Petroleum news

Vol. 25, No. 3 • www.PetroleumNews.com

A weekly oil & gas newspaper based in Anchorage, Alaska

Week of January 19, 2020 • $2.50

page 4 EIA: Brent expected to average $65 in 2020; new US crude records

ANWR leasing; XCD #8; unusual AGDC testimony; tax ballot & more

THE PAST WEEK HAS PRODUCED several interesting news stories and blog flashes, including a Washington Post interview with Interior Secretary David Bernhardt explaining why his department has not yet finalized its record of decision to lease parts of the 1002 area of the Arctic National Wildlife Refuge — because he wants to make sure Interior's plan can withstand all legal challenges. More on this later.

First, three interesting tidbits, starting with Jeff Landfield's Alaska Landmine blog on Jan. 12, commenting

see **INSIDER** *page 9*

CEQ issues proposed rule to modernize NEPA regulations

The Council on Environmental Quality has released a notice of proposed rulemaking to update its National Environmental Policy Act regulations. Public comments are being accepted through March 10.

NEPA was signed into law in 1970 and CEQ's NEPA regulations were promulgated in 1978 and have not, CEQ said, been comprehensively updated since then.

NEPA compliance has become increasingly complex and time consuming for agencies and applicants, the council said, with the average length of an environmental impact statement more than 600 pages and the average time for federal agencies to complete

see **NEPA REGS** *page 11*

Furie asset sale hearing delayed again, rolls two weeks to Jan. 27

Furie Operating Alaska LLC has rescheduled an omnibus hearing on its Chapter 11 bankruptcy case, originally set for Jan. 13, to Jan. 27 at 11:00 a.m. Eastern Time.

The hearing, which includes the sale hearing on the sale of Furie's assets, was adjourned with permission of the court to the later date, remaining before U.S. Bankruptcy Judge Laurie Selber Silverstein at the U.S. District Court of the District of Delaware.

The sale hearing was originally scheduled for Nov. 20, under a bidding procedures order signed Sept. 26 by Selber Silverstein.

The order set forth an ambitious schedule for the sale of the company's assets, which would have seen the matter largely

see **HEARING DELAYED** *page 11*

RCA extends confidentiality ruling time for BP-Hilcorp pipeline issues

The Regulatory Commission of Alaska said in a Jan. 7 order that it is extending its time to rule on petitions for confidential treatment of filings by Harvest Alaska, Hilcorp Alaska and Harvest Midstream in applications for sale of pipelines by BP Pipelines (Alaska) to Harvest Alaska. Harvest Alaska is the subsidiary of Hilcorp which owns the company's pipelines.

The pipelines in question, part of BP's sale of its Alaska assets to Hilcorp, are the PTE Pipeline, the Milne Point Pipeline and the transfer of BP's certificate of public convenience and necessity for the trans Alaska oil pipeline system.

The commission has said it would not set a timeline for its decision on the transfers until it ruled on petitions for confi-

see **RCA RULING** *page 8*

EXPLORATION & PRODUCTION

Placer resurrection

AEX files for Corps permit; unit in default, working with DNR on resolution

By KAY CASHMAN
Petroleum News

The dispute between the Alaska Department of Natural Resources' Division of Oil and Gas and ASRC Exploration appears to be close to resolution, with permitting of the Placer unit moving forward.

In mid-December AEX applied for a key Placer permit with the U.S. Army Corps of Engineers per a public notice posted by the agency Jan. 15.

The Placer unit had been terminated by the division in July, but an email from DNR Deputy Commissioner Sara Longan with the following statement from Commissioner Corri Feige confirmed a settlement is in the works: "ASRC Exploration LLC and the Department of Natural Resources continue to work closely together to move the Placer unit forward into development and, ultimately, production. We are hopeful to resolve soon."

What changed for AEX is not clear at this time. It is possible the company found a partner, as it had put the 8,768-acre Placer unit on the market in May.

Permit application details

The Corps permit applied for by AEX is for work in waters of the United States, specifically involving the Miluveach River, with the possible result of connecting Placer to the nearby Mustang field operated by Brooks Range Petroleum Corp., where Placer oil might be processed.

see **PLACER PERMITTING** *page 12*

NATURAL GAS

Arctic opportunities

$1 trillion global investment needed for Arctic projects, says CEO of Qilak LNG

By STEVE SUTHERLIN
Petroleum News

The Arctic will need significant outside capital to reach its vast potential, Mead Treadwell, CEO, Qilak LNG said in remarks to the Arctic Ambitions conference in Anchorage Jan. 9.

"When analysts have looked at what is the investment potential in the Arctic, you take the number of projects that are credibly on the drawing board someplace in the North, and it adds up to about a trillion dollars," Treadwell said. "There's 4 million of us who live in the Arctic, and we don't have enough money in our mattresses to cover it; we have to be competitive globally in raising funds."

It's a message Treadwell has taken to heart. He said he and Qilak President and COO David Clarke found a backer in Lloyds Energy of Dubai for their plan to export liquefied natural gas directly from a proposed facility offshore Point Thomson on the North Slope, to markets in Asia via ice breaking tankers.

The Arctic has a host of commercial opportunities and products, and energy looms large in the region.

Arctic energy accounts for 40% of Russia's GDP, and energy makes up the lion's share of Alaska's $50 billion GDP, Treadwell said, adding, "Greenland's independence movement was somewhat based on

see **ARCTIC PROJECTS** *page 12*

EXPLORATION & PRODUCTION

Cleanup on grand scale

Alberta faces an estimated $58.6B liability for thousands of abandoned wells

By GARY PARK
For Petroleum News

The Alberta government hopes to untangle the most complicated feud between the energy industry and landowners no later than March 31 when Energy Minister Sonya Savage unveils "an entire suite of policies dealing with well licenses and liabilities" that will set a new course to clean up the mess created by abandoned wells.

The overhaul will cover "everything from licensing to operations, to transfers of licenses, to abandonment and reclamations, to the orphan wells ... and even to post-closure and legacy sites," she told the Calgary Herald.

Without going into detail, she said the package will involve the role of the Alberta Energy Regulator, AER, the province's industry controlling agency, along with "some regulatory and policy changes."

450,000 wells drilled

The scope of the challenge is captured in a few statistics and cost estimates stemming from the drilling of 450,000 oil and gas wells over the past century whose end-life cleanup — in the absence of fixed timelines on remediation — has mostly been left to whatever sense of corporate and community responsibility has been taken on by the companies involved.

see **WELL CLEANUP** *page 11*

ENVIRONMENT & SAFETY

Embracing net zero

Leading oil sands players join rush to eliminate greenhouse gas emissions by 2050; observers believe moves vital to company images

By GARY PARK
For Petroleum News

Unlike anything anyone could have imagined even 5 years ago, Canada's leading synthetic and conventional crude oil producers are scrambling on to a wagon destined for net-zero greenhouse gas emissions no later than 2050 — matching the Canadian government's own target.

That means the Canadian industry is headed in exactly the opposite direction from the Trump administration which has just announced changes to the U.S. National Environmental Policy Act that would accelerate approvals of major projects including pipelines.

For companies such as Canadian Natural Resources, Cenovus Energy and MEG Energy, the objective is to lower GHGs by 30% over the next decade, on track for the "net-zero" goal, reflecting political pressure from the government of Prime Minister Justin Trudeau and, perhaps even more, the threat of taps being turned off by investors unless those companies demonstrate a commitment to a drastic overhaul of their environmental, social and governance or ESG policies.

Peter Tertzakian, a Calgary energy economist, believes the issues tied to ESG present an opening for oil sands producers.

He told the Calgary Herald investors are "setting the environmental policies — the pension funds, the big players — and companies that are able to certify and validate that they have reduced their emissions are going to have access to capital."

A clear reinforcement of that message came earlier in January when he world's largest fund manager, BlackRock Inc., joined more than 300 other major investors — with total assets under management of more than US$41 trillion — in the Climate Action 100+ initiative, which is applying undisguised pressure for corporate action and enhanced disclosure on climate issues.

Benjamin Israel, a senior analyst at the Alberta-based energy and environment think-tank Pembina Institute, said the targets set by Cenovus, which is currently producing about 380,000 barrels per day from its oil sands and liquids operations, show some companies are willing to exceed existing policies.

He noted that if at some stage there is a drop in oil demand it will affect corporate production, meaning that only the "best, the most competitive oil will be able to maintain market share. Carbon competitiveness will be a very important driver."

Pembina said the Cenovus announcement is a "great example of leadership at the individual corporate level."

Cenovus had earlier played a pioneer role when it held conventional oil and gas operations in Saskatchewan and Alberta, starting almost 20 years ago when it injected 6,500 metric tons a day of carbon dioxide into the Weyburn-Midale CO2 Monitoring and Storage Project, which now safely holds 30 million metric tons underground in the world's largest GHG storage partnership of 37 companies. Cenovus has since unloaded its conventional holdings that underpinned Weyburn.

Canadian Natural Resources, which is targeting up to 1.2 billion barrels of oil per day in 2020 (a maximum 970,000 bpd of crude oil plus synthetic crude and natural gas liquids) — making it the largest combined producer in Canada — and MEG have both set long-term "aspirational" targets of net-zero emissions from their oil sands

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UTILITIES

● UTILITIES

Some ideas for the transmission network

GDS suggests expanding the Railbelt Reliability Council to include oversight of the operation of the Railbelt transmission grid

By ALAN BAILEY

For Petroleum News

GDS Associates, having conducted a review of the issues relating to the management of the Alaska Railbelt electricity transmission grid, has suggested that oversight of the grid could be added to the responsibilities of the Railbelt Reliability Council, as an alternative to forming a separate organization for transmission system management. Late last year all six of the Railbelt electricity utilities signed a memorandum of understanding for the formation of the RRC, and implementation of the RRC is now moving ahead.

During a Jan. 8 Regulatory Commission of Alaska public meeting GDS executives described their concepts for the RRC expansion. GDS, under contract to Alaska Railbelt Cooperative Transmission and Electric Co., had previously conducted a study that led to recommendations for the RRC formation.

The RRC, as currently constituted, will adopt and enforce reliability and operational standards for the electrical system; adopt and enforce system-wide interconnection protocols for the grid; and conduct system-wide integrated resource planning. The organization will also evaluate the use of security constrained economic dispatch of power generation in the system, seeking ways to make best use of the most cost-effective generation facilities.

But the management and operation of the transmission grid remains something of a problem. The grid is owned and operated by six independent utilities and the state of Alaska. This fragmented grid management arrangement leads, in particular, to problems with the stacking or "pancaking" of fees charged for the transmission of power across the grid, and to difficulties in justifying major grid upgrades: A single utility would likely struggle to justify funding for an upgrade when multiple utilities would typically benefit from the subsequent improvements to the grid operations.

Transco proposal

Last year four of the utilities and the American Transmission Co. formed a transmission company, or transco, for managing the transmission system, and filed an application to the RCA for a certificate to enable the transco to go into operation. But, following a series of questions over the transco proposal, the certificate application was later withdrawn. Questions raised included concerns over the transco being run as a for-profit business, and concerns over the governance of the company. Governance is a major issue because of the need to balance the needs of the utilities with the needs of other stakeholders in the electrical system, including independent power producers.

The RRC, on its part, will be governed by a 13-member board that includes equal representation from the utilities and other stakeholders.

During the Jan. 8 RCA meeting Tony Izzo, CEO of Matanuska Electric Association, explained that, in response to last year's transco proposal, MEA, in cooperation with Chugach Electric Association, had commissioned GDS to conduct due diligence on the transco concept. In addition, MEA had asked GDS to conduct a further study, to develop suggestions for how to achieve an independent, open and transparent management arrangement for the Railbelt transmission system. Izzo emphasized that the purpose of the GDS review has been to initiate a conversation among all the parties involved in the transmission grid management issue, building on the cooperation achieved in signing the RRC MOU.

Considered L48 best practices

Paul Wielgus from GDS told the commissioners that the review had involved considering the best practices of transmission organizations in the Lower 48 and evaluating how these best practices might be adapted for use in Alaska. A particular issue arises from the fact that the grid management arrangements must be cost effective, especially given the fact that the Railbelt transmission system, while encompassing a large geographic area, involves electrical loads and generation capacity that are very small in relation to the scale of typical Lower 48 systems.

Any solution applied to the Railbelt must also respect existing legacy asset ownership and agreements; must enable robust funding for the construction and operation of facilities; and must facilitate a high level of stakeholder engagement, Wielgus said. In addition, the solution must encompass the need for organizational independence and transparency; support for economic dispatch, the involvement of the existing utilities; and the enforcement of Railbelt-wide standards, he said.

John Chiles from GDS also commented that trying to resolve the problems though combining the existing utilities into a single utility would likely result in issues revolving around the market power of the utility.

And GDS has questioned the advisability of using a for-profit transmission company in the Railbelt, given potential conflicts of interest resulting from the desire to maximize profits.

Regional transmission organization

Instead, the GDS review has focused on a form of organization referred to as a regional transmission organization, or RTO. About half of the U.S. electrical transmission systems are overseen by RTOs, Wielgus said. An RTO has functional control over a transmission system but does not own or operate the transmission assets. And, key to the success of an RTO, is a high level of engagement with all stakeholders in the electrical system.

At the core of an RTO is an open access transmission tariff, or OATT, a document that defines the rules for transmission system access and use, including the fee structure for the system. The tariff is developed through a stakeholder process, is approved by a board of directors, and goes to a government regulatory body for approval. In Alaska the RCA would have regulatory authority over the OATT.

A tariff for Railbelt electrical transmission would need to enable a one-stop shop for transmission system use, with uniform terms for rates and access across the system. And planning for transmission upgrades would be top-down, system wide, with strong stakeholder engagement, and with the RTO ensuring that system efficiencies can be achieved, Chiles explained.

Existing legacy agreements, such as the agreements for the shipment of power from the Bradley Lake hydropower facility on the Kenai Peninsula, would be grandfathered into the OATT.

The utilities would continue to own and operate the existing transmission assets, under the terms of the OATT. New assets could be developed by the utilities, or by third parties, through a competitive bidding procedure. Cost recovery arrangements for new assets would need to be negotiated between the various parties involved. The RTO would oversee the bidding arrangements and cost allocation negotiations, with the RCA reviewing the results.

Bolt on to the RRC

Taking into account the relatively small scale of the Railbelt transmission system, GDS suggests that, rather than establishing a separate RTO organization, the RTO functions could be bolted into the RRC, thus becoming subject to RRC governance. No separate transmission company would be required.

Functions to be added to the RRC would consist of functional control of the transmission system, OATT administration and ancillary services associated with the RTO. It would, however, be worth considering contracting out the RTO functions, at least initially, to minimize startup costs and to retain the possibility of a rethink based on initial experience of how the arrangements work, Chiles said.

GDS suggests that implementation would involve standing up the RRC, as is currently planned. The next step would be to develop a Railbelt systemwide OATT and to make the RRC responsible for OATT administration. However, achieving a consensus agreement among stakeholders over the terms of the OATT could prove a lengthy process, with cost allocation and the allocation of transmission rights often proving particularly contentious, Wielgus commented. ●

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EXPLORATION & PRODUCTION

DNR set to release Smith Bay well data

The Alaska Department of Natural Resources, Division of Oil and Gas, said Jan. 13 that it would release Smith Bay well data within 30 days.

Data relates to Caelus Energy Alaska Smith Bay LLC's CT 1 and CT 2 wells, both exploratory wells drilled in Smith Bay in 2016 and plugged and abandoned that same year.

Alaska Oil and Gas Conservation Commission records show that CT 1 was drilled to a measured depth of 7,070 feet and a true vertical depth of 6,943 feet. CT 2 was drilled to a MD of 9,300 feet and a TVD of 9,030 feet.

Division records show CT 1 was drilled in section 17 of township 17 north, range 9 west, Umiat Meridian; CT 2 was drilled in section 4, township 17 north, range 10 west, UM.

—PETROLEUM NEWS

● FINANCE & ECONOMY

EIA: Brent expected to average $65 in '20

US crude production forecast to set new records, 13.3 million bpd in 2020, 13.7 million bpd in 2021, up from 12.2 million in 2019

By KRISTEN NELSON
Petroleum News

Brent crude oil spot prices are expected to average $65 per barrel this year and $68 per barrel in 2021, the U.S. Energy Information Administration said in its January Short-Term Energy Outlook, released Jan. 14, the first outlook to include forecasts through 2021.

"We expect Brent crude oil prices to generally stay in a range between $60 per barrel and $70 per barrel," EIA Administrator Dr. Linda Capuano said in a statement accompanying the outlook. "However, a number of risk factors, such as geopolitical-related supply disruptions and the pace of global economic growth, could push prices out of this range."

Brent averaged $64 per barrel in 2019 — the December price averaged $67 per barrel, up $4 from November, EIA said.

Capuano said that while Brent is expected to average $65 this year, global oil inventories are forecast to build during the first half of the year and "some downward oil price pressures could emerge in the coming months, though geopolitical risks could limit downward price movements."

West Texas Intermediate is forecast to average about $5.50 per barrel lower than Brent in 2020 and 2021, EIA said, "based on the assumption of continued sufficient pipeline capacity from production areas in West Texas and from Cushing, Oklahoma, to refineries and export terminals along the U.S. Gulf Coast." The $5.50 discount is lower than the $7.35 per barrel spread in 2019.


LINDA CAPUANO

US Crude production

U.S. crude oil production is expected to "reach new records in 2020 and 2021," Capuano said. "Driven primarily by higher production in the Permian region of Texas and New Mexico, the outlook forecasts an average of 13.3 million barrels per day of U.S. crude oil production in 2020 and 13.7 million barrels per day in 2021," she said.

EIA said it estimates that U.S. crude production averaged 12.2 million bpd in 2019, up 1.3 million bpd from 2018.

The agency said the slowing growth of U.S. crude production it is forecasting results from fewer rigs operating over the past year, a decline it expects will continue into 2020 and 2021. But even with fewer rigs, EIA said, "production will continue to grow as rig efficiency and well-level productivity rises."

The price of West Texas Intermediate crude is forecast to rise by $2 per barrel from 2019 levels and average $59 per barrel this year, rising further to average $62 per barrel in 2021. EIA said it expects WTI prices above $60 per barrel "to contribute to rising crude oil production, as producers will be able to fund drilling programs through cash flow and other funding sources, despite a somewhat more restrictive capital market."

Onshore crude oil production in the Lower 48 is estimated to have averaged 9.9 million bpd last year, up from 8.8 million in 2018, and is expected to increase by almost 1 million bpd in 2020, and by another 400,000 bpd in 2021.

"Almost all of the Lower 48 production growth can be attributed to production from tight oil formations within the Permian region in Texas and New Mexico," EIA said, with the Permian accounting for 800,000 bpd of the expected Lower 48 production growth in 2020 and almost 400,000 bpd of growth in 2021.

"Favorable geology and technological and operational improvements have allowed the Permian region to become one of the most prolific regions for oil production," the agency said.

Gulf of Mexico production is forecast to average 2 million bpd this year, up 100,000 bpd from 2019, and to stay flat at 2 million bpd in 2021.

Alaska production is forecast to remain unchanged at 500,000 bpd in 2020 and 2021, EIA said.

EIA said it estimates that the U.S. has exported more crude and petroleum products than it has imported since September 2019. U.S. net imports of crude oil and petroleum products fell from some 2.3 million bpd in 2018 to 500,000 bpd in 2019. EIA said it is forecasting that the U.S. will be a net exporter of total crude oil and petroleum products by 800,000 bpd this year and by 1.4 million bpd in 2021.

Natural gas

"EIA's January outlook expects a 3% increase in U.S. dry natural gas production growth in 2020, building on record production from 2019," Capuano said, with most of that growth from the Permian region. She said EIA expects to see natural gas production decline in 2021, "as relatively low natural gas prices contribute to a reduction in natural gas directed drilling."

Dry natural gas production is expected to average 94.7 billion cubic feet per day this year, up 2.9% from 2019, but with a decline of 0.7% projected for 2021 to an average of 94.1 bcf per day, EIA said.

This year's expected natural gas production growth "is largely in response to improved drilling efficiency and cost reductions, higher associated gas production from oil-directed rigs, and increased takeaway pipeline capacity from the Appalachian and Permian production regions," the agency said.

The U.S. exported more natural gas than it imported in 2019. Net exports averaged 5.3 bcf per day, up 2 bcf from 2018, and forecast to rise to 7.3 bcf per day in 2020 and 8.9 bcf in 2021. "Rising LNG exports and pipeline exports changed the United States from its long history as net importer of natural gas, which it had been as recently as first quarter of 2017," EIA said.

U.S. liquefied natural gas exports averaged 5 bcf per day in 2019 and are expected to increase to 6.5 bcf per day in 2020 and 7.7 bcf in 2021.

EIA said U.S. LNG export capacity is expected to reach 8.9 bcf per day by the end of 2020, and 9.5 bcf per day in 2021. The agency said the additional capacity will "drive continuing growth in LNG exports" to that 7.7 bcf per day average in 2021, "as facilities gradually ramp up to full production."

There has also been an increase in U.S. natural gas exports by pipeline to Mexico with growth in infrastructure. Those exports averaged 5.1 bcf per day through October, a 10% increase compared to the same period in 2018. U.S. net natural gas imports from Canada decreased from 2018 to 2018, a trend which began in 2008, and that trend is expected to continue as Appalachian production displaces some Canadian imports to the U.S. Midwest.

Henry Hub spot prices averaged $2.57 per million British thermal units in 2019, down 59 cents from 2018, and EIA said it is forecasting the those prices will average $2.33 in 2020 and $2.54 in 2021, with some upward price pressure in 2021 "because of falling natural gas production that stems from the low prices forecast in 2020," but with falling demand for natural gas limiting upward price movement. ●

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

OWNER: Petroleum Newspapers of Alaska LLC (PNA)
Petroleum News (ISSN 1544-3612) • Vol. 25, No. 3 • Week of January 19, 2020
Published weekly. Address: 5441 Old Seward, #3, Anchorage, AK 99518
(Please mail ALL correspondence to:
P.O. Box 231647 Anchorage, AK 99523-1647)
Subscription prices in U.S. — $118.00 1 year, $216.00 2 years
Canada — $206.00 1 year, $375.00 2 years
Overseas (sent air mail) — $240.00 1 year, $436.00 2 years
"Periodicals postage paid at Anchorage, AK 99502-9986."
POSTMASTER: Send address changes to Petroleum News, P.O. Box 231647 Anchorage, AK 99523-1647.

● EXPLORATION & PRODUCTION

Court rules in favor of BLM, Conoco

Federal judge denies Nuiqsut and national enviro groups demand to grant injunction prohibiting further exploration in NPR-A

By KAY CASHMAN
Petroleum News

On Jan. 9 U.S. District Court Judge Sharon Gleason denied a legal challenge by the Native Village of Nuiqsut and five national environmental groups that claimed the Bureau of Land Management's environmental review of ConocoPhillips Alaska's 2018-2019 North Slope winter exploration plan and other industrial activity was deficient.

The village and its co-plaintiffs — Alaska Wilderness League, Center for Biological Diversity, Friends of the Earth, Natural Resources Defense Council and Sierra Club — also asked the court to issue an injunction prohibiting further exploration activities in the National Petroleum Reserve-Alaska until BLM redid its analysis.

Gleason upheld BLM's environmental assessment, or EA, and subsequent Record of Decision, or ROD, in a 73-page decision, ruling the agency's review did not violate the National Environmental Policy Act, NEPA, or the Alaska National Interest Lands Conservation Act, or ANILCA, as claimed by the tribal government and environmental groups.

Background included in order

Gleason provided background in her order, explaining that in August 2018 ConocoPhillips submitted an oil and gas exploration and appraisal plan to BLM that described activities the company planned to conduct on its NPR-A leases during the 2018-2019 winter season.

The exploration would occur to the west of Nuiqsut and the GMT1 and GMT2 projects in the Bear Tooth unit near the confluence of Fish and Judy creeks (GMT stands for Great Mooses Tooth).

In support of its exploration plan, in October 2018 ConocoPhillips applied for permits to drill up to six exploration wells in or near the Bear Tooth unit and submitted an application for a right-of-way grant, requests that the judge said deviated from several of the 2012 integrated activity plan, environmental impact statement and best management practices.

BLM released a preliminary EA analyzing ConocoPhillips' proposed operations on Nov. 9, 2018.

After the requisite public comment period closed, the agency published a final EA on Dec. 6, 2018, which proposed approving ConocoPhillips' applications. The EA tiered to the 2012 IAP/EIS and the supplemental EISs for the GMT1 and GMT2 drill pads.

BLM then issued a finding of no significant impact, or FONSI, and released a ROD that, among other things, authorized ConocoPhillips to conduct exploration drilling and testing at up to eight well sites and build associated infrastructure, including ice roads, snow trails, ice pads, an airstrip, and temporary housing for its employees during the 2018-2019 winter season. ConocoPhillips completed operations authorized by the ROD on April 28, 2019.

Several other projects also occurred in northeast NPR-A during the 2018-2019 winter season. The largest of these was construction of the road and drill pad for the GMT2 development.

ConocoPhillips also obtained authorization to engage in geotechnical exploration in the area, in order to locate "potential gravel resources" to "support oil and gas development in the Bear Tooth unit."

Nuiqsut close to projects

Gleason's order explained that Nuiqsut, population of around 500, is on the eastern border of NPR-A. In recent decades, several oil and gas development projects have been undertaken near Nuiqsut, which is "situated closer to current and foreseeable areas of petroleum development than any other community on the North Slope."

This development has created conflicts with the community's traditional ways of life.

A comment from the North Slope Borough on the GMT2 supplemental EIS explained: "Nuiqsut residents, more so than residents of other North Slope communities, and perhaps more so than any other Alaskan residents, have lived with a decades-long, ever-increasing, near constant level of frustration and apprehension as expanding oil and gas facilities and operations have impinged upon their traditional onshore and offshore subsistence harvest areas."

Many of ConocoPhillips' activities during the winter of 2018-2019 occurred in the general vicinity of Nuiqsut, the judge explained.

ConocoPhillips joins defense

Nuiqsut and the environmental groups initiated their legal challenge on March 1, 2019, claiming that BLM's environmental analysis of ConocoPhillips' 2018-2019 winter exploration plan was deficient in several ways, and seeking declaratory and injunctive relief, Gleason wrote.

Plaintiffs filed an amended complaint on March 26, 2019, which contained five claims for relief that said, among other things, that BLM's FONSI for the winter exploration program, and its associated decision not to prepare an EIS, failed to account for significant impacts to the Teshekpuk Caribou herd and subsistence activity and was thus in violation of NEPA and the Administrative Procedure Act, or APA.

The judge granted ConocoPhillips' motion to intervene on April 10, 2019.

NPR-A consists of 23.6 million acres and is the nation's largest single unit of public land. Established as the Naval Petroleum Reserve in 1923, the reserve was renamed and placed under the authority of the secretary of the Interior in 1976 by the National Petroleum Reserve Protection Act.

In 1980, the act was amended to direct the secretary of the Interior to "conduct an expeditious program of competitive leasing of oil and gas in the reserve." ●

Contact Kay Cashman at publisher@petroleumnews.com

EXPLORATION & PRODUCTION

ANS coastal areas open for tundra travel

The Alaska Department of Natural Resources, Division of Mining, Land and Water, said Jan. 8 that the eastern and western coastal areas opened for the 2019-20 winter season effective 9 a.m. that day.

The division said it has reviewed available data on snow cover and soil temperatures for North Slope state land, and recent snow survey data from permit holders indicate that snow depths are exceeding an average of 6 inches.

Soil temperature information gathered from previous inspection trips showed soil temperatures at the 30-centimeter depth tending lower but not yet reaching minus 5 degrees Celsius.

The division said that given persistent cold temperatures over the last two weeks, it is predicting that monitoring stations within the eastern and western coastal areas have met the criteria for opening (6 inches of snow and colder than minus 5 degrees Celsius soil temperature at a 30-centimeter depth).

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

While overall snow cover is good, it may be thin in some areas, the division said, and areas with thin snow cover should be avoided or special construction methods used to protect the tundra surface.

For questions, please contact the division's Northern Regional Land Office in Fairbanks at 907-451-2740.

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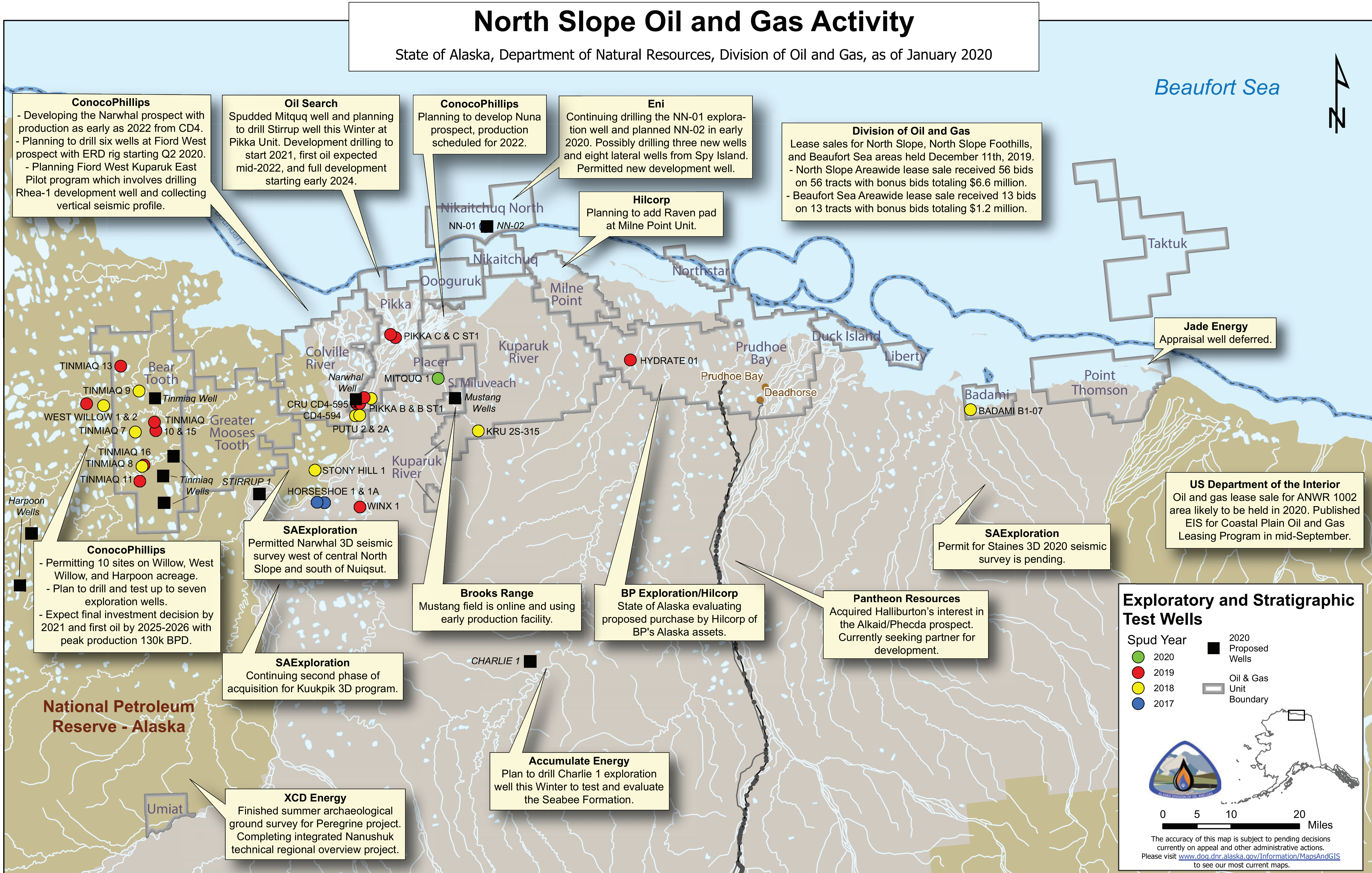
North Slope Oil and Gas Activity
State of Alaska, Department of Natural Resources, Division of Oil and Gas, as of January 2020
Beaufort Sea
ConocoPhillips
- Developing the Narwhal prospect with production as early as 2022 from CD4.
- Planning to drill six wells at Fiord West prospect with ERD rig starting Q2 2020.
- Planning Fiord West Kuparuk East Pilot program which involves drilling Rhea-1 development well and collecting vertical seismic profile.
Oil Search
Spudded Mitquq well and planning to drill Stirrup well this Winter at Pikka Unit. Development drilling to start 2021, first oil expected mid-2022, and full development starting early 2024.
ConocoPhillips
Planning to develop Nuna prospect, production scheduled for 2022.
Eni
Continuing drilling the NN-01 exploration well and planned NN-02 in early 2020. Possibly drilling three new wells and eight lateral wells from Spy Island. Permitted new development well.
Hilcorp
Planning to add Raven pad at Milne Point Unit.
Division of Oil and Gas
Lease sales for North Slope, North Slope Foothills, and Beaufort Sea areas held December 11th, 2019.
- North Slope Areawide lease sale received 56 bids on 56 tracts with bonus bids totaling $6.6 million.
- Beaufort Sea Areawide lease sale received 13 bids on 13 tracts with bonus bids totaling $1.2 million.
Jade Energy
Appraisal well deferred.
Taktuk
Nikaitchuq North
NN-01
NN-02
Nikaitchuq
Oooguruk
Northstar
Milne Point
Pikka
Duck Island
Liberty
Point Thomson
Colville River
Placer
Kuparuk River
Prudhoe Bay
Badami
BADAMI B1-07
PIKKA C & C ST1
HYDRATE 01
Prudhoe Bay
Deadhorse
TINMIAQ 13
Bear Tooth
TINMIAQ 9
Tinmiaq Well
WEST WILLOW 1 & 2
TINMIAQ 10 & 15
TINMIAQ 7
Greater Mooses Tooth
Narwhal Well
CRU CD4-595
CD4-594
MITQUQ 1
S. Miluveach
Mustang Wells
PIKKA B & B ST1
PUTU 2 & 2A
KRU 2S-315
TINMIAQ 16
TINMIAQ 8
TINMIAQ 11
Tinmiaq Wells
STIRRUP 1
STONY HILL 1
Kuparuk River
HORSESHOE 1 & 1A
WINX 1
Harpoon Wells
US Department of the Interior
Oil and gas lease sale for ANWR 1002 area likely to be held in 2020. Published EIS for Coastal Plain Oil and Gas Leasing Program in mid-September.
SAExploration
Permit for Staines 3D 2020 seismic survey is pending.
SAExploration
Permitted Narwhal 3D seismic survey west of central North Slope and south of Nuiqsut.
ConocoPhillips
- Permitting 10 sites on Willow, West Willow, and Harpoon acreage.
- Plan to drill and test up to seven exploration wells.
- Expect final investment decision by 2021 and first oil by 2025-2026 with peak production 130k BPD.
Brooks Range
Mustang field is online and using early production facility.
BP Exploration/Hilcorp
State of Alaska evaluating proposed purchase by Hilcorp of BP's Alaska assets.
Pantheon Resources
Acquired Halliburton's interest in the Alkaid/Phecda prospect. Currently seeking partner for development.
SAExploration
Continuing second phase of acquisition for Kuukpik 3D program.
CHARLIE 1
National Petroleum Reserve - Alaska
Accumulate Energy
Plan to drill Charlie 1 exploration well this Winter to test and evaluate the Seabee Formation.
Umiat
XCD Energy
Finished summer archaeological ground survey for Peregrine project. Completing integrated Nanushuk technical regional overview project.
Exploratory and Stratigraphic Test Wells
Spud Year
2020
2019
2018
2017
2020 Proposed Wells
Oil & Gas Unit Boundary
0
5
10
20
Miles
The accuracy of this map is subject to pending decisions currently on appeal and other administrative actions.
Please visit www.dog.dnr.alaska.gov/Information/MapsAndGIS to see our most current maps.

● EXPLORATION & PRODUCTION

State of Alaska posts new activity maps

Division of Oil and Gas releases North Slope and Cook Inlet maps with exploration and development work planned for 2020

By KAY CASHMAN
Petroleum News

The latest North Slope and Cook Inlet oil and gas activity maps were posted on the Alaska Department of Natural Resources' Division of Oil and Gas website on Jan. 14 (see North Slope map in the print and pdf versions of this story).

The Cook Inlet map highlights the following activities, with private sector 2020 work planned by two companies — Hilcorp and BlueCrest.

Hilcorp's plans include the following:

- Drill a development well in the offshore North Cook Inlet unit.
- Drill two rotary sidetracks, GP-53 and GP-55, and maintain production in the Granite Point offshore unit. GP-53RD completed and online with initial rate of approximately 950 barrels of oil per day.
- Conduct an offshore field study to identify rig workovers, sidetrack drilling, waterflood optimization and other ways to increase production from the Trading Bay unit.
- North Trading Bay A-10 RD well suspended.
- Install two subsea power cables to Baker and Dillon platforms at Middle Ground Shoal unit in anticipation of potential platform reactivation.
- Drill new grass roots development well at Cannery Loop unit.
- Identified six prospects in Grassim Oskolkoff participating area in Ninilchik unit with drilling possible in 2020 or 2021 plan of development periods.
- Signed an agreement with Doyon Ltd. for a two-phase oil and gas exploration program in the Yukon Flats area. Phase 1 will be conducted in 2020-21 and include airborne gravity surveys and data analysis. Phase 2, depending on phase 1, will be done in 2022-23 and consist of a seismic survey.

BlueCrest, HEX and Raser

BlueCrest is planning to drill its first trident fishbone well in 2020 at its Cosmopolitan unit.

HEX LLC was the successful bidder in the U.S. Bankruptcy Court for the District of Delaware for the assets of Furie Operating Alaska LLC, including the Kitchen Lights unit and associated infrastructure. HEX, which bid $15 million, is 100% owned by John L. Hendrix (see related story in this issue).

A fourth company is also noted for Cook Inlet — Salt Lake City-based Raser Power Systems. The division is reviewing Raser's application for a geothermal prospecting permit on three Mount Spurr tracts.

The company's application was in response to a Feb. 20, 2019, division call for applications for geothermal exploration of the Mount Spurr area on the west side of Cook Inlet, involving 12 tracts on approximately 28,800 acres. The acreage is east of Lake Chakachamna, northwest of Trading Bay and 40 miles west of Tyonek on the southern flank of Mount Spurr.

Separately, the division recently released the Moquawkie 2D seismic survey through the Geologic Materials Center.

The division also issued a decision of no substantial new information for the 2020 Alaska Peninsula areawide lease sale, augmenting the Cook Inlet areawide lease sale area with the Southwest Cook Inlet exploration license area.

see **NEW ACTIVITY** page 8

EXPLORATION & PRODUCTION

US drilling rig count drops by 15 to 781

The U.S. active drilling rig count dropped by 15 to 781 the week ending Jan. 10, down from 796 the previous week and down by 294 from 1,075 a year ago.

The company reported that 659 rigs targeted oil (down 11 from the previous week; down 214 from a year ago) and 119 targeted natural gas (down four from the previous week; down 83 from a year ago). There were three miscellaneous rigs active (unchanged from the previous week and up by three from a year ago).

The company said 45 of the holes were directional, 698 were horizontal and 38 were vertical.

Oklahoma and Pennsylvania were each up one rig from the previous week.

Rig counts were unchanged from the previous week in California, Utah and West Virginia.

Alaska, Colorado, North Dakota, Ohio and Wyoming were each down by one rig.

New Mexico was down by two rigs and Louisiana was down by three.

Texas, the state with the most active rigs in the country at 396, was down by seven from the previous week.

Baker Hughes shows Alaska with seven rigs active for the week ending Jan. 10, down two from a year ago.

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

Baker Hughes released December worldwide rig counts Jan. 8.

The company said the December international rig count averaged 1,104 (up eight from November and up 79 from December 2018), North America averaged 939 (down seven) and worldwide the average was 2,043 rigs (up one), 1,761 land rigs and 282 offshore.

Regionally the U.S. has the most active rigs, followed by the Middle East (430), Asia Pacific (226), Latin America (191), Europe (139) and Africa (118).

The U.S. rig count averaged 804 in December, Baker Hughes said, down six from November and down 274 from December 2018. The Canadian rig count averaged 135 in December, down one from November and down six from December 2018.

—KRISTEN NELSON

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NET ZERO

operations.

Those goals are within reach through advances in technologies such as Weyburn's carbon capture and sequestration project along with increased use of solvents for oil extraction, said Cenovus Executive Vice President Al Reid.

"On GHG emissions, we'll need more of some of the things that we're already doing, but we're also going to have to push ourselves," he conceded, adding that will require technologies "that we know exist ... but aren't economic today."

Those methods would likely include co-generation units relying on natural gas and efforts to curb methane leaks.

Reid acknowledged that there will have to be advances in technologies that are barely on the radar, but his confidence that GHG reductions are possible shows Alberta is capable of meeting Cenovus's goals.

But critics have been quick to point out that lowering GHGs from extraction is a long way from making the same gains at the consumption end, which account for 80% of global GHGs. ●

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RCA RULING

dential treatment. By regulation RCA has 30 days after the end of the comment period to rule on petitions for confidential treatment. The public comment period ended Dec. 13, which would have required a decision on the confidentiality issue on Jan. 10.

The commission said it received numerous comments in response to its public notices and also requested and received new documents from Harvest Alaska and BPPA.

"We need additional time to review those recent filings and issue our ruling on the petitions for confidential treatment and motions for waiver," the commission said, and as a result it is extending time to rule on those matters to Feb. 11.

The commission noted that as it previously explained, it would set no timeline on a decision on applications for sale of pipelines and transfer of certificate until it rules on the petitions for confidential treatment and motions of waiver.

In addition to the financial filings they already provided to RCA, in January Harvest Alaska and BP Pipelines (Alaska) submitted the asset and sale agreement related to the proposed pipeline transfers — both a complete copy and a partially redacted copy of the "Purchase and Sale Agreement By and Among The Standard Oil Company and BP Pipelines (Alaska) Inc., as Seller, and Hilcorp Alaska, LLC and Harvest Alaska, LLC, as Buyer" dated Aug. 26.

The submittal was filed as confidential and the companies also filed a petition for confidential treatment of the PSA, the purchase and sale agreement. The redactions included names of employees and specific salary information, "certain dollar amounts and percentages, and the disclosure schedules, none of which are related to the issue in front of the Commission."

In filings supporting their petitions for confidential treatment of financial filings and the PSA, Hilcorp said its financial information is not disclosed to the public and disclosure of that information would "give their competitors an unfair advantage, and unfairly advantage potential competitors, buyers, and contractors, especially where those competitors, buyers, or contractors do not make their own financial information public."

In arguments for confidentiality of the PSA, the companies said the sale was a negotiated transaction on a number of subjects that each of the parties wants to maintain confidential.

The parties also said information "within the PSA goes far beyond that related to the transfers of the regulated pipeline infrastructure at issue in the" application before the commission.

They said disclosure of the PSA would provide competitors "valuable insight into the disclosing party's negotiating strategy and economic valuations of interests in oil and gas properties."

—KRISTEN NELSON

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NEW ACTIVITY

ConocoPhillips on North Slope

ConocoPhillips dominates activities on the North Slope (see adjacent map). To the west it's developing the Narwhal prospect with production as early as 2022 from CD4.

Starting in second quarter, the company has six wells planned at the Fiord West prospect with Doyon's new extended reach drilling rig.

Also in the works is ConocoPhillips' Fiord West Kuparuk East Pilot program which involves drilling the Rhea-1 development well and collecting a vertical seismic profile.

The company also permitted 10 sites at the Willow, West Willow and Harpoon prospects, with expectations of drilling and testing up to seven exploration wells this winter.

Expect ConocoPhillips' final investment decision for Willow by 2021, first oil by 2025-26, with peak production at 130,000 barrels a day.

Finally, ConocoPhillips is planning to develop its Nuna prospect, with production scheduled for 2022.

Oil Search has spud its Mitquq prospect well and is planning to drill the Stirrup well this winter. Pikka unit development drilling is scheduled to start in 2021, with first oil expected mid-2022, and full output starting in early 2024.

Eni is continuing drilling the NN-01 exploration well and planned NN-02 at its Nikaitchuq North unit. The company might be drilling three new wells and eight laterals from Spy Island for the project. The map says Eni permitted a new development well, and that first oil from Nikaitchuq North is expected in mid-2022, with full development starting in early 2024.

Hilcorp plans to add Raven pad at its Milne Point unit.

Another company planning to drill this winter is Accumulate Energy, with the Charlie 1 exploration well. which will test and evaluate the Seabee formation.

SAExploration permitted its Narwhal 3D seismic survey south of Nuiqsut and is continuing the second phase of acquisition for the Kuukpik 3D program. The company has a permit pending for the Staines 3D 2020 seismic survey.

Other companies noted on the North Slope map but with no timing listed for drilling are Jade Energy, Pantheon Resources and XCD Energy.

Upcoming lease sales are also noted and, of course, the state is evaluating the proposed purchase by Hilcorp of BP's Alaska assets. ●

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INSIDER

on a Jan. 9 Alaska Gasline Development Authority board meeting. The meeting, Landfield wrote, was to provide an update on the Federal Energy Regulatory Commission permit application, but it "started off a bit loose" with former AGDA board member Joey Merrick and former president Keith Meyer both testifying at the beginning during public comment.

"Merrick was concerned that AGDA had taken previous work off the website. Meyer said that the current path of the board will not result in a gasline anytime soon. He also said he put together a private group that could take it over. The board did not seem amused," Landfield wrote.

The second tidbit: Stockhead, an online business news pub "dedicated to connecting investors with emerging ASX-listed companies," put XCD Energy (ASX:XCD) in its Top 10 biggest oil and gas gainers in the small cap space in December.

XCD Energy, which was No. 8 on the list, "picked up additional oil and gas leases in the highly prospective Nanushuk oil fairway on Alaska's North Slope in mid-December. The leases are adjacent to and complementary to the company's existing leases, bringing its total portfolio up to 195,373 acres," Stockhead wrote.

Dougal Ferguson is XCD's managing director and oversees the company's leases in Alaska.

Check out Stockhead's December list: https://stockhead.com.au/energy/here-are-decembers-top-10-oil-gas-small-caps/

The third tidbit was first reported in the Anchorage Daily News, which said the group behind a ballot measure to boost taxes paid by major oil producers in Alaska has gathered enough signatures to put the measure before voters. ADN promised an announcement from the group on Friday, Jan. 17, the day this edition of Petroleum News is released online.

DOUGAL FERGUSON

To qualify to put the measure on the 2020 ballot, the group needs just 28,501 registered Alaska voters from at least 30 of the 40 House districts.

More on ANWR leasing

Back to the Jan. 14 Washington Post story on ANWR leasing and its interview with Bernhardt.

"I want to make sure that record of decision is a record that can be well defended," Bernhardt was quoted as saying. "There have been issues raised during the development … that I want to make sure that I feel very confident that we've adequately addressed."

The Trump administration, the Post wrote, is caught between trying to make its leasing plan "legally ironclad" while still completing the controversial lease sale before the next presidential election. The 2017 budget bill that opened exploration in the 1002 area orders the feds to conduct two lease sales of 400,000 acres each by the end of 2024, at the latest.

Per the Post, Bernhardt's latest comments are "a change of tone from last year, when the Interior secretary vowed a speedy environmental review and lease sale" in the 1.6 million acre 1002 area that is part of the 19.3 million refuge.

For nearly three years, the Post reported, "environmental groups, Native American tribes and Democratic attorneys general have often prevailed in their legal challenges against the Trump administration's energy and environmental agenda."

One of the "leading litigators, the environmental advocacy group Earthjustice, says it has won 33 of the 39 lawsuits it has brought against the Trump administration through 2019."

Bernhardt himself is an attorney, the Post noted

Exploration underway

As reported in a Jan. 9 news bulletin from Petroleum News, exploration is underway on Alaska's North Slope, with the first company, Oil Search, reporting it spud a well in one of the two prospects it's drilling this winter.

The Mitquq 1 exploration well was spud on Dec. 24, using Nabors 7ES rig.

The well, which is approximately 5.6 miles from the planned Nanushuk Central Processing Facility location in the Pikka unit, will test Cretaceous Brookian sandstone (Nanushuk) analogues east of the unit for the prospect's potential as a tie-back to planned Pikka infrastructure.

Secondary targets "may be penetrated to evaluate exploration upside within the Torok, Kuparuk C and Alpine C reservoirs," the company said.

A sidetrack to an offset location for further reservoir evaluation is a possibility.

—KAY CASHMAN

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Oil Patch Bits

Calista Corp. acquires interest in Delta Constructors

Calista Corp. said Jan. 6 that it has acquired a 25% interest in Delta Constructors, a leading oil and gas construction firm operating in Alaska, Canada and the Lower 48.

Calista's minority, non-controlling stake in Delta Constructors is owned by Bektuq Holding LLC, a holding company for Calista subsidiaries working in the energy, engineering and environmental sector.

"Delta Constructors' strong performance in Alaska and elsewhere will complement and diversify Calista's current investments for the benefit of our Shareholders. I am excited about working with our new partner to expand our services to current and future customers in the resource development sector," said Calista Corp. President/CEO Andrew Guy.

Delta Constructors was founded in Anchorage, Alaska, in 2007 and subsequently expanded to Canada and the Lower 48.

Calista also recently acquired its JV majority partner Nordic Well Servicing Inc., thereby acquiring full ownership of Nordic Calista Services, a drilling and workover company that primarily operates on the North Slope.

Companies involved in Alaska's oil and gas industry

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

Wolfpack Land Company is Offering 4,761 Acres of Prime Mineral Interest Ownership in the Kenai, Alaska Area for Oil and Gas Leasing

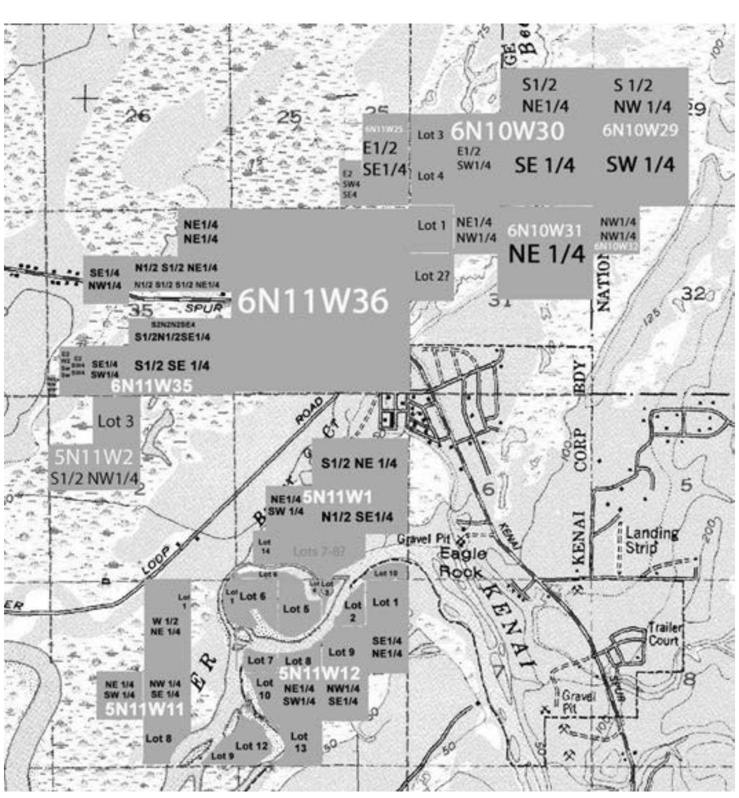
Beaver Loop Road Area

Township 5 North, Range 11 West (Surveyed)
Section 1, Lots 6-8, 10, 14, S1/2NE1/4, N1/2SE1/4, NE1/4SW1/4;
Section 2, Lots 3 and 6, Sl/2NW1/4.
Section 11, Lots 1, 8, 9, W1/2NE1/4, NW1/4SE1/4, NE1/4SW1/4;
Section 12, Lots 1-13, NE1/4SW1/4, SE1/4NE1/4, NW1/4SE1/4.
Containing 1,063.51 acres, more or less.

Township 6 North, Range 10 West (Surveyed)
Section 29, SW1/4, S1/2NW1/4
Section 30,Lots 3 & 4, E1/2SW1/4, SE1/4, S1/2NE1/4
Section 31,Lots 1 & 2, NE1/4NW1/4NE1/4
Section 32,NW1/4NW1/4
Containing 947.98 acres, more or less.

Township 6 North, Range 11 West (Surveyed)
Section 25, El/2SE1/4,El/2SW1/4SE1/4
Section 35, NE1/4NE1/4, N1/2S1/2NE1/4, N1/2S1/2S1/2NE1/4, SE1/4NW1/4, E1/2SW1/4SW1/4, E1/2W1/2SW1/4SW1/4, W1/2SW1/4SW1/4SW1/4, SE1/4SW1/4, S1/2SE1/4, S1/2N1/2N1/2SE1/4, S1/2N112SE1/4.
Section 36,All
Containing 1,105 acres, more or less.

Aggregating 3,116.49 acres, more or less.

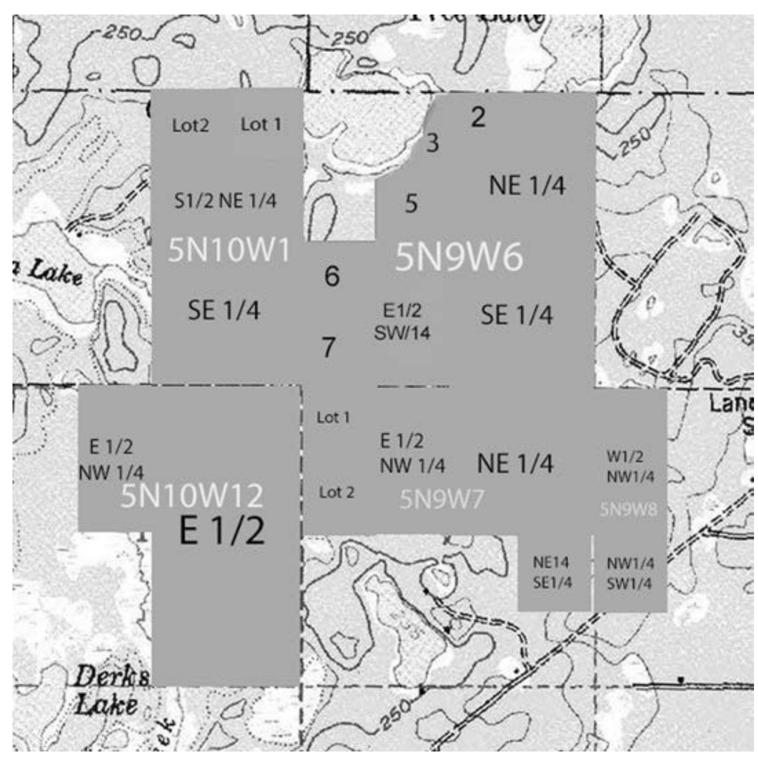


Robinson Loop Road Area

Township 5 North, Range 9 West (Surveyed)
Section 6, Lots 2, 3, 5-7, SW1/4NE1/4, El/2SWl/4, SEl/4;
Section 7, Lots l, 2, El/2NWl/4, NEl/4, NEl/4SEl/4;
Section 8,Wl/2NW1/4, NWl/4SWl/4.
Containing 926.23 acres, more or less.

Township 5 North, Range 10 West (surveyed)
Section l, Lots l, 2, Sl/2NEl/4, SEl/4;
Section 12, El/2, El/2NWl/4.
Containing 718.96 acres, more or less.

Aggregating l,645.19 acres, more or less.



These fee mineral rights have significant known hydrocarbons on or very near them. This prospect is not in a remote area. Everything is road accessible, winter and summer, with easy access to oilfield suppliers. Seismic data available.

Terms: $3,000/acre, 25% royalty.

For more details contact Wolfpack Land Company, Houston, Texas, at jim5thgn@outlook.com, jim@applecapital.net, or (907) 394-9148.

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WELL CLEANUP

As a result, the AER now estimates there are 93,000 inactive wells in Alberta, 11,000 of them accumulating in the past five years amidst a collapse in commodity prices, company bankruptcies and a maturing producing basin.

In late 2018, the AER pinned the liability for cleanup at C$58.6 billion, a drastic revision from the estimate of C$260 billion including oil sands mining remediation that an AER vice president disclosed during a public presentation.

In 1964 the Alberta government started requiring companies to obtain reclamation certificates, of which 6,077 wells are still active today, 5,487 have suspended production without being cleaned up and 3,695 have been plugged, which the industry and government rate as "abandoned," but not remediated.

Farmers, ranchers and their attorneys accuse oil and gas companies of failing to perform their duty, raising concerns about the current total of inactive wells they suggest will completely overwhelm the AER and the Alberta government.

Investor confidence issue

While she does not favor fixed timelines, Savage insisted the government is determined to restore investor confidence by ensuring environmental responsibilities are managed in "an appropriate time frame."

Canadian Association of Petroleum Producers Vice President Brad Herald said the industry's main lobby organization supports "increased stringency for companies to retire their end-of-life obligations. That has to be done with some sensitivity to the economic challenges of today."

Martin Olszynski, a professor of environmental law at the University of Calgary, said two measures are required to ensure the financial burden of the abandoned wells does not land on the public: Timelines for closure and sufficient bonding at the outset.

The Alberta government of Premier Jason Kenney has made overtures to the Canadian government to employ some of the thousands of engineers and others who have been laid off during the industry downturn to help with the cleanup. So far there has been no response from Prime Minister Justin Trudeau.

Kenney has also suggested funds could be raised from flow-through shares that could involve oil-field service companies selling shares to investors, with the proceeds tagged for orphan-site cleanup.

Many observers suggest that a failure by the two governments to find common ground will only compound a growing environmental disaster. ●

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HEARING DELAYED

wrapped up by the end of 2019.

HEX LLC, 100% owned by member manager John L. Hendrix of Anchorage, was the successful bidder for the assets, primarily the Cook Inlet Kitchen Lights offshore unit, and related infrastructure such as the Julius R offshore platform, onshore processing facility and all related pipelines.

HEX bid $15,000,010, according to a Dec. 6 notice filed in the U.S. Bankruptcy Court for the District of Delaware, which noted that the transaction with the successful bidder will be a purchase of equity securities through a plan of reorganization.

Following the auction, the debtors selected Energy Capital Partners Mezzanine Opportunities Fund A LP, debtor-in-possession agent and prepetition term loan administrative agent, as the alternate bidder.

In its voluntary Chapter 11 bankruptcy in the Delaware court Aug. 9, Furie listed about $450 million in debt against assets it listed at an estimated value of less than $50 million.

The debtors will seek an order approving the sale of all of the debtors' right, title and interest in and to the assets, free and clear of any pledges, liens, security interests, encumbrances, claims, charges, options and interests to the maximum extent permitted by section 363 of the Bankruptcy Code, with such interests to attach to the net proceeds of the sale of the assets with the same validity and priority.

Additional matters for consideration

In addition to the sale hearing, the omnibus hearing will also include several other matters in the Furie Chapter 11 bankruptcy.

The court will consider an interim application for compensation of Prime Clerk LLC as the administrative advisor to the debtors for the period of Aug. 9 to Sept. 30, filed by Prime Clerk.

It will also consider an interim application for compensation of Womble Bond Dickinson LLP as co-counsel to the debtors for the period of Aug. 9 to Oct 31, filed by Womble Bond Dickinson.

Also under consideration will be an interim application for compensation of Halperin Battaglia Benzija LLP as counsel to the independent managers for the period of Sept. 24 to Oct. 31, filed by Halperin Battaglia Benzija.

The court will hear an application/motion to employ/retain Stoel Rives LLP as special Alaska counsel to the debtors, filed by Furie. Stoel Rives has an extensive history with Furie, having been retained by the company for various matters since 2011 — the year the company, then named Escopeta Oil, transported the Spartan 151 jack-up rig to Cook Inlet.

—STEVE SUTHERLIN

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NEPA REGS

these reviews four and a half year.

President Trump issued Executive Order 13807 in 2017 establishing a One Federal Decision policy, including a two-year goal for completing environmental reviews for major infrastructure projects, and directing CEQ to consider revisions to its regulations.

CEQ said key elements of the proposed rule include presumptive time limits and page limits, requiring a senior agency person to change, of one year for completion and a 75-page limit for environmental assessments and a two years for completion and a 300-page limit for environmental impact statements.

Clarification of terms and applicability would include, among other changes, threshold consideration of whether NEPA applies to a particular action, stating that analysis of cumulative effects is not required under NEPA and clarification that "reasonable alternatives" must be technically and economically feasible.

The proposed rule would also allow applicants to assume a greater role in preparing EISs under the supervision of an agency.

Three levels of review

NEPA requires detailed statements for "major Federal actions significantly affecting the quality of the human environment," CEQ said, quoting the statute, and regulations provide federal agencies with three levels of review: categorical exclusions, environmental assessments and environmental impact statements.

Actions that normally do not have significant effects can be reviewed with CEs. Actions that are not likely to have significant effects can be reviewed with EAs, allowing agencies to focus resources on actions likely to have significant effects and require EISs.

The proposed revisions add a section describing the three levels of NEPA review and the basis for deciding which level is appropriate for a proposed action, CEQ said.

Agencies have developed and documented more than 2,000 CEs, CEQ said, estimating that each year federal agencies apply CEs to some 100,000 federal agency actions which typically require little or no documentation. A new section would provide "additional clarity on the process that agencies follow in applying a CE."

If an agency has not categorically excluded a proposed action, it can prepare an EA and if the EA demonstrates the action's effects would not be significant, the agency documents its reasoning in a finding of no significant impact, completing the NEPA process. Otherwise, CEQ said, the agency uses the EA to help prepare an EIS, with an estimated 10,000 EA's prepared by federal agencies each year.

CEQ is proposing a revision "to clarify that an agency must prepare an EA when necessary to determine whether a proposed action would have a significant effect or the significance of the effects is unknown, unless a CE applies to the proposed action or the agency decides to prepare an EIS."

Environmental impact statements

Federal agencies typically publish some 170 final EISs a year.

CEQ said one of the EIS revisions is the deletion of "all" before "reasonable alternatives," and said while it provides no guidance on the range of alternatives an agency must consider, its view is "that NEPA's policy goals are satisfied when an agency analyzes reasonable alternatives, and that an EIS need not include every available alternative."

The council said, "it is not efficient or reasonable to require agencies to develop detailed analyses relating to alternatives outside the jurisdiction of the lead agency." Such alternatives, CEQ said, "would not be technically feasible due to the agency's lack of statutory authority to implement that alternative."

CEQ said applicants and contractors "would be able to assume a greater role in contributing information and material to the preparation of environmental documents, subject to the supervision of the agency."

Agencies would, however, "remain responsible for taking reasonable steps to ensure the accuracy of information prepared by applicants and contractors."

Actions not subject to NEPA

CEQ is proposing to add provisions allowing agencies to identify actions not subject to NEPA, determinations which they may make in their agency NEPA procedures or on an individual project basis.

The threshold applicability analysis would include: whether the proposed action is a major federal action — allowing exclusion of those with minimal federal involvement or funding; whether action in whole or part is a non-discretionary action for which the agency lacks authority to consider environmental effects; whether action for which compliance with NEPA would conflict with requirements of another statute; whether action would be inconsistent with congressional intent due to requirements of another statute; or whether analyses or processes under other statutes serve the agency function of compliance with NEPA.

The council said it is proposing to strike the definition of cumulative impacts and the terms "direct" and "indirect" to focus agency time and resources "on considering whether the effect is caused by the proposed action rather than on categorizing the type of effect."

CEQ said it is also proposing "to change a position to state that analysis of cumulative effects, as defined in CEQ's current regulations, is not required under NEPA." Agencies should, CEQ said, "focus their efforts on analyzing effects that are most likely to be potentially significant and be effects that would occur as a result of the agency's decision," with the intent "to focus agencies on analysis of effects that are reasonably foreseeable and have a reasonably close causal relationship to the proposed action."

The council said it also "proposes to clarify that effects should not be considered significant if they are remote in time, geographically remote, or the result of a lengthy causal chain."

It is also codifying a finding in the "Public Citizen" case that "effects do not include effects that the agency has no authority to prevent or would happen even without the agency action, because they would not have a sufficiently close causal connection to the proposed action."

—KRISTEN NELSON

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PLACER PERMITTING

Per the 30 day public notice, the project site is located within sections 4, 9, 15, 15, 22, 26, 27 of township 11 north, range 7 east, Umiat Meridian; Latitude 70.31429º N., Longitude 150.3745º W.; near the village of Nuiqsut. The proposed gravel road will take off from the existing gravel road between the Mustang pad and the Mustang gravel pit near section 35 of township 1N, range 7E, UM.

The Mustang pad is about 45 miles west of Deadhorse and can be accessed via the Spine Road. The purpose of the Corps permit is to "develop oil within the Kuparuk C reservoir, contained within the Placer unit," the public notice said.

The work AEX proposes is to discharge approximately 68,000 cubic yards of gravel to construct a seven-acre gravel pad, the top width of which varies between 250 and 400 feet and the bottom width varies between 270 and 420 feet, with a length of 1,000 feet. The pad will be 5 feet high (with 2:1 fill slope.).

Approximately 325,000 CY of gravel will be used to build a seven-mile access road. The dimensions of the road will be 24 feet wide at the top, 44 feet minimum bottom width, 5 to 6 feet high, 2:1 fill slope.

The road will have a 37-acre footprint; the total footprint of the single-pad Placer project would be 45.5 acres.

Oil to Pikka or Mustang

In its Corps application, AEX said a three-phase pipeline with vertical support members will transport fluids from the pad to a "nearby processing facility."

While the processing facility was not named, the maps provided by AEX in its Corps application show the pipeline connecting to the nearby Mustang field pad.

However, in paperwork filed in the last year with the state, AEX has said it was looking at either piping its oil to the new Pikka development that is expected to produce its first oil in 2022 or to take it to Mustang, which is currently utilizing an n early production facility, prior to constructing a larger permanent facility.

Detring Energy Advisors of Houston, Texas, which was retained by AEX to market Placer, said in an advertisement that the unit has a development-ready project with the Kuparuk C reservoir and the potential for additional stacked plays in the Alpine and Nanushuk intervals.

Placer, Detring said, could have 110 million barrels of original oil in place, with between 35 million and 45 million barrels of oil recoverable across all horizons, noting Placer is in a good neighborhood, with the ConocoPhillips' Kuparuk River oil field on the east and bordering the Oil Search-operated Pikka unit on the west.

"Well and analog data indicate the field is an ideal development candidate due to favorable average porosity (23.4 percent), high permeability (430 mD), and light oil viscosity (26.2API @ 1.51-1.85cP)," Detring said, adding, the "reservoir model indicates Kuparuk C development generates $107 million PV-10 value (BTAX) and greater than 8,000 barrels per day of oil peak rate utilizing two producers and two injectors."

Detring also said that of three wells drilled to date in the Placer unit, two are usable for future development. ●

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ARCTIC PROJECTS

projections of oil and gas potential in the North, and we all know what Norway has done in the North Sea since the 1980s."

Russia is already shipping 16.5 million tons of Arctic LNG from a facility in Yamal, through the Arctic Ocean to markets in the Atlantic region and the Pacific region, he said.

"We have not yet made our Arctic oil and gas province work, but it can and we will," he said. "Most of the modules at Yamal were hauled north right past Alaska from Korean shipyards through the Bering Straits," he said. "Korea and Japan — in an age of sanctions — our strongest allies in East Asia have just come up with the commitment to triple the size of this facility."

The key to the voyage is double acting tankers, sporting a bow that is made for open water and a stern that is made for ice breaking, he said.

The ships are designed by Aker Arctic Technology Inc. of Helsinki, Finland, and 15 were built in Korea for the Yamal project.

Qilak hired Aker to do a draft report of how to apply the technology in Alaska, Treadwell said.

New age of Arctic energy participation

The Russian project and its attendant technology have ushered in a new age of Arctic energy participation in the global economy, Treadwell said.

"In 2018, about 320 million tons of LNG was consumed in the world, 16.5 million tons of that came out of the Russian Arctic," he said. "They've got commitments to double and triple, going up to about 45 million tons; Putin has announced that he'd like to get up to 100, and here we are in North America."

"I said to my counterpart in Yamal, you know, when your tankers go by, I hope you'll wave at us." Treadwell said. "But if you thumb your nose I won't blame you, because you beat us to the market."

While the Russians have gotten the jump on Alaska in getting their Arctic gas to market, Alaska's North Slope is blessed with significant geographical advantages to serve LNG-thirsty markets in northeast Asia.

"If Russia is doing 2,600 miles of sea ice to get to the ice limit in the Bering Strait, we have only about 600 miles from the Prudhoe Bay area, the Point Thomson area to get to the Bering Strait." he said. "That means much less ice breaking."

After Sakhalin Island, Treadwell added, Alaska is the closest potential LNG provider to northeast Asia.

No costly overland pipeline required

The Qilak project has advantages over a long-studied proposed gas pipeline from the North Slope to the Cook Inlet port of Nikiski on the Kenai Peninsula, Treadwell said.

"Most people don't realize this, but geographically, Prudhoe Bay and Nikiski are about the same distance from Tokyo," Treadwell said. "If you're shipping something from south Alaska or from north Alaska it's about the same distance, shipping wise."

"If you a look at the capital cost per delivered ton of LNG with an 800-mile pipeline, it's about $2,150 at (a project cost of) $43 billion, and we have a minimum order quantity of 20 million tons a year," he said. "If on the other hand you can take gas slightly offshore, put it on a barge, manufacture it into LNG on the barge, and pick it up with those ice breaking tankers that the Russians are using, your capital cost to get LNG to the market on the water is about $1,250 ... it's also a much smaller order quantity."

ExxonMobil signed a heads of agreement with Lloyds Energy that "basically reserves that gas at Point Thomson for us to do a feasibility study, for us to finalize our off take agreement, and for us to finance an LNG project that would take 560 million feet a day — expandable to about a billion cubic feet a day," Treadwell said.

"It's about 3,300 nautical miles to Tokyo. A round trip, plus six port days each tanker would take about a month round trip, with a slightly longer time in the winter," he said. "We believe that one tanker a week would be taking gas out of our module 12 miles off of Point Thomson."

"All told, it's about a $5 billion project to start," Treadwell said. "Lloyds Energy has already spent about $60 million developing both upstream and downstream concepts."

A number of Alaska communities and projects on the water may be able to benefit right away from Arctic LNG.

"We were asked when we announced the Qilak project, 'what are you going to do to make gas available for Alaskans?'" Treadwell said. "To which my answer is this: Russia is traveling by with gas that sells for $8 a million Btus in Asia, why don't we bring in some now?"

"If Yamal gas is good enough for Boston and Puerto Rico, it's good enough for us, and it will help develop the market for LNG in places like Red Dog, like Nome, places like Western Alaska," I believe that we will see LNG bunkering and LNG fuel in our power generation in Western Alaska fairly soon."

Not too late to crack Asia market

Treadwell believes Alaska can get its Arctic gas into Asia markets, despite the expanding supply of Russian gas.

"Here's the argument that we make to you politically in the Asian marketplace," Treadwell said. "To our allies in Japan and Korea we say, you know what you're doing with Russia; we understand, but if you're going to open up a huge new gas province in Russia, how about 4 million tons to open up a huge new gas province in North America?"

The head of the Japan Bank for International Cooperation (JBIC), Gov. Maeda — who met with Gov. Dunleavy on his last trip to Japan — I brought him to Washington to meet with our delegation and the White House, Treadwell said. "He sat down at the White House and he said, 'You know, we've got a trade issue between us and we're not here to talk about trade, but we do have an agreement between the United States and Japan called the Japan-United States Strategic Energy Partnership (JUSEP). Under that program we've agreed to help invest $10 billion in U.S. LNG upstream, and we like this project in Alaska. Furthermore, we have agreed with the United States and Australia that we are going to help to fund the projects downstream in response to China's Silk Belt and Road policy. We plan to develop a power plant in the Philippines and we're going to team up with this Alaskan project and Lloyds to help bring that gas to the Philippines.'"

"So, we're getting very strong support from the Japanese government on this," Treadwell said. ●

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