

Not surprising since the company press releases announcing Hilcorp's acquisition of all of BP's Alaska assets did not say Hilcorp was taking over operatorship of the North Slope Prudhoe Bay oil field; only that Hilcorp was acquiring BP's interest in it.

"BP is the operator until the transaction closes. In the meantime, we will be having conversations with Hilcorp regarding operatorship."—ConocoPhillips

Before the Aug. 27 sale announcement, it was rumored ConocoPhillips would be operating the western half of Prudhoe and Hilcorp the eastern half.

Hilcorp was asked on Aug. 30 whether it will be

see **PRUDHOE OPERATOR** *page 10*

FINANCE & ECONOMY

Royalty investor relief?

BP Prudhoe Bay Royalty Trust may benefit as Hilcorp takes over from BP

By STEVE SUTHERLIN
Petroleum News

The closing share prices of the BP Prudhoe Bay Royalty Trust (NYSE: BPT) have been in a downward trend recently due to lower oil prices and falling production at the Prudhoe Bay field on Alaska's North Slope, but there may be some relief in store for trust investors as Hilcorp Alaska assumes ownership of BP's share of the field.

BP in August announced the sale of its interest in the Prudhoe Bay field, along with its other Alaska assets, to Hilcorp.

The royalty trust has been under pressure as investors eye the potential for continued profitable production at the field in today's oil price environment. Some analysts have concluded that the field could become uneconomic as early as 2022 if oil prices don't recover from the current $50-60 range.

For BP Prudhoe Bay Royalty Trust and the oil field upon which it relies, Hilcorp may represent the prescription for a longer life span based on lower operating costs and production enhancements extending the life of the field.

As its name implies, the trust relies on royalties

see **ROYALTY TRUST** *page 7*

PIPELINES & DOWNSTREAM

Tied in regulatory knots

Enbridge faces battles over Line 5 upgrade plans, probe of fixed shipping contracts

By GARY PARK
For Petroleum News

Enbridge, the largest combined Canadian based shipper of oil and natural gas, is caught up in tangles on several fronts.

Since mid-August its regulatory agenda has been fully occupied with a constitutional showdown stemming from the new Michigan government's moves to block Enbridge's proposal to modernize its 66 year old Line 5.

The line, which carries 540,000 barrels per day of crude from Alberta to refineries in Sarnia, Ontario, is a vital element of the company's Mainline network to transport 70% of crude leaving Western Canada, much of it destined for the U.S.

The Line 5 battle is now mostly focused on a lawsuit filed by the state asking a county court to compel the decommissioning of a section of the line which connect Lake Michigan and Lake Huron.

But that tussle is now sharing centerstage for the company since Canada's energy regulator agreed to hear complaints from most of the country's largest oil producers over Enbridge's plan to change fixed crude shipping contracts on the Mainline system.

see **REGULATORY KNOTS** *page 11*

ALTERNATIVE ENERGY

FERC issues Grant Lake hydro license

Hydropower system on Kenai Peninsula will involve 5 megawatt powerhouse using water diverted from lake in hills near Moose Pass

By ALAN BAILEY
For Petroleum News

The Federal Energy Regulatory Commission has issued a license to Kenai Hydro LLC for the construction of a hydropower system at Grant Lake on Alaska's Kenai Peninsula. The agency published a final environmental impact statement for the project in May. Kenai Hydro is a subsidiary of the Alaska Electric and Energy Cooperative, the entity that generates and transmits power as part of Homer Electric Association. HEA wants to build the facility in support of a goal for the use of the renewable energy as part of the utility's power generation inventory.

Grant Lake is an L shaped water body in the hills above and to the east of the Seward Highway, where the highway runs through the valley of Moose Pass. The 5 megawatt hydro facility would use water diverted from Grant Lake through a tunnel to a powerhouse near the outlet of Grant Creek canyon, a natural rock canyon.

Environmental impacts

While the project proposal has raised numerous concerns about possible impacts on the Kenai River watershed, the FERC has recognized that the hydro facility would provide power for the Alaska Railbelt and thus displace some power generated from nonrenewable resources. The project will clearly have some environmental impacts, but the approved design of the system includes features targeted at keeping those impacts to a minimum. For example, rather than using a dam at the outlet from Grant Lake, a water intake below the lake's natural water level will be installed, in conjunction with a diversion weir and an underground bypass pipe that will be able to maintain the required minimum flow rate in Grant Creek.

A 3.6 acre detention pond will store water that can be used to boost power generation without causing rapid fluctuations in the flow rate in Grant Creek, at times when the hydropower system has to provide reserve power in support of peaks in power demand on the Alaska Railbelt electrical system.

Although salmon and other fish species spawn in the lower reaches of Grant Creek, there are impassible falls that prevent anadromous fish from reaching Grant Lake.

The Iditarod Trail

One particular challenge results from the fact that historic Iditarod Trail from Seward to Nome passes through the project area. The FERC license says that Kenai Hydro has proposed some rerouting of the trail to accommodate the hydropower system and that the EIS had found that the proposed project does not conflict with the character of the trail. Under the terms of the license, Kenai Hydro, in consultation with the relevant state and federal agencies, must develop a plan for rerouting the trail — the U.S. Forest Service must approve the plan. There are stipulations regarding trail maintenance and maintenance costs within the impacted section of the trail route. ●

Contact Alan Bailey at abailey@petroleumnews.com

contents

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● EXPLORATION & PRODUCTION

July ANS production down 3% from June

Largest month over month increases at Kuparuk, Oooguruk units, biggest drop at Prudhoe Bay; Cook Inlet production up 8% from June

By KRISTEN NELSON

Petroleum News

Alaska North Slope crude oil and natural gas liquids production averaged 474,619 barrels per day in July, down 3% (14,524 bpd) from a June average of 489,144 bpd, but up 14% from a July 2018 average of 416,357 bpd. Crude averaged 434,162 bpd, down 1.7% from June, 7,275 bpd, while NGLs averaged 40,458 bpd, down 15.2% from June, 7,248 bpd. Both volumes are up from July 2018, crude by 14.3% from 379,830 bpd and NGLs by 10.8%, from 36,526 bpd.

Production data reported here is from the Alaska Oil and Gas Conservation Commission, which provides volumes by field and well on a month delay basis.

Kuparuk up 2.1%

The ConocoPhillips Alaska operated Kuparuk River field had the largest month over month production increase, averaging 104,024 bpd in July, up 2,147 bpd, 2.1%, from a June average of 101,878, and up 1.7% from a July 2018 average of 102,274 bpd.

In addition to the main Kuparuk pool, the field produces from satellites at Meltwater, Tabasco and Tarn, and from West Sak.

Oooguruk, operated by Eni, averaged 8,720 bpd in July, up 1,109 bpd, 14.6%, from a June average of 7,611, but down 10% from a July 2018 average of 9,696 bpd.

The Hilcorp Alaska operated Northstar field averaged 9,198 bpd, up 8.8%, 741 bpd, from a June average of 8,457 bpd, but down 1.6% from a July 2018 average of 9,351 bpd. Northstar production for July included 7,911 bpd of crude, up 1,191 bpd, 17.7%, from a June average of 6,720 bpd (and down 3.1% from a July 2018 average of 8,167) and 1,287 bpd of NGLs, down 450 bpd, 25.9%, from a June average of 1,737 bpd, but up 8.7% from a July 2018 average of 1,184 bpd.

Nikaitchuq, operated by Eni, averaged 20,175 bpd in July, up 4%, 781 bpd, from a June average of 19,394 bpd, and up 9.3% from a July 2018 average of 18,454 bpd.

The Hilcorp operated Endicott field averaged 7,387 bpd in July, up 1.4%, 98 bpd, from a June average of 7,289 bpd and up 1.6% from a July 2018 average of 7,268 bpd. Endicott's July production included 6,606 bpd of crude oil, up 1.4%, 94 bpd, from a June average of 6,512 bpd, but down 0.2% from a July 2018 average of 6,619 bpd, and 781 bpd of NGLs, up 0.6%, 4 bpd, from a July average of 777 bpd and up 20.4% from a July 2018 average of 649 bpd.

Prudhoe down 6.5%

All other North Slope fields, led by the BP Exploration (Alaska) operated Prudhoe Bay field, had month over month production declines.

Cook Inlet production averaged 14,336 bpd in July, up 7.6%, 1,011 bpd, from a June average of 13,325, but down 3.8% from a July 2018 average of 14,904 bpd.

At Prudhoe, July production averaged 230,325 bpd, down 15,939 bpd, 6.5%, from a June average of 246,265 bpd, but up 1.9% from a July 2018 average of 226,020 bpd. Prudhoe July production included 191,936 bpd of crude oil, down 4.5%, 9,137 bpd, from a June average of 201,073, but up 0.3% from a July 2018 average of 191,327 bpd, and 38,389 bpd of NGLs, down 6,803 bpd, 10.7%, from a June average of 45,192 bpd, but up 10.7% from a July 2018 average of 34,693 bpd.

In addition to the primary reservoir, production volumes from Prudhoe include Aurora, Borealis, Lisburne, Midnight Sun, Niakuk, Polaris, Point McIntyre, Put River, Raven and Schrader Bluff.

The Hilcorp operated Milne Point field averaged 26,765 bpd in July, down 8.3%, 2,433 bpd, from a June average of 29,198, but up 54.3% from a July 2018 average of 17,346 bpd.

Point Thomson, operated by ExxonMobil Production Co., averaged 4,201 bpd in July, down 622 bpd, 12.9%, from a June average of 4,823 bpd, but up 5,734.5% from a July 2018 average of 72 bpd. Production from Point Thomson, where facilities are rated at 10,000 bpd, was down below 100 bpd for three months last summer. The company has had technical challenges at the high pressure field and production has bounced around considerably. In a 2017 development plan the company told the state that "production to date has been impacted by gas injection compressor availability and reliability."

ConocoPhillips Alaska's Greater Mooses Tooth in the National Petroleum Reserve-Alaska, which came online last October, averaged 11,335 bpd in July, down 161 bpd, 1.4%, from a June average of 11,496 bpd.

ConocoPhillips' Colville River averaged 50,991 bpd in July, down 144 bpd, 0.3%, from a June average of 51,136 bpd, but up 112.4% from a July 2018 average of 24,013 bpd. The July 2018 volumes were due to what the company described as a major maintenance shutdown at the field, which began in mid July last year and lasted a month. In addition to oil from the main Alpine pool, Colville production includes satellite production from Fiord, Nanuq and Qannik.

Badami, operated by Savant Alaska, a Glacier Oil & Gas company, averaged 1,497 bpd in July, down 6.3%, 101 bpd, from a June average of 1,598 bpd, and down 19.6% from a July 2018 average of 1,862 bpd.

Cook Inlet up 7.6%

Cook Inlet production averaged 14,336 bpd in July, up 7.6%, 1,011 bpd, from a June average of 13,325, but down 3.8% from a July 2018 average of 14,904 bpd.

The largest month over month Cook Inlet increase was at Hilcorp Alaska's Trading Bay field, which averaged 1,337 bpd in July, up 629 bpd, an increase of 88.2% from a June average of 710 bpd. That average had been a drop of 51.6% from a May average of 1,469 bpd. Hilcorp has had various maintenance projects underway this summer, reducing production from some of its inlet facilities. The Trading Bay July average was down 14% from a July 2018 average of 1,554 bpd.

The largest percentage increase, 118.6%, was at Hilcorp's Beaver Creek field, which averaged 755 bpd in July, up 409 bpd from a June average of 345 bpd, and up 793.8% from a July 2018 average of 84 bpd. Hilcorp has been redrilling wells at the field, bringing the 5RD2 redrill online in November and the 04RD online in July.

Hilcorp's Granite Point field averaged 2,541 bpd in July, up 121 bpd, 5%, from a June average of 2,420 bpd, but down 10.7% from a July 2018 average of 2,846 bpd.

Middle Ground Shoal, another Hilcorp field, averaged 1,389 bpd in July, up 87 bpd, 6.7%, from a June average of 1,302, and up 14% from a July 2018 average of 1,219 bpd.

Redoubt Shoal, operated by Cook Inlet Energy, a Glacier Oil & Gas company, averaged 1,026 bpd in July, up 40 bpd, 4.1%, from a June average of 986 bpd, but down 20.3% from a July 2018 average of 1,287 bpd.

Hilcorp's McArthur River, Cook Inlet's largest field, averaged 4,650 bpd in July, up 22 bpd, 0.5%, from a June average of 4,628, but down 2.4% from a July 2018 average of 4,765 bpd.

Cook Inlet Energy's West McArthur River field averaged 390 bpd, down 111 bpd, 22.1%, from a June average of 501 bpd, and down 60.7% from a July 2018 average of 994 bpd.

BlueCrest's Hansen field, the Cosmopolitan project, averaged 1,371 bpd in July, down 98 bpd, 6.7%, from a June average of 1,469 bpd, but up 58.5% from a July 2018 average of 865 bpd.

Hilcorp's Swanson River field averaged 877 bpd in July, down 86 bpd, 8.9%, from a June average of 963 bpd, and down 32% from a July 2018 average of 1,290 bpd.

ANS crude oil production peaked in 1988 at 2.1 million bpd; Cook Inlet crude oil production peaked in 1970 at more than 227,000 bpd. ●

Contact Kristen Nelson at knelson@petroleumnews.com

EXPLORATION & PRODUCTION

Drop in US rigs continues, count down 12

Baker Hughes reports the number of rigs drilling for oil and natural gas in the U.S. continues its steep drop, down by 12 the week ending Aug. 30 to 904, following a drop of 19 the week ending Aug. 23.

In its weekly rig count, the Houston oilfield services company said the active rig count was down 144 from 1,048 active rigs a year ago.

The company reported that 742 rigs targeted oil (down 12 from the previous week; down 120 from a year ago) and 162 targeted natural gas (unchanged from the previous week; down 22 from a year ago). There were no miscellaneous rigs active.

The company said 70 of the U.S. holes were directional, 784 were horizontal and 50 were vertical.

North Dakota was up three rigs from the previous week; Alaska was up by one.

The rig counts in California, Ohio and West Virginia were unchanged from the previous week.

Colorado, Louisiana, New Mexico, Pennsylvania, Utah and Wyoming were each down by one rig.

Oklahoma was down by two rigs.

Texas, the state with the most active rigs at 441, was down five from the previous week.

Baker Hughes shows Alaska with nine rigs active for the week ending Aug. 30, up from five a year ago.

The U.S. rig count peaked at 4,530 in 1981. It bottomed out in May 2016 at 404.

—KRISTEN NELSON

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● GOVERNMENT

State, feds to cooperate on offshore oil and gas

By KAY CASHMAN

Petroleum News

The federal government and the state of Alaska signed a memorandum of understanding Aug. 30 to closely cooperate on resource exploration and development on the outer continental shelf, or OCS.

The agencies involved were the federal Bureau of Ocean Energy Management and the Alaska Department of Natural Resources. According to a statement issued by BOEM, the MOU will be in effect for the next three years and can be extended if both parties agree.

"The state of Alaska and BOEM have always worked hand-in-glove when it comes to safely developing resources from Alaska's OCS lease areas," DNR Deputy Commissioner Sara Longan was quoted as saying in a statement from BOEM. "This MOU will facilitate better and more frequent coordination with our federal counterparts. The state of Alaska will continue to offer our expertise and support for holding

see **OFFSHORE O&G** *page 6*

● PIPELINES & DOWNSTREAM

Trump administration tariffs rebounding

Pipeline fee proposed for Cactus II Permian basin line in response to steel increases opposed by producers Encana, ConocoPhillips

By GARY PARK

For Petroleum News

Encana and ConocoPhillips, two leading producers in Canada and the Permian basin, and both victims of nagging shortages of takeaway capacity, are mounting a fight against proposed pipeline fees stemming from the Trump administration's steel tariffs.

In a filing with the U.S. Federal Energy Regulatory Commission they are urging the regulator to reject a surcharge on the Cactus II pipeline, one of three large new Permian lines scheduled to come on stream by mid-2020.

Their challenge is against the prospect of a 5 cent a barrel fee on the line, arguing that the system owner Plains All American has failed to demonstrate that the surcharge is "just and reasonable."

Meanwhile, Plains has applied to the U.S. Department of Commerce for the third time to lift the 25% tariff it pays on steel imported from Greece.

Encana and ConocoPhillips say Plains should wait to learn whether it will be exempt from the tariff before getting the pipeline fee approved.

Tariffs added to construction costs

Plains estimates the steel and aluminum tariffs imposed last year add US$40 million in construction costs to the US$1.1 billion budget estimate for Cactus II.

Plains ordered the steel before President Donald Trump introduced the tariffs but did not receive the first shipment until the summer of 2018 after the tariffs came into effect.

Plains Chief Executive Officer Willie Chiang said the tariffs were unfair because his company was unable to find an alternative domestic steel producer capable of meeting its specifications.

Plains' first two waiver requests were turned down.

The proposed shipping fee would generate about US$33,500 a day for Plains if Cactus II operates at its capacity of 670,000 barrels per day.

James Coleman, an energy professor at Southern Methodist University, said the dispute is a clash of the Trump administration's goals of global energy dominance and revising free trade, resulting in a transportation cost that producers don't need.

The other two pipelines are Kinder Morgan's 800,000 bpd Grey Oak system and Epic Midstream's 900,000 bpd crude line.

Global commodities trader Trafigura, one of the biggest exporters of U.S. crude that routinely ships barrels overseas, has a long-term agreement to carry 300,000 bpd on Cactus II and has already started filling its share of the line.

Plains is proposing pipeline expansions in Canada, Montana and Wyoming with connections to new pipeline systems to deliver more Canadian crude to Houston and the Texas Gulf Coast. ●

Contact Gary Park through publisher@petroleumnews.com

● PRODUCERS MAGAZINE PREVIEW

Amaroq doubles Nicolai Creek production

Well work pays dividends in improving well performance; company focusing on dealing with water and sand disposal as wells age

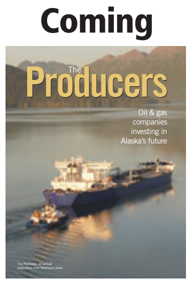
By ALAN BAILEY
For Petroleum News

Thanks to remedial and upgrade work involving the Nicolai Creek No. 10 well, gas production from the Nicolai Creek field onshore the west side of Cook Inlet has recently doubled, Scott Pfoff, president of Amaroq Resources, the field operator, told Petroleum News on Aug. 30.

"We've gone from about 250,000 cubic feet (per day) to 500,000 cubic feet (per day)," Pfoff said.

However, as the field continues to age, there are challenges resulting from long term production declines. In particular, the field's gas compressors were designed to handle larger volumes than are now being produced. And the wells tend sometimes to load up with excess water, Pfoff said.

Coming



Nov. 17, 2019

Acquired in 2018

Amaroq acquired the field in January 2018 as part of the fallout from the bankruptcy of Aurora Gas, the previous field operator — Aurora Gas had operated five onshore gas fields on the west side of the inlet. At the time of its Nicolai Creek purchase Amaroq had been called Aurora Exploration, a completed separate company from Aurora Gas. Given the name confusion, in 2018, after the Nicolai Creek acquisition, Pfoff changed the name of his company to Amaroq Resources. Alaska oil and gas investor Paul Craig has a one-third interest in the company through Craig's company, Trading Bay Oil & Gas LLC.

Since its acquisition of the Nicolai Creek field, Amaroq has pursued a program of field maintenance and well workovers, rather than drilling new development wells. That strategy continues, with the company focusing on achieving good performance from the field's existing wells, Pfoff said.

The field has six gas wells, four of which are currently producing gas. Two of the wells, the No. 2 and No. 3 wells, have been shut in for some time because of mechanical issues — both of these wells probably require drilling rig remediation and Amaroq has no near term plans for dealing with them, Pfoff commented.

In 2018 Amaroq conducted a slickline operation on the No. 9 well, boosting production from that well by 50%. And a coiled tubing workover of the No. 11 well in the third quarter of that year increased that well's performance by around 85%.

The No. 10 well

The focus this year has been the No. 10 well. Remedial work on this well during the first quarter of the year resulted in excessive water production. As a consequence Amaroq had to shut the well in until relatively recently. The company has now been able to stabilize production at significantly higher levels than previously.

"We increased our water storage capabilities and did some additional upgrades to surface facilities," Pfoff said.

One issue involved fine sand passing through screens designed for sand capture, a problem that necessitated improvements to the sand handling capabilities of the surface facilities, he said.

SCOTT PFOFF

There is also some parted tubing downhole in the No. 10 well. But fixing this would require the use of a drilling rig. So Amaroq has been conducting the workover operations and surface facility improvements ahead of a decision on whether a rig operation would be economically justified. It is possible to continue operating the well as is, albeit at a production rate lower than would be possible if the tubing is fixed, Pfoff said.

Sand and water production

As the field matures, the disposal of produced sand and water has become an issue. Currently the sand and water are stored at the surface. However, disposal of these waste materials is needed.

Amaroq plans to convert one of the Nicolai Creek wells to a water disposal well. The company has been talking with the Alaska Oil and Gas Conservation Commission about this, with a view to filing a permit application for water injection.

"As a result of those discussions we're going to perform injectivity tests on the well we want to convert, and then we'll incorporate those results in our application," Pfoff said.

Further development?

Amaroq has no plans for exploration outside the Nicolai Creek field, Pfoff said. However, there is potential to extend the existing field. The company is also interested in developing further oil and gas pools at deeper levels below the field, in the Nicolai Creek unit. Currently, rights to those deeper prospects belong to Apache Alaska Corp., which acquired 3D seismic over the acreage in early 2012.

In its current plan of operations, filed with the state, Amaroq has acknowledged the potential to drill an additional production well, the Nicolai Creek No. 12 well, targeting deeper sands in the Beluga and Upper Tyonek formations to the north of the current production area. Aurora Gas had conducted an evaluation of this potential well. However, Amaroq does not want to tackle this until the company has dealt with achieving good performance from the field's existing wells, Pfoff said.

In addition to continuing gas production at Nicolai Creek, Amaroq has also considered the possibility of converting part of the field into a gas storage facility, with the capability of holding between 2.5 billion and 3 billion cubic feet of gas. An engineering study conducted several years ago confirmed that possibility. But, in the absence of any recent interest from potential gas storage customers, Amaroq has no current plans to proceed with the storage option.

"It's not the kind of project we can go out and do on spec," Pfoff said.

COURTESY LYLE SSAVAGE

A coiled tubing operation in progress in the Nicolai Creek No. 10 well

AOGCC bonding

One challenge that has emerged for Amaroq is a new AOGCC policy to

see **PRODUCERS PREVIEW** *page 7*

● GOVERNMENT

O&G defenders, critics test Colorado law

By DAN ELLIOTT
Associated Press

The petroleum industry's defenders and critics are testing the limits of a new Colorado law that flips the state's priorities from producing energy to protecting the public.

Officials in energy-friendly Weld County say the law gives the county complete control over the location of new wells in unincorporated areas. That could challenge the state's attempts to tighten regulations.

Just across the county line in Longmont, environmental activists are trying to use the same statute to revive the city's ban on hydraulic fracturing, which the courts threw out under the previous laws. Because fracking is standard practice in the area, the ban would essentially prohibit all drilling.

Democratic Gov. Jared Polis signed the bill into law on April 16. In addition to switching the state's top priority to public health and the environment, it gives cities and counties new powers to regulate the drilling locations.

The Colorado Oil and Gas Conservation Commission is in the early stages of rewriting its rules to comply with the law — referred to as Senate Bill 181 — and several counties are looking at drafting their own regulations.

It's too early to measure the impacts, but the industry is clearly concerned. The Colorado Oil and Gas Association invited Polis to speak Aug. 28 at a session titled "Can You Still Drill for Oil in a Blue State?"

Polis told the audience that was a silly question. He said international markets and overseas instability have more impact on the industry than state regulations.

"Energy is not inherently political, it's inherently economic," he said.

Dan Haley, president of the Oil and Gas Association,

Environmental groups Colorado Rising and Our Longmont say the new law clears the way for Longmont and other local governments to ban oil and gas drilling.

asked Polis several times to respond to industry concerns about its standing in the state.

The governor eventually replied he values industry jobs but added that they're part of a diverse state economy.

Colorado ranks fifth in the nation for crude oil production and sixth in natural gas, and much of that is concentrated in Weld County northeast of Denver.

Final word to counties?

Weld County Commissioner Barbara Kirkmeyer, a fierce defender of the industry, argued hard against the new bill and led a short-lived campaign to overturn it after it became law.

Now she maintains the bill, coupled with older statutes on local government powers, gives counties like hers the final word on land-use decisions that affect the industry in areas outside cities.

"Basically what S.B. 181 said is the state no longer has land use authority," she said in an interview.

Weld County established an oil and gas department and adopted its own rules, but Kirkmeyer said energy companies won't have free rein to drill wherever they want. The county rules are similar to ones the state had before the new law was passed, she said.

The goal is to ensure a common-sense approach to regulating oil and gas companies, Kirkmeyer said.

"We are willing to work with them for responsible energy development in our county," she said.

Democratic Senate Majority Leader Stephen Fenberg, a sponsor of Senate Bill 181, disputed Kirkmeyer's interpretation of the law. The intent was to give both the state and local governments a say in regulating the surface impacts of oil and gas, and to allow cities and counties to enact stricter rules than the state's, but not more lenient ones, he said.

"I would argue that the Weld County commissioners know this," he said, accusing them of "political theater."

Polis said Aug. 28 that state officials are working on a written agreement with Weld County officials but offered no details.

Can drilling be banned?

Environmental groups Colorado Rising and Our Longmont say the new law clears the way for Longmont and other local governments to ban oil and gas drilling.

Longmont voters approved a fracking ban in 2012, but the Colorado Supreme Court overturned it in 2016, saying only the state could regulate the industry under the laws in force at the time.

Senate Bill 181 "flips the script" on state and local control, said Democratic state Rep. Jonathan Singer of Longmont, who supports the ban.

"The state does not take precedence over what local governments want to do when it comes to protecting our health and safety," he said.

The two environmental groups asked the courts to restore the ban earlier in August. The case is pending.

Fenberg said the law doesn't specifically allow or prohibit local drilling bans. But he said they could open a city or a county to damage claims from mineral rights owners who can't access their underground oil and gas reserves.

If the goal is to protect public health and safety, strong local regulations are a better option than a ban, he said. ●

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OFFSHORE O&G

routine lease sales in Alaska's prolific OCS basins."

Part of the U.S. Department of the Interior, BOEM's mission is to manage development of OCS energy and mineral resources in an environmentally and economically responsible way. The OCS begins three miles offshore; the submerged lands between this boundary and the shoreline are managed by DNR.


SARA LONGAN

"The different jurisdictions aside, both the state and BOEM understand that this is one big ocean," said Dr. Walter

"Regulatory considerations are often made and clarified during these coordination activities, especially for projects within the state submerged lease area. This deliberation is key to identifying possible regulatory issues early on, which often mitigates the element of surprise for a lessee or project applicant and avoids delays." —Sara Longan

Cruickshank, acting director of BOEM. "To manage these resources and protect the environment in a responsible way, it is critical the state and federal agencies involved communicate with each other and work together whenever possible. This MOU codifies and formalizes those practices and gives both parties a blueprint for moving forward."

Asked by Petroleum News why the agreement was for only three years, Longan replied in a Sept. 1 email that "using MOU term dates provides the opportunity to assess the efficacy of the MOU, whether the original intent is met, and whether the MOU is still necessary or needs amendment."

How the MOU will help

Some of the areas highlighted for cooperation in the MOU include:

• The process of planning lease sales.

• Industry plans to conduct OCS exploration development or production activities.

• Environmental reviews.

• National Historic Preservation Act consultation.

• Air emissions and air-quality monitoring.

• Wastewater discharges from oil and gas activities.

When asked for more specifics on how the MOU will work and benefit leaseholders and companies interested in investing in OCS lease and projects, Longan said: "The state of Alaska continues to call for reliable OCS lease sales, in part, by partnering with BOEM and sharing subject matter expertise and information about oil and gas activities taking place on state leases. The MOU requires routine coordination and lines out the type of information sharing that ultimately helps enhance and inform BOEM's lease planning efforts and OCS project reviews. This coordination and partnership aids industry by helping ensure all relevant information is made available to BOEM in a proactive manner. Furthermore, regulatory considerations are often made and clarified during these coordination activities, especially for projects within the state submerged lease area. This deliberation is key to identifying possible regulatory issues early on, which often mitigates the element of surprise for a lessee or project applicant and avoids delays." ●

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ROYALTY TRUST

from the Prudhoe Bay field, specifically 16.4246% of the first 90,000 barrels of net daily production. Its shares will become essentially worthless should the field shut down.

Since notching a close of $128.75 per share on Jan. 3, 2011, in a triple-digit oil price environment, BPT shares have fallen to close at $8.23 per share on Sept. 4.

Hilcorp is a lean operator, however, with a track record of revitalizing production in aging fields. For BP Prudhoe Bay Royalty Trust and the oil field upon which it relies, Hilcorp may represent the prescription for a longer life span based on lower operating costs and production enhancements extending the life of the field.

Payout since 1989

The BP Prudhoe Bay Royalty Trust was founded by Standard Oil Company and BP Exploration on February 28, 1989. Its share price rose to $35 on Sept. 17, 1990, and slumped to under $4.50 per share in 1999 before riding higher oil prices to a share price peak in 2011.

In the second quarter of 2019, the trust recorded a dividend rate of $0.5510499 per unit, based on an actual average daily production for the quarter of 74,254 barrels. This is an increase over Q1 2019 dividend levels, but lower than 2018 quarterly dividend payouts in the range of $1-$1.50 per share.

At an annual dividend rate of $3.28 per share, the annual dividend yield is 39.84% as of Sept. 4. This high yield is primarily a function of share prices falling in 2019, including a 36.6% share price drop in July.

Such a high dividend yield does look juicy, but often an extremely high yield is a danger signal, known as a dividend trap, masking underlying flaws in the security which may result in an unsustainable dividend or worse, an unsustainable business model. Those dangers appear to be largely priced into the current share levels.

With the entrance of Hilcorp, the market's view of BPT may be excessively pessimistic.

Slope successes

Like the BP Prudhoe Bay Royalty Trust, Hilcorp was founded in 1989. It is the largest privately owned oil and natural gas producer in the country.

"Hilcorp is a leader in taking on legacy oil and gas assets across the United States and reinvigorating production with innovation and integrity," the company said on its website. "We thrive on efficiency and create value through both energy production and the positive impacts it has on the communities where we work."

In the last five years, Hilcorp has "exponentially increased reserves and production," the company said.

Hilcorp has been active on the North Slope since 2014, coaxing more oil out of its three producing North Slope oil fields by increased drilling, reworking wells and by reinjecting natural gas and injecting polymer and water into reservoirs.

The company also invests in upgrading old infrastructure to ensure that pipelines and wells can continue to perform effectively into the future.

At the Milne Point unit, which went online in 1985, Alaska economist Ed King said Hilcorp has been doing a "tremendous job squeezing additional life out of this mature asset since purchasing it from BP" in 2014.

According to data from the Alaska Oil and Gas Conservation Commission, 8.3 million barrels were produced from Milne Point in FY19 — a million barrels more than in FY18.

At the Duck Island unit, which holds the Endicott field and went online in 1987, King said Hilcorp was able to "maintain a fairly flat production rate over the last two years." (Previously Hilcorp had boosted output.)

After starting regular production in 2001, the Northstar field is already nearing the end of its economic life, currently producing about 10,000 bpd for Hilcorp, he said. "In fact, the Northstar unit saw an increase of 317,587 barrels of oil (a 9% increase) over FY18."

In Alaska's Cook Inlet, Hilcorp has increased oil production from 10,000 bpd in 2012 to 16,000 bpd in 2019, while revitalizing natural gas production to become the state's largest producer of natural gas.

If Hilcorp can achieve similar results at Prudhoe Bay, perhaps the shares of the BP Prudhoe Bay Royalty Trust are oversold. ●

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PRODUCERS PREVIEW

increase the levels of surety bonding required for the plugging and abandonment of defunct oil and gas wells in the state. While the AOGCC has been concerned that traditional bonding levels fall short of the realistic cost of adequately plugging a well, increased bonding levels increase field operation costs and hence impact the economics of a field: Small operators such as Amaroq have argued that, if the state sets bond levels that are too high, the state will lose some oil and gas production when some fields are forced to close as a consequence.

On the other hand if an operator fails to plug and abandon a well, the cost of the plugging operations will default to the landowner, often the state of Alaska.

In late 2017 Amaroq's purchase of Nicolai Creek was delayed after the AOGCC ruled that it required $7 million in surety bonding for the field's wells. The purchase ultimately went ahead after the commission reduced the bonding requirement to $200,000. For many years the minimum bonding requirement in Alaska had been not less than $100,000 for a single well and not less than $200,000 for blanket coverage of all an operator's wells in the state. However, the commission had only required bonding at these minimum levels, except in situations where there had been regulatory violations.

After lengthy hearings, in May of this year the commission increased the minimum statewide bonding level to $400,000 per well for one to 10 wells, with minimum bonding levels running to millions of dollars for larger numbers of wells. Pfoff said that the bonding levels as now stipulated render the Nicolai Creek field uneconomic. Although, the increased bonding was required by Aug. 16, Amaroq had meanwhile filed a motion for reconsideration of the revised regulations, Pfoff said. Elevating the bond amount for Amaroq remains on hold until the motion has been considered, he said.

A healthy market

At the same time, although Pfoff is concerned about lack of competition, given the few gas producers in the Cook Inlet, he sees the Cook Inlet gas market as relatively healthy.

"Right now, the way I see it, I can increase production quite a bit at Nicolai Creek and not have any trouble selling the gas at a good price," Pfoff said.

Using the current wells and well completions the field probably has a remaining four to five-year life, Pfoff said. But, with much upside possible, if successfully developed, field life could extend considerably, he said. And Pfoff expressed satisfaction with the progress that his company has made in saving the field from closure.

"We are proud of the fact that we have managed to prevent the plugging of one of the five gas fields affected by the Aurora Gas bankruptcy; keeping it in production; generating royalty and taxes to the state of Alaska; directly and indirectly employing personnel on the west side of the Cook Inlet," he commented. ●

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● PIPELINES & DOWNSTREAM

ND: Study 'undermines' Washington's law

ASSOCIATED PRESS

A federal study analyzing the volatility of Bakken crude supports the state's petition to overturn Washington state's oil shipment safety restrictions, North Dakota's attorney general said.

Washington Gov. Jay Inslee in May mandated a lower vapor pressure limit for Bakken crude shipped through the state by rail. In July, North Dakota and Montana asked the Trump administration to overrule that law.

Several Bakken crude-carrying trains have derailed and exploded in recent years, leading to scrutiny of the high vapor pressure of North Dakota oil.

The Sandia National Laboratories study completed in August concluded that "vapor pressure is not a statistically significant factor" in the severity of oil train crashes, the Bismarck Tribune reported.

Wayne Stenehjem, attorney general for North Dakota, said Aug. 28 that the study "vastly undermines the reasoning behind the state of Washington enacting this statute because they assume without evidence that Bakken oil is more volatile."

"The net result is Bakken oil is no different than any other kind of oil with respect to volatility," Stenehjem added.

Washington Gov. Jay Inslee's office said in a statement that the state will defend its statute. Officials intend to submit comments to the federal Pipeline and Hazardous Materials Safety Administration.

"Every governor has a responsibility and a right to protect the health and safety of their communities and environment," said spokeswoman Tara Lee. "As Washington has experienced an enormous spike in the numbers of oil trains traveling through our state, this legislation is a reasonable approach to anticipated increased volumes of volatile crude oil."

The study analyzed oil from the Bakken, the Permian Basin in Texas and crude stored in the federal Strategic Petroleum Reserve, each with a different vapor pressure. Researchers conducted the studies by igniting pools of oil on fire and creating fireballs while measuring the height of flames, burn rate and fireball dimensions, among other factors.

"The results from this work do not support creating a distinction for crude oils based on vapor pressure with regards to these combustion events," according to the study.

Kari Cutting, vice president of the North Dakota Petroleum Council, said in a statement that the study "conclusively determined" that Bakken crude does not have different physical and combustible characteristics from other crude oil. ●

● EXPLORATION & PRODUCTION

Report: New Mexico oil boom to continue

ASSOCIATED PRESS

New Mexico's oil and gas industry is expected to keep growing at a record pace, resulting in more revenue for the state and billions of dollars in new infrastructure investments to get the commodities to market, according to a study commissioned by industry trade groups.

The predictions were outlined in a report presented to state lawmakers during a meeting Sept. 3 in Roswell. The report, compiled by a national consulting group, was commissioned by the New Mexico Oil and Gas Association and the American Petroleum Institute.

Analysts estimate it will take $174 billion of new infrastructure to keep pace with expected growth through 2030. That would include investments by the industry in new pipelines, access roads, well pad construction, processing plants and refineries.

Ryan Flynn, executive director with the New Mexico Oil and Gas Association, said he doesn't see it as an infrastructure challenge but rather natural growth in investment that will come from "hitting a new normal of continually high production."

Development in the basin, which straddles parts of New Mexico and West Texas, has been surging. Energy companies have invested billions of dollars in the region in recent years and government scientists have estimated that reserves within the basin could be enough to potentially double the nation's onshore oil and gas resources.

In its latest forecast, the U.S. Energy Information Administration said it expects the United States to pump about 12.3 million barrels of crude oil a day in 2019 and 13.3 million barrels a day in 2020, both of which would be record levels.

Much of the increase is expected to come from the Permian Basin as operators use hydraulic fracturing and other techniques to squeeze more oil and gas from shale formations.

With continued growth, the report estimates that production value in New Mexico would increase from $17 billion in 2017 to more than $72.6 billion in 2030, tripling the industry's contribution to the state's gross domestic product. ●

Petroleum news

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PRUDHOE OPERATOR

the sole operator of Prudhoe Bay, but had not replied as of close of business Sept. 4.

Elephant rumor

In its Aug. 11 edition, Petroleum News, or PN, carried an article about the rumor, piecing together the possible story behind it from a combination of public information previously confirmed by BP, as well as unnamed sources.

The story began in April 2014 when BP announced the sale of three smaller producing North Slope oil fields to Hilcorp: Milne Point, Endicott and NorthStar, as well as the undeveloped Liberty prospect. The deal included all of BP's working interest in the Endicott and Northstar oil fields and a 50% interest in Liberty and Milne Point. BP's interest in pipelines associated with those fields were also included.

The two oil fields that are key in the Aug. 27 sale announcements by BP and Hilcorp are the mature Milne Point and Endicott fields where oil production had been steadily declining.

Hilcorp, which by 2014 had established itself in the Cook Inlet basin and elsewhere as technically skilled at teasing more oil out of mature fields, as well as finding and developing additional reserves, was rumored to be auditioning for a much bigger role; that of Prudhoe Bay operator.

According to PN sources close to the 2014 deal, "on a moment's notice" BP could have stepped in at any time and "for any reason and taken back either Milne or Endicott."

Instead, Hilcorp proved itself a capable operator.

All three partners in agreement?

At the time of the 2014 (unconfirmed) agreement to eventually sell Hilcorp a piece of Prudhoe Bay and enable it to ultimately take over as operator, the other two major owners in Prudhoe Bay would have had to agree with BP.

Per the rumor ExxonMobil, with a 36% working interest, did agree, but according to unnamed sources, ConocoPhillips' agreement came with a caveat: the longtime North Slope operator wanted to operate the west side of Prudhoe, allowing Hilcorp to take over the east side of the field, which until 2000 had been operated by ARCO Alaska (predecessor to ConocoPhillips) with BP operating the western half.

Since then BP has operated the entire unit.

Again, none of the Prudhoe partners ever confirmed the rumor about a 2014 agreement.

Hilcorp likely to grow oil output

Regardless of what was or wasn't decided in 2014, Hilcorp has fewer layers of management than BP, Conoco or Exxon, and has a reputation for operating efficiently while maintaining or increasing oil and gas production.

For example, when Hilcorp took over operatorship of Milne Point, it was able to run with field with less than half the employees BP had used. (It did replace some employees by hiring contractors.)

What's more, Hilcorp increased investment in the mature oil field, which had gone online in 1985, and bumped up production.

On Aug. 5, Ed King of King Economics Group reported impressive fiscal year 2019 output numbers from the Hilcorp-operated Milne Point oil field, his data taken from the Alaska Oil and Gas Conservation Commission.

At the Milne Point unit, King said Hilcorp had been doing a "tremendous job squeezing additional life out of this mature asset since purchasing it from BP."

All told, 8.3 million barrels were produced from Milne in FY19 — a million barrels more than in FY18. (In April, total oil production averaged 25,260 barrels per day, up 17.7% from April 2018.)

Milne produces mainly from the Kuparuk (light oil) and Schrader Bluff (viscous oil) reservoirs and will soon also be producing from the Ugnu and Sag River (both viscous) reservoirs, per Hilcorp' s 37th plan of development filed with the state.

Hilcorp has invested in a new drilling pad in the field — Moose Pad — which came online in June 2018.

Following on the heels of Moose Pad, which was the first new Milne pad since 2002, Hilcorp is planning to build another new pad in the unit, R-Pad.

Furthermore, the company recently received authorization to install the third polymer injection facility at Milne Point, a technology Hilcorp first brought to the North Slope.

Injecting polymer and water into the field has been more successful in coaxing the viscous crude — oil with the consistency of syrup — from the reservoir than conventional waterflood, David Wilkins, Hilcorp senior vice president for Alaska, said in November.

Using polymer, Hilcorp expects to increase crude recovery from 10 to 15% of the oil in place at Milne to as much as 50%, per slides Wilkins used in his presentation at the Resource Development Council of Alaska's annual conference.

In short, Hilcorp has the potential of increasing profits at Prudhoe Bay for all its owners, as well as boosting the state of Alaska's take with a production increase.

The question is, will Conoco and Exxon allow Hilcorp to operate the entire Prudhoe unit or will one of them operate part of it? ●

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UNIT TERMINATED

confirmed that it did want a hearing, which was held last September to address three issues: the condition and status of the North Shore No. 1 well; whether that well was physically capable of producing hydrocarbons; and what unit operations BRPC had conducted between August 2009 and August 2014.

The Beechey Point unit is north of Prudhoe Bay, between the Milne Point and Northstar units. In 2009 there were 25 state oil and gas leases in the unit, some 52,876 acres.

Discoveries in area

In its 2009 approval of the unit's formation the division said there had been a number of discoveries over the years in the area of the unit, which has been part of several former units but has not been developed.

In the winter of 2006-07 BRPC drilled its first exploration well, the North Shore No. 1, and the Sak River No. 1. The company sidetracked the North Shore No. 1 the following winter and tested more than 2,000 barrels per day of oil from the Ivishak formation. The company also acquired 130 square miles of seismic data covering the entire BPU area.

On July 10, 2008, the division said, it determined that the North Shore No. 1 was capable of producing in paying quantities.

The 2009 unit approval called for BRPC to have all permits in place for North Shore development by the end of 2010 and to apply for an initial participating area by Oct. 1, 2012. First production was anticipated by Jan. 1, 2013.

The unit had five exploration blocks and by Dec. 1, 2010, BRPC was to commit to drill a well within one of those exploration blocks, with the first exploration well completed by July 1, 2011. BRPC was also required to drill a second exploration well by July 1, 2013.

The wells were not drilled.

In 2012 the division approved a voluntary contraction of the unit to seven leases, some 10,757 acres.

Automatic termination

In the September 2014 notice of automatic unit termination DNR cited regulations which require automatic termination after 5 years unless certain conditions are met, including a unit well certified capable of production in paying quantities.

In her May 2019 decision, Feige said there are two requirements for extending a unit beyond its initial 5 year term: a unit well certified capable of producing hydrocarbons in paying quantities and the operator either producing from the unit or "conducting operations under an approved plan of exploration or development."

BRPC has described the Gwydyr Bay South No. 1 as a unit well, but that well, Feige said, was drilled in 1976 and at no point in the unit's history has a DNR commissioner authorized it as a unit well. And, she said, according to the Alaska Oil and Gas Conservation Commission, that well was plugged and abandoned in 2002, "making it physically incapable of producing. A well capable of producing in paying quantities is one that could flow if turned on."

While North Shore No. 1 was drilled prior to formation of the unit, it was designated a unit well under the unit agreement, Feige said, but noted that based on email correspondence, it appears the well had issues, described as "junk in the hole," which made production impossible.

No operations since 2010

Feige said even if the North Shore No. 1 was capable of producing in paying quantities, "unit operations were not conducted in accordance with an approved plan between the summer of 2010 and unit termination in 2014."

She said a timeline provided by BRPC at the 2018 hearing showed that operations were limited to 2009-10 winter season exploration drilling and an archaeological clearance in 2010.

BRPC also asked for reconsideration of the unit termination based on the opportunity to negotiate a plan of development and Feige said much of the company's testimony at the 2018 hearing "reiterated this desire and emphasized BRPC's view of the resource potential across multiple active and former units near Beechey Point."

"An operator's intentions to conduct operations in the future, or to conduct business transactions that would allow development to occur in the future, fail to comply with the regulation," Feige said.

—KRISTEN NELSON

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REGULATORY KNOTS

Enbridge has proposed shifting away from a month by month system to allocating 90% of the space on the mainline to committed shippers in contracts lasting up to 20 years, starting in 2021.

The Canadian Energy Regulator, CER, formerly known as the National Energy Board, said it will "expedite" a process to handle comments from producers and Enbridge before the company's "open season" for shipping contracts ends on Oct. 2.

It asked producers and Enbridge to express their views on whether the regulator had the authority to stop the open season and what harm would result if the process was paused rather than allowed to continue.

This compounds a series of bottlenecks facing Canadian producers, including the Line 5 squabble and delays on starting construction on Keystone XL and the Trans Mountain expansion, that have resulted in heavy rationing.

Canadian Natural opposition

The Mainline plan has encountered heated opposition from Suncor Energy, Shell Canada, Canadian Natural Resources, MEG Canada, ConocoPhillips Canada and the Explorers and Producers Association of Canada.

In a letter to the CER, Canadian Natural President Tim McKay said Enbridge's proposal is "completely inappropriate and is being made at a time when considerable market power imbalance exists because of the shortage of capacity leaving the Western Canadian Sedimentary Basin."

His company said the CER should direct Enbridge to halt the open season until the regulator can consider the market power issues raised by producers.

It said the CER should also approve the new terms and conditions and tolls before shippers are required to sign any binding contractual commitments for pipeline space.

McKay argued that Enbridge's plan disadvantages non-integrated producers (those who do not have access to their own refineries) "in favor of shippers who can supply their own downstream" facilities.

Conoco, Suncor others in opposition

Kirk Johnson, president of ConocoPhillips Canada, said the plan creates uncertainty for companies with contracts to link up with U.S. pipelines, such as Flanagan South from Illinois to Oklahoma.

Suncor told the CER that "the terms and conditions of the open season are not fair, just or reasonable," while Shell said congestion on export pipelines out of Canada meant Enbridge was forcing shippers to sign up for unfair tolls, or risk being left without market access.

Shell Canada President Michael Crothers said the open season offering "may represent an abuse of market power."

Guy Jarvis, Enbridge's executive vice president for liquids pipelines, told Bloomberg the "offering that we've got in the open season is responding to the needs of our customers and is supported by shippers representing the majority of the volume on our system."

Calgary-based investment bank GMP First Energy said the CER should extend the open season if it needs more time to make a ruling.

It said in a note that "we fear if the open season is concluded in its current form, this will result in more pricing power being transferred to U.S. Midwest refiners and onerously burdensome long-term commitments on the books for Canadian producers."

Genscape analyst Mike Walls said producers are concerned that if a relatively "few refiners in the U.S. control a large portion of the Mainline space their access to customers will be limited as well as their ability to get more diverse markets such as the Gulf Coast.

Four companies with their own major refineries in the Midwest — Exxon Mobil, BP, Marathon Oil and Valero — had no comment on the showdown.

Line 5 battle

The Line 5 battle is now mostly focused on a lawsuit filed by the state asking a county court to compel the decommissioning of a section of the line that runs across the Straits of Mackinac which connect Lake Michigan and Lake Huron.

Bad River Band, a Native American tribe in Wisconsin with 7,000 members, has filed its own federal lawsuit in hopes of forcing Enbridge to remove sections of the pipeline that cross the reservation.

The action contends the threat of a rupture has been growing as earth around a portion of the pipeline has eroded and could soon wash away the soil that covers and supports the line.

Enbridge said it will consider rerouting Line 5 and "remains open to this option as a solution."

However, the company gained an important ally in Michigan's Republican majority Legislature, which said in brief filed with the state's Court of Claims that it acted properly last year when it passed an act that enabled Enbridge to build a tunnel beneath the Straits of Mackinac to replace the underwater section of the existing line.

The document accused Attorney General Dana Nessel of trying to "subvert the democratic process in order to replace a duly-enacted law."

Last December the Michigan Department of Natural Resources announced that the Mackinac Straits Corridor Authority, in correspondence with outgoing Gov. Rick Snyder, signed an agreement to build a multipurpose tunnel under the straits to house multiple utility lines, while the old Line 5 would be removed and a new link built.

That agreement did not contain a timeline for removing the existing line, which was immediately challenged by the new Democratic Michigan administration.

Nessel's office said the agreement by the former government "did not provide fair notice to legislators and the public" about the plans to house a new Enbridge oil line in a tunnel.

Line 5 is also involved in a second lawsuit in which Michigan is trying to have the land use agreement in the Straits of Mackinac overturned by arguing the pipeline is a public nuisance.

An Enbridge spokesman said the company is reviewing Michigan's latest filing but remains focused on preconstruction tunnel work. ●

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EMISSIONS RULE

According to an EPA news release, the primary proposal involves removing from regulation potential emissions sources involved in the transmission and storage components of oil and gas industry operations, including compressor stations and underground storage vessels. There is an alternative proposal that would retain these industry components within the regulations but would remove limitations on methane emissions from the equipment. And, while volatile organic compound emission limits would remain for production and processing operations, limits for methane emissions from these operations would be removed.

EPA: remove duplicative burdens

The EPA says that it is responding to an order by President Donald Trump, directing federal agencies to review regulations that potentially burden the development or use of domestic energy resources.

"EPA's proposal delivers on President Trump's executive order and removes unnecessary and duplicative regulatory burdens from the oil and gas industry," said EPA Administrator Andrew Wheeler. "The Trump administration recognizes that methane is valuable, and the industry has an incentive to minimize leaks and maximize its use. Since 1990, natural gas production in the United States has almost doubled while methane emissions across the natural gas industry have fallen by nearly 15 percent."

The American Petroleum Institute expressed its support for the EPA action.

"We support EPA's efforts to adhere to its statutory obligations under the Clean Air Act," the API wrote in an Aug. 29 press release. "Under this proposal the oil and gas sector will continue to be effectively regulated. The regulation of volatile organic compounds drives down methane emissions and allows for innovation and technological advancements that help environmental performance and strengthen industry actions to reduce emissions."

Environmental organization concerns

On the other hand, the Environmental Defense Fund expressed its concern that the weakening of the regulations would lead to undesirable emissions of methane, smog-forming compounds and other air pollutants.

"The EPA has proposed weakening requirements for finding and repairing methane leaks at oil and gas facilities, even though the EPA found the current standards are more cost-effective than the agency expected," the fund commented in a statement responding to the EPA announcement.

Key questions revolve around the appropriateness of the regulations and the cost of compliance.

"Today's proposed change focuses on removing costly and duplicative barriers while promoting market-focused solutions," wrote Thomas Pyle, president of American Energy Alliance, "Incentives to reduce emissions already exist for this industry without the heavy hand of the government and today's announcement is a breath of fresh air from the previous administration that made every effort possible to regulate the oil and gas industry out of business."

In 2018 the Oil and Gas Climate Initiative, a coalition of 13 major oil companies, set an aggressive target to reduce the methane intensity of their industry by 2025. And according to various media reports, some major oil companies such as Shell, ExxonMobil and BP have expressed support for government regulation of the emissions. In a March 20 opinion piece in the Houston Chronicle, Susan Dio, chairman and president of BP America, commented that BP supports the need to control methane emissions and that BP and other companies are highly focused on the issue.

"But voluntary actions by several energy companies are not enough to solve the problem," Dio wrote, reflecting on the issue of methane leakage. "The best way to help further reduce and ultimately eliminate methane emissions industrywide is through direct federal regulation sources."

—ALAN BAILEY

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INSIDER

Balash resigned his position at the Department of Interior effective Aug. 30 and will soon be going to work as senior vice president of external affairs for Oil Search, the company leading the North Slope exploration and development renaissance with its huge Nanushuk oil discovery and Pikka development.

In a Sept. 4 statement to Petroleum News, Christina Livesey and Tom Walsh, managing partners of PRA, said Chantal Walsh has joined them as a third managing partner.

CHANTAL WALSH

Prior to accepting the appointment as division director in the Walker administration, Chantal, a life-long Alaskan, worked as a petroleum engineering consultant for numerous PRA clients, including Hilcorp, Chevron, Unocal, BP and Brooks Range Petroleum. Shortly after launching PRA more than 22 years ago with Tom and their three original PRA partners Chet Paris, Doug Dickey and Bob Ravn, Chantal accepted a petroleum engineering position with ARCO, and later rejoined her original employer BP for a brief second career with the company.

"Chantal is a certified petroleum engineer, with great breadth of knowledge and experience across the oil and gas engineering disciplines, and she is excited to rejoin the PRA family and the management team," Livesey and Tom said.

Chantal and Tom's son, Zan Walsh, a recent mechanical engineering graduate of Portland State University, has also joined the PRA team as an entry level engineer and is quickly gaining experience working on PRA-managed drilling, completion, and wellwork projects.

Balash grew up in North Pole

Balash, who grew up in North Pole and still has family in the area, oversaw the Bureaus of Land Management and Ocean Energy Management while he was with Interior.

JOE BALASH

Prior to that he served as the chief of staff to U.S. Senator Dan Sullivan, R-Alaska, and as former commissioner of the Alaska Department of Natural Resources.

In a lengthy post on his Facebook page Sept. 4, Balash said he will be based in Oil Search's Anchorage office.

Leaving the Department of the Interior, he said, was not an easy decision, but he is "excited to be coming home with a company that is doing great things."

"Public service has been a passion of mine for more than 20 years. I love being involved in the decisions that affect our state and country, and I'm so grateful for the trust that has been placed in me that allowed me those opportunities. But with my oldest child graduating from high school, it felt like the right time to pursue a new path with new challenges, ideally a lot closer to home."

Balash said he started taking calls from search firms in May.

"When the first contact turned out to be on behalf of an exploration and production company in Alaska, I was gob smacked," he said.

Already familiar with Oil Search during his time at DNR, he had worked "with Bill Armstrong on a multitude of issues relating to his company's lease interests — many of which eventually became the Oil Search-led Pikka project," Balash said, referring to the founder of Armstrong Energy, which with Repsol discovered the untapped Nanushuk formation and brought Oil Search to Alaska as a partner.

"From tax policy, to unitization, and exploration plans, I learned then about the considerable potential believed to be present, assuming the State did its part regarding the oil and gas investment climate," Balash wrote in his Facebook post.

Most recently, he was "pleased to see Oil Search receive a Record of Decision from the Corps of Engineers to proceed with development at Pikka. At 120,000+ barrels of daily production, I knew this was a key piece of Alaska's economic and fiscal future."

"Oil Search is doing great things in Alaska and …I want to be part of their success. Helping them get Pikka constructed over the next several years and continuing to pursue exploration targets means that I get to continue to help the State and people I love dearly."

Oil Search, Balash said, "has a unique approach to dealing with local partners that I fully respect and will take pride in."

"We are pleased to welcome Joe Balash to the Oil Search team later this month," Oil Search's top executive in Alaska, Keiran Wulff, said Sept. 4.

Balash will replace Cindy Bailey, who will "continue to serve Oil Search as an executive advisor," he said.

"Joe is a proud Alaskan and brings significant regulatory and external affairs experience to Oil Search," Wulff said.

—KAY CASHMAN

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WELL POSTPONED

Jade No. 1, an oil well, in the first quarter of 2020 in the Sourdough prospect on ADL 343112 in area F of the Point Thomson unit.

The state lease, the most southeasterly in Point Thomson and adjacent to the western border of the ANWR 1002 area, holds two mid-1990's Sourdough oil discovery wells that were drilled by BP (at the time partnered with Chevron). In a 1997 press release BP estimated Sourdough held 100 million barrels of recoverable oil.

Jade holds a 95% working interest in the lease, per a farmout agreement with Point Thomson operator ExxonMobil and the other working interest owners. The deal with Jade also satisfied drilling requirements the Thomson unit owners had with the state of Alaska.

In November, as part of the farmout, Exxon assigned a 63% working interest in ADL 343112's Tract 32 to Jade, retaining a small overriding royalty. In July, BP did the same, transferring its 32% working interest and keeping a small overriding royalty, leaving just ConocoPhillips 5%.

The Exxon and BP assignments gave both North Slope producers some skin in the game, fully aligning them in delivering a successful Sourdough development.

Opstad says he expects Jade to have 100% working interest by the end of year.

How does Hilcorp's recently announced acquisition of BP's assets in Alaska bode for Jade and its plans at Sourdough?

"Jade is the operator of Sourdough and the relationship between Jade and Hilcorp is governed by the farmout agreement Jade previously executed with BP."

"I haven't talk to them (Hilcorp) yet … while BP was very good to work with, I have no reason think that Jade's relationship with Hilcorp won't be equally open and constructive," Opstad said.

Sourdough and KIC wells

At the time the first two Sourdough wells were drilled, BP and Chevron were and until Hilcorp's purchase of all BP's assets in Alaska closes next year still technically are, partners in KIC No. 1, the only well ever drilled in the ANWR 1002 area.

The results of the KIC well and both Sourdough wells are confidential except to a very few, including BP and soon Hilcorp.

In the 1990s BP's Sourdough discovery would have required processing facilities and a 50-plus-mile pipeline to the start of the trans-Alaska oil pipeline at Prudhoe Bay.

But proximity to the existing infrastructure and pipeline connection at Point Thomson has changed the situation for Sourdough.

As of March 31, 2019, the Point Thomson line was capable of shipping 70,000 barrels of liquids per day and could be expanded, per its owners.

Jade plans to first drill a vertical pilot hole to true vertical depth then plug it back and drill a high angle penetration into the Brookian reservoir, noting it "firmly believes … the deployment of horizontal production wells is a critical element in commercializing the PTU Brookian opportunity in Area F, as well as its adjoining areas."

Upon completion of "drilling and extended production testing, analysis of that data will be integrated into the Jade 3D Brookian seismic model," the company said in filings with the Alaska Department of Natural Resources' Division of Oil and Gas.

With those results in hand, Jade will put together a third plan of development and submit it to the division.

The company's first plan of development for Area F was approved April 4 by acting Division of Oil and Gas Director James Beckham.

In his approval, Beckham said that based on analysis of the appraisal well data, Jade "will move forward accordingly with additional development at Area F and adjoining areas in the 2020-2021 winter drilling season (presumably now changed to 2021-2022). Current plans include drilling an additional lateral into the Brookian reservoir and production testing. The need for additional delineation wells and the overall economic feasibility of a field development program at Area F will be considered following the 2020-2021 season."

—KAY CASHMAN

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