Petroleum news

page 3 March ANS output down 1.8%; also down 1.8% from 2019

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King's rules of ANS oil pricing; Josh Norum new ATA president

ALASKA OIL IS FAR LESS IMPORTANT to West Coast refineries than it once was, Alaska economist Ed King said in the first article of a three-part series about how the pricing of Alaska North Slope oil works.

The article, released May 4 and published by King Economic Group, deals with the fundamentals of supply and demand in the physical market.

While Alaska once contributed a significant share of supply to the West Coast market, it now meets only about a fifth of refinery needs, King said.

Declining production from Alaska and California has pushed

see INSIDER page 11

2020 ANWR lease sale not certain

As the second quarter of 2020 rolls by, the likelihood of a federal oil and gas lease sale this year in the 2002 Area of the Arctic National Wildlife Refuge is becoming more remote.

The U.S. Bureau of Land Management released its Coastal Plain Oil and Gas Leasing Program Final Environmental Impact Statement Sept. 12, 2019, leading to anticipation that a sale might be scheduled later that year.

But BLM has not yet issued a record of decision on the final EIS yet, BLM Alaska Communications Director Lesli J. Ellis-Wouters told Petroleum News May 5.

"The lease sale will not happen until we issue that record of decision," she said. "I don't have any information on when it could possibly be signed; I do know that after we do sign the

see ANWR SALE page 9

Hilcorp's new development plan for Ninilchik bolsters gas output

On May 1, Hilcorp Alaska submitted its 16th plan of development for the Ninilchik unit to the Alaska Department of Natural Resources' Division of Oil and Gas. The annual POD, which proposes more well work, some drilling but no major facility upgrades at the southern Cook Inlet unit, will be in effect Aug. 1 through July 31, 2021.

Seven fields account for 83% of Cook Inlet natural gas production, the largest being Ninilchik, which data from the Alaska Oil and Gas Conservation Commission shows averaged 38,154 thousand of cubic feet per day in March, 18% of inlet gas production, down 11.4%, 4,930 mcf per day, from a February average of 43,083 mcf per day, but up 2.4% from a March 2019 average of 37,244 mcf per day.

see NINILCHIK UNIT page 7

Kuparuk: Rigs down right now, but Conoco's goal 25 more years

ConocoPhillips Alaska, operator of the North Slope's second largest field, Kuparuk, prefaces its newly filed Kuparuk unit plan of development with a warning that the plan was "envisioned prior to COVID-19 and the market downturn."

"The nature and extent of impacts to previously planned activities is very uncertain and will depend in part on the duration and severity of public health and market conditions," the company said in the POD submitted to the Alaska Department of Natural Resources' Division of Oil and Gas May 1. It covers Aug. 1 through July 31, 2021.

ConocoPhillips has already announced responses to COVID-19 and market conditions.

see KUPARUK PLAN page 8

EXPLORATION & PRODUCTION

AK bright spots

ConocoPhillips can bring oil back online quickly; local employment stable

By KAY CASHMAN

Petroleum News

The bright spots for Alaska in the current low oil price environment have largely come from the state's biggest spender, ConocoPhillips, with its comparatively small North Slope budget cuts; Hilcorp with its continued North Slope and Kenai Peninsula drilling programs; and Oil Search with its relatively small North Slope employment reductions. This has all occurred in the face of a disconnect between the price of Alaska North Slope crude

RYAN LANCE

from the benchmark Brent price, when ANS oil dropped below Brent instead of tracking slightly above it.

Even the May 5 price rally did not correct the divide, with Brent at $30.97 a barrel and ANS at $18.55. But Don Wallette, ConocoPhillips executive VP & CFO, said April 30 that the relationship between ANS and Brent will return to normal "once demand picks up in California and the rest of the West Coast," the primary market for North Slope oil.

Furthermore, a few days after the company said

see BRIGHT SPOTS page 8

EXPLORATION & PRODUCTION

Hilcorp survey approved

BOEM gives go ahead for geohazard survey for Lower Cook Inlet drilling sites

By ALAN BAILEY

For Petroleum News

On May 1 the Bureau of Ocean Energy Management announced that it had issued a permit, allowing Hilcorp Alaska to conduct a geohazard site clearance survey in federal waters of the Lower Cook Inlet, southwest of Kachemak Bay.

The approximately 88 square-mile survey area covers portions of 11 of 14 outer continental shelf leases that Hilcorp obtained in a June 2017 federal OCS lease sale. A geohazard survey of this type is an essential prerequisite to the drilling of offshore exploration wells. Federal regulations require a hazard evaluation to be conducted over the entire area within about 1.5 miles of a well site.

Hilcorp conducted its planned offshore 3D seismic survey during the summer of 2019.

BOEM said that Hilcorp expects to begin the surveying in late summer and that the survey operations must be completed by Oct. 31. The exact length of the survey timeframe will depend on the weather and on any schedule adjustments needed to accommodate the protection of marine mammals, the agency said.

A geohazard survey vessel will conduct the operation, with data being collected using equipment

see HILCORP SURVEY page 11

EXPLORATION & PRODUCTION

Last frontier struggles

Newfoundland seeks federal money to trigger exploration, keep offshore alive

By GARY PARK

For Petroleum News

Of Canada's three offshore hydrocarbon basins, only one has survived the endless turmoil of this century and it is now engaged in a raw battle for survival.

The resource rich Canadian portion of the Beaufort Sea has quietly faded off the scene since the departure of mostly foreign-based companies which held the key to tapping Arctic resources, while the prospects of opening up the waters off British Columbia remain just that — prospects that are unlikely to ever see serious exploration and development.

That leaves Newfoundland, which produced about 245,000 barrels per day of crude in 2019, 5%

The Canadian Atlantic's only other fossil-fuel hope is the C$10 billion Goldboro LNG project in Nova Scotia and it too has been affected by COVID-19, joining about a dozen other North American LNG players in a holding pattern.

of Canada's total oil output, but 25% of national conventional crude volumes.

Charlene Johnson, chief executive officer of the Newfoundland and Labrador Oil and Gas Industries Association, candidly admits the basin is in "crisis mode" to the point of begging for

see FRONTIER STRUGGLES page 11

● EXPLORATION & PRODUCTION

From losers to winners

Energy industry & environmentalists form rare united front to explore use of abandoned wells to tap into geothermal energy sources

By GARY PARK

For Petroleum News

A C$1.7 billion federally financed program to start cleaning up abandoned oil gas wells is underway in three provinces of Western Canada at the same time that unlikely partners are using the opportunity to develop renewable technologies.

As the provinces of Alberta, Saskatchewan and British Columbia go to work on site reclamations, the fossil-fuel industry has also linked up with environmentalists to explore ways of achieving new life from old wells and create a major economic opportunity.

But the initial focus of the Alberta government remains on using the cleanup program to provide jobs for about 5,300 skilled workers in its province.

Energy Minister Sonya Savage said calls from oil service companies have inundated her office since the Canadian government announced in mid-April that its cash allocation to tackle orphan wells would cover between 25% and 100% of total project costs, depending on how much site owners can cover of the estimated C$30,000 budget per well.

SONYA SAVAGE

The objective is to remove the economic and environmental liabilities posed by wells that are an eyesore across width swaths of the three provinces, including the failure of many oil and gas companies to pay the leases owing to landowners.

The Alberta Energy Regulator, the provincial government's chief energy agency, has a list of 94,000 inactive wells that qualify for the program.

Clean Energy Canada

Unannounced until recently, there is a new twist that brings together petroleum companies, environmentalists and a fledgling geothermal industry in an alliance called Clean Energy Canada.

The partnership hopes it can attract incentives and investments, with Chief Executive Officer Kevin Krausert, who is also CEO of Alberta-based Beaver Drilling, confident that geothermal energy can create new lines of business.

The process extracts hot water or steam from wells that are several miles deep and generates electricity through large power turbines for delivery of continuous

The Alberta Energy Regulator, the provincial government's chief energy agency, has a list of 94,000 inactive wells that qualify for the program.

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ON THE COVER

EXPLORATION & PRODUCTION

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● EXPLORATION & PRODUCTION

March ANS crude down 1.8% from February

Largest month-over-month volume gain at Point Thomson, largest volume drop at Prudhoe Bay; Cook Inlet crude down 6.3% from February

By KRISTEN NELSON
Petroleum News

Alaska North Slope production averaged 512,920 barrels per day in March, down 1.8%, 9,501 bpd, from a February average of 522,421 bpd and also down 1.8% from March 2019 when production averaged 522,334 bpd.

Crude oil production averaged 456,325 bpd, 89% of ANS production, down 1.4%, 6,225 bpd from a February average of 462,549 and down 2% from a March 2019 average of 465,742 bpd.

Natural gas liquids production averaged 56,595 bpd, 11% of ANS production, down 5.5%, 3,276 bpd, from a February average of 59,872 bpd and basically unchanged from March 2019 NGL production of 56,592 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.

Point Thomson

The largest month-over-month increase was at the ExxonMobil-operated Point Thomson field, which averaged 7,601 bpd, up 31.6%, 1,827 bpd, from a February average of 5,774 bpd, although down 21.4% from a March 2019 average of 9,674 bpd. ExxonMobil has had compressor issues at the high-pressure field, resulting in wide production fluctuations. In its most recent plan of development the company told the state it was addressing issues with its gas injection equipment, had begun installing upgraded components and expected to receive and install remaining equipment during the 2020-21 period.

As noted in the April 19 issue of Petroleum News, two compressor trains are now reported to be operating at the field, with an increase in condensate production expected from approximately 5,000 bpd to 10,000 bpd, which is the rated facility capacity at the field, with each of the two trans capable of 5,000-6,000 bpd.

Small increases elsewhere

Several North Slope fields had small month-over-month production increases.

ConocoPhillips Alaska's Colville River field averaged 51,747 bpd in March, up 1.1%, 541 bpd, from a February average of 51,206, but down 4.4% from a March 2019 average of 54,142 bpd.

In addition to oil from the main Alpine pool, Colville production includes satellite production from Fiord, Nanuq and Qannik.

The ConocoPhillips-operated Kuparuk River field, the Slope's second largest, averaged 102,382 bpd in March, up 0.5%, 469 bpd, from a February average of 101,913 bpd but down 2.3% from a March 2019 average of 104,830 bpd.

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

The Hilcorp Alaska-operated Endicott field averaged 7,426 bpd in March, up 2.8%, 201 bpd, from a February average of 7,225 bpd and up 1.6% from a March 2019 average of 7,313. Endicott production averaged 6,569 bpd of crude in March, up 4%, 253 bpd from 6,316 bpd in February, and up 2% from a March 2019 average of 6,443, and 857 bpd of NGLs in March, down 5.7%, 52 bpd, from a February average of 909 bpd and down 1.5% from a March 2019 average of 870 bpd.

Eni's Oooguruk averaged 8,719 bpd in March, up 0.5%, 47 bpd, from a February average of 8,672 bpd, and up 10.2% from a March 2019 average of 7,912 bpd.

Month-over-month declines

The largest month-over-month decline was at the Slope's largest field, the BP Exploration (Alaska)-operated Prudhoe Bay, which averaged 269,686 bpd in March, down 3.4%, 9,555 bpd, from a February average of 279,241, and down 1.5% from a March 2019 average of 273,766 bpd.

Crude production at Prudhoe averaged 217,045 bpd in March, down 2.8%, 6,269 bpd, from a February average of 223,314 bpd and down 1.8% from a March average of 220,977, while the fields NGL production averaged 52,641 bpd in March, down 5.9%, 3,286 bpd, from a February average of 55,927 bpd and down 0.3% from a March 2019 average of 52,789 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 30,624 bpd in March, down 4.2%, 1,336 bpd, from a February average of 31,960 bpd, but up 33.7% from a March 2019 average of 22,910 bpd.

Hilcorp has been working to increase production from the field since it acquired a 50% interest and took over operatorship in 2014. In February, before the oil price crash, the company said it expected to reach 40,000 bpd at the field by the end of this year.

Eni's Nikaitchuq averaged 18,956 bpd in March, down 5.4%, 1,089 bpd, from a February average of 20,044, but up 14.7% from a March 2019 average of 16,527 bpd.

see **ANS PRODUCTION** *page 6*

March Cook Inlet gas production drops 2.6%

Natural gas production from Southcentral Alaska's Cook Inlet basin averaged 211,619 mcf per day in March, down 2.6%, 11,800 mcf per day, from a February average of 223,304 mcf and down 3% from a March 2019 average of 218,334 mcf per day.

This data is from the Alaska Oil and Gas Conservation Commission, which reports production on a month-delay basis. For natural gas AOGCC reports measurements in thousands of cubic feet, mcf.

Production is dominated by seven large fields, which account for 82% of Cook Inlet natural gas production.

The largest is Hilcorp Alaska's Ninilchik field, which averaged 38,154 mcf in March, 18% of inlet gas production, down 11.4%, 4,930 mcf per day, from a February average of 43,083 mcf per day, but up 2.4% from a March 2019 average of 37,244 mcf per day.

Hilcorp's Kenai gas field averaged 36,060 mcf per day in March, 17% of inlet production, up 4.6%, 1,590 mcf per day, from a February average of 34,471 mcf and up 4.9% from a March 2019 average of 34,364 mcf per day.

Swanson River, another Hilcorp field, averaged 32,265 mcf per day in March, 15.3% of inlet production, down 5.8%, 1,989 mcf per day, from a February average of 34,254 mcf and down 9.7% from a March 2019 average of 35,715 mcf per day.

Hilcorp's McArthur River averaged 20,264 mcf per day in March, 9.6% of inlet production, down 2.2%, 454 mcf per day, from a February average of 20,718 mcf and down 15.1% from a March 2019 average of 23,879 mcf per day.

Beluga River, operated by Hilcorp, averaged 18,578 mcf per day in March, 8.8% of inlet production, down 0.7%, 139 mcf per day, from a February average of 18,717 mcf and down 32.1% from a March 2019 average of 27,360 mcf per day.

Hilcorp's North Cook Inlet field averaged 14,023 mcf per day in March, 6.6% of inlet production, down 26.5%, 5,049 mcf per day, from a February average of 19,071 mcf and down 4.9% from a March 2019 average of 14,738 mcf per day.

Furie's Kitchen Lights averaged 13,927 mcf per day in March, 6.6% of inlet production, down 3%, 432 mcf per day, from a February average of 14,360 mcf but up 528.9% from a March 2019 average of 2,215 mcf per day, when the company was recovering from hydrate blockages in its lines.

Smaller gas fields

Hilcorp's Beaver Creek averaged 7,246 mcf per day in March, up 2.8%, 195 mcf per day, from a February average of 7,051 mcf but down 11.2% from a March 2019 average of 8,163 mcf per day.

Hilcorp's Cannery Loop field averaged 4,829 mcf per day in March, up 1.1%, 51 mcf per day, from a February average of 4,779 mcf and up 14.9% from a March 2019 average of 4,200 mcf per day.

Hilcorp's Deep Creek averaged 4,092 mcf per day in March, down 0.5%, 22 mcf per day, from a February average of 4,113 mcf and down 17.5% from a March 2019 average of 4,962 mcf per day.

Hilcorp's Granite Point averaged 3,483 mcf per day in March, up 0.5%, 18 mcf per day, from a February average of 3,465 mcf and up 23% from a March 2019 average of 2,831 mcf per day.

BlueCrest's Hansen field averaged 4,154 mcf per day in March, down 9%, 412 mcf per day, from a February average of 4,566 mcf and down 50.5% from a March 2019 average of 8,385 mcf per day.

Hilcorp's Ivan River averaged 362 mcf per day in March, down 3.8%, 14 mcf per day, from a February average of 376 mcf and down 7.1% from a March 2019 average of 390 mcf per day.

AIX's Kenai Loop field averaged 5,241 mcf per day in March, up 0.4%, 21 mcf per day, from a February average of 5,219 mcf but down 3.9% from a March

see **COOK INLET** *page 6*

FINANCE & ECONOMY

Furie assets: $18 million cleaner

A stipulation between Furie Operating Alaska LLC and Shelf Drilling Offshore Resources Limited II, to reclassify an $18,828,456.03 claim against Furie and its related Chapter 11 debtors, represents a solid step toward clearing up liens for Furie's proposed asset sale to Hex LLC.

The stipulation said Shelf has determined that it will not contest that it does not have any security interests or other secured claims or liens against any of the debtors or the debtors' estates.

The order, which approved reclassifying Shelf's secured claims as general unsecured claims, was signed April 15 by Judge Laurie Selber Silverstein and filed in the U.S Bankruptcy Court for the District of Delaware.

The stipulation said Shelf has determined that it will not contest that it does not have any security interests or other secured claims or liens against any of the debtors or the debtors' estates.

Shelf filed proofs of claims on Dec. 4 against the debtors, and Furie responded with an adversary complaint Feb. 14 declaring that Shelf's alleged liens against the debtor's estates were not valid.

Selber Silverstein will hear the details of the proposed asset sale to Anchorage-based Hex in a May 8 omnibus hearing in Delaware.

Furie contracted with Shelf for use of the Randolph Yost jack-up drilling rig, which sailed from Singapore on the purpose-built semi-submersible heavy-lift vessel Tai An Kou, reaching Alaska March 2016 in Kachemak Bay.

Furie said the Randolph Yost rig — bigger and more powerful than the Spartan — could more easily be cantilevered over Furie's Julius R natural gas production platform for development drilling. The larger rig allowed the company to eliminate costly supply runs by accommodating more materials on site.

Furie had planned to use the rig to target potential oil accumulations below the Tertiary strata in Cook Inlet.

The Randolph Yost is currently stored at the Offshore Systems OSK Dock in Nikiski. In addition to the Julius R platform, the Furie assets include the offshore Cook Inlet Kitchen Lights unit, an onshore processing facility, and related pipelines.

—STEVE SUTHERLIN

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Kay Cashman	PUBLISHER & FOUNDER
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Judy Patrick Photography	CONTRACT PHOTOGRAPHER
Forrest Crane	CONTRACT PHOTOGRAPHER
Renee Garbutt	CIRCULATION MANAGER

ADDRESS
P.O. Box 231647
Anchorage, AK 99523-1647

NEWS
907.522.9469
publisher@petroleumnews.com

CIRCULATION
907.522.9469
circulation@petroleumnews.com

ADVERTISING
Susan Crane • 907.770.5592
scrane@petroleumnews.com

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● EXPLORATION & PRODUCTION

No new drilling proposed for Kenai Loop gas field

AIX submits sixth plan of development and operations for small gas field north of Cannery Loop; two wells in production at field

By KRISTEN NELSON
Petroleum News

AIX Energy LLC, operator of the Kenai Loop gas field, has submitted its the sixth plan of development and operations for the Kenai Loop gas field to the Alaska Department of Natural Resources' Division of Oil and Gas.

Kenai Loop includes DNR, Mental Health Trust Office and Cook Inlet Region Inc. leases; AIX acquired the field in 2014 out of a bankruptcy by the field developer, Buccaneer.

Buccaneer acquired the initial DNR leases for the field in 2010, AIX said, and acquired Mental Health Trust leases in 2011. The discovery well, KL 1-1, was completed in 2011, with a flow rate of 10 million cubic feet per day from the Tyonek sand at 9,700 feet. A second well, KL 1-2, was drilled in 2011 but was a dry hole and is currently shown by the Alaska Oil and Gas Conservation Commission as suspended, the company said.

Buccaneer completed 23 square miles of 3D seismic in April 2012, with processing completed that July; subsequent wells were drilled based on the company's interpretation of that 3D data.

KL 1-3 was completed in 2012 as a sand producer at 9,700 feet, 300 feet structurally deeper than KL 1-1. In 2013 KL 1-4 was completed in 9,700-foot sand, 100 feet shallower than KL 1-1. That well tested at 2.5 million cubic feet per day, "but was determined to be in the same reservoir as KL 1-1. KL 1-4 has not been tied into the production system and has been used to monitor reservoir pressure," AIX said.

For the sixth plan of development and operations, May 7, 2020-May 6, 2021, AIX said its planned activities include well work and compression.

As of March 2020

AIX said it has made no major changes to the facilities at the field, which is currently developed from one drill pad. A second pad, constructed in 2012, was never used in operation and was decommissioned in 2017, with the surface lease released to the Trust Land Office.

Of the four wells at the field, KL 1-1 is an active producer; KL 1-2 is temporarily suspended and may be used in the future as a disposal well; KL 1-3 is an active producer; and KL 1-4 is a shut-in producer, which is not tied into the field's production system.

see **KENAI LOOP** page 5

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UNITED FRONT

electricity to the power grid.

Krausert told the Globe and Mail that the opportunity "pivots the whole tired narrative of energy versus the environment (and could) build a new energy future for Canada where oil and gas is part of the solution."

He aims to build "an integrated system where technologies like geothermal can be used to run oil sands operations and reduce their per-barrel (greenhouse gas) emissions."

Krausert said the alliance could help the oil sands sector achieve its vision of net-zero emissions by 2050.

However, John Redfern, CEO of Calgary-based geothermal company Eavor Technologies, said geothermal could be left behind altogether unless there is a political will to encourage investment or expansion of the green fuel.

Mark Scholz, CEO of the Canadian Association of Oilwell Drilling Contractors, endorses the cooperative effort, but says it won't save the drilling sector which can only survive if it obtains liquidity and support measures from the Canadian government.

Marla Orenstein, director of the natural resources center at the independent Canada West Foundation, said the abandoned wells are good candidates for a multi-faceted opportunity to repurpose energy uses such as geothermal, micro-solar, hydrogen, recovery of lithium or other metals, or carbon capture and storage.

She said creating new energy lives for the orphan wells "would help diversify the energy sector, expedite a smart energy transition and create new economic opportunities for landholders."

Orenstein said a multi-stakeholder group is working to identify a pilot program to partially remediate inactive wells for new energy purposes. ●

Contact Gary Park through publisher@petroleumnews.com

● EXPLORATION & PRODUCTION

At 408 US rig count approaches record low

By KRISTEN NELSON
Petroleum News

At a count of 408 for the week ending May 1, the U.S. drilling rig count is approaching the low of 404 it hit in May 2016.

Baker Hughes reported the 408 count for U.S. oil and gas drilling rigs, down from 465 from the week ending April 24 and down 582 from a year ago.

The count continues a recent steep drop: down by 64, 73, 62, 64, 44 and 20 rigs respectively, a total of 317, over the previous six weeks.

In its weekly rig count the Houston oilfield services company said 325 rigs targeted oil, down 53 from the previous week and down by 482 from a year ago, while 81 targeted natural gas, down four from the previous week and down 102 from a year ago. There were two miscellaneous rigs active, unchanged from the previous week and up by two from a year ago.

The company said 23 of the holes were directional, 374 were horizontal and 11 were vertical.

No states had week-over-week rig counts increases.

Rig counts were unchanged in Alaska (3), California (5), Ohio (9) and West Virginia (7).

The rig count in Texas, which at 201 has the most active rigs, was down by 30 from the previous week and down by 283 from a year ago.

The largest rig count drop by basin was in the Permian, which also has the most active rigs at 219. The Permian count was down 27 from the previous week and down 240 from a year ago.

Colorado (8) was down by seven rigs.

Oklahoma (15) and Utah (0) were each down by five rigs.

New Mexico (66) was down by four rigs.

Pennsylvania (23) and Wyoming (4) were each down by two rigs.

Louisiana (39) and North Dakota (26) were each down by one rig.

Baker Hughes shows Alaska with three active rigs for the week ending May 1, down by six from a year ago.

The largest rig count drop by basin was in the Permian, which also has the most active rigs at 219. The Permian count was down 27 from the previous week and down 240 from a year ago.

The U.S. rig count peaked at 4,530 in 1981. It bottomed out in May 2016 at 404. Baker Hughes has issued North American rig counts since 1944 and international rig counts since 1975.

Baker Hughes' international rig count, onshore and offshore, released for April on May 1, shows a count for international rigs of 915 in April, down 144 from a March count of 1,059 and down 147 from an April 2019 count of 1,062. The offshore portion of the international count for April was 228, Baker Hughes said, down 16 from 244 in March and down 23 from an April 2019 count of 251.

The average U.S. rig count for April was 566, down 206 from 772 in March and down 446 from 1,012 in April 2019. The average Canadian rig count for April was 33, down 100 from 133 in March and down 33 from 66 in April 2019.

The worldwide rig count, international plus North America, was 1,514 in April down 450 from 1,964 in March and down 626 from 2,140 in April 2019.

The company said the count reflects rigs actively exploring for oil or natural gas in the U.S., Canada and international markets. Weekly counts began for the U.S. and Canada in 1944; the monthly international rig count was initiated in 1975. ●

Contact Kristen Nelson at knelson@petroleumnews.com

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KENAI LOOP

As of the end of March, cumulative production at the field was 27.7 billion cubic feet of natural gas, 8,848 barrels of water; and 2,673 barrels of condensate.

"AIX's marketing goals are to continue to pursue value-added, near-term gas sales opportunities (to align with existing and future production capacity), while maintaining pricing discipline," the company said. During the fifth plan of operations, which covered May 7, 2019-May 6, 2020, AIX obtained static reservoir pressures on KL 1-1 and KL 1-3, the field's producing wells, and "updated the material balance estimates of gas in place and reserves."

The company said its management and technical teams met with Cook Inlet Region Inc. and its technical representatives in February to provide an update on the status of the field and exploration lease "and to discuss potential prospects and exploration opportunities."

Proposed plan

For the sixth plan of development and operations, May 7, 2020-May 6, 2021, AIX said its planned activities include well work and compression.

AIX purchased and installed a natural gas fired compressor in the winter of 2018, with startup in February 2019. KL 1-3 is on compression and KL 1-1 will be put on compression when required, the company said, based on a cost/benefit analysis "to provide increased deliverability, to provide redundancy to meet firm gas sales obligations and to possibly increase ultimate recovery."

The company will also evaluate "recompleting wells to provide additional deliverability."

The plan to obtain static reservoir pressures on KL 1-1 and KL 1-3 requires a complete field shutdown of 72 hours, and AIX said it "will attempt to shelter the work during planned pipeline or facility maintenance."

AIX told DNR that it has not identified any drilling opportunities within the producing state lease, ADL 391094, for the proposed sixth plan. ●

Contact Kristen Nelson at knelson@petroleumnews.com

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COOK INLET

2019 average of 5,454 mcf per day.

Hilcorp's Lewis River averaged 1,090 mcf per day in March, down 2.1%, 23 mcf per day, from a February average of 1,113 mcf, but up 380.3% from a March 2019 average of 227 mcf per day.

Hilcorp's Middle Ground Shoal averaged 265 mcf per day in March, down 4.7%, 13 mcf per day, from a February average of 278 mcf but up 10.6% from a March 2019 average of 240 mcf per day.

Amaroq's Nicolai Creek averaged 282 mcf per day in March, up 6.2%, 16 mcf per day, from a February average of 265 mcf but down 34.9% from a March 2019 average of 432 mcf per day.

Hilcorp's Nikolaevsk averaged 421 mcf per day in March, down 2.9%, 12 mcf per day, from a February average of 434 mcf but up 2.2% from a March 2019 average of 412 mcf per day.

North Fork, operated by Glacier Oil and Gas' Cook Inlet Energy, averaged 3,625 mcf per day in March, down 2.4%, 90 mcf per day, from a February average of 3,715 mcf, but up 2.1% from a March 2019 average of 3,551 mcf per day.

Redoubt Shoal, also operated by Glacier's CIE, averaged 268 mcf per day in March, down 1.4%, 4 mcf per day, from a February average of 271 mcf but up 12.6% from a March 2019 average of 238 mcf per day.

Hilcorp's Trading Bay averaged 2,920 mcf per day in March, the same volume as its February production, but down 1.2% from a March 2019 average of 2,955 mcf per day.

West McArthur River, operated by Glacier's CIE, averaged 71 mcf per day in March, up 13%, 8 mcf per day, from a February average of 63 mcf, but down 29.4% from a March 2019 average of 100 mcf per day.

Cook Inlet natural gas production peaked in the mid-1990s at more than 850,000 mcf per day.

—KRISTEN NELSON

Contact Kristen Nelson at knelson@petroleumnews.com

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ANS PRODUCTION

The Hilcorp-operated Northstar field averaged 9,636 bpd in March, down 2.9%, 288 bpd, from a February average of 9,925 bpd and down 13.5% from a March 2019 average of 11,133 bpd.

Northstar production included an average of 6,539 bpd of crude oil in March, down 5.1%, 350 bpd, from a February average of 6,888 bpd and down 20.3% from a March 2019 average of 8,200 bpd, and a March average of 3,098 bpd of NGLs, up 2%, 61 bpd, from a February average of 3,036 bpd and up 5.6% from a March 2019 average of 2,933 bpd.

ConocoPhillips' Greater Mooses Tooth in the National Petroleum Reserve-Alaska averaged 4,892 bpd in March, down 4.2%, 213 bpd, from a February average of 5,105 bpd, and down 60.3% from a March 2019 average of 12,310 bpd.

Badami, operated by Glacier Oil and Gas Co.'s Savant Alaska, averaged 1,252 bpd in March, down 7.7%, 105 bpd, from a February average of 1,357 bpd and down 31.1% from a March 2019 average of 1,817 bpd.

Cook Inlet crude down 6.3%

Crude oil production from the Cook Inlet basin in Southcentral Alaska averaged 13,228 bpd in March, down 6.3%, 888 bpd, from a February average of 14,116 bpd and down 13.7% from a March 2019 average of 15,329 bpd.

Hilcorp Alaska's McArthur River field, Cook Inlet's largest, averaged 4,075 bpd in March, down 4.7%, 200 bpd, from a February average of 4,275 bpd and down 16.9% from a March 2019 average of 4,903 bpd.

Hilcorp's Granite Point field averaged 3,258 bpd in March, down 2.7%, 90 bpd, from a February average of 3,348 bpd, but up 20% from a March 2019 average of 2,714 bpd.

Hilcorp's Trading Bay field averaged 1,324 bpd in March, up 1.8%, 24 bpd, from a February average of 1,300 bpd but down 9.5% from a March 2019 average of 1,462 bpd.

Middle Ground Shoal, another Hilcorp field, averaged 1,245 bpd in March, down 1.2%, 15 bpd, from a February average of 1,260 bpd and down 11.5% from a March 2019 average of 1,408 bpd.

BlueCrest's Hansen field averaged 1,068 bpd in March, down 6.3%, 72 bpd, from a February average of 1,140 bpd, and down 31.6% from a March 2019 average of 1,562 bpd.

Hilcorp's Swanson River averaged 919 bpd in March, down 1.9%, 19 bpd, from a February average of 938 bpd and down 16.7% from a March 2019 average of 1,104 bpd.

Redoubt Shoal, operated by Glacier's Cook Inlet Energy, averaged 904 bpd in March, down 30.6%, 399 bpd, from a February average of 1,303 bpd and down 28% from a March 2019 average of 1,256 bpd.

West McArthur River, also operated by Glacier's CIE, averaged 254 bpd in March, down 23.3% from a February average of 331 bpd and down 56.2% from a March 2019 average of 579 bpd.

Hilcorp's Beaver Creek averaged 180 bpd in March, down 18.8%, 42 bpd, from a February average of 222 bpd and down 47.2% from a March 2019 average of 341 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

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NINILCHIK UNIT

The Ninilchik unit straddles the Kenai Peninsula coastline for some 16 miles from near Clam Gulch to just north of Ninilchik. The unit is primarily offshore, with nine pads onshore — from north to south, they are Abalone, Falls Creek, Bartolowits, Blossom, Grassim Oskolkoff, Ninilchik State, Susan Dionne, Paxton and the new Pearl pad, which is on private land just beyond the southern boundary of the unit. (Pearl can be accessed via the road located at MP 131.2 of the Sterling Highway.)

Since unit operator Hilcorp drilled the seven Pearl stratigraphic test wells in the summer of 2017, it has been planning to drill the Pearl 2A delineation well, incorporating findings from the vertical strat wells (one 540-foot hole and six 600-foot holes). Specifically, the company intended to drill the Pearl 2A development well in advance of mandatory unit contraction on May 31 of this year.

In its 16th POD Hilcorp said that production from Pearl 2A "will necessitate" both unit and participating area reconfigurations. In its 15th POD the company said there was a possibility the well would be drilled late in the period, but most likely would be done in the16th POD period.

In its proposed 16th POD, Hilcorp deferred drilling to an even later date — "late in the 2022 POD period, contingent on market conditions, but will most likely extend beyond the 2022 POD period."

The Kalotsa 5 well is still scheduled, however. Hilcorp said it will be drilled as early as third quarter. This well will target the top of the Beluga structure and drill through to the Tyonek.

During the 15th POD period the Kalotsa 6 well, targeting the Beluga reservoir, was drilled and completed and began production at 3,100 mcf per day in October.

Wellwork projects finished during the 15th POD included the Kalotsa 3 well, where perforations were done in the Tyonek sands, which added about 1,000 mcf a day to production in August.

The same thing was done in the Tyonek sands in Kalotsa 4, adding 14,000 mcf per day in January.

Paxton 2 work scheduled for July at the end of the 15th POD period includes pulling existing velocity string, setting a cast iron bridge plug, or CIBP, up to six perforations in the upper Tyonek, and rerunning velocity string.

The following work was done earlier in other Paxton wells under the 15th POD:

• Paxton 9, perforations in the Beluga BLG-53 sand, adding 200 mcf a day in. January.

• Paxton 4, perforations in the Beluga BLG-41 sand, adding 3,300 mcf in January.

• Paxton 9, additional perforations this month in the Lower Beluga sands.

In July at the end of the 15th POD a rig workover is planned for the Falls Creek 3 well to pull existing dual completion and recomplete the well to Lower Beluga sands.

In October perforations were added in the Beluga BLG-58/58A sands and reperforated the Beluga 59 sm1d, adding 100 mcf a day to Falls Creek 6.

In the 16th POD period that begins Aug. 1 a potential rig workover is planned to recomplete the Frances 1 well in the Beluga sands. Former Ninilchik operator Marathon Petroleum identified a potential prospect, Abalone, just north of the Falls Creek participating area within the Ninilchik unit. Hilcorp drilled the Abalone 1 exploration well in 2013.

In its 16 POD Hilcorp said another Abalone well must be drilled before mandatory unit contraction, noting "it is unknown at this time when Hilcorp will complete this project due to market conditions."

A field study of the Ninilchik unit's Grassim Oskolkoff participating area in early 2018 identified six potential locations and a re-evaluation of the Blossom 1 exploratory well. The results suggested that the Blossom 1 well might have missed its target due to geologic faulting. Unless market conditions change, Hilcorp does not expect to drill the six Grassim Oskolkoff wells or sidetrack Blossom 1 during the 16th POD period.

In fact, the company said, it will most likely drill the Blossom sidetrack in the 2022 POD or 2023 POD periods.

Grassim Oskolkoff workover and well work projects recently, currently and soon to be completed, include:

• GO 6, perforations in the Beluga BLG-58/58A sands and reperforation the Beluga 59 sm1d, adding 100 mcf per day starting in October.

• GO 8, due to the slugging/loading issues present in the well, Hilcorp began adding up to four perforations in the Middle Tyonek in April, followed by perforations in the Lower Beluga sands. If necessary, the installation of a velocity string in is planned for July.

Hilcorp is currently installing an additional 1480 HP compressor to add additional 6-8 million cubic feet a day capacity to allow for extra throughput from the Kalotsa and Susan Dionne pads, the company said in its 16th POD.

Hilcorp is also currently converting Susan Dionne 8 to a Class II disposal well.

Planned operations for this month at Susan Dionne 5 include installing downhole plunger lift to aid in water unloading, and pulling existing velocity string, setting CIBP, perforating Tyonek T-19, and rerunning velocity string in the Ninilchik State 1 well.

Hilcorp's long-range development goal at Ninilchik is to delineate and bring all the unit's underlying oil and/or gas reservoirs into production, thereafter maintaining and enhancing output, which is what the company has done at Ninilchik and in its other Cook Inlet and North Slope fields.

But, Hilcorp warned, additional Beluga and Tyonek well drilling is "highly dependent of the current well work results," as well as current risked resource and economics, market demand, pipeline capacity, and competitiveness within Hilcorp's gas project portfolio.

Note: All indications are the Alaska Department of Natural Resources will be open to relaxing unit termination deadlines given the current extraordinary circumstances.

—KAY CASHMAN

GOVERNMENT

AOGCC public meetings to be telephonic

The Alaska Oil and Gas Conservation Commission will hold its public meetings telephonically until further notice, beginning in June, due to health mandates issued as a result of the COVID-19 virus, the commission said in a notice posted May 4.

The meetings are scheduled for 10 a.m. on June 3, July 1, Aug. 5, Sept. 2, Oct. 7, Nov. 4 and Dec. 2.

The call-in number for the meetings is 1-800-315-6338; the meeting code is 14331.

The commission said phone lines will be available starting at 9:45; each meeting agenda will provide an opportunity for general public participation "in the form of public comments on subjects relevant to the AOGCC's work."

A final agenda will be available on the commission's website.

—PETROLEUM NEWS

EXPLORATION & PRODUCTION

No new drilling planned at Nikolaevsk

Hilcorp Alaska has submitted a 13th plan of development for the Nikolaevsk unit to the Alaska Department of Natural Resources' Division of Oil and Gas.

The small unit, with one producing gas well, is on the southern Kenai Peninsula, inland from Cosmopolitan and northeast of North Fork.

Hilcorp said that during calendar year 2019 natural gas production from the Red No. 1 well averaged 476 thousand cubic feet per day, with total production for the year 174 million cubic feet.

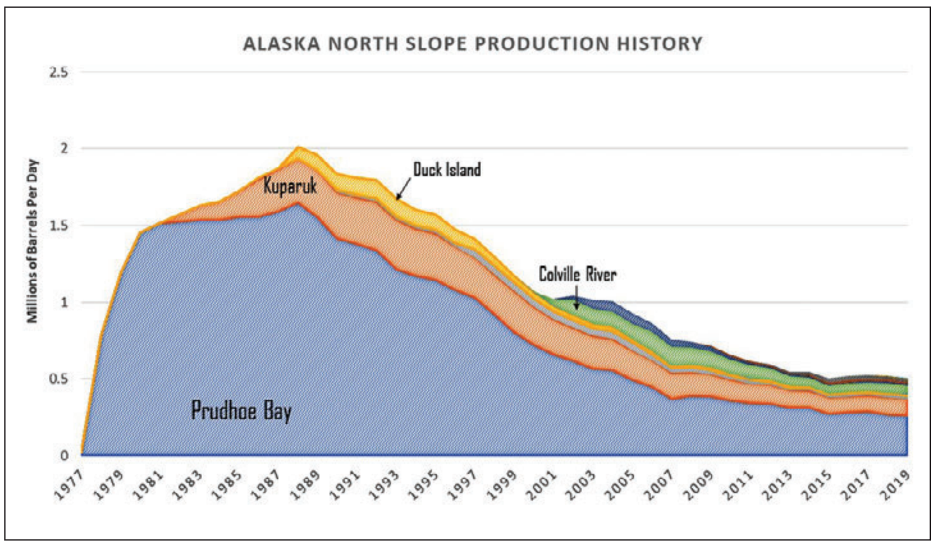
The company did not do any development projects at the unit during the 2019 POD, which covered Aug. 1, 2019, through July 30, 2020.

For the 2020 POD, Aug. 1, 2020, through July 30, 2021, Hilcorp plans no long-range development activities and no exploration or delineation activities.

The company said it anticipates continued gas production from the Red No. 1, and "will evaluate and execute well work opportunities as they arise."

—KRISTEN NELSON

ED KING



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BRIGHT SPOTS

it was cutting its North Slope oil output by 100,000 barrels a day because it understandably didn't like the price, ConocoPhillips Alaska spokeswoman Natalie Lowman told Petroleum News: "The actions we announced April 30 did not include layoffs or retirement packages. The employee numbers today — ~1,100 — have not changed since March," she said May 5.

At the top of the list of recent positive news is the ease and short amount of time it will take ConocoPhillips to put its 100,000 barrels of crude back online when oil prices increase.

In the company's first quarter earnings webcast ConocoPhillips Executive VP & COO Matt Fox explained: "We can bring the production back across the Lower 48, Canada, and Alaska within a few weeks. … But to get to full production in a matter of weeks, we are making sure that we're not doing anything that's going to take any risk either from a reservoir or wells or facilities perspective."

That's why, he said, in Alaska, "we're not shutting in completely. We're getting down to a rate that's a minimum sort of operating level that we can consistently operate at for a period of time. … There's no risk of reservoir damage … so we can come back in a couple of weeks."

Since mature North Slope fields such as Prudhoe Bay and Kuparuk are in a slow but steady decline, new oilfield developments like ConocoPhillips' Willow project are important.

Although the company shortened this past winter's exploration season because of concerns for worker safety connected to the coronavirus, results from its Tinmiaq appraisal wells near Willow and rank exploration well in the Harpoon prospect appear promising.

According to Fox the Tinmiaq results were what was "expected," and the Willow project is on track.

"We're working through Willow, and we're in the concept selection stage just now. We have a timeline that would get us to the end of this year with the opportunity to select the concept. And by that, I mean, how big a facility do we build, how many drill centers do we have and so on," Fox said, noting no decision has been made to defer Willow.

"And we expect permits here this summer supporting the development at Willow, both at the federal and state levels," added Ryan Lance, ConocoPhillips chairman and CEO.

It appears, Fox said, in the Harpoon well they "clipped the edge of the topset based on its log response. … We won't know that for sure until we get a chance to drill the second well," a reminder that ConocoPhillips executive Michael Hatfield said in November that 3D seismic imaging indicates Harpoon has "high-potential Brookian topset targets with stacked plays."

When asked about encountering hydrocarbon fluids in the Harpoon well, Fox said: "Yes, we did encounter hydrocarbons. … it looks from a lithological perspective similar to other lithological signatures we're seeing on the edge of these topsets." ●

Contact Kay Cashman at publisher@petroleumnews.com

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KUPARUK PLAN

In early April the company said it was demobilizing its North Slope rig fleet (see story in April 12 edition of Petroleum News), citing the COVID-19 risk to its North Slope workforce and the need to significantly reduce the number of personnel on the Slope.

On April 30 ConocoPhillips announced company-wide production cuts for June, including a curtailment of 100,000 barrels per day of production from Kuparuk River and the western North Slope, citing "unacceptably low oil prices resulting from global oil demand destruction caused by the impacts of the COVID-19 pandemic, combined with a global over supply of oil." (See story in May 3 edition of Petroleum News.)

But while there may not be a lot of activity in the coming year, in discussing facilities issues the company said it was looking at upgrades to support another 25 years of Kuparuk production.

Kuparuk field

ConocoPhillips is the majority working interest owner at Kuparuk. Chevron U.S.A. Inc. and ExxonMobil Alaska Production Inc. each hold minority working interests.

There are 46 drill sites for Kuparuk and 878 active wells, 506 producers and 372 injectors, with average oil production in 2019 of 73,000 bpd, water production of 557,000 bpd and water injection 675,000 bpd.

Activities for calendar year 2019 included: 22 coiled tubing drilling wells, including five West Sak wells, for a peak incremental oil rate of approximately 2,100 bpd gross.

Non-rig wellwork activity included slickline, electric line and service coiled tubing jobs, adding some 8,000 bpd gross.

The greater Kuparuk area "operates under full field miscible injectant with approximately half being imported and half being indigenous," the company said.

To optimize production, depletion mechanisms must be prioritized and staged "to load the existing pipeline and facilities infrastructure in the most cost efficient manner," ConocoPhillips said.

Development drilling targets high value locations and shut-in wells are candidates to be sidetracked to new bottomhole locations, with horizontal multilateral and CTD sidetrack technologies expected to play an increasing role.

The company said no new drill sites are planned before July 2021.

Natural gas liquids imports from Prudhoe Bay resumed in September 2018, and the increased NGLs to blend with gas for miscible injectant, MI, allowed for an expanded enhanced oil recovery program at Kuparuk, with the switch to full-field MI in October 2019 allowing for additional targets at Central Processing Facility 3 and several CPF1 drill sites.

ConocoPhillips said Kuparuk received an average of 83 million cubic feet of MI injection in 2019, with an oil rate from EOR estimated at 7,700 bpd.

"Alternative EOR opportunities for Kuparuk are being explored with laboratory investigation and field testing of promising methods to recover additional resources that are currently considered residual oil," the company said.

A long-term plan of lean gas chase is anticipated, given favorable gas production in the field, since studies have shown oil rate benefits from injecting lean gas following an MI flood, allowing for recovery of a proportion of NGLs trapped as a result of the EOR process and maintaining liquid rates in high water cut producers.

Facilities

ConocoPhillips said gas handling limits will continue to constrain greater Kuparuk area production and debottlenecking continues to be studied, with an emphasis on smaller projects with high added value.

Water handling capacity has also been a constraint, and the company said upgraded blades began to be phased in during turbine overhauls beginning in 2014, allowing for increased speed and increased water injection capacity.

Several facility projects are being evaluated to restore and enhance water injection capability.

Gas lift is the most common artificial lift method at Kuparuk and with water cuts now as high as 95% in some Kuparuk wells, "many wells cannot lift from the bottom due to the gas lift system pressure constraints," ConocoPhillips said.

This has been mitigated in miscible water alternating gas and immiscible water alternating gas areas "by the returned miscible injectant and lean gas, which provides an artificial lift benefit from the sand face," the company said, but there are issues such as increased water injection and studies are underway "to improve the artificial lift system, as well as evaluate the lift benefits from large scale lean gas injection."

Other facility issues include the need to upgrade electronic equipment since that used at Kuparuk "is becoming obsolete at an increasing rate as manufacturers introduce new equipment and no longer wish to support older equipment."

"Obsolescence of the turbines driving the water injection pumps and power generation equipment may require large capital expenditures," the company said.

Key here is ongoing field life: "Much of the operations support infrastructure will be assessed for upgrade or replacement to target another 25 years of production from the KPA and the KRU satellite fields," ConocoPhillips said.

Large infrastructure projects done in the past include upgrading and refurbishing portions of the Kuparuk camp and office, the company said.

Appraisals

ConocoPhillips said the overlying Nuna Moraine is being tested for productivity and waterflood performance, with a two-well pilot drilled in late 2018 and two follow-up well pairs planned to further de-risk waterflood performance.

"Coupled with results from special core analyses, this dynamic data will guide

see **KUPARUK PLAN** *page 9*

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KUPARUK PLAN

future plans for Nuna Moraine."

The company said it brought the 1H-Ugnu-401 well back online in April 2019. The well had been shut-in in 2016 because of electric submersible pump problems, which the company said it is continuing to troubleshoot "in an effort to determine if higher oil production rates can be sustained."

Alaska Oil and Gas Conservation Commission records show the 1H-Ugnu-401 produced 822 barrels in April 2019 but nothing since.

West Sak

Next to the main field itself, West Sak has the most production of the greater Kuparuk area pools, averaging 21,700 bpd of oil in 2019 and 18,300 bpd of water, with 36,000 bpd of water injected. There were 117 active wells at West Sak in 2019, 55 producers and 62 injectors. West Sak is developed from 10 drill sites.

ConocoPhillips said injection and production in the West Sak oil pool is challenged by matrix bypass events — highly conductive conduits between injectors and producers which "effectively short circuit the waterflood resulting in poor pattern sweep without remediation." Four new matrix bypass events, MBEs, developed in 2019; five MBE remediation treatments were attempted.

AOGCC approved viscosity reducing water alternating gas injected as an EOR process for the West Sak oil pool in 2014; four injectors received viscosity reducing injection in 2018 and ConocoPhillips said results suggest positive benefits.

A five well West Sak program was approved and started in 2019, with two injectors and a dual lateral producer completed in 2019. Future drilling at West Sak will initially focus on completion of the five well program; there are also plans to expand the 3R drill site to accommodate up to nine new wells, a project that could include formation of the North West Sak participating area.

ConocoPhillips said the overlying Nuna Moraine is being tested for productivity and waterflood performance at Kuparuk, with a two-well pilot drilled in late 2018 and two follow-up well pairs planned to further de-risk waterflood performance.

"Development of the West Sak and NEWS oil pools may be enhanced by installation of new drill sites to provide infrastructure and access for new drilling targets," the company said.

Smaller pools

There are also three smaller pools at Kuparuk: Tarn, Tabasco and Meltwater

There are 56 active wells at Tarn, 39 producers and 17 injectors, and the field averaged 6,150 bpd of oil production in 2019 and 16,300 bpd of water, with 26,900 bpd of water injection.

Continuous MI injection was the development plan for Tarn, but a higher quality reservoir discovered during drilling from the 2N and 2L pads "reopened the potential of using an MWAG recovery process," which, compared to MI, "is expected to yield higher recoveries than the original straight gas injection approach due to improved mobility control," ConocoPhillips said.

NGL importation from Prudhoe ceased in 2014, and "immiscible water-alternating gas utilizing lean gas was applied to the Tarn reservoir through late 2018." NGL imports resumed in 2018 and the field was returned to MWAG flood.

Tabasco had eight active wells in 2019, five producers and three injectors. Oil production averaged 1,390 bpd, water production averaged 13,640 bpd and water injection averaged 13,970 bpd.

Waterflood is the major recovery mechanism at Tabasco.

ConocoPhillips said that in recent years "reservoir management optimization by shutting in the central canyon producers to increase the pressure support on the peripheral wells shows positive results on total oil production and stabilization of water production," with study of waterflood optimization strategies planned for the next 5 years and long term.

"In-depth geological study shows that the shallow portion of the Tabasco reservoir has not been adequately swept when compared to the deeper portion," the company said.

Meltwater, at drill site 2P, has 10 producers and seven injectors, and averaged 450 bpd of oil in 2019, and 40 bpd of water.

Miscible injection stepped at Meltwater in 2019, ConocoPhillips said, and the field was converted to waterflood. There was a decade of gas-only injection, and the company said it expects it will be at least 7 years before it sees benefits of water injection.

Further development drilling opportunities are being analyzed, with possible opportunities for coiled tubing drilling sidetracks or conversion of producers to injectors.

—KRISTEN NELSON

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ANWR SALE

record of decision we would be posting a notice in the Federal Register announcing the lease sale."

Ellis-Wouters indicated that the COVID-19 pandemic may be contributing to the delay.

"There's really no normal timeline between an EIS and a record of decision," She said. "It's normal to take time in between those two processes, but I think there's probably a lot more world happenings going on these days than had been anticipated."

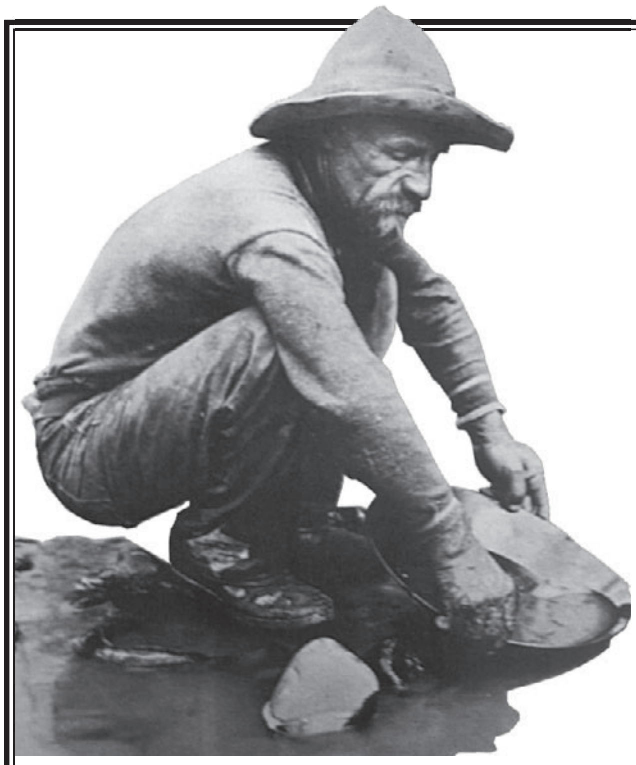
In a Jan. 14 Washington Post story, Interior Secretary David Bernhardt said the Trump administration is trying to make its leasing plan legally ironclad, while completing a lease sale before the 2020 election.

"I want to make sure that record of decision is a record that can be well defended," Bernhardt was quoted as saying. "There have been issues raised during the development … that I want to make sure that I feel very confident that we've adequately addressed."

The 2017 budget bill which opened exploration in the 1002 area orders the feds to conduct two lease sales of 400,000 acres each by the end of 2024.

—STEVE SUTHERLIN

Contact Steve Sutherlin at ssutherlin@petroleumnews.com



PAID ADVERTORIAL

THE TRUE BACKBONES OF ALASKA ARE THE ALASKA NATIVES, PRE-STATEHOOD RESIDENTS AND HOMESTEADERS THAT VOTED AND CREATED THIS GREAT STATE OF ALASKA ARE THE FORGOTTEN REAL HEROES OF ALASKA

"RESULTS ALWAYS DEFINE INTENT"

Alaska has been a state the last 60+ years. Since Alaska became a state some 60 years ago, not one sole resident Alaskan has been able to explore or produce a single drop of oil or gas from his or her property. As a result, the immense wealth generated by Alaska's oil and gas has gone outside the state rather than staying in the hands of individual Alaskans.

Something is terribly wrong with this "result." So, let's try to get to the heart of how we got here and what we can do to change it.
After buying Alaska from Russia coaxing more citizens to come to the new territory of Alaska to homestead became a strategic necessity for the defense of the lower 48 states of America.

Following world war II, the US government desperately needed to have more new settlers to come, reside and settle in the new territory of Alaska to attempt to provide needed local civilian contract personnel in Alaska and produce fresh food and milk to service the thousands of soldiers and sailors who were being stationed in the territory of Alaska that were providing the 1st line of defense to protect the lower 48 states from any threats of any foreign nation.

Since Alaska's gold rush, the US had been trying to entice new citizens to come to the territory of Alaska. The US government promise to any new settler was that they could come pick a new homestead in the territory of Alaska. The US Interior Department rules were clearly understandable by any new Alaskan homesteader. If he or she lived on that homestead for two years and made certain improvements on the land, then they could keep the land and all the oil or gas that might be produced beneath it. That was how the Katalla Oil Field, Alaska's first oil field, was developed and was the enabling fact that allowed the Kennecott Copper mine to profitably produce and sell Alaska's copper for the next 30 years. To this day, this shallow oil field of wells less than 1000 feet deep is still owned by private citizens.

Many lower 48 citizens came up to the frigid new territory of Alaska to attempt to prove-up a new Alaskan homestead. These new folks soon found out living in the Alaskan brush was an arduous task that required some cash, but a whole lot of extreme physical work, extreme privation, and a lot of ingenuity just to prove up his new homestead and survive for the two year requirement. To be awarded a homestead they had to live in an area having few if any roads, few neighbors, a lot of big bears, and no electricity or running water. But they knew if they toughed it out, they would end up owning the land and everything below it to call their own.

This all changed when Swanson River Oil Field was discovered on the Kenai Peninsula in 1957. Suddenly there was a major push to stop any homesteader anywhere in Alaska from being able to own their oil and gas beneath their property. It took an act of congress to ensure that the pre-1957 homesteaders got to keep their oil and gas, but everyone else was out of luck. Those that homesteaded their property after 1957 did not even get to keep the gravel, much less the oil and gas beneath their land. The state government could clear the trees off their property and take the gravel if they needed it to build a road.

But the pre-1957 homesteaders were different; they owned the oil or gas beneath their lands **ONLY IF** they could get it to the surface and could cash in on it. The bottom line is this, if you cannot get the oil or gas beneath your property to the surface, you don't frickin own it.

In the 1970's the federal government only required a $10,000 bond to drill on federal lands. On homesteader's land, the state of Alaska in its infinite wisdom set a bonding requirement that was ten times higher. Before any homesteader could even think about drilling even a shallow oil or gas well on their own land they would have to come up with $100,000 cash bond. How many homesteaders do you know had an extra $100,000 laying around in 1970? It is important to note that there are thousands of oil and gas wells in the lower 48 that produce from less than a couple hundred feet below the surface.

But wait, it gets even better. The state of Alaska has now raised the homesteader's bonding requirement from $100,000 to $400,000! Even though the homesteader or their heirs technically own their oil and gas if they can get it to the surface, the high bonding requirements deprives them of their ability to get it to the surface where it can actually be sold and put into their bank account.

Another thing, the high $400,000 drilling bond cost is just another form of state-imposed taxation. Unfair taxation was the premise that caused the 1770-settlers of Boston to dump all its English tea into the Boston Harbor.

This is a double whammy! The land is already required by law to be pledged as collateral to pay all well plugging costs beneath his own homestead regardless, even if someone else had drilled the well. Even though there are only a couple of hundred of pre-1957 homesteaders, the state of Alaska bureaucrats who are pushing for higher bonding amounts are effectively throwing the homesteader who helped create this great state of Alaska under the bus.

The end result of these unreasonable excessive drilling bonds is that not one Alaskan resident has ever been able to produce or sell a single drop of Alaska's oil or gas since Alaska became a state some 60 years ago.

You might be thinking, "But what about the environment? If we let people drill on their own land, won't they trash it?" This land is their life. The homesteaders love their land more than anyone. They and their heirs know the tremendous sacrifice and effort they had to put in to get this land. It is preposterous to say they don't care about what happens to their land.

This writer believes that the current elected governmental officials are trying to do their best to restore equity back to the individual citizens of Alaska. We just need to make sure they do the right thing by lowering the bonding requirements so that individual Alaskans can be capable to rightfully explore for oil or gas on their own property.

Please again carefully remember, it is only when the oil or gas has come to the surface of the homestead can any homesteader be able to convert this produced oil and gas to cash-in-hand, and be deposited in the homesteader's own bank account.

The state should be compelled to disclose all its findings for these drastic measures penalizing and depriving pre-statehood homesteaders of the option to convert any or all of their oil and gas beneath their pre-statehood homestead to the homesteader's ownership.

-Jim White

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HILCORP SURVEY

mounted on and towed behind the vessel. In addition to using shallow seismic equipment such sidescan sonar, Hilcorp anticipates collecting water and seabed sediment samples, while also collecting cores from the seabed, BOEM's approval document says. Trained observers on the vessel will monitor for marine mammals, to ensure that appropriate measures can be taken to avoid wildlife disturbance.

Environmental impact assessments

BOEM said that it had originally conducted an analysis of the potential environmental impacts of Hilcorp's likely activities, including the geohazard survey, when preparing an environmental impact statement for the 2017 Lower Cook Inlet lease sale. The agency has now determined that this analysis had been sufficient to enable approval of Hilcorp's survey permit application without further review.

In July of last year the National Marine Fisheries Service issued a letter of authorization for the unintended disturbance by Hilcorp of marine mammals during the company's anticipated oil and gas activities throughout the Cook Inlet over the next five years. Those activities included conducting a 3D seismic survey in the Lower Cook Inlet in 2019 or 2020; conducting an outer continental shelf geohazard survey in the Lower Cook Inlet in 2020 or 2021; and drilling two to four exploratory wells between February and November in 2020 through 2022. Each well would take 40 to 60 days to complete and would require a jack-up rig, the letter of authorization said. The newly approved plan for the geohazard survey encompasses five potential well locations.

Seismic in 2019

Hilcorp conducted its planned offshore 3D seismic survey during the summer of 2019.

However, given the likely timing of the geohazard survey, as indicated in BOEM's letter of authorization, it appears that Hilcorp may move ahead with the survey but will not start its offshore exploration drilling this year.

In March Hilcorp Senior Geologist Dave Buthman told the Alaska Geological Society that Hilcorp was working to bring the Seadrill West Epsilon jack-up rig to Cook Inlet for the planned offshore drilling. There are two jack-up drilling rigs currently stationed in the Cook Inlet region: the Spartan 151 and Randolph Yost rigs. But both of these rigs are apparently limited to maximum water depths of 150 feet. In March 2019 Mike Dunn, Hilcorp development manager, told the Alaska Support Industry Alliance that the water depth at the proposed drill sites is at least around 180 to 190 feet. Buthman said that the West Epsilon rig can drill to subsurface depths of 25,591 feet in water depths up to about 393 feet.

Highly prospective

Although some distance south of most of the producing Cook Inlet oil and gas fields, the area of the planned drilling is north of the Augustine-Seldovia arch, a geologic structure to the south of which the thick Tertiary rock sequence hosting the producing fields of the region thins out. The successful Cosmopolitan oil field lies under the nearshore waters of the Inlet immediately to the northeast, near where Hilcorp is planning to develop its new Seaview gas field. Underneath the Tertiary sequence lies a thick sequence of Mesozoic strata that also have known oil potential.

Buthman told the Geological Society that Hilcorp is particularly interested in what it refers to as the Blackbill prospect, an oil prospect penetrated by ARCO's Raven No. 1 well in 1982. The prospect, about halfway across the inlet, due west of the town of Homer, contains a known oil resource in a Cretaceous reservoir within the Mesozoic sequence, Buthman indicated. He said that Hilcorp's 2019 3D seismic survey had revealed a 65,000-acre, four-way closure with the oil discovery at the top.

Hilcorp also has exploration interests on the Iniskin Peninsula, immediately west of the company's offshore acreage. There is known oil potential in the Mesozoic in the Iniskin area. ●

Contact Alan Bailey at abailey@petroleumnews.com

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INSIDER

the refineries to meet most of their demand by importing from other countries, he said, adding, "Given the nature of the supply chain, it is more likely that refineries cut back on imported cargoes (purchased as needed) than Alaska supply (purchased on long-term contract)."

Competition from foreign oil does affect the pricing in the Alaska oil contracts however, he said.

The lion's share of Alaska crude is sold in three refining centers — Anacortes, San Francisco, and Long Beach — that satisfy the needs of Washington, Oregon, California, Arizona and Nevada, King said. Five of the refineries are in Washington state and 15 are in California.

Transportation takes a slice of sales

Feeder pipelines moving the oil to Prudhoe Bay on average cost 60 cents per barrel to operate, although tariffs range from 25 cents to nearly $20 per barrel, King said. The 800-mile Trans-Alaska Pipeline System tariffs add an average cost of about $5.50 per barrel.

The lion's share of Alaska crude is sold in three refining centers — Anacortes, San Francisco, and Long Beach — that satisfy the needs of Washington, Oregon, California, Arizona and Nevada, King said.

"The average cost of shipping oil from Valdez to the West Coast is about $3.50 per barrel," King said. "That pays for the fuel, labor, and overhead required to operate, load, and unload a very large crude carrier."

King's entire report can be found at: https://kingeconomicsgroup.com/pricing-ans-part-1-physical-market-dynamics/

—STEVE SUTHERLIN

Norum takes gavel as new ATA president

ON MAY 1 JOSH NORUM of Sourdough Express was passed the gavel to become the 2020-2021 president of the Alaska Trucking Association. The outgoing president is Jamie Benson of Federal Express.

"I have been a part of this group for six years now and am proud to be able to serve on an organization that has been a much needed advocate for the trucking industry," Norum said. "I am the fifth member of my family to be the ATA president — my Great Uncle Gene Rogge (1959-1960), Great Grandpa Leo Schlotfeldt (1963-1964), Grandpa Whitey Gregory (1982-1983) and Uncle Jeff Gregory (1999-2000).

JOSH NORUM

Sourdough Express, which operates facilities in Anchorage and Fairbanks, is a fourth generation family organization. Since 1898, it has been servicing the commercial freight needs of Alaskan businesses throughout the state including the oil and gas industry.

ATA is celebrating its 60th anniversary this year. From its inception, the organization's goal has been straightforward — to foster and promote the interests of the trucking industry in Alaska.

Among other things, ATA works to promote highway and driver safety, influence government and regulatory agencies, boost the industry's image, and provide education and information about the industry.

—KAY CASHMAN

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FRONTIER STRUGGLES

Canadian government financial incentives to stimulate exploration in a region estimated to hold 5.1 billion barrels of resources.

Refinery idled

While the province and the industry wait for a response, Newfoundland has been dealt a major setback with the idling of its Come-by-Chance refinery that can process up to 130,000 bpd of crude and supply major harbors on the U.S. East Coast, including Boston and New York.

That made the facility the first North America refinery to crumble under pressure of COVID-19.

Facing global run cuts which some expect will soon reach 20 million bpd, Come-by-Chance said it had to face the reality of concerns about worker safety as the virus spreads.

It was quickly followed by word that Husky Energy was halting major construction on its West White Rose project — a satellite field in its operating White Rose project of the Jeanne d'Arc Basin — for the same COVID-related reasons.

Hope now rests with a plea from Newfoundland Natural Resources Minister Siobhan Coady to her federal counterpart Seamus O'Regan arguing that the Newfoundland offshore "would be a good return on investment ... and supply the world with some of its lower carbon per barrel of oil."

Nalcor Energy, the Newfoundland's government's energy corporation, estimates each barrel from its offshore generates 12 kilograms of greenhouse gas emissions, compared with a global average of 18 kilograms and an oil sands average of 44 kilograms.

Coady and Johnson say they would like to model Newfoundland on Norway, whose government introduced exploration incentives in 2005 that doubled the number of companies operating in that region prompting it to invite bids on 36 new offshore exploration blocks, despite opposition from environmental groups.

Johnson, noting that Norway reported 17 offshore discoveries last year, said just one Newfoundland discovery of 800 million to 1 billion barrels "would rapidly change our economics."

The Newfoundland government said it would settle for a restoration of an Atlantic investment tax credit for oil and gas activities that was phased out in the 2012-2016 period.

LNG also on hold

The Canadian Atlantic's only other fossil-fuel hope is the C$10 billion Goldboro LNG project in Nova Scotia and it too has been affected by COVID-19, joining about a dozen other North American LNG players in a holding pattern.

Pieridae Energy, the Goldboro owner, said its final investment decision will be delayed past its deadline of Sept. 30.

Company Chief Executive Officer Alfred Sorensen said "market conditions and global fallout" have impacted Pieridae's ability to give a go-ahead, "but we are confident it will happen once conditions improve and we can better analyze the landscape."

The project is designed to accommodate two LNG trains each capable of producing about 10 million metric tons a year of LNG from 1.3 billion cubic feet per day of natural gas.

So far Pieridae has a 20-year agreement to sell all of the LNG from its first liquefaction train to German utility UniperSE, starting between Nov. 30, 2024, and May 31, 2025, but that startup date is probably out of reach if the company gains extension of its final investment deadline to June 2021.

Other North American LNG proposals have delayed their investment decisions from mid-2019 to the end of 2020 or later. The ranks of another dozen proponents have been reduced by half, while analysts estimate that only one or two projects will move forward this year. ●

Contact Gary Park through publisher@petroleumnews.com