Petroleum news

page 3 December ANS averages 507,185 bpd, down 3.4% from 2019

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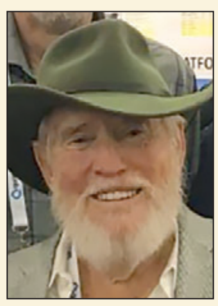
Alaska wildcatter Jim White dies: fierce property rights defender



JIM WHITE

James (Jim) Wynn White, independent oilman and Alaskan wildcatter, died Jan. 22 in Houston, Texas, at the age of 90. White was owner of Alaskan Crude Corp.

White moved his family to Kenai, Alaska, in 1968, working first for Unocal at its new fertilizer plant in Nikiski, before setting out into various business ventures in the Kenai area.

In the mid-1970s, White opened Copper Valley Machine Works, a machine shop in Glennallen, to serve the construction of the trans-Alaska oil pipeline, according to his son and fellow oilman, James A. White.

see JIM WHITE page 8

Peregrine drilling exception from Biden administration seems likely

DAVID WALL

It might be wishful thinking, but as of the evening of Jan. 27 an exception to the Biden administration's 60-day freeze on drilling permits looks possible for 88 Energy's first of two Peregrine Project oil exploration wells. If that happens the company said it plans to immediately restart field operations, which were halted Jan. 21.

Scott de la Vega, Biden's acting secretary of the Interior, effectively shut down 88 Energy subsidiary Emerald House's winter exploration

see PEREGRINE DRILLING page 11

IGU OKs Hilcorp gas contract, providing up to 11 years of supply

During its Jan. 19 meeting the board of the Interior Gas Utility approved a new gas supply contract with Hilcorp Alaska. Hilcorp produces gas from multiple fields around the Cook Inlet. IGU's current supply contract, also with Hilcorp, expires on March 31. Although the initial term of the new contract is five years, there are options to extend the contract by two further three-year terms, thus making it possible to have the contract run for up to 11 years.

Before deciding on the Hilcorp contract, IGU and its gas supply consultant, Mary Ann Pease, had made contact with every gas supplier in the Cook Inlet region, evaluating among other things supply redundancy, achieved through the operation of multiple fields and wells, through backup sources of supply, and through

see GAS CONTRACT page 12

Canada's 'modest' recovery hopes end after Biden pulls plug on KXL

The reaction was "modest" to word of a predicted 14% hike this year in Canada's upstream oil and natural gas sector.

The analysts who took that cautious line were right to hedge their bets.

Less than a week after the Canadian Association of Petroleum Producers targeted a rise of C$3.36 billion from last year's capital outlay of C$24 billion the industry was jolted out of its brief lull.

Just six hours after he was sworn in as U.S. president, Joe Biden went to work on his list of campaign promises and cancelled a permit allowing TC Energy to complete work on its Keystone XL pipeline.

That scuttled industry hopes of ending a continuous and

see RECOVERY HOPES page 10

EXPLORATION & PRODUCTION

Set to sign off

Oil Search to push on with Pikka construction without 3rd partner if needed

By KAY CASHMAN

Petroleum News

KEIRAN WULFF

Although Oil Search prefers to bring in another partner before sanctioning Pikka development at the end of 2021, it is not a requirement for moving ahead with construction of the North Slope oil field, a company official told Petroleum News after being asked whether moving forward with Pikka phase 1 construction later this year was contingent on securing a third partner.

In answer to an email to her and Oil Search Managing Director Keiran Wulff, Amy Burnett, U.S. media and communications manager, told Petroleum News on Jan. 27: "As previously announced, we do intend to launch a formal divestment process following FEED entry, with plans to complete it prior to FID. Our preference continues to be a pre-FID sell down to ensure we have an aligned joint venture as we go into construction. We are open to delaying sell-down if our commercial terms are not met." (FEED stands for front-end engineering and design and FID means final investment decision.)

The joint venture Burnett refers to is with

see PIKKA PUSH page 10

FINANCE & ECONOMY

ANS charts steady course

Inflationary US oil and gas restrictions offset COVID-19 spike worries

By STEVE SUTHERLIN

Petroleum News

Alaska North Slope crude slid 23 cents Jan. 27 to close at $55.53 per barrel. West Texas Intermediate rose 24 cents to close at $52.85, and Brent lost 10 cents to close at $55.81.

The major indexes remained steady, closing near the prices seen a week prior, despite fears early in the week about new COVID-19 breakouts in China, and reports that the Chinese government is dissuading its citizens from traveling over the Lunar New Year holiday which is traditionally a high travel period. The traditional festivities last over 15 days, and most Chinese people will get seven days off from work from Feb. 11 to Feb. 17.

> *"Renewables are coming of age, with wind and solar expanding quickly, but — even by 2045 — in our WOO they are only estimated to make up just over 20% of the global energy mix."*
> *—OPEC Secretary General Mohammad Sanusi Barkindo*

Markets have also been wary of mutations of the COVID-19 virus such as those discovered in Britain that cause the virus to be more transmittable between people, perhaps because those infected with the virus produce more infectious

see OIL PRICES page 11

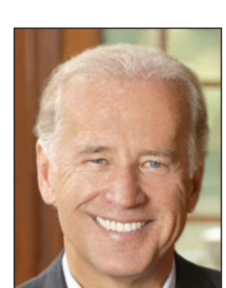
PIPELINES & DOWNSTREAM

RIP KXL; what's next?

Alberta vents at Biden, Trudeau, plans legal action; others argue KXL 'not needed'

By GARY PARK

For Petroleum News



JOE BIDEN

JUSTIN TRUDEAU

President Joe Biden has dug his heels in. And Canadian Prime Minister gets the message.

That's where things stand for Keystone XL.

Trudeau, during a 30-minute phone chat with Biden on Jan. 22, raised the issue of his government's disappointment that the new U.S. administration wasn't even willing to revisit discussions on the pipeline.

All he got by way of consolation was being the first foreign leader to have a one-on-one with Biden.

That left Alberta Premier Jason Kenney to lash out at Biden for refusing to even hear the case for KXL or acknowledge that the pipeline was a different project from the one that the U.S. leader, when he was vice president, joined President Barack Obama in revoking six years ago.

War on trade issues?

Some Canadian governmental aides said some

see KXL FUTURE page 10

● NATURAL GAS

Conditional ROWs proposed for LNG Project

Alaska Department of Natural Resources has analysis, proposed decision, out for public comment for 2 ROW leases for state lands

By KRISTEN NELSON

Petroleum News

The Alaska Department of Natural Resources is requesting public comment on an analysis and proposed decision by DNR Commissioner Corri Feige on two right-of-way lease applications from the Alaska Gasline Development Corp. The leases would be conditional because AGDC does not yet have project funding for the proposed Alaska LNG Project, which would move natural gas from Point Thomson and Prudhoe Bay to a liquefaction facility at Nikiski.

Written comments on the proposed ROWs are due by 5 p.m. March 1.

DNR will hold three online public hearings on the proposal: Feb. 23 at 9 a.m., Feb. 24 at noon and Feb. 25 at 5:30 p.m.

Details on the hearings and documents on the proposal are available at:

https://dog.dnr.alaska.gov/Services/Pipeline?pipeline=Alaska%20LNG.

Areas covered

The Point Thomson Transmission Line would move natural gas from Point Thomson some 63 miles to the AKLNG gas treatment plant near Deadhorse, with some 62.5 miles of the route on state-owned lands. The route, with related facilities, would occupy some 2,034 acres of state lands during construction and 607 acres during operation. The proposed Point Thomson line would be 32 inches in diameter, with a maximum allowable operating pressure of 1,150 pounds per square inch gauge and be elevated on vertical support members.

The mainline pipeline would transport natural gas some 807 miles from the gas treatment plant to the Nikiski liquefaction facility, with the route roughly paralleling the trans-Alaska oil pipeline route to Livengood and then roughly paralleling the Parks Highway south to the Susitna River where the line would diverge from the highway, running southwest to Beluga, then across Cook Inlet, south to Boulder Point on the Kenai Peninsula and southwest roughly paralleling the shore and public roads to the liquefaction facility at Nikiski.

CORRI FEIGE

The mainline ROW includes the gas treatment plant, the one-half mile 60-inch diameter Prudhoe Bay transmission line, the liquefaction facility's marine facility and some 452 miles of the mainline pipeline. Related facili-

see ROW COMMENT page 3

contents

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● EXPLORATION & PRODUCTION

December North Slope production steady

ANS averages 507,185 barrels per day, up marginally from November, down 3.4% from December '19; Cook Inlet crude production up 2%

By KRISTEN NELSON
Petroleum News

Alaska North Slope production averaged 507,185 barrels per day in December, up 862 bpd, 0.2%, from a November average of 506,323 bpd, but down 3.4% from a December 2019 average of 524,914 bpd.

Crude production, accounting for 89.1% of ANS barrels, averaged 451,798 bpd in December, down 0.3%, 1,238 bpd, from a November average of 453,036 and down 3.3% from a December 2019 average of 467,224 bpd. ANS natural gas liquids averaged 55,387 bpd in December, up 3.9%, 2,100 bpd, from a November average of 53,287 bpd, but down 4% from a December 2019 average of 57,688 bpd.

Production data are from the Alaska Oil and Gas Conservation Commission which reports production by field and well on a month delay basis.

The largest month-over-month per-barrel increase was at the Slope's largest field, Prudhoe Bay, operated by Hilcorp North Slope, which averaged 280,262 bpd in December, up 2.6%, 7,140 bpd, from a November average of 273,122 bpd, and up 1% from a December 2019 average of 277,402 bpd. Prudhoe crude oil production, which accounted for 81% of the field's production, averaged 227,076 bpd in December, up 2.3%, 5,087 bpd, from a November average of 221,988 bpd and up 1.5% from a December 2019 average of 223,779 bpd. Prudhoe NGL production averaged 53,186 bpd in December, up 4%, 2,053 bpd, from a November average of 51,133, but down 0.8% from a December 2019 average of 53,623 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.

Other fields with month-over-month volume increases include Endicott, Nikaitchuq and Oooguruk.

Eni's Nikaitchuq averaged 15,849 bpd in December, up 3.8%, 574 bpd, from a November average of 15,275 bpd, but down 22.9% from a December 2019 average of 20,564 bpd.

Eni's Oooguruk averaged 7,608 bpd in December, up 6.2%, 442 bpd, from a November average of 7,166 bpd, but down 6.9% from a December 2019 average of 8,170 bpd.

The Hilcorp Alaska managed Endicott field averaged 7,219 bpd in December, up 88 bpd, 1.2%, from a November average of 7,131 bpd, but down 3.1% from a December 2019 average of 7,446 bpd. Endicott crude oil production, 86.8% of the field's production, averaged 6,262 bpd in December, up 2.1%, 131 bpd, from a November average of 6,131 bpd but down 3.3% from a December 2019 average of 6,474 bpd. Endicott NGL production averaged 956 bpd in December, down 4.3%, 43 bpd, from a November average of 999 bpd, and down 1.6% from a December 2019 average of 972 bpd.

Crude production, accounting for 89.1% of ANS barrels, averaged 451,798 bpd in December, down 0.3%, 1,238 bpd, from a November average of 453,036 and down 3.3% from a December 2019 average of 467,224 bpd.

Month-over-month declines

All other North Slope fields had month-over-month drops in production volumes, although the drops at Northstar and Greater Mooses Tooth were marginal.

The smallest was at the Hilcorp-operated Northstar field, which averaged 6,910 bpd in December, down 1 bpd from a November average of 6,912 bpd, and down 32.9% from a December 2019 average of 10,304 bpd. Northstar crude oil production, 82% of the field's volume, averaged 5,666 bpd in December, down 1.6%, 92 bpd, from a November average of 5,768 bpd, and down 21.4% from a December 2019 average of 7,211 bpd. Northstar NGL production averaged 1,244 bpd in December, up 7.8%, 90 bpd, from a November average of 1,154 bpd, but down 59.8% from a December 2019 volume of 3,093 bpd.

ConocoPhillips Alaska's Greater Mooses Tooth in the National Petroleum Reserve-Alaska averaged 3,473 bpd in December, down 7 bpd, 0.2%, from a November average of 3,480 bpd, and down 44.8% from a December 2019 average of 6,297 bpd.

Badami, operated by Savant Alaska, a Glacier Oil and Gas company, averaged 1,622 bpd in December, down 195 bpd, 10.7%, from a November average of 1,817 bpd, but up 20% from a December 2019 average of 1,351 bpd.

Hilcorp's Milne Point averaged 35,984 bpd in December, down 0.7%, 266 bpd, from a December average of 36,249, but up 19.5% from a December 2019 average of 30,124 bpd.

Point Thomson, operated by ExxonMobil Production, averaged 7,644 bpd in December, down 11.6%, 1,003 bpd, from a November average of 8,646 bpd, but up 39.2% from a December 2019 average of 5,491 bpd.

The ConocoPhillips-operated Kuparuk River field averaged 96,026 bpd in December, down 1.8%, 1,726

see ANS PRODUCTION page 5

Inlet gas production down marginally

Natural gas production in Cook Inlet averaged 225,968 thousand cubic feet per day in December, down 1,068 mcf, 0.5%, from a November average of 227,036 mcf per day, but up 6.1% from a December 2019 average of 212,927 mcf per day.

Data are 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.

In December 85.1% of Cook Inlet natural gas production came from the eight largest fields.

Hilcorp Alaska's Kenai gas field averaged 45,473 mcf per day, 20.1% of inlet gas production, down 464 mcf per day, 1%, from a November average of 45,937 mcf but up 35.9% from a December 2019 average of 33,463 mcf per day.

Hilcorp's Ninilchik averaged 31,327 mcf per day, 13.9% of inlet gas production, up 1,535 mcf per day, 5.2%, from a November average of 29,791 mcf, but down 5.1% from a December 2019 average of 33,017 mcf per day.

Hilcorp's McArthur River, the inlet's largest oil producer, averaged 28,096 mcf per day in December, 12.4% of inlet gas production, down 3,197 mcf per day, 10.2%, from a November average of 31,293 mcf, but up 26.6% from a December 2019 average of 22,188 mcf per day.

Beluga River, operated by Hilcorp, averaged 23,895 mcf per day in December, 10.6% of inlet gas production, down 293 mcf per day, 1.2%, from a November average of 24,188 mcf, but up 17% from a December 2019 average of 20,416 mcf per day.

Hilcorp's Swanson River averaged 19,442 mcf per day in December, 8.6% of inlet gas production, down 611 mcf, 3.1%, from a November average of 20,053 mcf, and down 36.1% from a December 2019 average of 30,436 mcf per day.

Hilcorp's North Cook Inlet averaged 17,302 mcf per day in December, 7.7% of inlet gas production, down 358 mcf, 2%, from a November average of 17,661 mcf and down 0.7% from a December 2019 average of 17,421 mcf per day.

Kitchen Lights, operated by Furie, averaged

see INLET GAS page 5

continued from page 2

ROW COMMENT

ties include some 632 access roads, 153 potential material sites, 109 potential excess material disposal sites, 57 various work areas and camps, eight compressor stations, one heater station, 11 launchers/receivers and the mainline material offloading facility at Beluga.

DNR said AGDC has requested a nominal 110-foot-wide ROW for pipeline construction and a 53.5-foot-wide ROW for operations. The proposed mainline would be 42 inches in diameter, have a maximum allowable operating pressure of 2,075 psig and be buried for most of the route.

The ROW for the mainline, with related facilities, would occupy some 50,570 acres of state land during construction and some 3,631 acres of state land during operation.

Conditional ROWs

The analysis and proposed decision signed by DNR Commissioner Corri Feige says AGDC has the capacity to satisfy some of the standards required by state statute, "but additional technical expertise and project funding must be secured before AGDC is fit, willing, and able to design, construct, operate, and terminate the project."

While significant work has been completed, "until additional technical expertise and project funding have been obtained, AGDC cannot satisfy the fit, willing, and able requirement" of state statute, Feige said.

State statutes allow the commissioner to offer a conditional ROW, which is what is proposed, providing the applicant up to 10 years to prove they can meet all statutory requirements "and be found fit, wiling, and able to design, construct, operate, and terminate their project."

Conditional leases under the ROW statute "do not convey a property right in the leasehold," the commissioner said, have additional conditions and "do not allow construction of the project until the lease has been converted into a conventional AS 38.35.100(a) ROW lease." ●

Contact Kristen Nelson at knelson@petroleumnews.com

EXPLORATION & PRODUCTION

Upper foothills open for off-road travel

The Alaska Department of Natural Resources' Division of Mining, Land and Water said Jan. 21 that the upper foothills area has met required soil temperatures and snow cover for off-road tundra travel.

The last time the upper foothills met the required 9 inches of snow and colder than minus 5 degrees C at a depth of 30 centimeters was in March 2017, the division said.

The opening applies only to operators with valid off-road vehicle travel permits for operation on state-owned North Slope lands.

The division noted that while overall snow cover is good, it may be thin in some areas and those areas should be avoided or special construction methods used to protect the tundra surface.

The division's stipulations for winter off-road vehicle travel require adequate frost and snow cover and approval of individual routes of travel.

The last time the upper foothills met the required 9 inches of snow and colder than minus 5 degrees C at a depth of 30 centimeters was in March 2017, the division said.

Periodic site inspections will be conducted by state personnel to ensure compliance, the division said.

The upper foothills is the third of the Slope's four areas to open this season.

The western coastal area opened for winter season tundra travel Dec. 17 and the eastern coastal area opened Jan. 5. Those areas require 6 inches of snow and the same minus 5 degrees C temperature at 30 centimeters depth.

Questions should be directed to the division's Northern Region Land Section in Fairbanks at 907-451-2740.

—PETROLEUM NEWS

EXPLORATION & PRODUCTION

US drilling rig count up by 5 to 378

The Baker Hughes U.S. rotary drilling rig count continues to rise, up by five to 378 for the week ending Jan. 22, but still down by 416 from a count of 794 a year ago.

When the count hit 244 in mid-August last year, it was not just the low for 2020, but the lowest the count has been since the Houston based oilfield services company began issuing weekly U.S. numbers in 1944.

Prior to 2020, the low was 404 rigs in May 2016. The count peaked at 4,530 in 1981.

The count was in the low 790s at the beginning of 2020, where it remained through mid-March, when it began to fall, dropping below what had been the historic low in early May with a count of 374 and continuing to drop through the third week of August when it gained back 10 rigs.

The Jan. 22 count includes 289 rigs targeting oil, up two from the previous week but down 387 from 676 a year ago, 88 rigs targeting gas, up three from the previous week but down 27 from 115 a year ago, and one miscellaneous rig, unchanged from the previous week and down two from a year ago.

Twenty-two of the holes were directional, 338 were horizontal and 18 were vertical.

Alaska up by 2

The largest increase, up six from the previous week, was in Texas (175), which has the most active rigs in the country.

Alaska (5) was up by two; North Dakota (11), Ohio (5) and West Virginia (12) were each up by one.

Rig numbers were unchanged from the previous week in California (7), Colorado (8), Louisiana (47), Oklahoma (17), Utah (3) and Wyoming (4).

New Mexico (65) was down by five from the previous week and Pennsylvania (18) was down by one.

Baker Hughes shows Alaska with five active rigs Jan. 22, up by two from the previous week but down by five from a year ago.

The rig count in the Permian, the most active basin in the country, was down by one from the previous week at 188, and down 217 from a count of 405 a year ago.

—KRISTEN NELSON

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Kay Cashman	PUBLISHER & FOUNDER
Mary Mack	CEO & GENERAL MANAGER
Kristen Nelson	EDITOR-IN-CHIEF
Susan Crane	ADVERTISING DIRECTOR
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Gary Park	CONTRIBUTING WRITER (CANADA)
Steve Sutherlin	CONTRIBUTING WRITER
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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● UTILITIES

RCA still working on ERO governance

Complications over how to ensure balanced board structure are raising legal issues and delaying completion of draft regulations

By ALAN BAILEY
For Petroleum News

Complications in resolving how the Regulatory Commission of Alaska can develop regulations that would ensure balance in the board of an electric reliability organization are continuing to further delay the completion of draft regulations for ERO certification, RCA Commissioner Antony Scott told a public meeting of the commission on Jan. 13.

The commission is developing regulations to enable the implementation of Senate Bill 123, a bill passed by the Alaska Legislature last year to enable the formation of EROs in Alaska. The primary purpose of the statute and its associated regulations is to enable the formation of an ERO for the Railbelt electrical system, to enable a more unified and efficient approach to the overall management of the system.

The Railbelt utilities are in the process of forming the Railbelt Reliability Council, or RRC, to become an ERO for the Railbelt. The RRC will ultimately require RCA certification.

First of three dockets

The docket for the development of ERO certification regulations is the first of three dockets for implementing SB 123. The second docket is dealing with regulations for integrated resource planning for the electrical system and with commission pre-approval for the construction of new major facilities for the system. The third docket is dealing with regulations for reliability standards and the rules for ERO operation.

The commission had originally hoped to publish the draft regulations for ERO certification for public review around the end of September. However, regulation development is proving significantly more complicated than the commission had originally hoped. During the Jan. 13 meeting two commissioners expressed concern about a July 1, 2021, deadline that the Legislature had set for completing all of the SB 123 regulations — a deadline of this type is unrealistic, said Commissioner Stephen McAlpine.

Balancing the governance

The development of regulations for ERO certification is proving particularly challenging because these regulations will need to clarify the rules under which the commission may approve the structure of an ERO board of directors. Acceptable ways of achieving an appropriate balance of interests in the board, including the interests of electric utilities, electricity consumers, independent power producers and other electricity system stakeholders, are difficult to determine. For example, the member-owned cooperative nature or public ownership of the Railbelt utilities mean that a utility actually represents some combination of the interests of the utility as an electricity provider, and the interests of the utility members as electricity consumers.

Without appropriate balance, board decisions may be skewed towards the interests of some particular group of stakeholders.

Legal issues

In drafts of the ERO certification regulations the commission had moved from a less prescriptive to a more prescriptive form of regulation, telling an ERO candidate the RCA's expectations for the ERO board structure and balance. However, Scott told the Jan. 13 meeting that this approach had raised legal issues relating to the rights of a corporation to select its own board of directors. So, rather than requiring ongoing commission oversight of an ERO's governance, the commission needs to provide clarity over what the commission would approve as an acceptable board arrangement.

Scott said that, given the legal issues involved, it is necessary at this stage to review the draft regulations with attorneys from the state Department of Law, before continuing to make further revisions to the draft, and before sending draft regulations to the state Legislature for review. ●

Contact Alan Bailey at abailey@petroleumnews.com

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INLET GAS

14,690 mcf per day in December, 6.5% of inlet gas production, up 1,391 mcf, 10.5%, from a November average of 13,299 mcf, but down 0.7% from a December 2019 average of 14,797 mcf per day.

Hilcorp's Beaver Creek averaged 11,961 mcf per day in December, 5.3% of inlet gas production, down 1,848 mcf, 13.4%, from a November average of 13,809 mcf, but up 62.8% from a November 2019 average of 7,347 mcf per day.

Smaller inlet gas fields

The smaller gas fields in Cook Inlet collectively accounted for just under 15% of inlet natural gas production in December.

Hilcorp's Ivan River averaged 6,169 mcf per day in December, up 2,488 mcf, 67.6%, from a November average of 3,682 mcf, and up 1777.4% from a December 2019 average of 329 mcf per day.

Hilcorp's Cannery Loop averaged 5,158 mcf per day in December, up 178 mcf, 3.6%, from a November average of 4,981 mcf but down 11.9% from a December 2019 average of 5,854 mcf per day.

AIX's Kenai Loop averaged 5,085 mcf per day in December, down 0.2%, 10 mcf, from a November average of 5,094 mcf and down 4.5% from a December 2019 average of 5,323 mcf per day.

Hilcorp's Granite Point averaged 3,773 mcf per day in December, up 0.4%, 15 mcf, from a November average of 3,758 mcf and up 15.5% from a December 2019 average of 3,267 mcf per day.

Hilcorp's Deep Creek averaged 3,496 mcf per day in December, down 3.7%, 133 mcf, from a November average of 3,629 mcf and down 17.2% from a December 2019 average of 4,220 mcf per day.

Gardes Holdings' North Fork averaged 3,126 mcf per day in December, down 1.8%, 58 mcf, from a November average of 3,184 mcf and down 12.8% from a December 2019 average of 3,583 mcf per day.

BlueCrest's Hansen averaged 2,784 mcf per day in December, down 2.2%, 62 mcf, from a November average of 2,846 mcf and down 47.4% from a December 2019 average of 5,298 mcf per day.

Hilcorp's Trading Bay averaged 2,250 mcf per day in December, up 15.7%, 305 mcf, from a November average of 1,945 mcf but down 28.6% from a December 2019 average of 3,149 mcf per day.

Amaroq's Nicolai Creek averaged 381 mcf per day in December, up 21.7%, 68 mcf, from a November average of 313 mcf and up 33.5% from a December 2019 average of 285 mcf per day.

Hilcorp's Nikolaevsk averaged 328 mcf per day in December, down 5%, 17 mcf, from a November average of 345 mcf and down 18.4% from a December 2019 average of 402 mcf per day.

Hilcorp's Middle Ground Shoal averaged 260 mcf per day in December, up 7.3%, 18 mcf, from a November average of 242 mcf and up 23.1% from a December 2019 average of 211 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

bpd, from a November average of 97,752 bpd, and down 6.6% from a December 2019 average of 102,825 bpd. In addition to the main Kuparuk pool, Kuparuk produces from satellites at Meltwater, Tabasco and Tarn, and from West Sak.

ConocoPhillips' Colville River averaged 44,589 bpd in December, down 4,185 bpd, 8.6%, from a November average of 48,773 bpd and down 18.8% from a December 2019 average of 54,941 bpd.

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

Cook Inlet up marginally

Cook Inlet crude oil production averaged 11,161 bpd in December, up 221 bpd, 2%, from a November average of 10,940 bpd, but down 21.1% from a December 2019 average of 14,145 bpd.

Hilcorp's Beaver Creek averaged 127 bpd in December, down 7 bpd, 5.3%, from a November average of 134 bpd and down 36.1% from a December 2019 average of 198 bpd.

Hilcorp's Granite Point averaged 2,904 bpd in December, down 54 bpd, 1.8%, from a November average of 2,958 bpd and down 12.2% from a December 2019 average of 3,306 bpd.

The Hansen field at Cosmopolitan, operated by BlueCrest, averaged 927 bpd in December, up 10 bpd, 1.1%, from a

Cook Inlet crude oil production averaged 11,161 bpd in December, up 221 bpd, 2%, from a November average of 10,940 bpd, but down 21.1% from a December 2019 average of 14,145 bpd.

November average of 917 bpd, but down 21.5% from a December 2019 average of 1,181 bpd.

Hilcorp's McArthur River, Cook Inlet's largest oil field, averaged 3,930 bpd in December, up 87 bpd, 2.3%, from a November average of 3,843 bpd but down 11% from a December 2019 average of 4,414 bpd.

Hilcorp's Middle Ground Shoal averaged 1,260 bpd in December, up 18 bpd, 1.5%, from a November average of 1,242 bpd, but down 0.3% from a December 2019 average of 1,263 bpd.

Hilcorp's Swanson River averaged 808 bpd in December, up 19 bpd, 2.4%, from a November average of 789 bpd, and up 9.6% from a December 2019 average of 737 bpd.

Hilcorp's Trading Bay averaged 1,206 bpd in December, up 149 bpd, 14.1%, from a November average of 1,057 bpd but down 7.8% from a December 2019 average of 1,309 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

● LAND & LEASING

Division denies Glacier's Badami expansion

E. North Slope unit operator lacks sufficient work plan for expansion area, no geo proof of connectivity between unit, new area

By **KAY CASHMAN**

Petroleum News

On remand from the commissioner of the Alaska Department of Natural Resources, the director of the Division of Oil and Gas denied an application from operator Savant Alaska to expand the eastern North Slope Badami unit in a decision issued on Jan. 22. Savant is a Glacier Oil and Gas company.

As Petroleum News previously reported, Glacier put Badami on the market in mid-November, using BMO Capital Markets Energy Group to handle the divesture. As of Jan. 26, the unit and its assets remain for sale on BMO's website.

STEPHEN RATCLIFF

One of the selling points listed by BMO is the oil field's "low risk, quantified upside development," which includes "stacked pay horizontal development of the Killian sands" outside the Badami unit — i.e. in the proposed expansion area.

Savant restarted the eastern North Slope Badami pad in October after halting production in May because the price of oil had tanked. The suspension placed the unit into warm-standby status with a small crew to oversee facilities including field infrastructure, the Badami Pipeline and a private airstrip.

During the 24 days the field produced in October it yielded more than 2,000 barrels of oil a day, newly appointed Glacier President Stephen Ratcliff said in early November.

Turn-key operation

In its Badami asset overview, BMO said unit was a turn-key, 100% operated, "cash flow positive asset … with significant exploration and exploitation potential from highly prolific stacked pay reservoirs," producing approximately 2,000 barrels of oil per day, primarily from the Badami and Killian sands.

BMO said the "Hilcorp/BP retention of ARO and select plugging obligations limits buyer exposure," noting the Killian sands are "primed for development following" its successful B1-07 well.

B1-07 was drilled in the East Mikkelsen prospect between Badami and the Point Thomson unit in early 2018 by Savant after it had been purchased by Miller Energy and Miller had emerged from bankruptcy as Glacier Oil and Gas, which renamed the prospect Starfish. The first Badami Killian oil discovery was made in the B1-38 well in 2010 by Savant before the company was purchased by Miller.

Savant's common carrier Nutaaq pipeline, which also serves the Point Thomson unit, stayed in operation when the field was put in warm shut down.

According to Alaska Oil and Gas Conservation Commission records, Badami averaged 1,252 barrels of oil per day in March, down 7.7% from a February average of 1,357 bpd and down 31.1% from a March 2019 average of 1,817 bpd.

Seven wells in the Badami sands participating area produced 716 barrels in March; with the other 804 bpd coming from an "undefined pool," which in fact was mainly the Killian. B1-07 produced 664 bpd and B1-38 140 bpd.

B1-11A was the highest Badami sands producer at 320 bpd.

Badami produced 173 barrels of water in March.

BMO also said Badami has produced more than 700 million barrels of oil since 2018 and "is currently making 1,250 barrels of oil per day," with no explanation of the discrepancy between what Ratcliff said was the unit's October output unless that's what the field produced in November.

In its asset overview, BMO also said a "75 mi seismic survey covers entire block and confirms subsurface model" and that the "existing Glacier-owned, BP-constructed infrastructure supports full field development and optionality for third party revenue/volumes."

BMO pointed to Badami's "38,500 bo/d facility with capacity for additional volumes on or offset the unit" and "multiple access points via barge landing and 5,500 ft airstrip."

Another one of BMO's bullet points was the "70 mbo/d capacity Nutaaq pipeline owned and operated by Glacier (12" diameter, 25 miles long) that connects Point Thompson and Badami to Endicott." Nutaaq is a common carrier line.

Two reasons for denial

There were two reasons for the division's denial of Savant's expansion request.

Section 11.1 of the Badami unit agreement says the unit operator should, "when warranted" expand the unit area to include "any additional lands determined to overlie any reservoir, any part of which is within the unit area." While there is current production from Killian sands in the Badami unit and evidence of Killian sands outside the unit in the proposed expansion area, the data provided by Savant in its application (and more recent updated data provided in December) "does not support a reasonable interpretation" that the Killian reservoir in the unit extends into the leases in the proposed expansion area, including the leases that were partially approved in the 2013 decision. Because Savant's data neither shows that any additional lands in the leases at issue overlie any part of the existing Badami unit reservoir nor that the unit reservoir is in communication with any

see **EXPANSION DENIED** page 7

State approves Badami expansion

Reprinted from the March 24, 2013, issue of Petroleum News

The Alaska Department of Natural Resources has agreed to expand the Badami unit to include portions of two leases overlying the East Mikkelsen oil prospect but will not include an additional five leases also requested for expansion by two leaseholders.

The expansion adds some 2,204 acres from ADL 391001 and ADL 390825 along the eastern edge of the unit, which is currently the easternmost producing field on the North Slope. The leases overlie a known Brookian reservoir in the Killian sands tested by Humble Oil & Refining Co. on ADL 390825 in 1971 with its East Mikkelsen No. 1 well.

With the ruling, Badami-operator Savant Alaska LLC must drill an exploration well in the expansion area next winter. The directional well would target the Hue Shale, allowing Savant to test the entire Canning formation, including the Badami and Killian intervals.

The two leases are held by the Alaska Venture Capital Group.

If successful, East Mikkelsen would be developed jointly with the existing unit.

Humble Oil drilled East Mikkelsen No. 1 to a total depth of 15,205 feet and encountered hydrocarbons in the Killian sandstone interval of the Canning formation between 11,516 feet and 11,572 feet measured depth. A five-hour test collected 39 barrels of 24 degree API oil from the well bore, correlating to approximately 180 barrels of oil per day.

Smaller expansion

Savant originally asked the state to add seven leases to Badami — one it held with partner ASRC Exploration LLC and six others held by the Alaska Venture Capital Group — but the state ultimately determined that only a portion of two leases met the criteria.

In its application last November (2012), Savant said the seven leases would "connect subsurface potential and surface infrastructure" for the two companies. By combining the leases into a single unit, "drilling targets could be reached more easily and development could occur more efficiently and safely with less environmental impact on the area."

But the state determined that only portions of two leases met the criteria for unitization.

ADL 391001 and ADL 390825 were set to expire on Jan. 31 and Feb. 29, 2012, respectively, but were extended by unitization proceedings. Now, the un-unitized portion of ADL 391001 is called ADL 392392 and extended to Jan. 31, 2014, and the un-unitized portion of ADL 390825 is called ADL 392393 and extended to March 1, 2014.

All six Alaska Venture Capital Group leases are also still pending to be included in the proposed Telemark unit, which the state said it plans to address in a separate decision.

A new phase for Badami

Badami came online in August 1998, but geologic troubles have kept the unit from producing as its owners once hoped; production has been sporadic, and the field has been periodically shut in due to connectivity issues within the reservoir. The field reached peak production of 7,450 barrels per day in September 1998, but former operator BP suspended production from February to May 1999 (to "recharge" the wells), again from 2003 until 2005 and a third time starting in September 2007.

see **BADAMI HISTORY** page 7

PETROLEUM NEWS FILE

The Badami pad

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EXPANSION DENIED

other reservoir in the proposed expansion area, the division denied the unit expansion request and vacated the entire 2013 decision (see sidebar to this story).

The division gave a second reason for turning down the expansion, saying Savant "did not provide sufficient plans to develop the expansion area."

A little background

In 2016, Savant's parent company, Miller Energy Resources Ltd., went through bankruptcy proceedings and became Glacier Oil & Gas Corp. Savant continued to operate the Badami unit under its parent, Glacier.

In a July 25, 2019, letter to Savant, the division asked the company to provide an updated work plan that reflects current dates and work commitments because the original work plan attached to the application, submitted almost seven years prior (November 2012), was out of date.

The agency also made a point of saying Savant was "not at fault" but the passage of time made the plan sufficiently out of date, forcing the division to make considerable assumptions about the company's current work commitments and timeline. An updated work plan therefore was necessary for the division to consider any work commitments as part of the remanded application.

The proposed expansion area covers 10,121.33 acres. The division partially approved the application in its March 15, 2013, decision. Savant appealed that decision and the matter was remanded to the division by the DNR commissioner on July 2, 2018.

The division received additional material on Dec. 11, 2020, from Savant in support of its application.

Upon remand and "comprehensive review of record," the division denied the application finding that the proposed expansion of the Badami unit did not promote conservation of all natural resources, did not promote the prevention of economic and physical waste and did not provide for the protection of all parties of interest, including the State of Alaska, per AS 38.05.180(p); 11 AAC 83.303. ●

Contact Kay Cashman at publisher@petroleumnews.com

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BADAMI HISTORY

Savant Alaska and ASRC Exploration joined the project in late 2008, eventually bringing the field back into sustained production by drilling and hydraulically fracturing additional horizontal wells to boost production.

Savant became the operator in late 2011.

As of January 2013, the Badami unit had produced slightly more than 6 million barrels of oil and 30 billion cubic feet of natural gas. The five wells in the Badami field were producing 214 barrels of oil and 27,000 cubic feet of natural gas as of January 2013.

Among those was the Badami B1-38 well Savant drilled in 2009, completed in early 2010 and brought online in late 2010.

—ERIC LIDJI

Editor's note: A 2014 update in the division's Jan. 22, 2021, decision said the agency's previous decision severed ADL 390825 and assigned the non-unitized portion of that lease to ADL 392393 — that lease was extended to Feb. 29, 2014. Similarly, the previous decision severed ADL 391001 and assigned the non-unitized portion of that lease to ADL 392392 — that lease was set to expire on Jan. 31, 2014. Because the director's decision was appealed, neither lease 390825 nor 391001 were severed; nor were the non-unitized portions of those leases assigned to leases 392393 and 392392, respectively.

GOVERNMENT

AOGCC fines AIX $30,000 at Kenai Loop

The Alaska Oil and Gas Conservation Commission issued an order Jan. 25, fining AIX Energy LLC $30,000 for failure to maintain a functional subsurface safety valve on the KL1-1 well at the Kenai Loop gas field.

The commission said it issued a notice of proposed enforcement action to the company Dec. 15, specifying correction actions and the $30,000 civil penalty.

In addition to identifying the violation, the December notice proposed that the company submit an application for sundry approval to bring the KL1-1 well into regulatory compliance "and describe how it will prevent recurrence of this violation."

The commission said AIX installed a subsurface safety valve in the well prior to beginning production in January 2012.

The commission granted a SSSV waiver in February 2012 as part of approval to install a 4,000-foot capillary string inside the well's production tubing "to mitigate flow assurance issues from hydrate formation in the well, and installation of a lock-out ring across the SSSV to prevent its closure."

But a February 2020 inspection by the commission "confirmed the capillary string was no longer installed in the KL1-1 production tubing."

AOGCC said it notified AIX in an Aug. 13 letter that it was reviewing whether the safety valve system in the well met the commission's regulations "and specifically the requirement to make operational the SSSV when the capillary string was removed from the production tubing."

The commission said information gathered during its review "shows the capillary string was removed from KL1-1 on June 23, 2015," and said removal of the capillary string "violated the SSSV waiver."

The commission said AIX acknowledged receipt of the notice of proposed enforcement in a Jan. 8 letter and "concurred in whole with the proposed action."

On Jan. 18, the company "provided additional information regarding the timing for procurement and installation of an SSSV in KL1-1."

The commission said mitigating circumstances include demonstrated good performance of the SSSV system during testing at six-month intervals since production began from KL1-1, AIX's compliance history at Kenai Loop and no injury to the public.

In addition to the fine, AIX has until Feb. 25 to apply for sundry approvals for well work necessary to make the KL1-1 SSSV functional, and within 10 days of the decision the company "shall provide a detailed written explanation that describes how it intends to prevent recurrence of this violation."

—KRISTEN NELSON

PIPELINES & DOWNSTREAM

NMFS: Kenai LNG cool down project unlikely to adversely affect inlet habitat

In response to the Federal Energy Regulatory Commission's request for a thorough review and written opinion on the environmental impact of Trans-Foreland Pipeline's proposed Kenai LNG Cool Down Project, the National Marine Fisheries Service provided FERC's environmental staff with a Letter of Concurrence on Jan. 26, agreeing with FERC's determination to allow the project to proceed.

"NMFS staff concurs that the proposed action is not likely to adversely affect Cook Inlet beluga whales or their critical habitat, western DPS Steller sea lions, Western North Pacific DPS gray whales, Western North Pacific DPS humpback whales, Mexico DPS humpback whales, or sei whales," said the letter signed by Jonathan M. Kurland, NMFS assistant regional administrator for protected resources.

The March 29, 2019, application was filed by Marathon Petroleum subsidiary

see **LNG PROJECT** *page 8*

GOVERNMENT

AOGCC expands Torok oil pool at Kuparuk

Deletes Torok oil pool from Oooguruk unit, where Eni no longer holds acreage previously held by Caelus prior to its sale of tracts

By KRISTEN NELSON
Petroleum News

In Jan. 21 orders the Alaska Oil and Gas Conservation Commission has approved adding to the areal extent of the Kuparuk River Torok Oil Pool at the request of unit operator ConocoPhillips Alaska and, on its own motion, contracting that acreage from the Oooguruk Torok Oil Pool, where acreage is no longer held by the Oooguruk unit operator.

This is an area of the North Slope formerly held by Caelus Alaska. In 2019, Caelus sold its Oooguruk producing assets to Eni and the more southerly portion of its acreage in this area, where it was developing Nuna, to ConocoPhillips.

In June 2019 ConocoPhillips applied to the Alaska Department of Natural Resources' Division of Oil and Gas to include Nuna, which lies immediately south of Oooguruk, to the Kuparuk River unit. The Nuna prospect ConocoPhillips acquired from Caelus includes 11 tracts covering 21,000 acres.

"This transaction represents an attractive addition to our expanding North Slope position and will allow ConocoPhillips to cost effectively develop Nuna utilizing Kuparuk River Unit infrastructure," Joe Marushack, ConocoPhillips Alaska president, said in a 2019 statement.

ConocoPhillips told the division in its application to add the Nuna prospect to the Kuparuk River unit that development of the expansion area through existing KRU facilities would not require standalone processing facilities and said the reserves in the expansion area "are not large enough to support the costs of full processing facilities."

In its AOGCC application ConocoPhillips said the expansion would make the western, northern and southern boundaries of the KRU Torok oil pool equivalent to the current KRU boundary, allowing for development of the Torok over the area.

The company told the commission expansion of the Torok oil pool "will allow for development of the Torok from KRU 3S pad, and the newly named KRU 3T pad (previously known as Nuna pad)."

Previous plans

Caelus, when it was the operator at Oooguruk and Nuna, sanctioned Nuna development in 2015 and built a new pad and a 2.5-mile access road.

Pioneer Natural Resources, the previous Oooguruk operator, had proposed Nuna development in late 2010, having drilled through the Torok formation for several years to target deeper oil reservoirs, but Nuna was too far south of Oooguruk to be developed from those facilities, and Pioneer wanted to build at least one onshore drill site and potentially standalone facilities. Caelus acquired Pioneer's Alaska assets in late 2013, and by early 2014 was estimating some $550 million for new facilities and $800 million to $900 million for drilling, a price tag of some $1.4 billion for Nuna development.

AOGCC approved the Torok oil pool at Kuparuk in 2016, allowing ConocoPhillips to proceed with an oil development program from existing Drill Site 3S. The Torok pool at Kuparuk is in the northwest corner of the unit and the company estimated in its 2016 applications that development from DS-3S could access between 100 million and 500 million barrels of oil in place, with an estimated 5% primary recovery rate and a range of 13-55% recovery with enhanced recovery programs. Separate development of a hypothetical second drill site was estimated to access between 100 million and 500 million barrels of oil in place, with similar recovery rates.

Consistent development rules

The commission said expanding the Kuparuk River Torok oil pool to include the acreage recently acquired by ConocoPhillips "is necessary to ensure consistent development rules."

The Torok oil pool at Kuparuk "is defined as the accumulation of oil and gas common to and correlating with the interval within the Kalubik No. 1 well between the measured depths of 4,991 and 5,272 feet on the resistivity log recorded in exploratory well Kalubik No. 1," the commission said.

In its contraction order for the Torok oil pool at Oooguruk the commission said that in 2019 DNR approved a request from Caelus to contract the Oooguruk unit "to exclude leases in the southern portion of the unit. On June 20, 2019, the DNR approved Eni as the new operator for the OU."

The commission said its regulations require that an area injection order be restricted to a single operator, and since the current Oooguruk Torok oil pool includes acreage now operated by Eni and ConocoPhillips, the pool rules for Oooguruk and Kuparuk "must be adjusted to ensure consistent rules." ●

Contact Kristen Nelson at knelson@petroleumnews.com

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LNG PROJECT

Trans-Foreland, which also owns the adjacent Kenai Refinery. Trans-Foreland wants to "bring parts of the Kenai LNG Plant out of current warm idle status by importing LNG and using the LNG to cool existing LNG storage tanks and associated LNG facilities," as well as minor modifications to prevent environmental and economic waste from boil-off gas. The modifications are collectively referred to as the Kenai LNG Cool Down Project.

The project will allow the Kenai LNG Terminal to import up to four tanker loads of LNG annually and provide up to 7 million standard cubic feet per day of boil-off gas to the refinery.

During periods when BOG generation is insufficient to meet the refinery's needs, a portion of the LNG would be vaporized and delivered to the refinery along with the BOG.

The existing export terminal includes a pretreatment facility, a 0.2 billion cubic feet per day liquefaction unit, three 35,000-cubic-meter LNG storage tanks, a BOG management system, a marine loading/unloading dock and ancillary facilities. The terminal has not exported LNG since 2015 and has been maintained in a warm idle state since 2018.

Trans-Foreland does not propose to activate the liquefaction portion of the plant.

NMFS noted that the LNG facility upgrades "will occur entirely on land, therefore the construction of the upgrades is not expected to impact water resources, fishes, marine mammals, and/or threatened and endangered species."

The project will allow the Kenai LNG Terminal to import up to four tanker loads of LNG annually and provide up to 7 million standard cubic feet per day of boil-off gas to the refinery. During periods when BOG generation is insufficient to meet the refinery's needs, a portion of the LNG would be vaporized and delivered to the refinery along with the BOG.

And "because this project proposes no change in vessel operations … no additional adverse effects from vessel operations are expected," NMFS said.

Since the Kenai LNG plant is not currently generating emissions, this project, NMFS said, "would result in an increase in carbon dioxide equivalents emissions … due to LNG import and venting emissions from LNG ship unloading events. A CO2e is the number of metric tons of CO2 emissions with the same global warming potential as one metric ton of another greenhouse gas."

This project, which "routes BOG gas to the Kenai refinery, would result in lower emissions than venting and flaring the gas during previous LNG export operations. Venting and flaring emissions from the Kenai LNG Plant during export mode resulted in more than 1 million tons of CO2e/year, compared with CO2e from the proposed project, which is estimated at approximately 52,500 tons/year. Any effects to listed species or critical habitat attributable to these emissions would be insignificant," NMFS said.

—KAY CASHMAN

Contact Kay Cashman at publisher@petroleumnews.com

COURTESY WHITE FAMILY

continued from page 1

JIM WHITE

With no houses available in the boomtown, White and his family set up residence at the Caribou Hotel, which happened to be hosting a geophysical crew doing seismic work in the Copper River basin. White took an interest in the work and learned of various prospective structures across the basin.

White chose a spot, filed for a federal lease, and spudded the Alicia No. 1 well in 1976, using a small water well rig.

He vowed to drill until he either hit gas or ran out of money, reaching a depth of 1,600 feet before plugging and abandoning the well in 1982.

White was a fierce proponent and defender of private property rights, and it was in relation to the Alicia No. 1 well that White filed the first of his many lawsuits which have contributed richly to oil and gas case law in Alaska.

The initial lease term was for a period of two years, and when White requested an extension it was denied.

White reasoned that he had paid for a two-year lease, but the Feds restricted him to winter drilling only, so in effect, he had enjoyed only two six-month drilling periods, and as such he was entitled to two more of the same.

He lost the case in federal court, but that decision was reversed on appeal and a two-year extension was granted.

The family returned to Kenai when pipeline work wound down, and White worked on various jobs in Kenai and in Prudhoe Bay.

In 1985, White re-entered a long-time abandoned gas well near the town of Ninilchik on the southern Kenai Peninsula, his son James said. The well and field, known as the Susan Dionne, became a major gas producer on the Kenai Peninsula. It is still producing today.

"That was kind of his thing, going in and reentering wells that had been plugged and abandoned by the majors," his son said. "They were looking for oil, and weren't interested in gas or little puddles, as they called them."

In 1986 White re-entered a gas well that had been previously abandoned near Kenai, Alaska.

White signed a top lease on land holding the Cannery Loop No. 2 well with the homesteader owner, his son said.

"Unocal drilled the well and Pacific Gas and Electric paid for it, and then they plugged and abandoned it, but they were holding on to it because it was part of the unit," his son said. "Dad told the home-

see **JIM WHITE** *page 9*

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JIM WHITE

steader, 'If you give me that top lease, if I get this lease back, I'll re-enter it.'"

White got the lease and re-entered the well, and he also acquired 4,700 nearby acres that Cook Inlet Region Inc. had sold to Amoco.

White spent 35 years working on the well — known as the Mike Pelch 1 well — to bring it onto production.

The Pelch well, along with the Katalla KS-01 and Burglin 33-1 wells are currently the focus of an administrative appeal to the Alaska Superior Court against the Alaska Oil and Gas Conservation Commission over a retroactive bonding requirement imposed by the commission on Alaska Crude Corp., as operator of record.

That action likely will continue.

"My goal is to carry on and finish what he got started up there," White's son James said.

White was born in Rosebud, Texas, on Jan. 15, 1931.

"My family, my relatives all were ranchers and farmers and a lot of them had oil and gas on their properties and of course the economy of Texas, if you had a job you would be working for an oil company way back when," White said in a 2019 interview.

"I can remember going to Kilgore, Texas, when I was probably 8, somewhere in that range; that would be like 1939," he said. "You could step off of one drill floor to another drill floor."

"Back in those days, if you had a city lot you could drill on it, so those guys that had city lots, they'd drill on 'em," White said. "Literally you could walk a block and never touch the ground, just walking on different drilling rig floors."

Of course, they've changed the rules since then, he said.

White said that mineral rights don't mean a thing if one cannot get the hydrocarbons out of the ground.

"Oil and gas can't convert to your ownership until you get it to the surface," he said. "The damn stuff moves below ground; it does migrate."

In Texas, oil is said to be captured, he said.

"The Texas rule was back in those days that if you owned a piece of property if you wanted to get any production from it you had to drill it," White said. "You had a city lot, you could put a well down on it and whatever that well would produce, you got to keep it and sell it."

During that era, Texas produced so much oil that the price of crude went to 10 cents a barrel, he said.

"Texas had no laws governing production … the old governor at the time decided to get some laws to regulate this thing because the courts were plugged with lawsuits of all these various landowners suing each other wanting to get whatever they figured their fair share was," he said. "The governor goes out of his door to a couple of doors down in the hall there in the capital building and goes into the Railroad Commission; he figures those guys didn't have anything to do, and they made them the AOGCC for the state of Texas."

They did pass rules, and things changed for the better for the pumpers, he said. "One of the first things they figured was producing too much oil was waste; producing too much oil got its price down so much it's not worth the money to pump it," White said. "The rule came out that the Texas Railroad Commission could limit the amount of oil that could be produced in Texas."

But regulation can work against the interests of the royalty owner if it prevents the owner from capturing the oil or gas, White said, adding that the new rules in Alaska requiring bonding of $400,000 per oil or gas well of any sort serve as a de facto confiscation of mineral rights.

"When Texas became a state, if you wanted to homestead, you just went out and squatted on a piece of ground, applied for it, and you got 160 acres," White said.

In Alaska, everybody that homesteaded prior to statehood got the surface and all the oil and gas below the land, if it existed," he said. "That was the rule and that's what they got."

"But in Texas, you can operate 10 wells for $25,000 cash," he said. "Of course, you can't do that up there; they want you to put up $400,000 a well."

"It's obvious, I don't know any homesteader that's got $400,000 laying around most of the month for him to drill a 100-foot well in his back yard," he said.

"The story needs to be told," White said. "It's still America."

—STEVE SUTHERLIN

Contact Steve Sutherlin at ssutherlin@petroleumnews.com

Petroleum news — Oil Patch Bits

Security Aviation acquires a second Learjet 45

Security Aviation, an Anchorage based Part 135 on-demand charter operator, announced Jan. 5 the addition of a second Bombardier Learjet 45 to its existing fleet, the only such aircraft available for charter in Alaska.

The new Learjet is wide area augmentation systems capable, meaning it uses an extremely accurate navigation system developed for civil aviation. It is also advanced airborne censor equipped and equipped with BR modification and gross weight increase kit to allow for better performance, fuel efficiency and range. The Learjet offers amenities like executive leather seating, a refreshment station and an enclosed lavatory.

The jet's primary use will be for expedited passenger and light cargo transportation throughout Alaska, Canada and the Lower 48, as well as emergency response services. The Learjet is available for charter 24/7, and seats up to eight passengers. The aircraft cruises at 535 mph with a range in excess of 2,000 statute miles.

Security Aviation has more than 35 years of operating experience in Alaska and is currently the only on-demand charter operator in the state to offer mid-size charter jet service. For more information visit https://securityaviation.biz.

COURTESY SECURITY AVIATION

Companies involved in Alaska's oil and gas industry

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- Oil Search
- PND Engineers, Inc.
- PRA (Petrotechnical Resources of Alaska)
- Price Gregory International

Q-Z

- Raven Alaska – Jon Adler
- Resource Development Council
- SeaTac Marine Services
- Security Aviation
- Shoreside Petroleum
- Soloy Helicopters
- Sourdough Express
- Strategic Action Associates
- Tanks-A-Lot
- Weston Solutions
- Wolfpack Land Co.

All of the companies listed above advertise on a regular basis with Petroleum News

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PIKKA PUSH

Repsol E&P USA. Oil Search has an agreement with Repsol that ensures it remains operator for the companies' shared acreage on the North Slope, even though its ownership percentage is smaller.

Fourth quarter report

There was nothing new about its Alaska operations in Oil Search's fourth quarter report released Jan. 27.

The company indicated it expects to commit within weeks to start FEED work on the Pikka project, which is Oil Search's only major investment planned for this year as its proposed LNG expansion in Papua New Guinea remains stalled.

Wulff was quoted as saying the company is "ready to enter" FEED "in early 2021" at Pikka.

"Strong alignment has been achieved with our partner, Repsol, for the phased development program which is now targeting first oil in 2025 at 80,000 barrels of oil per day from a single well pad. Initial development costs have more than halved and the breakeven cost of supply under US$40 a barrel makes the project resilient to lower oil prices," he said.

"Our resource position also continued to improve, with independently certified Alaska 2C contingent resources at 967.9 mmbbl (gross), representing a 94% increase since asset acquisition. Most of this upgrade was due to our discoveries earlier in 2020 at Mitquq and Stirrup, which reinforced the potential for an additional stand-alone development in our core Alaska development area," Wulff said.

Elsewhere in the report the company said, "results to date support the potential development of Mitquq as a satellite to Pikka and Stirrup as a potential stand-alone development. Further appraisal drilling of the Mitquq and Stirrup trends will be required to confirm the full size and extent of these discoveries."

Oil Search previously said a sell-down process will start this quarter to bring in a third partner, effectively spreading risk and reducing each participant's capital outlay — a common practice for North Slope developments.

"In Alaska, we hope to see a sell-down in equity, although market conditions remain challenging," Bernstein analyst Neil Beveridge was reported as saying after Oil Search's fourth quarter report was released.

Company-wide Oil Search showed a 37% increase in revenue from third quarter to US$259.5 million largely due to higher LNG prices.

Year-end revenue dropped 32% to US$1.074 billion due to particularly weak oil and LNG prices earlier in 2020.

Regarding spending in Alaska, Oil Search posted fourth quarter US$61.4 million year to date and US$145.2 million exploration and evaluation expenditure.

Pikka unit development expenditure year to date was US$99.6 million.

"We expect that 2021 will continue to be another challenging year and the company is absolutely focused on maintaining the operational discipline that resulted in excellent results in 2020 despite the difficult conditions," Wulff said. ●

Contact Kay Cashman at publisher@petroleumnews.com

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KXL FUTURE

provinces "want to go to war" with the U.S. on trade issues and portrayed Biden as a "bully" for overriding a project that has been approved on five occasions by the U.S. State Department as a project that posed no material threat to greenhouse gas emissions.

Trudeau was apparently unable to even argue that the Alberta oil sands sector, which was going to supply 80% of KXL's volumes of 830,000 barrels per day, has made sizeable strides in reducing its GHG emissions by 30% per barrel over the past decade, that TC Energy was going to achieve net-zero emissions on KXL operations by 2025, that TC and the Alberta government were working to create an equity interest for U.S. and Canadian First Nations, that the pipe for the pipeline would be manufactured in the U.S. and that killing KXL would raise U.S. reliance on OPEC crude.

JASON KENNEY

Even if KXL is in fact doomed, Canadian oil producers retain a tight grip on their 50% share of U.S. oil imports, with the U.S. Energy Department estimating shipments at 3.8 million bpd and analysts forecasting that those volumes could reach 4.2 million-4.4 million bpd over the next few years.

Pipeline expansions currently underway in the U.S. are expected to raise capacity in the Lower 48 by 950,000 bpd before 2025, including an expansion of the existing Keystone line from 590,000 bpd to 760,000 bpd.

Excess export capacity?

Thomas Liles, Rystad Energy's vice president for North American shale, said in a note that "the reality is that Western Canada — for the first time in recent memory — may soon reach a juncture at which it has excess oil export capacity."

Wood Mackenzie research director Mark Oberstoetter said in a note that assuming other pipelines in the works "go ahead on schedule — we will be over-piped. If you add them all up, you can make the argument KXL was not needed."

Having confined itself to voicing disappointment at the loss of jobs for KXL, the Trudeau government left its ambassador to the U.S., Kirsten Hillman, to explain why Canada has no choice but to turn its attention to other pressing bilateral issues.

She said it was apparent in the Biden-Trudeau chinwag that there was no hope of Biden walking back his decision.

"I think we now need to focus on moving forward with (the Biden) administration and there are so many ways in which we are going to be aligned with them to our mutual interest. I'm eager to get going on that," Hillman said.

She expressed confidence that Canada remains the "best partner" for helping Americans meet their energy needs and transitioning to a clean economy.

A joint panel is being formed to explore those possibilities, with Canada clinging to hope that its fast-emerging expertise on reducing greenhouse gas emissions carbon capture and storage, and using its abundant gas resources to develop hydrogen will find a role in developing those initiatives.

Many observers are certain that the days of mega-pipelines to the U.S. are over, but they are not ruling out increased crude-by-rail shipments (which are legal provided they do not involve laying new rail lines) and tanker shipments to Gulf Coast refineries when the Trans Mountain pipeline expansion starts shipping crude out of the Port of Vancouver.

Moving into the spotlight is the proposed Alaska-to-Alberta rail project which could carry up to 1 million bpd of crude bitumen for tanker shipment from Alaska to Asia and the chances of reviving TC Energy's Energy East (strongly opposed by Quebec) to deliver 1.1 million bpd of crude bitumen to Atlantic Canada for refining and export.

Thus, the debate goes on. ●

Contact Gary Park through publisher@petroleumnews.com

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RECOVERY HOPES

dramatic decline from a capital spending peak of C$81 billion in 2014, thought TC Energy has yet to disclose how much spending on KXL in Canada will be shelved.

For CAPP the overall spending forecast represented a "stabilizing of industry investment and the beginning of a longer-term economic recovery."

But Tim McMillan, chief executive officer of the petroleum sector's chief lobby organization, wisely injected a cautionary note.

"There's a lot of unknowns," he said. "There always is."

Drilling expectations

CAPP expects 3,300 new wells will be drilled this year, up from 3,000 in 2020, but far short of the 4,250 wells completed in 2019, which raises a question about how much confidence there is in the Canadian industry over the chances of growing demand and commodity prices.

McMillan noted that the Paris-based International Energy Agency has targeted a 5% growth in global oil demand through the current decade and a 15% gain in natural gas consumption.

"I think there's great opportunity for growth globally," McMillan said. "The question then becomes: 'Is it going to happen in countries like Canada, or will it happen in the Middle East, offshore Brazil or Africa?'"

Like many in the industry, McMillan says there is a case for Canada to seek investors by building on stronger environmental and safety regulations.

Analysts' views

Phil Skolnick, managing director of equity research for Eight Capital, told the Financial Post that commodity prices have been making gains against a complicated background, notably how far the Biden administration will go in ushering in new regulations and incentives to boost renewable energy and electric-powered vehicles. next decade as they try leveraging technology to lower their costs of exploration, production and processing while reducing their greenhouse gas emissions.

"This shift has the potential to improve the free cash flow generation of the assets, which fits with the new-found focus on returns and shareholder yields among North American E&Ps as they emerge from last year's down-cycle."

Planned investment in west

The planned investment in Canada is primarily concentrated on Canada's three western provinces.

Conventional oil and gas budgets have been set at C$20 billion, up C$2.8 billion from 2020, while oil sands spending is expected to grow by C$600 million to C$7.3 billion.

In addition, he said political turmoil in Venezuela has dealt a setback to that country's heavy crude output, which is Canada's key rival in seeking market share.

Skolnick also noted that COVID-19 has raised questions about oil demand.

"We are finding that a lot of things we thought were essential travel, aren't essential anymore," he said. "We're find out that a lot can be done on Zoom."

Bob Brackett, an analyst at Sanford C. Bernstein, said oil sands operators are likely to remain cautious over the

One year ago, CAPP's initial forecast was set at C$37 billion, which collapsed during the oil price war between Russia and Saudi Arabia and COVID-19 which wiped out more than C$12 billion of planned spending.

In Alberta, the initial 2021 upstream investment forecast was expected to rise 18% to C$11.8 billion, bolstered by the Alberta government's municipal tax relief for new wells and its corporate income tax reduction plan, along with a commitment to slash red tape.

In British Columbia — unaffected by KXL — upstream activity for 2021 is forecast to rise 29% to C$3.9 billion, driven mostly by the province's support for LNG development.

The B.C. government also gave a lift to industry confidence by announcing it would refund a portion of the provincial carbon tax above C$30 per metric ton.

Saskatchewan is forecast to grow by C$100 million to C$2.8 billion, tied to the province's vision of a 25% increase in oil output to 600,000 barrels per day, coupled with enhanced investment incentives and a rebate on electricity bills.

All three provinces have also reached equivalency agreements with the Canadian government on methane emission reduction regulations, establishing a regulatory framework that opens the door to a "solutions-focused approach while enabling industry to advance technological innovation."

In Newfoundland and Labrador offshore investment is expected to remain flat at C$1.5 billion but is encouraged by the creation of an industry task force that will recommend a plan for the distribution of C$320 million in federal funding for the offshore.

—GARY PARK

Contact Gary Park through publisher@petroleumnews.com

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OIL PRICES

particles than with previous variants.

Glitches in the rollout of COVID-19 vaccines and supply concerns have added further angst to oil markets.

On the other hand, Goldman Sachs analysts have concluded that actions taken by the Biden administration including restrictions on North American hydrocarbon leasing, drilling and pipelines are bullish for oil prices.

"As we have argued, policies to support energy demand but restrict hydrocarbon production (or increase costs of drilling and financing) will prove inflationary in coming years given the still negligible share of transportation demand coming from EVs (and renewables)," Goldman analysts said in a note.

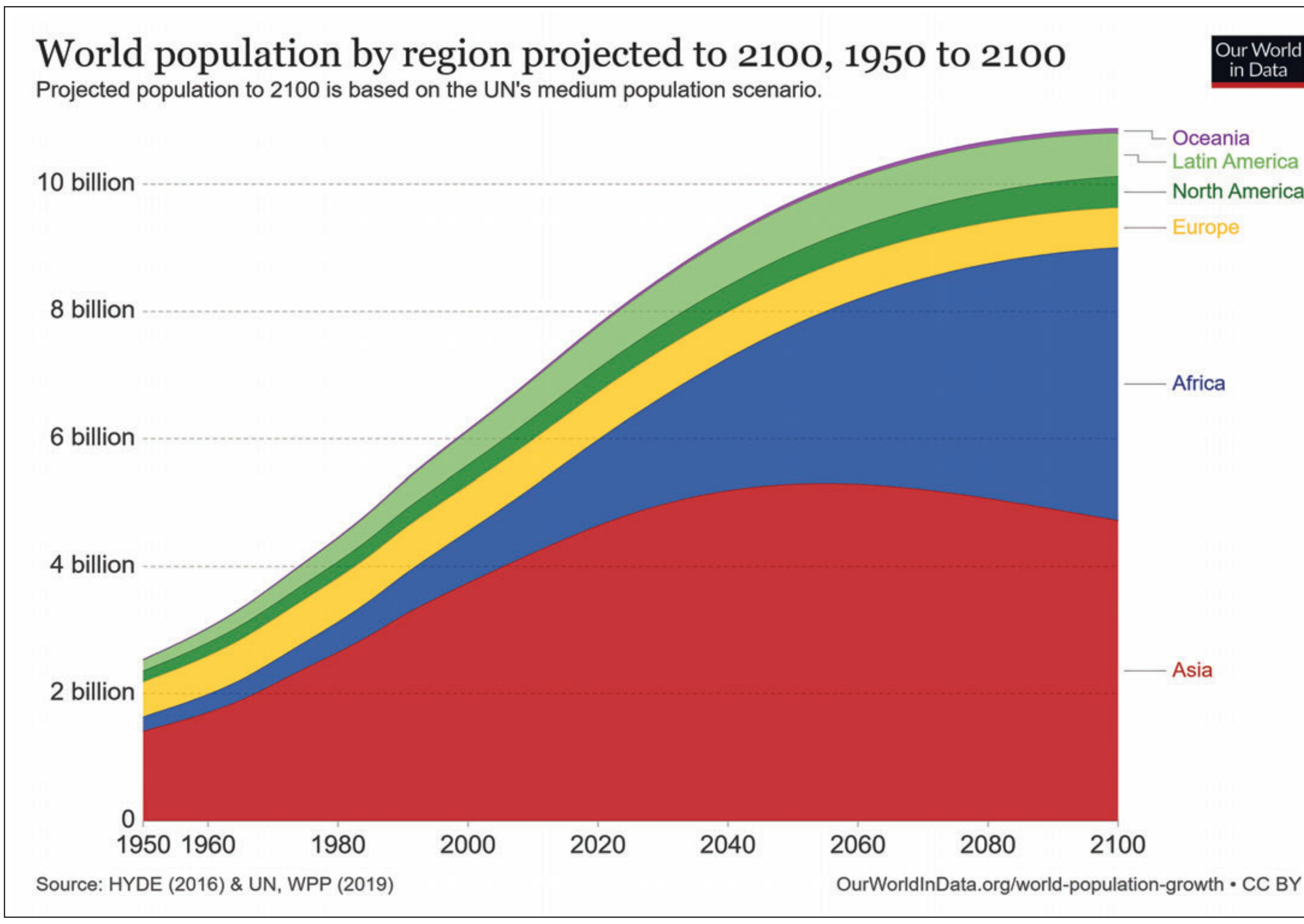
Further, Goldman said, initial comments suggest little urgency in lifting sanctions with Iran, adding, "Combined with a push for greater fiscal spending — and hence higher energy demand — these initial actions reinforce our constructive view on oil and gas prices."

Goldman was also positive about additional funding and resources to aid in the vaccine rollout.

"A faster vaccination roll-out would in turn accelerate the rebound in jet fuel consumption, which still accounts for more than half of the remaining lost oil demand," it said.

Oil prices were further buoyed Jan. 27 by a U.S. Energy Information Administration report that U.S. commercial crude oil inventories (excluding those in the Strategic Petroleum Reserve) decreased for the week ending Jan. 22 by 9.9 million barrels from the previous week, which saw a build of 4.4 million barrels.

Also bullish were reports by MarketWatch of possible supply disruptions from Iraq and Libya. Iraq said it intends to reduce production to meet its commitments under the OPEC+ agreement, while Libya's exports may be compromised by its Petroleum Facilities Guard, over claims of unpaid salaries.



Multilateral approach supports needed investment

The Organization of the Petroleum Exporting Countries World Oil Outlook 2020 says $12.6 trillion will be required between now and 2045 in the upstream, midstream and downstream oil sectors.

OPEC Secretary General Mohammad Sanusi Barkindo, in remarks delivered Jan. 27 by teleconference to the S&P Global Platts Americas Petroleum and Energy Conference, said global multilateralism is needed to help drive the global energy transition.

Stability will be essential to helping bring on board the huge investments required in years ahead, he said.

"To place this in some further context, our current assessments show that upstream capital expenditure could have fallen by more than 30% in 2020, beyond the 23% losses experienced in both 2015 and 2016," Barkindo said. "If this is not rectified it could leave long-term scars, not only for producers, but consumers too."

Barkindo said the multilateral approach of OPEC and its allied producing countries has shown what can be achieved, but the future will need a broader coalition to tackle energy challenges.

Looking longer term to 2045, the global economy is expected to more than double in size, with world population projected to grow by over 1.7 billion people, he said.

"There are some who believe the oil and gas industries should not be part of the energy future, that they should be consigned to the past, and that the future is one that can be dominated by renewables and electric vehicles," Barkindo said. "It is important to state clearly that the science does not tell us this, and the statistics related to the blight of energy poverty do not tell us this either."

The science and statistics indicate a need to reduce emissions and use energy more efficiently, he said.

"Renewables are coming of age, with wind and solar expanding quickly, but — even by 2045 — in our WOO they are only estimated to make up just over 20% of the global energy mix," Barkindo said. "Oil and gas combined are forecast to still supply over 50% of the world's energy needs by 2045, with oil at around 27% and gas at 25%." ●

Contact Steve Sutherlin at ssutherlin@petroleumnews.com

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PEREGRINE DRILLING

drilling program in the National Petroleum Reserve-Alaska on the afternoon of Jan. 21 when he emailed Order 3395 to the project operator. The order had been signed the day before.

De la Vega's unanticipated action transferred the authority of local Interior bureaus and offices to issue, revise, or amend any and all permits, authorizations or plans of operations for "purposes of reviewing the questions of fact, law, and policy they raise" for up to 60 days.

The order delayed issuance of the last of the company's permits for two NPR-A wells, forcing 88 Energy to shut down exploration operations until late March, which was too close to the end of the North Slope winter drilling season to restart operations in 2021.

De la Vega's order transferred the power to issue permits to top agency people in the Lower 48 —all Biden political appointees.

National Wildlife Federation official

Final approval for 88 Energy's Peregrine wells, Merlin 1 and Harrier 1, rests with appointee Laura Daniel Davis, principal deputy assistant secretary of Land and Minerals Management, who most recently was the chief of policy and advocacy for the National Wildlife Federation. Prior to that Davis served as chief of staff to Interior Secretaries Sally Jewell and Ken Salazar in the Obama administration.

An operations update that same day from 88 Energy said the Merlin 1 drilling permit "is anticipated to be complete by Thursday 28th January."

Before the surprise order from de la Vega, 88 Energy had said the Alaska office of the Bureau of Land Management, which was reviewing the drilling permit for the first well, Merlin 1, "indicated that it is now very close to being complete with only minor outstanding items," and was "anticipated to be complete by Jan. 28."

Positive indicators next

Shortly thereafter more promising news came from Interior, starting with 88 Energy receiving "confirmation" from the Alaska BLM office that Davis intended to sign the permit.

In the meantime, Alaska's congressional delegation was meeting with White House staff, explaining among other things that a 60-day delay during the short winter drilling season effectively delayed drilling for one year on the North Slope.

Then on Jan. 27 a group of Native leaders issued a press release saying de la Vega's directive and other orders from President Joe Biden resulted in "considerable economic impacts on the indigenous people of the North Slope of Alaska."

Also, on Jan. 27 a fact sheet from Interior said Biden's latest executive order relating to oil and gas leasing and activities on federal lands allowed permitting and permitted operations to continue as normal on existing leases.

It likely helped that 88 Energy already had all its other federal approvals for Peregrine Project exploration, including the NPR-A right-of-way permit from BLM.

On Jan. 27 the company's managing director David Wall told Petroleum News: "We have everything except the permit to drill. The snow road (95 miles long) is 30 percent or more complete already."

An operations update that same day from 88 Energy said the Merlin 1 drilling permit "is anticipated to be complete by Thursday 28th January," the day Petroleum News goes to press.

The cost of the exploration program to date (Jan. 27) is approximately $3 million per Corri Feige, commissioner of the Alaska Department of Natural Resources, including the cost of mobilization for All American Rig 111.

Feige also said that permitting decisions were often deferred to Washington, D.C., top agency officials during the Obama-Biden administration, slowing the process.

88 Energy's wells will target the prolific Nanushuk formation. Merlin 1 is considered a direct analogy to ConocoPhillips Willow oil discovery, while ConocoPhillips' Harpoon prospect is interpreted to lie on the same sequence boundaries as Harrier 1. They are two of just three total exploration wells being drilled on the North Slope this winter.

—KAY CASHMAN

Contact Kay Cashman at publisher@petroleumnews.com

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GAS CONTRACT

records of service to other utilities, Dan Britton, IGU general manager, told the board.

Gas pricing

Gas pricing in the first year of the Hilcorp contract begins at $7.60 per mcf, a price slightly below that of IGU's current Hilcorp contract, but a little above Hilcorp's pricing levels for utilities in the Cook Inlet region. The price increases to $7.91 in year five of the contract.

Britton told the board that the contract's pricing levels reflect IGU's relatively small size compared with other utilities, and the fact that Hilcorp is accepting a seasonal swing in IGU's gas demand. Other Hilcorp contracts include peaking services involving additional fees, Britton said. Hilcorp has agreed to start the new gas pricing on Jan. 1, 2021, if the IGU board approves the new contract.

IGU obtains its gas through its Titan LNG plant on Cook Inlet near Point MacKenzie.

There was a lengthy board discussion regarding the contract, the suitability of its terms and the appropriateness of the gas pricing. The discussion included a defeated motion to hold a separate work session to discuss the contract in detail — apparently the terms of the contract had previously been discussed in executive session. Ultimately a motion to approve the contract was passed on a five to two vote.

Gas supply chain

IGU obtains its gas through its Titan LNG plant on Cook Inlet near Point MacKenzie. Hilcorp supplies gas to the plant through Enstar Natural Gas Co.'s gas pipeline network. The LNG is transported to Fairbanks by road trailer for storage in IGU's LNG storage tanks. At the end of last year the utility completed a new 5.25 million gallon tank in central Fairbanks, and the utility is nearing completion of the installation of storage tanks at North Pole.

The Hilcorp contract involves the availability of gas from multiple gas fields through five separate delivery points into Enstar's system, for shipment to the Titan plant, Britton said. Britton also commented that part of the process for establishing continuing gas supplies involved investigating possible sources of LNG, other than the Titan plant.

Expanding gas usage

A key IGU objective is to expand the utility's customer base in the Fairbanks region, in part to help address severe winter air pollution in the region — the intent is to persuade people to convert to the use of natural gas rather than fuel oil or wood stoves for heating buildings.

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The utility has been planning to expand the Titan plant, to support an increasing number of customers. However, a decision on this expansion has been placed on hold, because of uncertainty over future gas demand as a consequence of the impact of the COVID-19 pandemic on the price of fuel oil. However, IGU does plan to increase its customer base through its ability to store more LNG, using its expanded Fairbanks storage tank capacity.

And, so, the utility needs a gas feedstock supply arrangement that, on the one hand, ensures reliable supplies for customers while, on the other hand, enables some level of supply flexibility to meet uncertain future demand expansion.

Price predictability

Britton emphasized to the board the ability of the new contract to meet these IGU needs by providing predictable pricing well into the future, coupled with flexible supply levels.

"We know what the cost of gas will be for the next 11 years," Britton said. "The need for this contract fits well within our mission. We have in excess of 1,400 customers today and we have a commitment to provide them with a secure firm gas supply contract."

By comparison, the cost of heating oil is highly unpredictable, even just weeks into the future, Britton commented.

Supply flexibility

In terms of supply flexibility, the new contract only requires Hilcorp to commit to a minimum purchase of 833 million cubic feet per year of gas for the initial five-year term of the contract. That volume corresponds to the level of IGU's current gas sales. The maximum committed by Hilcorp for potential supply amounts to 5 million cubic feet per day, or 1,825 million cubic feet for the year, the maximum production capacity of the existing Titan plant. In addition, should IGU decide to move ahead with the Titan expansion, the utility can give Hilcorp 18 months' notice to increase the daily supply maximum to up to 15 million cubic feet.

The resulting level of certainty over the availability of expanded gas supplies will be become particularly important if IGU seeks bonding for the financing of the Titan expansion, Britton pointed out.

On the other hand, for a fee of $145,775 per year, IGU can opt to reduce the minimum contracted supply volumes by up to 30%, should some other cheaper gas supply become available, Britton said. And, as with other utility gas supply contracts in the Cook Inlet region, IGU would receive a pro rata share of Hilcorp gas, should there be some unanticipated constraint on gas supplies.

"I'm pleased with the contract and the flexibility it provides us, and the opportunity to continue to look for additional supplies, and the potential opportunities for savings in the future," Britton said. "It provides the utility with a substantial security of supply … and predictability for the next 11 years."

—ALAN BAILEY

Contact Alan Bailey
at abailey@petroleumnews.com