# Petroleum news

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**page 3** EIA forecasts $49 Brent in 2021; lower US production next year

## Finnex deal falls apart, North Slope Mustang oil field in AIDEA's hands

TOM STOKES

The Finnex LLC deal to purchase the assets of the Mustang oil field, which lies between the Kuparuk River and Colville River units on the North Slope, appears to have fallen through, putting the Southern Miluveach unit in the hands of AIDEA-owned Mustang Holding LLC, per a Dec. 4 decision by Alaska's Division of Oil and Gas.

AIDEA, the Alaska Industrial Development and Export Authority, is the primary lender for the Mustang oil field.

Anchorage-based Finnex was formed on June 23. According

*see* **FINNEX DEAL** *page 11*

## Oil shortage looms on horizon; OPEC+ restraint calms prices

Despite lower future demand due to the COVID-19 pandemic and a transition to alternate forms of energy, the world risks insufficient oil supplies to meet its needs through 2050 — unless exploration speeds up significantly and capital expenditure of at least $3 trillion is made by the industry, according to a report by Rystad Energy.

To meet global cumulative demand over the next 30 years, undeveloped and undiscovered resources of 313 billion barrels of oil need to be added to currently producing assets, Rystad said in a Dec. 9 release.

"The scope of exploration will have to expand significantly," said Palzor Shenga, Rystad senior upstream analyst. "Unless we

*see* **OIL PRICES** *page 11*

## APDC buys into Project Peregrine, All American Rig 111 drilling wells

DAVID WALL

On Dec. 4, 88 Energy Ltd. said it has finalized a farm-out agreement with Alaska Peregrine Development Company LLC, or APDC, on its 100% owned Project Peregrine in the National Petroleum Reserve-Alaska. The acreage was acquired by 88 Energy in July in an off-market takeover of XCD Energy.

On Nov. 9, the Perth-based ASX and AIM listed independent had said planning and permitting for the first well of two wells in its North Slope Project Peregrine remained on schedule for a February spud. 88 Energy also said that day that

*see* **PROJECT PEREGRINE** *page 10*

## 9th Circuit vacates, remands to BOEM, agency's Liberty approval

The 9th Circuit has sent BOEM back to the drawing board — at least in part — on the environmental impact statement it produced for the Liberty project.

In late August 2018 the U.S. Department of the Interior's Bureau of Ocean Energy Management issued a final EIS for Hilcorp Alaska's Liberty project, followed in October 2018 by a record of decision.

The BOEM decision was appealed in December 2018 by the Center for Biological Diversity, Defenders of Wildlife, Friends of the Earth, Greenpeace USA and Pacific Environment.

On Dec. 7 the U.S. Court of Appeals for the 9th Circuit vacated BOEM's decision and remanded it to the agency "for

*see* **LIBERY EIS** *page 10*

EXPLORATION & PRODUCTION

# Oil and more oil

*Oil Search's 3 new North Slope discoveries pose challenge in current market*

**By KAY CASHMAN**
*Petroleum News*

When Oil Search established its Alaska office in March 2018 it started with three people. Today the company employs around 150.

1 2 SERIES

In the next two years Oil Search drilled four new wells, increasing its Pikka/Horseshoe area contingent oil reserves from approximately 500,000 barrels to nearly a billion barrels.

At the end of March 2018 Alaska North Slope crude was selling on the West Coast in the high $60s per barrel and climbing. Today it is struggling to stay above $40 and even with spikes of good news about OPEC deals and COVID-19 vaccines, it has not managed to hit $49.

And to top it off, many financial institutions and several major oil companies that might have considered investing in Alaska projects in 2018 are not interested in the Arctic now — not even with all the high quality, light oil that North Slope explorers such as Oil Search and ConocoPhillips are finding.

In other words, it is a whole new world for Oil Search than it was two and a half years ago when the company first became a North Slope operator.

Added to the list above might be the fact Oil Search is the third largest leaseholder in Alaska,

*see* **OIL SEARCH** *page 8*

LAND & LEASING

# W Harrison Bay unit OK'd

*State of Alaska approves new Beaufort shallow water unit; 2 well commitment*

**By KAY CASHMAN**
*Petroleum News*

On Dec. 8 the Alaska Department of Natural Resources' Division of Oil and Gas posted on its website a Dec. 7 approval of Shell Offshore Inc.'s application to form the West Harrison Bay unit in the shallow state waters of the Beaufort Sea west of the central North Slope.

In a Dec. 9 statement to Petroleum News Shell spokesperson Cindy Babski made it clear Shell will not operate the leases.

"The unitization term ends in December 2025 (per the Dec.7 approval), allowing Shell time to pursue a commercial agreement with an alternative operator. Shell has no intention of operating these leases, which were originally purchased in 2012 and were due to expire in 2022. Shell will transition to an alternative operator and fully divest out of the venture. We have sold or relinquished all our frontier licenses in Alaska and have no plans for frontier exploration offshore Alaska," Babski said.

> ***"Shell will transition to an alternative operator and fully divest out of the venture. We have sold or relinquished all our frontier licenses in Alaska and have no plans for frontier exploration offshore Alaska."***
> ***—Shell spokesperson Cindy Babski***

*see* **W HARRISON BAY** *page 8*

LAND & LEASING

# ANWR sale bid opening set

*Bids due Dec. 31, opening Jan. 6; KIC requests incidental take for seismic*

**By STEVE SUTHERLIN**
*Petroleum News*

The U.S. Department of the Interior Bureau of Land Management Alaska State Office has announced an early January date for its oil and gas lease sale bid opening for tracts in the Coastal Plain of the Arctic National Wildlife Refuge.

The bid opening will be at 10 a.m. Alaska Standard Time Jan. 6, according to a notice filed Dec. 7 in the Federal Register.

The BLM must receive all sealed bids Dec. 31 by 4 p.m. Alaska Standard Time. The opening and reading of the bids will be available via video livestreaming at www.blm.gov/live.

Alaska's congressional delegation lauded the BLM announcement.

"This is a tremendous step forward for our state and the countless Alaskans who make a living in our energy sector," said Rep. Don Young. "Finally achieving what was promised by ANILCA four decades ago is in sight, and I want to thank everyone involved for their ongoing hard work and commitment."

On Nov. 17, BLM Alaska published a notice in the Federal Register calling for nominations and comments on 32 tracts covering all 1.6 million acres of the ANWR Coastal Plain to consider in the lease sale. The plain, also referred to as the ANWR 1002 area, was set aside by Congress years ago

*see* **ANWR SALE** *page 9*

● PIPELINES & DOWNSTREAM

# Enbridge wasting no time

*Swings into action on construction of Line 3 after final regulatory approvals; observers edgy about prospect of showdown*

**By GARY PARK**

*For Petroleum News*

Enbridge started work Dec. 2 on replacing the U.S. portion of its corroding Line 3 crude pipeline from the Alberta oil sands to Superior, Wisconsin, after gaining what proponents view as their final U.S. permits.

But it's still too soon to close the book on a protracted battle for approval of plans to raise capacity on the system to 790,000 barrels per day from the existing 390,000 bpd.

"Until the barrels are freely flowing, we should take nothing for granted," said Tim McMillan, chief executive officer of the Canadian Association of Petroleum Producers.

It's still possible Line 3 will encounter state and federal legal hurdles, along with the prospect that Native and environmental protesters will delay the start of service from mid-2021 to 2022, according to a note by Height Commentary.

### Latest green lights

The latest green lights came from Minnesota state agencies in mid-November and the U.S. Corps of Army Engineers at the end of November, followed on Dec. 3 by a 4-1 vote of a Minnesota Public Utilities Commission panel to deny a request from two tribes to prevent Enbridge from moving forward with construction.

The PUC regulators said further stalling work would hurt some of the 4,200 workers who are moving into northern Minnesota.

"I think it would be an unconscionable disregard for the irreparable harm to these workers if the commission grants a motion to stay," said Commissioner Valerie Means. "I will not support … driving these workers into unemployment when work is available, can be done safely and there's no credible evidence to the contrary."

However, the PUC has warned Enbridge not to engage in "counterinsurgency tactics of misinformation campaigns designed to interfere with the public's legal exercise of constitutional rights."

Leaders of the activists anticipate strong police and private security responses to protests and fear a crackdown that would match the one near the Standing Rock Sioux Reservation in 2016 during resistance to the Dakota Access pipeline.

### Commercial operations in Canada

The Canadian portion of Line 3 began full commercial operations Dec. 3 of its C$5.3 billion, 600-mile development across the Canadian Prairies. The U.S. section from North Dakota to Wisconsin is expected to cost US$2.9 billion. Final construction is expected to take another six to nine months.

Leo Golden, Enbridge's vice president of major projects, said the regulatory progress is "proof of what can be achieved when people come together with an open mind and a willingness to talk and to build, rather than to take apart. It's been a very long road and it certainly

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FINANCE & ECONOMY

# EIA sees Brent averaging $49 next year

*Agency estimates US crude output averaged 11.2 million bpd in November; average expected to fall below 11 million bpd by March*

By KRISTEN NELSON

*Petroleum News*

Brent crude oil spot prices averaged $43 per barrel in November, up $3 per barrel from October, the U.S. Energy Information Administration said Dec. 8 in its December Short-Term Energy Outlook.

The increase followed "news that multiple COVID-19 vaccines appeared to be effective and that OPEC and its partners would limit production increases planned for January 2021," EIA Administrator Dr. Linda Capuano said in remarks accompanying the outlook.

LINDA CAPUANO

EIA said it expects Brent to average $43 per barrel in the fourth quarter, increasing to an average of $49 per barrel next year, with the higher forecast reflecting the agency's "expectation that while inventories will remain high, they will decline with rising global oil demand and restrained OPEC+ oil production." Brent is expected to average $47 in the first quarter, up $5 per barrel from the agency's November forecast, rising to average $50 in the fourth quarter, up $1 per barrel from last month's outlook.

EIA said higher first quarter price expectations reflect steeper expected inventory draws following the Dec. 3 OPEC+ decision to limit previously planned January production increases. The agency said it expects high global inventory levels and surplus crude production capacity to "limit upward pressure on oil prices through much of 2021."

EIA prefaced its forecast with a warning, regularly included in the months of the pandemic, that the outlook is subject to "heightened levels of uncertainty" because of COVID-19, related reduced economic activity and resulting changes in energy demand and supply patterns.

U.S. gross domestic product declined 4.4% in the first half of the year compared to the same period in 2019. GDP began rising in the third quarter, the agency said, and its expectation is that GDP will grow by 3.1% in 2021 compared to this year.

## OPEC production

"Following OPEC and its partners' decision to limit oil production increases planned for January, EIA lowered its forecast for OPEC crude oil production to an average 25.7 million barrels per day in the first quarter of 2021, which is 1.7 million barrels per day lower than our November forecast," Capuano said.

EIA said OPEC production this year is estimated to average 25.6 million bpd. Annualized 2021 production is expected to average 27.5 million bpd, with the increase reflecting potential OPEC production increases and increases in Libyan production.

OPEC had planned to increase production by 2 million bpd in January, but instead set the target increase at 500,000 bpd and said it would access markets and demand monthly.

## US crude production

"EIA estimates crude oil production totaled 11.2 million barrels per day in the United States in November," Capuano said. "We expect U.S. oil production will decrease to 11.0 million barrels per day in February 2021 as decline rates at existing wells outpace production from newly drilled wells in the Lower 48 states over the coming months."

The agency said it expects Lower 48 crude production to increase from 8.7 million bpd in February to 9.1 million bpd next December, "as drilling increases in response to rising oil prices," with the increase contributing to total U.S. crude oil production averaging 11.4 million bpd in December 2021.

EIA said that on an annual average basis it expects U.S. crude oil production to fall from 12.2 million bpd in 2019 to 11.3 million bpd this year and 11.1 million bpd in 2021.

*see* **EIA OUTLOOK** *page 7*

EXPLORATION & PRODUCTION

# On one hand, on the other …

*Canada Energy Regulator's 30-year forecast points to rise in crude oil, natural gas production, until 2040, then moderate decline*

By GARY PARK

*For Petroleum News*

Canadians trying to find middle ground in the debate over the future of their fossil fuel industry got both ends of the argument in a report issued by the Canada Energy Regulator in late November.

The federal government agency that reviews and decides on major development and pipeline project applications updated its energy outlook for the next 30 years by forecasting that oil and natural gas output will peak before 2050, the supposed magic target date for the Canadian government's targeted net-zero carbon emissions.

The CER's Energy Futures report said Canada's crude oil production could grow by about 18% to 5.8 million barrels per day over the next 20 years, while natural gas output could rise by 17% to 18 billion cubic feet per day.

However, the report also forecasts declines in crude output of 500,000 bpd through the 2040s to 5.3 million bpd by 2050 and 1.2 bcf/d in gas to 16.8 bcf/day over the same period.

"While fossil fuel consumption declines in the evolving scenario, it still makes up over 60% of Canada's fuel mix in 2050," renewable energy is expected to increase by 45% during the next three decades, the CER report said.

The agency said it expects the use of renewables and nuclear energy will grow by 31%, but, if global efforts to reduce greenhouse gas emissions do not develop beyond measures currently in place, fossil fuel consumption will remain relatively stable.

In that scenario, the crude benchmark price is expected to average US$75 a barrel over the 2025-50 period, compared with US$57 if there is a growing global shift towards stronger emissions reduction and greener energy.

## Cost, carbon competitive

CER Chief Executive Officer Gitane De Silva offered the blunt assessment, contrary to many initial interpretations, that the report "does not state new pipelines should not be built," adding "the report is a projection not a prediction."

She said that although Alberta as the stronghold of Canada's oil and gas output is a resilient province "the future of the (petroleum) industry depends very much on its remaining cost competitive and carbon competitive."

CER chief economist Darren Christie noted that available pipeline capacity is "well recognized to be something that helps (the transportation system) work efficiently and provides access to different markets."

That thinking covers about 1.8 million bpd of combined additional shipping space in three pipeline projects — the Trans Mountain expansion, Keystone XL and the replacement of Enbridge's Line 3.

Alberta Energy Minister Sonya Savage said that in general the CER findings confirm that oil and gas "will continue to dominate the energy mix for decades to come. It makes the case that the oil sands production is increasing and we are going to need additional pipeline capacity. But it also makes the case that emissions from the oil sands need to come down with technology."

One strong indication of the industry's support for more pipeline capacity is backing for the Trans Mountain expansion to 890,000 bpd. So far 13 companies have signed 15- and 20-year shipping contracts covering 80% of system's new volumes, with the balance available on the spot market.

Kevin Birn, an analyst with energy consultant IHS Markit, said that even in the

*see* **ENERGY FUTURE** *page 7*

● EXPLORATION & PRODUCTION

# State conditionally approves Placer POD

*Division requires plan of development by end of January, alternative to Mustang for production, written quarterly reports, meetings*

**By KRISTEN NELSON**
*Petroleum News*

The Alaska Department of Natural Resources' Division of Oil and Gas has conditionally approved — with modifications — ASRC Exploration's fifth plan of development for its Placer unit on the North Slope.

Modifications to the proposed POD (see story in Oct. 11 issue of PN), to which AEX must agree in writing by Dec. 17, include:

•AEX must provide a development plan to the division by Jan. 31, 2021, including well locations, target formations and estimated drill dates;

•Because the Mustang facility at the Southern Miluveach unit is in indefinite cold shutdown, AEX must formulate an alternate plan for facility access and provide it to the division by June 30, 2021;

•Quarterly reports are required throughout the POD period, with the first due by April 3; and

•Quarterly update meetings are required with the division coinciding with the written quarterly updates.

There are four state oil and gas leases, 1,480 acres, in the Placer unit, which lies between the Kuparuk River and Pikka units, northwest of the Southern Miluveach unit. AEX had planned to send production to the Mustang facilities at the Southern Miluveach unit for processing, but the Mustang facility went into warm and ultimately cold shutdown after initial test production reported to the Alaska Oil and Gas Conservation Commission in November 2019, and that unit is currently under Alaska Industrial Development and Export Authority control, with a search underway for a new operator (see story on page 1 of this issue).

*AEX received a 404 Permit from the Corps of Engineers, authorizing discharge of fill to construct a 7-mile road leading to a 7-acre pad and received an oil discharge prevention and contingency plan from the Alaska Department of Environmental Conservation.*

### Termination delayed

In the Dec. 3 decision on the proposed POD, division Director Tom Stokes said the Placer unit, formed in September 2011, was terminated in 2019 "after several years of AEX's failure to conduct operations," a decision which was stayed until July 31, 2020, to allow AEX to propose reasonable plans of development or seek partners for unit development.

The proposed second amended fourth POD for Placer, received Jan. 10, 2020, was conditionally approved, delaying termination.

In the fourth POD AEX committed to obtaining all necessary U.S. Army Corps of Engineers permits; submitting North Slope Borough Title 19 rezone applications and completing the rezone process with the NSB Planning Department; finalizing a facility access agreement with Brooks Range Petroleum Corp. to utilize Mustang facilities at the Southern Miluveach unit for Placer production; conducting surveys for road, pipeline and pad layout; beginning facilities front-end engineering and design; and obtaining all state permits for ice road construction and building an ice road to facilitate gravel road and pad construction.

The division added requirements to the fourth POD requiring AEX to post a $1 million performance bond which would be released if sustained unit production was established by Oct. 31, 2022; the division also required AEX to provide quarterly updates.

AEX received a 404 Permit from the Corps of Engineers, authorizing discharge of fill to construct a 7-mile road leading to a 7-acre pad and received an oil discharge prevention and contingency plan from the Alaska Department of Environmental Conservation.

It also successfully satisfied the division's added requirements for the performance bond and the quarterly updates.

"However, due to circumstances surrounding the COVID-19 pandemic, as well as the foreclosure of BRPC, AEX was unable to accomplish their remaining commitments for the 4th POD period," Stokes said.

### Proposed fifth POD

For the proposed fifth POD, AEX committed to:

•Finalize a facilities access agreement with the Mustang facility operator and, once that agreement is in place, start facilities front-end engineering and design;

•Restart discussion with the NSB Planning Department regarding the Title 19 rezone application;

•Submit a plan of operations application to the division;

•Start various federal and state permit applications in the first quarter of 2021;

•Conduct road, pipeline and pad layout surveys by the end of June 2021;

•Obtain master service agreements with contractors and start ice road construction for gravel road and pad construction in the first quarter of 2021; and

•Expedite and conduct civil engineering FEED for gravel road and drill site placement within Placer to Mustang starting in July 2021.

In addition to the work AEX proposed, the division added four other requirements, as noted above, and gave AEX until Dec. 17 to accept the proposed additional requirements. ●

*Contact Kristen Nelson at knelson@petroleumnews.com*



*continued from page 2*

### LINE 3

wasn't easy."

He said Line 3 will not be able to reach its full design capacity until Enbridge has replaced its existing line in Minnesota.

The new capacity is desperately needed by the oil sands industry that is relying on crude-by-rail shipments to move barrels into the U.S while producers face another year of government-mandated production cuts to offset low crude prices.

"Any incremental market is absolutely welcomed from an upstream producer perspective," said Ben Brunnen, vice president of CAPP.

Mark Oberstoetter, with the energy consultant Wood Mackenzie, said progress on Line 3 is "permission (for the industry) to grow again" and attract new investment.

However, consultant IHS Markit observed that it has taken an average of seven and a-half years from when filings were made to obtain regulatory approvals, and more than 10 years for Keystone XL.

Kevin Birn with IHS said expanding the existing Keystone system, building the U.S. portion of Line 3 and adding 50,000 bpd to Enbridge's Express system could potentially see an extra 400,000 bpd of pipeline space come on stream in 2021. ●

*Contact Gary Park through publisher@petroleumnews.com*


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

**NEWS**
907.522.9469
publisher@petroleumnews.com

**CIRCULATION**
907.522.9469
circulation@petroleumnews.com

**ADVERTISING**
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scrane@petroleumnews.com

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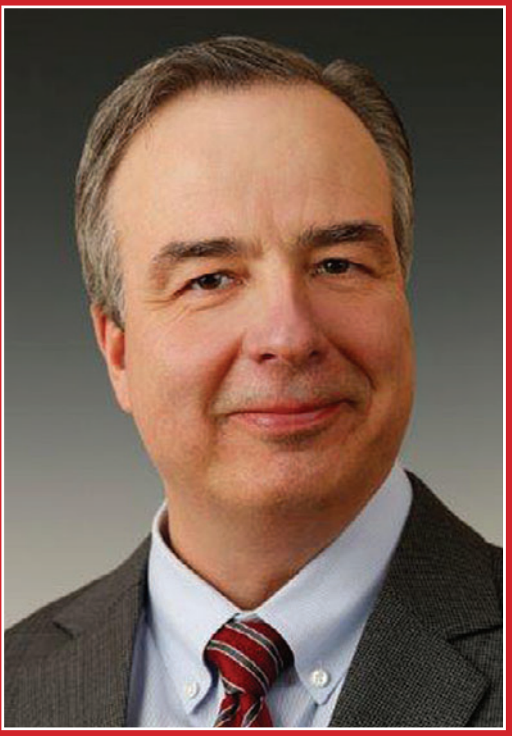
# Congratulations

# Celebrating 20 years of Alpine production!

Congratulations ConocoPhillips Alaska on 20 years of oil production from the Alpine field. West of the central North Slope, the Alpine field is one of the largest conventional onshore oil fields developed in North America in the past 25 years.

Alpine is a model for future oil developments as directional drilling and other innovations have minimized its environmental footprint.



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● GOVERNMENT

# AOGCC hears BlueCrest bonding request

*Company has $5 million in escrow account with Pioneer, previous Cosmopolitan owner, with $3 million dedicated to P&A of all wells*

By KRISTEN NELSON
*Petroleum News*

The Alaska Oil and Gas Conservation Commission has just heard another appeal of the amounts required in its new bonding regulations.

At a Dec. 8 hearing, BlueCrest requested a reduction of plugging and abandonment bonding at Cosmopolitan to reflect $3 million in escrow dedicated to P&A of wells at the field.

John Martineck, BlueCrest's chief operating officer, told the commission that BlueCrest had $700,000 on deposit with one or more agencies before AOGCC's bonding increase: $500,000 with the Alaska Department of Natural Resources and $200,000 with AOGCC.

BlueCrest has added $550,000 to its original AOGCC bonding, which now stands at $750,000, he said, with a total AOGCC requirement of $2,250,000 for the six wells at the field.

But, he said, the company actually has a total of $6,250,000 set aside as bonds or in escrow accounts for P&A and land reclamation, because when BlueCrest purchased Cosmopolitan from Pioneer Natural Resources Co. in 2012, BlueCrest set aside $5 million in an escrow account, controlled by Pioneer, with $3 million for P&A of wells and $2 million for surface reclamation.

Martineck asked that the $550,000 in additional bonding with AOGCC be returned.

In an August letter to the commission, Martineck said the company's estimate to P&A the wells is $400,000-$500,000 per well.

"Thus," he said in August, "the bonding and other financial assurance BlueCrest has in place is well in excess of the current estimated costs of abandonment and reclamation at Cosmopolitan."

### Commission questions

But the $5 million is not in a form accessible to the commission, which had asked for validation of the $5 million held by Pioneer for reclamation of the Hansen production facility site, $2 million, and $3 million for plugging, re-plugging and abandonment of wells. Pioneer confirmed the escrowed $5 million, and its purposes, to the commission in

see BONDING REQUEST page 7

● NATURAL GAS

# Future hydrogen production in Alaska?

*Does the state's abundance of natural gas provide an opportunity to cash in on what appears to be a burgeoning clean fuel?*

By ALAN BAILEY
*Petroleum News*

While Alaska's economy continues to rely heavily on oil production, with some level of global oil demand likely to continue well into the future, is there potential for the state to also benefit from the increasing interest in carbon-neutral fuels by moving into the production of hydrogen from natural gas? During a Dec. 10 talk to Commonwealth North consultant Mark Foster talked about this intriguing possibility.

There is much interest in the use of hydrogen in conjunction with fuel cells as a means of powering road vehicles, as an alternative to the use of battery powered electric vehicles. Liquid ammonia, a material containing hydrogen and nitrogen, can also be used as a clean fuel, as a substitute for diesel fuel. Most hydrogen is currently produced through the steam reforming of natural gas, a resource that Alaska has in plenty. And the state has past experience of manufacturing ammonia from natural gas at a fertilizer plant on the Kenai Peninsula.

Primarily using findings from a hydrogen road map recently published by McKinsey & Co, Foster outlined some of the opportunities and challenges that Alaska would face in entering the hydrogen industry.

Foster commented that the manufacture of hydrogen from natural gas results in the production of carbon dioxide. So, to market the hydrogen as a clean fuel, it is necessary to capture and sequester that carbon dioxide. Clean hydrogen can be manufactured through the electrolysis of water. However, this production technique is significantly more expensive than production by the steam reformation of gas, even taking into account the cost of carbon sequestration, Foster said. The steam reforming technique is likely to remain competitive for some time into the future, he commented.

And Alaska, with its existing oil and gas infrastructure, and with the possibility of injecting waste carbon dioxide into underground reservoirs, seems to have the potential for developing a hydrogen industry.

"I do think that there is a lot of opportunity across the oil and gas sector to monitor and potentially build up their hydrogen production capacity, as hydrogen markets grow on the demand side around the world," Foster said.

The big growth opportunity for hydrogen demand revolves around its use as a road transportation fuel, particularly in applications such as trucking fleets. Applications that can benefit from the high energy density of hydrogen seem particularly appropriate. Currently hydrogen is used to fuel material handling technologies such as forklifts. And, although transportation only shows up as tiny portion of current hydrogen usage, there are early indications of a future increase in demand for the fuel. Anheuser-Busch's fleet of vehicles for delivering products around the United States, for example, has 10 hydrogen fuel cell vehicles for every electric truck ordered, Foster said.

"So there's some very interesting validations going on by people who have been in the logistics business a long time and understand it," he said.

Other possibilities include use by the Department of Defense in its vehicle fleet, and the mixing of hydrogen with the natural gas used for heating buildings, to reduce the carbon footprint of space heating. The use of hydrogen fuel cell powered motors in railroad locomotives is another possibility.

In Alaska there are potential synergies with the aviation and shipping industries, with the use of hydrogen in the manufacture of fuels for these industries, Foster said.

With much research and pilot testing in the offing, big questions revolve around how quickly the price-performance characteristics of the hydrogen-based technology will ramp up. Will it become possible to reach the kind of improvements in price and performance that have been achieved with wind and solar energy technologies? Foster suggested that hydrogen technology

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## EIA OUTLOOK

### US natural gas

"Despite falling U.S. natural gas production during much of 2020 and growing LNG exports in recent months, reduced U.S. consumption resulting from warmer November temperatures contributed to natural gas inventories ending the month 8% higher than the previous five-year average. However, we expect that declines in natural gas production will outpace declines in consumption for the remainder of the winter as well as contribute to more natural gas withdrawals compared with the previous five-year average," Capuano said.

EIA is forecasting U.S. dry natural gas production to average 90.9 billion cubic feet per day in 2020, down from a 2019 average of 93.1 bcf, with monthly average production falling from a record 97 bcf per day in December 2019 to 87.1 bcf in April 2021, "before increasing slightly."

Dry natural gas production is forecast to average 87.9 bcf per day in the U.S. in 2021, with production expected "to begin rising in the second quarter of 2021 in response to higher natural gas and crude oil prices."

The agency estimated that the U.S. exported 9.4 bcf per day of liquefied natural gas in November, "the most for any month on record." EIA said it expects LNG demand to continue increasing, driven primarily by forecasts of colder-than-normal winter weather in northern Asia and Europe and South Korean coal plant closures.

U.S. LNG exports are forecast to exceed 9.5 bcf per day in December through February, and average 8.5 bcf per day in 2021, "a 30% increase from 2020," EIA said.

Capuano said that in the December outlook "EIA decreased the forecast for Henry Hub spot prices in 2021, reflecting our expectation of larger natural gas inventories than previously forecast. We expect prices of natural gas at Henry Hub to average $3.01 per million British thermal units in 2021."

Henry Hub averaged $2.61 per million Btu in November, EIA said, up from an October average of $2.39. The price is expected to reach a monthly average of $3.10 per million Btu in January. ●

*Contact Kristen Nelson at knelson@petroleumnews.com*

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## ENERGY FUTURE

midst of a challenging price scenario, crude supply in Western Canada remains "resilient."

Eager to advance their own view of the report, environment groups hailed the findings as evidence backing their insistence that work on the Trans Mountain expansion should be stopped immediately.

Cam Fenton, a team lead at 350.org, said the report makes it clear that the C$12.6 billion Trans Mountain project and Keystone XL are not necessary, even if Canada introduces net-zero legislation, while Tom Gunton, a resource and environmental planning professor at Vancouver's Simon Fraser University, said it's pretty clear that even tougher federal climate policies are coming.

On the flip side, Canadian Prime Minister Justin Trudeau, whose government owns Trans Mountain, renewed his commitment to the expansion, saying in November that Canada's oil sector should not have to rely on the United States as its sole export market.

"We purchased Trans Mountain and are busy building (the expansion) so that we get access to markets across Asia," he told a Canadian Broadcasting Corp. program in Calgary.

In addition, he was emphatic that his administration supports construction of Keystone XL, regardless of the barriers Joe Biden is expected to erect after he occupies the White House in January.

The CER gave more attention than previously to emerging technologies that could lower both fossil fuel demand and greenhouse gas emissions, including utility-scale battery storage, electrification of vehicles and buildings, hydrogen-powered applications to transportation and industry, carbon capture and solvent-driven heavy oil production, many of which are being introduced across Canada, especially Alberta which is trying to develop new jobs to offset the loss of thousands of jobs in the oil and gas sector. ●

*Contact Gary Park through publisher@petroleumnews.com*

continued from page 6

## BONDING REQUEST

September.

At the Dec. 8 hearing, AOGCC Chair Jeremy Price said the commission did not have access to the agreement spelling out purposes of the $5 million escrow account.

Martineck said the agreement is confidential under an agreement BlueCrest has with Pioneer but said he would request that the portion of the contract related to the escrow agreement be made available to the commission.

Price asked what triggers release of the escrow funds and Martineck said that was not spelled out in the agreement which just describes the purpose of the funds.

Asked what would happen if BlueCrest declared bankruptcy, Martineck said the money would be available for P&A and reclamation.

AOGCC's regulations require that it have exclusive access to P&A funds, Price said. Martineck said he didn't know that there was a mechanism for exclusive access for AOGCC to the escrowed funds.

Commissioner Dan Seamount asked if the funds could be moved into a bond dedicated to AOGCC.

Martineck said he would ask Pioneer.

Commissioner Jessie Chmielowski said the commission needed more information and detail on the purpose of the money — when it would be released and who would have control. She also asked about the $400,000-$500,000 estimate for P&A of each well. Martineck said that was an internal estimate. Chmielowski said she was interested in how BlueCrest came up with the numbers.

She also asked about the confidentiality of the P&A agreement and Martineck said it was part of the purchase and acquisition agreement.

At the close of the hearing Price said while AOGCC's regulations have some exceptions to the requirement that P&A funds be exclusively available to AOGCC, this situation doesn't fall within those exceptions.

The commission needs a bond to AOGCC, he said.

The commission left the record open to close of business Jan. 4 for response to questions. ●

*Contact Kristen Nelson at knelson@petroleumnews.com*

## NATURAL GAS

### Interior Energy Project reports status

The Interior Energy Project, an Alaska Industrial Development and Export Authority sponsored project to bring increased supplies of affordable natural gas to Fairbanks and its surrounds, has issued its latest quarterly report to the state Legislature. The project continues to make progress but has been slowed somewhat as a consequence of the COVID pandemic.

Gas for Fairbanks is liquified at the Titan LNG plant near Point Mackenzie on Cook Inlet and transported as LNG to Fairbanks using newly acquired road trailers. A new 5.25 million-gallon LNG storage tank was completed in Fairbanks at the end of 2019. This tank is providing LNG capacity to increase the number of gas consumers in Fairbanks.

Meanwhile, Interior Alaska Natural Gas Utility, or IGU, a Fairbanks-based gas utility, had completed the purchase of Fairbanks Natural Gas, to form a single, consolidated gas utility in the Fairbanks region.

A front end engineering and design project for a planned expansion of the Titan plant was completed in the first quarter of this year. However, with the impact of the pandemic on the price of fuel oil in Fairbanks leading to increased uncertainty over how much demand there might be for the use of natural gas to heat buildings, in April IGU decided to defer a final investment decision for the Titan expansion.

IGU has moved ahead with the installation of LNG storage facilities in North Pole, to open up new gas supplies there. Completion of this project will be delayed from September to Nov. 30 because of impacts from the pandemic, the quarterly report says.

Some expansions were made to the gas distribution networks in Fairbanks and North Pole in 2015, but no further expansions have been made since then. However, given the additional gas supply capabilities from the new LNG storage facilities, IGU has installed more than 200 new service lines to buildings and has allowed new customers to begin using natural gas, the report says.

Meanwhile, the Regulatory Commission of Alaska has approved the merger of IGU's and FNG's certificates of public necessity and convenience, thus confirming the consolidation of the utilities.

—ALAN BAILEY

continued from page 6

## HYDROGEN HOPES

will probably need government policy support for around a decade, for the technology to become cost competitive. Another driver would be greenhouse gas emissions policies.

However, hydrogen production and use has the potential to create domestic revenue and domestic jobs, with a locally produced energy resource that comes with significant benefits in terms of reducing air pollution and greenhouse gas emissions.

"That's the basic pitch," Foster said. ●

*Contact Alan Bailey at abailey@petroleumnews.com*

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## W HARRISON BAY

The 81,000-acre unit application included a plan of exploration, or POE, in which Shell said two wells would be drilled within five years, which the agency also approved with the unit formation effective Dec. 7.

Shell told the division it does not intend to operate the West Harrison Bay unit's 18 leases; rather it applied for the unit to prevent the leases from expiring, expecting to bring in another company to operate in 2021.

Shell picked up the West Harrison Bay leases in 2012 "because prospectivity was recognized in the Brookian and Beaufortian megasequences," the company's application said, noting it redirected focus to these leases, and "generated five stand-alone prospects in the Nanushuk formation and multiple leads in both the Torok formation and Jurassic Alpine-like plays."

Review of the confidential data and interpretations of the data provided by Shell "reasonably supports an interpretation that the unit encompasses the minimum area required to include all or part of several potential hydrocarbon accumulations (PHAs) in the Nanushuk and Torok formations," division Director Tom Stokes confirmed in the Dec. 7 decision.

"The area encompassing the PHAs … will require extensive drilling, testing, and additional delineation work to determine its commercial viability," he said.

Although the unit area "saw scattered exploration efforts during the 1970s and 1980s." it "remains lightly explored today," Stokes wrote, noting no wells have been drilled within the unit boundary.

The West Harrison Bay unit lies northwest of the Oil Search-operated Pikka unit, approximately 7 miles north of the Bear Tooth unit (specifically directly north of the Willow discovery) and 13 miles northwest of the Colville River unit, both of which are operated by ConocoPhillips.

### Second POE due Oct. 6, 2021

In the POE, Shell also committed to several non-drilling activities, including completing a data gap and alternatives analysis to determine what additional studies are required to advance exploration activities in the unit, initiating an exploration phase project scoping, and finalizing subsurface well design and layout to optimize the reservoir.

Shell further committed to acquiring (and giving to the division) additional seismic information that can be interpreted to support the presence of a prospect(s) within the designated "flex wave area" of the unit by no later than the end of September 2022.

Shell provided the additional seismic information on Nov. 19. The division has not yet validated the dataset.

One well is to be drilled in the West Harrison Bay unit no later than two years from the effective date of the unit agreement — or two wells by no later than five years from the effective date. If the wells are not drilled within that timeframe, then the $3.25 million performance bond posted by Shell must be surrendered in full to the department, and the unit will automatically terminate five years from the effective date.

The initial POE period runs from Dec. 7 through Dec. 6, 2021. A second POE is due Oct. 6, 2021. ●

*Contact Kay Cashman at publisher@petroleumnews.com*

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## OIL SEARCH

which likely puts some pressure on the company because of work commitments/expectations from state, federal and Native landowners, whose leases generally have terms of seven to 10 years.

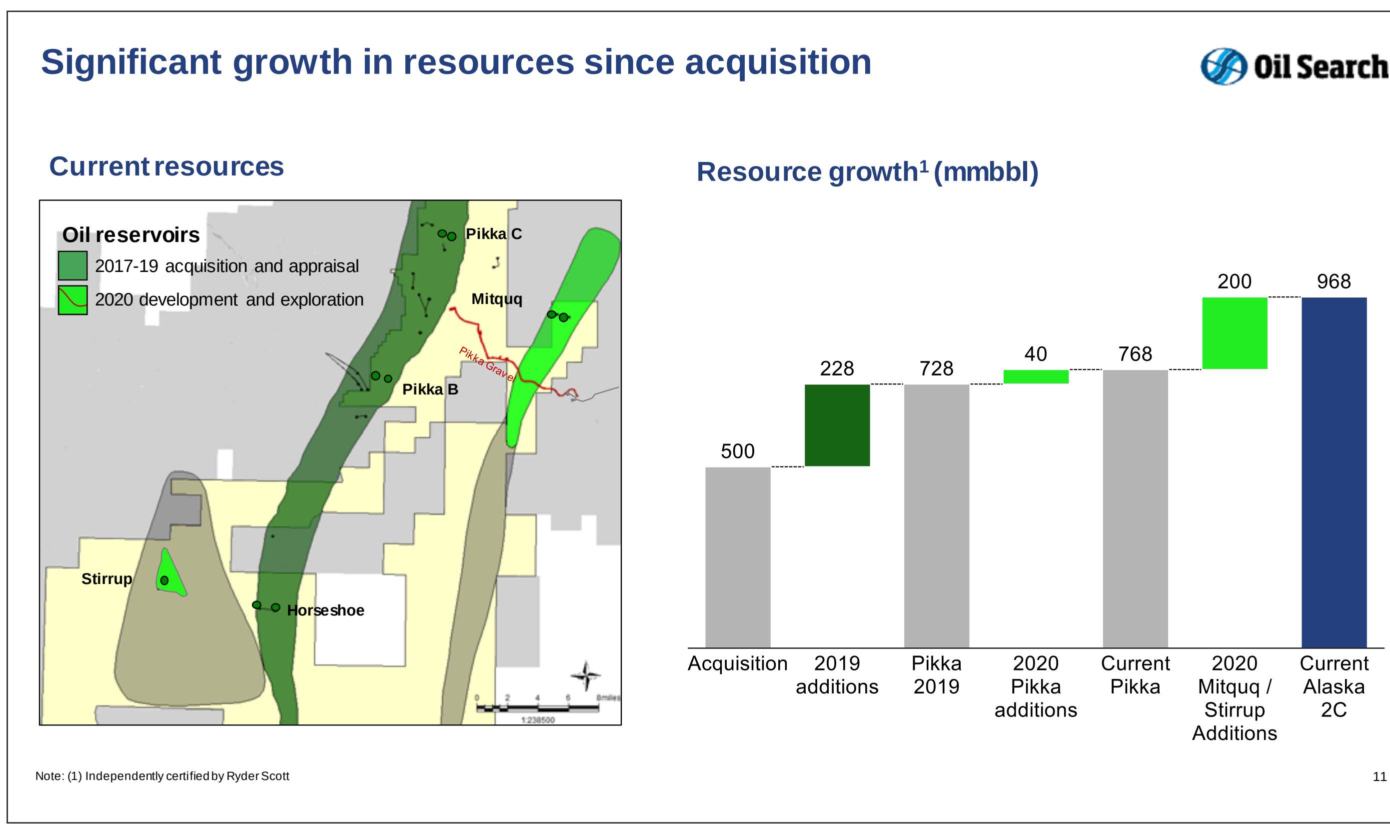
### News and clarifications

In early December Oil Search Alaska COO Matt Elmer spoke to attendees of a Resource Development Council virtual meeting in Anchorage about the company's plans for its Alaska leasehold, with special emphasis on its first big development, Pikka.

The most interesting updates in Elmer's presentation and in the related emails between Petroleum News and Oil Search's manager of U.S. media and communications Amy Burnett, include the following:

• Pikka phase 1 production peak of 80,000 barrels of oil per day will be reached "shortly after" startup in 2025 — exactly when in 2025 the company is not yet saying.

• Elmer and a resource map accompanying his presentation indicate the 2020 Mitquq exploration well (two penetrations) discovered a separate reservoir lying to the east and parallel with the Pikka Nanushuk reservoir, its tentative length and width similar to that of Pikka




(see map in pdf or print version of this this story).

• The 2020 Stirrup exploration well also discovered a separate reservoir that lies west of both Pikka and the Horseshoe discovery — this is the well that had the highest flow rate, somewhere in the 3,800 barrel-a-day range, of any North Slope Nanushuk well that has been drilled from a straight hole with a single stage frac.

• Between 40 and 50 wells will be drilled during Pikka phase 1.

### Meeting the challenges

Oil Search, which turned 90 years old in 2019, has "a consistent history of growth in phases" that is "illustrated by the way the LNG projects in PNG were progressed," Elmer noted. (As previously reported, Pikka has moved to a phased approach.)

"Alaska is clearly a long-term growth and investment area for Oil Search. Our plan is to be here for a long time. Pikka's just the start. … We have a number of opportunities to develop after Pikka," he said.

Regarding 2020, Elmer said, "I think

*see* **OIL SEARCH** *page 9*

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## ANWR SALE

because of its oil and gas potential.

BLM Alaska must receive all nominations and comments on the tracts on or before Dec. 17, the notice said.

U.S. Secretary of the Interior David L. Bernhardt signed a record of decision Aug. 17, approving the Coastal Plain Oil and Gas Leasing Program in the refuge.

Although the Interior Board of Land Appeals ruled against the state Nov. 9 in a decades-long border dispute over title to 19,322 acres along the western edge of the refuge, the land in question may not be included in the upcoming sale.

IBLA's denial of an appeal filed by the Alaska Department of Natural Resources' Division of Mining, Land and Water over a 2016 BLM decision cleared the way for the state to litigate its position in federal court, should it so choose.

"Tract number 29 covers the disputed Staines-Canning River area. It is currently under litigation with the State of Alaska," the Nov. 17 notice said. "The BLM may elect to not offer this tract in the upcoming sale."

The leasing program is required by law in the Tax Cuts and Jobs Act of 2017 (Public Law 115-97), which was passed by Congress and signed into law by President Donald Trump on Dec. 22, 2017. The first of two congressionally mandated lease sales in the area must be held no later than the end of 2021.

### KIC files incidental take authorization

The Kaktovik Inupiat Corp. has filed an authorization request under the Marine Mammal Protection Act of 1972 to take by harassment small numbers of polar bears incidental to its eastern ANWR Coastal Plain seismic survey and associated activities scheduled to occur between Jan. 21 and Sept. 30.

The U.S. Fish and Wildlife Service published a notice of receipt of application and proposed incidental harassment authorization in the Federal Register Dec. 8, together with an availability of draft environmental assessment, and request for comments.

USFWS estimated that the project may result in the nonlethal incidental take of up to three polar bears.

"This proposed authorization, if finalized, will be for take of three polar bears by Level B harassment only," USFWS said in the notice. "No take by injury or death to polar bears is likely and therefore such take is not included in this proposed authorization."

KIC's Marsh Creek East 3D seismic program would consist of activities such as overflights for aerial infrared surveys in January and February to locate maternal polar bear dens; staging and mobilization of vehicles and equipment; small crew surveys for hazards, ice integrity and snow depth assessment; seismic surveys via a sled camp with rubber-tracked vibrator trucks; camp setup and mobilization; aerial activities for crew and supply transport; digital elevation modeling for river-crossing slope analysis; and cleanup activities during the summer of 2021, USFWS said.

Comments on the proposed authorization and the draft environmental assessment must be received by USFWS no later than Jan. 7. ●

*Contact Steve Sutherlin at ssutherlin@petroleumnews.com*

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## OIL SEARCH

we are all looking forward to it passing us by and getting into 2021."

But Oil Search had a very successful 2020 in terms of resource growth and tackling current market conditions.

For example, significant discoveries at Mitquq and Stirrup de-risked resources in the Quokka and Horseshoe trends.

*But Oil Search had a very successful 2020 in terms of resource growth and tackling current market conditions. For example, significant discoveries at Mitquq and Stirrup de-risked resources in the Quokka and Horseshoe trends.*

2020 also saw an increase in Oil Search's confidence in Pikka due to well and seismic results, Elmer said.

A slide accompanying his presentation said the company saw additional potential Pikka resource in the Nanushuk, Alpine and Kuparuk reservoirs.

### Lowering costs

In 2020 Oil Search was "introduced to quite a bit of challenge with COVID, the consequences being a low oil price and a complete shift in the oil price environment," Elmer said.

"When you put those two things together — a growing resource and a lower price — we've had to look hard (asking)… how do we approach it differently to make it more robust in a low oil price world."

First, Elmer said, the company focused on improving the project's resilience, its breakeven cost. They were able to lower it to "something below $40 a barrel."

"We're very comfortable at that breakeven cost moving this project forward," although, he said, they would be happier "getting it down to $35 per barrel," so they're still looking at "other options."

The other piece "we focused on was reducing the near-term expenditure. The original project, which was the three drillsite, 120,000 barrel a day approach was a $6 billion investment. And given where prices were and the way the environment was shaking out, that was too steep to take on, so the company decided on a phased approach with one drillsite initially, dropping the upfront expenditure to $3 billion and starting with 80,000 barrels a day."

### How to build it

"The other piece we did was we also shifted our focus on how we're going to build our facility," Elmer said.

Traditionally on the North Slope companies "go with large, custom-built sealift processing facilities, so we're pivoting a bit and we're going to move to more of a smaller module and truckable facilities and a much more standardized design versus a custom design. And that's allowing us to drive costs down quite a bit. And it also reduces our risk and uncertainty both on cost and on schedule," Elmer said.

"Once we come online we'll have self-funding growth … as we move forward with the project," he said. ●

*Editor's note: See part 2 of this story in the next weekly edition of Petroleum News.*

*Contact Kay Cashman at publisher@petroleumnews.com*

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## PROJECT PEREGRINE

a preferred bidder had been selected for the Peregrine farm-out on one well, although the name of the successful bidder and details of their deal wouldn't be made public until the farm-out paperwork was finalized.

As it turns out, APDC is farming in for a 50% ownership of the 195,000-acre Peregrine Project by contributing US$11.3 million towards the cost of one of the two wells planned for this winter, the Merlin 1 (estimated gross cost US$12.6 million).

In the Dec. 4 announcement from 88 Energy's board of directors, APDC was identified as "a special purpose investment vehicle organized for Project Peregrine," its members "a consortium of private US entities managed by individuals that have extensive experience in oil and gas, including owning businesses that directly operate in the sector."

"Being able to secure a farm-out deal with a high caliber partner on close to two for one deal terms in the current oil and gas environment is a major coup for our shareholders," 88 Energy Managing Director Dave Wall said.

"APDC is a close cultural fit for our proposed future plans for Project Peregrine. … We look forward to potential success as we approach the imminent spud of Merlin 1 in February 2021," he said.

### Rig 111 under contract

On Dec. 7, 88 Energy announced it executed a rig contract with All American Oilfield LLC for the use of Rig 111 to drill the two Project Peregrine wells, Merlin 1 and Harrier 1. Both North Slope NPR-A wells will be drilled to a depth of approximately 6,000 feet in order to intersect the prospective Nanushuk topset horizons on trend to discoveries to the north of the project area.

The wells will be drilled by 88 Energy operating subsidiary Accumulate Energy Alaska, which is run by longtime North Slope geologist Erik Opstad.

### Targeting Nanushuk reservoir

The main target of the wells is the prolific Nanushuk reservoir.

Merlin 1 is considered a direct analogy to ConocoPhillips' Willow oil discovery, while ConocoPhillips' Harpoon prospect is interpreted to lie on the same sequence boundaries as Harrier 1.

The prospects lie between the Umiat oil field to the south and Willow and Harpoon to the north.

Opstad told Petroleum News that the Nanushuk can be reached at less than 5,000 feet in the area, while a third prospect in the Peregrine block, Harrier Deep, has a Torok objective at about 10,000 feet. It will not be drilled in the 2020-21 winter season.

### Dropping some Icewine acreage

As part of its annual review of leases, 88 Energy said Dec. 7 that the Icewine joint venture has "determined that several leases at Project Icewine are no longer considered prospective and, consequently, a decision has been made to not renew these leases."

The leases represent approximately 25% of the gross lease position, resulting in a 231,000 net acreage position for 88E in the Central North Slope, the company said, reducing the "ongoing rental costs at the project as focus shifts to the farm-out effort in the vicinity of the recently drilled Charlie-1 well."

"In a new development, Pantheon Resources announced that its Talitha-A well, located close to the northern border of the 88E central acreage position, is scheduled to spud in January 2021. Several of the prospective horizons in Talitha-A are interpreted to extend into 88E acreage," 88 Energy said.

—KAY CASHMAN

*Contact Kay Cashman at publisher@petroleumnews.com*

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## LIBERTY EIS

further proceedings."

### The project

Liberty is in federal waters off the eastern North Slope. Oil was discovered in the area by Shell between 1982 and 1987, and the existence of a field at Liberty was confirmed by BP at its Liberty No. 1 exploration well in 1997.

Development has been a challenge.

BP proposed an artificial gravel island in 1998, then changed the plan to ultra-extended reach drilling, but technical issues — and the Deepwater Horizon disaster — resulted in cancellation of the project in 2012.

Hilcorp became involved in 2014 when it took over interests in several of BP's North Slope properties, including a 50% interest in Liberty. Hilcorp moved ahead with an island plan similar to BP's original concept.

That plan was the subject of the 2018 BOEM final EIS and ROD.

### Foreign oil consumption

The court said it "concluded that BOEM acted arbitrarily and capriciously by failing to quantify the emissions resulting from foreign oil consumption in its EIS as required by the (National Petroleum Policy Act), or, at least, explaining thoroughly why it could not do so, and summarizing the research upon which it relied."

The court disagreed with an argument by the Center for Biological Diversity that BOEM had unlawfully used different methodology for greenhouse gas emissions from Liberty and from the no-action alternative, saying "the record indicates that BOEM did not apply different methods in comparing the action and the no-action alternatives."

*"We agree with CBD that the mitigation measures proposed by FWS are too vague to enforce," the court said. "The administrative record does reflect a 'general desire' to impose mitigation strategies, but it does not reflect a definite commitment to those improvements."*

But the court said it found "persuasive" CBD argument's "that BOEM arbitrarily failed to include emissions estimates resulting from foreign oil consumption in its analysis of the no-action alternative."

The court said BOEM used a model that assumed foreign oil consumption would remain static whether or not Liberty oil was produced.

BOEM found that the no-action alternative would result in less oil consumption, with amounts varying with the price of oil, but BOEM said it did not have reliable information to enable it to capture data to show impacts of greenhouse gas resulting for the reductions.

The court said it agrees with CBD "that BOEM was both required and able to estimate the variable and include its effect."

It said an EIS is required by NEPA to consider indirect effects of a proposed action.

"The record belies BOEM's contention that it could not have summarized or estimated foreign emissions with accurate or credible scientific evidence," the court said.

BOEM concluded that not drilling would result in more emissions than drilling — a conclusion the court called counterintuitive.

"Without further explanation, we cannot ascribe the implausibility of the result to BOEM's expertise or rational decision-making," the court said.

"BOEM has the statutory authority to act on the emissions resulting from foreign oil consumption," the court said, and agreed with CBD "that BOEM's alternatives analysis in the EIS was arbitrary and capricious."

### FWS and ESA

CBD also challenged the Fish and Wildlife Service's compliance with the Endangered Species Act in the biological opinion it prepared for BOEM discussing effects of the project on threatened species and habitats.

"CBD argues that FWS violated the ESA because portions of its biological opinion and incidental take statement were arbitrary and capricious," the court said.

"We agree with CBD that the mitigation measures proposed by FWS are too vague to enforce," the court said. "The administrative record does reflect a 'general desire' to impose mitigation strategies, but it does not reflect a definite commitment to those improvements."

The ESA requires BOEM to ensure its actions "are not likely to jeopardize the continued existence of the listed species or result in destruction or adverse modification of its critical habitat," duties which cannot be met by relying upon "a legally flawed biological opinion or failing to discuss information that might undercut the opinion's conclusions," the court said.

The court said because it concludes that FWS's biological opinion is invalid — at least in part — "BOEM's reliance on it is unlawful."

In providing relief, the court said that in addition to the emissions issue in BOEM's decision, it holds "that FWS violated the ESA by (1) relying upon uncertain, nonbinding mitigation measures in reaching its no-adverse-effect conclusion in its biological opinion, and (2) failing to estimate the Liberty project's amount of nonlethal take of polar bears."

—KRISTEN NELSON

*Contact Kristen Nelson at knelson@petroleumnews.com*

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## FINNEX DEAL

to an Alaska Division of Corporations filing, Thyssen Petroleum Alaska LLC holds 85% of Finnex and Galactico LLC the remaining 15%. An affiliate of Thyssen was part of a joint venture the original operator of the Southern Miluveach unit, or SMU, put together — Brooks Range Petroleum Corp, or BRPC.

The SMU was formed on March 31, 2011, and currently contains five state leases covering approximately 8,960 acres.

BRPC drilled the North Tarn No. 1A discovery well in 2012. The resulting Mustang field is estimated to hold some 21.2 million proven barrels of oil in place.

BRPC spent the next seven years responding to a series of technical, economic, political and logistical complications. While some of those complications were inherent to the Mustang field and to the company, others were external, such as the 2017 veto by then-Gov. Bill Walker of previously approved oil and gas tax credits designed to offset exploration expenses.

With the start of commercial production on Oct. 30, 2019, BRPC became the first small independent oil company in Alaska to bring a North Slope field from discovery to production. The company conducted an extended production test from its North Tarn 1A well using temporary processing facilities, exporting oil to the Alpine Pipeline System. By the time a flaring permit for the unit expired on Nov. 27, the company had produced 10,999 barrels of oil.

"In late October 2020, Mustang Holding informed the Division that it had not reached an agreement to transfer the working interest or operatorship to Finnex and that Mustang Holding, through experienced oilfield services companies, would be maintaining the SMU in a cold shutdown mode while AIDEA continued to pursue an operator for the SMU and related assets," division Director Tom Stokes wrote in his recent decision to Geoffrey A. Johns of Mustang Holding.

Mustang Holding asked the division for recognition of the transfer of working interest to its name and requested it be named operator of the SMU, which the agency approved on Dec. 3 and 4, respectively.

On Oct. 1, then-operator BRPC and Finnex filed the eighth annual plan of development for the SMU with the division, promising sustained oil production from the Mustang field by third quarter 2021.

The division now considers the eighth plan of development "as if it were initially submitted by Mustang Holding and considers the stated intentions and capabilities of Mustang Holding in its finding and decision," which was to disapprove the plan with modifications.

"Mustang Holding does not possess the technical capabilities … to carry out the work commitments found in the 8th POD, but does possess, through competent contractors, the ability to maintain the SMU in cold shutdown," Stokes wrote. "By maintaining the SMU in cold shutdown status, Mustang Holding will be preserving the SMU Infrastructure … in a manner to allow for their marketing and an expedient acquisition by an operator who can return the SMU to production," thus also protecting the interest of the state of Alaska, the unit's landowner.

### Quarterly reports

Mustang Holding or its successor operator must provide quarterly reports on the status of the SMU infrastructure. They are due no later than the 15th day of the first month of the immediately following quarter — e.g., the first quarterly report for 2021 covering the period of Jan. 1 through March 31 is due no later than April 15, and so on.

By Jan. 4 Mustang Holding also has to give the division a 2020 year-end report about any progress made regarding continued viability and operations of the SMU.

**—KAY CASHMAN**

*Contact Kay Cashman at publisher@petroleumnews.com*

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## OIL PRICES

see a momentous transition in the global energy mix sooner than currently expected, or a much faster development pace than the current norm, upstream players may have to more than double their conventional exploration efforts in order to meet global oil demand through 2050."

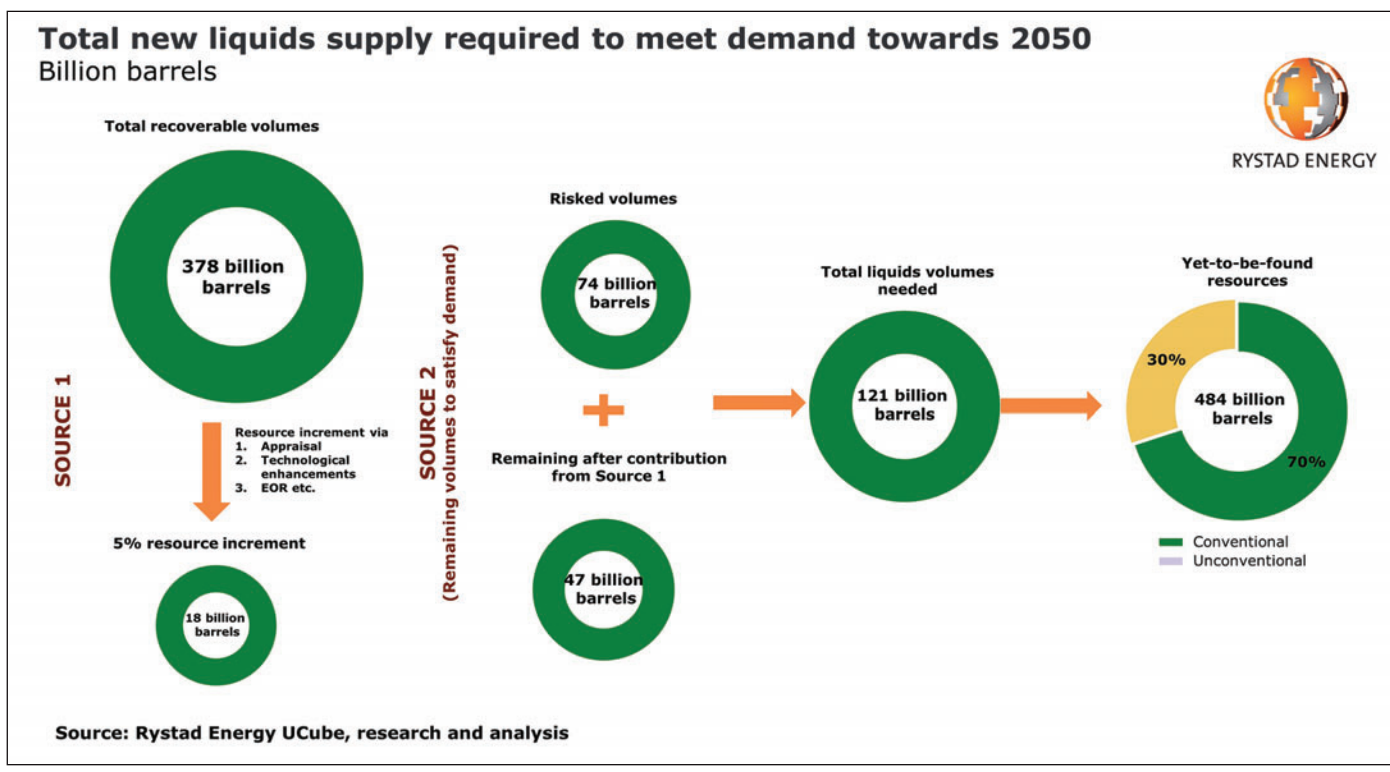
To meet projected demand, exploration programs will have to discover a worthy-to-develop resource of 139 billion new barrels of liquids by 2050, "an impossible task if this decade's low exploration activity levels persist," Rystad said.

Rystad said it set the target high because not all existing discovered volumes are profitable to develop.

"In theory, the total undeveloped supply would amount to 248 billion barrels of oil between 2021 and 2050," Rystad said. "However, when we dive deeper into these discoveries and look at their discovery decade and current status, we find that about 74 billion barrels are highly unlikely to materialize and need to be replaced by new discoveries."

In global conventional exploration potential, there are two main sources for new volumes: further appraisal of existing fields and resources, and new discoveries, it said.

Based on discovery rates of the current decade and the latest trends, Rystad expects global conventional discovered liquid volumes could settle at around 4 billion barrels per year, with an average discovery size of around 40 million barrels, Rystad said, adding that explorers would need to announce at least 100 new conventional discoveries each year at that rate to meet demand.




### OPEC+ moderates 2021 increase

Oil prices have held steady after the Organization of the Petroleum Producing Countries and its allied producing countries held back on a planned Jan. 1 production increase of 2 million barrels per day, agreeing to an increase of just 500,000 bpd.

The cartel made the announcement following negotiations at its 12th OPEC and non-OPEC Ministerial Meeting Dec. 3.

OPEC+ had planned to reduce its existing production cuts of 7.7 million bpd to 5.7 million bpd, but now will observe a 7.2 million bpd reduction after a new spike in worldwide COVID-19 cases caused a slower recovery of oil demand than that projected by OPEC when cuts were implemented in the spring.

Alaska North Slope crude popped 66 cents on the news Dec. 3, to close at $47.87 per barrel. West Texas Intermediate jumped 36 cents Dec. 3, to close at $45.64, while Brent jumped 46 cents to close at $48.71.

On Dec. 8, ANS closed at $48.67, up 73 cents; WTI closed at $45.60, down 16 cents; and Brent closed at $48.84, up 5 cents.

WTI was trading at $45.69, and Brent traded at $48.86 at Petroleum News press time Dec. 9.

Renewed lockdowns due to more stringent COVID-19 containment measures continue to impact the global economy and oil demand recovery, with prevailing uncertainties over the winter months, OPEC said in a Dec. 3 statement, adding that it is vital that its Declaration of Cooperation participants and all major producers remain fully committed to efforts aimed at balancing and stabilizing the market.

**—STEVE SUTHERLIN**

*Contact Steve Sutherlin at ssutherlin@petroleumnews.com*