Petroleum news

page 6 Threat of tax increase puts ConocoPhillips investment at risk

Vol. 25, No. 32 • www.PetroleumNews.com | A weekly oil & gas newspaper based in Anchorage, Alaska | Week of August 9, 2020 • $2.50

ConocoPhillips 2Q report shows $222M Alaska loss, restores output

RYAN LANCE

In July ConocoPhillips restored the rest of its curtailed Alaska production, which was an estimated 100,000 barrels of oil a day for the month of June.

According to the big independent's July 30 second quarter earnings report and conference call, a total of approximately 40 million barrels of oil equivalent (mostly oil) was curtailed from its two producing Alaska units — the North Slope Colville River unit, which holds the Alpine field, had ramped down to an average of 25,000 bpd from 55,000-60,000 bpd and the Kuparuk River unit, which went to 35,000 bpd from about 100,000 bpd.

see CONOCO 2Q REPORT page 11

Powering up hydrogen: Alberta funds new ways to produce fuel

As public demand — backed by some of the sharpest minds in industry and the environmental movement — pushes increasingly to advance green energy alternatives to oil and natural gas, the Canadian and Alberta governments have started releasing funds for a series of trial hydrogen projects.

The chemical element is fast emerging as a key component of global efforts to reduce greenhouse gas emissions, GHGs, especially through that fuel-cell technology that shows signs of taking over from diesel to power large-freight transport. At the same time it is helping to clean up industrial processes and energy generation.

The two governments believe Canada may have a competitive edge through its ability to tap vast gas infrastructure to

see HYDROGEN PROJECTS page 11

Kuparuk POD lists continuing field work, despite rig laydowns

Kuparuk River unit operator ConocoPhillips Alaska filed its proposed 2020 Kuparuk River unit plan of development on April 30, the same day the company, which operates Kuparuk and the Colville River and Greater Mooses Tooth units on the western North Slope, announced its plan to curtail oil production by some 100,000 barrels per day from those North Slope fields for the month of June, citing unacceptably low oil prices resulting from the decline in global oil demand due to COVID-19 and global oversupply.

In early April the company said it was demobilizing its North Slope rig fleet, citing the COVID-19 risk to its North Slope

see KUPARUK POD page 9

Pikka unit amendment confirming Oil Search as operator approved

BRUCE DINGEMAN

The first amendment to the Pikka unit agreement filed June 1 by operator and working interest owner Oil Search (Alaska) was approved July 29 by the Alaska Department of Natural Resources' Division of Oil and Gas.

The unit consists of 89 North Slope tracts (leases and parts of leases) that are jointly managed by the landowners, the state of Alaska and Arctic Slope Regional Corp.

Oil Search, with a 51% interest, had filed the "belt and suspenders" amendment on behalf of itself and the other Pikka unit

see PIKKA AMENDMENT page 9

GOVERNMENT

Bonding limbo

AOGCC's proposed surety well bond revisions don't fix duplication, overlap

By KAY CASHMAN

Petroleum News

SARA LONGAN

JEREMY PRICE

More than a year after first being asked by the Alaska Department of Natural Resources, a landowner, to reconsider their new surety well bonding regulation that contains much higher bonding costs and duplicates the coverage required by landowners, the Alaska Oil and Gas Conservation Commission is proposing revisions that do not resolve the problem of overlap with DNR financial assurance agreements.

Typically, the agreements that DNR requires of operators cover the proper plugging and abandonment of wells; the most common exception being large oil and gas companies such as BP, ConocoPhillips and ExxonMobil which are self-insured. Rather, the quasi-judicial commission is proposing language that appears to clarify what

see BONDING LIMBO page 10

FINANCE & ECONOMY

Brent breaks $45 level

Prices jump on July inventory draw; Continental to restore shut in production

By STEVE SUTHERLIN

Petroleum News

Brent oil closed above $45 per barrel Aug. 5 for the first time since the coronavirus pandemic staggered markets in early spring. Prices jumped on news from the Energy Information Administration that crude oil inventories fell by 7.4 million barrels during the week ending July 31.

The American Petroleum Institute also reported an inventory draw — of 8.587 million barrels — for the last week of July.

A week earlier, the EIA said inventories were down 10.6 million barrels, after a build of 4.6 million barrels in the second week of July.

Prices began to move upward on Aug. 4 as

> *While the inventory draws have been bullish for prices, the partial return of curtailed OPEC+ oil production beginning in August is likely to moderate upward price action over the next few months.*

Brent rose 28 cents to the $44.43 level.

In recent days, Alaska North Slope crude has lagged Brent. On Aug. 4 ANS rose 59 cents to $42.74. On Aug. 5, ANS crude reached $43.49, an increase of 75 cents.

While the inventory draws have been bullish for prices, the partial return of curtailed OPEC+ oil

see OIL PRICES page 12

FINANCE & ECONOMY

Trouble for oil sands

Pressured by activists, institutional investors, big money players flee oil sands

By GARY PARK

For Petroleum News

Alberta is getting a full view of where the oil sands industry is heading ... at least, through European eyes.

Bankers, insurers, investors and some of the world's largest operators are diving for cover as they abandon their roles in the financing, extraction, processing and refining of bitumen from the oil sands and covering the risks of pipelines out of the region.

The lengthening list of Europeans quitting one of the world's largest resources of energy now includes Germany's Deutsche Bank, insurance powerhouse Zurich, France's leading upstream player Total and Swiss insurance company Zurich.

> *Insurance giant Zurich has decided not to renew coverage for the Trans Mountain pipeline expansion but refused to divulge its reasons.*

All have come under mounting pressure from environmental campaigners, their own governments and some Indigenous groups, combined with their belief that world oil demand will peak in 2030.

Total

Total announced it is writing off C$9.3 billion worth of oil sands assets and cancelling its membership in the Canadian Association of Petroleum

see SANDS TROUBLE page 8

● EXPLORATION & PRODUCTION

Conoco applies for KRU Torok pool changes

AOGCC pool rules for Kuparuk, Oooguruk, require changes reflecting inclusion of Torok area formerly part of Oooguruk into KRU

By **KRISTEN NELSON**
Petroleum News

ConocoPhillips Alaska acquired 100% ownership in the Nuna prospect adjacent to the Kuparuk River unit from Caelus Natural Resources Alaska in 2019 and applied to the Alaska Department of Natural Resources Division of Oil and Gas to have the 11 tracts, 21,000 acres, added to the Kuparuk River unit. The tracts were included in the 12th expansion of the Kuparuk River unit.

The company has now applied to the Alaska Oil and Gas Conservation Commission to have the Kuparuk River Torok oil pool expanded to include that acreage. 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 said in a July 24 application to the commission.

When it acquired the acreage in 2019 ConocoPhillips said it represented "an attractive addition to our expanding North Slope position and will allow ConocoPhillips to cost effectively develop Nuna utilizing Kuparuk River Unit infrastructure."

The company said 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)."

In applying to the division for the unit expansion the company said development of the expansion area through existing KRU facilities would minimize environmental impacts because "the tract owners will not have to build stand-along processing facilities solely for the benefit of these areas," since the Kuparuk River unit working interest owners, ConocoPhillips, Chevron U.S.A. and ExxonMobil Alaska Production, already have facility sharing agreements in place.

ConocoPhillips told the division reserves in the expansion area "are not large enough to support the costs of full processing facilities," and even if such standalone facilities were economic, "there would be economic waste due to the existence of duplicate facilities and services that could be provided by the KRU."

Hearing scheduled

AOGCC noticed the application Aug. 3, and said ConocoPhillips had requested amendments to both the conservation order and the area injection order for the Torok oil pool, and said that on its own motion it is proposing to amend the conservation order and the area injection order for Oooguruk, removing the acreage from the Oooguruk orders, since Oooguruk operator Eni US Operating Co. does not hold the leases for the area.

A hearing has been tentatively scheduled on the application for Sept. 15 at 10 a.m. at the commission's Anchorage office, but the commission said if a request for a hearing is not timely filed it may issue an order without a hearing.

Development plans

ConocoPhillips said the pool rules order for Torok, issued in July 2016, "includes the accumulation of hydrocarbons common to and correlating with the interval between the measured depths of 4,991 and 5,272 feet in the Kalubik No. 1 well."

see **POOL CHANGES** *page 4*

contents

Petroleum News | *Alaska's source for oil and gas news*

● NATURAL GAS

Cook Inlet natural gas down 5% for June

Production averaged 193,942 mcf per day; Kenai top gas producer at 33,225 mcf per day, 17% of Cook Inlet production for the month

By KRISTEN NELSON
Petroleum News

Natural gas production from Cook Inlet averaged 193,942 thousand cubic feet per day in June, down 5.2%, 4,250 mcf, from a May 2020 average of 198,445 mcf per day, and down 8.8% from a June 2019 average of 212,674 mcf per day.

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

The seven largest gas producers in the inlet accounted for 79% of the basin's production in June, led by Hilcorp Alaska's Kenai gas field, which averaged 33,225 mcf per day in June, up 2.3%, 736 mcf, from a May average of 32,489 mcf and up 5.8% from a June 2019 average of 31,406 mcf per day.

The seven largest gas producers in the inlet accounted for 79% of the basin's production in June, led by Hilcorp Alaska's Kenai gas field, which averaged 33,225 mcf per day in June, up 2.3%, 736 mcf, from a May average of 32,489 mcf and up 5.8% from a June 2019 average of 31,406 mcf per day.

Hilcorp's Ninilchik field averaged 30,364 mcf per day in June, up 0.5%, 157 mcf, from a May average of 30,207 mcf per day, but down 23.2% from a June 2019 average of 39,524 mcf per day.

Hilcorp's McArthur River field, the inlet's largest oil producer, averaged 23,380 mcf per day of gas in June, down 1.3%, 304 mcf, from a May average of 23,684 mcf per day, but up 4.2% from a June 2019 average of 22,435 mcf per day.

Hilcorp's Swanson River averaged 22,306 mcf per day in June, down 24.4%, 7,210 mcf, from a May average of 29,516 mcf per day, and down 19.3% from a June 2019 average of 27,639 mcf per day.

The Beluga River field, operated by Hilcorp, averaged 17,053 mcf per day in June, down 3.6%, 640 mcf, from a May average of 17,692 mcf per day, and down 33.8% from a June 2019 average of 25,756 mcf per day.

Hilcorp's North Cook Inlet averaged 14,069 mcf per day in June, up 7.3%, 959 mcf, from a May average of 13,110 mcf per day and up 12.5% from a June 2019 average of 12,506 mcf per day.

Furie's Kitchen Lights field (acquired by HEX Alaska at the end of June), averaged 13,316 mcf per day in June, down 2.9%, 399 mcf, from a May average of 13,715 mcf per day, and down 13.1% from a June 2019 average of 15,318 mcf per day.

Smaller fields

The remaining 15 Cook Inlet fields account for 21% of inlet production.

Hilcorp's Beaver Creek averaged 9,851 mcf per day in June, down 2.5%, 253 mcf, from a May average of 10,104 mcf per day but up 30.3% from a June 2019 average of 7,559 mcf per day.

Hilcorp's Cannery Loop averaged 5,911 mcf per day in June, up 13.2%, 688 mcf, from a May average of 5,223 mcf per day, and up 79% from a June 2019 average of 3,302 mcf per day.

AIX's Kenai Loop averaged 4,813 mcf per day in June, up 10.3%, 451 mcf, from a May average of 4,362 mcf per day, but down 11.9% from a June 2019 average of 5,460 mcf per day.

Hilcorp's Deep Creek averaged 3,986 mcf per day in June, up marginally from a May average of 3,980 mcf per day but down 15.9% from a June 2019 average of 4,741 mcf per day.

Hilcorp's Granite Point averaged 3,678 mcf per day in June, up 3.2%, 112 mcf, from a May average of 3,566 mcf per day and up 42% from a June 2019 average of 2,590 mcf per day.

BlueCrest's Hansen field, the Cosmopolitan project, averaged 3,491 mcf per day in June, up 25.6%, 710 mcf, from a May average of 2,780 mcf per day but down 53.6% from a June 2019 average of 7,519 mcf per day.

The North Fork field, operated by Cook Inlet Energy, a Glacier Oil & Gas company, averaged 3,437 mcf per day in June, down 1%, 35 mcf, from a May average of 3,472 mcf per day, but up 22.2% from a June 2019 average of 2,812 mcf per day.

Hilcorp's Trading Bay averaged 2,695 mcf per day in June, up 23%, 503 mcf, from a May average of 2,191 mcf per day and up 44% from a June 2019 average of 1,871 mcf per day.

Hilcorp's Lewis River averaged 1,063 mcf per day in June, down 2%, 21 mcf, from a May average of 1,083 mcf per day and up 1080% from a June 2019 average of 90 mcf per day.

Hilcorp's Nikolaevsk averaged 464 mcf per day in June, up 123.3%, 256 mcf, from a May average of 208 mcf per day, but down 19.7% from a June 2019 average of 578 mcf per day.

Amaroq's Nicolai Creek averaged 336 mcf per day in June, up 53.5%, 117 mcf, from a May average of 219 mcf per day, but down 14.7% from a June 2019 average of 394 mcf per day.

Hilcorp's Ivan River averaged 269 mcf per day in June, down 16.3%, 52 mcf, from a May average of 322 mcf per day and down 38.1% from a June 2019 average of 435 mcf per day.

Hilcorp's Middle Ground Shoal averaged 238 mcf per day in June, down 45.3%, 197 mcf, from a May average of 434 mcf per day but up 15.9% from a June 2019 average of 205 mcf per day.

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

Contact Kristen Nelson at knelson@petroleumnews.com

PIPELINES & DOWNSTREAM

FERC revises Kenai LNG Cool Down EA date

The Federal Energy Regulatory Commission said Aug. 5 that it will issue an environmental assessment for Trans-Foreland Pipeline Co.'s Kenai LNG Cool Down Project on Sept. 3, with a 90-day federal authorization decision deadline of Dec. 2.

Trans-Foreland filed an application with FERC for the project in March 2019 and an original schedule had called for release of an EA Dec. 13, 2019, with a 90-day federal authorization decision deadline March 12, 2020.

That original schedule was revised in December 2019 after Trans-Foreland told FERC in October of that year that it would not file certain information until January 2020.

FERC staff issued a follow-up data request Dec. 9, 2019.

Trans-Foreland is proposing facility modifications at the Kenai LNG Plant to bring parts of the plant out of warm idle to allow for import of liquefied natural gas with the goal of providing up to 7 million standard cubic feet per day of natural gas to Trans-Foreland's affiliated Kenai Refinery.

FERC suspended the schedule in April of this year because an equivalency determination was required from the U.S. Department of Transportation's Pipeline and Hazardous Material Safety Administration. The original equivalency determination from PHMSA addressed project siting, FERC said, but did not address another issue, location of the trim vaporizer.

FERC said PHMSA issued a letter in May, "clarifying that it had no objection to the location of the trim vaporizer."

In an April 2019 project description the company said Trans-Foreland Pipeline Co. owns the Kenai LNG Plant, which is operated by Trans-Foreland's affiliate Tesoro Logistics GP. Trans-Foreland is a wholly owned subsidiary of Tesoro Alaska Co. and since 2018 has been part of Marathon Petroleum Corp.

The project includes installation, construction and operation of a new boil-off gas booster compressor unit, trim vaporizers, ancillary facilities, additional LNG transfer system valves and equipment to manage existing BOG facilities.

—KRISTEN NELSON

PIPELINES & DOWNSTREAM

Seaview pipeline ROW approved by state

The Alaska Department of Natural Resources' Division of Mining, Land and Water Southcentral Regional Office has approved a private non-exclusive easement requested by Hilcorp Alaska for a proposed 10-inch diameter buried gas gathering pipeline near Anchor Point.

The easement authorizes "construction, survey, operation and maintenance" of the line from the Seaview Pad to existing Enstar gas transmission infrastructure.

The easement authorizes "construction, survey, operation and maintenance" of the line from the Seaview Pad to existing Enstar gas transmission infrastructure.

DNR's Division of Oil and Gas approved a lease plan of operations for Seaview June 15. The existing Seaview Pad is on private land at an operating mine site off the Old Sterling Highway 1.5 miles south of Anchor Point on the Lower Kenai Peninsula.

Hilcorp drilled stratigraphic tests in the area in 2017 and applied to the state in the summer of 2018 for an exploration plan which included construction of the Seaview pad and two exploration wells.

The Seaview Pad was constructed in 2018 at an existing gravel mine on private surface lands. Exploration phase of the project included drilling of the Seaview 8 and 9 wells. The discovery well, Seaview 8, was completed in December 2018 to a vertical depth of 10,148 feet and tested for gas in May 2019.

Hilcorp plans to bring the Seaview 8 online as a gas production well late this year, with drilling of the Seaview 9 planned for late this year.

In its private non-exclusive easement for the Seaview Pipeline, the division said the easement is some 865 feet long by 30 feet wide, an estimated 0.59 acres, with two temporary staging areas, one approximately 150 feet by 150 feet and the other some 1,189 feet long by 45 feet wide, a combined land area of some 1.73 acres.

The division said Hilcorp plans to bore under the north and south forks of the Anchor River to complete installation of the pipeline. Terms of the temporary staging areas are temporary easements lasting 3 years; for the pipeline, the term of the easement is 25 years.

—KRISTEN NELSON

Petroleum news
www.PetroleumNews.com

Kay Cashman	PUBLISHER & FOUNDER
Mary Mack	CEO & GENERAL MANAGER
Kristen Nelson	EDITOR-IN-CHIEF
Susan Crane	ADVERTISING DIRECTOR
Heather Yates	BOOKKEEPER
Marti Reeve	SPECIAL PUBLICATIONS DIRECTOR
Steven Merritt	PRODUCTION DIRECTOR
Alan Bailey	CONTRIBUTING WRITER
Eric Lidji	CONTRIBUTING WRITER
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

Petroleum News and its supplement, Petroleum Directory, are owned by Petroleum Newspapers of Alaska LLC. The newspaper is published weekly. Several of the individuals listed above work for independent companies that contract services to Petroleum Newspapers of Alaska LLC or are freelance writers.

OWNER: Petroleum Newspapers of Alaska LLC (PNA)
Petroleum News (ISSN 1544-3612) • Vol. 25, No. 32 • Week of August 9, 2020
Published weekly. Address: 5441 Old Seward, #3, Anchorage, AK 99518
(Please mail ALL correspondence to:
P.O. Box 231647 Anchorage, AK 99523-1647)
Subscription prices in U.S. — $118.00 1 year, $216.00 2 years
Canada — $206.00 1 year, $375.00 2 years
Overseas (sent air mail) — $240.00 1 year, $436.00 2 years
"Periodicals postage paid at Anchorage, AK 99502-9986."
POSTMASTER: Send address changes to Petroleum News, P.O. Box 231647 Anchorage, AK 99523-1647.

● EXPLORATION & PRODUCTION

US weekly rig count holding steady at 251

By KRISTEN NELSON
Petroleum News

The Baker Hughes U.S. rig count for July 31 shows the number of active oil and gas drilling rigs in the U.S. holding steady at 251, the same as the count for the week ending July 24, although down 691 from 942 a year ago.

The number of rigs drilling for oil, 180, was down by one from the previous week and down by 590 from 770 a year ago; the number of rigs targeting natural gas was up by one to 69 from a week ago and down by 102 from 171 a year ago; two rigs were listed as miscellaneous, unchanged from the previous week and up by one from a year ago.

Prior to this week, each week in the previous 12 set a new low record for the number of active rigs: 374 rigs on May 8 of this year; 339 rigs on May 15; 318 on May 22; 301 on May 29; 284 on June 5; 279 on June 12; 266 on June 19; 265 on June 26; 263 on July 2; 258 on July 10; 253 on July 17; and 251 on July 24.

The Houston oilfield services company has issued a weekly rig count since 1944. Prior to this year, the low was 404 rigs in May 2016.

Twenty-two of the holes were directional, 216 were horizontal and 13 were vertical.

North Dakota (11), Oklahoma (11) and Texas (104) were each up by one rig from the previous week.

Rig counts were unchanged for Alaska (3), California (4), Colorado (5), Ohio (6), Oklahoma (10), Pennsylvania (20), West Virginia (5) and Wyoming (1).

Louisiana (29) was down by one rig from the previous week and New Mexico (49) was down by two rigs.

Baker Hughes shows Alaska with three active rigs July 31, unchanged from the previous week and down by nine from a year ago.

The rig count in the nation's most active basin, the Permian (124), was down by two rigs from the previous week, and down by 318 from a count of 443 a year ago.

Baker Hughes has issued weekly rig counts for the U.S. and Canada since 1944 and began issuing international rig counts in 1975.

The U.S. rig count peaked at 4,530 in 1981. The count for this week and last, 251, is a new low. Prior to that the previous low was 404 rigs in May 2016. ●

Contact Kristen Nelson at knelson@petroleumnews.com

continued from page 2

POOL CHANGES

The company said 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)."

Testing of the Torok in Kuparuk began in 2013 with recompletion of the 3S-19 well, ConocoPhillips said. "Since that time four horizontal wells (2 producers, and 2 injectors), and a vertical data collection well (Moraine 1) have been drilled to assess the Torok," with 10.5 million barrels of oil produced from the Torok from these wells.

"The Torok consists of lower Cretaceous-aged, Brookian lower slope-to-basin floor turbidite deposits comprised of thinly laminated mudstones, siltstones, and very fine to fine-grained sandstones sourced from the paleo-Brookian shelf margin to the west. The sandstones and siltstones have been interpreted to be locally continuous, sheet-like deposits within turbidite lobe complexes," with gross thickness reaching some 300 feet but thinning to the southwest, southeast and northeast, the company said.

There are two additional horizontal wells planned, one producer and one injector, with both approved by KRU working interest owners. The wells will be drilled at 3S pad as part of the next rotary drilling program, ConocoPhillips said. ●

Contact Kristen Nelson at knelson@petroleumnews.com

ASSOCIATIONS

Alliance calls for board nominations

The Alliance Board Nominations & Elections Committee is looking for members to serve on the organization's board of directors.

There are six, three-year terms available in the fiscal year 2021 election.

Election results will be announced at the annual meeting on Oct. 15. Newly elected members will begin serving their term on Oct. 16.

Board members of the Alliance are leaders in the oil, gas and mineral resource industries. The Alliance's number one priority is to advocate on behalf of its members to the oil, gas and mining producing and exploring companies.

Board members facilitate this priority by focusing on improving the business climate for the support industry by communicating with legislators and the administration in Juneau, educating the general public about the support industry and issues that affect it, serving on committees and participating in and supporting Alliance events throughout the year.


REBECCA LOGAN

Board members review industry issues, voice Alliance positions and develop strategies to improve and empower the organization. An individual may serve a maximum of two consecutive 3-year terms on the board.

Anyone interested in running for a seat on the Alliance board should forward the following materials to Rebecca Logan, general manager of the Alliance at rlogan@alaskaalliance.com or send by U.S. Mail to 3301 C Street, Suite 205, Anchorage, AK 99503:

- Written statement of candidacy confirming their intent to run for a seat on the board. This may be provided in a letter format.
- Biography in the form of a brief summary of employment, involvement in industry and/or business-related organizations and other pertinent information.
- Photograph, with a digital headshot preferred.

Nominations must reach the Alliance by Sept. 2.

The nominee's company must be an Alliance member in good standing for an individual to qualify as a candidate for the board.

—PETROLEUM NEWS

FINANCE & ECONOMY

BP cuts dividends, ups alternative energy

BP plc said Aug. 4 it plans to slash dividends as the global oil company prepares for declining sales of fossil fuels by boosting investment in alternative energy projects.

London-based BP said it will increase spending on low-carbon technology, including renewable energy projects, 10-fold to $5 billion a year over the next decade. The company expects oil and gas production to drop by about 40% over the same period.

To help finance the strategic shift, BP said it will cut dividends to 5.25 cents a share from 10.5 cents in the first quarter. That will help the company meet its previously announced goal of achieving net zero carbon emissions by 2050 or sooner.

BP announced the shift as it reported a second-quarter operating loss of $6.68 billion as the COVID-19 pandemic cuts oil prices and demand for energy. The figure, which excludes one-time items and changes in the value of inventories, compares to an operating profit of $2.81 billion in the same period last year.

"These headline results have been driven by another very challenging quarter, but also by the deliberate steps we have taken as we continue to re-imagine energy and reinvent BP," chief executive Bernard Looney said. "In particular, our reset of long-term price assumptions and the related impairment and exploration write-off charges had a major impact."

The dividend cut comes at a time of tremendous change for BP. It had already embarked on a restructuring plan to ensure its long-term viability that includes 10,000 job cuts globally. Markets rose 7.5% in early trading on the news. Many thought BP should have made the cut three months ago at the same time as rival Royal Dutch Shell, which cut its dividend for the first time since World War II.

Amid pressure to decrease reliance on fossil fuels in an effort to fight climate change, BP wants to eliminate or offset all carbon emissions from its operations and the oil and gas it sells to customers by 2050, an ambitious target.

—ASSOCIATED PRESS

PIPELINES & DOWNSTREAM

DNR proposes renewal of Nuiqsut line ROW

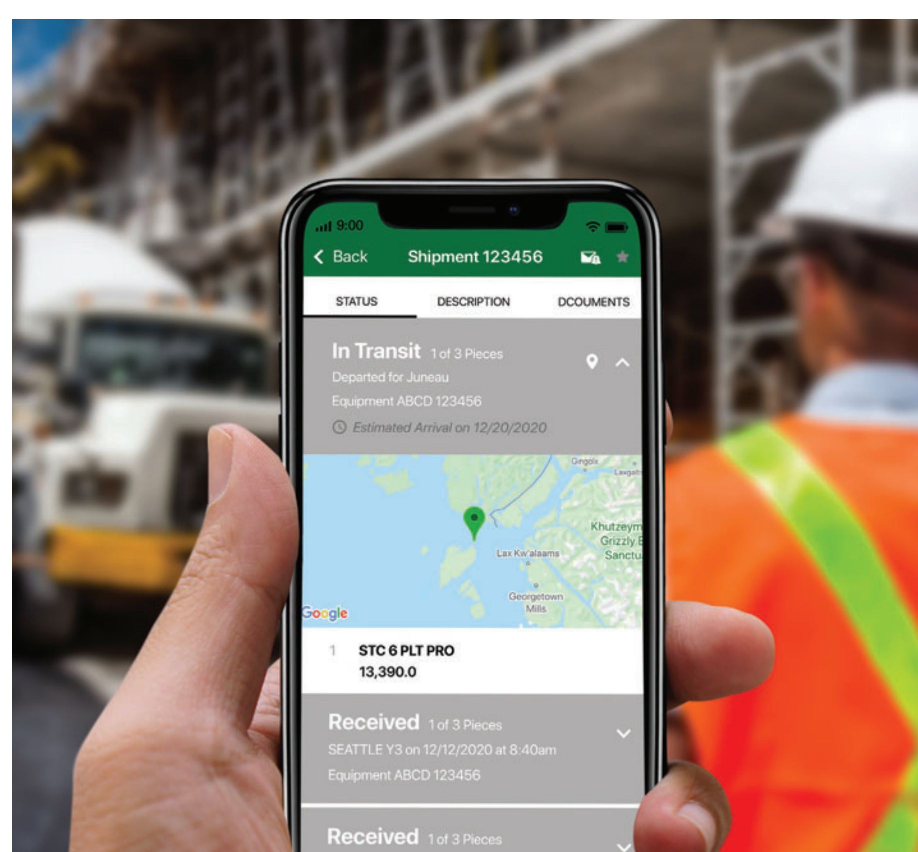
The Alaska Department of Natural Resources has proposed renewing the right-of-way lease for the Nuiqsut Natural Gas Pipeline, the pipeline that delivers natural gas from the Alpine oil field to the village of Nuiqsut on the North Slope. Gas from the line fuels an electricity power generation plant at Nuiqsut. The 14.4-mile, 3.5-inch diameter line crosses state land as well as Native land and hence requires a state right of way, held by the North Slope Borough.

In 1999, as part of a surface use agreement for the construction of the facilities for the Alpine oil field, ARCO Alaska Inc. agreed to make gas available at no charge to Kuukpik Corp., the Nuiqsut village corporation. The North Slope Borough funded the construction of the gas pipeline from the Alpine production facilities and donated the capital infrastructure to the village. The borough has been operating the system as an unlicensed utility, with customers in the village covering the operating costs of the village gas supply system. The Alpine field went into operation in 2000.

DNR issued the original 20-year right-of-way lease for the pipeline on March 13, 1999. In April 2019 the North Slope Borough filed a lease renewal application for a further 20-year term — the borough had earlier been granted an extension to the timeframe for filing the application. In proposing to grant the 20-year lease extension, DNR says that it has found the North Slope Borough to be in full compliance with the lease terms. And DNR is also proposing to modify the rules for closing the pipeline corridor to mining operations, while also allowing future lease extensions to be for 30 years rather than 20 years.

The only issue of significance that has impacted the pipeline was some pipeline coating damage, which was repaired in 2018. The majority of the repair sites are now in excellent condition, and the North Slope Borough is operating a continuous monitoring and upkeep program for coating repairs, the DNR says.

—ALAN BAILEY



EXPLORERS' PREVIEW

Tax uncertainty puts investment at risk

Big explorer and developer ConocoPhillips Alaska waits on Nov. 3 tax initiative ballot outcome to determine 2021 capital budget

By KAY CASHMAN
Petroleum News

The North Slope's most active explorer, ConocoPhillips Alaska, is holding off on re-starting its exploration program in the upcoming winter of 2020-21 until the outcome of the tax initiative ballot in the Nov. 3 election is known.

Scott Jepsen, the company's vice president of external affairs and transportation, said May 8, 2020, that getting North Slope jobs and production back to a normal level of activity is partly dependent on the state's investment climate, "and by that, I mean on whether or not the oil tax initiative passes." The initiative calls for "a significant tax increase" which "will put a brake on future investment," he said, echoing the conviction of several other oil and gas companies in Alaska.

Coming

August 2020

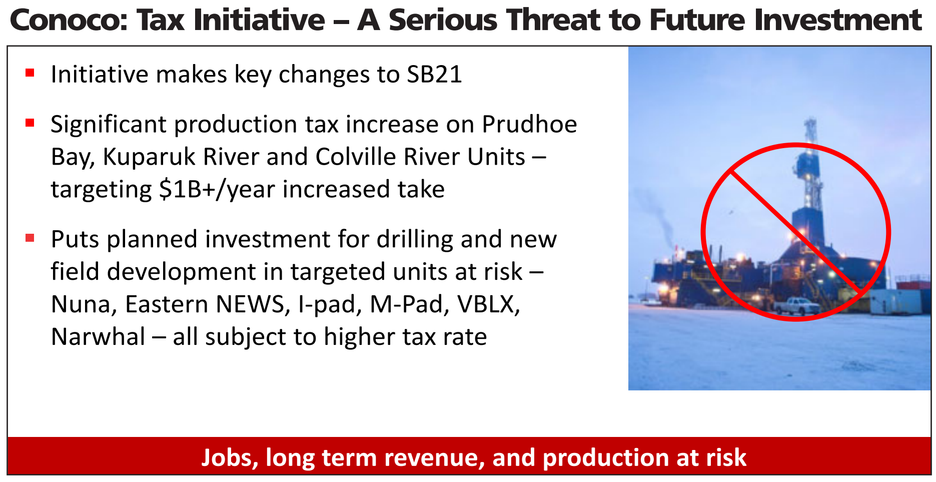
John Roper, director of media relations and crisis communications for ConocoPhillips out of Houston, said "the capital reductions we announced in March and April assumed we don't resume drilling activity at our North Slope operations for the remainder of 2020. We haven't yet set our capital plans for 2021."

Those plans "will depend on our outlook for prices and, specifically in Alaska, the outcome of the tax initiative," Roper said.

In the previous winter of 2019-20, ConocoPhillips drilled three of its planned six to seven exploration wells before it cut the season short because of concerns for worker safety connected to the coronavirus.

High cost area

In a June 4, 2020, CERA Week interview/discussion between Daniel Yergin, vice chairman of IHS Markit, and Ryan Lance, ConocoPhillips chairman and CEO, Yergin asked about the new oil potential in Alaska.



CONOCOPHILLIPS ALASKA

RYAN LANCE

Lance talked about the company's big North Slope Narwhal and Willow oil discoveries, which are primarily in the Nanushuk formation.

Those "new petroleum systems" offer Alaska the opportunity to "stabilize production going through TAPS," the trans-Alaska pipeline system, Lance said. "We see a lot of opportunity in Alaska," he told Yergin, noting ConocoPhillips "took some of our partners out" and now "own a 100% position."

But if the new tax initiative passes, it increases the "above-ground risk." The North Slope is already a "high cost area," Lance said.

And although ConocoPhillips has operated in Alaska for "a long time … if the tax rate goes up, cash flows go down and we have to manage in a rational environment," Lance said.

2019-20 exploration

The results from the three wells ConocoPhillips drilled in early 2020 — two Tinmiaq wells near the big Willow discovery and a rank exploration well in the Harpoon prospect — appear promising.

According to Matt Fox, ConocoPhillips executive vice president and COO, Tinmiaq results were what was "expected," and Willow development is on track. (Willow is anticipated to have a peak production of 130,000 barrels of oil per day over a 30-year life.)

"We're working through Willow, and we're in the concept selection stage just now. We have a timeline that would get us to the end of this year with the opportunity to select the concept. And by that, I mean, how big a facility do we build, how many drill centers do we have and so on," Fox said on April 30, 2020, in a first quarter earnings conference call, noting no decision has been made to defer Willow. (On July 30, 2020, days after The Explorers magazine goes to press, ConocoPhillips has scheduled its second-quarter earnings conference call, so check Petroleum News for updates.)

In the Harpoon well they "clipped the edge of the topset based on its log response. … We won't know that for sure until we get a chance to drill the second well," Fox said, a reminder that ConocoPhillips executive Michael Hatfield said in November 2019 that 3D seismic imaging indicates Harpoon has "high-potential Brookian topset targets with stacked plays." Hatfield is president of Alaska, Canada and Europe for the company.

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

'Beast' a game-changer

In March 2020 a new ultra-extended reach drilling rig, built by Doyon Drilling for ConocoPhillips, was delivered to the CD2 pad in ConocoPhillips Colville River unit northwest of the main Alpine field to assist with development of the unit's Fiord West prospect on the environmentally sensitive Beaufort Sea coast.

Doyon 26, also known as the "Beast," can reach reservoirs some 7 miles from its surface location. This means the high-tech ERD rig will be able to reach 154 square miles of reservoir versus the standard 55 square miles accessed by other North Slope rigs.

Fox described it as the "largest mobile extended reach drilling rig in North America and maybe the biggest in the world." Doyon 26 is yet another example of ConocoPhillips massive investment in Alaska.

MICHAEL HATFIELD

MATT FOX

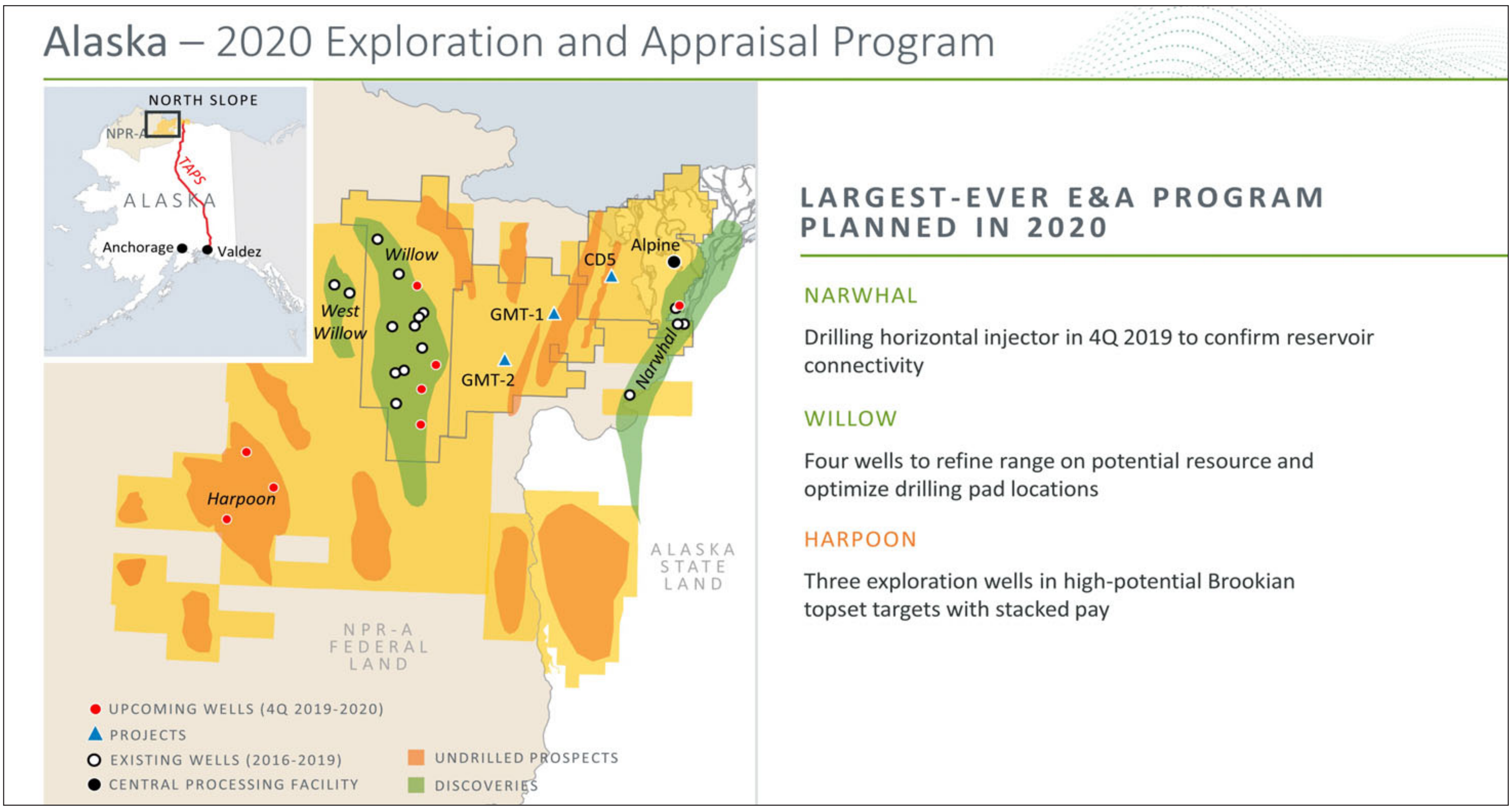
The 9.5 million-pound ERD rig — weight equivalent to almost 10 fully loaded Boeing 747s — has four 2,200 horsepower mud pumps.

Doyon 26 can burn a mix of processed field gas and diesel, displacing about 50% of the diesel required to operate the rig, which will be a big savings for ConocoPhillips, both in terms of cost and emissions.

Other drilling rigs do not have the capability to access Fiord West without a new gravel pad, additional pipelines and more road being built — hence increasing the development footprint.

ConocoPhillips Alaska has been working on the rig from initial FEED, or front end engineering design, studies and con-

see CONOCO OUTLOOK page 7



CONOCOPHILLIPS ALASKA

continued from page 6

CONOCO OUTLOOK

cept stage for about four years, recognizing what a game-changer the rig will be for it in Alaska.

The company anticipated Doyon 26 spudding its first well near the end of April 2020.

But that all changed with ConocoPhillips April 8, 2020, statement to Petroleum News, saying it was demobilizing its North Slope rig fleet due to the coronavirus pandemic.

Top of the ladder


JOE MARUSHACK


SCOTT JEPSEN

On April 16, 2020, in ConocoPhillips' second round of spending cuts since oil prices plunged and the coronavirus struck, Alaska once again lucked out with only $200 million of the company-wide $1.6 billion capex reduction coming from the state. Alaska spending for 2020 was reduced March 18, 2020, from approximately $3.4 billion to $3.2 billion; the April 16 announcement brings it down to about $3 billion.

Before disaster struck on April 20, 2020, and crude fell into negative territory for the first time in history as the COVID-19 pandemic decimated oil demand, Alaska was slated to receive about half of ConocoPhillips world-wide exploration capital.

In fact, the company remained on track to invest $25 billion of capital over the next 10 years in Alaska, Hatfield said in a fourth quarter conference call Feb. 4, 2020.

"In short, we've got a big program that we're executing across our assets in Alaska, including at the non-op asset in Prudhoe Bay," he said.

"These investments will increase the state's production and mitigate the current decline through TAPS."

ConocoPhillips spending plans for Alaska are not surprising given its recent discovery of approximately 1 billion barrels of light, sweet oil west of the central North Slope and into the National Petroleum Reserve-Alaska. Afterall, the company has said 75% of its prospective exploration acreage in the state has yet to be drilled.

But if there is a negative change in Alaska's fiscal regime, ConocoPhillips' investment plans will change. Still, the company is hopeful that the ballot initiative to increase oil and gas taxes will be rejected.

"We've been in Alaska for over 40 years; we know Alaskans understand the industry; it's the lifeblood of the state's economy," Hatfield said. "We believe Alaskans will understand that short-term revenue gain is a risky and fleeting proposition if it comes at the cost of billions of dollars of investment over the coming years."

Sell-down on hold

At the end of 2019, ConocoPhillips was looking for a North Slope exploration and development farm-in partner to take a 15-25% interest in some of its prospects.

But the sell-down is on hold.

"At this point, we only plan to sell down after the uncertainty related to the citizens' initiative has been resolved, and after we've fully interpreted the results of our exploration and appraisal program, and when we've progressed … Willow through the concept select gate," Don Wallette, executive vice president and CFO, said Feb. 4, 2020. "After we've satisfied those three criteria, that's when we plan to execute this sell-down, so that pushes the sell-down most likely well into next year."

He said the company would not execute a sell-down in a way that causes it to lose control of the investment pace.

"We're already confident that there's multiple quality parties that are interested in these great assets," he said.

"We would be open to an equal-value strategic transaction or a swap rather than cash, if that makes sense," Wallette said. "We're going to resolve some of these uncertainties, and then we'll approach the market." ●

Contact Kay Cashman at publisher@petroleumnews.com

FINANCE & ECONOMY

Exxon lost $1B in 2nd quarter on oil use

Exxon lost $1.1 billion in the second quarter, its economic pain deepening as the pandemic kept households on lockdown, diminishing the need for oil around the world.

The Irving, Texas-based oil giant brought in $32.6 billion in revenue during the second quarter, less than half of what it brought in at the same time last year.

The quarter was one of the worst on record for the oil industry. The price of a barrel of benchmark U.S. crude fell below $0 in April, a stunning downfall that had not before been seen in the industry. Producers had been pumping far more oil than the world was using as global travel all but shut down, and storage tanks were filling up. Exxon announced that month that it would cut its capital spending budget by 30%, to $23 billion, and its cash operating expenses by 15%, in 2020.

Oil prices have recovered somewhat since but have been stuck at around $40 a barrel for weeks, fetching 30% less than a barrel did a year ago and well below what most producers need to make ends meet.

Oil prices have recovered somewhat since but have been stuck at around $40 a barrel for weeks, fetching 30% less than a barrel did a year ago and well below what most producers need to make ends meet.

Big industry job loses

As a result, the U.S. oil industry lost more than 100,000 jobs since February, with 45,000 of those jobs shed by upstream oil and gas companies in Texas alone, according to Rystad Energy, a consulting firm.

"The global pandemic and oversupply conditions significantly impacted our second quarter financial results with lower prices, margins, and sales volumes," said Darren Woods, chairman and CEO, in a statement July 31. "We responded decisively by reducing near-term spending and continuing work to improve efficiency by leveraging recent reorganizations."

Exxon Mobil Corp. produced 3.6 million barrels of oil-equivalent, down 7% from last year. That included a 12% drop in natural gas production.

Chevron Corp. lost $8.27 billion during the quarter, a sharp contrast to the $4.3 billion it brought in during the same quarter last year. The San Ramon-based oil giant brought in $13.49 billion in revenue, about a third of what it brought in last year.

"The past few months have presented unique challenges," said Michael Wirth, Chevron's chairman of the board and CEO, in a statement. "The economic impact of the response to COVID-19 significantly reduced demand for our products and lowered commodity prices."

Phillips 66, the Houston-based oil refining and logistics company, lost $141 million during the quarter.

—ASSOCIATED PRESS

continued from page 1

SANDS TROUBLE

Producers, CAPP.

The company said it now views oil reserves with high production costs that are to be produced beyond 2040 to be "stranded" given its own carbon-reduction goals.

The write-downs include C$7.3 billion tied to its 24.6% ownership of the Fort Hills oil sands mines operated by Suncor Energy and its 50% stake in the Surmont thermal recovery project operated by ConocoPhillips.

In addition, Total will write off C$2 billion in other oil sands properties, along with its US$1.07 billion holding in Australia's LNG assets.

Total said it is also quitting CAPP because of a "misalignment" between the public positions stated by the Canadian industry's leading lobby organization and those expressed three months ago in Total's own climate change strategy.

CAPP Chief Executive Officer Tim McMillan said there was a contradiction between Total's asset write-downs and its increased "focus in Africa, Brazil and the Middle East," border-line democracies where the company has increased investment and focus in recent years.

Alberta Energy Minister Sonya Savage said the oil sands will continue to offer investment in a "stable and ethical democracy. At the same time Total is dismissing the leadership of Canadian producers who are doing their part to reduce greenhouse gas emissions while it continues to invest in countries such as Myanmar, Nigeria and Russia."

"This highly-hypocritical decision comes at a time when international companies should be increasing their investment in Alberta, rather than abandoning a source of stable, reliable, supply of energy," she said,

The ban will block financing and capital market transactions in oil sands exploration, production, transport or processing that will cover pipelines, upgraders and refineries.

Banks backing out

The latest flurry of pull-outs comes on the heels of Norway's US$1 trillion sovereign wealth fund decision to dump its stakes in oil sands majors Suncor, Canadian Natural Resources, Cenovus Energy and Imperial Oil over "unacceptable greenhouse gas emissions," although it made no mention of Chinese-controlled Husky Energy.

Two years ago, Europe's largest bank, HSBC Holdings, said it would no longer offer financial services for new oil sands projects or pipelines, a move that led Suncor to end all business with HSBC, including its conventional operations in Europe.

Total's move came two days after Frankfurt-based Deutsche Bank said it would join a list of European lenders and insurance companies that have opted out of backing new oil sands projects.

The German bank said its new fossil fuels policy will also prevent it from investing in projects that use hydraulic fracturing in countries with scarce water supplies and all new oil and gas projects in the Arctic region.

TMX insurance

Insurance giant Zurich has decided not to renew coverage for the Trans Mountain pipeline expansion but refused to divulge its reasons.

TMX, which has another 10 insurers, mostly in the United States, said it has the insurance it needs for its existing operations and the expansion.

Trans Mountain's annual liability insurance contract, dated a year ago, listed Zurich as the lead insurer for the first C$8 million of potential payouts.

British Columbia's president of Indian chiefs Stewart Phillip said he hopes other companies will follow Zurich's lead and end their "complicity in violations of Indigenous rights ... because the pipeline expansion does not have the consent of all impacted First Nations along the route."

Jackie Forrest, executive director of ARC Energy Research Institute, said that although the oil sands impact on carbon emissions is often misjudged in comparison to other crude oil sources there is little question that Canada must commit to a net zero carbon target.

She said a benchmark for European banks is a peer-reviewed study by Stanford University in 2018 that rated Canada as the fourth most carbon-intensive of 50 countries, trailing only Cameroon, Venezuela and Algeria. ●

Contact Gary Park through publisher@petroleumnews.com

continued from page 1

KUPARUK POD

workforce and the need to significantly reduce personnel on the Slope.

In a July 30 letter approving the company's proposed 2020 Kuparuk POD, the Alaska Department of Natural Resources' Division of Oil and Gas said that after it received the April 30 proposed POD it notified ConocoPhillips "that the POD submittal was deemed incomplete," requesting amendments to address the division's questions and concerns. Following responses to its questions, in early June the division deemed the POD complete.

Reduced production

ConocoPhillips had said it would reduce its North Slope production from the Kuparuk, Colville River and Greater Mooses Tooth units by 100,000 bpd in June, with ramp down beginning in late May. In mid-June, the company said it would resume normal production operations in July.

What about the oil that wasn't produced in during July?

The division quoted ConocoPhillips that once production curtailment ended, about 50% of the volume curtailed would be recovered over the next 3 years, with the remainder recovered over the life of the field.

The company said market and public health considerations are key to the resumption of drilling activities.

"The public has an interest in diligent exploration, evaluation, and development of the State's resources," the division said in approving the POD.

It said ConocoPhillips' 2020 Kuparuk POD plans "protect this public interest by the resumption of normal production operations in July 2020, along with any and all maintenance, workovers and the like either to increase or maintain production, maximize revenues, and prevent waste by continued production for existing wells."

2020 proposed activities

At the Kuparuk participating area sidetracks may be done from existing wells which are currently shut-in due to mechanical problems or low production, and both rotary and coiled tubing drilling rigs may be used. Assessments will be done of operations and support infrastructure to determine upgrade or replacement which would contribute to continued production.

At the Meltwater PA, development opportunities are being analyzed based on a reevaluation of 2008 seismic, recent surveillance, water injection supply and business climate, with possibilities including coiled tubing drilling sidetracks or producer to injector conversions.

At the Tabasco PA waterflood optimization is being studied to maintain or improve field performance over the next 5 years along with replacement of the progressive cavity pump in the 2T-215 well to bring it online.

At the Tarn PA, the company plans to convert the 2L-311 well from jet pump to gas lift, increase pressure support in 2L and initiate a surfactant injectant pilot program.

At the West Sak and NEWS PAs, there will be continued monitoring of rigless electric submersible pump performance and diagnostics of matrix bypass events (dramatic water breakthrough events with direct flow from injector to producer, interrupting waterflood process), continued surveillance of recent West Sak CTD wells, extension of viscosity reducing water alternating gas to 1H NEWS and evaluation of future West Sak development wells including for rotary wells and two CTD wells, along with assessing operations and support infrastructure for future upgrade or replacement.

There are also tract operations in the plan, with continued evaluation of the overlying Moraine-Torok interval from two existing horizontal producer and injector wells pairs, with two additional pairs planned in the future and continuing ESP troubleshooting at the Ugnu formation in the 1H-Ugnu-401 wells to determine if higher production rates can be sustained.

—KRISTEN NELSON

Contact Kristen Nelson at knelson@petroleumnews.com

continued from page 1

PIKKA AMENDMENT

working interest owner, Repsol E&P USA, 49% (see story in the June 28 issue of Petroleum News).

Although the unit agreement declares Oil Search the operator, mentions of Repsol being the operator still appeared in random official documents. The purpose of the amendment was to make certain everyone understood Oil Search was unit operator.

The June 1 filing, which was signed by both Oil Search (Alaska) President Bruce Dingeman and Repsol (signature illegible), also updated relevant addresses and other contact information.

Oil Search mailed the amendment to both DNR Commissioner Corri Feige and to Rex Rock Sr., president of ASRC.

History of unit agreement

The initial 33-lease Pikka unit was formed effective June 1, 2015, by then-working interest owner and operator Repsol, along with working interest owners Armstrong subsidiary 70&148, which brought Repsol into the play, and GMT Exploration Co.

DNR approved the first expansion of the Pikka unit on Nov. 29, 2016, and ASRC approved it on Feb. 28, 2017.

In a March 7, 2018, letter to DNR and ASRC, Oil Search was designated as successor unit operator in accordance with an article in the agreement. DNR and ASRC approved the change in operatorship on March 20 and 21, respectively.

A revised Pikka unit operating agreement between the working interest owners was filed with DNR and ASRC on Oct. 9, 2019.

Pikka is expected to produce 135,000 barrels of oil per day, with production starting in 2025, and that is excluding output from what is anticipated to be Oil Search's next North Slope development from the nearby Horseshoe discovery with its most recent Stirrup prospect find.

—KAY CASHMAN

Contact Kay Cashman at publisher@petroleumnews.com

continued from page 1

BONDING LIMBO

was already understood — that it will only allow a reduction in the bond amount if an operator demonstrates it has coverage in place with the landowner that is "dedicated exclusively to the plugging and abandonment of a well or wells."

Similar to the coverage required by AOGCC under its new bonding regulation that went into effect April 18, 2019, DNR's "bonds held for the plugging and abandoning of wells will only be released after the work has been performed," DNR Deputy Commissioner Sara Longan said in an early May 2019 letter to AOGCC that asked for reconsideration.

Three extra years

The primary change proposed in AOGCC's Aug. 4 public notice increases the number of annual installments an operator can make from 4 years to 7 years. These payments are for what AOGCC billed operators for retroactive bonding increases.

AOGCC's new bonding regulation reflects concerns that previous bonding levels fell short of the realistic cost of plugging and abandoning wells. If an operator fails to P&A a well and has insufficient bonding to cover the costs, those costs fall on the landowner; on state land that is DNR.

Prior to the new bonding regulation enactment in April 2019, the commission generally required bonding at the statutory minimum level of $100,000 for a single well and $200,000 for blanket coverage of all an operator's wells in the state. Under the new regulation the required bonding is $400,000 per well for one to 10 wells; a $6 million bond for 11 to 40 wells; a $10 million bond for 41 to 100 wells; a $20 million bond for 101 to 1,000 wells; and a $30 million bond for more than 1,000 wells.

The primary change proposed in AOGCC's Aug. 4 public notice increases the number of annual installments an operator can make from 4 years to 7 years.

Six small companies protest

Under some circumstances the commission may increase or decrease the required bonding level, but of the filings for reconsideration filed by six small oil and gas companies — AIX Energy, Alaskan Crude, Amaroq Resources, Cook Inlet Energy, Malamute Energy and Savant Alaska — only one company's bonding has been reduced.

In late March of this year, AOGCC reduced the bond required for four AIX Energy wells at the Kenai Loop field from $1.6 million to the $200,000 bond AIX already had in place with the commission, based on the company having a $950,000 certificate of deposit in place for plugging and abandoning with the landowner, Mental Health Trust Land Office.

On the issue of duplication of bonding between agencies, AOGCC Commissioner Dan Seamount told Petroleum News in August 2019 that the commission is required by statute to have a bonding program.

Deter O&G investment

Longan said DNR was worried that the increases in the bonding levels would deter oil and gas investment in the state, and especially hurt small to mid-size oil and gas explorers and producers.

She also noted that the new bonding levels exceed those of other states.

"Current Alaska bonding requirements already parallel or exceed other states. For example, New Mexico's counterpart to AOGCC has a law similar to Alaska's which allows producers to provide a 'blanket plugging financial assurance' not to exceed $250,000. Texas is also similar to Alaska. It has a three-tiered bonding schedule which is capped at $250,000 for producers with more than 100 wells. North Dakota requires a blanket bond for all wells of $100,000," Longan told Petroleum News in an Aug. 6, 2019 email.

In October 2018, under former Gov. Bill Walker's administration, DNR had provided comments during the public comment period for the new regulation that did not raise these concerns or the issue of duplication, and instead supported AOGCC's actions.

It should be noted that Walker was decidedly less supportive of Alaska's oil industry than the current governor, Mike Dunleavy, and that the AOGCC bonding amount hasn't changed in at least 40 years. (The current equivalent of the minimum 1980 bond amount of $100,000 would be $350,000.)

Separate authorities

Longan also said Aug. 6, 2019, "Agencies often have shared goals and separate authorities to help protect the state's interest during the operational life of a field including the proper DR&R. We have suggested AOGCC collaborate with DNR to fully understand the comprehensive state bonding requirements. Without agency collaboration, there will be duplication and overlap."

And collaboration seemed to finally be happening — see story in June 20 issue of Petroleum News titled, "Duplicate bonding solved? AOGCC appears to be working with landowners that do initial surety bonding."

"Since AOGCC implemented its new oil and gas surety bonding standards, DNR and AOGCC have successfully been working to increase our coordination, with a goal of ensuring all parties fully understand existing statewide bond coverage," Longan told Petroleum News in a June 1, 2020, email.

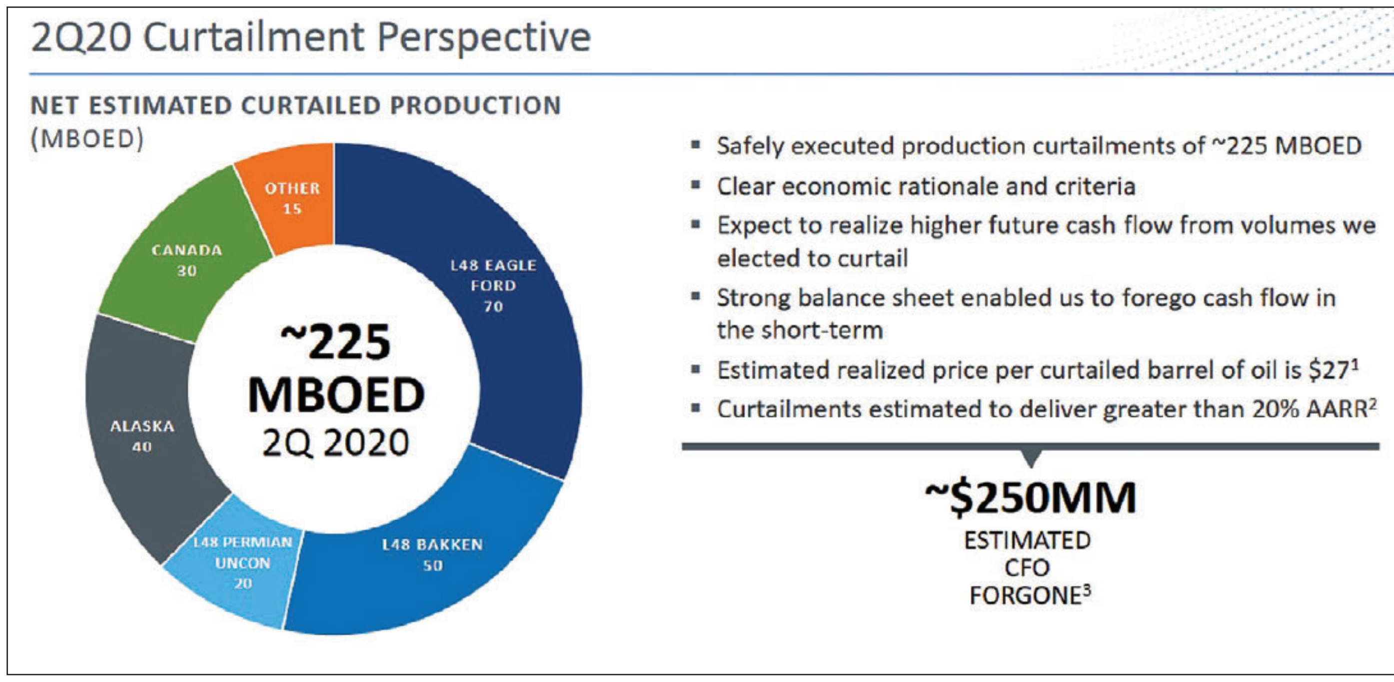
Neither Longan nor AOGCC Chair Jeremy Price was able to comment on the proposed changes on Aug. 5.

AOGCC has scheduled a hearing on the changes for Sept. 1. Written comments can be submitted until 4:30 p.m. on Sept. 10. ●

Contact Kay Cashman at publisher@petroleumnews.com

continued from page 1

CONOCO 2Q REPORT



Other Alaska news in the quarterly report included:

• ConocoPhillips made a finance lease payment of $200 million upon acceptance of the ultra-extended reach drilling rig, Doyon 26.

• ConocoPhillips completed appraisal testing at Narwhal with "encouraging" initial results. (The U.S. Geological Survey now refers to this Nanushuk system of discoveries and associated sand bodies as the Pikka-Narwhal-Horseshoe trend.)

Nothing was mentioned about last winter's exploration results from the Tinmiaq (Willow) or Harpoon prospect wells beyond what was already reported.

In a follow-up question regarding North Slope development, appraisal and exploration drilling, ConocoPhillips Alaska spokeswoman Natalie Lowman said, "We do not intend to resume drilling activity at our North Slope operations for the remainder of 2020. The capital reductions we announced in March and April were directed under the premise that we would not resume drilling activity this year."

Lowman also said the company's "estimated obligations to the state of Alaska in the form of taxes and royalties totaled $85 million. So even though ConocoPhillips Alaska had a net loss of $222 million, we still paid the state of Alaska $85 million in taxes and royalties. And despite this quarter's loss, the company invested $223 million in capital in the state, which represents 25% of ConocoPhillips' $876 million global capital spend in 2Q 2020."

Company-wide performance

ConocoPhillips reported company-wide second-quarter earnings of $300 million, or 24 cents per share, compared with second quarter 2019 earnings of $1.6 billion, or $1.40 per share.

Excluding special items, second quarter adjusted earnings this year were a loss of $1 billion, or 92 cents per share, compared with second quarter 2019 adjusted earnings of $1.1 billion, or $1.01 per share.

Special items for the current quarter were primarily due to a realized gain on the completion of the Australia-West divestiture and an unrealized gain on Cenovus Energy equity.

Cash provided by operating activities was $200 million. Excluding working capital, cash from operations was $700 million.

"Headline second-quarter performance was dominated by weak realized prices, coupled with our rational economic action to curtail production in favor of expected higher future prices," said Ryan Lance, ConocoPhillips chairman and chief executive officer.

"Importantly, our underlying business results were strong, reflecting our ongoing commitment to safely executing our plans and the dedication of our workforce during this challenging time," he continued. "We are monitoring the market closely to develop a view around the timing and path of price recovery and to guide our corresponding actions. For example, as the market strengthened late in the second quarter, we began reversing our second-quarter curtailments and ramping up production across the Lower 48, Alaska and Canada."

ConocoPhillips "financial strength, flexibility and portfolio diversity represent a distinct competitive advantage that enables us to navigate and preserve value in this volatile environment," Lance said.

—KAY CASHMAN

Contact Kay Cashman at publisher@petroleumnews.com

continued from page 1

HYDROGEN PROJECTS

extract hydrogen.

The International Energy Agency says hydrogen is enjoying "unprecedented momentum" around the world because it is light, storable, energy-dense and produces no direct emissions of pollutants or GHGs.

Alberta pilot project

In Alberta, a pilot project to operate hydrogen-powered trucks between Edmonton and Calgary has received C$7.3 million from a government corporation funded by a GHG tax on large emitters.

This is the first step in establishing a "very aggressive and profitable hydrogen industry," said Dale Nally, Alberta's associate minister of natural gas.

In addition, the province is about to pump C$58 million into a string of small-scale ventures to develop a market for the alternative energy source.

Canada's Natural Resources Minister Seamus O'Regan is ready to join forces with Alberta in exploring the new technology, promising to have "a comprehensive strategy in place by the end of summer."

However, he shares the concern of others that hydrogen fuel remains expensive to produce and will take time to lower those costs.

Net-zero GHGs

Dozens of countries are now working towards net-zero GHGs, with Australia establishing a fund worth the equivalent of US$220 million for hydrogen projects, while Norway has earmarked US$370 million for green technologies including hydrogen power solutions.

In July Germany's federal cabinet adopted a national hydrogen strategy aimed at making the country a leading player in evolving the technology.

A month ago, the European Commission published a report on a "hydrogen strategy for a climate-neutral Europe," calling for the economic bloc top concentrate on green hydrogen.

"For hydrogen to contribute to climate neutrality, it needs to achieve a far larger scale and its production must become fully decarbonized," the report said.

Carbon capture and storage

Simon Dyer, executive director of the Alberta-based Pembina Institute, said carbon capture and storage can play an important role in "decarbonizing Canada's energy systems ... as we build a more sustainable economy for all Canadians."

The IEA said that for hydrogen to make a significant contribution to cleaner energy it must be adopted in sectors where it is largely absent, such as transport, buildings and power generation.

HSBC analyst Sean McLoughlin told the Globe and Mail that demand for hydrogen-based electric vehicles is trailing sales of battery-powered vehicles, whose costs are falling, while charging points in homes and communities are on a rapid growth curve. In contrast, hydrogen refueling infrastructure is scarce.

McLoughlin said an estimated 13,000 hydrogen-powered vehicles were in use at the start of 2019, led by Japan, with China making bold strides to move ahead.

In addition to the Canadian and Alberta governments, British Columbia has been a pioneer, opening Canada's first hydrogen refueling station in 2018 and growing that to a small network of government-sponsored retail stations.

British Columbia has been spurred on by Vancouver-based Ballard Power, which was founded in 1979 to develop fuel cell membranes. Its shares have been on a sickening ride over 25 years, peaking at C$132 in 2000, plunging to almost rock bottom, then recovering to C$21 over the past year, as it briefly attracted global investors, who often bolted for the exit door.

Alberta could work its way to the leading edge of the technology from its current role of producing millions of metric tons a year of hydrogen, which is used to convert oil sands bitumen into synthetic crude, gasoline, diesel, jet fuel, plastics and fertilizers.

—GARY PARK

continued from page 1

OIL PRICES

production beginning in August is likely to moderate upward price action over the next few months.

However 2020 may turn out to be a better year than originally expected by oil price prognosticators.

A Reuters survey of 43 analysts and economists released July 31 forecast Brent crude to average $41.50 per barrel in 2020, up from a $40.41 consensus in its June survey. Brent is expected to average $49.85 in 2021.

On the demand side, the poll projected a contraction of between 7.2 million and 8.5 million barrels per day for the full-year 2020.

Oil is "caught-up in a step-wise rebalancing process," said Harry Tchilinguirian, head of commodity research at bank BNP Paribas. "It's in demand recovery where the uncertainty lies, with COVID-related developments generating concerns that the pace of reopening may be impeded."

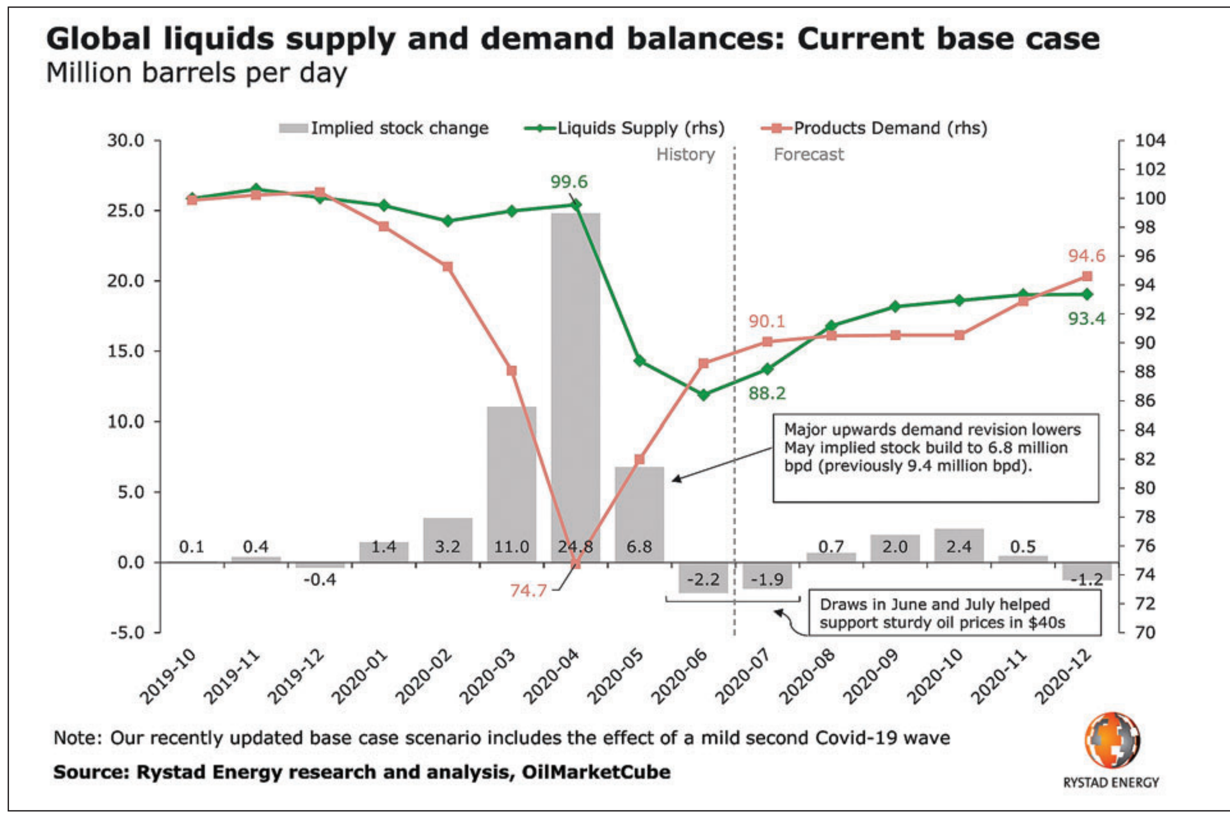
If the COVID-19 situation improves, demand will improve, and so will prices.

"A breakthrough of the $40 to $45 range is possible if the comeback of the global economy will be faster and stronger than expected," LBBW analyst Frank Schallenberger said.

A Rystad report released July 28 predicted that demand will exceed supply in December, despite recent COVID-19 spikes and the OPEC+ production increases.

But the report (covered in Petroleum News last week), anticipated a 170 million-barrel supply glut due to OPEC+ production activity before supply and demand balance at the end of the year.

If the Rystad projections play out, the stage will be set for higher prices in 2021, as predicted by the Reuters poll.



Explosion roils oil markets

Oil trading saw a spike in volatility Aug. 4 as a massive explosion at Lebanon's main port in its capital Beirut was at first feared to have been an attack.

President Donald Trump said Aug. 4 that the explosion was a "terrible attack" which American generals told him it was likely caused by a bomb.

"They seem to think it was an attack," Trump said. "It was a bomb of some kind, yes."

By the following day, it was understood to have been an unfortunate industrial accident due to ignition of an estimated 2,750 metric tons of explosive ammonium nitrate stored at a warehouse, possibly involving fireworks as well.

More than 135 people were killed and 5,000 wounded in the explosion, according to the Red Cross.

While a conflagration in the Middle East could rapidly escalate oil prices, the Lebanon event is not seen to have a lasting impact on oil prices. Trading on Aug. 4 settled down with benchmark prices ending slightly higher across the board.

Continental increases production

Continental Resources Inc. sees higher prices coming, and the company is increasing production after shutting in 70% of its production in May and June due to the COVID-19 pandemic.

"We expect third quarter production to range between 280,000 and 300,000 boe per day," CEO William B. Berry said in a Aug. 3 conference call. "Consequently, production will increase in the second half of 2020, and we expect to exit the year at 310,000 to 330,000 boe per day."

Berry said the company's actual July volumes will be in line with previous guidance of about 225,000 to 250,000 boe per day.

"As we look forward, there are a number of factors positioning us for a strong second half of 2020 and beyond," he said.

"We're bringing back essentially all our oil production in August," Berry said. "So we're up and running all the production that we had shut-in."

The company said the return of prices to the $40 level spurred the increased production, along with the expectation of higher pricing in the future.

"$40 a barrel, we don't believe that's going to be here long term," Executive Chairman Harold G. Hamm said. "Just that's not going to be sufficient to hold production levels in the U.S. and the world, so we think that's a very short-term situation anyway." ●

Contact Steve Sutherlin at ssutherlin@petroleumnews.com