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Hammer falls on Guitar unit; AK, Alberta railroads pencil deal

SAMUEL NAPPI, PRESIDENT of Alliance Exploration, received a certified letter June 27 from Alaska Department of Natural Resources Commissioner Corri Feige that gave him 20 days to comment on his company’s failure to post a $500,000 bond to cure a default terminating the Alliance-operated Guitar unit. (See the Oil Patch Insider article “Alliance looking for partner for North Slope well next to Prudhoe” in the June 30 issue of Petroleum News.) In a Feb. 7 letter to Nappi, Feige effectively gave Alliance a certificate of public convenience and necessity this February. The certificate of public convenience and necessity is the best option for effective and efficient electrical transmission,” RCA said in an April order. In 2015 RCA opened a docket to gather information about the Alaska Railbelt electric transmission system. Alaska Railbelt Transmission LLC, ART, applied for a certificate of public convenience and necessity this February. The commission said it noted some deficiencies in the application see INSIDER page 12

First oil at Mustang by early September, says Bart Armfield

With approvals and permits in place, the first small independent to take an oil field from discovery to production on the North Slope should be delivering oil into the trans-Alaska pipeline by early September. Brooks Range Petroleum Corp. has been working for seven years to bring the Mustang project in the Southern Miluveach unit into production and is now waiting on just one thing: According to a July 2 email from Bart Armfield, BRPC president and CEO, the company is “making significant progress with the Mustang project, but still have components of the process facility Missing.”

Alaska Railbelt Transmission plays as the best option for effective and efficient electrical transmission,” RCA said in an April order. In 2015 RCA opened a docket to gather information about the Alaska Railbelt electric transmission system. Alaska Railbelt Transmission LLC, ART, applied for a certificate of public convenience and necessity this February. The commission noted some deficiencies in the application see ART WITHDRAWAL page 10

State lease sales again include SALSA blocks with wells required

The state has published the sale notice for its fall oil and gas lease sales, the Beaufort Sea areawide, the North Slope areawide and the North Slope Foothills areawide. As the Alaska Department of Natural Resources’ Division of Oil and Gas announced in May, this year’s sale will include, as did last year’s, Special Alaska Lease Sale Areas, SALSA, in the North Slope and Beaufort Sea areawide sales. The division posted an updated version of the SALSA data see LEASE SALES page 6

Significant step

Oil Search exercises $450M option to buyout Armstrong at Pikka, Horseshoe

The days of the Alaska North Slope producing under 500,000 barrels of oil a day may soon be over as the first major U.S. conventional oil discovery in decades drew closer to production on June 27 when Oil Search Ltd. exercised its option to sharply increase its stake in Pikka and Horseshoe leases west of the central North Slope. The company and minority partner Repsol SA are planning a Pikka development that will produce 120,000 bpd, initially from the big Brookian Nanushuk discovery and then later tapping into other stacked plays in the unit. Oil Search is looking at early production of some 30,000 bpd in 2022 with full production in 2024 versus its original plan of full production in late 2023. The $450 million option Oil Search exercised was with privately held Armstrong Energy and Armstrong’s minority partner GMT Exploration that effectively doubled the company’s acreage in the leased acreage, per the June 27 statement from Oil Search’s Sydney office (it was received June 27 in the U.S. but dated June 26, the date in Australia). Armstrong initially brought Oil Search to the North Slope in March 2018 with a $400 million offer on SALSA blocks with wells required see OIL SEARCH OPTIONS page 11

AK LNG DEIS published

FERC evaluates, discards alternatives proposed for AGDC project in scoping period

The Federal Energy Regulatory Commission published a draft environmental impact statement for the Alaska Gasline Development Corp. sponsored Alaska liquified natural gas project on June 28, beginning a public comment period which would lead to a final EIS and record of decision on the project next year. The draft EIS assesses potential environmental effects of construction of the Alaska LNG Project in accordance with the National Environmental Policy Act, and FERC said its “staff concludes that approval of the Project would result in a number of significant environmental impacts, but the major- ty of impacts would be less than significant based on the impact avoidance, minimization, and miti- gation measures proposed by AGDC and those recommended by staff in the draft EIS,” although, FERC said, “some of the adverse impacts would be significant even after the implementation of mitigation measures.” Cooperating agencies included the U.S. see AK LNG page 10

It’s a gas — maybe

Progress for LPG exports, petrochemical could be lift for Canada’s gas producers

From a peak price at Alberta’s AECO trading hub of almost US$8 per million British thermal units in 2008, producers have experienced a sickening descent to under US$2 in 2015 where the price level has remained ever since. That has translated into a grim outlook for Alberta which raked in CS$ billion in gas royalties in the 2005-06 fiscal year and ended the last budget year at a bleak CS$446 million. see GAS PRODUCERS page 8

{image: Petroleum News logo and page 10 header}

By KAY CASHMAN Petroleum News

The Federal Energy Regulatory Commission published a draft environmental impact statement for the Alaska Gasline Development Corp. sponsored Alaska liquified natural gas project on June 28, beginning a public comment period which would lead to a final EIS and record of decision on the project next year. The draft EIS assesses potential environmental effects of construction of the Alaska LNG Project in accordance with the National Environmental Policy Act, and FERC said its “staff concludes that approval of the Project would result in a number of significant environmental impacts, but the major- ty of impacts would be less than significant based on the impact avoidance, minimization, and miti- gation measures proposed by AGDC and those recommended by staff in the draft EIS,” although, FERC said, “some of the adverse impacts would be significant even after the implementation of mitigation measures.” Cooperating agencies included the U.S. see AK LNG page 10

By GARY PARK For Petroleum News

Just as the newly elected Alberta government was opening up a second front to defend its embattled oil and natural gas industry, unexpected rein- forcements for gas producers have surfaced in the shape of liquified petroleum gas, LPG, exports and the prospects of a resurgent petrochemical sector. The breakthroughs coincided with a broad- based initiative by the government of Premier Jason Kenney to find answers to a decade-long slump in gas prices. From a peak price at Alberta’s AECO trading hub of almost US$8 per million British thermal units in 2008, producers have experienced a sick-
Microbiomes flag hydrocarbon reservoirs

By STEVE SUTHERLIN
Petroleum News

Netherlands-based Biodentify uses new DNA analytical methods and advanced machine-learning algorithms to identify potential hydrocarbon reservoirs. The science is used to predict oil and gas deposits based on microbiome reactions to micro-seepages of gas molecules.

“What we’re trying to do is to help you avoid drilling a lot of dry holes,” said Robert Chelak, in a presentation to a May 31 technical breakout session at the state Geologic Materials Center in Anchorage. The session focused on the potential for new investigative technologies and machine learning systems to better assist geoscientists and resource companies to meet the challenges of interpreting Alaska geology.

The mix of microbial species in a near surface soil sample is compared to a database to correlate DNA, soil samples and relevant production data from previous drilling, Chelak said. The DNA fingerprint of the sample is an indicator of the presence of vertical micro-seepage to the surface from hydrocarbon accumulations in underlying strata.

“Predicting where reservoirs are by doing DNA fingerprinting, and machine learning,” Chelak said.

“It’s mind blowing; it’s new; it’s innovative; it’s only been around for about two years.

“We want to make sure we’re ... going into areas where there is reservoir, versus shooting seismic or drilling wells in areas where we don’t need to be,” he said. “We want to make the areas that are productive very highly productive; we want to drill the best locations, maximize your profit, and minimize the impact on the environment.

“In Alaska, where you’re opening up for exploration, the environment is a big deal,” he said.

Medical breakthrough

The company’s technology is borrowed from a medical science breakthrough that uses saliva to test for tumors, as opposed to a much more invasive biopsy.

The process was developed in a lab in Holland, Chelak said, adding that one of the company’s founders, Chris te Stroet, postulated that the science could be adapted to the oil and gas industry.

Vertical upward micro-seepage occurrences have been known since the 1930s, Chelak said, adding, “The Russians were looking at this.”

see RESERVOIR SCIENCE page 9
Alaska - Mackenzie Rig Report

The Alaska - Mackenzie Rig Report as of July 2, 2019. Active drilling companies only listed.

TD = rigs equipped with top drive units   WO = workover operations   CT = coiled tubing operation   SCR = electric rig

This rig report was prepared by Marti Reeve

Baker Hughes North America rotary rig counts*

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*Issued by Baker Hughes since 1944

Cook Inlet Basin – Onshore

BlueCrest Alaska Operating LLC

Land Rig

BlueCrest Rig #1
Anchor Point, drilling production section of H14

Glacier Oil & Gas

Rig 37
West McArthur River Unit Workover
Glacier Oil & Gas

All American Oilfield LLC

IDECO H-37
AAO 111
North Slope stacked

Aurora Well Services

Franks 300 Svs. Explorer III
AWS 1
Nikolski

Hilcorp Alaska LLC

TSM-850
147
Stacked
Seawave
Hilcorp Alaska LLC

TSM-850
169

Cook Inlet Basin – Offshore

Hilcorp Alaska LLC

National 110
C (TD)
Platform C, stacked
Hilcorp Alaska LLC

Rig 53
Shellhead Platform, stacked
Hilcorp Alaska LLC

Rig 56
Monopod A-13, stacked
Hilcorp Alaska LLC

Spartan Drilling

Baker Marine Llc (skidoff, jack-up
Spartan 151, stacked at Rig Tenders
Hilcorp Alaska LLC
where pre mobilization work is being performed

Feris Operating Alaska

Randoff Yotl jack-up
Nikolski, Osk dock

Glacier Oil & Gas

National 1300
35
Ogoprey Platform, activated
Glacier Oil & Gas

**Mackenzie Rig Status**

**Canadian Beaufort Sea**

SDC Drilling Inc.

SDC CANNAR Island Rig A2
SDC
Set down at Roland Bay
Available

**Central Mackenzie Valley**

Alaska

TSM-7000
37
Racked in Norman Wells, NT
Available

**Alaska - Mackenzie Rig Report** is sponsored by:
Oil and gas bonding goes to Supremes

Oval arguments on lawsuit opposing Alaska Tax Credit Certificate Bond Corp. to be heard by Alaska Supreme Court on Sept. 12

By KAY CASHMAN

Petroleum News

Credit holders cover state’s cost

To get paid under HB 331, the credit holders will have to accept a discount of up to 10% less than the face value of their certificates because that difference will be used by the state to cover the borrowing costs of the bonds. (There are provisions in the legislation allowing a discount closer to 5% for companies that meet certain qualifications, such as agreeing to provide the state an overriding royalty interest, committing to reinvest the money in Alaska within 24 months, agreeing to an early waiver of confidential seismic data, or having refinery or gas storage credits.)

Supporters of the bond plan said it was a way to restart stalled investment by small companies in Alaska’s oil and gas industry.

But opponents claimed it was unconstitutional.

One of those opponents, Juneau resident Eric Forrer, a former University of Alaska Regent, challenged the bonding plan by filing a public interest lawsuit in Alaska Supreme Court.

Generally, the state constitution forbids voters from incurring future debt unless it’s in response to a natural disaster, for capital projects approved by voters, or it’s in the form of bonds sold to support a specific project that is repaid through subsequent revenue from that project.

So the corporations that already use such bonding are the Alaska Industrial Development and Export Authority and the Alaska Housing Finance Corp.

Lawsuit dismissed Jan. 2

Superior Court Judge Jude Pate dismissed Forrer’s lawsuit on Jan. 2, concluding HB 331 did not create unconstitutional “state debt” for the purposes of Article 9, section 8 of the Alaska Constitution.

“The court rightfully affirmed that when bonds are ‘subject-to-appropriation,’ they are not truly a debt owed by the State,” Attorney General Kevin G. Clarkson said Jan. 3. “HB 331 was an innovative solution to the difficult problem faced by Alaska’s oil and gas explorers, and I am pleased that the superior court has upheld it as constitutional.”

Commenting on the program, Tangeman said the tax credit bond program allows the state to follow through “in paying down the tax credits, so industry and the financial markets know we are open for business. This will bring more stability to state finances and help the business community to get the economy back on track.”

Set a danger precedent

Forrer disagreed and appealed Pate’s ruling to the Alaska Supreme Court, contending that approving the tax credit bond plan would set a precedent for lawmakers and local governments to be able to do something similar in countless other situations, potentially burdening the state with additional debt.

State attorneys said similar tactics have already been used to pay for capital projects—and that a provision in HB 331 calls for the bond repayments to be “subject to appropriation” by the legislature each year, meaning the state would not ultimately be liable for defaulting on the payments.

If the Legislature ever decided not to see O&G BONDING page 6

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Overseas (sent air mail) — $240.00 1 year, $436.00 2 years

Canada — $206.00 1 year, $375.00 2 years

“Periodicals postage paid at Anchorage, AK 99502-9986.”
May ANS production down 0.3% from April

By KRISTEN NELSON
Petroleum News

Alaska North Slope production averaged 513,740 barrels per day in May (406,072 bpd of crude and 53,068 bpd of natural gas liquids), down 0.3%, 1,551 bpd, from an April average of 515,292 bpd and down 3.4% from a May 2018 average of 531,827 bpd.

The month-over-month decrease was entirely in NGLs, which were down 3.9%, 2,148 bpd, from an April average of 55,216 bpd, while crude was basically flat, up 0.1%, 597 bpd, from an April average of 406,075 bpd. NGLs were up 3.1% from May 2018, when they averaged 53,657 bpd, while crude was down 4.1% from May 2018, when it averaged 480,363 bpd.

Production data reported here is from the Alaska Oil and Gas Conservation Commission, which provides volumes by field and well on a month-delay basis.

Up month-over-month

The largest May over April increase was at Oooguruk, which Eni acquired from Cencos in January subject to approvals. The field averaged 9,293 bpd in May, down 16.9%, 1,539 bpd, from an April average of 10,827 bpd up 16.3% from a May 2018 average of 5,774 bpd. The field’s May production averaged 11,335 bpd from three wells, down 7.5%, 918 bpd, from an April average of 12,253 bpd.

Northstar, operated by Hilcorp, averaged 10,655 bpd in May, down 6.3%, 718 bpd, from an April average of 11,373 bpd and down 4.0% from a May 2018 average of 10,701 bpd. The field’s production included an average of 8,335 bpd of crude oil (down 2.1% from an April average of 8,510 bpd and up 1.1% from a May 2018 average of 8,297 bpd) and 2,320 bpd of NGLs (down 19%, 543 bpd, from an April average of 2,863 bpd, and down 3.5% from a May 2018 average of 2,804 bpd).

The Hilcorp-operated Endicott field averaged 7,071 bpd in May, down 3.5%, 287 bpd, from an April average of 7,358 bpd and up 6.2% from a May 2018 average of 6,655 bpd. Endicott production included 6,291 bpd of crude (down 2.4% from an April average of 6,510 bpd and up 5.1% from a May 2018 average of 5,976 bpd) and 779 bpd of NGLs (down 11.9% from an April average of 895 bpd and up 14.8% from a May 2018 average of 767 bpd). ConocoPhillips’ Colville River unit averaged 51,759 bpd in May, down 1.7%, 926 bpd, from an April average of 52,661 bpd and down 21.2% from a May 2018 average of 65,641 bpd. In addition to oil from the main Alpine pool, Colville production includes satellite production from Foid, Nanuq and Qannik.

Eni’s Nank一款ch field averaged 16,640 bpd in May, down 1.4%, 238 bpd, from an April average of 16,878 bpd and down 14.4% from a May 2018 average of 19,441 bpd.

Cook Inlet

Cook Inlet production averaged 13,779 bpd in May, down 10.5%, 1,619 bpd, from an April average of 15,397 bpd and down 11.8% from a May 2018 average of 15,620 bpd.

BlueCrest’s Hansen field, the Cosmopolitan project, was the only Cook Inlet field with a month-over-month production gain, averaging 1,713 bpd in May, up 2.7%, 45 bpd, from an April average of 1,668 bpd and up 103.7% from a May 2018 average of 841 bpd. Last May the field was producing from two wells; this May it is producing from five wells.

Hilcorp’s Middle Ground Shoal had the steepest month-over-month production decline, averaging 173 bpd in May, down 86.9%, 1,148 bpd, from an April average of 1,321 bpd, and down 77.6% from a May 2018 average of 1,392 bpd. 2018 and 2019 plans of development for Middle Ground Shoal indicate maintenance work at the A and C platforms from which the field is producing. There is no current production from the Baker and Dillon platforms.

Hilcorp’s Beaver Creek field averaged 351 bpd in May, down 15.9%, 66 bpd, from an April average of 417 bpd, but up 308.3% from a May 2018 average of 86 bpd. Hilcorp did a redrill at the field in November; last October, the last full month of production prior to the re-drill, production at the field averaged 71 bpd.

Hilcorp’s Trading Bay field averaged 1,469 bpd in May, down 9.1%, 146 bpd, from an April average of 1,615 bpd and down 15.2% from a May 2018 average of 1,731 bpd.

Hilcorp’s Granite Point averaged 2,452 bpd in May, down 5.2%, 135 bpd, from an April average of 2,586 bpd, and down 14.1% from a May 2018 average of 2,853 bpd.

West McArthur River, operated by Cook Inlet Energy, a Glacier Oil & Gas company, averaged 553 bpd in May, down 3.9%, 22 bpd, from an April average of 575 bpd and down 38.6% from a May 2018 average of 908 bpd.

Redoubt Shoal, also operated by Cook Inlet Energy, averaged 1,191 bpd, down 3.3%, 40 bpd, from an April average of 1,231 bpd but up 2.2% from a May 2018 average of 1,165 bpd.

Hilcorp’s Swanson River averaged 1,044 bpd in May, down 6.2%, 28 bpd, from an April average of 1,072, and down 29.8% from a May 2018 average of 1,486 bpd.

Hilcorp’s McArthur River field, Cook Inlet’s largest, averaged 4,834 bpd in May, down 1.6%, 78 bpd, from an April average of 4,912 and down 6.4% from a May 2018 average of 5,166 bpd.

ANS crude oil production peaked in 1988 at 2.1 million bpd. Cook Inlet crude oil production peaked in 1970 at more than 227,000 bpd.

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LEASE SALES

guide at dog.dnr.alaska.gov/Library/SALSA.

DNR Commissioner Corri Feige said May 15 that feedback for the 2018 SALSA program and the data compilation associated with the program had been enthusiastic, but that informal polling after the 2018 sale — which drew no bids on any of the blocks — found that there just wasn’t enough time from the August release of the SALSA information for potential bidders to do a thorough evaluation.

“By signaling our intentions earlier this year, potential bidders will have much more time to evaluate and consider opportunities,” Feige said when the updated SALSA guide was posted in May.

The SALSA presentation describes these areas as an opportunity to bid on large, contiguous acreage blocks, groups of North Slope and Beaufort Sea areawide lease sale tracts that will be offered together.

The division has gathered publicly available data bearing on the SALSA areas, and “each lease sale block has 3D seismic data acquired through the State of Alaska Tax Credit Program which remain available through the Department of Natural Resources for a modest fee. This compilation is meant to provide a jump start in understanding what data is available for the SALSA blocks,” Feige said.

Sale notice

In-person bid submission for the fall sales will be Dec. 9 from 9 a.m. to 4 p.m.

in Suite 1100 of the Atwood Building, 550 West 7th Avenue, Anchorage, Alaska, or by mail to DNR Division of Oil & Gas, Attn: Lease Sale, 550 W. 7th Ave., Suite 1100, Anchorage AK 99501-356.

Bid opening will be Dec. 11 beginning at 9 a.m. in the Kahuna 1 Meeting Room in the Dena’ina Center in Anchorage.

The Beaufort Sea areawide has a minimum bid of $25 per acre, a royalty rate of 16.67%, a primary lease term of eight years and annual rent of $10 per acre.

The North Slope areawide is divided into the north subregion and the south subregion. The only difference is the royalty rate, which is 16.67% in the north subregion and 12.5% in the south subregion. The minimum bid is $25 per acre, the primary lease term is eight years and the annual rent is $10 per acre.

In the Foothills areawide, the minimum bid is $10 per acre, the royalty rate is 12.5%, the primary lease term is 10 years and the annual rental rate is $1 per acre in year one, $1.50 per acre in year two, $2 per acre in year three, $2.50 per acre in year four, and $3 per acre in years five through 10.

Gwydyr Bay

The block offerings require bidding for the entire block and there is a requirement that a well be drilled on each block to a specified target.

The Gwydyr Bay Block is 23,012 acres of state-owned uplands and state-owned tide and submerged lands in nine leases in the North Slope and Beaufort Sea areawide sales, north of the Prudhoe Bay unit and east of the Milne Point unit.

The minimum bid is $25 per acre, the royalty rate is 16.67%, the primary lease term is eight years and the rental rate is $10 per acre per year.

The lease includes a work commitment that a well be drilled in the block before the seventh anniversary of the lease. The well must penetrate “to the base of the Kuparuk C interval as observed as the LCU correlative stratigraphic surface seen in the Hemi Springs State 1 well (API No. 50-10320007-00-00) at 7,289 feet measured depth.”

Specified well data must be provided to the state.

Storms

The Storms block is 30,592 acres of state-owned uplands in 12 leases in the North Slope areawide. The block is south of the Prudhoe Bay and Guitar units and west of the trans-Alaska oil pipeline. The minimum bid is $25 per acre, the royalty rate is 16.67%, the primary lease term is eight years and the rental rate is $10 per acre per year.

The lease includes a work commitment that a well be drilled in the block before the seventh anniversary of the lease. The well must penetrate “to the base of the Kuparuk C interval as observed as the LCU correlative stratigraphic surface seen in the S. Harrison Bay #1 well (API No. 50-02921056-00-00) at 7,256 feet measured depth.”

Specified well data must be provided to the state.

OG & BONDING

repay the bonds, supporters acknowledged it would likely have a negative impact on the state’s credit rating and reputation in the financial community, which is what happened when former Alaska Gov. Bill Walker originally decided not to repay the credits. Small oil and gas explorers had used the state credit certificates as collateral to secure loans from large banks to fund exploration and then were unable to repay the loans, earning a bad reputation worldwide for the state of Alaska’s reliability in dealing with the oil and gas industry.

Whereas the industry understood the state’s inability to continue the tax credit programs, it was less understanding when the Walker administration reneged on existing obligations.

The passage of the bonding plan by the Legislature resulted in the state pay- ing just $2.8 million in tax credits in 2018, but earlier this year Revenue paid $100 million against existing obligations, which reportedly was a lifesaver to at least two of the state’s smaller explorers Petroleum News interviewed.

continued from page 1

continued from page 4


Our CDR2-AC rig reflects the latest innovations in Arctic drilling to provide our customers with incident free performances and operational and technical excellence.

CDR2-AC is the first Arctic rig designed and built by Nabors specifically for Coiled Tubing Drilling operations. The rig was built to optimize CTD managed pressure drilling to provide precise control of wellbore pressures for improved safety, decreased costs, and increased wellbore lengths.

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Learn more about Nabors’ new drilling technologies at Nabors.com.

NABORS ~ MISSION TO ZERO
Safer, Smarter - Incident Free
Lawsuit challenges US Keystone approvals

Environmentalists asked a federal judge July 1 to cancel permits and other approvals issued by the U.S. Army Corps of Engineers for the Keystone XL oil pipeline from Canada, opening another legal fight over a long-delayed energy project backed by President Donald Trump.

Attorneys for the Northern Plains Resource Council, Sierra Club and other groups filed the latest lawsuit against the $8 billion tar sands pipeline in Montana, where they’ve previously won favorable rulings in related cases.

They claim the Army Corps did not examine the potential for oil spills and other environmental damages when it approved plans submitted by pipeline developer TC Energy. The line would cross hundreds of waterways along a 1,184-mile path from Canada to Nebraska.

Almost all the crossings fall under an Army Corps program that gives blanket approval to individual pieces of a bigger project without considering the potential cumulative impacts, according to the lawsuit. That means no analysis was done of the possibility that the line would break and cause an oil spill or of its potential contributions to climate change, the lawsuit says.

The U.S. Army Corps public affairs office said in response to queries from The Associated Press that it was not commenting because the matter is under litigation.

First proposed in 2008, Keystone XL was rejected by President Barack Obama but revived under Trump. An appeals court in June lifted an injunction that blocked construction of the project. That came after Trump issued a new permit in a bid to nullify a legal challenge to the pipeline by canceling its previous permit.

FINANCE & ECONOMY

Non-OPEC members back production cuts

OPEC members won the support July 2 of other major oil producing nations to extend a production cut for another nine months in a bid to shore up prices at a time of waning demand.

Member nations of the Organization of the Petroleum Exporting Countries on July 1 agreed to the extension. With strong backing from Russia, the biggest member of the non-OPEC group meeting July 2, the others unanimously approved the proposal.

“In order to help maintain the current stable status of the market and avoid buildup of inventories, we have decided to keep the level and the magnitude of the cuts intact,” Russian Energy Minister Alexander Novak told the forum after the vote.

The 10 non-OPEC nations present at the meeting at OPEC’s headquarters in Vienna also included Mexico, Bahrain, Oman and Kazakhstan. The United States, one of the world’s major oil producers, is not involved in the discussions and won’t be bound by any agreement.

Opening the July 2 meeting, Novak urged approval of the extension.

Heading into the meeting, OPEC heavyweight Saudi Arabia said the nine-month extension was the right move to make given the current market conditions.

“I see demand picking up strongly in the second half of the year and I see compliance greatly improving,” Saudi Arabia’s Energy Minister Khalid Al-Falih told reporters. “And I see the length of this agreement as nine months sufficiently long to bring inventories down and to balance the market.”

The current deal to support prices reduced production by 1.2 million barrels per day starting from Jan. 1 for six months and will now run into next year with the extension. Most of the cuts came from OPEC nations, who agreed to reduce 800,000 barrels per day, with the rest of the cuts coming from Russia and other non-OPEC countries, though not from the United States.

—ASSOCIATED PRESS

US drilling rig count unchanged at 967

On June 28 the number of rigs drilling for oil and natural gas in the U.S. was unchanged from the previous week at 967. A year ago, the count was 1,047 active rigs.

Houston oilfield services company Baker Hughes reported that 793 rigs targeted oil (up four from the previous week) and 173 targeted natural gas (down four). One miscellaneous rig was active.

The company said 68 of the U.S. holes were directional, 840 were horizontal and 59 were vertical.

Louisiana and Oklahoma were each up two rigs from the previous week.

Texas, with the largest number of active rigs at 464, was up by one from the previous week as was Wyoming.

In California, Ohio, Pennsylvania, Utah and West Virginia the rig counts were unchanged from the previous week.

New Mexico was down one rig from the previous week, as was North Dakota. Alaska and Colorado were each down two rigs from the previous week.

Baker Hughes shows Alaska with seven rigs, down two from a year ago.

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

The idea was to start production at relatively low rates and then, as production ramped up, use the revenue to upgrade the production facilities to a larger scale.

Production will start at about 1,000 barrels per day, using a single well. Then, during the year, the company will drill a 6,000-foot lateral side-tracker from a partially completed well, thus enabling an additional 2,000 to 3,000 bpd of production.

The drilling of two more wells should then elevate total production to about 6,000 bpd, likely by the end of the year.

Total eventual field development would result in about 17 injection and production wells, Armfield told Petroleum News in April.

In a recent filing with the Alaska Oil and Gas Conservation Commission, Lawrence Vendé, BRPC’s exploration and subsurface development manager, said the Kuparuk oil pool within the Southern Milieuvech unit is a continuation of Kuparuk C and A sands in the Kuparuk River unit, and lies between minus 5,800 feet true vertical depth subsea and minus 6,400 feet TVDSS.

BRPC is the unit operator. Working interest owners are Alaska Venture Capital Group, Brooks Range Petroleum Corp., Curalco Petroleum, Mustang Operations Center 1, Mustang Road, Nubon Drilling Technologies USA and TP North Slope Development.

—KRISTEN NELSON

EXPLORATION & PRODUCTION

Lawsuit challenges US Keystone approvals continued from page 1

MUSTANG OIL

being fabricated at NANA.

We are hopeful that we can manage the schedule and get our first oil by the first part of September.

Mustang is the first development in the Southern Milieuvech unit, which sits in the increasingly crowded “billion-dollar fairway,” which was ARCO Alaska’s description of the land between the Kuparuk River unit and the Colville Valley unit, both now operated by ARCO’s successor, ConocoPhillips.

BRPC discovered the Mustang oil field in 2012 but a series of technical, economic and logistical complications led to years of delays, requiring alternative approaches to development.

To avoid losing the unit and its leases to expiration, BRPC successfully applied for certification of an existing well and proposed a plan to start production in the short term by connecting a 6,000-barrel-per-day Early Production Facility to the nearby Alpine Pipeline.

The company had originally planned to start the field using permanent 15,000-bpd production facilities. However, that plan was based on a $120 oil price in 2014.

Following the subsequent oil price crash, BRPC had to put the project into “warm standby” mode before coming up with the plan to install the modestly priced temporary production facility.

—ASSOCIATED PRESS
Natural gas cabinet post

Following his election in April, Kenney wasted no time acknowledging the plight of gas by creating a cabinet post for natural gas.

The newly appointed Minister Dale Nally said beleaguered producers have for too long “felt like second cousins” of Big Oil.

“But here’s the reality ... if we can get natural gas to (LNG) markets, it’s a game changer for Alberta,” he said, noting that “some days we are almost giving this product away for free.”

Faced with what he rates as an “extreme sense of urgency,” Nally said he is troubled by the financial failure of mid-size Trident Exploration in April, which quit the sector, dumping 4,700 wells on to Alberta regulators.

Based on warnings from his own sources, he said Trident is “not alone ... there are about a dozen other producers in a similar plight and they could go the same way as Trident.”

Simon Bregazzi, chief executive officer of Jupiter Resources, Canada’s fifth-largest gas-weighted producer at about 420 million cubic feet per day, rated Trident as “the tip of the iceberg,” an outlook which he said was well known to the government.

Nally was quick off the mark in seeking an answer to domestic transportation constraints that put a chokehold on Alberta prices at a time when global gas demand rose by 5% (18% in China).

Working group

Meetings were called in May and resulted in the formation of a working group that includes five producers, TC Energy (the gas shipping giant that was formerly known as TransCanada) and a number of industry organizations.

TC Energy added to the volatility of AECO prices in 2017 when it started restricting production for interruptible gas deliveries, while prioritizing firm-service contracts.

A 2018 report commissioned by the previous Alberta government called for a reversal of TC Energy’s “restriction protocol,” but Nally is not ready to take that step, favoring a more collaborative approach.

He suggested that could include changing new markets in North America and increased sales to Alberta’s petrochemicals operations.

LPG turnaround

The first encouraging hint of a turnaround has come from LPG operators, led by Calgary-based AltaGas which ended May by shipping the first load of propane to Asia from its C$500 million terminal near Prince Rupert.

Chief Executive Officer Randy Crawford said AltaGas is keen to engage in competition with the United States, which has been accelerating energy production over recent years, with its eye on accessing Asian markets.

AltaGas said it has an edge by offering a 10-day shipping connection from British Columbia compared with 25 days from the U.S. Gulf Coast.

At least 50% of the company’s initial exports of liquefied propane has been contracted to Japan-based Idemitsu Energy.

AltaGas expects to ship 1.2 million metric tons of propane a year that could increase if it proceeds with plans for a barge-based floating facility and is able to find a partner to build a pipeline to deliver natural gas to the processing facility.

Although Alberta gas producers are hopeful they can secure a slice of the business, AltaGas has not said where it will obtain its feedstock beyond identifying Alberta and British Columbia as the sources.

Two other propane ventures are in advanced stages, with Pembina Pipeline targeting mid-2020 for completion of a C$260 million terminal near Prince Rupert to handle 1.5 billion cubic feet per day of raw gas, for permitted capacity of 25,000 barrels per day of propane.

Pacific Traverse Energy hopes to begin exports in 2022 under a 25-year license to deliver 1.25 million metric tons a year from Kitimat.

LNG demand in Asia

Despite a series of setbacks to plans for exporting LNG from British Columbia continued strong demand in Asia is prompting investors to take a fresh look at those prospects.

AltaGas and Japan-based Idemitsu suspended work on their Triton LNG venture in 2016 after failing to sign sufficient long-term contracts for a first phase of 550,000 metric tons a year.

AltaGas Senior Vice President Dan Woznow said, “people are knocking on our door wondering what’s next.”

Greg Kist, who heads a fledgling consortium known as Rockies LNG Partners, representing 10 producers, said Western Canada’s gas industry wants to put a spotlight on the need to construct an LNG project beyond the Shell-led LNG Canada mega-project that plans to start shipments in 2024.

Although the Rockies group does not expect to become terminal operators it hopes to play a role in bringing together producers, First Nations and industry players with the ability to advance a pipeline from the gas fields of British Columbia and Alberta and an LNG plant.

Petrochemical

On the petrochemical front, there is the prospect of a turnaround in Alberta if Chevron Phillips Chemical Co. succeeds in its US$15 billion bid to acquire Nova Chemicals, based on a Reuters report.

The joint venture between Chevron and Phillips 66 could mean the return of a multinational “with big pockets” to Alberta, said Bill Rawluky, executive director of natural gas liquids at H&S Inc.

Nova is run by the UAE state-owned Mubadala Investment Co. (which has global assets valued at US$225 billion), while Chevron Phillips has 31 facilities in the United States, Europe and the Middle East.

Since it was acquired for US$500 million in 2009, the company’s business has grown rapidly, tapping into the shale boom in North America.

Rawluky said there is a special advantage for companies to build petrochemical plants in Canada based on the incentives offered by the Alberta government.

He said the attraction would be cheap ethane because natural gas prices are so low, adding there has been strong speculation the company may move another big ethane cracker being built in Alberta.

Capital spending on industrial chemical facilities in the province is forecast by members of the Chemistry Industry Association of Canada to climb by 65% this year to C$1.9 billion, up C$300 million from the most recent peak in 2014.

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The company said its database with over 2,500 samples from both onshore and offshore locations, with related production data on bio markars, is used as modeling input to its proprietary “localized triple loop” computational model. Six plays in the United States are extensively sampled: Bone Spring (Permian), Bakken, Antrim, Avalon, Lewis, Haynsville and Marcellus. In addition, studies have been carried out both on and offshore the Netherlands as well as offshore Norway.

The sample data is merged with characteristics on productivity, the age of the producing interval, type of play (oil vs. gas), geology and climate and soil type. Local fingerprinting

Chelak said when Biodentify first studies a field, the samples are initially matched against the company’s large database to build a map of prospective sub areas of the study area. On a job in the Haynsville shale, “we were using the fingerprint from all of the other areas of the United States,” he said. The company then took local samples from producing areas and dry areas and added the data back into the database before re-running the process. Of the 362 samples taken, three were from known producing areas and four were from dry areas.

“ar the first map was 70% accurate; the final map is about 86% accurate in predicting where the reservoir is,” he said. “Based on the information that came out of this, we looked at the wells that were drilled in the area,” Chelak said. “Approximately 100 wells were drilled in the area—they would have only needed to drill 46 wells to get the same amount of production over the producing area. ‘‘Wells in this area wells are between $6 million and $10 million; it would have saved about $300 million in drilling costs,’’ he said.

The savings don’t stop there, he said. Later in the production phase of the field, it is possible to go back and re-survey to see if there are some remaining hydrocarbons that could yet be produced—without having to go back and shoot more seismic.

Machine learning

Due to the massive computing power now available combined with machine learning, Biodentify is able to surpass the accuracy and richness of information from a traditional geochemistry study. ‘‘In a strictly geochemistry study, people will take the samples, they’ll put it in a Petri dish, they’ll grow it in a lab, and they’re looking at about five to maybe 10 microorganisms that would grow that would indicate hydrocarbons being there,’’ Chelak said. ‘‘But you can get a lot of false positives with geochemistry; the microorganisms can come back to life, and again they’re only looking at about five to 10.’’

‘‘We’re looking at 50 to 200, and a majority of those are the ones that find the micro bubbles toxic; 35% of the ones we’re looking for are the ones that are living, that are flourishing off of hydrocarbon molecules that are coming up.

‘‘Things are changing over time; these organisms are feeding off each other; they’re competing with each other; there’s things that happen—there may be a slight spill of some sort that would affect the microorganisms in that particular area,’’ Chelak said. ‘‘There’s climate change, but that will affect all of the things we have programmed into our machine learning (which) can filter those things out.

‘‘We’re trying to find the signal of that 50 to 200 in all of the noise that we have in the background.’’

Contact Steve Satherlin at stevespa@hotmail.com

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

and ART supplemented it in May, also fil- ing an errata removing Matanuska Electric Association from its list of affili- ates. In its May order finding the applica- tion complete RCA required additional filings from ART: the entities who would participate in providing the proposed service; explanation of commercial and regulatory terms in which ART would provide service; and how “ART intends to participate in the construction and ownership of transmission assets in the service territories of entities that are not affiliates of ART.”

For the date of this information was June 20, the date on which ART notified RCA it was withdrawing its application.

Chugach, MEA not participants

The Railbelt utilities were never united behind the ART filing. Matanuska Electric Association told RCA in various filings that it believed the application is “substantially deficient and premature.” MEA Chief Executive Officer Tony Leno told the commission in a March filing that drafts from the applica- tion were first presented to a Railbelt utilities managers meeting in early December. He said “MEA subsequently proposed that the Railbelt utilities under- take a joint due diligence effort and enlist independent industry, legal and regulatory experts to review the draft proposal,” but the other utilities weren’t interested, so MEA began its own due diligence of the proposal.

He said MEA advised fellow utilities at a February RUM meeting that an early review of the proposal “raised significant concerns” and said its continuing due dilu- gence review “will include analysis of alterative(s) to the no bid, sole-source, for-profit transmission company advanced by ATC.

ART Development Co. LLC, is a Wisconsin-based partner in ART “that, in its opinion, the commission said in its February notice of the filing, “is a privately-owned limited liability company, which was organized on February 22, 2019.”

In a May filing Lee Thibert, CEO of Chugach Electric Association, said American Transmission Co., ART, is the parent of ART’s largest equity owner. ML&P was a participant in the ART application and Thibert noted that in late December, Chugach and the Municipality of Anchorage signed regulatory agreements on a proposed acquisition of Municipal Light & Power by Chugach, several provisions of which prohibit ML&P’s participation in any disco Polo filing without Chugach’s participation or consent.

He also noted Chugach is concerned by the impact “involvement with a non-member, for-profit entity on Chugach’s tax-exempt status.”

Trasco

ART would be a transco, a transporta- tion company, Thibert said, and “Chugach’s position from the beginning has been that formation of a Trasco must be synchronized with the formation of an RBE (railbelt regulatory council) and a power pool.” A transco “owns, plans, con- structs, operates, and maintains transmission lines used to transmit electric power,” Thibert said. “Trasco performs inte- grated regional planning, and establishes, administers, monitors and enforces the reliability and cyber security standards, inspection protocols, and some tar- iff requirements with which a transco must comply.” And, economic dispatch resulting from a power pool creates sav- ings “that can meet the Project objectives.”

&Amdash;JEFF GREGG
buy-in of Armstrong and GMT’s working interests in the project, transfers by op-eratiorship from Armstrong to Oil Search’s wholly-owned subsidiary, Oil Search Alaska.

Aligning interests with Repsol

In this latest action, Oil Search and Repsol have aligned their interests across many of their shared North Slope assets (see adjacent chart and map), resulting in Oil Search retaining 51% in the Pikka unit and the Horseshoe block, while also purchasing a 51% interest in leases Repsol acquired in 2017, which are immediately east of Horseshoe within the prospective Nanushuk trend.

If the Armstrong-GMT option closes at the end of August, the alignment will result in a net payment of $64.3 million from Repsol to Oil Search.

Looking better and better

The decision to invest more heavily in Alaska, which was part of an effort to diversify away from dependence on liquefied natural gas production in Papua New Guinea, comes after Oil Search reviewed drilling and 3D seismic results in the Pikka and Horseshoe over the past 18 months.

In its June 27 statement Oil Search said it was taking into consideration drilling results from the 2018 ConocoPhillips Putu tests, and two Oil Search wells, Pikka B and C, drilled earlier this year.

“All these wells, which included six reservoir penetrations, were drilled in, or immediately adjacent to, the Pikka unit Nanushuk trend,” the company said. “An integrated analysis of the results of these wells, with detailed reservoir and resource modelling, has increased Oil Search’s conf-dence that there will be a material upgrade to the resource estimates, above the acquisition case, which assumed 400 million barrel gross within the Pikka unit Nanushuk reservoir and 100 mbbl/bbl gross” in adjacent exploration acreage.

Armstrong and Repsol have previously estimated Nanushuk could hold 1.2 billion barrels of recoverable light oil.

“Material upgraded reserves were added to these assets through successful drilling and test- ing over that time and attractive development options have been matured,” Oil Search said June 27. “As soon as the analysis is completed, upgraded resource estimates will be validated through an assurance process and formally announced ahead of a FEED decision on the initial (Pikka) development,” Oil Search said. FEED, or front-end engineer- ing and design, was supposed to be decided this summer, but June 27 Oil Search was less specific, saying it would take place “in the second half of 2019.”

Early output, sharing talks

The 30,000-bpd early production system will use existing capacity in the processing facilities of an “adjacent,” but unnamed, operator, which will generate early cash-flow for the partners, Oil Search said.

Discussions for possible facilities shar- ing on the 120,000-bpd development are also underway with “current North Slope operators,” Oil Search said. Negotiations are targeted to be completed by the time a Pikka FEED decision is made.

The Nanushuk oil field lies between ConocoPhillips’ Colville River unit on the west and Conoco’s Kuparuk River unit on the east.

Armstrong ties, final EIS

As far as its ongoing and future relation- ship with Armstrong, Oil Search said the two companies would continue to work together in reviewing opportunities on the North Slope, in accordance with the area of mutual interest agreement, or AMI, that was entered into as part of the original March 2018 acquisition.

Oil Search also said “material progress” has been made on key permits, most notably the approval of the Environmental Impact Statement Record of Decision, received in May from the U.S. Army Corps of Engineers, which was a major Pikka project milestone.

Taking on a third partner

Oil Search and Repsol originally intend-
continued from page 1

INSIDER

a one-year extension for drilling a Guitar well but also placed the unit in default: If the company does not drill the well by the March 2020 deadline, the unit could be terminated. (Alliance had requested a two-year extension to the drilling commitment.)

In its most recent plan of exploration filed with DNR on June 11, under 11 AAC 83.390 the company was to post a statewide operator bond of $500,000 by June 25, which was not done, prompting the June 27 notice. The other major owner of Alliance, Barry Foote, told Petroleum News that although the unit could have an upside in the neighborhood of 200-300 million barrels of oil, the company’s owners had reached the limit of what they were willing to invest in the acreage ($1.5 million) without a farm-in partner.

Adjacent to the giant Prudhoe Bay unit and close to infrastructure, Foote said Guitar was the least expensive and least risky play on the North Slope today.

“I hate to see all the work we’ve done . . . (including) processing 3D seismic go to waste, but . . . we need a partner to move forward . . . and we need them yesterday,” he said.

Foote said Feige, part of the administration of Gov. Mike Dunleavy, “seems to be willing” to work with Alliance on curing the default and getting a well drilled, but the only real solution at this point, he said, would be a partner who is able to help shoulder the cost of drilling.

For more information contact Derek Foote, Alliance’s manager of land operations for Alaska, via email at dfoote45@gmail.com or by phone at 907-955-5525.

The clock is ticking ...

— KAY CASHMAN

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ART WITHDRAWAL

He said MEA served ART with an initial set of discovery requests, in response to virtually all of which ART simply referred to its application.

In a lengthy filing in May, Parnell said MEA had a number of concerns, including that the structure proposed by ART “is a complex sole source, for-profit structure” which is partially taxable, would impose “first-of-its-kind, complex tax issues on the Railbelt utilities” and potentially threatens their tax-exempt status.

“The introduction of a for-profit entity to the Railbelt carries with it a novel motivation — profit seeking rate base growth — in conflict with the existing not-for-profit industry centered on the public interest standard,” Parnell said.

A utility must demonstrate that it is fit, willing and able to operate. That, Parnell said, cannot be evaluated because ART relies in part on ML&P transmission assets and expertise, but ML&P cannot make those commitments under provisions of its December 2018 asset purchase and sale agreement with Chugach Electric.

While the agreement between ML&P and Chugach hasn’t yet been submitted to the commission, Parnell said in May, “that contract establishes the rights and obligations of the parties thereto regarding the subject assets,” and under the agreement ML&P does not have a unilateral right to commit assets to ART.

— KRISTEN NELSON