Petroleum news

page 6 EIA: 500,000 bpd drop in US crude output; at $32, Brent down $24

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Hilcorp continues to drill; Wulff moves to strengthen Oil Search

Oil Patch Insider

ONE MAJOR ALASKA OIL AND GAS PRODUCER and explorer has not cut the number of drilling rigs it has working in the state. As of April 8, privately owned Hilcorp had two rigs working on the North Slope and one in the Cook Inlet basin.

Furthermore, Hilcorp received approval April 7 from Alaska's Division of Oil and Gas to drill 11 new development wells and install associated infrastructure on I Pad in the North Slope Milne Point unit. The project is scheduled to start April 13.

A new conductor and well house will be installed for each new I Pad well. The existing pipe rack and pipe header system

see **INSIDER** *page 10*

RCA has many questions; hearing a possibility, as is intervention

The Regulatory Commission of Alaska has resolved initial issues in Harvest Alaska's acquisition of BP Pipelines (Alaska)'s interest in the trans-Alaska oil pipeline, and its share in the Milne Point and Point Thomson pipelines, and is now turning its attention to whether the acquisitions meet its statutory standards and whether they are in the best interest of the public.

In March the commission ruled financial information in its dockets on the acquisition must be considered confidential (see story in March 22 issue of Petroleum News). It had previously ruled that copies of the sales agreement were confidential.

And the commission set a date of Sept. 28 to issue final orders on the dockets.

see **HILCORP TAKEOVER** *page 8*

Charlie well results so-so; 88E pursues HRZ unconventional

Australia independent 88 Energy says its Charlie 1 appraisal well is being plugged and abandoned after its primary oil target could not be tested because it was "poorly developed," and although a large pool of natural gas condensates was encountered in the Torok formation the company has to determine whether it can be commercially developed on the North Slope because of its likely high gas content.

88 Energy Managing Director David Wall said in an April 7 statement that in coming months samples of the gas condensates will be analyzed for commercial viability. The samples were taken at approximately 10,500 feet and 10,650 feet.

Charlie 1 reached a total vertical depth of 11,112 feet on March 30, having drilled through and logged all seven targets,

see **CHARLIE WELL** *page 10*

Virus spreads tentacles; impacts two British Columbia LNG projects

Of the only two LNG projects under construction in British Columbia, LNG Canada has slashed its construction workforce at the Kitimat terminal by 50% and Woodfibre LNG has delayed its completion date by a year, both of them attaching the blame largely to COVID-19.

The pandemic has also affected work to convert a refinery near Edmonton to switch from processing synthetic crude oil to raw bitumen feedstock.

In its latest report, Trans Mountain said there have been no delays to work on the C$12.6 billion expansion of its existing pipeline to ship 890,000 barrels per day of oil sands bitumen to a tanker terminal in the Port of Vancouver.

see **VIRUS FALLOUT** *page 8*

EXPLORATION & PRODUCTION

Half completed

ConocoPhillips demobilizes Slope rig fleet; several exploration wells drilled

By KAY CASHMAN
Petroleum News

The North Slope's most active explorer and largest oil producer, ConocoPhillips Alaska, said April 8 that it is demobilizing its North Slope rig fleet, confirming information from Petroleum News sources who said the company terminated its off-road winter drilling season early — after completing Tinmiaq 18 and 20 exploration wells, as well as a rank exploration well in its Harpoon prospect, Harpoon 2.

The Tinmiaq and Harpoon wells are in the National Petroleum Reserve-Alaska. (See map in pdf and print versions of this issue of Petroleum News and another map at: https://dog.dnr.alaska.gov/Information/MapsAndGis#a and scroll down to North Slope activity maps, click on the latest for January 2020.)

ConocoPhillips had hoped to complete up to three wells at Harpoon and four Tinmiaq wells this season.

Twenty-five miles southwest of Willow, the Harpoon prospect is viewed by the company as a potential standalone development or as a tie-back to the Willow hub.

The Tinmiaq wells were drilled by Doyon 141 and the Harpoon well by Doyon 142.

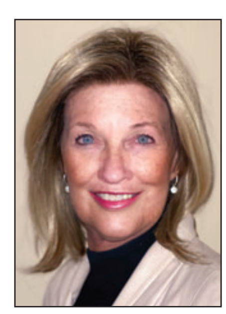
see **CONOCO DRILLING** *page 11*

FINANCE & ECONOMY

Price, production drop

Spring revenue forecast has ANS price down 18.7% from fall, production down 1.1%

By KRISTEN NELSON
Petroleum News



LUCINDA MAHONEY

The Alaska Department of Revenue's Spring 2020 Revenue Forecast, released April 6, shows a sharp drop in the forecast West Coast price for Alaska North Slope crude from the fall forecast, and a smaller drop in ANS production.

The department's fall forecast, issued in December, had ANS West Coast pegged at $63.54 per barrel for fiscal year 2020, which ends June 30, and $59 per barrel for FY 2021, which begins July 1.

The spring forecast shows the projected average ANS West Coast price for the fiscal year ending June 30 at $51.65 per barrel, down $11.89 from the fall forecast, 18.7%, and the 2021 fiscal year price at $37 per barrel, down $22, 37.3%, from a fall forecast of $59 per barrel.

In a cover letter for the spring forecast, Revenue Commissioner Lucinda Mahoney said the forecast is based on ANS "oil prices remaining below $30.00 per barrel for the remainder of FY 2020, resulting in an annual average price of $51.65 per barrel. The ANS price forecast is $37.00 for FY 2021,

see **REVENUE FORECAST** *page 10*

PIPELIENS & DOWNSTREAM

Not yet a done deal

Observers caution Keystone XL still faces legal challenges, market questions

By GARY PARK
For Petroleum News

The hallelujah chorus that greeted word of a return to construction on the Keystone XL pipeline, fueled by the Alberta government's decision to acquire a US$1.1 billion equity stake and provide a US$4.2 billion loan guarantee, is rapidly being drowned out by doubters.

Within days of the March 31 announcement of a go-ahead by TC Energy and Alberta, buckets of cold water were being dumped on the optimists.

Moody's Investors Service was quick to change the credit outlook for TC Energy and its subsidiaries from stable to negative, reflecting concerns about the costs of getting the long-delayed, hotly contested project to start delivering 830,000 barrels per day of bitumen from the Alberta oil sands to Steele City, Nebraska, by mid-2023, with an ongoing connection to U.S. Gulf Coast refineries that are configured to process heavy crude.

"The negative outlook reflects the very high level of execution risk related to the environmental, social and governance factors associated with (Keystone XL)," said Moody's Vice President and Senior Credit Officer Gavin MacFarlane.

"We do not assume that the project will be completed in our current forecasts for the company and will only incorporate cash flow when the project is complete," he said.

Legal, regulatory, protest issues

Moody's said the project could be disrupted by ongoing "demonstrations and civil unrest" as well as

see **KEYSTONE XL** *page 10*

● EXPLORATION & PRODUCTION

US drilling rig count plunges 64 to 664

By KRISTEN NELSON

Petroleum News

Baker Hughes reports the number of rigs drilling for oil and natural gas in the U.S. the week ending April 3 was 664, down by 64 rigs, eclipsing a 44-rig drop from the previous week and a 20-rig drop the week before that, and down by 361 from 1,025 a year ago.

In its weekly rig count the Houston oilfield services company said 562 rigs targeted oil, down 62 from the previous week and down by 269 from a year ago, while 100 targeted natural gas, down two from the previous week and down 94 from a year ago. There were two miscellaneous rigs active, unchanged from the previous week and up by two from a year ago.

The company said 41 of the holes were directional, 593 were horizontal and 30 were vertical.

There were no states with an increase in drilling rigs from the previous week.

Rig counts were unchanged in Louisiana (44), Ohio (9), Pennsylvania (24), Utah (8) and West Virginia (15).

The largest rig count drop by basin was the Permian, which also has the most active rigs at 31. The count in that basin was down 31 from the previous week and down 111 from a year ago.

The rig count in Texas, the state with the most active rigs at 338, was down by 30 from the previous week, and down by 161 from a year ago.

Oklahoma was down by 10 rigs (to 29); New Mexico was down by nine rigs (to 100); North Dakota was down by six rigs (to 42); and Wyoming was down by five rigs (to 14).

California was down by two (to 10); Alaska (8 rigs) and Colorado (18 rigs) were each down by one rig.

The eight-rig count Baker Hughes shows for Alaska for the week ending April 3 is unchanged from a year ago.

The largest rig count drop by basin was the Permian, which also has the most active rigs at 31. The count in that basin was down 31 from the previous week and down 111 from a year ago.

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

Worldwide count down

Baker Hughes released its monthly worldwide rig count April 3, showing a March international rig count (which excludes North America) of 1,059, down 26 from a February count of 1,085, but up 20 from a March 2019 count of 1,039.

The offshore portion of the international rig count was 244, down by one rig from 245 in February and down three from 247 in March 2019.

In March the U.S. rig count averaged 772, down 19 from 791 in February, and down 251 from 1,023 in March 2019. The Canadian rig count averaged 133 in March, down 116 from 249 in February and down 18 from 151 in March 2019.

The March worldwide rig count, which includes North America, was 1,964, down 161 from 2,125 in February and down 249 from 2,213 in March 2019. ●

Contact Kristen Nelson at knelson@petroleumnews.com

contents

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EXPLORATION & PRODUCTION

Focus on production maintenance, facilities

Hilcorp submits development plans for oil and gas fields online since the 1960s: McArthur River, Middle Ground Shoal, Trading Bay

By KRISTEN NELSON
Petroleum News

Hilcorp Alaska has submitted annual plans of development for three oil and gas fields which have been producing from Cook Inlet platforms since the 1960s: the Middle Ground Shoal field in the unit of the same name and the Trading Bay and McArthur River fields in the Trading Bay unit.

Maintaining and enhancing production is the stated goal for these fields, but there is also a good deal of facilities work planned for the plan period of July 1 through June 30, 2021.

Maintaining and enhancing production is the stated goal for these fields, but there is also a good deal of facilities work planned for the plan period of July 1 through June 30, 2021.

Middle Ground Shoal

Hilcorp produced 459,000 barrels of oil and 91.074 million cubic feet of natural gas from Middle Ground Shoal at platforms A and C in Cook Inlet in calendar year 2019. There are four platforms in the unit, A, C, Baker and Dillon; only the A and C platforms are currently producing.

The company said it performed multiple workover operations not anticipated when it submitted the 2019-20 plan.

On the facilities side, Hilcorp completed diver tactile inspections at Platform A and inspection and stabilization of gas pipeline where needed. At Baker Platform the company removed three subsea cathodic protection anode sleds for inspection and recabling — all work anticipated in the 2019-20 plan.

The company also installed galvanic anode sleds on A1 and B1 pipelines traveling from onshore to Platform A; replaced cathodic protection cable between beach and onshore facility due to vandalism; and performed nearshore visual and nondestructive testing inspections between the beach and tidal flats of A1 and B1 pipelines on extremely low tide.

For 2020, Hilcorp plans to delineate underlying oil or gas reservoirs and said it is "continuing to pursue rate adding opportunities off both A and C platforms. If economic hurdles are met, Hilcorp plans to update completion designs to minimize scale formation, squeeze water producing intervals, add perforations, clean out scale in producer/injection wells, and repair damaged wells."

The company said it is also looking at drilling several rotary wells and some coil tubing wells and is evaluating all subsurface work conducted over the past two years "for potential development scenarios from Platforms A, C, and Baker. This includes rotary infill drill locations, Coil Tubing Sidetracks, and step out exploration tests."

Facilities work planned includes leg wrap inspection/repair at Platform A; subsea flange inspection at Platform A; and a "close interval survey on A1 and B1 pipelines."

On the Baker Platform, Hilcorp said it will clean and temporarily abandon in place B gas pipeline and inspect subsea platform brace joints critical to the structure's integrity.

On the Dillon Platform, the company will clean and temporarily abandon in place A gas pipeline.

McArthur River

Hilcorp produced 1.7 million barrels of oil and 8.347 billion cubic feet of natural gas from the McArthur River field in calendar year 2019. The field is Cook Inlet's largest oil producer.

The company did no grassroots drilling at the field but performed one workover operation.

On the facilities side, Hilcorp installed the fin fan cooler on the Grayling Platform west centaur gas lift compressor and replaced the north crane on the Steelhead Platform.

Hilcorp said long-range proposed development at McArthur River includes "plans to delineate all underlying oil or gas reservoirs into production, and maintain and enhance production once established."

The company will continue evaluating existing completions for rig workover opportunities "to optimize the drawdown and lift mechanisms at McArthur River Field wells," and continue working on the Grayling gas sands field study to identify additional subsurface opportunities.

Workover operations are planned on two wells on the Dolly Varden Platform, with additional electronic submersible pump repairs or replacements on "all McArthur River Field platforms" as needed.

Facilities work includes doing repairs or replacing equipment as needed on the Dolly Varden Platform.

On the Grayling Platform, an inline inspection will be performed on the gas pipeline and other repairs or replacements as needed.

No major facility upgrades are planned for the King Salmon Platform or the Steelhead Platform, but repairs or replacement equipment will be installed as needed.

Cathodic protection repair on the rectifier is planned for the Trading Bay Production Facility.

Trading Bay

Hilcorp produced 506,800 barrels of oil and 1.145 billion cubic feet of natural gas from the Monopod Platform at the Trading Bay field in calendar year 2019.

The company drilled the A-10RD to evaluate the Hemlock and Tyonek G-zone sands, but the well was a dry hole and was not completed. It also performed multiple workover operations.

On the facility side, Hilcorp completed its anticipated oil pipeline reroute project.

In early 2019 corrosion damage was discovered on the oil pipeline riser at the Monopod Platform and remediation was required. The work lasted seven weeks, with the platform shut-in for 15 days and the A-10RD drilling operation delayed.

For 2020-21 Hilcorp said it is working on a Trading Bay field study "to identify additional rig workover, rotary sidetrack, perforation adds, and waterflood optimization opportunities."

Workover operations are planned on the A-15RD2 to restore production from the Hemlock zone in the McArthur River field, and electronic submersible pump repairs or replacement will be done as needed.

Facilities work planned includes inline inspections on oil and gas pipelines at the Monopod Platform, regulatory inspections as required and repairs or replacements as needed to support ongoing drilling and production activities.●

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LAND & LEASING

State issues new info call for fall sales

The Alaska Department of Natural Resources' Division of Oil and Gas has issued a call for "substantial new information that has become available over the past year" for state acreage in the Beaufort Sea Areawide, North Slope Areawide and North Slope Foothills Areawide oil and gas lease sale areas, where sales are tentatively scheduled for the second half of the year.

The most recent best interest findings for the sale areas are: Beaufort Sea 2019; North Slope 2018; and North Slope Foothills 2011.

The division said it "generally considers 'substantial new' information to be published research, studies, or data directly relevant to matters" in statute that has become public over the last year.

Information must be received by 5 p.m., May 4.

—PETROLEUM NEWS

● GOVERNMENT

Vehicle fuel efficiency rule issued

DOT and EPA finalize regulations requiring 1.5 percent improvement per year to 2026 in fuel efficiency for cars and light trucks

By ALAN BAILEY
For Petroleum News

The U.S. Department of Transportation and the Environmental Protection Agency have published a final rule for fuel efficiency standards for cars and light trucks for vehicle model years 2021 to 2026.

The rule specifies formulae for determining the required efficiencies for vehicle models, based on the square footages of vehicle footprints. Essentially, the efficiency standard amounts to a required efficiency improvement of 1.5% per year. The agency had announced a proposed rulemaking in August 2018 — the final rule now incorporates adjustments based on public comments on the proposed rule. The rule leaves the current regulated limits for vehicle methane and nitrogen oxide emissions unchanged.

Updates 2012 rule

In 2012 the Obama administration issued efficiency standards for model years 2017 and beyond, with the standards forming part of the administration's policies targeting the reduction of U.S. greenhouse gas emissions. However, under the terms of the relevant statutes, the administration could not enforce these standards beyond 2021 — the new rule, in effect, puts in place standards forward from that 2021 time limit.

The 2012 rule envisaged fuel efficiency improvements of around 5% per year over that same time period, according to an opinion piece by Elaine Chao, Secretary of Transportation, and Andrew Wheeler, EPA Administrator, published in the cleveland.com website on April 3.

The 2012 rule envisaged fuel efficiency improvements of around 5% per year over that same time period, according to an opinion piece by Elaine Chao, Secretary of Transportation, and Andrew Wheeler, EPA Administrator, published in the cleveland.com website on April 3.

Supports president's policy

Chao and Wheeler characterized the terms of the new rule as supporting President Trump's commitment to re-invigorate the American auto manufacturing industry by rewriting costly and increasingly unachievable fuel economy and carbon dioxide emissions standards. The agencies argue that, by making the standards more easily achievable, the cost of car construction will be reduced, thus making new cars more affordable. That, in turn, will lead to an increase in the sales of new cars, with a resulting use of safer and cleaner vehicles — that would lead to fewer road accidents, the agencies say.

The new rule is expected to reduce traffic fatalities by 3,300 and injuries by 397,000 during the period when the new regulations apply, Chao and Wheeler commented.

Cost-benefit analysis

The cost-benefit analysis for the new regulations also takes into account the reduction in the cost of fuel since the 2012 rule was issued. Essentially, although higher fuel efficiency will lead to reduced vehicle operational costs that can offset at least some of the manufacturing costs associated with high fuel efficiency, there is a law of diminishing returns, as the fuel efficiency becomes higher, the rule argues. Hence, an adequate overall cost benefit can result from lower efficiency levels than were proposed in 2012, the rule indicates.

The analysis in the new rule considers the benefits to be gained from lower greenhouse gas emissions, as fuel efficiency rises. However, rather than considering the worldwide cost benefit that may be achieved from reduced emissions from vehicles sold in the United States, as was done in the 2012 rule, the new rule only takes into account benefits anticipated within the United States. The new rule also reduces the estimated greenhouse gas impact of regulated fuel efficiency savings by taking into account the likely impacts of reduced fuel costs and the market incentives for achieving improved fuel economy.

Also, in September the federal administration issued its One National Program Rule, clarifying that federal law for tailpipe greenhouse gas emissions and zero emissions vehicles preempts state and local law. This rule also withdrew a waiver to preemption, granted to California in 2013, allowing California to enforce its own vehicle greenhouse gas and zero emissions programs. The rule has been challenged in the U.S. Court of Appeals for the District of Columbia.

A controversial issue

The extent to which vehicle emissions in the United States should be restricted has proven controversial. In a March 31 press release, environmental law firm Earthjustice said that automobile manufacturers, 18 states, the District of Columbia, and a coalition of cities and counties have opposed the new standards.

"In the midst of a public health crisis, the Trump administration is once again putting oil industry profits ahead of the American people," said Earthjustice attorney Paul Cort. "Weakening clean car standards will dramatically increase air pollution and harm public health. Transportation is the largest source of carbon pollution in the country, and this move undercuts one of our most important tools to solve the climate crisis."

On the other hand, on April 6 the American Energy Alliance announced that a coalition of 48 small business and consumer groups, led by the Alliance, had sent a letter to President Trump, supporting the new vehicle fuel efficiency rule.

"President Trump inherited a … mandate from his predecessor that was impossible to achieve without dramatically altering the automobile market or making the cost of vehicles out of reach for most American families," said Thomas Pyle, president of the American Energy Alliance. "This new … rule will make cars more affordable for consumers at a time when they need it the most. The rule puts power back into the hands of drivers, not bureaucrats, and most importantly it will save lives." ●

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● GOVERNMENT

AOGCC amends pool rules for conformity

Changes requested by BP for Greater Point McIntyre Area rules will promote operational efficiency, simplify commission's oversight

By KRISTEN NELSON
Petroleum News

In an April 3 ruling, the Alaska Oil and Gas Conservation Commission approved requests by BP Exploration (Alaska) for amendments to pool rules at oil pools in the Greater Point McIntyre Area on the North Slope.

BP requested the changes on Feb. 20, citing making operations more efficient and simplifying compliance oversight for AOGCC.

The requests cover well spacing requirements, pressure survey requirements and well testing for a number of oil pools in the Greater Point McIntyre Area: Lisburne, West Beach, Point McIntyre, Niakuk, Raven and North Prudhoe Bay. The commission said there were also requested changes which applied only to the Lisburne oil pool or the Point McIntyre oil pool.

Well spacing

The Lisburne, West Beach, Point McIntyre, Niakuk and Raven oil pools had different spacing requirements: one well per quarter section at Lisburne with no pay opened within 1,000 feet of another well; one well per 160 acres at West Beach until circumstances warranted AOGCC changing that requirement; one well per 40 acres at Point McIntyre with no pay open within 500 feet of another well; at Niakuk the AOGCC could approve any well at least 500 feet from the area boundary without open pay within 1,000 feet of another well; and one well per 20 acres at Raven with no pay open within 500 feet of the area external boundary.

BP requested that interwell spacing be eliminated and the only requirement be a 500-foot offset from property lines where the landowner is not the same on both sides of the line.

"At the time the spacing requirements in these pool rules were imposed wells were being drilled nearly vertically," the commission said in its ruling. With modern horizontal and multilateral wells, flexibility was needed to drill as dictated by geology and reservoir models, AOGCC said, and standardization of spacing requirements would improve recovery while protecting correlative rights.

The commission amended conservation orders for all the named pool rules to read:

"There shall be no restrictions to well spacing within the affected area except that no pay may be opened in a well which is closer than 500 feet of an external property line where the owners and landowners are not the same on both sides of the line."

Pressure surveys

Requirements on frequency of pressure tests and when they were required to be submitted varied across the Lisburne, West Beach, Point McIntyre, Niakuk, North Prudhoe Bay and Raven oil pools.

The commission said BP requested "that the pressure survey requirements be modified so that compliance with regulatory oversight becomes simpler and data is collected in a meaningful manner."

"The inconsistency in where pressure surveys need to be collected and how the results are to be reported makes it more difficult for the operator to stay in compliance without yielding any benefit that

The Lisburne, West Beach, Point McIntyre, Niakuk and Raven oil pools had different spacing requirements …

could not be obtained by more uniform collection and reporting requirements," the commission said in summarizing BP's request.

There have been decades of development and reporting and the Prudhoe Bay unit pools (the Greater Point McIntyre Area is part of the Prudhoe Bay unit) are well understood and have sophisticated reservoir models, the commission said. BP recommended targeted pressure surveys be included in the annual reservoir surveillance reports, which would be consistent with how other pools at Prudhoe are managed.

The commission amended pool rules for the affected fields to require annual submittal of pressure surveillance in conjunction with annual reservoir surveillance reports.

The commission said that in addition to requested changes applying across pools, BP made a number of requests which applied only to a single pool, including gas oil ratio testing requirements at Lisburne, water injection limits at the Lisburne gas cap water injection project and an enhanced oil recovery project report for the Point McIntyre oil pool.

All requested amendments were approved.

Pool specific

The commission said the existing rules allowed it to make administrative amendments if the proposed changes did not promote waste or jeopardize correlative rights, were based on sound engineering and geoscience and did not increase risk of fluid movement into freshwater.

All of BP's requested changes comply with those requirements, the commission said.

Consolidating rules across the Greater Point McIntyre Area pools and the changes to the Lisburne and Point McIntyre pool rules will simplify operations for BP, "make uniform the compliance requirements, and will not impact ultimate recovery. Eliminating interwell spacing requirements, while maintaining a minimum offset distance from property lines where ownership changes, will maximize ultimate recovery while also protecting correlative rights," the commission said.

AOGCC also said it is revising the rules, where necessary, for consistency with the language it currently uses. ●

Contact Kristen Nelson at knelson@petroleumnews.com

● FINANCE & ECONOMY

EIA forecast cites heightened uncertainty

Agency projecting 500,000 bpd drop in US production for 2020, further drop next year; Brent down $24 per barrel at $32 for March

By KRISTEN NELSON
Petroleum News

All market forecasts are subject to uncertainty, the U.S. Energy Information Administration said in releasing its Short-Term Energy Outlook April 7, but the sudden increase in crude oil supply combined with the impact on demand of the COVID-19 pandemic have made this outlook "subject to heightened levels of uncertainty" as those impacts on energy markets are still evolving.

"Significant disruptions to the global economy and reduced travel related to COVID-19 led EIA to lower expected demand growth for 2020," EIA Administrator Dr. Linda Capuano said in an April 7 statement accompanying the STEO release. "EIA estimates that consumption of global petroleum and liquid fuels in the first quarter fell by 5.6 million barrels per day compared with the same period last year. We forecast liquid fuels demand will decrease by 5.2 million barrels per day in 2020 before increasing by 6.4 million barrels per day in 2021." With the drop, EIA estimated first quarter demand at 94.4 million bpd, down from 100.7 million bpd in 2019.


LINDA CAPUANO

In March, the Organization of the Petroleum Exporting Countries and partner countries, OPEC+, suspended agreed-upon production cuts, and despite resulting market oversupply and recent news of emergency OPEC+ meetings, EIA said it is assuming those cuts will not be re-implemented.

The agency said it is assuming that Saudi Arabia will ramp up its production to near full capacity in the second quarter "in an attempt to regain global market share as higher-cost production declines elsewhere."

There is typically a six-month lag between price changes and production, but EIA said "current market conditions, combined with the COVID-19 pandemic, will likely reduce this lag as many producers have already announced plans to reduce capital spending and drilling levels."

Which means storage volumes will grow.

"EIA expects global liquid fuels inventories to grow by an average 3.9 million barrels per day in 2020 as a result of widespread travel limitations and sharp reductions in economic activity," Capuano said, with global petroleum inventories estimated to "increase an average of 11.4 million barrels per day during the second quarter of 2020, which would be the largest rate of inventory increases on record."

Prices down

Brent crude oil averaged $32 per barrel in March, down $24 per barrel from the February average "and the lowest monthly average since January 2016," EIA said.

"EIA expects large stock builds will put downward price pressure on crude oil prices for several months," Capuano said.

Brent is forecast to average $33 per barrel this year, $10 lower than its forecast last month, and down from a 2019 average of $64 per barrel.

The agency expects prices to average $23 per barrel in the second quarter, increasing to $30 per barrel in the second half of the year, and averaging $46 per barrel in 2021, "as a return to declining global oil inventories puts upward pressure on prices."

US crude production to drop

"The EIA April forecast of U.S. crude oil production is lower than the March forecast as a result of lower crude oil prices. We forecast U.S. crude oil production will be 0.5 million barrels per day lower in 2020 compared with 2019, and we expect a further decline in 2021," Capuano said.

U.S. crude production is now forecast to average 11.8 million bpd this year, the agency said, and to decline a further 700,000 bpd in 2021, marking the first annual decline since 2016.

There is typically a six-month lag between price changes and production, but EIA said "current market conditions, combined with the COVID-19 pandemic, will likely reduce this lag as many producers have already announced plans to reduce capital spending and drilling levels."

IHS Markit said in an April 8 release that its calculations show oil and gas companies focused on North America plan to reduce spending in 2020 by 36% from last year, due to the collapse in demand and low oil prices. The company said North American cuts are estimated to be $24.4 billion from last year, with international companies also cutting significantly, by 20% to 30%, with a substantial part of that cut, for some of the companies, coming from U.S. operations.

"The Big Cut is here. The U.S. government can't order cutbacks like other countries. But economics and the market are mandating dramatic budget cuts that will bring down U.S. production this year," said IHS Markit Vice Chairman Daniel Yergin.

Between North American E&P companies, non-North American E&P companies and international oil and gas companies, IHS Markit said capex in 2019 was $317.1 billion, projected to drop to $235.1 billion this year, a difference of 26%, $82 billion.

Natural gas

EIA said the Henry Hub natural gas spot price averaged $1.74 per million British thermal units in March as warmer

see EIA FORECAST page 7

● FINANCE & ECONOMY

ISER: $4.1 billion hit to Alaska Q2 GDP

Report projects GDP, employment losses in state's most vulnerable industries, with multiplier effects – not including oil and gas

By STEVE SUTHERLIN
Petroleum News

Alaska could take a $4.1 billion dollar hit to its gross domestic product in the second quarter of 2020, accounting for both direct and indirect effects of losses to the state's most vulnerable industries, according to a March 27 report by Mouhcine Guettabi of the Institute of Social and Economic Research, University of Alaska Anchorage. The loss would represent a 7.4% decrease in GDP relative to the second quarter of 2019.

"Direct GDP losses due to the decline in economic activity — not including declines in oil prices — could amount to almost 2 billion dollars," he said.

The projected losses do not account for reductions in employment and GDP that may occur in the oil and gas industry as a result of much lower prices. Nor do they account for behavioral responses by households and businesses as a result of the federal aid package, Guettabi said, adding that the projections will only materialize if closures last for an extended period.

Based on the severe decline in the oil markets and the stock markets, most economic observers anticipate a U-shaped recovery rather than V-shaped one, Guettabi said.

"Alaska will not escape the damage as the tourism season is in serious jeopardy, oil prices have significantly declined, and the recent establishment closures as of Mid-March are affecting a few sectors, mainly the Leisure and Hospitality industry," Guettabi said. "The economic effects from social distancing measures as well as the decline in travel will have far reaching consequences for the Alaska economy in both the short and long run."

Moody's report said workers in transportation and travel, leisure and hospitality, temporary help services and oil drilling and extraction among the most likely to be affected.

Guettabi said a recent Moody's analytics report said that as many as 80 million Americans are in high or moderate risk of a layoff, and that at least 10 million of those in relatively high risk occupations will actually be laid off. Moody's report said workers in transportation and travel, leisure and hospitality, temporary help services and oil drilling and extraction among the most likely to be affected.

Alaska in very precarious position

"The state is in a very precarious position right now," Guettabi said in an "Ask a UAA expert" video posted March 21 on YouTube.

"The state budget is very very dependent on oil revenues and, since the passage of Senate Bill 26, on the performance of the Permanent Fund," he said. "The stock market is declining; oil prices are declining, which means that the two largest sources of revenue for the state are both being hit really hard."

Almost 10% of all jobs in Alaska are in leisure and hospitality, the sector most sensitive to closures as well as declines in travel, Guettabi said in the ISER report.

GDP in the first quarter of 2019 was $54.9 billion, with $1.6 billion coming from accommodation and food services, $2.3 billion from retail trade and $7.4 billion from transportation and warehousing.

Guettabi's findings suggest that March 2020 employment will be 26,319 less than in March 2019, with total wages in March 2020 down $34 million from March 2019.

April 2020 — the first full month post closures — employment will be 27,072 less than April of the previous year, while total wages lost will equal $79.1 million dollars, he said.

"Once we account for the multiplier effects, we conclude that April employment in 2020 will be around 48,000 less than April 2019," he said.

Guettabi said that the multiplier effect on GDP, wages and employment may be much smaller if government aid reaches businesses quickly. ●

The ISER report can be found at: https://pubs.iser-alaska.org/media/aae6343a-e2f6-4404-88ac-e7ed6b2e9724/Ak_econ_covid19.pdf

The "Ask a UAA expert" video can be found at: https://www.youtube.com/watch?v=zddlPnGnTjo

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EIA FORECAST

than normal temperatures reduced space heating demand. The agency is forecasting that prices will begin to rise at the end of the second quarter as U.S. natural gas production declines and demand increases. Henry Hub spot prices are forecast to average $2.11 per million Btu this year and increase in 2021 to an annual average of $2.98 "because of lower natural gas production compared to 2020."

U.S. dry natural gas production averaged 92.2 billion cubic feet per day last year, a record, and is forecast to average 91.7 bcf per day this year, dropping to 87.5 bcf per day in 2021, although "rising in the second half of 2021 in response to higher prices."

U.S. liquefied natural gas exports are expected to average 6.6 bcf per day in the second quarter of the year, and 6 bcf in the third quarter because of lower expected global demand.

Lower 48 assumptions

EIA said its model for Lower 48 production assumes a reduction in rigs and wells when West Texas Intermediate falls below $45 a barrel or Henry Hub falls below $2 per million Btu.

In addition to changes based on its model, the agency said it "assumes a further 15% reduction in activity on average in the second quarter of 2020 and a 12% reduction in the third quarter of 2020 to account for the unprecedented effects of COVID-19 on the level of drilling activity as many producers have already announced plans to reduce capital spending and drilling levels."

For natural gas production, EIA said its Lower 48 model assumes a reduction in rigs and wells when WTI falls below $45 per barrel or Henry Hub falls below $2 per million Btu. As with crude, EIA is assuming a further 15% reduction in activity in the second quarter and a 12% reduction in the third quarter because of COVID-19 impacts.

In an April 7 release, IHS Markit said low oil prices could result in a drop of 8-10 bcf per day of associated gas by the end of 2021. Associated gas, produced together with oil, is nearly one-third of total U.S. gas production, the company said, and volumes will fall as crude oil production drops, a reduction in gas supply which "will help offset or even overtake the drop of gas export demand as a result of COVID-19."

Narmadha Navaneethan, director of North American upstream research for IHS Markit, said: "Roughly speaking, for every 500,000 bbl/d of oil production drop, we see associated gas volumes fall by about 1 Bcf/d. Considering the depth and duration of the global oil situation, we could see an 8 Bcf/d reduction in associated gas." ●

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HILCORP TAKEOVER

Now it is tackling the main issues and on April 2 it ordered the companies to provide answers to a dozen pages of what it called "initial questions."

RCA said it is "mindful" of the Sept. 28 deadline for a final order in the proceeding but is allowing 30 days for the companies to respond, "given current circumstances."

Then it cautioned the companies:

"We advise BP and Harvest Alaska that the completeness, clarity, and candor of answers to the preceding questions will shape the course of future proceedings in these dockets, including whether there is a need for a hearing, whether participation by intervenors may aid our resolution of the issues raised by the applications, and what (if any) conditions on the approvals sought by applications may be necessary to protect the public interest."

Range of questions

The scope of questions RCA asked and the level of detail it requested, are broad, beginning with "all operational risk assessments performed for TAPS, MPPLLC, or PTEP in the last ten years." It requested details on the process for establishing work plans and budgets for the pipelines; a list of scheduled pipeline repairs, replacements or improvements and what known work is not currently scheduled; a list and description of each incident resulting in a reportable spill or damage "or any other major pipeline operational upset since inception."

It wants to know how the pipelines are insured against unanticipated incidents, what insurance mechanisms BP has used and how Harvest Alaska intends to insure against unplanned incidents affecting operation of the pipelines and asked if BP has agreed to provide any backstop for Harvest Alaska's operational liability.

Since the Milne Point and Point Thomson pipelines are limited liability companies, with liability exposure limited to LLC assets, are the members of those LLCs obligated to cover unanticipated expenses not reflected in their tariff rates, the commission asked.

For the trans-Alaska oil pipeline, the commission asked for a detailed description of how Alyeska Pipeline Service Co. is funded, and how Harvest would fund any large or unusual amounts requested by Alyeska.

"Explain whether recent changes in the financial markets have impacted Harvest Alaska/Hilcorp Alaska/Harvest Midstream's access to the capital necessary to fund this transaction," the commission said, and also asked what financial reserves have been set aside to fund Alaska operations.

The commission asked for copies of the financial assurance agreements Harvest has with the Alaska Department of Natural Resources.

RCA also asked what insurance bonding or security DNR has required for right-of-way leases for the pipelines.

And it wants specifics on the BP corporate guaranty which will remain in place after the transfer of BP's Alaska assets.

DR&R

The commission asked for a lot of dismantlement, removal and restoration information: all studies BP or Alyeska have done to estimate DR&R costs "since the inception of TAPS"; whether any DR&R funds have been expended to date; responsibility of other TAPS carriers if an individual carrier is unable to cover its cost of DR&R; and how much money BP has collected in its rates for DR&R "by destination, by shipper, and by month since the inception of TAPS through interstate and intrastate rates" to cover its share of DR&R.

"Please confirm that BP's liability for DR&R extends to a lawfully-ordered refund of DR&R overcollections," RCA said. It also asked for a schedule of the extent to which BP has assumed responsibilities for DR&R associated with former TAPS carriers such as Unocal Pipeline Co.

"Is there a BP backstop for Harvest Alaska's DR&R liability should Harvest Alaska fail, for whatever reason, to adequately perform or fund its share of DR&R costs?" the commission asked.

And it wanted to know how DR&R collections and anticipated expenditures are recorded in BP's financial filings, including a copy of the most recent such recording.

The commission noted that once BP's Alaska assets are owned by Harvest, "BP will no longer be subject to clear RCA jurisdiction as it will have no intrastate pipeline assets in Alaska," and asked if it is the company's position that RCA would have "jurisdictional reach" in DR&R matters.

It asked for an explanation of the arrangements for planning BP's DR&R obligations at the end of the useful life of TAPS, and what the arrangements are "between Harvest Alaska and BP to ensure Harvest Alaska has the capabilities to assume BP's DR&R responsibilities, both financially and operationally?"

And if a new component of TAPS is put in service, how will that asset be distinguished for DR&R purposes?

The commission also wants to know about DR&R responsibilities for the Milne Point and Point Thomson pipelines.

—KRISTEN NELSON

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VIRUS FALLOUT

Chief Executive Officer Ian Anderson said in early March that construction would continue in British Columbia and Alberta, targeting an in-service date of December 2022.

Peter Zebedee, chief executive officer of LNG Canada, said the fallout from COVID-19 has forced the company to "gradually and methodically draw down" by 750 the work force at the C$40 billion terminal facility at Kitimat, with initial export capacity of 14 million metric tons a year.

The biggest private investment infrastructure project in Canadian history is "taking an abundance of caution" to prevent COVID-19 from gaining a foothold in workers' camps, said a spokeswoman.

Coastal GasLink pipeline, which will deliver natural gas feedstock for liquefaction at Kitimat, has shrunk its workforce of 1,200 to 400 over the last month and plans to continue the ramp down.

Aside from COVID-19 the company said spring thaw will put an end to major construction, although some employees and contractors will be retained to perform environmental monitoring, pipe delivery and stockpiling, as well as some right-of-way site preparation. Pipe installation is still scheduled for the summer.

In northeast British Columbia, 60% of the 420-mile route was cleared by the end of February.

Woodfibre LNG, which had hoped to start exports of 2.1 million metric tons a year in 2024 from its terminal close to Vancouver, said substantial construction which was expected to start this summer will be stalled until mid-2021 after a fabrication yard in Asia was shut down to hinder the spread of coronavirus.

A spokeswoman said another delay was caused by Woodfibre's preferred U.S. construction contractor for the marine port which filed for Chapter 11 bankruptcy protection in the United States.

The company has now applied to the B.C. Environmental Assessment Office for a five-year extension to its environmental certificate, which expires in October.

The spokeswoman said the company is meeting all of its "pre-construction commitments" and is delaying only the start of construction.

In issuing new guidelines on March 21 covering COVID-19 management measures for the construction industry, the British Columbia government said they would pose problems for major undertakings, such as the Site-C hydro dam and LNG Canada.

"We're calling for remote-camp megaprojects to be tooled down to all but essential or critical-path work," said Andrew Mercier, executive director of the B.C. Building Trades Council.

In Alberta, the virus has forced another delay on the Sturgeon refinery 30 miles northeast of Edmonton — a four-phase project to convert 240,000 bpd of bitumen blend feedstock into low-sulfur diesel and other products.

The refinery has been processing synthetic crude oil into diesel since November 2017, but hopes to advance its operations to raw bitumen, increasing the value of its output.

Multiple issues during the initial commissioning phase have pushed the estimated completion costs to C$9.9 billion from C$5.7 billion.

Since last June, the Alberta government — which is providing 75% of the bitumen feedstock through its petroleum marketing commission — has been making payments of C$27 million a month related to obligation to pay 75% of debt-servicing costs.

"It's frustrating for us because we are paying (for a refinery that isn't meeting its objective) at a time when we've got an economic downturn," said Energy Minister Sonya Savage.

—GARY PARK

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● GOVERNMENT

Furie settles state air quality notices

Bankruptcy judge signs order approving settlement of notices of permit violations for $4,970.51; no admission of fault by Furie

By STEVE SUTHERLIN

Petroleum News

Judge Laurie Selber Silverstein signed an order approving a settlement agreement between the State of Alaska and Chapter 11 debtor Furie Operating Alaska LLC regarding alleged violations of Furie's air quality operating permits spanning from 2014 to 2019. The order was signed March 19 in the U.S. Bankruptcy Court for the District of Delaware.

The agreement will settle matters relating to an Oct. 10, 2019, notice to Furie — as owner and operator of the Julius R. platform in the Kitchen Lights unit — of violation of an air quality minor source specific permit.

It also settles a Jan. 29, 2020, notice alleging that Furie unlawfully failed to obtain a Title V operating permit, and unlawfully certified permit applications as true, accurate and complete, when those permit applications included incorrect and misleading information.

The State of Alaska also said that Furie operated five rented diesel-electric generators on the Julius R. platform for intervals that in aggregate exceeded the 12 consecutive month residence time limit authorized for a non-road engine.

Under the settlement agreement, Furie will pay the state $4,970.51 in lieu of any civil penalties that might otherwise be assessed.

In return, the state agrees to "release and forever discharge Furie from "all civil claims and causes of action" arising from the matter.

Terms of settlement highly favorable to debtors

"In this case, the terms of the settlement agreement are highly favorable to the debtors," Furie said in its motion for the approval.

Furie said that the maximum civil penalty that Furie is potentially liable for if the alleged violations were proven is $100,000 for the initial violation, and up to $5,000 for each day the violation continues.

"As it stands, the settlement agreement proposes to resolve the alleged violations for less than the potential liability for even a single day's worth of continued violations, without taking into account the potential liability for the initial violation," Furie said.

Furie said it is also potentially and concurrently liable in a civil action brought by the State of Alaska for the full amount of actual damages caused to the state by any violation, including all incidental administrative costs.

The settlement agreement specifically says that the sum of $4,970.51 is to cover the state's enforcement costs.

"This means that the settlement amount is no more than a subset of expenses that might otherwise be recovered in a civil action by the State of Alaska, which could include abatement costs, environmental restoration costs, and actual damages, among other things," Furie said.

The settlement agreement calls for the immediate resolution of the alleged violations, eliminating the need for litigation or administrative proceedings to contest the matter, Furie said.

"Any such actions would be a substantial drain on the debtors' limited resources and divert attention away from these Chapter 11 cases," Furie said.

The settlement funds are to be paid to the state within 30 days of approval by the bankruptcy court. ●

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Petroleum news

Oil Patch Bits

Fugro wins NOAA contract for shoreline mapping services

Fugro said April 7 that it has signed a 5-year indefinite delivery indefinite quantity contract with the U.S. National Oceanic and Atmospheric Administration to provide shoreline mapping services in support of the agency's coastal mapping program. Issued through NOAA's national geodetic survey, this multi-year contract is NOAA's second consecutive award to Fugro for services such as the provision of aerial imagery, topobathymetric lidar and shoreline feature compilation. National geodetic survey uses these data to update NOAA nautical charts, define U.S. territorial limits, support coastal management activities and perform inundation modeling.

"Fugro is proud to continue working with NOAA to update and improve the nation's shoreline mapping needs," said Edward Saade, president of Fugro in the U.S. "This work closely aligns with our NOAA hydrographic surveying services contract, which was awarded to Fugro last December. In both cases we are focused on using innovative technologies to streamline the delivery of high-quality Geo-data while improving operational safety and significantly reducing our carbon footprint."

The new shoreline mapping services indefinite delivery indefinite quantity contract is active now and will run until March 20, 2025. Fugro is one of four contractors who will receive task orders under the program. The total maximum value of work to be shared among all contractors is US$40 million.

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CHARLIE WELL

four of which had oil shows.

The well's primary target was the Seabee formation. An attempt was made to take a sample from the Lower Lima, being the better of the two Lima targets in the Seabee. This attempt, the company said, was unsuccessful due to insufficient reservoir quality.

However, given the various targets "were not intersected optimally, there still may be potential for higher quality reservoir at a different location," 88 Energy said, noting that "excellent vertical seismic profile data was obtained … which will now be used in conjunction with other log data and the existing 3D seismic, to remap the targets. Sidewall core analysis will also assist with determining where improved reservoir is likely to exist. Mud gas, observed while drilling in the Seabee, indicated that the hydrocarbons at this horizon are heavier than those in the Torok and this is the horizon where 'live oil' was observed across the shakers in the nearby Malguk 1 well," drilled by BP in 1991 using 2D seismic.

The Charlie well was designed as a step out of Malguk 1, which like Charlie 1 encountered oil shows with elevated resistivity and mud gas readings over stacked horizons during drilling. Malguk was not tested due to complications resulting in a lack of time before the 1991 winter drilling season closed.

While its partner Premier Oil Plc chose to exit the project because the well results did not meet their expectations, 88 Energy said the $23 million from Premier was in the joint venture's bank account and that the well costs remain within the expected budget, so no additional costs will be incurred.

Detailed logs and sidewall cores were acquired in the HRZ formation during drilling of Charlie 1, which 88 Energy said in an April 9 quarterly report will be analyzed in the months ahead. The HRZ, it said, remains a viable target and "options to commercialize this potentially large"

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INSIDER

will be used for the wells.

Portable pipe supports will be added to the pipe rack for the laterals.

Approximately 1,320 feet of new flowlines will be installed to connect the wells to the headers, the division said.

Up to 10 thermosiphons may be installed dependent upon site conditions.

Doyon 14 or Hilcorp's Innovation drill rig will be used to drill the new I Pad wells. Drilling equipment will include boilers, mud tanks, mud pumps, a rig generator, work trailers, and light plants.

Some rig support equipment and materials may be staged at nearby pads. Infrastructure installation equipment will include an excavator, mini excavator, super sucker, zoom boom, weld truck, and possibly a ground thaw unit, the division said.

There is more good news about another up and coming player on Alaska's North Slope — Oil Search.

Keiran Wulff, the top executive of ASX-listed Oil Search Ltd (OSH), parent of Oil Search Alaska, is taking measures to bolster the company's financial position in order to weather a possible sustained period of weak oil prices, so that when market conditions improve the company will be ready to move forward.

Early in the week of April 5, Wulff launched a successful share sale that raised approximately $720 million in U.S. dollars, which will be followed later in the week by a sale of shares to retail investors that has been fully underwritten to raise an additional $49.5 million.

In addition to the 2020 capex reductions announced on March 18 that included eight employee layoffs in Anchorage and 92-plus in Sydney, Wulff also extended the maturity on a $300 million loan facility by 10 months to June 2021.

"We had a lot of discussions with our investors and we had a lot of discussions with our own banks, and it was clear to us that in addition to our capital reductions and our operating cost reductions we needed to strengthen the balance sheet so that we were in a strong position and that's exactly what we've done," he told The Australian Financial Review in an interview that appeared in the publication April 8.

"So, we decided to do it early and decisively and making clear that we were able to position the company for an extended period but also deliver our growth when we come out of it."

In Alaska where Oil Search has no current production the junior reduced its 2020 development spending from $120-140 million to $110-130 million and decreased exploration and evaluation investment from $220-240 million to $150-170 million, for a total of $260-300 million.

In Papua New Guinea the company reduced its 2020 capital expenditures to $150-180 million, including development, exploration and evaluation, and production.

What the reductions mean for Oil Search in PNG is freezing all activity other than maintaining its current oil, condensate and natural gas production.

In Alaska the reductions translate into no exploration in the winter of 2020-21, and while early development activities in the Pikka unit, including laying gravel roads, will be completed, all further work on the early production system for the Pikka Nanushuk project, including ordering long lead items, is being placed on hold. The company now plans to concentrate on full field development, so that the project is ready to move promptly towards final investment decision "when market conditions improve."

Another cost reduction: Oil Search's board and executive team agreed to take a 20% salary cut for the next six months, the company said March 18.

Furthermore, Wulff told The Australian Financial Review that several options would be on the table by the time the Alaska and PNG development projects were moving forward, including a possible sell down of LNG interests in PNG if a proposed deal reflected the quality of the asset.

Another future option is selling a 15% interest in some of Oil Search's Alaska assets — an action that was put on hold March 18. But the company also said at the time that "discussions are continuing with several parties who, due to the quality of the Alaskan assets, continue to express strong interest in a purchase."

—KAY CASHMAN

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KEYSTONE XL

more legal and regulatory challenges.

The firm underlined some views that President Donald Trump could impose an outright cancellation of the project, despite his action three years ago to reverse President Barack Obama's decision to halt the project.

James Coleman, a law professor at Southern Methodist University in Taxes, said Keystone XL still faces legal hurdles, including a challenge launched by environmental and Indigenous groups before the U.S. District Court in Montana.

He told the Calgary Herald that although most states the pipeline will traverse have either approved or support the project "that doesn't mean there might not be some legal risk. You can never predict what a court is going to do."

However, BMO Capital Markets analyst Ben Pham said the slump in West Texas Intermediate and Western Canadian Select prices — all of which would make Keystone XL uneconomic if the project was operating today — are likely to be just "transitory impacts," while the Alberta government was "effectively bearing the risk of the U.S. election" results in November should a Democrat be elected to the White House and the Democrats gain control of the Senate while retaining the House.

Also on the upside, Stephanie Kainz, senior associate at the RS Energy Group, said that once the pipeline is completed it will improve market access for oil sands production and the price Alberta producers receive.

She said an end to the current gloom will allow the industry to bring on more upstream projects and "hopefully infuse more capital" into the Canadian energy sector.

That aligns with the thinking of Alberta Premier Jason Kenney who has broken with his strongly held opposition to government intervention in the market, even though he argues that Canada's "failure to get pipelines built has been a failure of government policy and politics (blocking the use of export tankers in northern British Columbia waters and tougher environmental scrutiny of new projects), not of markets."

Kenney noted that even former Alberta premiers Ernest Manning (in the 1950s) and Peter Lougheed (in the 1970s) sacrificed their unyielding belief in the private sector to support the energy industry when it was struggling to attract investment. Manning helped launch the first cross-Canada natural gas pipeline while Lougheed provided public money to advance the oil sands as a commercial enterprise. ●

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REVENUE FORECAST

climbing to $53.00 by FY 2029. The oil price forecast is based on futures market prices and reflects the extreme supply and demand imbalance gradually relaxing over the next several years."

Revenue's daily price update for April 7 showed ANS at $18.21 per barrel, down $9.88 from the previous day, and production at 509,747 barrels per day.

Revenue noted in the forecast that oil prices had "crashed to near $20 per barrel based on supply and demand fundamentals." It said the Organization of the Petroleum Exporting Countries "has broken down and Saudi Arabia and Russia are engaged in a price war, pledging to maintain or increase production regardless of price."

It would be easy to blame OPEC, the department said, but "there has also been an unprecedented decline in oil consumption due to the pandemic. Simply put, there is currently too much oil in the world presently and from an economics perspective, the current low prices are needed to remove supply from the market or stimulate demand."

Revenue said the spring forecast assumes that pandemic-related shutdowns will continue through the end of the current fiscal year, with reversal of shutdowns during the first half of FY 2021 (July through December 2020), with overall economic activity returning to baseline levels by FY 2022 (July 2021 on).

ANS production is expected to average 486,400 barrels per day in FY 2020, "remaining stable at 486,500 barrels per day in FY 2021, and slightly climbing to 491,000 by FY 2029," Mahoney said.

"The spring forecast for oil production was developed prior to the March 2020 oil price crash. Given the long lead time for Alaska oil projects and high level of uncertainty, the production forecast has not been further revised at this time," she said.

The fall forecast estimated FY 2020 ANS production averaging 492,100 bpd and FY 2021 ANS averaging 490,500 bpd. The spring figures are drops of 1.1% and 0.8%, respectively.

Cook Inlet production was forecast at 16,200 bpd in the fall forecast and is down 12.4% in the spring forecast to an estimated 14,200 bpd, a number which more closely tracks current production volumes.

Mahoney said the spring forecast is issued in "a period of extreme uncertainty" due to the COVID-19 pandemic and "highly volatile investment markets and oversupplied oil markets."

The spring forecast is for unrestricted general fund revenue at $1.6 billion for FY 2020 and $1.2 billion for FY 2021 — it was $2 billion in FY 2019 — with a $2.9 billion transfer from the Permanent Fund to the general fund in FY 2020 and $3.1 billion in FY 2021 (it was $2.8 billion in FY 2019) — overall a reduction in UGF revenue of $527 million from the fall forecast for FY 2020 and $461 million for FY 2021.

Total state revenue, unrestricted and restricted, was $11.18 billion for FY 2019, and is forecast to be $6.57 billion for FY 2020 and $10.57 billion for FY 2021.

Of the $527 million UGF reduction, $461 million is a reduction in expected petroleum revenue.

"Petroleum revenue reductions are largely a function of a lower oil price forecast," the department said.

For FY 2019, UGF petroleum revenue was $2.04 billion. The spring forecast is for petroleum revenue of $1.1 billion for FY 2020, with FY 2021 petroleum revenue dropping to $716.6 million.

The largest parts of petroleum revenue are production tax and royalties.

Oil and gas production tax was $595.5 million in FY 2019 and is forecast at $267.6 million in FY 2020 and $122.3 million in FY 2019. Oil and gas royalties were $1.07 billion in FY 2019 and are forecast at $646.2 million in FY 2020 and $410.9 million in FY 2019.

Total petroleum revenue was $2.225 billion in FY 2019, drops to $1.397 billion in FY 2020 and $835.3 million in FY 2021, and then is forecast to rise gradually, reaching $1.346 billion in FY 2029. ●

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CONOCO DRILLING

"Due to the heightened COVID-19 risk to our North Slope workforce, we are taking action to significantly reduce the number of personnel on the Slope in a managed fashion," ConocoPhillips Alaska spokesperson Natalie Lowman told Petroleum News April 8. "To do this, we are making the difficult decision to demobilize our rig fleet. Given the high degree of uncertainty on how the situation plays out, we can't say how long these measures will be in place."

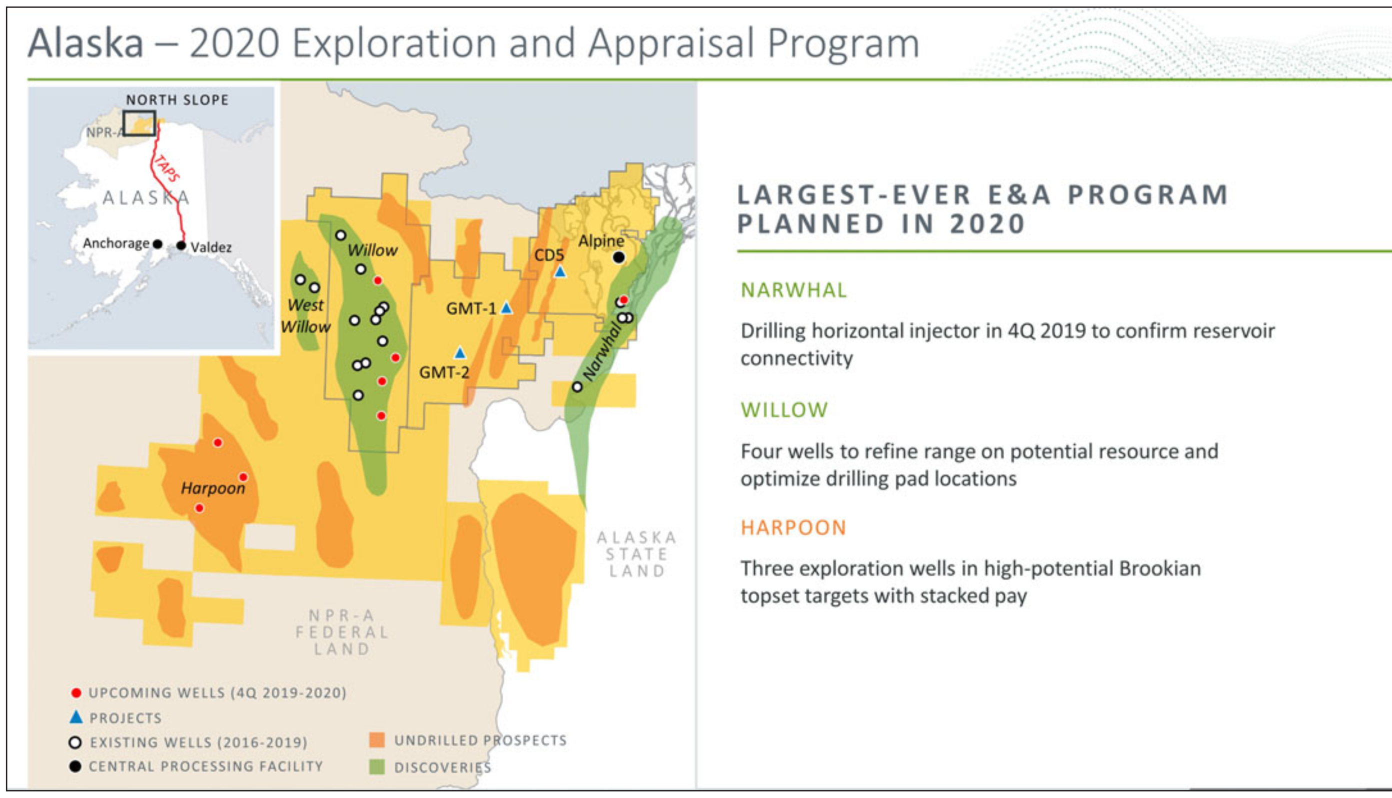
This includes development and exploration drilling.

The U.S. Bureau of Land Management said in its environmental assessment that vertical seismic profiles will be done at some of ConocoPhillips new winter wells.

State and federal geologists have said the geological targets in the new well areas are Nanushuk and Torok.

Michael Hatfield, president, Alaska, Canada and Europe, said Nov. 19 that Harpoon has "high-potential Brookian topset targets with stacked plays."

Although ConocoPhillips does not consider it to be part of its exploration program, the Fiord West Rhea 1 well west of the Alpine field involved an ice pad and short ice road. It was drilled and completed by Doyon 25.



CONOCOPHILLIPS ALASKA

In an investor's market update conference call March 18, ConocoPhillips said it would trim North Slope drilling programs in the Kuparuk River unit, laying down two rigs, which PN's rig report shows as Nabors CDR3 and Doyon 19. It also said it would reduce drilling in the Alpine area, which in the April 8 announcement would put these rigs on standby: Doyon 25, Doyon 141 (which had been at Tinmiaq 18) and Doyon 142. ●

ERD wells deferred

On March 27 the Alaska Department of Natural Resources' Division of Oil received an application from ConocoPhillips Alaska to delay by one year the contraction of Fiord West from the Colville River unit, as well as postpone drilling and sustained production by a year.

The filing was also addressed to the other area landowner, Arctic Slope Regional Corp.

The division approved the request, which was in the form of a unit amendment, on April 1.

Under the unit agreement, which has been amended several times, ConocoPhillips was required to spud a well in the Fiord West Kuparuk participating area by June 30, 2021, and drill two additional wells by Nov. 30, 2022, as well begin sustained production from one well by Nov. 30, 2022, in order to retain all the Fiord West leases from contracting out of the Colville River unit Nov. 30, 2024.

What the company asked for in its March 27 filing was to extend all those deadlines by one year.

The big new extended reach drilling rig, Doyon 26, was part of the company's deal with the state.

At the time ConocoPhillips' request for a one-year extension appeared to be unnecessary since the seven modules that make up the new ERD rig were either on their way to, or already at, CD2 pad for assembly.

The company told Petroleum News April 1 that "the Doyon 26 rig will target Fiord West for its initial wells," having a few days earlier said: "We still anticipate a first spud near the end of April."

But that all changed with the company's April 8 statement to Petroleum News saying it was demobilizing its North Slope rig fleet.

Looking for additional flexibility

In its March 27 filing ConocoPhillips told the division: "As operational concerns change daily due to the coronavirus pandemic" the assembly and acceptance testing of Doyon 26 "may be delayed out of concern for the health and safety of CPAI (ConocoPhillips Alaska Inc.) employees and contractors on the North Slope. Given the recent oil price downturn and ongoing coronavirus pandemic, there is significant uncertainty around the volatility and duration of current oil market conditions. This amendment is requested to allow CPAI some additional flexibility within the terms of the Fiord West lease extension and deferral of unit contraction, while still progressing Fiord West Kuparuk participating area development to and through the November 2025 date."

Fiord West 'highly important'

The Fiord West development is still "highly important" to the company's ongoing North Slope development, ConocoPhillips Alaska's manager of land and business development, John F. Schell Jr., said in the company's March 27 filing, which he signed.

To date, he wrote, the company "has undertaken significant efforts to progress" the Fiord West leases toward sustained production, including paying $750 million in lease bonus bid replacement payments, contracting for a new ERD rig, posting a $10 million performance bond, and drilling two pilot wells in the Fiord West Kuparuk PA, including the 2020 Rhea pilot well to collect information in support of future Fiord West Kuparuk development.

In addition, ConocoPhillips has "completed multiple infrastructure projects in support of ERD rig mobilization, including a gravel pad expansion at CD2, construction of a new mud plant, construction of a new grind and truck dump facility, expansion of the existing cement plant on CD1, as well as construction and upgrades to the water supply and distribution system supporting these facilities," Schell said.

But, as Schell wrote, "as operational concerns change daily due to the coronavirus pandemic" the ERD rig "assembly and acceptance testing may be delayed."

In its approval, the division said: "Any of the subject lands that do not qualify for inclusion in a participating area in whole or in part, or which do not otherwise qualify for lease extension (i.e., continuous drilling, certified well, shut in production, or held by production) will terminate on November 30, 2025."

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resource continue to be pursued. The joint venture plans to conduct a formal farm out process to fund further appraisal of what it calls Project Icewine unconventional.

In a mid-2019 interview with Petroleum News, 88 Energy said that finalization of advanced analysis using state-of-the-art technology had significantly advanced the joint venture's understanding of the nature of their HRZ play, noting that analysis "confirmed that the HRZ is an excellent source rock with good potential as an economic shale play. The nature of the dominant kerogen in the HRZ has been demonstrated to be prone to more rapid transformation into hydrocarbons than other shales initially used for comparison. This means that the thermal maturity window for volatile oil in the HRZ is at lower temperature than that typically seen in other plays."

The Charlie well was operated by 88 Energy subsidiary Accumulate Energy Alaska LLC, using Nordic Calista Rig 3.

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