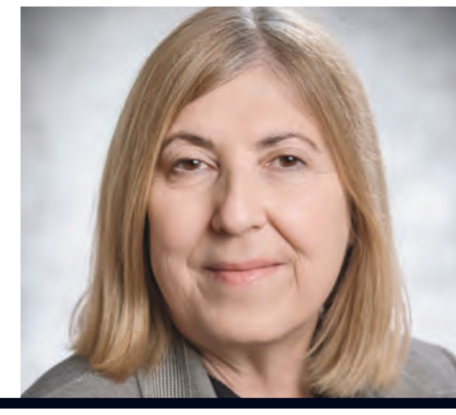
Petroleum news



page 3 EIA: US could be leading crude producer in '19 at 12 million bpd

Vol. 23, No. 28 • www.PetroleumNews.com *A weekly oil & gas newspaper based in Anchorage, Alaska* Week of July 15, 2018 • $2.50

Paul Craig looking to shoot 3-D seismic over South Nanushuk; Parnell joins Holland & Hart

Oil Patch Insider

PAUL CRAIG, VETERAN OIL AND GAS INVESTOR and independent in Alaska, is negotiating with a publicly traded oil and gas company interested in completing a 3-D seismic program over the 35,423-acre South Nanushuk prospect which lies about 20 miles south of Armstrong's Horseshoe wildcat; and, farther south of the 2013 discovery west of the central North Slope.

"I am actively negotiating terms with management. When operations begin, the partner company may collaborate with

see **INSIDER** *page 10*

Work continues on NPR-A legacy wells; focus on most problematic

The federal Bureau of Land Management is continuing to deal with old abandoned legacy wells on the North Slope, primarily in the National Petroleum Reserve-Alaska. The wells, many of which were not properly plugged, were drilled by the U.S. Navy and the U.S. Geological Survey between 1944 and 1982. The Alaska Oil and Gas Commission, with oversight of well safety in Alaska, has for a number of years been pushing for the appropriate remediation of the wells. BLM, the federal agency that manages the NPR-A, is responsible for the remediation.

During a July 11 AOGCC public meeting, BLM officials described the most recent well remediation project in the

see **LEGACY WELLS** *page 8*

State reconsidering Badami unit expansion request from late 2012

Alaska's Division of Oil and Gas is reconsidering an appeal for the further expansion of Savant Alaska's Badami unit, the division announced July 2. The unit includes the Badami oil field, to the east of the central North Slope.

The unit expansion in question dates back to late 2012, when Savant asked the state to add seven leases to the unit, including six leases held by Alaska Venture Capital Group LLC. Since that time AVCG has sold most of the interest in those six leases, with six companies now holding the leases and Caracol Petroleum being the largest leaseholder. Brooks Range Petroleum Corp. currently operates the leases. The proposed lease expansion would extend the Badami unit east, towards ExxonMobil's Point Thomson unit. The leases straddle the Beaufort Sea coast.

see **BADAMI REQUEST** *page 11*

Enbridge sets new course; chases regulated line, utility business

Enbridge, the largest energy pipeline company in North America by market-cap, has taken its third bold step of 2018 to shrink its debt load and focus on long-distance pipelines.

In a C$4.3 billion deal, the Calgary-based company unloaded its Western Canadian natural gas processing plants and gathering pipelines to Brookfield Infrastructure and its partners.

The assets are spread across rich gas plays in the Montney, Peace River Arch, Horn River and Liard basins in northern British Columbia and Alberta.

Brookfield Chief Executive Officer Sam Pollock said the transaction is "strategically positioned for the continued development of the prolific Montney Basin," encompassing

see **ENBRIDGE MOVES** *page 8*

EXPLORATION & PRODUCTION

Jack-up on site

Furie planning completion of two more Kitchen Lights gas production wells

By ALAN BAILEY
Petroleum News

Furie Operating Alaska is planning to complete one well and drill another, to achieve a target of having a total of four production wells on line in its Kitchen Lights gas field in Cook Inlet by the end of this year's drilling season, Scott Pinsonnault, the company's chief operating officer, told Petroleum News July 9. The Spartan 151 jack-up rig is on site at the Julius R. production platform, being cantilevered over the platform.

"They've been rigging up ... for the last five or six days," Pinsonnault said.

The field is currently producing gas from the KLU Nos. 2 and 3 wells — in April Furie used a coiled tubing unit to conduct a workover of the No. 3 well.

The company has been augmenting its staff, adding a new vice president of operations and an HSE official, and has contracted with Petrotechnical Resources of Alaska to act as its technical arm, Pinsonnault said.

"We're currently producing around 17 million (cubic feet) a day out of two wells," Pinsonnault said.

The plan now is to complete the KLU No. 1 well that was drilled but not completed in 2016, before proceeding to drill another development well, the

see **FURIE WELLS** *page 9*

PIPELINES & DOWNSTREAM

Eying pipeline buy-in

Alberta, BC First Nations to discuss aboriginal stake in Trans Mountain expansion

By GARY PARK
For Petroleum News

The prospect of Native communities acquiring an equity stake in the Trans Mountain pipeline is gathering momentum ahead of a meeting scheduled for Vancouver on July 25.

Leading the way are the Fort McKay and Mikisew Cree First Nations of Alberta, who raised C$545 million last year through a bond issue to buy 49 percent of Suncor Energy's storage facilities at the northern end of the oil sands region.

Several other First Nations have expressed support for the pipeline since the Canadian government negotiated a takeover of the project, saying they would be interested in assuming an ownership position.

Michael LeBourdais, chief of the Whispering Pines Indian Band near Kamloops in south-central B.C., said he has been approached by Canada's major banks with proposals to finance an equity stake in Trans Mountain.

Fort McKay Chief Jim Boucher told the Vancouver Sun said there has been communication with the government, including Finance Minister

see **PIPELINE BUY-IN** *page 7*

NATURAL GAS

Legislators get update

Quarterly report from AGDC, departments of Natural Resources, Revenue

By KRISTEN NELSON
Petroleum New

The Alaska Legislature's House and Senate Resources committees heard a quarterly update July 11 on the Alaska LNG project from the Alaska Gasline Development Corp. and the departments of Natural Resources and Revenue. The three have statutory responsibilities for the project to liquefy Alaska North Slope natural gas and ship it to Asian markets as liquefied natural gas.

AGDC was represented by Dave Cruz, chair of the AGDC board, Frank Richards, senior vice president, program management and Lieza Wilcox, vice president, commercial and economics.

Gov. Bill Walker, a long-time LNG project proponent, budgeted AGDC to accept unlimited third-party financing in the current budget, but legislators first restricted the amount the agency could accept and then eliminated the provision entirely.

While it was not discussed in the presentation, AGDC's slide pack from the meeting includes 2018 and 2019 funding targets, and states: "Current fund balance will cause project delay due to inability to advance engineering and Lump Sum Turn Key (LSTK) negotiations," with $53.4 million of funds remaining as of June. Those funds are what remains from earlier legislative appropriations for the project.

A "spend profile" in the packet showed a minimum spend of $53 million for 2018 and 2019, but

see **AGDC UPDATE** *page 11*

● EXPLORATION & PRODUCTION

AEX details work done under 2nd POD

By KRISTEN NELSON

Petroleum News

ASRC Exploration LLC, AEX, has amended its June 11 third plan of development proposal for its North Slope Placer unit to include work accomplished under the second POD, which covers Sept. 9, 2017, to Sept. 8, 2018 (see story on plans proposed in third POD in July 1 issue of Petroleum News).

The July 2 amendment details work accomplished under the second POD which includes merging and reprocessing Tabasco 3-D data with portions of the WBA and Kookpuk survey data, with processing completed and work begun to interpret the data.

AEX is also working on mapping the extent of the Kuparuk C sands within Placer and estimates that preliminary interpretation from existing data will be completed before the end of the second POD in early September.

"AEX is currently in MOU negotiations with nearby operators regarding facility optimization for Placer development," the company said.

Kuparuk C reservoir studies, including modeling to determine the number and location of wells needed to produce the reservoir, are also part of the second POD, and AEX said that based in interpretation of results, it is "reviewing the potential for implementing hydraulic fracturing within the Kuparuk C."

On facilities issues, AEX said it completed an initial surface facility study during the first POD, and based on results from that study, began a second surface facility cost study for new routing options. The company said it is looking at alternative routing to proposed processing facilities at Nanushuk (the Oil Search and Repsol development proposed for the area between the Kuparuk River and Colville River units), based on the environmental impact statement for that project, and is doing cost estimates of new pipeline and road routing alternatives.

AEX is also evaluating facility sharing opportunities for processing Placer oil through either the Southern Miluveach unit Mustang Operations Center or through facilities in the Kuparuk River unit. The company said it

see PLACER UNIT page 3

contents

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● FINANCE & ECONOMY

EIA: US could be leading producer in 2019

Agency projecting 11.8 million bpd next year; previous record of 9.6 million in 1970; forecasts Brent to remain above $70 this year

By KRISTEN NELSON
Petroleum News

The U.S. could be the world's leading crude oil producer in 2019, the U.S. Energy Information Administration said July 10 in its Short-Term Energy Outlook.

"In 2019, EIA forecasts that the United States will average nearly 12 million barrels of crude oil production per day. If the forecast holds, that would make the U.S. the world's leading producer of crude," said EIA Administrator Dr. Linda Capuano.

U.S. crude oil production is estimated to have averaged 10.9 million barrels per day in June, EIA said, up 100,000 bpd from May. The agency is forecasting an average of 10.8 million bpd this year, up from 9.4 million bpd in 2017, and rising to an average of 11.8 million bpd in 2018, with both of those forecast levels surpassing the previous 1970 record of 9.6 million bpd.


DR. LINDA CAPUANO

Domestic growth

EIA said 600,000 bpd of the expected 1.2 million bpd of crude production growth from June 2018 to December 2019 comes from tight rock formations in the Permian region in Texas and New Mexico, with the remaining increase from the Bakken, Eagle Ford, other Lower 48 regions and the federal Gulf of Mexico — collectively another 600,000 bpd of increase.

By the end of 2019 EIA expects the Permian to be producing 4 million bpd, some 600,000 bpd more than estimated June 2018 levels, and representing about one-third of forecast U.S. crude oil production at that time.

"Favorable geology along with technological and operational improvements have allowed the Permian to become one of the most economic regions for oil production," EIA said. But growth is expected to be slower in 2019 than this year by some 400,000 bpd, reflecting increasing pipeline capacity constraints, the agency said, "which are expected to lower wellhead prices for the region's oil producers and to have a dampening effect on Permian's full production potential in the near term."

In the first quarter exports, including pipeline and LNG, averaged 9.6 bcf per day, up 9 percent from the first quarter of 2017 and up 67 percent from the first quarter of 2016.

In the Eagle Ford, production is expected to increase by some 200,000 bpd to 1.4 million bpd this year, and then increase to 1.5 million bpd in 2019. "The Eagle Ford region covers a significantly smaller geographic area with fewer prolific formations and fewer opportunities to drill compared with the Permian region. However, the Eagle Ford region does not have the same pipeline capacity constraints as the Permian region. Some producers could potentially target the Eagle Ford region and move away from the Permian in 2018 and in 2019, because the Permian region continues to experience constraints," EIA said.

The Bakken, mostly in North Dakota, is expected to produce 1.2 million bpd this year and 1.4 million bpd in 2019, surpassing the previous record of 1.2 million set in 2015. EIA said much of the recent growth in the Bakken reflects removal of pipeline capacity constraints. "However, the Bakken region contains fewer identified prolific formations than the Permian region and is more significantly affected by winter weather," EIA said.

The federal Gulf of Mexico is expected to produce 1.7 million bpd this year and 1.9 million bpd in 2019. Ten new projects are expected to come online this year, and seven more in 2019. EIA said if those projections are reached, Gulf production in both years would be the highest on record.

Elsewhere in the Lower 48, growth from June 2018 through December 2019 is expected in the Niobrara and Anadarko regions, with both forecast to grow by 100,000 bpd.

EIA said Alaska production is expected to remain flat at 500,000 bpd this year and next.

Oil prices

"EIA forecasts Brent crude oil spot prices to remain above $70 per barrel this year," Capuano said.

The agency expects Brent to average $73 per barrel in the second half of this year and $69 in 2019, with West Texas Intermediate expected to average $6 lower than Brent in the second half of the year and $7 lower in 2019.

Brent crude oil spot prices averaged $74 per barrel in June, down almost $3 from the May average, EIA said.

"Despite the decline, June marked the third consecutive month in which Brent crude oil spot prices averaged more than $70" per barrel, EIA said. "The price decline in June largely reflected market expectations in the early part of the month that OPEC, along with certain non-OPEC producers including Russia, would announce a production increase at the June 22-23 meetings," the agency said.

The Organization of the Petroleum Exporting Countries did announce plans to increase production starting July 3, EIA said, but Brent spot prices increased after the announcement, possibly reflecting an expectation that those production increases would not be enough to offset falling production in Venezuela and Libya, and the potential for reduced volumes from Iran following the U.S. withdrawal from the Joint Comprehensive Plan of Action on Iran nuclear development.

In the second quarter of 2017 Brent averaged $50 per barrel, compared to $75 per barrel in the second quarter of 2018.

"The rising prices largely reflect continuing draws in global oil inventory levels," EIA said, with global petroleum and other liquid fuels inventories down by an average of 500,000 bpd in 2017 and by 200,000 bpd in the first half of 2018.

Natural gas

"The July outlook continues to forecast record production for U.S. dry natural gas in 2018 and 2019," Capuano said. "Assuming the forecast holds, we will see production top 81 billion cubic feet per day in 2018, and another increase that will push production up to roughly 84 billion cubic feet in 2019."

EIA said estimated dry natural gas production averaging 81.3 bcf per day in 2018 would be an 11 percent increase from 2017; a rise to 84.5 bcf per day in 2019 would be another 4 percent rise.

"The expected growth in natural gas production is largely in response to improved drilling efficiency and cost reduction, as well as higher crude oil prices that contribute to higher associated gas production from oil-directed rigs," EIA said, with forecast natural gas increases supported by planned expansions in liquified natural gas and pipeline exports.

In the first quarter exports, including pipeline and LNG, averaged 9.6 bcf per day, up 9 percent from the first quarter of 2017 and up 67 percent from the first quarter of 2016.

Average Henry Hub natural gas prices have remained below $3 per million British thermal units since January, with the agency expecting an average of $2.99 this year and $3.04 in 2019. ●

Contact Kristen Nelson at knelson@petroleumnews.com

continued from page 2

PLACER UNIT

has a memorandum of understanding with Brooks Range Petroleum Corp. to revaluate use of the SMU Mustang production facilities and is in initial discussions with ConocoPhillips Alaska for a Kuparuk River unit facility sharing agreement.

AEX said it is in continuous discussions with BRPC on the status of the SMU Mustang facilities and has advanced KRU facility sharing negotiations with ConocoPhillips with a confidentiality agreement and meetings and has completed economic analysis for that alternative.

"AEX is currently in MOU negotiations with nearby operators regarding facility optimization for Placer development," the company said. ●

Contact Kristen Nelson at knelson@petroleumnews.com

● EXPLORATION & PRODUCTION

State partially approves amended SMU POD

Brooks Range Petroleum proposal to flare gas for 3-6 months denied; new completion dates for Southern Miluveach work approved

By KRISTEN NELSON
Petroleum News

Brooks Range Petroleum Corp. has received approval for new completion dates for certain work commitments at its Southern Miluveach unit, but the Alaska Department of Natural Resources' Division of Oil and Gas denied a request to flare gas in conjunction with 2018 operations for an undetermined period estimated by the company at three to six months.

The plan of development for the unit covering the 2018 calendar year was approved in December, subject to BRPC submitting quarterly reports on its progress.

The division said in December that timely operations were imperative, and that delays, such as in module installation, with the unit sitting untouched for months, might lead the division to "conclude that BRPC has ceased operations and the unit would automatically terminate. Thus, it will be critical for BRPC to timely complete the above work commitments or risk losing the unit."

In its amendments to the 2018 POD BRPC said additional on-pad piles would be installed starting in the third quarter of the year; that work was originally proposed for the first quarter of 2018.

In May BRPC submitted a proposed amendment to the approved fifth POD, "reflecting new completion dates for certain work commitments set forth in the Fifth POD and a new strategy for unit operations ... not previously contemplated in the Fifth POD," the division said. The amendment was found complete in May.

Delayed work commitments

The division said the amendment to the POD "largely delays work commitments" from the approved fifth POD to later in that POD period or into the next POD period.

The division said the schedule was acceptable as a POD.

"Whether this schedule and BRPC's action will be sufficient for the Division to conclude that 'operations are being conducted' remains an open question. IF BRPC is not conducting operations, SMU will automatically expire," the division said, adding that it "will revisit this issue as it receives BRPC's next quarterly update."

Gas flaring

On the gas flaring proposal — which it denied — the division said the amendment to the fifth POD proposed flaring gas from the SMU M-02 well.

BRPC told the division in the amended POD that it plans to begin production from existing wells: North Tarn 1A; SMU M-02 (which, the company said, requires perforation and stimulation); Mustang 1 (which requires drilling of a lateral extension/possible sidetrack); and said work on these wells would begin prior to completion of the early production facility which the company proposes to bring in so that production can begin in late 2018 or early 2019.

BRPC told the division it plans to flare gas associated with SMU M-02 which is not needed for power generation and said less than a third of the gas expected to be produced would be used for power generation.

The division said it found that the flaring proposal was "unusual and would result in unnecessary physical waste," and denied that portion of the proposed POD amendment.

Transportation costs

BRPC told the division that it planned to begin production before a pipeline connection was available and planned to truck the crude from the SMU M002 well to the Alpine Pipeline until a tie-in was completed.

"Trucking oil under these circumstances may not qualify as a 'reasonable cost of transportation' under SMU lease terms," the division said. If BRPC proceeds with trucking oil, the Division will evaluate these costs when it audits BRPC's royalty filings. Underpayment of royalties is subject to interest," the division said.

Amended POD

In its amendments to the 2018 POD BRPC said additional on-pad piles would be installed starting in the third quarter of the year; that work was originally proposed for the first quarter of 2018.

Commenting on the company's quarterly report the division said: "BRPC did not report any operations at the Unit, indicating that it had failed to fulfill its first quarter 2018 commitment to install remaining on-pad piles."

Cross-country pipeline installation, which the original POD said would take place in the fourth quarter of 2018 or the first quarter of 2019, is on the same schedule in the amended POD, which says installation would begin in the fourth quarter of 2018 depending on tundra travel availability.

The 2018 POD says the Alpine tie-in will be completed in the fourth quarter of 2018 or the first quarter of 2019; the amended POD says engineering work is ongoing for the ConocoPhillips Alaska-executed tie-in work, with field work to begin as early as the fourth quarter. ●

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● EXPLORATION & PRODUCTION

Deep Creek contraction delay approved

Division agrees to defer contraction by a year, given Hilcorp's continuing exploration drilling program in Kenai Peninsula unit

By ALAN BAILEY

Petroleum News

Alaska's Division of Oil and Gas has agreed to delay by a further year the contraction of Hilcorp Alaska's Deep Creek unit on the Kenai Peninsula. In a June 28 letter to Hilcorp, division Director Chantal Walsh commented that Hilcorp's plans to continue a program of stratigraphic test well drilling and to conduct some exploration drilling in the unit provide justification for delaying the contraction until May 31, 2019. The unit had been scheduled for contraction on May 31, 2018.

Hilcorp's most recent plan of development for Deep Creek, approved on May 17, says that the company wants to drill four to six stratigraphic test wells in the unit and that the company had drilled two of these wells in October 2017. The company said that it plans to drill the remaining two to four wells by July 30, 2019. The wells would target the Sterling and Beluga formations.

The idea is to use the results of this test well drilling to inform the drilling of exploration wells, also targeting the Beluga and Sterling, in 2019.

"Because these exploration and development plans are contingent on the completion of the remaining stratigraphic test wells planned for the DCU, extension and delay of the mandatory unit contraction for an additional one year is warranted," Walsh wrote in her June 28 letter.

Formed in 2001

Unocal formed the Deep Creek unit in 2001 from a combination of state leases and leases owned by Cook Inlet Region Inc. Sustained gas production began from the Happy Valley participating area in November 2004. Hilcorp acquired the unit on Jan. 1, 2012, when the company purchased all of Unocal's assets in the Cook Inlet basin. Production, which comes from a gas pool in the Tyonek and Beluga formations, and from the Sterling, has been declining. However, Hilcorp has its drilling plans, with the objective of bringing more gas on line.

Under state regulations, 10 years after production starts in a unit the area of the unit must be contracted to include just those lands that include an approved participating area, or that facilitate production in some manner. On that basis, the Deep Creek unit should have contracted on Nov. 14, 2014. However, since then Hilcorp has requested and been granted a series of contraction delays, given the company's plans for further exploration and development in the unit. ●

Contact Alan Bailey at abailey@petroleumnews.com

ENVIRONMENT & SAFETY

Looking for ideas on produced water usage

The U.S. Department of Energy Office of Fossil Energy has formed an agreement with Chevron Technology Ventures, to provide expertise in a CTV competition seeking creative ways of using water produced in association with oil and gas production. Because the water contains impurities that are difficult to deal with, it is generally more cost effective to dispose of the water, typically through re-injection, rather than to treat and use it. But could the water be more usefully employed in agriculture, mineral extraction, or could it be better re-used in oil and gas production?

CTV, a division of Chevron USA Inc., organizes a series of technical challenges. Participants submit ideas for solving some technical problem and CTV selects winners. In the case of the produced water challenge, CTV is looking for ideas for water management at a delivered price in the range 40 cents to 75 cents per barrel. Up to three finalists will each receive an award of $25,000 and be considered for participation in a field trial, participation in a CTV program or considered for an equity investment.

DOE says that under its agreement with CTV the agency will share its technical expertise, to help CTV's prizewinner selection. The agency will also provide experts to help answer technical questions that may arise during the judging. Over time, DOE will also seek other cooperative opportunities with CTV. However, DOE will not participate in judging the applications or determining the prizewinners, DOE says.

"Collaboration between FE (the Office of Fossil Energy) and industry is critical to the continued development of cost-effective solutions to oil and natural gas challenges," said Assistant Secretary for Fossil Energy Steven Winberg. "The department's cooperation with Chevron Technology Ventures will provide important perspectives and ideas for overcoming produced water challenges."

—ALAN BAILEY

● LAND & LEASING

Company close to finalizing N.M. leases

ASSOCIATED PRESS

An Artesia-based oil company is close to finalizing numerous leases with mineral rights owners in Carlsbad as it moves ahead with plans to drill under the southeastern New Mexico city.

Santo Petroleum got approval from city councilors in 2017 to go door to door and offer residents five-year leases for their mineral rights.

The Carlsbad Current-Argus reports that the company has obtained about 3,000 leases in the last year, covering the majority of the planned leasing area.

"Santo is well down the path of its planned lease acquisition activity," Santo President Hanson Yates said. "We are nearing the end of the lease acquisition phase of the project."

Owners were offered a signing bonus up front and a percentage of the subsequent revenue, should the wells prove productive.

The company plans to drill wells up to 2 miles deep outside city limits and then drill horizontally up to 2 miles into Carlsbad to access potential crude oil.

Yates said Santo hasn't published a specific timeline for drilling development due to the complexity of readying such a large number of leases and tracts to drill.

Biggest leases

The two biggest leases were with the City of Carlsbad and Carlsbad Municipal Schools. The city leased about 175 acres and was paid about $824,000. The school district received about $148,000 for 149 acres.

The company plans to drill wells up to 2 miles deep outside city limits and then drill horizontally up to 2 miles into Carlsbad to access potential crude oil.

Carlsbad City Administrator Mike Hernandez said the wells will be much deeper than the water table and that the project will have little effect on activities on the surface.

Carlsbad's ground water supply is about 300 to 500 feet deep, he said.

"We've had our experts prove to us that it is safe," he said.

The project is another sign that the Permian Basin is booming.

"It just fits in with everything that's going here," Hernandez said. "The royalties will be a huge benefit in the long term. They said it could pump millions into the city."

Superintendent Greg Rodriguez was not as confident that the school district will see a large return. The main reason he signed the lease was to get the upfront bonus. That money means more can be spent on school supplies and other student needs, he said.

Rodriguez was certain the project won't disturb district-owned structures on the surface. He said similar deals were enacted at rural school districts in West Texas to no detriment. ●

● LAND & LEASING

BLM delays leasing near Great Sand Dunes

By DAN ELLIOTT
Associated Press

Environmental groups opposed the sale of drilling leases, saying the land is too close to the park, a wilderness area and wildlife habitat.

The U.S. government on July 10 delayed a decision on a contentious proposal to allow oil and gas drilling near Great Sand Dunes National Park in southern Colorado, saying it first wants to consult with the Navajo Nation, which owns land in the area.

The Bureau of Land Management had planned to sell drilling rights on 29 square miles of public land east of the park at a Sept. 6 auction, but Navajo officials requested a formal consultation, and the agency agreed.

The bureau said the land could still be offered at a future auction.

A spokesman for the Navajo Nation didn't immediately respond to emails seeking comment.

The Navajo reservation — in Arizona, New Mexico and Utah — doesn't include Colorado. But tribal President Russell Begaye told The Denver Post the Navajos consider the area near Great Sand Dunes park to be part of their ancestral lands and bought 26 square miles there last year.

"This land is sacred and the Navajo Nation will always protect the beauty and sacredness of the land," he told the newspaper in May.

Environmental groups opposed the sale of drilling leases, saying the land is too close to the park, a wilderness area and wildlife habitat. Some warned drilling waste or spills could threaten water quality.

"It doesn't make a lot of sense they would choose this location," said Kimberley Pope, an organizer for the Sierra Club in Colorado.

Agency issues

Some state and federal officials also raised questions.

Great Sand Dunes park officials were concerned about the effects drilling could have on air quality, noise and dark skies, according to Fred Bunch, the park's chief of resource management, who submitted written comments to BLM about the potential sale.

The bureau oversees the sale of minerals under most federal land.

The Colorado land under consideration for drilling is about 200 miles south of Denver and reaches to within a mile of the park's eastern boundary. The sand dunes are about 4-1/2 miles west, but mountains stand between the potential drilling sites and the dunes.

The park says its dunes are the tallest in North America, some more than 700 feet high. The dunes cover 30 square miles.

The move comes amid a push by the Trump administration to rein in environmental regulations and quicken the pace of mineral sales on public land.

The Western Energy Alliance, which represents the oil and gas industry, said BLM should complete the consultation with the Navajos quickly and put the rights up for auction soon.

Kathleen Sgamma, president of the alliance, said the land isn't near the Navajo Nation, and drilling would be done in a way that protects culturally important features.

"Of course, the leases are on the other side of a mountain range, so they would not impact the Great Sand Dunes National Park either," she said.

Colorado Gov. John Hickenlooper had asked federal officials to listen to the Navajos' concerns and was pleased that they did, spokeswoman Jacque Montgomery said. ●

continued from page 1

PIPELINE BUY-IN

Bill Morneau, Natural Resources Minister Jim Carr and Minister of Infrastructure Amarjeet Sohi.

"They are responding favorably," he said. "So far, we have received encouragement."

Boucher saw no problem for the aboriginal communities in raising money on the bond market.

Previous benefits agreements

When Kinder Morgan was the pipeline owner, 10 Alberta and 33 British Columbia First Nations along the pipeline route signed benefits agreements valued at C$400 million, and some in British Columbia have expressed interest in becoming ownership partners.

That option is likely to be further pursued at the Vancouver meeting which is being hosted by the Fort McKay and Mikisew nations.

Although he was unaware of the meeting, Lower Nicola First Nation Chief Aaron Sumexheltza said he was open to a discussion, despite the fact that the original Trans Mountain line is now 60 years old.

Ellis Ross, an opposition member of the British Columbia legislature, said he was positive some B.C. First Nations would be eager to invest in the pipeline once the Canadian governments makes the terms public.

He said that including indigenous communities as owners of economic projects would be the "last piece of the puzzle" to fully involve aboriginals in rights and title on their claimed lands.

Considerable interest

Morneau's office said "many investors have already expressed interest" in joining the project, along with Canadian pension funds and "others," but would not indicate what form First Nations investment might take.

The agreements Kinder Morgan struck with First Nations included environmental monitoring, contracting opportunities, job training and direct revenue payments worth an estimated C$400 million over an undisclosed number of years, but did not open the door to equity discussions.

Michael LeBourdais, chief of the Whispering Pines Indian Band near Kamloops in south-central B.C., said he has been approached by Canada's major banks with proposals to finance an equity stake in Trans Mountain.

Stephen Buffalo, president of the Indian Resource Council that represents 130 First Nations across Canada, said it is "imperative that indigenous people are included in all discussions and decisions relating to Kinder Morgan," and demanded an equity role for those nations.

The closest First Nations came to becoming partners in a major pipeline was when Enbridge funded stakes valued at C$300 million for 26 indigenous groups in its Northern Gateway line covering a 10 percent chunk of the project's equity, but the venture was scuttled in 2016 by the Liberal government of Prime Minister Justin Trudeau, at the same time it approved the Trans Mountain expansion. ●

Contact Gary Park through publisher@petroleumnews.com

NATURAL GAS

LNG carrier traverses Northern Sea Route

An icebreaking LNG carrier has successfully traversed the Northern Sea Route around the Arctic coast of Russia without icebreaker support, transporting LNG from the Yamal LNG plant on the Kara Sea to China, according to a report in the American Journal of Transportation. The vessel, the Vladimir Rusanov, arrived in the Bering Sea on July 6, heading for the Chinese port of Juiangsu Rudong, having embarked from the Kara Sea on June 25, the report said. The vessel is jointly owned by Mitsui O.S.K. Lines and China COSCO Shipping Corp. Ltd. and is the first of three similar vessels that the companies have commissioned.

In August 2017, the Christophe de Margerie became the first LNG tanker to traverse the Northern Sea Route, unaided by an icebreaker, delivering LNG from a gas terminal on the Barents Sea coast to South Korea.

Prior to its current voyage to China, the Vladimir Rusanov had been engaged in carrying LNG from Yamal west to European destinations. But the summer opening of the Northern Sea Route provided an opportunity for the first delivery of Yamal LNG to East Asia via the Bering Strait, the American Journal of Transportation reported.

—ALAN BAILEY

continued from page 1

ENBRIDGE MOVES

19 processing plants and liquids handling facilities, with a combined operating capacity of 3.3 billion cubic feet per day and more than 2,000 miles of gathering pipelines.

Enbridge CEO Al Monaco said the sale raises to C$7.5 billion his company's non-core asset disposals this year, more than doubling its initial target of C$3 billion, taking a sizeable bite out of its C$61.2 billion long term debt, while helping it to advance C$22 billion in growth projects over the next two years, including its C$9 billion Line 3 replacement to serve U.S. Midwest refineries.

He said the sale "significantly advances our strategic priority of moving to a pure play regulated pipeline and utility business model."

Kvisle: savvy transaction

Hal Kvisle, the former CEO of Enbridge's chief Canadian rival TransCanada, said it was a savvy transaction for Brookfield.

"I think they just saw the size and scope of this gas gathering and processing business and they bid aggressively and won it. The Montney is an extraordinary development."

As well, Kvisle said the transaction is significant for Canada's LNG market, which he described as having both economic and environmental benefits.

Enbridge's balance sheet has been a constant focus for analysts since the company forked over C$37 billion in 2016 to merge with Houston-based Spectra Energy.

Canaccord Genuity analyst David Galison said the asset sales should help Enbridge both pay down debt and fund its growth portfolio.

Since taking out Spectra, the company had engaged in multiple strategy changes by rearranging its core assets through an acceleration of its deleveraging process, he said.

Moody's Investors Service Vice President Gavin MacFarlane said in a release that Enbridge's "all-stock acquisition of its sponsored vehicles is credit positive ... and reduces near-term risks. We still see structural subordination across the corporate family but this is a big step in a credit-friendly transaction," he said reinforcing the views of those who believe the pressure is on Enbridge to streamline its corporate structure.

Moody's had downgraded the company's credit rating seven months ago, saying its credit strengths were "offset by high leverage, a persistently large capital investment program and material corporate and capital structure complexity."

Jennifer Rowland with Edward Jones said in an email that 2018 is a "big year of execution for Enbridge and they are indeed executing on key items that should restore investor confidence."

—GARY PARK

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continued from page 1

LEGACY WELLS

NPR-A and discussed with the commissioners continuing plans for further remediation work.

136 wells

BLM originally listed a total of 136 wells that required attention. In 2013 the agency identified 68 wells that by then had either been cleaned up or did not require further action. And the U.S. Geological Survey was using 18 of the wells for climate monitoring.

Dealing with the wells is expensive and logistically challenging, especially given the remote nature of the territory in which the wells were drilled and the vast area of land across which the wells are scattered. During the AOGCC meeting Rob Brumbaugh, BLM Alaska oil and gas section chief, commented that the general approach to the remediation effort is to focus on high priority wells that present significant environmental hazards, while also dealing with clusters of nearby wells.

Last winter's project

In the past winter a contractor working for BLM tackled a cluster of five wells deep inside the NPR-A, to the west of Umiat. The wells involved consisted of the Square Lake No. 1, the Wolfe Creek Nos. 1 to 3, and the Titaluk No. 1. The wells had been drilled by the U.S. Navy between 1951 and 1952, in a search for oil and gas resources, Jessie Chmielowski, BLM senior petroleum engineer, told the commission.

The project involved staging equipment at the Meltwater 2P pad before using appropriate vehicles to move the equipment, including a mini-rig, to the remote well sites. The journey from the pad to the first of the wells took 10 days, Chmielowski said. It took another 24 days to complete the work on the wells, and six days to return to the staging pad, she said. Food supplies were flown to the field team using a ski equipped aircraft.

Work at the wells involved surface excavation, the installation of cement plugs to the surface, the trimming off and plating of the top of the surface casing, and then backfilling the excavation. Although four of the wells had encountered little more than gas shows, the Wolfe Creek No. 1 had found a gas pool and had produced gas at a little under 1 million cubic feet per day, Chmielowski said. Ensuring that there would be no continuing leakage of gas from that particular well involved building up the fluid level in the well before emplacing a cement plug, she said.

Funding for the work

Funding of $50 million for the BLM legacy well program has come from the Helium Act, passed by Congress in 2013. Work carried out with the Helium Act funding, including the five-well program conducted in the past winter, has brought total expenditure to around $44 million, Brumbaugh said (some $2 million has been sequestered and is unavailable for the work). Unfortunately, the $4 million that remains and is allocated for fiscal year 2019 is insufficient to achieve much, he said. However, U.S. Sen. Lisa Murkowski, R-Alaska, has secured an additional $10 million in funding, he said (she was also responsible for the $50 million in the Helium Act).

One complication is that five of the legacy wells, including the Gubik No. 2 well, a high priority well that is releasing gas, lie in Arctic Slope Regional Corp. land, rather than in the NPR-A. The $4 million remaining from the Helium Act funding, can only be used for projects inside NPR-A, Brumbaugh said.

However, other high priority wells, including the Simpson core 26 and the Iko Bay well, are inside the NPR-A.

Brumbaugh said that he could not comment on which wells BLM may tackle next, given that the agency has not yet put out a task order for the work. He did confirm that the Simpson No. 1 well, west of Smith Bay, is one focus of attention. That particular well needs to be plugged and is near a cluster of other wells, including several Simpson core test wells.

Lost wells

There was some discussion about four so-called "lost wells," old Navy wells whose approximate locations are known but which cannot be found. Brumbaugh said that BLM has access to photographs used in 1952 in conjunction with the development of quad maps. One strategy is to find evidence of the well locations on these photos, as a guide to the exact well locations. If that approach fails, an alternative possibility may be to use ground penetrating radar to detect the metalwork known to exist in the wells, he said.

Commissioner Cathy Foerster commented that one lost well of particular concern is the J.W. Dalton No. 1 well, on the Beaufort Sea Coast north of Teshekpuk Lake, a well that was known to have been leaking gas.

Temperature monitoring wells

Foerster also commented that, while

see LEGACY WELLS *page 10*

continued from page 1

FURIE WELLS

KLU No. 4 well. And so, Furie's expectation is to have four producing wells for the Kitchen Lights field by November, Pinsonnault said. This year's development drilling will satisfy the contractual requirements associated with a gas supply agreement with Enstar Natural Gas Co.

As a development well, the KLU No. 4 well will target gas in the Sterling and Beluga formations. However, Furie also hopes to extend the drilling down into the Tyonek formation, as an exploration venture, Pinsonnault said.

Augmenting staff

The company has been augmenting its staff, adding a new vice president of operations and an HSE official, and has contracted with Petrotechnical Resources of Alaska to act as its technical arm, Pinsonnault said.

Petroleum News understands that Bruce Webb, who had been the company's senior vice president, left the company at the end of May.

In its most recent drilling, in 2016, Furie had been using the Randolph Yost rig, which is currently moored at Nikiski, on the Kenai Peninsula. However, PRA issued a request for proposal for this year's drilling: the result is the use of the Spartan 151, which had been moored in Seward. Pinsonnault expressed a view that, given the amount of potential offshore drilling in the Cook Inlet, there would be advantage in having a rig continuously available in the region.

"It's my belief that the operators in the inlet should retain a rig for future activity," Pinsonnault said.

Delivering on commitments

With outstanding commitments, both in terms of gas supplies and in terms of the Kitchen Lights plan of development, Furie's current focus is to deliver on those commitments.

"It's been a tremendous effort to get where we are in 90 days, to mobilize, permit, define the operational tempo for the summer," Pinsonnault said. The company had acquired something of a reputation for promising more than it has delivered, he said.

"Our primary goal at the company now is to change that," he said.

And the company has adequate funding for this year's work, with Energy Capital Partners, the company's lender, investing more money in the Kitchen Lights venture. Furie is also waiting to see what happens in relation to past tax credits due to the company, following the recent signing by Gov. Walker of the bill authorizing the use of bonds to reimburse for the credits.

There is continuing exploration potential in the Kitchen Lights unit, including the possibility of drilling deep for oil in the Jurassic strata that underlie the Tertiary rocks that host producing oil and gas fields in the Cook Inlet basin.

"We're currently taking a holistic look at the Kitchen Lights unit to define what the art of the possible is and factor that into our communications with the state … and what we need to submit to them," Pinsonnault said. "That's work that's underway. We've got to submit a new plan of development in October, and our goal is to define what we think is possible."

Development history

The history of the Kitchen Lights gas field development dates back to November 2011, when Escopeta Oil Co. announced the discovery of a huge gas field during the drilling of the KLU No. 1 well from the Spartan 151 rig. The announced size of the find was later scaled back, although the field is clearly substantial.

In 2012 Escopeta spawned Furie and Cornucopia Oil and Gas Co., Furie's owner company. And in the summer of that year, Furie re-entered the No. 1 well to continue drilling. Later during the drilling season, the company stopped drilling that well and started drilling the KLU No. 2 well, another exploration well. By the end of that year the company had started the permitting process for installing an offshore gas production platform in the Kitchen Lights unit, envisaging twin pipelines to shore and an onshore production facility.

In 2013 Furie drilled the KLU No. 3 well, not far from the No. 1 well, to further appraise the gas discovery. And in the summer of 2015 Furie installed the Julius R. production platform, together with a single subsea pipeline for delivering gas to an onshore gas processing facility. The company formed a gas supply agreement with Homer Electric Association and, in December 2015, the field went on line, producing from the No. 3 well.

see **FURIE WELLS** *page 10*

Oil Patch Bits

New Young Brothers Kapena class tug christened

COURTESY FOSS

Young Brothers, an independent subsidiary of Foss Maritime, said July 2 that its new tug the Kāpena Jack Young has been christened in Louisiana. The Kāpena Jack Young is named after Captain Jack Young, one of three brothers who founded Young Brothers in 1900. The christening of the Kāpena Jack Young was held at Port Fourchon with representatives of Young Brothers, Foss Maritime, Conrad and Damen in attendance, as well as Sharon Young, Jack Young's granddaughter, who sponsored the vessel.

The first of four new ocean going tugs that will soon begin neighbor island service, the Kāpena Jack Young, was designed by Damen USA and built by Louisiana-based Conrad Shipyard. Kāpena means captain in the Hawaiian language, and the name for the class of ships celebrates the skill and innovation of Young Brothers' Hawaiian navigators and will be home-ported in Kaunakakai, Moloka'i. The new class of tugs are designed to match Young Brothers' fleet of modern high capacity barges, and will improve the company's ability to provide just-in-time cargo service to neighbor island communities, while enhancing service through lower maintenance down time, better tow speeds, greater operating efficiencies, and lower emissions.

"The four new Kāpena class tugs, represent our future while honoring our past. Once in service, the average age of our fleet will be reduced from an average age of 44 years to 12 years young," said Joe Boivin, president of Young Brothers. "The new tugs reinforce our commitment to safety, environmental stewardship and customer service."

Companies involved in Alaska's oil and gas industry

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

continued from page 1

INSIDER


PAUL CRAIG

other companies looking to shoot in the area," Craig told Petroleum News July 3, "But the plans are not contingent on any other parties joining the shoot."

Major new oil discoveries in the Nanushuk formation on Alaska's North Slope are causing some significant rethinking of the oil potential of the region, as companies move towards development of the exciting finds and assess further exploration opportunities west of the central North Slope.

Petroleum geologist Paul Decker from Alaska's Division of Oil and Gas recently talked to Petroleum News staff geologist and senior writer Alan Bailey about the nature and significance of the new discoveries (see article in June 24 edition, "Looking at it again").

Decker views the new Nanushuk and Torok oil plays as opening the possibility of further significant oil finds to the west of the central North Slope. The plays may also prove valuable as a geologic paradigm for oil prospects in the newly opened 1002 area of the Arctic National Wildlife Refuge, he said.

Two recent finds on their way to development consist of the Pikka/Horseshoe trend in the Nanushuk in the Colville River delta region by Armstrong and partners Repsol and Oil Search and ConocoPhillips' Willow discovery in the Nanushuk of the northeastern National Petroleum Reserve-Alaska, both north of Craig's South Nanushuk prospect.

—KAY CASHMAN

Sean Parnell signs on with Holland & Hart

IN MID-JUNE, THE LAW FIRM of Holland & Hart announced the addition of Sean Parnell, former governor of Alaska, to the firm's Anchorage office. Parnell brings more than 30 years of combined public service and legal expertise serving the business, government, and infrastructure development.

Parnell's public service career includes serving from 2009-2014 as governor. He also served as lieutenant governor and is a former Alaska state senator and representative.

As an attorney, Parnell's decades-long experience in commercial transactions, natural resources and litigation was developed in private practice, as in-house counsel, as director of state government relations for a major oil company, and in government service.


SEAN PARNELL

At Holland & Hart, Parnell will continue serving his existing Alaska business clients, as well as new clients in energy and infrastructure development.

"The extensive connections and relationships Sean has fostered at state, federal, and Western regional levels make Sean a valuable resource for clients undertaking infrastructure or natural resource exploration and development. Sean provides the firm's energy and natural resources clients with a unique combination of experience as a former government leader, legislator, administrator, and legal advisor," said Kyle Parker, administrative partner of the firm's Anchorage office.

"Sean is a strong addition to our highly regarded energy industry team," said Liz Sharrer, chair of Holland & Hart. "His many years of leadership in public service and his commitment to economic development align with our firm's goal to continue expanding service and support of Alaska-based clients."

Holland & Hart is a full-service law firm that has approximately 470 lawyers across eight states and in Washington, D.C.

—PETROLEUM NEWS

continued from page 8

LEGACY WELLS

there is no intent to require the plugging of the 18 wells that the USGS is using for temperature monitoring, so long as the wells are in use, AOGCC is concerned to ensure that the wells are actually being used and that they are safe. She said that she would like USGS to report on its well usage, and for USGS and BLM to submit a plan for determining the mechanical integrity of the wells.

Brumbaugh commented that one of the temperature monitoring wells, the Tulageak well, about 20 miles east of Utqiagvik, is a particular worry because of its vulnerability to coastal erosion. In five years or so it will probably become necessary to plug that well. The plugging operation would likely cost around $22 million to $25 million and would tie up a season of well remediation work, he said, adding that BLM has already started to prime Washington for the future need for the money for the project.

There was discussion about the need to try to deal with the Iko Bay well, a well that a contractor made an abortive attempt to plug in 2016. There are questions over whether that well can now be plugged effectively. And nothing is currently being planned because there is litigation in progress regarding the 2016 project — the contractor wants to be paid but they haven't completed the work, Chmielowski said.

Surface cleanups

There was also discussion about the need for surface cleanups at well sites, an important issue but an issue over which the Alaska Department of Environmental Conservation rather than AOGCC has jurisdiction. Although BLM clears up surface debris when remediating legacy wells and has identified a number of high priority surface contamination sites, the surface locations will probably not be tackled until the high priority wells have been dealt with, Chmielowski said.

Foerster said that she has a list of 18 wells that still require attention.

—ALAN BAILEY

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continued from page 9

FURIE WELLS

In 2016 Furie signed a gas supply agreement with Enstar — that agreement was contingent on the drilling commitments that Furie is now focusing on completing. In the summer of that year Furie used the Randolph Yost rig to drill the KLU No. A-2 well, with that well going into production in the fall. Furie also drilled the KLU No. A-1 well that year but was unable to complete that well before the end of the drilling season.

In 2017 Furie said that the Randolph Yost rig would complete the A-1 well before drilling the KLU No. 6 well, an exploration well that would target a deep Jurassic prospect — the rig was large enough to conduct the required deep drilling. But that 2017 drilling never happened, with Furie blaming the state's hiatus in the payment of tax credits for the suspension of the drilling activity.

The pause in the drilling has now clearly ended, with Furie intent on bringing its offshore gas field into full operation. ●

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continued from page 1

BADAMI REQUEST


ANDY MACK

The concept behind the lease expansion was to enable exploration drilling in the East Mikkelsen prospect that underlies a combination of Savant and AVCG leases. The prospect includes the site of the East Mikkelsen Bay No. 1 well, drilled by Humble Oil in 1971. That well encountered oil in the Killian sands, above the Hue shale source rock, with a tested flow rate of 700 barrels per day of 24 degree API oil.

Partial approval

In March 2013 the division approved inclusion of parts of two of the leases into the Badami unit but declined to expand the unit across the remainder of the seven leases: The approved expansion included the location of the Mikkelsen well. The state argued that only those lease portions met the qualifications for a lease expansion. In April 2013 Savant appealed the state's decision, claiming that effective exploration of the prospect required access to all seven of the leases that had been included in the unit expansion application. The matter has remained unresolved ever since, despite meetings between Savant and state officials.


CARL GIESLER

On July 2 Andy Mack, commissioner of the Alaska Department of Natural Resources, sent a letter to Carl Giesler, CEO of Glacier Oil and Gas Corp., Savant's owner company, telling Giesler the department had reviewed Savant's appeal and was remanding the matter to the division for reconsideration.

Starfish prospect

In the past winter Savant's B1-07 exploration well succeeded in locating an oil pool in the Killian sands in the Starfish prospect, in the Badami unit to the southwest of the Badami oil field development area. That well tested production rates above 2,500 barrels of oil per day and has since gone on line at Badami.

Savant's latest Badami plan of development, approved by the division in April, says that "if B1-07 well results are favorable, and if economic conditions warrant," the company "intends to drill up to two additional wells in the Badami unit during the winter of 2018-2019." The plan also says that, to fully explore and delineate the Badami unit, an additional drilling pad will likely be needed.

—ALAN BAILEY

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continued from page 1

AGDC UPDATE

a maximum of $797 million, were the funds available. The majority of the $797 million, $700 million, was listed as LSTK FEED (ramp-up).

Richards said the project is at the de-risk regulatory stage, with the next step lump sum turn key FEED, front-end engineering and design. The project completed pre-FEED in 2016. A final investment decision is projected for 2019, followed by project execution and first gas in 2024-25.

A slide on technical actions says AGDC has completed a construction execution plan and has a lump sum turn key contracting strategy.

Agreements

Wilcox said AGDC is progressing negotiations on anchor capacity with the Joint Development Agreement parties — Sinopec, China Investment Corp. and Bank of China. It is also advancing definitive agreements and optimal sale and financing arrangements for the entire project.

In May AGDC announced that BP Alaska had agreed to key terms of a gas sales agreement, including price and volume, with plans to finalize a long-term gas sales agreement this year. Wilcox said AGDC is working diligently to reach gas supply agreements with the other North Slope producers and is nearing completion on a level similar to that achieved with BP. AGDC is also looking at detailed gas sales agreements or sections of them and negotiating them, Wilcox said.

She said AGDC doesn't expect partial production but expects all the North Slope resource — including the state's interest — to come into the project; to close the deal for financing, 100 percent of the gas would be required.

Wilcox discussed the modeling AGDC is doing with a full investment model planned for completion in 2018-19.

A tolling structure still underlies the modeling, she said, which has a commercial structure with gas purchase and LNG sale.

Model inputs include 75 percent debt, $32.6 billion, and 25 percent equity, $10.8 billion, for total capex of $43.4 billion.

In the past AGDC has talked about a $1 per million British thermal unit price to natural gas suppliers on the North Slope but is now pegging the wellhead gas purchase at between $1 and $2, Wilcox said, and the market price of LNG delivered to Asia, which AGDC has put at $8, is now shown as $8-$9 delivered to Asia with 80 cents shipping.

The schedule in the presentation showed that the project would ramp up one train at a time, with Train 1 operational in the fourth quarter of 2024; train 2 in the fourth quarter of 2025; and train 3 in the fourth quarter of 2026.

Department of Revenue

Deputy Commissioner of Revenue Mike Barnhill and Maria Tsu, Alaska Gasline Project financing specialist, presented for the Department of Revenue, with Tsu speaking to the department's modeling efforts, focused on calculating equity returns and net revenues to the state depending on its level of equity ownership and how it is financed. An Alaska LNG project module models economics of project and fiscal impacts, Revenue's slide pack said. Greengate LLC is advising on development of the model and will provide validation. The module is still under development.

A royalty and tax fiscal module uses the department's existing fiscal model to analyze implications for oil and gas royalties and taxes, which is being adapted as data needs are assessed. DOR is coordinating with DNR on analysis of upstream impacts.

Barnhill called the modeling effort foundational to Revenue's work on the project, and said the department looks to the role it has in statute, as set out in Senate Bill 138, which includes reports to the Legislature, including recommending legislation to permit co-owner participation in the project by municipalities, regional corporations and residents; consulting with DNR on gas sales agreements; and reengaging the Municipal Advisory Gas Project Review Board.

Revenue also discussed potential risks to the state s an investor and as a resource owner and taxing authority, as well as mitigating measures.

Prior to a final investment decision, the risk level is highest, and Tsu said return is proportional to risk and the investor should be compensated for risk in a greenfield project. As key milestones are reached, she said, the project is de-risked and the level of return should then be lower than at very early stages of the project.

Department of Natural Resources

Commissioner Andy Mack, Deputy Commissioner Mark Wiggin and senior project advisor Steve Wright presented for the Department of Natural Resources.

Mack said the current project represented a paradigm shift to debt for capacity, with 75 percent of project cost borne by the debtor, not the state.

DNR is working royalty in kind vs. royalty in value issues, including eliminating switching between RIK and RIV, Wiggin said. If RIK is selected — with the state taking royalties (and probably also taxes) in gas molecules — DNR would develop and execute a gas sales agreement with AGDC. If RIV is selected, DNR would need to address the valuation process used to calculate royalty gas value. Right now, he said, the valuation method is the higher-of methodology.

Wright said DNR is looking at ways to mitigate risk. When the Joint Development Agreement team signed the agreement it kicked off a new phase for DNR, he said, with potential buyers identified.

None of the presenters had time to finish, but some issues were addressed in slides — such as a statement by DNR that AGDC had the primary responsibility for mitigating negative netback risk by ensuring that sales/purchase agreements with LNG and in-state purchasers are coordinated with gas sales agreements with the gas resource owners.

The department said it can control the amount of risk to the state "by having a minimum price provision in its gas supply agreement with AGDC or by taking its royalty in-value."

DNR also identified AGDC's plan for lump sum turn key contracts for major project components as addressing cost overrun risk.

The department said it "appreciates the criticality of project expandability as a means of promoting future gas exploration and development," and noted that AGDC has said throughput could be increased by adding trains to the gas treatment plant and the LNG plant, and adding compression stations to the pipeline. With expanded compression, DNR said, the pipeline is sized for maximum gas volumes of 4.3 billion cubic feet per day, some 27 million tons per annum, as opposed to the planned project at 20 million tons per annum. ●

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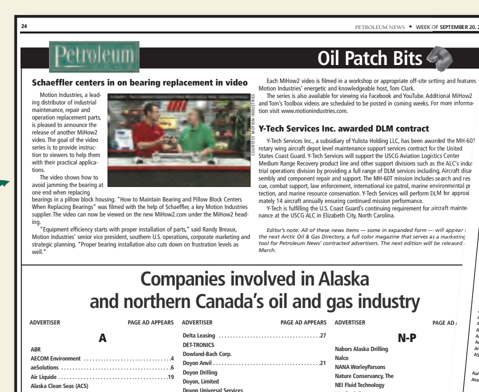

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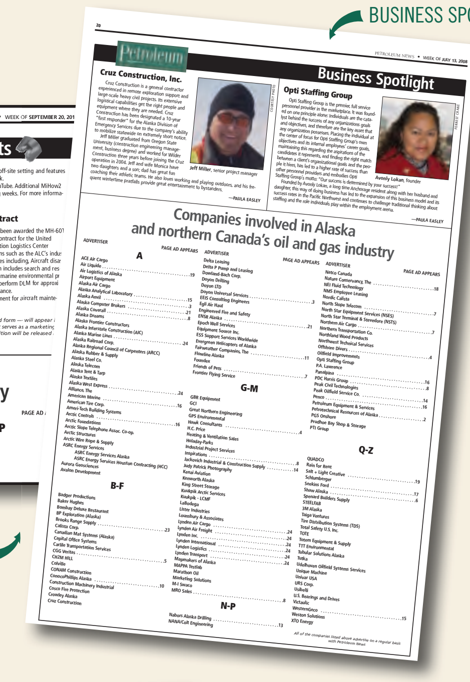

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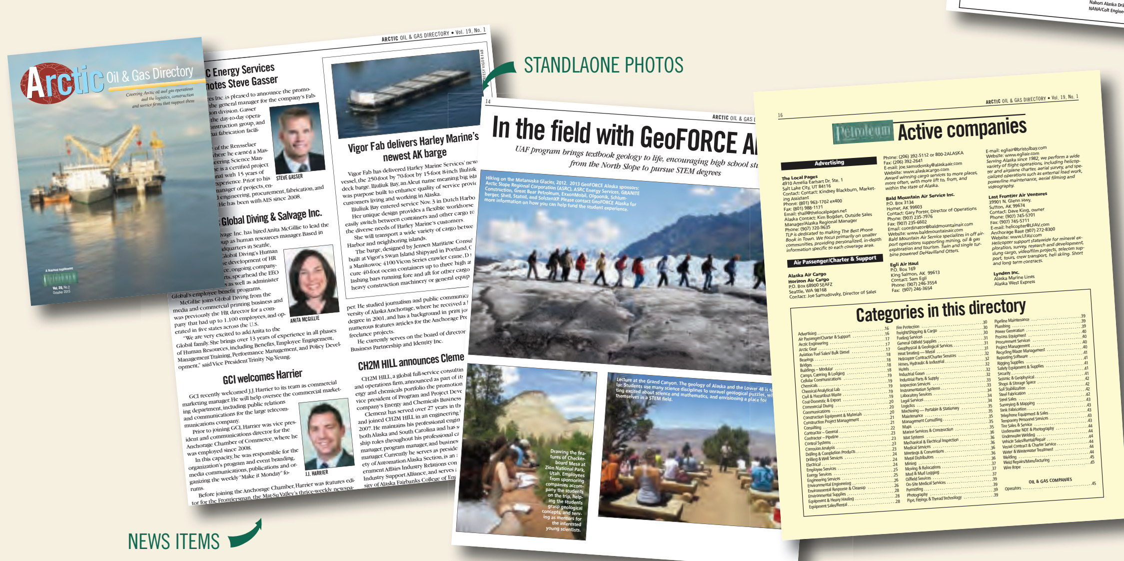

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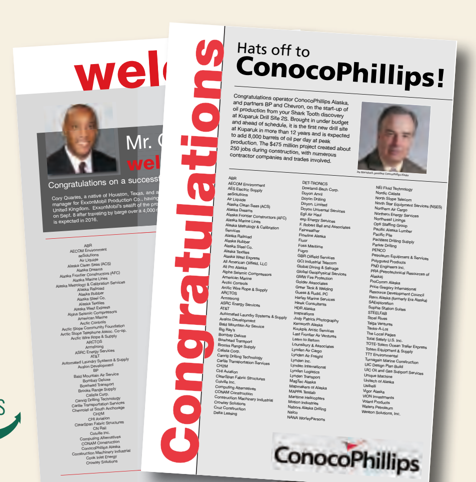

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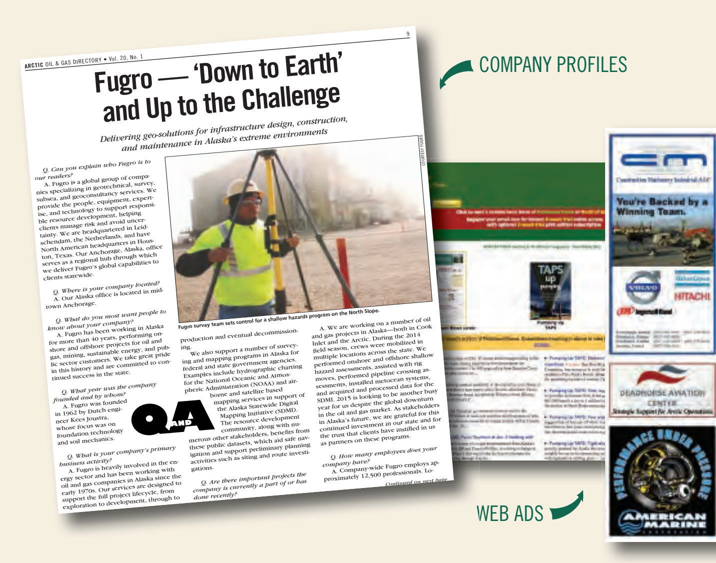

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