Petroleum news

page 6 Phillips, Marathon began shipping LNG from the Kenai facility in 1969

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BLM aims to get it right; carefully prepares for ANWR 1002 lease sale

CHAD PADGETT

The oil and gas lease sale planned by the U.S. Department of the Interior for the petroleum rich ANWR 1002 area will likely be held next year versus by the end of December.

"We are still working through the process and want to get this right," Derrick Henry, public affairs specialist at Interior's Bureau of Land Management told Petroleum News Nov. 4.

"We are working under the timeframe established in the Tax Cuts and Jobs Act of 2017, which directs the Secretary of the Interior through the BLM to establish the

see **ANWR LEASE SALE** page 10

Anchorage Assembly approves revised Chugach-ML&P deal

On Oct. 30 the Anchorage Assembly approved changes to the terms of the proposed acquisition of Municipal Light & Power by Chugach Electric Association. The Municipality of Anchorage owns ML&P.

As reported in the Nov. 3 issue of Petroleum News the parties to a Regulatory Commission of Alaska hearing into the acquisition agreed to a series of revisions to the originally agreed terms of the purchase, with the state's Regulatory Affairs and Public Advocacy Section yet to determine its position on the changes. The RCA commissioners and the parties in the hearing have agreed to continuing the hearing, reviewing the changes to the deal rather than continuing to review the deal in its entirety. So,

see **CHUGACH-ML&P** page 11

BLM NPR-A sale date Dec. 11

The federal Bureau of Land Management's Alaska State Office will hold its 2019 National Petroleum Reserve-Alaska oil and gas lease sale Dec. 11 at 10 a.m. Sealed bids for the 350-tract sale are due by 4 p.m. Dec. 9.

BLM said in a Nov. 5 Federal Register notice that the 350 tracts in the sale contain some 3.98 million acres.

The detailed statement of sale is available at the BLM Alaska website at www.blm.gov/alaska/lease-sales.

Opening and reading of the bids will be available via video livestreaming at www.blm.gov/live.

"This is one of several actions we are taking to further expand energy development in Alaska," said BLM Alaska State Director Chad Padgett in a Nov. 5 statement. "We are working on a new

see **NPR-A SALE** page 11

RDC conference has presentations of interest to Alaska O&G industry

The 40th annual Resource Development Council conference is scheduled for Nov. 20 and 21 at the Dena'ina Center in Anchorage.

The conference registration desk and exhibits open at 7 a.m. on Wednesday, the 20th, with an eye-opening breakfast, followed by opening remarks at 8 a.m. by fisheries, forestry, mining, tourism and oil and gas representatives, including Kara Moriarty, president and CEO of the Alaska Oil and Gas Association.

Also, economist Neil Fried from Alaska Department of Labor will talk about Alaska Economic Trends, 2020 forecast.

Presentations of particular interest to the oil and gas industry

see **RDC CONFERENCE** page 10

EXPLORATION & PRODUCTION

Mustang online!

First North Slope field taken from discovery to production by small independent

By KAY CASHMAN
Petroleum News

In response to a query from Petroleum News, Majid Jourabchi of Houston-based Thyssen Petroleum confirmed Nov. 6 that the North Slope Mustang oil field is online, utilizing an early production facility, or EPF.

Mustang is operated by Brooks Range Petroleum Corp., or BRPC, run by Bart Armfield, who has been with the project from the beginning.

It is the first oil field that a small independent has taken from discovery to production on the North Slope.

BART ARMFIELD

According to Jourabchi, Mustang oil was trucked from the field for the first few days.

"We trucked the oil because COP needed to certify the meters, open the blinds and have a person on location," he said.

ConocoPhillips did that Nov. 2. Since then the oil has been flowing through Mustang's pipeline to the Alpine pipeline and on to the trans-Alaska pipeline.

"The first few days of production was sold to Eni because we did not have enough storage

see **MUSTANG ONLINE** page 10

FINANCE & ECONOMY

Furie stay modified

Court: State can recoup 2014 tax credit overpayments from unpaid credits

By STEVE SUTHERLIN
Petroleum News

The automatic stay in the Chapter 11 bankruptcy case of Furie Operating Alaska and related companies has been modified to allow the state of Alaska to pursue the collection of overpayment of calendar year 2014 tax credit reimbursements in the amount of $2,370,772, which the Department of Revenue identified in an Aug. 9 audit notice and demand for payment.

U.S. Bankruptcy Judge Laurie Selber Silverstein signed the modification order Nov. 4 "for the limited purpose of permitting: (a) the adjudication of any administrative or judicial appeal of the debtors' oil and gas production tax liability for the taxable period beginning on January 1, 2014 and ending on December 31, 2014 under Alaska Statute 43.55; and (b) the State of Alaska to offset tax credit overpayments to debtor Cornucopia Oil & Gas Company, LLC for the year 2014 against pre-petition tax credits owed by the State of Alaska

"The unassigned tax credits are more than sufficient to eliminate Cornucopia's 2014 overpaid tax credit liability," DOR said.

see **FURIE BANKRUPTCY** page 9

GOVERNMENT

More AOGCC hearings

Savant, Cook Inlet Energy, AIX Energy say other bonds should be considered

By KRISTEN NELSON
Petroleum News

The Alaska Oil and Gas Conservation Commission began scheduling hearings on reconsideration requests for its increased bonding requirements in October, setting hearing dates for three companies, Alaskan Crude, Amaroq Resources and Malamute Energy (see story in Nov. 3 issue of Petroleum News).

The commission had received three more appeals and has now scheduled hearings for those companies — AIX Energy LLC, Cook Inlet Energy LLC and Savant Alaska LLC. (Cook Inlet Energy and Savant Alaska are Glacier Oil & Gas subsidiaries.)

In requests for reconsideration various of the companies dispute the number of permitted wells they have, ask for consolidation of bonding for companies which share the same parent, argue that other DR&R bonds in place should reduce the AOGCC required amount and say amounts required for DR&R are less that what the commission is requiring in bonding.

The AOGCC bonding requirement, formerly $100,000 for a single well and $200,000 for multiple wells, was raised in May after a series of hearings. The new amounts reflect the commission's concern that companies would abandon wells, leaving the landowner, typically the state of

see **AOGCC HEARINGS** page 8

● EXPLORATION & PRODUCTION

AOGCC fines BP $20,000 over NGL meters

By KRISTEN NELSON

Petroleum News

The Alaska Oil and Gas Conservation Commission has fined BP Exploration (Alaska) Inc. $20,000 for violating an August 2018 conditional approval of natural gas liquids custody transfer measurement equipment.

In an Oct. 30 order the commission said it issued a notice of proposed enforcement action to BP in July based on the company's "failure to submit required meter performance reports" for NGL custody transfer meters. The commission had proposed a $30,000 fine, reduced to $20,000 following a review.

Violations cited in the July proposed action concerned NGL sales to ConocoPhillips Alaska Inc.'s Kuparuk River unit. The proposed $30,000 fine included $15,000 for the initial violation of failure to provide a meter performance report and $15,000 for the initial violation of failure to provide notification for AOGCC witness as required.

The commission said the notice also proposed that BP "submit the required information and describe how it will prevent recurrence of this violation."

Violations cited in the July proposed action concerned NGL sales to ConocoPhillips Alaska Inc.'s Kuparuk River unit.

Custody transfer

The commission said custody transfer measurement equipment used for sale of Prudhoe NGL was conditionally approved by AOGCC in August 2018 with requirements including a monthly meter prove frequency notification to the commission to provide an opportunity to witness meter proves, "required actions before making changes to the custody transfer measurement equipment, and reporting following proves."

BP initiated sales of NGL to Kuparuk in September 2018 "and immediately encountered mechanical problems which prevented the use of meter proving equipment," the commission said. AOGCC approved continued sales based on an alternate means of demonstrating meter accuracy. On April 6 the commission was given verbal notice of the initial NGL meter prove which was witnessed April 7, with subsequent monthly meter proves in May, June and July.

But the commission's approval letter required that BP "provide information (table and graph) used to validate meter performance each month," as well as giving 24-hour notice to the commission for the opportunity to witness meter proves. BP did not provide notice of meter proves in May and June, and there were no meter performance reports submitted in April, May, June and July.

Mitigating circumstances

BP acknowledged receipt of the commission's notice of proposed action, requested an informal review "and provided the current meter factor control chart for the NGL custody transfer meter." BP asked clarifying questions at an informal review held in August, the commission said, and "provided an updated NGL custody transfer meter proving procedure, a BPXA organizational management-of-change, and an excerpt from BPXA's Compliance Task Management System showing key personnel responsibilities related to the NGL custody transfer meter."

The commission said mitigating circumstances it considered included BP's "lack of good faith in its attempts to

see NGL METERS page 4

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● EXPLORATION & PRODUCTION

Commission hears pool rules presentation

BlueCrest proposes Hansen pool rules, triggered by multiple spacing exceptions required for fishbone lateral well design at field

By KRISTEN NELSON
Petroleum News

In early June the Alaska Oil and Gas Conservation Commission said that in response to requests from BlueCrest Alaska Operating LLC for spacing exceptions at the Hansen H10 well and its fishbone lateral branches, a request which would result in 63 spacing exceptions, the commission was scheduling a public hearing to establish pool rules for development and operation of the Hansen oil pool at the Cosmopolitan unit.

BlueCrest, which has been producing from the Hansen oil pool since 2017, had not sought pool rules but had been operating under statewide AOGCC rules. The commission said it received 25 spacing exception requests from BlueCrest for the Hansen H10 well and its fishbone lateral branches June 7, and if the current request was granted, it would result in 63 spacing exceptions having been issued for the Hansen wells.

Oct. 10 hearing

A full hearing was not held until Oct. 10 — this summary of the hearing is from a transcript of the proceedings.

Commissioner Dan Seamount chaired the hearing, and as he explained in an overview of the proceedings, a hearing was scheduled for Aug. 13 and BlueCrest submitted an initial field and pool rules application Aug. 2. A hearing was begun on Aug. 13 but was continued because BlueCrest had not served notice to the Bureau of Ocean Energy Management. (There are federal tracts on the seaward side of the Cosmopolitan unit.)

The commission requested that BlueCrest refile its application and provide notice of service to BOEM, as well as providing answers to questions from the commissioners. BlueCrest refiled its application Aug. 30; on Oct. 2, BOEM notified the commission by letter that it had no objection to the proposed rules.

Andrew Buchanan for BlueCrest

Geologist Andrew Buchanan, vice president of BlueCrest Alaska, presented testimony for the company. The Cosmopolitan unit is 100% owned and operated by BlueCrest, he said, and consists of four state leases, 13,314 acres offshore, with 11 wells drilled and 20 sidetracks. (BlueCrest acquired Cosmopolitan from Buccaneer Energy in 2014 and began crude oil production in 2016, trucking the crude to the refinery in Nikiski.)

Buchanan said that since BlueCrest took over as operator it has drilled four wells and redrilled one well.

In describing the field's geology, he said one thing BlueCrest has noticed in its drilling is compartmentalization within the reservoir.

In response to a question from Seamount, Buchanan confirmed that the oil pool goes from the top of the Starichkof to the base of the Hemlock.

Development drilling is based on multilateral wells in what the company has described as a fishbone pattern — hence the need for the multiple spacing exceptions.

Buchanan said the company plans to do more appraisal in 2020, development reservoir management strategy and refine costs in 2021-22 and execute its development strategy in 2023-25.

The current development is by primary depletion using fishbone and extended reach drilling wells, and Buchanan said BlueCrest is looking at options for secondary recovery, probably gas injection for pressure maintenance. He said the facility would require upgrading to inject gas as the company doesn't currently have the compression needed — and, he said, BlueCrest would also have to find additional sources of natural gas.

Next well

Buchanan said the next producing well the company plans would require the 25 spacing exceptions — it would be three trident laterals off a single wellbore. That would about triple the reservoir penetrations, making well spacing one of the key rules the company is requesting, to waive well to well spacing restrictions within the field. BlueCrest does not plan, he said, to drill within 500 feet of a lease line so that is not an exception it is requesting.

In its pool rules application, submitted July 31, the company said: "By eliminating intra-pool spacing rules, BlueCrest will be able to target smaller, undrained portions of the pool that cannot be reached/contacted by wells conforming to current statewide spacing restrictions. … (helping) to maximize recovery from otherwise bypassed pay, while allowing for continued production from established development wells."

Another crucial request for the company is a three-week test duration for the blow out preventer test while the production section of a well is being drilled. The problem, Buchanan said, is that it takes a long time to get in and out of the hole — two days to get in and two to three days to back out.

He said BlueCrest has had instances where it had to come out of the hole prematurely to meet BOP operations when functional bits and tools were still in the hole.

There were two times when the company had to start coming out of the hole for BOP tests before the last lateral was drilled and it then was not economic to return to drill that last lateral, so the production from the last lateral was lost because the company won't be able to tap into that oil, Buchanan said.

Commissioner Jessie Chmielowski asked if that request related to the fishbone laterals only, not the parent well. Buchanan said, yes, the BOP exception would apply just to the production section, not to the surface or intermediate sections of the well.

In slides prepared for the presentation BlueCrest noted that its request for blowout preventer tests every 21 days, rather than every 14, is in line with what is required by the United Kingdom, the Netherlands, Denmark and Brazil, as well as by the rewrite of the U.S. Bureau of Safety and Environmental Enforcement well control rule for the outer continental shelf. ●

Contact Kristen Nelson at knelson@petroleumnews.com

EXPLORATION & PRODUCTION

US rig count continues to fall, down by 8

Baker Hughes reports the number of rigs drilling for oil and natural gas in the U.S. continued to fall the week ending Nov. 1, down by eight to 822, following a steep drop of 21 rigs the previous week.

In its weekly rig count the Houston oilfield services company said the active rig count was down 245 from 1,067 active rigs a year ago.

The company reported that 691 rigs targeted oil (down five from the previous week; down 183 from a year ago) and 130 targeted natural gas (down three from the previous week; down 63 from a year ago). There was one miscellaneous rig active (that count unchanged from the previous week and down one from a year ago).

The company said 53 of the U.S. holes were directional, 717 were horizontal and 52 were vertical.

Louisiana and Utah (with only five rigs active) were each up two from the previous week.

Rig counts in California, North Dakota, Ohio, West Virginia and Wyoming were unchanged.

Alaska and Colorado were each down by one rig.

New Mexico Pennsylvania and Texas (with the largest number of active rigs at 416) were each down two rigs from the previous week.

Oklahoma had the largest week over week drop, down three.

Baker Hughes shows Alaska with seven rigs active for the week ending Nov. 1, up from five a year ago.

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

—KRISTEN NELSON

● NATURAL GAS

Alberta natural gas market rallies

Startling price surge boosted by shrinking inventories, renewed investor interest; for many industry leaders too early to celebrate

By GARY PARK
For Petroleum News

From a desperate plight, Alberta's natural gas prices have made a sudden rebound since mid-September, skyrocketing by 420% in response to declining inventories and a bullish supply/demand balance entering the winter heating season.

The industry mood has been further bolstered by reports of interest from investors who have bypassed the Canadian gas sector over the past two years.

But the question is whether the signs of new life are merely fleeting or too late for many companies.

Andy Mah, chief executive officer of Advantage Oil and Gas, told the Financial Post he is not yet ready to proclaim a "180-degree shift in sentiment," despite seeing some "green shoots" linked to better access to natural gas storage facilities.

Gas prices have climbed by 77% in the first 10 months of 2019 to C$2.45 per thousand cubic feet, mcf, after starting the year at a dismal C$1.33 and often plunging below C$1 over that same period.

4 cents per mcf

Even so, the rally on commodity markets has lifted the spirits of producers who have slashed drilling plans, while allowing their output to fall since prices nosedived to a staggering 4 cents per mcf in May at the province's AECO trading hub.

Darren Gee, chief executive officer of Peyto Exploration and Development, said the turnaround has generated hope among some producers, who now feel that they can again compete with their rivals in the United States as the price gap has closed on Henry Hub North American benchmark levels in Louisiana.

He said AECO storage levels have been "dangerously low" and could be drawn down when it comes time to replenish them next summer.

Combined with an expanded storage system in 2021 there is a strong likelihood that "AECO will be a fair market again," Gee said.

The Alberta sector is entering the withdrawal season which starts in November with storage levels 27% below the five-year average, according to analysts at AltaCapital Corp.

However, despite strengthening fundamentals, AltaCapital is sticking with its forecast average AECO price of C$1.70 through the next five months.

New gas pipeline

Optimism gained a further lift on Oct. 18 when Alberta Premier Jason Kenney launched a new gas pipeline in central Alberta.

Calgary-based TransAlta celebrated the opening of its Pioneer Pipeline which is a key element of the utility company's conversion of its coal-fired power-generations plant to natural gas.

Pioneer's initial capacity of 130 million cubic feet per day is expected to reach 440 million cubic feet per day, which Kenney said will reduce greenhouse gas emissions in Alberta's power production by 50%.

"This is a good day for Alberta jobs, a good day for diversifying our economy and it's a good day for the environment," he said.

Kenney also took a swipe at climate activists, noting they are "opposed to natural gas ... opposed to zero-emitting nuclear power ... opposed to technological solutions ... opposed to the entire modern industrial economy. Their manifesto essentially calls for shutting down our entire economy. That is not a real solution."

TransAlta Chief Executive Officer Dawn Farrell said her company's plan to convert five of its plants to gas-powered generation will service Albertans for 25 to 50 years, creating time for the introduction of even more renewable.

Help too late

However, even if help is on the way it will likely be too late for a company such as mid-size producer Bellatrix Exploration, which has put itself on the sales block after filing for creditor protection after failing to reduce debt and improve liquidity.

Once worth more than C$2 billion, the company now has a market value of just C$15.5 million, while carrying a debt of C$357 million.

Bellatrix warned in its second quarter report its ability to continue as a going concern was in doubt and gave no guarantee it will complete a rescue transaction "given the level of secured debt obligations of the company."

Tristan Goodman, president of the Explorers and Producers Association of Canada, said that although there are "some signs of hope," additional bankruptcies and insolvencies in the gas industry "are a possibility." ●

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EXPLORATION & PRODUCTION

Qugruk 7 well data set for release

The Alaska Department of Natural Resources Division of Oil and Gas issued a public notice Nov. 1 announcing the future release of exploration data and information within 30 days for Repsol E&P USA Inc.'s Qugruk 7 exploration well.

The well was spud in February 2014 and plugged and abandoned in April of that year. The measured depth was 7,176 feet; the true vertical depth was 6,808 feet. The well is in what is now the Pikka unit at section 17, township 12 north, range 6 east, Umiat meridian.

—PETROLEUM NEWS

continued from page 2

NGL METERS

comply with the imposed conditions and need to deter similar behavior," and failure to submit information related to meter performance; the fact that there was "nothing different required in the conditions of approval and nothing ambiguous about the approval conditions requiring submittal of meter prove results"; and absence of equipment performance tracking equipment which compromised "the ability of AOGCC to make informed, fact-based decisions about how frequently to witness meter proves."

The commission said BP did submit information identified as missing and demonstrated acceptable meter performance. There was no injury to the public. AOGCC said it "has significantly reduced the penalty by not involving per-day or per-month assessments for the violations."

The commission reduced the civil penalty to $20,000 due within 30 days if BP chooses not to appeal the order. ●

Contact Kristen Nelson at knelson@petroleumnews.com

ENVIRONMENT & SAFETY

PWSRCAC questions oil spill regs review

Organization worries whether any changes to statutes and regulations may erode high standard of oil spill preparedness in Alaska

By ALAN BAILEY
For Petroleum News

The Prince William Sound Regional Citizens' Advisory Council has expressed concern about a notice of a 90-day public scoping period, announced on Oct. 15 by the Alaska Department of Environmental Conservation. DEC wants to gather ideas for potential changes to Alaska oil spill response regulations and statutes. The agency said that it wants members of the public to suggest "whether the current regulations could be made more clear and understandable without compromising environmental protection or if any portions may be outdated or duplicative."

PWSRCAC worries that the outcome of the review may be a diminution of the high standard of oil spill preparedness in Alaska. The council was formed in the wake of the Exxon Valdez oil spill disaster in 1989, to provide a forum for citizens to offer advice and input for the safe carriage of oil from the Valdez Marine Terminal.

Resolution passed

On Oct. 29 the council passed a resolution expressing strong opposition to any legislative or regulatory changes "that erode oil spill prevention and response standards, increase the risk of a catastrophic oil spill, or demonstrate a return of the complacency on the part of the oil industry and regulators that Congress determined to be a primary cause of the Exxon Valdez oil spill."

In a Nov. 4 press release the council said it is concerned that the regulatory reform initiative lacks specificity and transparency. The public scoping process should be halted until DEC clarifies the driving factors behind the initiative, PWSRCAC said.

"Strong statutes and regulations are a big part of why Alaska has not had a major oil spill since the Exxon Valdez disaster," said Donna Schantz, PWSRCAC executive director. "The world-class oil spill prevention and response system for the Valdez Marine Terminal and associated oil tankers is a direct result of post-Exxon Valdez spill laws and regulations designed to protect Alaskans and our environment, as well as commercial and sport fishing, aquaculture, recreation, tourism, subsistence and cultural interests."

Years of hard work

The current oil spill response framework, established by law and progressively enhanced, is the result of "years of hard work, critical thinking and creative problem solving by a group of experienced professionals and passionate stakeholders," the council said.

Robert Archibald, president of the PWSRCAC board, said that the protection of communities and the environment from oil spill hazards is a cost of doing business in Alaska and is not burdensome.

"Reducing any perceived burden to industry by rolling back or eliminating proven oil spill prevention and response requirements transfers the risk and burden of another oil spill to the communities, citizens and environment they were designed to protect," Archibald said. "This initiative disregards the efforts of hundreds of Alaskans who worked tirelessly on improving regulatory requirements after the Exxon Valdez oil spill to ensure that our state would never again suffer a similar environmental disaster."

The council encouraged the public to voice strong opposition to any legislative or regulatory changes that would erode oil spill prevention and response standards. And if changes are proposed, the public should insist that DEC provides a longer public comment period for the changes than the statutory 30 days, the council recommended.

Brune: DEC in listening mode

Jason Brune, DEC commissioner, told Petroleum News on Nov. 6, that the intent of the scoping period is to gather comments from the general public, industry and environmental groups on whether laws and regulations put in place 30 years ago are still appropriate, and whether everything is fully up to date. DEC would also welcome suggestions on any useful additions to regulations, based on experience with the operation of oil spill contingency plans, he said.

While not strictly necessary, the scoping process will enable DEC to decide on whether any changes are advisable. And all comments received are being published publicly, thus making the process transparent and open, Brune said.

"This is an extra step that we're taking to listen," Brune said. "We're in listening mode."

If DEC does determine that changes to the regulations are warranted, there would be a separate process for making the changes, including an opportunity for public comment on any change proposals. Recommended changes to statutes would need to be passed by the Legislature and signed by the governor.

"We have a mission at DEC to protect human health and the environment," Brune said. "We do not plan on gutting any of the requirements that ensure that we are adequately prepared for another major incident." ●

Contact Alan Bailey at abailey@petroleumnews.com

GOVERNMENT

AOGCC proposes repeal of outdated regs

The Alaska Oil and Gas Conservation Commission has published a notice of repeal of regulations which it describes as "outdated, unnecessary or duplicative." A more detailed description is available on the agency's website: www.commerce.alaska.gov/web/aogcc/Home.aspx.

The notice is dated Nov. 1. A hearing on the proposed changes will be held Dec. 10 beginning at 10 a.m. at the commission's Anchorage offices; comments will be accepted until 4:30 p.m. Dec. 10, after which the commission said it may adopt the proposed regulatory changes or other provisions dealing with the same subject.

One of the regulations requires testing of gas wells by a multi-point back-pressure method before regular production with test results and calculations reported to the commission on a specified form within 30 days. The commission said the requirement is outdated because it does not use the reports in any decision-making capacity, so eliminating the requirement for the report "and only requiring the operator submit a test report, in whatever format they normally receive them, if they close to conduct one, would remove an unnecessary testing and reporting burden from the operator."

Another regulation proposed for repeal concerns well control requirements and would be eliminated because it "is unnecessary and duplicative as it is covered adequately in other sections."

A regulation on reserve pits and tankage "is outdated and outside the authority of AOGCC and is more substantively covered by ADEC regulations," the commission said. The Alaska Department of Environmental Conservation regulates storage of drilling waste, drilling waste monofills and closure of inactive reserve pits, and the commission said ADEC has confirmed that it does not refer to AOGCC's regulations. ADEC regulations require that storage plans be submitted to ADEC in advance of operations and that storage may not begin until the plan is approved by ADEC.

A regulation covering common production facilities is redundant because of other commission requirements for custody transfer measurement and allocation measurement, and can be eliminated completely, the commission said.

A regulation prohibiting production or transportation of crude oil or natural gas in violation of regulations and orders of the commission "is extremely vague and overly board," and AOGCC said it has greater flexibility through emergency actions and through robust enforcement.

A regulation for emergency open pit storage of oil is being repealed, the commission said, as no statute applying to AOGCC gives it authority for the regulation. "ADEC would be the more appropriate agency of jurisdiction," the commission said.

Finally, a regulation requiring original signatures "is unnecessary and can be better handled by a guidance document."

—PETROLEUM NEWS

● HISTORY

Phillips, Marathon began shipping LNG in 1969

Part 1 of 2: The story of one of Alaska's first big projects, the Kenai LNG facility and terminal, the only US LNG facility to export to Japan

By KAY CASHMAN
Petroleum News

In November 1969, Phillips Petroleum, predecessor to ConocoPhillips, and its partner Marathon Petroleum commenced liquefied natural gas shipments to Japan. The Kenai LNG terminal in Nikiski, which began producing LNG in June of that year, was the only LNG export facility in the United States, and the first source of LNG to Japanese markets. Phillips, 70%, was the facility operator and Marathon, 30%, operated the LNG tankers.

The LNG facility and terminal were approximately 60 air miles from Anchorage and 10 miles from the city of Kenai on Alaska's Kenai Peninsula.

The move to export LNG was spurred by the 1959 discovery of the Kenai gas field by Union Oil Company of California in a 50-50 partnership with Ohio Oil Co., which in 1962 changed its name to Marathon Oil and is today called Marathon Petroleum.

It wasn't the first major discovery in Alaska, but the Kenai gas field changed the face of resource extraction in Southcentral Alaska, forcing companies to consider natural gas as a viable alternative to crude oil even though profits from gas were much lower and revenues to the state several orders of magnitude smaller. Still, natural gas soon became a significant part of Southcentral Alaska's economy.

FILE PHOTO

The LNG export operations included two specially designed tankers, one of which is shown above. The 799-foot ships were the Arctic Tokyo and Polar Alaska and were built in Sweden.

With more than 2.4 trillion cubic feet in recoverable reserves and the purity of its gas at 99% methane, the Kenai gas field could not be ignored.

Phillips' 1962 discovery of the North Cook Inlet gas field in the northern waters of Cook Inlet became a major contributor of natural gas to the Kenai LNG facility.

There were several other natural gas discoveries in the region, some as part of oil fields, and others that held primarily gas. Most of the onshore and offshore oil and gas discoveries in the Cook Inlet geological basin were made by what are today Marathon, ConocoPhillips and Chevron (then Union Oil of California).

In addition to the Kenai gas field and the North Cook Inlet field, the early gas fields included the 1961 Sterling gas field, the 1962 Beluga River gas field and the 1967 Beaver Creek gas field.

In 1963, Cook Inlet basin natural gas became the major fuel source for power generation to Southcentral Alaska communities.

And in 1968, the largest fertilizer plant on the West Coast opened in Nikiski using Cook Inlet gas as its primary feedstock.

Like oil, natural gas could be transported over long distances in pipelines. However, unlike oil, which is liquid at ambient temperature, gas is difficult to ship by sea. It can be chilled to extremely cold temperatures (minus 259 Fahrenheit/minus 161 Celsius), to become a liquid. In its chilled state, gas was 600 times denser. LNG could be transported on large marine vessels to markets, where it was re-gasified and used as conventional natural gas.

That said, liquefaction was a costly process, so the cost of the raw gas had to be low.

Huge for Phillips

Though it would soon be surpassed by Phillips' North Sea developments, the Kenai liquefaction project was the largest single expenditure Phillips had undertaken up to 1966, when design began.

The project demanded more than the $200 million in initial costs, a lot of engineering ingenuity and international cooperation, plant manager Paul Hammaker recalled in 1985, per a story in The Oklahoman.

"The main advantage of liquefying gas," Kenai plant engineer Tony Canfield told The Oklahoman in 1985, "is you can transport it in large volumes in areas where there is no pipeline network. … We couldn't build a pipeline from Kenai to Japan."

The Kenai LNG facility was designed by Phillips. The company's proprietary Optimized Cascade process was first created and then proven in the Kenai facility.

The cryogenic technology chilled the gas, shrinking it to less than one-600th of its original volume, making long distance shipping feasible.

As an aside, development of commercial quantities of LNG began in 1964, when Great Britain began importing the liquid from Algeria using a different liquefication technology.

Awash in natural gas

Natural gas production from the Kenai gas field ramped up slowly in the first few years, increasing to nearly 6 billion cubic feet in 1965 from around 200 million cubic feet in 1961.

In 1966, production jumped to more than 33 billion cubic feet and continued to grow rapidly in the years that followed.

Faced with more natural gas than they knew what to do with because there was little local demand for gas, Marathon began looking for alternative markets.

The company decided to use its share of the field on a new venture to ship Alaska natural gas to overseas markets, partnering with Phillips to build the facility and terminal near Nikiski.

They found Tokyo Gas Co. and Tokyo Electric Power Co., which wanted to switch from coal to cleaner LNG as a means of supplying growing energy needs while helping to reduce Japan's air pollution.

Phillips signed a sales agreement with the two utilities in March 1967 and embarked on an effort to get the gas out of the ground and to a processing facility, with Marathon responsible for transporting the product to the buyers.

Their plan called for several design and construction projects, including:

• A gas liquefaction plant with its own deepwater docking and loading terminal.

• The two largest LNG tanker ships ever built, each capable of carrying extremely cold LNG.

• The first LNG receiving and re-gasification facility in Asia, near Tokyo (constructed and paid for by the Japanese buyers).

• An offshore platform and production facility to be installed in upper Cook Inlet.

• Additional wells in the upper Cook Inlet and Kenai gas fields.

• Underwater, overland and underground pipelines to transport gas from the

see KENAI LNG page 7

EAGLE EYE HELICOPTERS

This photo is from a 2006 Petroleum News article: ConocoPhillips (70%) and Marathon (30%) own the Kenai LNG terminal at Nikiski. At the time, ConocoPhillips was the facility operator and Marathon operated the LNG tankers.

● GOVERNMENT

Alberta shuffles deck

Close to deal to return C$3.7B in crude-by-rail contracts to railways; scraps some grants, petrochemical venture loan guarantees

By GARY PARK
For Petroleum News

The five-month tap-dance by the new Alberta government to rearrange its petroleum industry holdings is gathering pace as the administration of Premier Jason Kenney scales back diversification programs to attract petrochemical projects and draws closer to off-loading a crude-by-rail, CBR, investment.

Leading the announcements, Energy Minister Sonya Savage said the government will scrap grants and loan guarantees for upgrading (which converts oil sands bitumen into synthetic crude for refining) and a petrochemical feedstock infrastructure program that was introduced by the former New Democratic Party administration.

She also said Alberta is within sight of selling a C$3.7 billion agreement with Canadian National and Canadian Pacific railways to buy tanker cars which would move 120,000 barrels per day to overcome a shortage of pipeline capacity.

The NDP government said the program would generate revenue of C$6 billion, an estimate Kenney scorned, arguing the financial risks were too high.

Savage said the negotiations are taking time because of the number and complexity of the contracts, but "we're getting there."

Production quotas key

TD Securities said a key point in the negotiations is retaining a provision that allows companies to exceed their production quotas as long as the additional volumes leave Alberta.

The investment firm forecast oil production growth of 8% to 30% in 2020 if a deal is reached.

So far, the government has earmarked C$1.5 billion for backing out of the program, although Finance Minister Travis Toews hopes the final figure will be in the range of C$800 million to C$900 million.

In the first seven months of 2019 propane prices at Edmonton averaged US$10.31 per barrel compared with US$25 in Texas and US$36.78 in the Far East, according to industry sources.

The 2019-20 Alberta budget estimated the CBR deal would cost taxpayers C$1.8 billion more than the cost of scrapping it.

On the petrochemical front, Savage confirmed the government has scrapped two government-backed programs in the name of fiscal responsibility, while sticking with a C$1.2 billion petrochemicals diversification venture.

She said the two programs offering financial backing to feedstock and infrastructure plans that have been discontinued "carried a high financial risk to our province ... we want to ensure that the innovation and development that industry can bring to the province is prudent and benefits Albertans and investors."

Royalty credits to continue

But for now, the government will continue offering royalty credits to privately funded large-scale projects that build facilities to turn ethane, methane and propane into products such as plastics, fabrics and fertilizers.

To date, two projects — one from Inter Pipeline and one from Nauticol Energy — have been awarded a combined C$150 million in credits, leaving C$950 million still available.

Associate Minister of Natural Gas Dale Nally said his department will continue gathering industry input and recommended potential changes to the diversification program to determine how Alberta can best attract private industry.

In a separate recent report, the Canadian Energy Research Institute found that new petrochemical plants in Alberta are economically competitive with new facilities in the U.S. Gulf Coast, Ontario and Korea.

It said total feedstock supply costs in Alberta are reduced by access to a surplus of natural gas in Western Canada, although the report did not cover corporate or carbon tax policy changes enacted by the Kenney government.

In the first seven months of 2019 propane prices at Edmonton averaged US$10.31 per barrel compared with US$25 in Texas and US$36.78 in the Far East, according to industry sources. ●

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KENAI LNG

fields to the liquefaction plant.

The first Cook Inlet production platform, the Tyonek, was fabricated in Japan and completed on location. It began operation in late 1968. While it was being installed, work progressed on the Upper Cook Inlet pipeline, which ran 13 miles underwater, then 30 miles south along the shore of Cook Inlet to the LNG plant.

Tokyo Gas built the LNG receiving and re-gasification terminal at Negishi, part of the giant Yokohama port complex, just south of Tokyo.

The two specially designed, 799-foot tankers, Arctic Tokyo and Polar Alaska, were built in Sweden. The loading process took about 18 hours and each ship first left for the 3,300 nautical mile trip to Japan with 555,000 barrels of LNG., arriving and unloading in November 1969. The Polar Alaska was the first to unload. ●

Editor's note: See the rest of the story in next week's edition of Petroleum News.

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AOGCC HEARINGS

Alaska, to pick up the cost for plugging and abandonment.

The commission notified companies with permitted wellheads in July, laying out the additional amounts required to bring bonding up to the new requirements which are based on the number of permitted wellheads: $400,000 per well for one to 10 wells; $6 million for 11-40 wells; $10 million for 41-100 wells; $20 million for 101-1,000 wells; and $30 million for more than 1,000 wells.

Formal appeals of the commission's new bonding, with requests for reconsideration, have come from smaller companies, two of which, Alaskan Crude and Malamute Energy, have permitted wellheads but no production.

Consolidation request

Glacier Oil and Gas, which has two subsidiaries operating in the state, is requesting consolidation of the bonds for those subsidiaries, Savant and Cook Inlet Energy.

The company's attorney, Elena M. Romerdahl of Perkins Coie LLP, said in an Aug. 2 request, that in addition to the July 25 separate requests for reconsideration of the bonding amounts the companies are requesting that the commission "allow Glacier to provide a single consolidated bond to satisfy the bonding obligations" of its two subsidiaries.

After a company exceeds 10 wellheads, Romerdahl noted, the per well bond "generally decreases as the number of permitted wellheads increases," with 1,000 permitted wellheads costing an operator $20,000 in bonding per well, "while an operator with 11 permitted wellheads is required to provide $545,454 in bonding per well", the maximum amount per well under the new regulations.

Collectively Savant and Cook Inlet Energy are responsible for 31 permitted wellheads (Savant five and CIE 26).

Individually, Savant would be required to provide bonding of $2 million (five wells at $400,000 each) and CIE $6 million. If a single bond could cover both subsidiaries the bonding required would be $6 million.

"The disparity in the amount of bonding required per wellhead under the Commission's amended regulation benefits large operators and penalizes small operators like Savant and CIE," Romerdahl said.

Savant Alaska

The first of this group of hearings is for Savant Alaska LLC and will be held at 10 a.m. Feb. 12 (all hearings are in the commission's Anchorage offices), with written comments accepted through the end of the hearing.

Attorney Elena M. Romerdahl of Perkins Coie LLC, representing Savant, said in a July 25 request for reconsideration that while the commission's letter on bonding identifies 12 permitted wells at the Badami unit, BP Exploration (Alaska) Inc.'s purchase and sale agreement for Badami states that BP as former Badami unit owner and owner of overriding royalty interests in Badami leases "agreed to retain DR&R obligations for all existing wells at the Badami Unit except wells B1-18A, B1-21, B1-36, and B1-38 and any wells that Savant or AEX (ASRC Exploration LLC) later modified or re-entered."

There were 11 Badami wells when the purchase and sale agreement was executed in 2011, Romerdahl told the commission, and Savant has re-entered two wells, B1-18A and B1-38. "Savant has not and does not plan to re-enter any of the other original Badami Unit wells," and pursuant to the PSA, "is therefore only responsible for the DR&R obligations, including plugging and abandonment, of 4 of the original Badami Unit wells: B1-18A, B1-21, B1-36, and B1-38."

Savant drilled B1-07 and is responsible for DR&R obligations for that wells, making it responsible for a total of five Badami wells.

Savant has a Badami DR&R agreement with the Alaska Department of Natural Resources "under which DNR obtained $1,375,000 to cover the DR&R obligations of Savant and its working interest partners at the Badami Unit, including plugging and abandonment of the 5 Badami Unit wells for which Savant is responsible." Romerdahl said on July 2 then-acting Director Jim Beckham of DNR's Division of Oil and Gas confirmed in a letter to Savant "that from DNR's perspective the DR&R Agreement covers all of Savant's DR&R obligations at the Badami Unit, including plugging and abandonment of the Badami wells for which Savant is responsible."

On July 22 Savant requested that DNR agree to terminate the Badami DR&R agreement and release funds held by DNR under that agreement. If DNR agrees, "Savant will immediately notify the AOGCC and transfer the amount currently held by DNR under the Badami DR&R Agreement to the AOGCC in satisfaction of the bonding requirements" under the commission's revised regulations.

Savant argues that with the $200,000 existing bond and the $1.375 million in bonds and pledged security with DNR, and five wells at Badami, Savant should only be required to post an additional $425,000 in bonds with AOGCC.

Cook Inlet Energy

The Cook Inlet Energy hearing is set for 11 a.m. Feb. 12, with written comments acceptable through the end of the hearing. The company's counsel, Elena M. Romerdahl of Perkins Coie, in an Aug. 2 letter requested consolidation of bonding for CIE and Savant, both of which are Glacier Oil and Gas subsidiaries.

In a July 25 letter addressing the CIE bonding amount, she said the commission's letter on CIE's bonding confirmed that the company has 26 permitted wellheads and would be required to establish a $6 million bond. The commission's letter sets out a schedule of payments by CIE to bring its current $200,000 bond with the commission up to the $6 million letter.

Romerdahl said the commission's letter does not acknowledge that in addition to the $200,000 bond with AOGCC, CIE also has a $500,000 bond with the Alaska Department of Natural Resources "that covers plugging and abandonment of CIE's 26 permitted wellheads" and a $324,000 bond with the U.S. Environmental Protection Agency "for plugging and abandonment of the WMRU 4D and Redoubt-D1 disposal wells."

She said CIE is not requesting a reduction in the amount of the bond but is requesting that the commission "acknowledge the additional $824,000 in bonds CIE currently has in place with DNR and the EPA" and reduce the AOGCC bonding by that amount, to $4,976,000.

AIX Energy

AOGCC has set a hearing for a request for reconsideration of bonding amounts by AIX Energy for Feb. 13 at 10 a.m. at the commission's Anchorage offices. Written comments will be accepted through the end of the hearing.

AIX LLC has four permitted wellheads and the commission is requiring the company to establish a $1.6 million bond. AIX currently has a $200,000 bond with the commission.

Elena M. Romerdahl of Perkins Coie, attorney for AIX, said in an Aug. 7 letter requesting recalculation of the company's bonding obligations that in addition to the $200,000 bond with AOGCC, AIX also has a $500,000 statewide bond with the Alaska Department of Natural Resources and $950,000 in financial security for the benefit of the Alaska Mental Health Trust Office to satisfy DR&R obligations on its four permitted wells, a total of $1,650,000.

In addition to the bonding and financial security in place with state entities, Romerdahl said that the Mental Health Trust "as landowner would be required to satisfy any DR&R obligations that AIX failed to complete."

She noted that based on actions the commission took related to the Northern Dancer 1 well in 2018, "the Commission can and would look to MHT as landowner for AIX's leases to complete plugging and abandonment of AIX's 4 wells if AIX failed to satisfy its DR&R obligations under those leases."

The bonding and financial security AIX has in place with the state exceed the estimated cost to remediate the four wells, Romerdahl said, and MHT's landowner status provides further assurance that DR&R obligations for the wells would be fully satisfied.

AIX also wrote the commission July 18, requesting reconsideration of the bonding amounts based on an independent engineering estimate which concluded that plugging and abandoning the permitted wells would cost $1,037,166, $562,834 less than the amount required under the commission's revised bonding regulations.

Romerdahl said the commission had granted reconsideration based on the July 18 letter, but said whether the commission grants the July 18 request to reduce the amount, "AIX requests that the Commission acknowledge the bonding and financial security currently in place" with the state for the four wells and additional assurance provided by MHT's landowner status. ●

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FURIE BANKRUPTCY

to debtor Cornucopia Oil & Gas Company, LLC to the extent permitted by Alaska Statute 43.55.023 or other applicable nonbankruptcy law and in accordance with Bankruptcy Code section 553."

Cornucopia, along with Corsair Oil & Gas LLC, is an affiliated debtor in the Furie bankruptcy.

Deutsche Oel & Gas S.A. of Luxembourg — according to its website — "operates the oil and gas business in the (United States) through Cornucopia Oil & Gas Company, LLC and Furie Operating Alaska, LLC — the operating company for Cornucopia, both headquartered in Anchorage, Alaska."

Deutsche Oel is not a debtor in the Furie case; it describes itself as "the holding company of a group of companies currently focused on the exploration and production of natural gas and crude oil in the Cook Inlet Basin in Alaska."

Full force and affect

Except as modified by the order, the automatic stay in the cases will otherwise remain in full force and effect.

"Notwithstanding the relief granted in this order and any actions taken pursuant to such relief," nothing in the order "shall be deemed an admission as to the validity of any claimed right of setoff against the debtors; a waiver of the debtors' right to dispute any claim on any grounds; a promise or requirement to pay any claim; a waiver of the debtors' rights under the Bankruptcy Code or any other applicable law; to alter any rights or obligations under the Prepetition Loan documents or the DIP documents as defined in the DIP Order; or to create any rights in favor of, or enhance or change the status of, any claim held by any person or entity."

Also, under the order, the 14-day stay of bankruptcy rule was waived, making the order immediately effective and enforceable upon entry.

Administrative, judicial appeals authorized

The Alaska Department of Revenue Tax Division, in its motion filed Sept. 11, sought authorization for administrative and judicial appeals of its determination that the state overpaid Cornucopia's production tax credits. DOR noted in the filing that Cornucopia filed an administrative appeal of that determination on Aug. 29.

DOR said Cornucopia has approximately $105 million in pre-petition production tax credits issued by the state, which can be assigned under state statutes for purposes of security. Of the $105 million, approximately $4 million are unassigned.

"The unassigned tax credits are more than sufficient to eliminate Cornucopia's 2014 overpaid tax credit liability," DOR said.

The Bankruptcy Code preserves the right of setoff, DOR said, adding, "The requirements for exercising the right of setoff are that the offsetting debts must be mutual, prepetition debts."

"Here, the debts are mutually owed between the State of Alaska and Cornucopia Oil and Gas, LLC, and both debts are prepetition in nature," DOR said. "Therefore, the requirements for offset are met."

The Section 362 automatic stay prohibits the "commencement or continuation … of a judicial, administrative or other action or proceeding against the debtor" concerning a pre-petition claim, DOR said.

"Although the administrative appeal itself, initiated by Cornucopia, may not violate the automatic stay, continuation of that appeal may require the stay to be lifted so that the administrative appeal, and any subsequent judicial appeals, may proceed," DOR said, adding that cause exists to lift the stay for this purpose because the administrative appeal was initiated by Cornucopia itself, and because it is in the interests of both Cornucopia and the state that the parties' respective rights be determined.

Once the amount of the state's over payment has been determined, cause exists to lift the stay to permit offset of any such overpayments by the state against unassigned tax credits otherwise due Cornucopia, because there are mutually offsetting debts, and because the state lacks adequate protection for payment in this liquidating Chapter 11, DOR said.

"If the state does not offset the unassigned credits against the overpayment of credits, the state will likely receive little, if any, payment on the taxes due," it said.

DOR said that to the extent the tax credit is considered property under Section 362, the tax credits are not necessary to achieve an effective reorganization because this is a liquidating bankruptcy.

DOR argued further that cause for relief from stay also exists in order to facilitate the resolution of the case.

"One of debtors' first-day motions was a motion to

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Petroleum news Oil Patch Bits

Fluor awarded engineering services agreement

Fluor Corp. said Oct. 31 that its consortium with the Branch of KMG Engineering LLP KazNIPImunaigas was awarded a three-year engineering services agreement, plus two potential one-year extensions, by Karachaganak Petroleum Operating B.V. for projects at its Karachaganak Field in Kazakhstan. Fluor booked the undisclosed contract value in the third quarter of 2019.

"This important award will allow Fluor to build a long-term relationship with KPO and to expand our capabilities and presence in Kazakhstan," said Mark Fields, group president of Fluor's energy and chemicals business. "Our involvement in the early stages of the project means we can work with KPO across a range of work to optimize the Karachaganak field with a focus on achieving an outstanding safety performance and operational excellence."

Fluor's scope of work includes feasibility studies, front-end engineering design and other engineering services. Fluor plans to open an office in Aksai for dedicated project personnel with scalable accommodation to meet all engineering requirements. An engineering team in Fluor's Farnborough, United Kingdom, office as well as global subject matter experts will also support project needs.

To the maximum extent possible, Fluor will leverage local engineering talent to execute its scope of work. Fluor will also provide training and knowledge transfer to increase local talent on the project during execution as project needs dictate.

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RDC CONFERENCE

during the first day of the conference include:

10: 30 a.m. — Far from tapped out, North Slope reemergence, by Scott Jepsen, senior vice president of ConocoPhillips Alaska.

Noon/Lunch — Transitions, the new North Slope, by keynote speaker Rex Rock, president and CEO of Arctic Slope Regional Corp.

1:30 p.m. — Four presentations, starting with an energy outlook through 2040, by David Khemakhem, energy and technology advisor, corporate strategic planning, Exxon Mobil Corp. and Darlene Gates, president, Exxon Mobil Alaska; Tribal governments and lands in trust in Alaska, by Tara Sweeney, assistant secretary, Indian Affairs, U.S. Department of the Interior; Burning fossil fuels cleaner in an era of climate change, by Dr. Brian Anderson, National Energy Technology Laboratory, U.S. Department of Energy; and Cook Inlet oil and gas development, the long view, by Benjamin Johnson, president and CEO of BlueCrest Energy.

3:30 p.m. — Two presentations, starting with Investment at risk again? Another oil and gas tax initiative (speaker information forthcoming); and Passing the torch on the North Slope, by Janet Weiss, president of BP Alaska and David Wilkins, Hilcorp's senior vice president for Alaska.

Presentations of special interest to the oil and gas industry during the second day of the conference include:

8:30 a.m. — Three presentations, The Alberta to Alaska railway, connection to the global marketplace, by Sean McCoshen, chairman and founder of A2A Rail; The new Alaska LNG export project, by Mead Treadwell, CEO of Qilak LNG; U.S. Ocean policy, past present and future, by Brent Greenfield, executive director of National Ocean Policy Coalition.

10:30 a.m. — We have the rocks and resources, how do we make Alaska's oil and mining renaissance a reality by Peter Caltagirone, senior legal and policy advisor, Department of Natural Resources.

Noon/Lunch — Two presentations, Pan Arctic business and the way forward, by Anu Fredrikson, Arctic Economic Council, followed by Development in the Arctic, by Lance Miller, vice president of natural resources for NANA Regional Corp.

1:30 p.m. — Two presentations, Comparing the ocean economies and development potential of Alaska and Norway, by Andreas Raspotnik of Nord University and the Arctic Institute; and the Alaska roadless rulemaking process, by Chad Vanormer, director of ecosystem, planning and budget, Alaska roadless rulemaking team, U.S. Forest Service and Robert Venables, executive director, Southeast Conference.

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MUSTANG ONLINE

capacity," Jourabchi said.

"Work on the field is a continuing and in the next couple of months we hope to achieve more milestones," he added.

"Work on the field is a continuing and in the next couple of months we hope to achieve more milestones." —Majid Jourabchi

Early production planned

BRPC drilled the Mustang discovery well, North Tarn 1A, in January 2012, and confirmed it at the Mustang 1.

Mustang, the first development in the Southern Miluveach unit, or SMU, is adjacent to the southwest edge of the Kuparuk River unit.

BRPC had planned to start the field using a permanent 15,000 barrel-per-day production facility. Following the oil price crash, the company put the project into "warm standby" before coming up with the plan to install the modestly priced EPF.

The idea was to ramp production up to 6,000 barrels per day and use the revenue to upgrade the production facilities to a larger scale, BRPC said in its Sept. 30 filing of the seventh annual plan of development for the SMU with Alaska's Division of Oil and Gas.

Initial production, BRPC said, will be from two existing wells — North Tarn 1A and SMU M-02. Mustang 1A will be next but the suspended well "requires drilling lateral extension/possible sidetrack," which will occur in January, BRPC said.

In the plan of development, or POD, the company said up to four new wells will be drilled in 2020 — one per quarter.

Full development plans

Longer range proposed development activities are as follows:

- Central processing facilities with a capacity to handle 15,000 bpd, 15 million standard cubic feet per day of gas, and 7,500 barrels of water per day.
- Drill site facilities.
- Non-process infrastructure including buildings and equipment.
- Up to 10 production wells and 11 injection wells.

Other activities for the first year and beyond included completion of the initial gas compression and water injection capabilities of the EPF that might continue into 2020, planning focused on bringing the modules built for the Mustang operations center, or MOC, to the North Slope during 2020, transporting and integrating MOC 1 in first quarter 2021, planning for integration and substitution of the temporary EPF with the permanent MOC process modules.

In addition to the four wells drilled in 2020, toward the end of that year and through third quarter 2021, six producer and seven injector wells will be drilled.

Kuparuk sands, EOR

Regarding plans for SMU acreage not in a participating area, BRPC continues to review all potential targets, including but not limited to the Kuparuk C and A sands, which are part of the Kuparuk oil pool, a continuation of the Kuparuk sands from the Kuparuk River unit.

In June, the Alaska Oil and Gas Conservation Commission approved an application from BRPC to inject fluids at Mustang for pressure maintenance and enhanced recovery from the Kuparuk oil pool within the SMU.

Waterflood is planned first, followed eventually by lean or miscible gas flood.

Water will be produced water from the field and seawater from the ConocoPhillips seawater pipeline, with gas from Mustang.

Per AOGCC, anticipated peak daily injection rates for individual wells would be 6,000 barrels of water and 6 million standard cubic feet of gas.

Water and water-alternating-gas injection into the Kuparuk River oil pool "will provide a substantial EOR benefit over primary recovery alone" and maximize ultimate recovery, as well as prevent waste.

BRPC told AOGCC that audited Kuparuk reserves are 21.2 million barrels of 1P (proven oil in place).

Presentation materials at an AOGCC hearing showed 2P at 32.8 million barrels 2P (probable) and 3P at 38.3 million barrels (possible) and showed primary recovery as estimated at 10-15% of original oil in place with waterflood adding 10-25%, for a total recovery after waterflood of up to 35%.

BRPC cited an average estimated recovery rate of 30% with waterflood, expected to rise to 40% with tertiary recovery.

Bringing in partners

When BRPC announced the Mustang discovery in 2012, it needed help to bring the field into production, which arrived in mid-2014, when JK E&P Group Pte. Ltd., Thyssen Petroleum North Slope Development LLC and MEP Alaska LLC acquired BRPC and a package of North Slope properties from Alaska Venture Capital Group and Ramshorn Investments Inc. for $450 million.

Additional help came from AIDEA, which partly financed two infrastructure ventures at the unit in return for an interest in unit leases.

Today, the five-lease, 8,960-acre SMU working interest owners are Caracol Petroleum LLC, TP North Slope Development LLC (Thyssen), BRPC, Nabors Drilling Technologies USA Inc., AVCG LLC, Mustang Road LLC, and MOC1 LLC. ●

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FURIE BANKRUPTCY

allow debtors to pay the state property tax," DOR said. "As stated in that motion, prompt payment of taxes owed to the State 'will ultimately preserve the resources of the debtors' estates, thereby promoting their prospects for a successful Chapter 11 process.'"

Resolution of tax credit overpayments, like property tax liability, would require debtors to expend time and incur costs to resolve a multitude of issues related to such obligations, DOR said, adding, "As debtors further explained, the tax obligations 'may be considered to be obligations as to which debtors' officers and directors may be held directly or personally liable in the event of nonpayment. In such events, collection efforts by the taxing authorities would provide obvious distractions to the debtors and their officers and directors in their efforts to bring the Chapter 11 cases to an expeditious conclusion.'"

"This court agreed with debtors' rationale and authorized the payment of property taxes, which debtors have since paid," DOR said. "The same rationale applies here, and the tax credits should be offset against Cornucopia's audit liability."

The DOR motion was signed Sept. 4 on behalf of Kevin G. Clarkson, attorney general, by Robert H. Schmidt, assistant attorney general. ●

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ANWR LEASE SALE

lease sales. The Act requires a lease sale within 4 years of enactment, which is 2021," he said.

The Act also calls for at least two areawide lease sales in the 1002 area by December 2024.

In July, Joe Balash, then-Interior assistant secretary, gave December as a rough estimate for the first lease sale.

"The preliminary final EIS (environmental impact statement) has gone to cooperators for review. … I will conduct government to government meetings in Arctic Village on the 8th and Kaktovik on the 9th (of August). … We should be able to publish the final EIS in early September," Balash said.

The process that was supposed to follow was BLM issuing a record of decision, the step that finalizes the EIS.

But no record of decision followed because of the care the agency is taking to make sure it does everything correctly, undoubtedly a reaction to promised challenges from anti-development groups.

Call for nominations, comments

Once the record of decision is published, BLM will issue a call for nominations and comments, which gives industry, conservation groups, Native communities and other stakeholders the opportunity to provide input as to which tracts should be included or excluded from the lease sale.

This process does not have a mandated timeline, but BLM normally allows 30 days.

That accomplished, the agency will be able to schedule the first lease sale in a proposed notice of sale that will include specifics of the sale, such as royalty rates for certain tracts, rental rates and minimum bid amounts, lease sizes, and projected oil and gas potential and distance from existing infrastructure for various areas.

Normally tracts having the highest potential and being closest to infrastructure are the smallest. Once the notice of sale is issued a 30-day clock starts ticking on the final comment period.

Most of 1.57 million acres

In the preliminary final EIS that BLM published in September, it had selected option B as a preferred alternative, which opens almost all the 1.57 million-acre ANWR 1002 area to oil and gas leasing.

The 1002 portion of the 19 million-acre Arctic National Wildlife Refuge is a narrow strip of coastline that had been set aside by Congress for potential development because of its hydrocarbon rich geology.

"This alternative offers the opportunity to lease the entire program area while providing protections for the many important resources and uses identified through scoping and public comments within the program area," Chad Padgett, Alaska state director for BLM, said in an introductory message in September's preliminary final EIS.

B is the least restrictive of the four alternatives analyzed by BLM and several cooperating federal and state agencies. Still, it requires 359,400 acres to be designated for no surface occupancy restrictions. Option A, the no-action alternative was rejected because it would not have allowed any leasing and so it was out of compliance with the 2017 federal Tax Cuts and Jobs Act that mandated oil and gas leasing in the ANWR 1002 area.

—KAY CASHMAN

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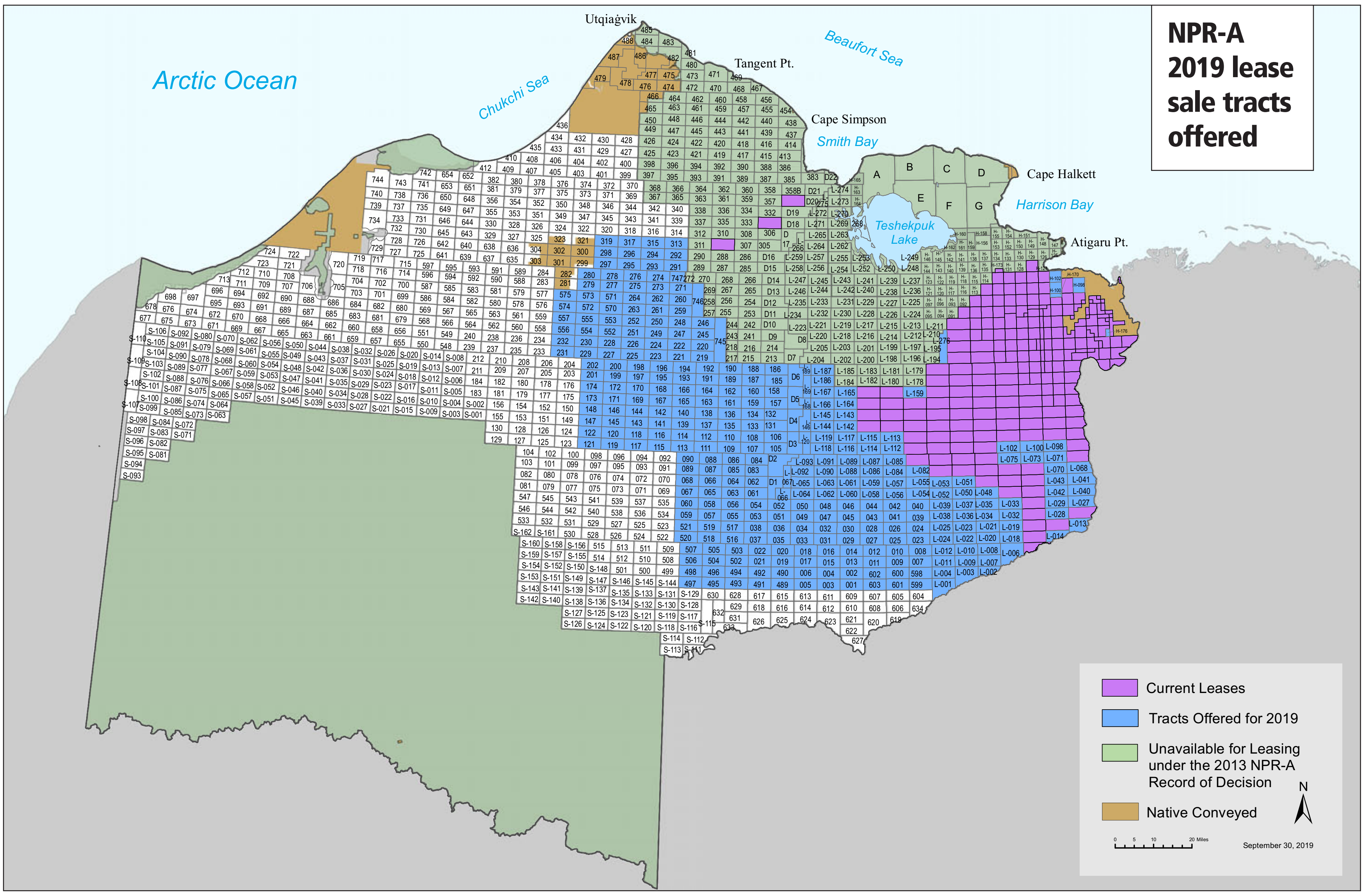

BUREAU OF LAND MANAGEMENT

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CHUGACH-ML&P

the question of whether the deal will go through now hinges on whether RCA will approve the changes — the Chugach Electric board has already approved the modifications.

The overall concept behind the proposed ML&P purchase is the consolidation of the two existing Anchorage based electric utilities, to eliminate duplicated functions and improve operational efficiency.

The Nov. 3 Petroleum News article incorrectly stated that the statutory deadline for completing the RCA hearing is Nov. 19. Originally that was the statutory deadline, but the deadline has been extended to Feb. 17.

The overall concept behind the proposed ML&P purchase is the consolidation of the two existing Anchorage based electric utilities, to eliminate duplicated functions and improve operational efficiency.

Changes to the original terms of the purchase include a reduction of the total purchase price; the creation of a $36 million fund for rate relief for existing ML&P customers; the dedication of $15 million in funding for a project addressing substance use disorder issues in Southcentral Alaska; the dismissal of appeals over the prudence of ML&P's construction of its Plant 2A power generation facility, and over the utility's approved rate of return on equity; and a revised agreement over the accounting for some of the use of Beluga River field natural gas.

—ALAN BAILEY

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NPR-A SALE

Integrated Activity Plan for the NPR-A. With advancements in drilling technology, it was prudent to develop a new plan that provides for greater economic development of our resources while still providing protections for important resources, such as subsistence uses."

BLM said there are currently 215 active leases in NPR-A, covering more than 1.5 million acres. The December sale will be the 15th in NPR-A since recent sales began in 1999; bids received for the 14 pervious sales generated more than $283 million, half of which went to the state of Alaska.

High potential tracts in the upcoming sale (5,760 acres) have a minimum bid of $25 per acre, a fixed royalty rate of 16 2/3% and a rental rate of $10 per acre. Low potential tracts (11,500 acres) have a minimum bid of $5 per acre, a fixed royalty rate of 12 1/2% and a rental rate of $3 per acre.

Previous sales

Prior to 1999, there were four oil and gas lease sales in NPR-A between 1982 and 1984, with 1.4 million acres leased but only one well drilled. By 1999, there were no remaining leases, but interest in the area was growing as ARCO Alaska (now ConocoPhillips) developed the Alpine field just to the east of NPR-A.

The 1999 sale drew considerable interest. There were 431 tracts offered, 3.9 million acres, and BLM received bids on 133 tracts, 867,721 acres, with a total of $104.6 million in total bids.

The next sale, in 2002, garnered bids of $63.8 million on 60 tracts, 579,269 acres.

There was high interest in the next three sales — held in 2004, 2006 and 2008 — with bids on 123 tracts ($53.9 million) in 2004, on 80 tracts in 2006 ($13.8 million) and 80 tracts in 2008 ($16.3 million).

Bidding gradually dropped off, although the 2016 sale (the sales became annual beginning in 2010) drew 67 bids ($18.8 million).

The most recent sales, in 2017 and 2018, drew bids on seven and 16 tracts, respectively, and bid amounts of $1.2 million and $1.5 million.

The first production from federal lands in NPR-A began in October 2018 from ConocoPhillips Alaska's Greater Mooses Tooth unit. That company's predecessor, Phillips Alaska, announced the first NPR-A discoveries from the current leasing program in May 2001. The most recent NPR-A discovery news came when ConocoPhillips announced its Willow find in January 2017 after exploration wells were drilled in the company's NPR-A Bear Tooth unit in 2016.

—KRISTEN NELSON

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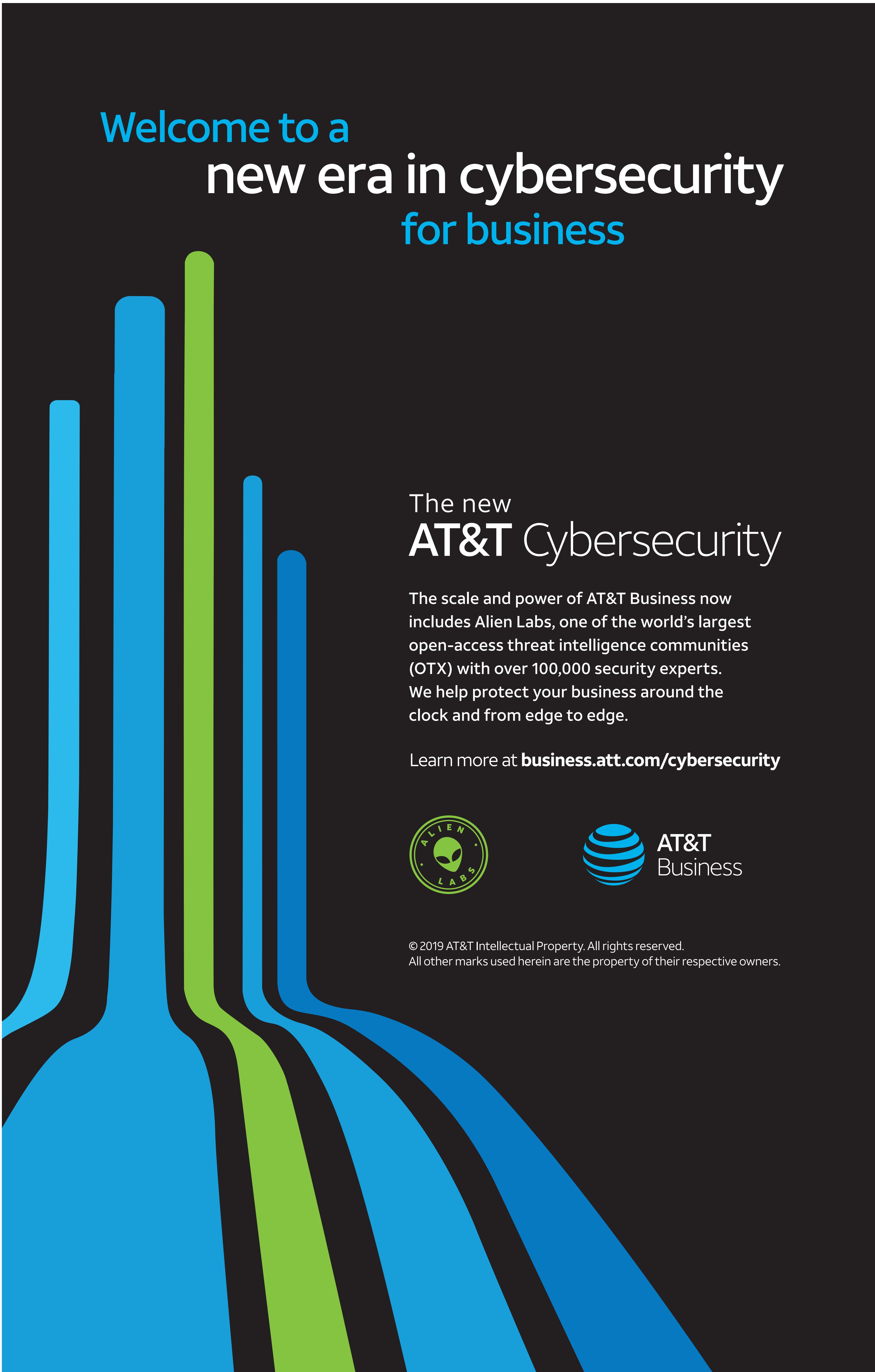
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