Petroleum news

page 4 August ANS output up 9.2% from July; Inlet oil up 8.4%, gas down

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Mustang Pad remediation OK'd; virtual data room up for buyers

ALAN WEITZNER

On Sept. 20, the Alaska Industrial Development and Export Authority received notification from Alaska's Division of Oil and Gas that repair work at the Mustang Pad in the Southern Miluveach unit could proceed, per an Aug. 30 request from unit operator Mustang Holding LLC to amend the SMU plan of operations.

Mustang Holding, the entity established to hold the SMU assets, was named operator in December 2020 when the division approved a request from the working interest owners to appoint the holding company operator after Brooks Range Petroleum Corp. resigned as operator due to BRPC's default on various financing agreements between it and AIDEA.

About 16 miles east of Nuiqsut, the Mustang Pad sits on state lease ADL 390680, one of five leases in the SMU, which

see MUSTANG PAD page 11

Biden names new commissioners to US Arctic Research Commission

President Joe Biden has appointed commissioners to the US Arctic Research Commission and designated a new chair.

A Sept. 24 statement from the White House said the U.S. depends on the USARC commissioners for "insightful guidance and rational, unbiased assessments of actions to maintain our position as an Arctic nation guided by science," and said Biden's "appointments reflect his commitment to ensure that USARC's focus on scientific research goals and objectives for the Arctic are derived from a broad range of expertise and perspectives."

Two-thirds of the appointed commissioners are residents of Alaska, one-third are Indigenous, half are women, the White House said.

Legislation establishing the commission specifies four commissioners will have academic or research experience, two will have industry perspectives and one will be an Indigenous representative.

David Kennedy, appointed by President Trump in

see NEW COMMISSIONERS page 11

8 Alberta Indigenous communities partner with TC Energy in pipeline

Suncor Energy has teamed up with eight Indigenous communities in Alberta in a C$40 million partnership to acquire a TC Energy stake in a pipeline that is crucial to the movement of oil sands crude.

The deal is another sign of Canada's First Nations playing an equity role in Canada's oil industry as they shift from confrontation to meaningful consultation with resource companies operating within their territorial lands.

However, many Indigenous groups continue to oppose such partnerships and deals.

The transaction will give Suncor and a coalition of three First Nations and five Metis communities, to be known as Astisiy, a 15% stake in the Northern Courier Pipeline that carries an asset value of about C$1.3 billion.

The remaining 85% of the pipeline is in the hands of the Alberta government's investment manager known as AIMCo.

Northern Courier consists of two 45-mile pipelines that carry bitumen along with diesel or conventional crude from Suncor's Fort Hills operation to a storage, blending and cooling facility

see PIPELINE PARTNERS page 10

FINANCE & ECONOMY

Brent price hits $80

Oil for Asian power generation may drive ANS prices higher this winter

By STEVE SUTHERLIN

Petroleum News

Alaska North Slope crude rose 13 cents to close at $78.50 per barrel Sept. 29, recouping a chunk of its 66-cent loss Sept. 28 which ended a five-day positive run for the index. Brent and West Texas Intermediate were on a similar trajectory for six days, but both continued to lose ground Sept. 29 — WTI down 46 cents to close at $74.83, and Brent down 45 cents to close at $78.64.

On Sept. 20, ANS closed at $73.86 before staging a run to $79.03 Sept. 27 for a gain of $5.17 or 7% from trough to peak.

Prices shot higher on strong inventory draws and a rapid recovery of demand.

On the supply side, a portion of oil production in the Gulf of Mexico remained shut-in after Hurricane Ida, and a few of the producers of the Organization of the Petroleum Exporting Countries and affiliated producers struggled to fulfill production quotas.

On Sept. 28, before heading lower on a strengthening U.S. Dollar, Brent traded above $80 for the first time since September 2018.

A surprise gain in U.S. crude stockpiles helped to cool prices the next day.

For the week ending Sept. 24, U.S. commercial

see OIL PRICES page 8

EXPLORATION & PRODUCTION

BlueCrest files 8th POD

Progressing offshore gas plans; oil drilling on hold until market improves

By KAY CASHMAN

Petroleum News

JOHN MARTINECK

BENJAMIN JOHNSON

On Sept. 29, BlueCrest Alaska filed the 8th plan of development for the Cosmopolitan unit with Alaska's Division of Oil and Gas. Operator of the Hansen field in the Cosmopolitan unit, the company said it will continue to suspend its drilling program "as long as the COVID pandemic, and the current market environment persist." The Cook Inlet unit, which is three miles offshore the southern Kenai Peninsula and five miles north of Anchor Point, is being developed from onshore.

The Hansen field produces primarily oil, but BlueCrest said it will continue to advance engineering and permitting for its offshore gas development in the 8th POD period, which runs from Jan. 1, 2022, through Dec. 31, 2022.

"There is a tremendous amount of uncertainty around investors/lenders extending funding to the oil and gas industry in Alaska considering the

see COSMO POD page 10

PIPELINES & DOWNSTREAM

Enbridge expands reach

Buys crude terminal company in Texas to provide stronger Gulf Coast position

By GARY PARK

For Petroleum News

Calgary-based Enbridge, North America's leading crude pipeline company, is enlarging its footprint by acquiring the continent's largest export terminal.

In a US$3 billion deal due to close in the fourth quarter it is buying the terminal and logistics company Moda Midstream Operating from private equity firm EnCap Flatrock Midstream to lock up the Ingleside Energy Center at Corpus Christi, Texas.

The facility has storage of 15.6 million barrels and is capable of shipping 1.5 million barrels per day of light crude from the U.S. Gulf Coast by accessing very large crude carriers.

Enbridge has been hunting for a stronger position on the Gulf Coast to meet a growing global demand for lower-cost, sustainable energy supplies.

The Texas transaction also adds to Enbridge's purchase of the 300,000 bpd Viola pipeline, a 20% stake in the 670,000 bpd Cactus 2 pipeline and a storage terminal for shipping crude from the Permian Basin in West Texas to export markets.

The proximity to Permian reserves, along with "cost effective and efficient export infrastructure … will be critical to capitalizing on North America's energy advantage," said company Chief

see ENBRIDGE REACH page 10

● FINANCE & ECONOMY

New Petro Star RIK state oil contract

New one-year contract will enable continued sale next year of state royalty oil for use in refineries in North Pole and Valdez

By ALAN BAILEY
For Petroleum News

On Sept. 23 the Alaska Department of Natural Resources issued a final best interest finding, saying that the state has successfully negotiated a contract for the sale of royalty in kind oil to Petro Star Inc., operator of oil refineries in North Pole and Valdez. Because of concerns about ensuring continuity of oil supplies for the refineries, the contract term is just one year, a term length that avoids the need for approval of the contract by the state Legislature during the upcoming legislative session.

DNR says that it anticipates negotiating a longer five-year contract later this year, as a follow on to the immediate one-year contract. In 2017 the state Legislature and Gov. Bill Walker approved the sale of RIK oil to Petro Star under a four-year contract that went into effect Jan. 1, 2018, and ends Dec. 31, 2021. The new one-year contract will run from Jan. 1, 2022, to Dec. 31, 2022.

The new contract involves the sale of 10,000 barrels of oil per day to Petro Star, a subsidiary of Arctic Slope Regional Corp., the Native regional corporation for the North Slope.

Oil in lieu of cash

The state obtains its royalty oil, known as royalty in kind, from oil producers in lieu of royalty payments made in cash, with the state subsequently raising revenue through the sale of the oil. The state sells its RIK oil to businesses such as Petro Star that are operating in the state. Currently the state has RIK sales contracts with Petro Star and Marathon Petroleum Supply and Trading Company LLC. Marathon operates an oil refinery at Nikiski on the Kenai Peninsula.

The state is entitled to royalties as a percentage of oil produced from state lands. The royalties may be collected in the form of oil (royalty in kind, or RIK), or as cash payments based on the royalty percentage of the wellhead value of oil produced (royalty in value, or RIV). The wellhead value of the oil is calculated from the U.S. West Coast spot price of North Slope crude, with adjustments, in particular to reflect the cost of shipping the oil from the North Slope to the West Coast.

Better value for the state

The DNR finding for the new Petro Star RIK contract says that, while in-state refineries have benefited from their ability to purchase RIK oil, the state has obtained more revenue over the years from the sale of RIK oil than it would have done from RIV payments. Essentially, because of differences between RIK and RIV pricing calculations, the RIK pricing, the price at which RIK oil is sold, tends to be higher. An obvious difference is the shorter transportation distances, and hence lower transportation costs, of oil shipped to Alaska refineries, versus to refineries on the West Coast — the price of the RIK oil in the new Petro Star contract uses a somewhat similar formula to the formula used to calculate the oil's wellhead value, but with an adjustment for in-state transportation rather than for transportation to the West Coast. ●

Contact Alan Bailey at abailey@petroleumnews.com

contents

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Alaska-Mackenzie Rig Report

The Alaska-Mackenzie Rig Report as of September 29, 2021.
Active drilling companies only listed.

TD = rigs equipped with top drive units WO = workover operations
CT = coiled tubing operation SCR = electric rig

This rig report was prepared by Marti Reeve

Alaska Rig Status

North Slope - Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
All American Oilfield LLC			
IDECO H-37	AAO 111	Deadhorse, Stacked in Cruz Yard	Available
Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Standby	Hilcorp Alaska LLC
Dreco 1000 UE	16 (SCR/TD)	Standby	
Dreco D2000 Uebd	19 (SCR/TD)	Standby	
AC Mobile	25	Alpine, MT7-06	ConocoPhillips
OIME 2000	141 (SCR/TD)	Standby	
	142 (SCR/TD)	Standby	
TSM 700	Arctic Fox #1	Standby	
ERD	26	Alpine, CD2-310	ConocoPhillips
Hilcorp Alaska LLC			
Rotary Drilling	Innovation	Milne Point, S Pad	Hilcorp Alaska LLC
Nabors Alaska Drilling			
AC Coil Hybrid	CDR-2 (CTD)	Milne Point, Cold Stacked	Available
AC Coil	CDR-3 (CTD)	Kuparuk	ConocoPhillips
Ideco 900	3 (SCR/TD)	Deadhorse, Stacked	Available
Dreco 1000 UE	7-ES (SCR-TD)	Kuparuk	ConocoPhillips
Mid-Continental U36A	3-S	Stacked	Available
Oilwell 700 E	4-ES (SCR)	Stacked	Available
Dreco 1000 UE	9-ES (SCR/TD)	Stacked	Available
Oilwell 2000 Hercules	14-E (SCR)	Deadhorse	Available
Oilwell 2000 Hercules	16-E (SCR/TD)	Stacked	Brooks Range Petroleum
Emsco Electro-hoist			
Oilwell 2000 Canrig 1050E	27-E (SCR-TD)	Stacked	Available
Oilwell 2000	33-E	Deadhorse	Available
Academy AC Electric CANRIG	99AC (AC-TD)	Stacked	Available
OIME 2000	245-E (SCR-ACTD)	12 Acre Pad, stacked	Available
Academy AC electric CANRIG	105AC (AC-TD)	Stacked	Available
Academy AC electric Heli-Rig	106AC (AC-TD)	Stacked	Available
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Deadhorse	Available
Superior 700 UE	2 (SCR/CTD/TD)	Deadhorse, stacked	Available
Ideco 900	3 (SCR/TD)	Deadhorse, stacked	Available
Rig Master 1500AC	4 (AC/TD)	Oliktok Point	ENI
Parker Drilling Arctic Operating LLC			
NOV ADS-10SD	272	Deadhorse, Stacked	Available
NOV ADS-10SD	273	Deadhorse, Stacked	Available

North Slope - Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Doyon Drilling			
Sky top Brewster NE-12	15 (SCR/TD)	Spy Island, S102-SE6	ENI
Nabors Alaska Drilling			
OIME 1000	19AC (AC-TD)	Oooguruk, Stacked	ENI

Cook Inlet Basin – Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
BlueCrest Alaska Operating LLC			
Land Rig	BlueCrest Rig #1	Stacked	BlueCrest Alaska Operating LLC
Glacier Oil & Gas	Rig 37	West McArthur River Unit Workover	Glacier Oil & Gas
Hilcorp Alaska LLC			
TSM-850	147	Stacked	Hilcorp Alaska LLC
TSM-850	169	Seaview	Hilcorp Alaska LLC

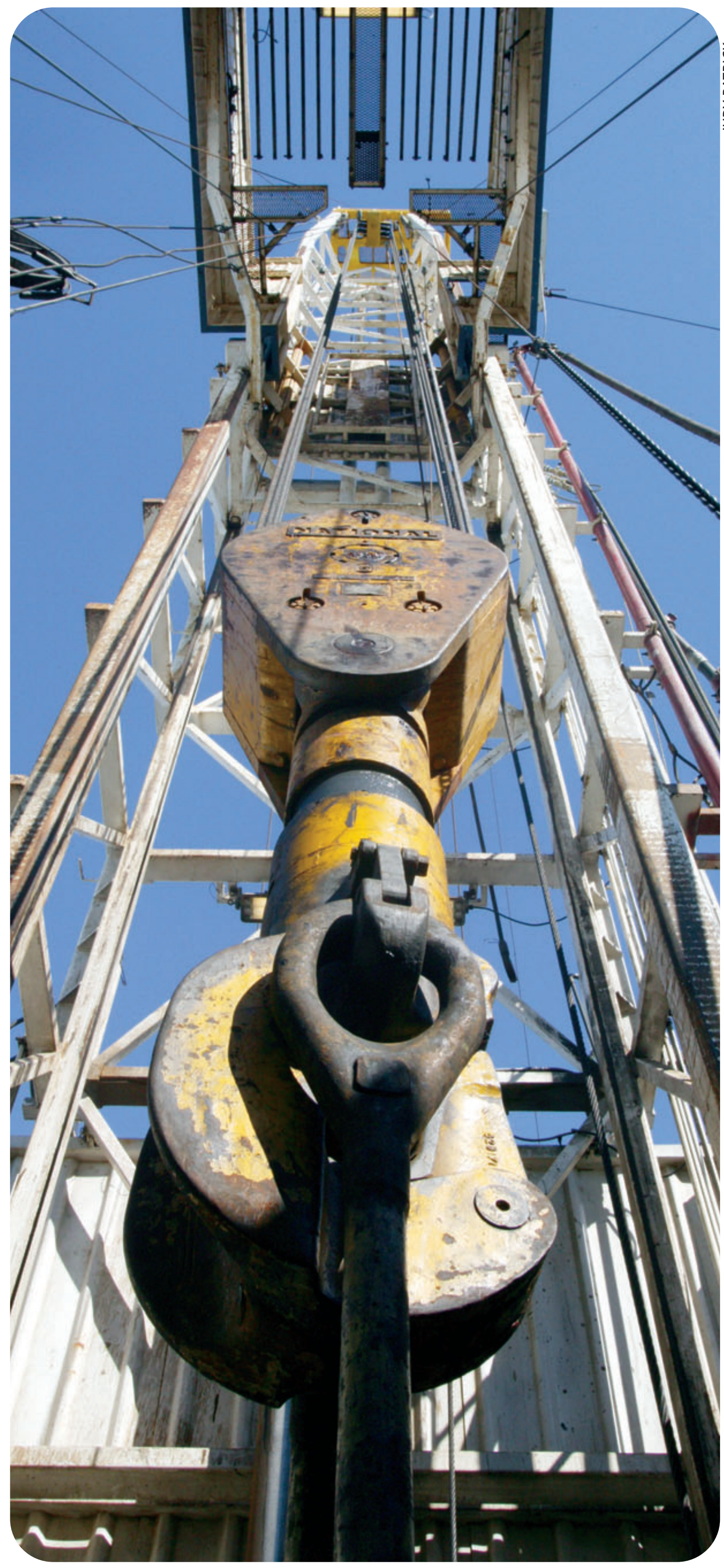
Cook Inlet Basin – Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Hilcorp Alaska LLC			
National 110	C (TD)	Platform C, Stacked	Hilcorp Alaska LLC
	Rig 51	Steelhead Platform, Stacked	Hilcorp Alaska LLC
	Rig 56	Monopod A-13, stacked	Hilcorp Alaska LLC
Nordic Calista Services			
Land Rig	36 (TD)	Kenai, stacked	Available
Spartan Drilling			
Baker Marine ILC-Skidoff, jack-up		Spartan 151, Tyonek Platform	Hilcorp Alaska LLC
Furie Operating Alaska			
Randolf Yost jack-up		Nikiski, OSK dock	Available
Glacier Oil & Gas			
National 1320	35	Osprey Platform, activated	Glacier Oil & Gas

Mackenzie Rig Status

Canadian Beaufort Sea

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
SDC Drilling Inc.			
SSDC CANMAR Island Rig #2	SDC	Set down at Roland Bay	Available



JUDY PATRICK

Baker Hughes North America rotary rig counts*

	Sept. 24	Sept. 17	Year Ago
United States	521	512	261
Canada	162	154	71
Gulf of Mexico	8	4	14

Highest/Lowest		
US/Highest	4530	December 1981
US/Lowest	244	August 2020

*Issued by Baker Hughes since 1944

EXPLORATION & PRODUCTION

ANS up 9.2% from July, down year-over-year

North Slope production averaged 447,204 bpd in August, down from 478,640 in August 2020; Cook Inlet averages 8,464 bpd, down 8.4%

By KRISTEN NELSON

Petroleum News

In August Alaska North Slope production averaged 447,204 barrels per day, up 9.2% from a July average of 409,720 bpd but down 6.6% from an August 2020 average of 478,640 bpd.

The month-over-month production increase was largely due to the end of planned maintenance turnarounds, particularly at Alpine, which had resulted in production from both the Colville River unit and Greater Mooses Tooth being down substantially in July. That turnaround ended in early August, so some August production was still affected.

Nikaitchuq also had a turnaround scheduled (23 days in August and September), and there was an eight- to 10-day turnaround at Northstar scheduled for this summer, as well as a turnaround at the Duck Island unit (that production is reported as Endicott).

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

ANS production was 89.5% crude oil in August, 400,051 bpd, up 7.9% from a July average of 370,903 bpd and down 7.5% from a July 2020 average of 432,436 bpd and 10.5% natural gas liquids, 47,153 bpd, up 21.5% from a July average of 38,817 bpd, and up 2.1% from an August 2020 average of 46,204 bpd.

Month-over-month increases

The largest August over July production increase was at ConocoPhillips Alaska's Colville River unit, which averaged 36,661 bpd in August, up 244.2% from a July average of 10,651, as Alpine facilities came back online following a lengthy turnaround July 9 through Aug. 3. August 2021 production from Colville was down 30.6% from an August 2020 average of 52,827 bpd.

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

Production from ConocoPhillips' Greater Mooses Tooth in the National Petroleum Reserve-Alaska, which is processed at the Alpine facilities, averaged 947 bpd in August, up 40.2% from a July average of 675 bpd but down 64.4% from an August 2020 average of 2,660 bpd.

Hilcorp Alaska's Northstar averaged 7,817 bpd in August, up 17.2% from a July average of 6,673 bpd but down 14.3% from an August 2020 average of 9,116 bpd. Northstar production is 59.3% crude and 40.7% NGLs, the highest percentage of NGLs of any North Slope field.

Increases at Milne Point are the result of drilling, wellwork and facilities upgrades Hilcorp has been progressing since it took over as operator (with a 50% working interest ownership) in late 2014, and as 100% WIO in mid-2019 after it acquired the remainder of BP's Alaska assets.

Hilcorp North Slope-operated Prudhoe Bay averaged 245,985 bpd in August, up 8.6% from a July average of 226,412 bpd and up 1.4% from an August 2020 average of 242,688 bpd. Prudhoe production was 82.3% crude oil, 202,459 bpd in August, and 17.7% NGLs, 43,526 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.

Hilcorp Alaska's Milne Point field averaged 37,062 bpd in August, up 6.3% from a July average of 34,861 bpd and up 12.1% from an August 2020 average of 33,069. Increases at Milne Point are the result of drilling, wellwork and facilities upgrades Hilcorp has been progressing since it took over as operator (with a 50% working interest ownership) in late 2014, and as 100% WIO in mid-2019 after it acquired the remainder of BP's Alaska assets.

The ExxonMobil Production-operated Point Thomson field averaged 9,575 bpd in August, up 1.5% from a July average of 9,435 bpd and up 16.6% from an August 2020 average of 8,213 bpd.

Month-over-month declines

The largest month-over-month production decline was at Eni's Nikaitchuq, which averaged 8,951 bpd in August, down 52% from a July average of 18,629 bpd and down 47.3% from an August 2020 average of 16,995 bpd. There was a 23-day turnaround scheduled at the field for August-September.

The Hilcorp Alaska-operated Endicott field averaged 4,676 bpd in August, down 15.4% from a July average of 5,525 bpd and down 34.6% from an August 2020 average of 7,144 bpd. The field had a summer 2021 turnaround scheduled. Endicott production is 90.5% crude and 9.5% NGLs.

Eni's Oooguruk averaged 5,812 bpd in August, down 12.1% from a July average of 6,613 bpd and down 16.4% from an August 2020 average of 6,954 bpd.

see **ANS OUTPUT** page 5

Cook Inlet gas production down 5.6%

Natural gas production from Cook Inlet averaged 187,410 thousand cubic feet per day in August, down 5.6% from a July average of 198,599 mcf per day and down 14.4% from an August 2020 average of 218,883 mcf per day.

Volumes 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.

The majority of Cook Inlet natural gas, 85.4%, comes from the inlet's eight largest fields.

Hilcorp's Kenai field topped the list in August, averaging 30,688 mcf per day, down 7.4% from a July average of 33,131 mcf per day and down 19.4% from an August 2020 average of 38,079 mcf per day.

Hilcorp's Kenai field topped the list in August, averaging 30,688 mcf per day, down 7.4% from a July average of 33,131 mcf per day and down 19.4% from an August 2020 average of 38,079 mcf per day.

Hilcorp's Ninilchik field averaged 29,590 mcf per day in August, down 2.9% from a July average of 30,483 mcf per day and down 7.2% from an August 2020 average of 31,879 mcf per day.

Beluga River, operated by Hilcorp (Chugach Electric Association owns 66.67% of the field, Hilcorp 33.33%) averaged 22,917 mcf per day in August, up 16.2% from a July average of 19,724 mcf per day and up 4.5% from an August 2020 average of 21,940 mcf per day.

Hilcorp's McArthur River field averaged 21,407 mcf per day in August, down 0.3% from a July average of 21,481 mcf per day and down 17.2% from an August 2020 average of 25,846 mcf per day.

see **INLET GAS** page 5

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INLET GAS

Hilcorp's North Cook Inlet averaged 20,191 mcf per day in August, up 5.9% from a July average of 19,071 mcf per day and up 12.3% from an August 2020 average of 17,976 mcf per day.

Hilcorp's Swanson River averaged 15,770 mcf per day in August, down 18% from a July average of 19,231 mcf per day and down 32.4% from an August 2020 average of 23,334 mcf per day.

Furie's Kitchen Lights averaged 11,285 mcf per day in August, down 1.8% from a July average of 11,488 mcf per day and down 18.9% from an August 2020 average of 13,908 mcf per day.

Hilcorp's Beaver Creek averaged 8,202 mcf per day in August, down 5.9% from a July average of 8,711 mcf per day and down 33.9% from an August 2020 average of 12,413 mcf per day.

The smaller fields combined account for under 15% of Cook Inlet natural gas production.

Hilcorp's Ivan River averaged 5,980 mcf per day in August, down 29.8% from a July average of 8,517 mcf per day but up 51.4% from an August 2020 average of 3,950 mcf per day.

Hilcorp's Deep Creek averaged 3,933 mcf per day in August, up 5.3% from a July average of 3,734 mcf per day and up 2.7% from an August 2020 average of 3,831 mcf per day.

Hilcorp's Cannery Loop averaged 3,795 mcf per day in August, down 8.3% from a July average of 4,138 mcf per day and down 27.4% from an August 2020 average of 5,230 mcf per day.

Hilcorp's Granite Point averaged 3,689 mcf per day in August, down 0.5% from a July average of 3,707 mcf per day but up 2.3% from an August 2020 average of 3,605 mcf per day.

Vision Operating's North Fork field averaged 3,135 mcf per day in August, up 0.5% from a July average of 3,119 mcf per day but down 6.2% from an August 2020 average of 3,341 mcf per day.

BlueCrest's Hansen field averaged 2,381 mcf per day in August, down 12.6% from a July average of 2,723 mcf per day and down 30.5% from an August 2020 average of 3,423 mcf per day.

AIX's Kenai Loop averaged 1,567 mcf per day in August, down 66.3% from a July average of 4,646 mcf per day and down 69.2% from an August 2020 average of 5,087 mcf per day.

Hilcorp's Lewis River averaged 1,126 mcf per day in August, up 23.5% from a July average of 912 mcf per day and up 5.3% from an August 2020 average of 1,069 mcf per day.

Hilcorp's new Seaview field averaged 600 mcf per day in August, down 44.7% from a July average of 1,085 mcf per day.

Amaroq's Nicolai Creek averaged 530 mcf per day in August, up 38.7% from a July average of 383 mcf per day and up 33.7% from an August 2020 average of 397 mcf per day.

Hilcorp's Nikolaevsk averaged 331 mcf per day in August, down 2.7% from a July average of 340 mcf per day and down 15% from an August 2020 average of 389 mcf per day.

Hilcorp's Trading Bay averaged 293 mcf per day in August, down 85.2% from a July average of 1,976 mcf per day and down 90.2% from an August 2020 average of 2,981 mcf per day. The field produces from the Monopod, which had a pipeline replaced recently; AOGCC data show wells active just a few days in August.

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

—KRISTEN NELSON

continued from page 4

ANS OUTPUT

Badami, operated by Savant Alaska, a Glacier Oil and Gas company, averaged 1,065 bpd in August, down 1% from a July average of 1,076 bpd. The field was not in operation in August 2020.

The ConocoPhillips-operated Kuparuk River averaged 88,652 bpd in August, down 0.6% from a July average of 89,170 bpd and down 10.4% from an August 2020 average of 98,973 bpd.

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

Cook Inlet crude down 8.4%

Crude oil production in Cook Inlet averaged 8,464 bpd in August, down 8.4% from a July average of 9,240 and down 24% from an August 2020 average of 11,144 bpd.

Hilcorp's Beaver Creek had the largest month-over-month increase, averaging 633 bpd in August, up 61.3% from a July average of 393 bpd and up 311.3% from an August 2020 average of 154 bpd.

Hilcorp's Granite Point averaged 2,654 bpd in August, up 0.6% from a July average of 2,637 bpd, but down 9.9% from an August 2020 average of 2,944 bpd.

Hilcorp's Swanson River held steady, averaging 907 bpd in both August and July, and up 17.3% from an August 2020 average of 773 bpd.

The largest month-over-month decline was at Hilcorp's Trading Bay field, which averaged 169 bpd in August, down 83.9% from a July average of 1,050 bpd and down 87.1% from an August 2020 average of 1,311 bpd. Trading Bay produces from the Monopod and the oil pipeline to that platform was replaced this summer, with connections completed and hydrotesting at the end of August, when the line was restarted. AOGCC data show most Trading Bay wells in production for just a handful of days in August

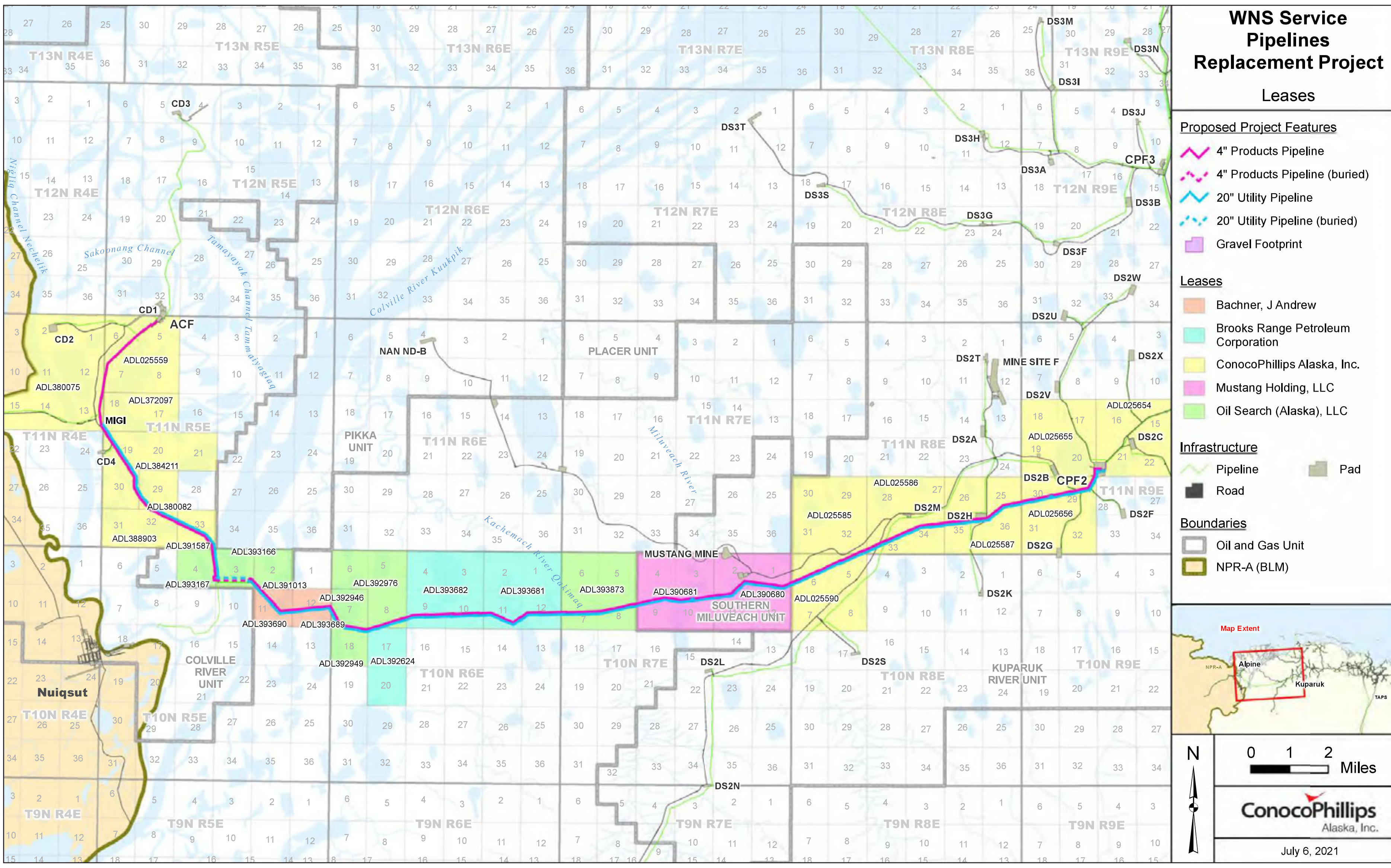
Hilcorp's McArthur River, Cook Inlet's largest oil field, averaged 3,224 bpd in August, down 4.1% from a July average of 3,360 bpd and down 14.9% from an August 2020 average of 3,787 bpd.

BlueCrest's Hansen field averaged 875 bpd in August, down 2% from a July average of 893 bpd and down 14.4% from an August 2020 average of 1,022 bpd.

Production from three Cook Inlet fields is currently suspended: Middle Ground Shoal (pending completion of a new pipeline expected next summer) and Redoubt Shoal and West McArthur River (these fields are up for sale by owner Glacier Oil and Gas).

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

Contact Kristen Nelson at knelson@petroleumnews.com



EXPLORATION & PRODUCTION

Preparing to head west to Willow, beyond

Conoco to start work in November on two North Slope pad expansions in support of the WNS Service Pipeline Replacement project

By KAY CASHMAN
Petroleum News

In preparation for its continued expansion west on Alaska's North Slope to Willow and other oil fields in the National Petroleum Reserve-Alaska, in late September ConocoPhillips Alaska received approval from Alaska's Division of Oil and Gas on its request to expand two pads that will add additional space to accommodate new modules and equipment in support of the Western North Slope (WNS) Service Pipeline Replacement project.

Applied for as amendments to plans of operations for both pads, which are in the Kuparuk River and Colville River units, the company was approved to expand Kuparuk's Central Processing Facility 2 pad, or CPF2, and Colville River's Miscible Injection/Gas Injection, or MIGI, pad north of CD4.

The MIGI pad expansion will result in placement of up to 8,000 cubic yards of clean gravel fill onto 0.7 acre of tundra to expand the northeast side. The CPF2 pad expansion involves placement of up to 13,000 cy of clean gravel fill onto 0.7 acre of tundra and 0.3 acre of gravel pad side slopes to expand the south and east side.

Work on the pad expansion projects is expected to begin Nov. 1 and be completed by June 30, 2024, and all project work will occur using existing gravel pads and roads.

Western pipeline project

The WNS Service Pipeline Replacement project components are being permitted separately with the State Pipeline Coordinator's Section.

The project includes replacing the existing Alpine 12-inch utility pipeline with a new 20-inch pipeline to transport seawater from CPF2 to the MIGI pad on a new pipe rack. A new 4-inch products pipeline will also be installed to transport diesel and other products from CPF2 to the Colville River unit's Alpine Central Processing Facility, or ACF, on a spare slot on the existing Alpine sales oil pipe rack.

The new pipelines will cross beneath the Colville River and will be installed using horizontal directional drilling, or HDD, techniques.

Pipeline installation will require building two new HDD transition pipeline pads north of the existing Alpine HDD location on the east and west sides of the Colville River. Support infrastructure includes vertical support members, thermosyphons, a cathodic protection anode, a fiber optic communication line, and surface facilities at ACF.

The WNS Service Pipeline Replacement project could begin as early as on Aug. 1, 2022, and will be completed by Dec. 31, 2023, when all supporting infrastructure at the CPF2 pad expansion is installed.

Pad expansion specifics

In its Sept. 20 approval of the CPF2 expansion, the division said the gravel would come from either the Arctic Slope Regional Corp. or Willow mine sites.

The expansion will be graded to match the elevation of the existing pad.

Approximately seven miles southwest of the Kuparuk Airport, CPF2 is on state lease ADL 25654.

The division's Sept. 27 approval of the expansion of the MIGI pad said it was to accommodate a new remote electrical and instrumentation module and a pigging module to contain pigging receivers and launchers in support of the WNS Service Pipeline Replacement project.

The MIGI pad is a wide area of the existing CD4 road on state lease ADL 380075, the MIGI pad is approximately six miles north of the town of Nuiqsut. ●

Contact Kay Cashman at publisher@petroleumnews.com

● GOVERNMENT

AOGCC tightening well suspension regs

By KRISTEN NELSON

Petroleum News

The Alaska Oil and Gas Conservation Commission is proposing changes in its regulations on temporary shutdowns of drilling or completion operations excluding wells drilled from mobile offshore drilling units from eligibility for suspension.

This issue came to the commission's attention last year after the Kitchen Lights unit changed hands (see story in Jan. 3, 2021, issue of PN).

John Hendrix, chief executive officer and president of Furie Operating Alaska, which bought the unit out of bankruptcy, told the commission that when the new owners took over they found a lot of things that needed to be cleaned up in the unit's wells.

Of note, three exploration wells in Cook Inlet, classified as suspended, had been plugged and cemented by the previous operator but had conductor pipe sticking up from the seafloor into the waters of Cook Inlet.

The wells, Kitchen Lights Unit Nos. 1, 2A and 4, were suspended by a previous operator in 2012 and 2013.

Furie asked for a variance from the commission's regulations, which require site clearance and do not allow casing stubs above the seabed.

The commission said the original decision to classify the wells as suspended was based on the previous operator's "request to preserve the ability to reenter the wells," based on applications to suspend the wells submitted in 2012 and 2013.

It ultimately classified the wells as plugged and abandoned, but did not remove the site clearance requirement (see story in March 7 2021, issue of PN).

The commission said the original decision to classify the wells as suspended was based on the previous operator's "request to preserve the ability to reenter the wells," based on applications to suspend the wells submitted in 2012 and 2013.

Proposed regulation changes

The proposed changes in the commission's regulations, public noticed Sept. 29, would exclude a well drilled from a mobile offshore drilling unit from eligibility for suspension status, specifically: "Wells drilled from a mobile offshore drilling unit that are not located on a fixed offshore platform are not eligible for suspension."

The revisions also add that in the case of an initial suspension, the wells must be on a pad or platform with active producing or service wells.

There are provisions for suspending wells that are not within a unitized area in the existing regulations. That provision is qualified to apply to initial suspensions only and amended by adding the qualifier "with active production."

Because Kitchen Lights was not in production when the wells at issue were suspended, they would not have qualified on that basis, in addition to the exclusion that applied because they were drilled from a mobile offshore drilling unit, thus removing the issue the commission faced with the three Kitchen Lights wells.

Other regulatory changes would shorten the required period for suspended well inspections and reduce the period of well suspension approval from up to 10 years at a time to up to five years at a time, and remove language related to due dates for wells granted suspension status before 2010.

The regulations would also be amended to codify what the commission called a longstanding practice that operators provide transportation to remote locations when an AOGCC inspector could not access the site by commercial transportation services or AOGCC vehicle.

The proposed regulations are available on the commission's website at www.commerce.alaska.gov/web/aogcc; comments are due by 4:30 p.m. Nov. 2 and should reference Docket R-21-001.●

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EXPLORATION & PRODUCTION

Baker Hughes rig count gains 9 to 512

For the week ending Sept. 17, the Baker Hughes U.S. rotary drilling rig count was up by nine rigs from the preceding week and the count was up by nine rigs again for the week ending Sept. 24, to 521, an increase of 260 from 261 a year ago.

When the count dropped to 244 in mid-August 2020 it was the lowest the domestic rotary rig 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 2020 when it gained back 10 rigs.

Baker Hughes shows Alaska with five rigs active Sept. 24, unchanged from the previous week and up three from a year ago, when the state's count stood at two.

The Sept. 24 count includes 421 rigs targeting oil, up 10 from the previous week and up 238 from 183 a year ago, with 99 rigs targeting gas, down one from the previous week and up 24 from 75 a year ago, and one miscellaneous rig, unchanged from the previous week and down by two from a year ago.

Twenty of the rigs reported Sept. 24 were drilling directional wells, 471 were drilling horizontal wells and 30 were drilling vertical wells.

Alaska rig count unchanged

Louisiana (43) and Oklahoma (39) had the largest week-over-week gains, each up by four rigs, followed by Texas (242) up by three rigs.

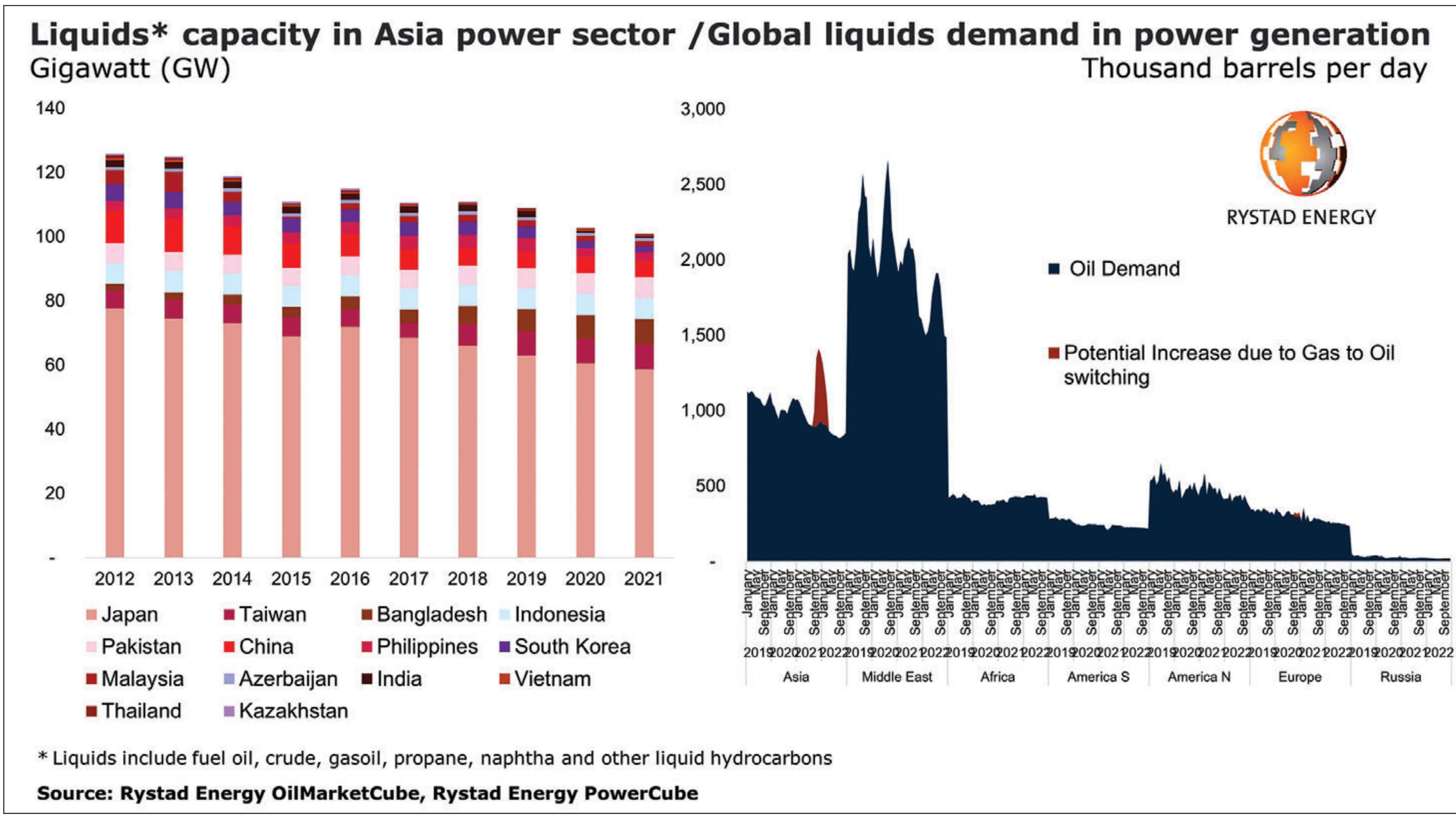
Utah (10) was down by one rig from the previous week.

Counts in all other states were unchanged, week over week: Alaska (5), California (6), Colorado (11), New Mexico (84), North Dakota (22), Ohio (12), Pennsylvania (18), West Virginia (8) and Wyoming (18).

Baker Hughes shows Alaska with five rigs active Sept. 24, unchanged from the previous week and up three from a year ago, when the state's count stood at two.

The rig count in the Permian, the most active basin in the country, was up by one from the previous week at 260 and up by 135 from a count of 125 a year ago.

—KRISTEN NELSON



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OIL PRICES

crude oil inventories (excluding those in the Strategic Petroleum Reserve) increased by 4.6 million barrels from the previous week to 418.5 million barrels, according to a report by the U.S. Energy Information Administration released Sept. 29. Analysts in a Reuters poll had expected a draw of 1.652 million barrels.

Despite the spike for the week, crude inventories remained about 7% below average for this time of year, the EIA said.

Total motor gasoline inventories increased by 0.2 million barrels last week and now are about 3% below the five-year average for this time of year, it said.

Analysts had expected a much larger gasoline build of 1.4 million barrels.

Nat gas fires up Asia oil demand

The switch from natural gas to oil for power generation is likely to boost oil demand in Asia by 400,000 barrels per day on average over the next two quarters, according to a Rystad Energy report released Sept 28.

Liquified natural gas prices have rallied recently in Europe and Asia, boosting the economic incentive to switch fuels, but while steep carbon regulations and operational constraints limit Europe's ability to burn oil in power plants, Asia has more flexibility, Rystad said.

If the gap between LNG and oil prices remains wide, it will support to already high oil prices, the consultancy said.

Asia's liquid-burning capacity for power generation has declined over the past 10 years, but still sits at about 100 gigawatts, primarily in Japan, Taiwan, Indonesia, Bangladesh and Pakistan, Rystad said. Asia currently consumes approximately 900,000 bpd of oil for power generation, leaving a monthly unused and available oil-burning capacity just above 550,000 bpd.

Japan would account for the lion's share with more than 300,000 bpd, followed by Indonesia with 58,000 bpd, Taiwan and Bangladesh with 39,000 bpd each and Pakistan with 33,000 bpd, Rystad said, adding that it assumes a load factor of 0.7 for all the liquid capacity, and considers that some older natural gas plants can switch to oil temporarily.

"This is a significant increase for Asia, when looking at its current oil-to-power use," said Claudio Galimberti, Rystad senior vice president, oil markets team. "From a global oil balance perspective too, this would be a significant shift, and it provides support to the current rally in oil prices."

Rystad said that based on its thermal efficiency scenarios for natural gas and oil in power plants, it is normally not economical to run oil.

However, Asian natural gas prices are currently forecasted to rise and stay well above $20 per million Btu over the coming winter.

"There is clear upside for oil demand in this region — unless the oil price were to increase even faster and cause the price spread to LNG to narrow," Rystad said.

Asia demand a bull case for ANS

The need for more fuel oil in Asia presents a bullish case for ANS crude. As Asian nations buy up oil to supplant natural gas, China and other nations will likely turn to the U.S. West Coast — where ANS is sold — for supplies.

In the glut of April 2020, when prices were at their pandemic nadir, tankerloads of crude schooled off the West Coast. The Trans-Alaska Pipeline System was forced into prorations, reducing oil throughput

see **OIL PRICES** *page 9*

● FINANCE & ECONOMY

OPEC long-term outlook on crude is rosy

By DAVID MCHUGH

Associated Press Business Writer

While acknowledging the inevitable advance of alternative energy sources and technology, OPEC said that oil would be the leading energy source for decades to come as crude prices reached three-year highs Sept. 28.

In its annual World Oil Outlook, OPEC acknowledged that more electric vehicles on the road and the push for alternative and renewable energy will indeed usher in an era of declining demand for oil in rich countries.

But the energy needs of expanding economies in other parts of world means that oil will be the world's No. 1 source of energy through 2045, OPEC said Sept. 28.

The long-term report from OPEC arrives as economies emerge from the most severe economic shocks from the global pandemic, snarling supply lines and creating tight supplies of nearly everything, including oil. Brent crude touched $80 per barrel Sept. 28 while the U.S. oil benchmark crude wasn't far behind, both reaching three-year highs. Hurricane Ida slammed into a critical port that serves as the primary support hub for the Gulf of Mexico's deepwater offshore oil and gas industry in the U.S., worsening the supply situation, at least temporarily.

The average price for gasoline in the U.S. rose again over the weekend, according to the Lundberg Survey, and now costs $1 more per gallon than it did last year at this time.

After being stung by deep production cuts in 2020 during the depths of the pandemic, OPEC has increased production slowly.

> *"Global primary energy demand is expected to increase by 28% in the period between 2020 and 2045, with all energies required, driven by an expected doubling in size of the global economy and the addition of around 1.7 billion people worldwide by 2045."*
> *—OPEC World Oil Outlook*

Report sees increase

"What is clear in this year's WOO is that energy and oil demand have picked up significantly in 2021, after the massive drop in 2020, and continued expansion is forecast for the longer-term," OPEC said. "Global primary energy demand is expected to increase by 28% in the period between 2020 and 2045, with all energies required, driven by an expected doubling in size of the global economy and the addition of around 1.7 billion people worldwide by 2045."

Only coal will see less use, while other sources of energy will see increasing demand, though the share will shift to include a bigger proportion for renewables, nuclear and natural gas, according to the group.

The 340-page report sketches out a future of declining demand for oil in wealthier countries that belong to the 38-member Organization for Economic Development and Cooperation, as efforts to fight climate change take hold in the form of renewables and alternative fuels in cars, airplanes and ships. It forecasts that the world's vehicle fleet would grow by 1.1 billion to 2.6 billion by the end of the report's timeframe in 2045 — and that 500 million of those would be electric powered, or 20% of all vehicles.

But growing populations and expanding middle classes in the rest of the world including China and India will mean increased demand for oil between 2020 and 2045, although much of that increase will take place in the earlier part of that period, the report, produced by OPEC's secretariat in Vienna, said.

Oil will satisfy 28.1% of the world's energy demand by 2045, down from 30% in 2020 — but ahead of natural gas with 24.4% and coal with 17.4%. Hydroelectric, nuclear and biomass energy sources and other renewables such as wind and solar make up the rest.

A key reason cited for declining energy use in the more-developed world was demography: shrinking and aging populations that usher in lower economic growth.

New policy intentions

The report noted that growing awareness of the need to accelerate actions to address climate change have resulted in ambitious new policy intentions to reach net zero emissions by 2050. The European Union, the United States, Japan, the UK, Canada and Brazil have proposed roadmaps to meet new goals.

In September, U.S. President Joe Biden signed an executive order setting a target for zero-emissions vehicles to account for half of all automobiles sold in the USA by 2030.

OPEC, however, noted "considerable doubts as to whether all these ambitious climate-mitigation commitments will be met in the proposed timeframe." For example, the European Union in July spelled out its Fit for 55 package, in which the 27-country bloc vowed to reduce emissions by 55% from 1990 levels by 2030. OPEC said that the plan "remains exactly that for the time being, a plan, which still needs to be negotiated and agreed by all EU Member States, leaving ample scope for exceptions and watering-down."

The UK will host the 26th UN climate change conference Oct. 31-Nov. 12 in Glasgow, Scotland, where national leaders will seek ways to reduce the emission of greenhouse gases and limit the rise in global temperatures. ●

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OIL PRICES

by 10% on April 24, and by another 15% in May. Spot cargoes of ANS crude sold at discounts as high as $6 from Brent crude prices.

China stepped in with a buying spree to take advantage of the sale prices, opportunistically snapping up ultra-cheap spot cargoes from Alaska, Canada and Brazil.

As excess West Coast cargoes made their way to Asia, ANS prices swung to premiums over Brent prices.

This winter, extreme weather could accelerate Asian competition for West Coast supplies.

A La Niña weather system is expected this winter. La Nina wind changes push cold water out of the depths of the Pacific Ocean, typically producing colder and snowier than normal conditions across most of the northern hemisphere.

Weather remains the wild card for ANS oil prices this winter. ●

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PIPELINE PARTNERS

located about 20 miles north of Fort McMurray, the oil sands capital.

Expected revenues C$16 million

The partnership is expected to generate gross annual revenues of C$16 million and help pay for a new aboriginal cultural center.

"For our community, this is a real shot in the arm," said Bill Loutitt, chief executive officer of McMurray Metis.

He said the agreement reflects years of relationship building between the area's Indigenous communities and companies such as Suncor.

Loutitt said the transaction will give his community's young people an opportunity to say: "I'm working for our own company and providing benefits for our community."

Ron Quintal, president of the Fort McMurray Metis Nation, said the deal will show that Indigenous communities and energy "can walk hand in hand and use those dollars not just to get (community) services but invest the revenues in other opportunities."

The Indigenous communities' participation is funded through a non-resource financing that is supported by a loan guarantee of up to C$40 million from the provincially owned Alberta Indigenous Opportunities Corp.

AIOC Chief Executive Officer Alicia Dubois said the number of communities involved in Astisiy makes the deal an "historic first," and allows the partners to negotiate more favorable borrowing terms and bolster their share of revenues in the process.

"It is an example of the type of Indigenous-to-industry partnership that AIOC would be pleased to do over and over again," she said.

Ben Hawkins, AIMCo's senior vice president of infrastructure and renewable resources, told the Globe and Mail that his agency is not yet ready to make the full transition to net-zero carbon emissions.

"So we see traditional energy sources — or infrastructure that conveys traditional energy sources — as still hugely important and potentially good investments ultimately helping is bridge to that net-zero reality," he said.

—GARY PARK

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ENBRIDGE REACH

Executive Officer Al Monaco, adding Ingleside will immediately add to the company's earnings.

The Ingleside facility and its existing pipelines will tie in with the Flanagan South and Seaway Twin pipelines which move heavy crude from Canada to the Gulf Coast, although analysts expect the terminal will primarily be used to export U.S. crude from Texas.

"Ingleside is not connected to our existing assets, but adds a complementary light value chain with sustainable competitive advantages," Enbridge said.

"It's expected the majority of North American crude exports will be light barrels from the Permian and Eagle Ford, with estimates suggesting Permian could comprise about 80 percent of U.S. exports by 2035."

Enbridge has teamed up with Enterprise Products Partners to build the Sea Port Oil Terminal, SPOT, in the Houston area, but some analysts now question whether Enbridge will proceed with developing that project, which is designed to more directly serve heavy oil producers in Western Canada.

Patrick Kenney, an analyst with the National Bank, said Enbridge's commitment to finance the SPOT terminal could now be "modest."

SPOT, planned to handle 2 million bpd of both heavy and light crude, has been scheduled for final approval in the second half of 2021.

But John Coleman, research director at Wood Mackenzie in Houston, said Enbridge could likely purchase both Ingleside and SPOT at the same time, catering to both its U.S. and Canadian customers.

"Just because Enbridge bought a highly attractive terminal in the Corpus Christi market, doesn't preclude the SPOT terminal because it gives them solutions for a more prevalent part of their client base," he said.

Enbridge has filed a regulatory application to expand the Ingleside terminal to ship 1.9 million bpd and expand the shipping berths to handle Suezmax tankers.

Enbridge, which has set a company-wide goal of becoming a net-zero emitter of greenhouse gases by 2050, said it plans to lower emissions from Ingleside by adding up to 60 milliwatts of solar power capability to the site.

Over the longer term, the company said there is the potential to develop additional low-carbon energy infrastructure within the facility such as renewable fuels and carbon-capture projects. ●

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COSMO POD

treatment the state of Alaska has given to the industry in its current obligation to pay the tax credits earned," John Martineck, president and COO of BlueCrest, wrote in the POD.

"We have run into increasing obstacles with existing and potential investors/lenders with the uncertainty of potential regulation changes midstream in the process," he said, likely referring to the bonding increases imposed retroactively by the Alaska Oil and Gas Conservation Commission, resulting in the company currently owing the agency $1.5 million (see full story in the March 21, 2021, Petroleum News titled "AOGCC denies BlueCrest request for reconsideration on bonding.")

"Investor/lenders like stability and follow through," Martineck added.

Some work done

In the 8th POD period the company said it will "evaluate options on all its wells to extend their lives" and perform hot oil treatments on the Hansen 1AL1, H4, H12, H14 and H16a wells to maintain production rates.

In the long-term, BlueCrest "plans to continue to develop the Starichkof/Hemlock oil reservoir as COVID and market condition dictates," Martineck wrote.

During the 7th POD period in 2021, the company's drilling program was on hold.

But the company completed the workover on the Hansen 1AL1 well and installed a gas lift system into the well to bring it back into production and extend its life.

Technical, regulatory challenges

For several years, BlueCrest has been developing Cosmopolitan using increasingly complex well designs to improve production while saving both time and money; it had planned to continue doing so.

Before the coronavirus, the Alaska subsidiary of the Dallas-based independent had been working through the permitting process on a proposed well with 24 distinct laterals.

The well would have combined three of its previously tested eight-lateral "fishbone" wells into a single well. In the "trident" well, BlueCrest would drill one main wellbore from the surface that would then split into three subsurface "fishbone" wells.

The project is as much a regulatory challenge as a technical one. BlueCrest needed to obtain 24 separate drilling permits from AOGCC, not to mention a field-wide development plan intended to obviate the need for requesting a series of spacing exemptions for each of the individual lateral wells.

In June 2020, AOGCC approved updated pool rules for the Cosmopolitan unit allowing BlueCrest to proceed with the 800-foot spacing of the fishbone design, provided that the company did not drill any wells within 500 feet of existing lease boundaries.

In its 2020 plan of development, BlueCrest proposed drilling at least one and possible two of the trident wells in 2020, but then COVID hit.

And by late September 2020, the company had yet to receive all its necessary permits for the first well, let alone a second. In its 2021 POD BlueCrest said that it had delayed the trident project in response to economic conditions brought on by the pandemic.

Worth the effort

Despite the challenges, BlueCrest believes that the complex trident design is worth it, especially given the inherent complexities of the Cosmopolitan unit's Hansen field — an offshore accumulation accessed from an onshore pad using directional drilling.

"Each fishbone well contacts the same amount of reservoir rock as seven-nine individual horizontal wells, and each trident well should recover the same ultimate reserves as three fishbone wells since the reservoir contact is the same, so, each trident well provides the same amount of reservoir contact as 21-27 individual wells," BlueCrest CEO and President J. Benjamin Johnson previously told Petroleum News.

Its pause in drilling has allowed BlueCrest to "advance the evaluation of developing the offshore gas reserves," the company told the division in its 2021 POD filed in September 2020.

"We have a large gas resource, proven; it's been tested, but it's expensive to develop," Johnson said, noting the gas is coalbed methane that has migrated onto the sands of the Tyonek formation, which lies above all the oil zones in the unit.

see **COSMO POD** *page 12*

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NEW COMMISSIONERS

December 2020, was appointed to a second term on the commission. Kennedy, formerly with the University of Alaska's Geophysical Institute in Fairbanks, spent 30 years with the National Oceanographic and Atmospheric Administration before retiring in 2014.

The newly designated chair is Dr. Michael Sfraga of Fairbanks, founding director of the Polar Institute and director of the Global Risk and Resilience Program at the Woodrow Wilson International Center for Scholars in Washington, D.C. Sfraga was with the University of Alaska for more than 30 years.

Elizabeth Qaulluq Cravalho of Kotzebue served on the Alaska Arctic Policy Commission and will hold one of the seats for representatives of private industry. She is vice president of lands at NANA Regional Corp., the Alaska Native corporation for Northwest Alaska.

Dr. Mark Myers of Anchorage, a geologist appointed by President George W. Bush as the 14th director of the U.S. Geological Survey, has worked for the State of Alaska in a variety of positions and is currently a private contractor. Myers is the other industry representative.

Dr. Jacqueline Richter-Menge, of Lyme, New Hampshire, an expert in Arctic sea ice, is serving a second term as a research representative, as she was previously appointed to the USARC in 2016, by President Obama.

Deborah Vo, of Anchorage, a program officer at the Rasmuson Foundation and a former special assistant for rural affairs to Senator Lisa Murkowski, is the commission's new Indigenous representative.

A vacancy exists for a representative from the research community, as former commissioner Major General Randy "Church" Kee, USAF (ret.) resigned, effective Sept. 10, 2021, to accept the federal position of Senior Advisor, Arctic Security Affairs, in the U.S. Department of Defense. He will assist with establishing the Ted Stevens Center for Arctic Security Studies, the DoD's sixth and newest regional center.

USARC is an independent federal agency created by the Arctic Research and Policy Act of 1984 with presidentially appointed members supported by staff in Washington, D.C., and Anchorage.

It delivers a biennial report to the president and Congress outlining recommended scientific research goals and objectives for the Arctic and develops and recommends an integrated national Arctic research policy and builds cooperative links to Arctic research within the federal government, the State of Alaska and with international partners.

—PETROLEUM NEWS

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MUSTANG PAD

lies between the Kuparuk River and Colville River units on Alaska's North Slope. Mustang is currently in cold shutdown.

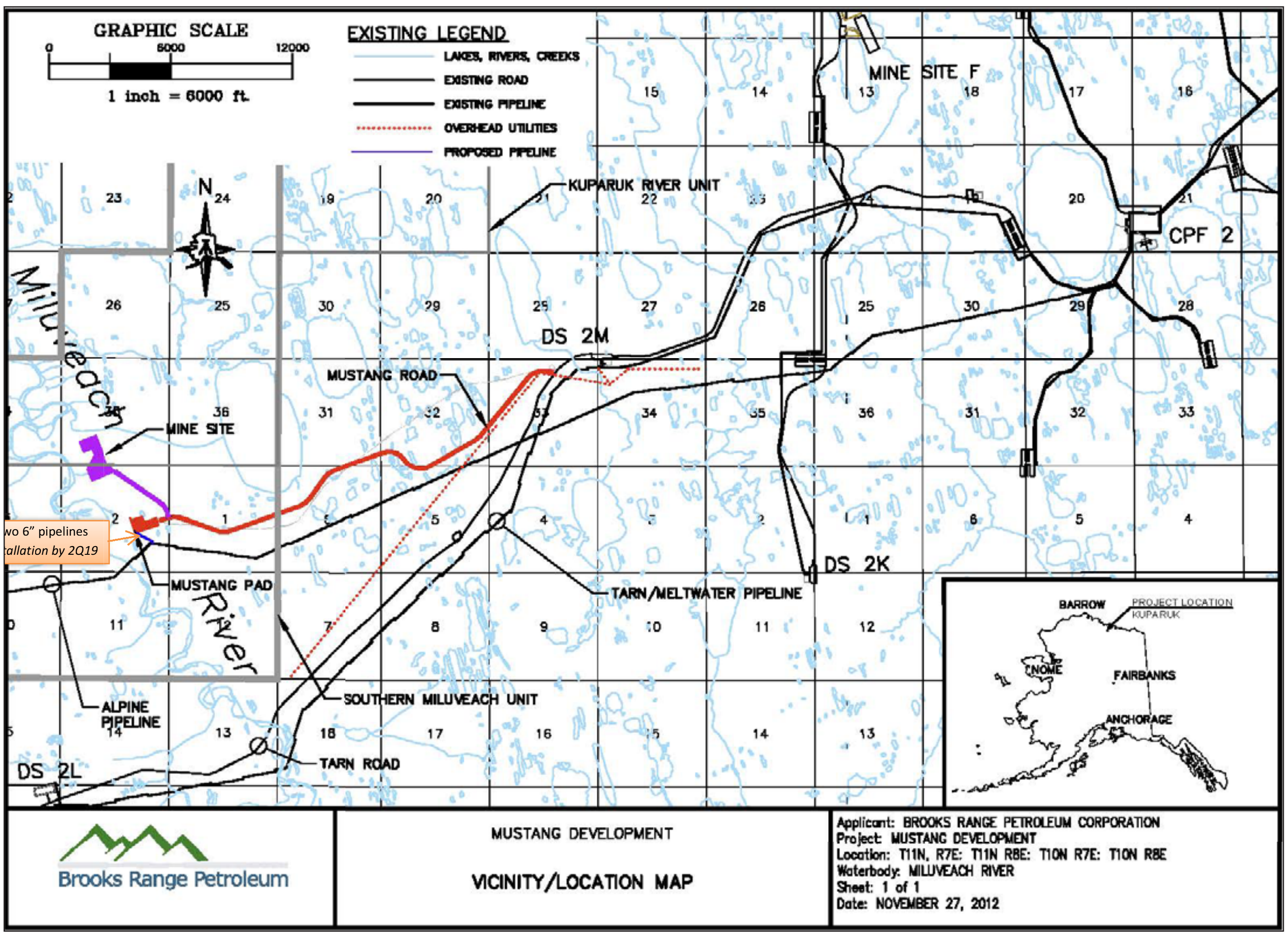
AIDEA chief investment officer for Mustang, Morgan Neff, is the main point of contact for the sale of, or the equity interests in, Mustang Holding. A virtual data room for qualified interested parties has been set up with access subject to signing a non-disclosure/confidentiality agreement.

The work approved on Sept. 20 includes remediating the sloughing of the Mustang Pad by cleaning up gravel from the pad's perimeter and placing and compacting it on areas of the pad that have eroded. About 40 yards of additional gravel will come from Deadhorse.

In addition to the gravel work, approximately 400 barrels of hydrocarbons will be removed from flow back tanks on the pad. Samples of their contents will be analyzed by the Arctic Fox lab and the remaining hydrocarbons will be disposed of at the Hilcorp Milne Point waste disposal location.

Also, approximately 1,700 barrels of storm water will be removed from secondary containment on the Mustang Pad and disposed of at the ConocoPhillips Alaska CPF-1 facility.

If the work has not started by Sept. 20, 2024, then the approval from the division will expire.



Budget increase

As previously reported in Petroleum News, on Aug. 12 when AIDEA's board passed a resolution to divest the assets of, or the equity interests in, Mustang Holding, an increased Mustang Holding budget for the balance of 2021 was part of the resolution.

The increase included the engagement of the law firm of Van Ness Feldman as counsel in the divestment. The services under the agreement are directed and managed from Van Ness Feldman's Washington, D.C., office, with the lead attorney and firm partner being Jonathan Simon.

AIDEA also deals with attorney Steven Willock in Van Ness Feldman's Seattle office.

Mustang Holding's revised 2021 budget is $500,000 more than the previously approved $1.59 million, bringing it to $2.1 million. The resolution also called for the transfer of additional funds in the amount of $850,000 from the Revolving Fund "in order to responsibly carry the project in cold shutdown status through calendar year 2021."

Furthermore, the resolution said the budget and project plan can be "non-materially amended and approved" at the discretion of AIDEA's executive director, Alan Weitzner.

The budget includes any needed pad remediation work to maintain Mustang in cold shutdown, property taxes, and professional fees regarding the competitive sale process, AIDEA staff said in background material.

Reserve estimates

In mid-June 2019 the Alaska Oil and Gas Conservation Commission approved an application by BRPC to inject water and natural gas at the SMU. The company requested authorization to inject fluids for pressure maintenance and enhanced recovery of hydrocarbons from the Kuparuk River oil pool within the unit.

The commission first held a hearing June 4, 2019, on the application, with testimony provided by BRPC.

The company drilled the discovery well, North Tarn 1A, in January 2012, and confirmed it at the Mustang 1 well in February 2012. The resulting Mustang field is estimated to hold some 21.2 million proven barrels of oil in place.

AOGCC said the Kuparuk River oil pool is defined in conservation order 432D. In addition to the SMU, portions of the oil pool lie within the Kuparuk River unit, which adjoins SMU, and the Milne Point unit.

Estimates of in-place and recoverable volumes for the SMU are based on audited reserves and analogous developments, the commission said, and include: 70 million barrels of original oil in place; 10-25% recovery of OOIP estimated from primary recovery, 7-17.5 million barrels; primary plus water injection (an additional 10-25% of OOIP), 7-17.5 million barrels incremental; primary plus water and lean gas injection (additional 1-5% OOIP above primary plus water injection), 0.7-3.5 million barrels incremental; and primary plus water and lean and enriched gas injection (additional 3-15% OOIP above primary plus water injection), 2.1-10.5 million barrels incremental.

BRPC expected to drill up to 11 horizontal production wells and 10 horizontal injection wells drilled parallel with the major faults, AOGCC said, noting hydraulic fracturing would be possible in some wells to enhance reserve recovery.

The commission said the anticipated peak daily injection rate for individual wells was 6,000 barrels of water and 6 million standard cubic feet of gas.

Water and water-alternating-gas injection into the Kuparuk River oil pool in the SMU, AOGCC said, "will provide a substantial EOR benefit over primary recovery alone, maximize ultimate recovery from the SMU-KROP, and prevent waste."

'Very competitive process'

In June 2020, AIDEA listed more than $76 million in principal, late fees, accrued interest and foreclosure fees on the property.

Production from the Mustang Pad's North Tarn 1A well was approximately 11,944 barrels of barrels of oil from field start-up on Oct. 30, 2019, to shut down on Nov. 27, 2019, when BRPC's financial troubles forced a shutdown.

The sale includes the Mustang gravel pad and road, pipelines and related facilities at, as well as the five state of Alaska leases underpinning the SMU. (A buyer would have to be approved by Alaska's Division of Oil and Gas to operate the leases.)

The initial production was handled with an early production facility module, or EPF. That production made BRPC the first small independent to go from discovery to production on the North Slope.

In its original plan of development for the unit for 2020, BRPC said revenue generated from initial production via the EPF would be used to finance a 15,000-barrel-per-day central processing facility that would accommodate Mustang production as well as third-party output from other independent operators in the area.

With the larger processing facilities in place, BRPC would have begun a development drilling campaign.

In briefing the AIDEA board prior to the vote on Aug. 12, Neff, said: "What we're looking at now as we're coming up on the one-year anniversary of the foreclosure of this asset is to properly move forward and monetize it by discussing and engaging with interested third parties that are qualified and have the ability to properly develop this asset that could, over time generate in excess of $200 million in royalty and tax revenue for the state," adding AIDEA is "looking at a very competitive process for this asset."

—KAY CASHMAN

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COSMO POD

"Cook Inlet needs this gas, and especially if any of the mines come online or if there's any new demand for the gas," he said.

In the meantime, the company has made strides to better handle and commercialize associated gas produced from its existing and future oil wells.

BlueCrest said in September 2020 that it had completed the commissioning of a new mechanical refrigeration unit capable of processing up to 35 million feet per day of natural gas, adding that the MRU will reduce the hydrocarbon dew point in the natural gas stream to meet strict pipeline quality specifications, while also allowing the company to process a much higher level of gas production.

"The gas that is with the oil contains natural gas liquids, and the MRU is basically a gas plant and the gas plant removes the natural gas liquids — the propane, butane, and that type of material," Johnson said. "In the Lower 48, the gas pipelines want the NGLs in the gas; in Alaska they don't want it."

"We're not sure exactly what its origin is, but it's intermixed within the oil zones, and so, one way or another it has absorbed natural gas liquids," he said. "There are two possibilities: one is that it is gas that has evolved off of the oil — most likely it's probably coalbed methane that has migrated and been trapped inside one of the oil zones."

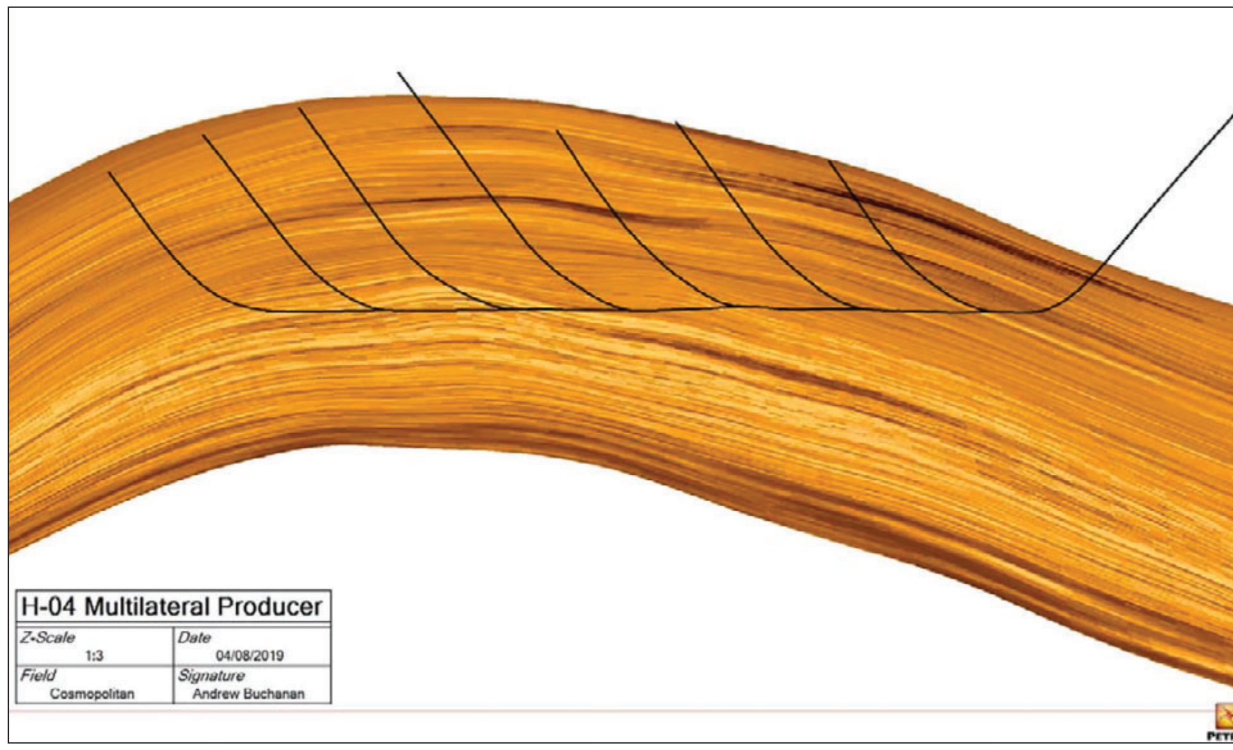
"Some of our oil wells initially will produce a lot of gas," Johnson said. "We have one well that — we were never able to open it up because we didn't have a MRU that could handle its gas rate — it probably would have made 17 million a day."

The oil well was producing gas from a gas zone inside the oil reservoir, he said, adding, "it's mostly been depleted; we do expect we will have a few more of those as we drill more fishbone oil wells."

The MRU is expected to handle as much gas as BlueCrest will ever produce from the oil zones, Johnson said.

If BlueCrest does develop its offshore gas, that gas is extremely dry, he said.

"There really won't be any natural gas liquids to worry about," Johnson said, adding that the MRU still may aid in cleaning up the gas from the offshore in some way in the future.



BLUECREST ALASKA OPERATING LLC

AIDEA amends loan

One piece of good news for the company: On Aug. 12 the Alaska Industrial Development and Export Authority amended BlueCrest's loan agreement, allowing the company to make interest only payments for one year that will be applied to the loan principal.

AIDEA entered into a loan agreement in July 2015 with BlueCrest, under which the quasi-state agency agreed to provide a line of credit of up to $30 million to finance the acquisition, transportation, set up and commissioning of a drilling rig, associated equipment and a camp facility for Cosmopolitan. The funds were fully disbursed.

In March 2016, Cosmopolitan went into production utilizing state-of-the-art extended-reach drilling technology to access the offshore oil reserves from its onshore drill site.

The wells are being drilled approximately 3 miles out and 1.5 miles down to reach the reservoir. Then the wells traverse an additional 1.5 miles horizontally through the productive sands.

After COVID-19 first hit Alaska and oil prices plummeted, AIDEA amended its loan agreement with BlueCrest, providing temporary relief from payments.

Due to ongoing COVID concerns and the inability of the state of Alaska to pay development tax credits owed BlueCrest, the company requested further relief.

In his comments to AIDEA's board, Morgan Neff, chief investment officer for the loan, said that "BlueCrest has been a very good borrower and in good standing and has always made payments on time on their existing agreement and the modified agreement. Not only that, they continue to produce oil and gas hydrocarbons that generate a significant amount of royalty revenue for the state."

To date, he said, Cosmopolitan has generated approximately $13.8 million in royalty revenue and has increased property values in the Kenai Peninsula Borough from $699 million to about $1.4 billion. ●

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