Petroleum news

page 4 History: Kerr-McGee reports 1,200 bpd from Schrader Bluff well

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EXPLORATION & PRODUCTION

Doing it again!

Bill Armstrong repeating on eastern North Slope what he did to west

By KAY CASHMAN
Petroleum News

Lagniappe is a Cajun word that loosely translates into "a good unexpected surprise" — apropos for the Nanushuk play west of Prudhoe Bay on the North Slope, which Bill Armstrong and a partner first drilled and identified as a huge oil reservoir in 2013 (Qugruk 3 well).

The discovery led to the 2-plus billion barrel Pikka oil field, today operated and being developed by Santos.

Since that discovery, the oil industry on the North Slope has been on a tear, drilling at Horseshoe, Putu, Mitquq, Stirrup, Willow and elsewhere.

Now Armstrong is leading the charge to find Pikka-look-alikes east of Prudhoe Bay. All reports say the play concept in Armstrong's Lagniappe's acreage is very similar: Multiple zones, onshore, good gravity oil, reasonably close to infrastructure.

The targeted objectives are slightly younger than what Santos has at Pikka et al but with better reservoir qualities —porosity and permeability — even though they are somewhat deeper.

Discovery announced

On March 17 APA Corp. and its partners

see **SOCKEYE-2 WELL** page 8

FINANCE & ECONOMY

China rallies ANS

China surprises with crude buying spree, boosting ANS price above Brent

By STEVE SUTHERLIN
Petroleum News

Alaska North Slope crude has been supported in maintaining its newfound premium over Brent, as China has emerged as a surprise active buyer of Pacific cargoes.

Suddenly it seems there is less oil tankered around the Pacific waiting to nail a spot market deal, and a berth at which to unload.

The West Coast market — where ANS is sold — is highly dependent on seaborne tankers to deliver its deficit consumption.

Each year of late, California oil production has declined, so more outside oil is needed. By that reasoning, seaborne oil prices are steadily gaining leverage to determine the West Coast crude price.

When a giant like China goes on a buying spree, Pacific crude prices elevate, and cargoes — including an occasional ANS cargo — flock to Asia.

More war would mean more sanctions on Russian gas, Flowers said. A scenario where all parties sign a mutually acceptable peace agreement looks least likely at this stage, but it would "open the door to material volumes of Russian gas into Europe."

see **OIL PRICES** page 6

EXPLORATION & PRODUCTION

Hilcorp plans 3 wells

Cook Inlet exploration drilling will be done with jack-up beginning in 2026

By KRISTEN NELSON
Petroleum News

Hilcorp Alaska is looking at drilling three exploration wells in Cook Inlet over the next 5 years, along with production drilling and pipeline work, involving ocean-going tugs, a jack-up rig and barges for the pipeline work.

The company laid out its plans in an application to the National Marine Fisheries Service for a letter of authorization for work in Cook Inlet, referencing 5 years of exploration and production drilling and pipeline laying or replacement work.

The first year of the authorization would run from approval to the end of 2025; the remaining four years the authorization would for calendar years through 2029.

The application to take small numbers of marine mammals incidental to oil and gas activities in Cook Inlet is for an incidental take authorization, where taking is limited to harassment. "An

In addition to drilling at Tyonek, Hilcorp said 10 drilling conductor pipes — also described as piles — will be driven into the sediment to support future well slots for production well drilling, not to exceed installation of two per year.

see **HILCORP INLET WELLS** page 7

Santos likely to deliver first oil from Pikka near end of 2025

BRUCE DINGEMAN

On March 17, APA Corp. announced an oil discovery on Alaska's North Slope from the Sockeye-2 exploration well in the Lagniappe area east of Prudhoe Bay.

Santos has a 25% stake in the joint venture with Apache holding 50% and Bill Armstrong's Lagniappe holding 25%.

The Sockeye-2 well was drilled to a depth of approximately 10,500 feet, successfully reaching a high-quality reservoir containing around 25 feet of net oil pay within a single, blocky, Paleocene-aged sand formation with an average porosity of 20%. Additionally, potential pay zones were identified in the shallower Staines Tongue formation.

Santos Executive Vice President and President Alaska Bruce Dingeman expressed excitement about the discovery and confirmed that strong progress has been made at the Pikka phase project.

see **SANTOS UPDATE** page 6

Spring Revenue Forecast has less short-term crude, lower prices

The Alaska Department of Revenue released its Spring 2025 Revenue Forecast March 12, an update of the Fall Revenue Forecast released in December. Compared to fall, the Alaska North Slope oil price forecast and the ANS oil production forecast for fiscal year 2025 (ending June 30) are up slightly, while the forecasts for FY 2026 (beginning July 1) are down more steeply.

The forecast for unrestricted general fund revenue for FY25 remains essentially the same as in the fall forecast, "as slightly higher expected petroleum revenues are offset by slightly lower revenues from other sources," the department said, but the FY26 unrestricted general fund, UGF, is now forecast at $70 million less than in the fall forecast. Changes in FY25 UGF include an expected $30 million increase in petroleum revenue

Before accounting for the transfer from the Permanent Fund Earnings Reserve, UGF revenue is now forecast at $2.6 billion for FY25 and $2.3 billion for FY26.

see **REVENUE FORECAST** page 6

AOGCC OKs Hilcorp non-custody transfer meter for pilot project

The Alaska Oil and Gas Conservation Commission has approved, with numerous conditions, a request from Hilcorp Alaska for use of non-custody transfer meters for power sold to a Duck Island unit third-party data center pilot project.

In a March 13 decision the commission said no extensions will be granted and if the pilot project extends beyond 5 years, the system used to measure the gas volume must be upgraded to custody transfer standards.

Hilcorp is the owner and operator of the Duck Island unit and uses gas as fuel at the Endicott oil and gas field within the unit. The company told the commission there is excess power generation capacity at the Endicott facility and it proposes to sell excess power to the third-party data center.

The issue addressed by the commission's order is that gas measurement for Endicott power generation uses "existing classical style venturi tube meters" for a volume of gas included in the company's monthly gas disposition report for which custody transfer measurement quality meter are not required.

see **DATA CENTER PROJECT** page 7

FINANCE & ECONOMY

EIA sees crude volumes up, prices down

Energy Information Administration says it expects global oil inventories to build later in year putting downward pressure on Brent

By KRISTEN NELSON
Petroleum News

In its March Short-Term Energy Outlook, released March 11, the U.S. Energy Information Administration said it expects global oil markets will remain relatively flat through mid-2025, with inventories increasing, before inventories begin to fall "in part due to decreasing crude oil production in Iran and Venezuela."

With decreasing production, the Brent crude oil spot price is expected to rise from about $70 per barrel to $75 per barrel in the third quarter.

Oil inventories are expected to build late in the year, putting downward pressure on oil prices, causing Brent to fall to an average of $68 per barrel in 2026. Brent averaged $81 last year and is forecast to average $74 per barrel this year.

One factor in falling prices is the expectation that OPEC+ will unwind its current production cuts and there will be growth in production from non-OPEC+ countries, EIA said.

Global oil markets

Brent averaged $75 per barrel in February, down $4 per barrel from January and down $8 from February 2024. The drop in prices in February was "driven largely by economic growth concerns related to potential tariffs by both the United States and other trade partners," EIA said.

Concerns about global oil demand growth have "persistently weighed on oil price over the last year," the agency said, while on the supply side, a ceasefire in the Russia-Ukraine conflict could add volumes from Russia back onto the market. In addition, countries outside OPEC+, primarily in North and South America, have continued to grow production, adding downward pressure on the price forecast.

Crude oil prices fell in February, but EIA said it expects upward price pressure will move Brent back into the mid-$70s in the coming months.

The U.S. sanctions on Iran, announced Feb. 24, could remove significant crude volumes from the market, while the revocation of licenses for Venezuelan oil production and exports will reduce production from that country this month, "tightening near-term oil market balances significantly" compared with February, EIA said.

Oil production is expected to rise by the end of the year, but the agency said there was significant uncertainty in its price forecast based on sanctions and the uncertainty of OPEC+'s adherence to the production increases it has announced.

Global production

Global liquid fuels production is forecast to grow in 2025 and 2026, EIA said, "due to a combination of the scheduled gradual increase in OPEC+ production and further growth from countries outside of OPEC+," with an increase of 1.4 million bpd expected this year and 1.6 million bpd in 2026.

OPEC+ production is expected to increase by less than 200,000 bpd in 2025, compared to a 1.3 million bpd decrease in 2024, and to increase by 500,000 bpd in 2026.

Countries outside of OPEC+ are expected to increase production by 1.2 million bpd in 2025 and 1 million bpd in 2026, with production growth driven by the United States, Canada, Brazil and Guyana.

EIA said global liquid fuels consumption continues to be less than the pre-pandemic trend, increasing by 1.3 million bpd this year and 1.2 million bpd in 2026, "driven primarily by demand from non-OECD Asia." India is expected to increase its consumption by 300,000 bpd both this year and next, driven by transportation fuels demand, while China is expected to increase its consumption by 300,000 bpd this year and 200,000 bpd in 2026, "as Beijing's economic stimulus efforts drive high-

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● EXPLORATION & PRODUCTION

Baker Hughes US rig count unchanged at 592

By KRISTEN NELSON
Petroleum News

The Baker Hughes' U.S. rotary drilling rig count was 592 on March 14, unchanged from the previous week, down by 37 from 629 a year ago and down by one from two weeks ago. Over the last eight weeks the rig count was up in five weeks, down in two and unchanged in one with a combined gain of 17 against a loss of five.

A drop of 17 to 731 on May 12, 2023, was the steepest weekly drop since June of 2020, during the first year of the COVID-19 pandemic, when the count also dropped by 17 to 284 on June 5, following drops as steep as 73 rigs in one week in April. The count continued down to 251 at the end of July 2020, reaching an all-time low of 244 in mid-August 2020.

For 2024, the count peaked March 1 (and again March 15) at 629, hitting its low point June 28 at 581. In 2023 the count peaked early in the year at 775 on Jan. 13, bottoming out Nov. 10 at 616.

When the count dropped to 244 in mid-August 2020, it was the lowest the domestic rotary rig count had been since the Houston based oilfield services company began issuing weekly U.S. numbers in 1944.

Prior to 2020, the low was 404 rigs in May 2016. The count peaked at 4,530 in 1981.

The count was in the low 790s at the beginning of 2020 prior to the COVID-19 pandemic, where it remained through mid-March of that year when it began to fall, dropping below what had been the historic low in early May with a count of 374 and continuing to drop through the third week of August 2020 when it gained back 10 rigs.

The March 14 count includes 487 rigs targeting oil, up by one from the previous week and down 23 from 510 a year ago, with 100 rigs targeting natural gas, down by one from the previous week and down 16 from 116 a year ago, and five miscellaneous rigs, unchanged from the previous week and up by two from a year ago.

Fifty of the rigs reported March 14 were drilling directional wells, 530 were drilling horizontal wells and 12 were drilling vertical wells.

Alaska rig count unchanged

Oklahoma (51) was up by two rigs from the previous week while New Mexico (102) was down by three rigs.

Rig counts in other states were unchanged from the previous week: Alaska (10), California (8), Colorado (8), Louisiana (29), North Dakota (32), Ohio (9), Pennsylvania (15), Texas (281), Utah (12), West Virginia (11) and Wyoming (21).

Baker Hughes shows Alaska with 10 rotary rigs active March 14, unchanged from the previous week and down by three from a year ago when the count was 13.

The rig count in the Permian, the most active basin in the country, was down by three from the previous week at 301 and down by 15 from 316 a year ago. ●

Contact Kristen Nelson at knelson@petroleumnews.com

● GOVERNMENT

Three gas pipeline bills in Legislature

Bills to add Fairbanks spur to AGDC's charter language in both House and Senate; Senate has bill for Alaska Gasline Finance Corp.

By KRISTEN NELSON
Petroleum News

Rep. Will Stapp, R-Fairbanks, introduced House Bill 119 Feb. 26, adding language to the statute governing Alaska Gasline Development Corp. which reads "an in-state natural gas pipeline advanced under this paragraph must include a direct spur line to the City of Fairbanks and the Fairbanks North Star Borough." A companion bill, Senate Bill 114, sponsored by Sen. Mike Cronk, R-Tok, Northway, was introduced in the Senate Feb. 28.

SB 125, introduced by Sen. Robert Yundt, R-Wasilla, on Feb. 28, establishes the Alaska Gasline Finance Corp. to "develop and have primary responsibility for financing a natural gas pipeline in the state." That bill has not yet been heard.

HB 119 was referred to House State Affairs and House Resources, and has been heard twice in House State Affairs, March 6 and March 11. The next hearing date had not yet been published when this issue of Petroleum News went to press.

HB 119

In his sponsor statement for HB 119, Stapp said when AGDC was established in 2010 with passage of HB 369, legislative findings specified that the state's natural gas sound, as a priority, be made available in the state. SB 138 broadened AGDC's purpose to advancing a liquefied natural gas project.

He cited 2020 census data demonstrating that the Fairbanks North Star Borough is the largest community in Interior Alaska and Fairbanks the second largest city in the state.

The current project, he said, bypasses Fairbanks, and AGDC, he said, has maintained that development of a Fairbanks spur line would need to be evaluated.

"HB 119 simply ensures that the development of a spur line to the City of Fairbanks and the Fairbanks North Star Borough be included in the Alaska LNG project by enshrining such language in the charter governing AGDC."

Comments

The Fairbanks North Star Borough passed a resolution Feb. 27, supporting a gas pipeline from the North Slope, "including a Fairbanks connector, to provide economic, environmental, and energy benefits to Fairbanks and the Interior region."

A letter from Golden Valley Electric Association President Travis Million supported passage of HB 119, calling natural gas a key legislative priority for GVEA.

"HB 119 sends a strong signal to private and public entities involved in the AKLNG discussions that Interior Alaska must no longer be a bystander, or secondary beneficiary of the project," Million said.

Elena Sudduth, general manager of the Interior Gas Utility, said in a March 5 letter of House State Affairs that it supports HB 119, which, it said, ensures "that Fairbanks, North Pole, and the greater Interior are included in the action taken to ensure Alaska's energy future" by mandating a direct spur to Fairbanks.

The standalone project

AGDC President Frank Richards responded to committee questions on AGDC's current project.

AGDC's original purpose, Richards said, was advancing an in-state natural gas pipeline, referred to as the standalone project, providing natural gas to Fairbanks and Southentral.

see GAS PIPELINE BILLS page 5

Petroleum news

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● THIS MONTH IN HISTORY

Kerr-McGee turning risk into reward

20 years ago: Kerr-McGee's success on Alaska's North Slope continues; good results from Schrader Bluff at Nikaitchuq No. 4

Editor's note: This story first appeared in the March 20, 2005, issue of Petroleum News.

By **KRISTEN NELSON**
Petroleum News

Kerr-McGee is two for two in Alaska, announcing a second successful drilling season with appraisal and exploration wells on Alaska's North Slope at prospects offshore the Kuparuk River and Milne Point units.

Kerr-McGee Oil & Gas Corp. said March 15, 2005, that it has tested the Schrader Bluff reservoir at its Nikaitchuq No. 4 horizontal appraisal well. The company said the well tested at rates up to 1,200 barrels per day during periods of the initial test, with the oil testing at 16 to 17 degrees API oil.

The viscous Schrader Bluff formation, called West Sak at Kuparuk, is under production at three fields onshore: the ConocoPhillips Alaska-operated Kuparuk River field and the BP Exploration (Alaska)-operated Milne Point and Prudhoe Bay fields. Both BP and ConocoPhillips have recently begun large-scale Schrader Bluff-West Sak developments using horizontal wells.

Kerr-McGee, a wholly owned affiliate of Oklahoma City-based Kerr-McGee Corp., said it also encountered the same Schrader Bluff interval at the Tuvaaq exploration well, some 3 miles to the west of Nikaitchuq No. 4, in the adjacent unit.

Kerr-McGee operates Nikaitchuq with a 70% working interest; Armstrong Alaska holds the remaining 30%.

Armstrong began acquiring leases in state waters in the Beaufort Sea in 2001, assembling the three adjacent prospects — Ooguruk, Tuvaaq and Nikaitchuq — and brought in operators Pioneer Natural Resources and Kerr-McGee.

Pioneer discovered oil at Ooguruk in 2003 and Kerr-McGee announced discoveries at Nikaitchuq in 2004.

The three prospects, Pioneer-operated Ooguruk and Kerr-McGee-operated Tuvaaq and Nikaitchuq, are adjacent offshore exploration units in the shallow waters of Harrison Bay. Exploration and appraisal drilling is done during the winter season from ice islands.

Kerr-McGee said it has increased its stake in Tuvaaq by acquiring an additional 40% working interest from Pioneer Natural Resources. Kerr-McGee now holds an 82% working interest in Tuvaaq and is the operator. Armstrong holds the remaining interest in Tuvaaq.

Kigun in Kuparuk River unit

Based on the results of drilling, Kerr-McGee said it is drilling a sidetrack, the Kigun well, to earn additional acreage.

The Kigun target is on ADL 355024, which is part of the ConocoPhillips Alaska-operated Kuparuk River unit. Kerr-McGee will operate Kigun with a 55% working interest upon completion of the drilling operations.

Kerr-McGee did not say if the prospect would remain in the Kuparuk River unit if the well proves successful.

"We are encouraged with the results we've seen thus far in Alaska," Dave Hager, Kerr-McGee's senior vice president responsible for oil and gas exploration and production, said in the company's statement. "Although we still need to complete the appraisal program, based on initial evaluation, it appears the Schrader Bluff interval might be developed throughout much of our 36,000 acres in the Nikaitchuq and Tuvaaq area."

Hager, speaking at the A.G. Edwards' Energy Conference in Boston March 15, 2005, said the company is targeting two reservoirs, the shallower Schrader Bluff and the deeper Sag River. The second horizontal appraisal well, the Nikaitchuq, is testing the Sag River formation; slides accompanying Hager's remarks described the No. 3 well as

see **HISTORY** page 5

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EIA OUTLOOK

er demand growth."

Natural gas

There was increased consumption of natural gas in the U.S. in January and February driven by below-normal temperatures, decreasing volumes in underground storage, expected to result in lower volumes of gas in storage for the rest of the year, resulting in an increase in the forecast for natural gas prices.

Henry Hub is now forecast to average $4.20 per million British thermal units in 2025, up 37% from EIA's October forecast and to average $4.50 per million Btu in 2026 on growth in global demand for liquefied natural gas.

Plaquemines LNG Phase 1 and Corpus Christi Stage 3 both started LNG production in December, with Plaquemines exports estimated to average 1.1 billion cubic feet per day in February, at 85% nominal capacity for the facility.

Two additional projects — Golden Pass and Plaquemines LNG Phase 2 — are expected to start up in the next 2 years, but the timing is uncertain.

"We expect China's imposition of tariffs on U.S. LNG that were enacted in early February to have little to no effect on U.S. LNG exports because destination-flexible U.S. LNG cargoes can be routed to other global markets," EIA said.

U.S. LNG exports were 12 bcf per day in 2024 and are forecast to be 14 bcf per day this year and 16 bcf per day in 2026.

EIA said U.S. dry natural gas production held steady in 2024 and is expected to increase by 2% both this year and next, rising to 105 bcf per day in 2025 on increased natural gas prices and increasing to 107 bcf per day in 2026. ●

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HISTORY

DAVE HAGER

drilling a new fault block. "We did test the Sag River at one of our vertical wells last drilling season at a rate of 960 barrels a day, 38 degree API," he said. "What we want to see now is what will it do out of a horizontal well."

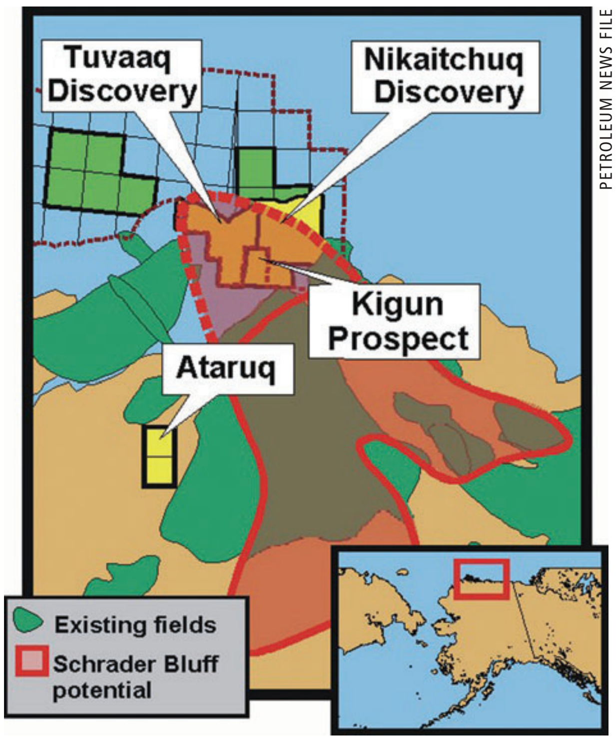
Results from the Tuvaaq well, Hager said, prove "the existence of the Schrader Bluff formation, the shallower formation, 3 miles to the west of Nikaitchuq." The Kigun prospect, he said, is being drilled to earn that acreage.

Hager said Kerr-McGee believes "that the Schrader Bluff may be well developed over much of the approximately 36,000 acres in the Nikaitchuq, Kigun and the Tuvaaq areas."

Onshore, he said, the Schrader Bluff is being developed on 160-acre spacing, and with "approximately 36,000 acres gross … I think you can see the potential that exists with this particular program." One of the slides accompanying Hager's remarks showed a resource of 30 million to 60 million barrels for the company's Alaska discoveries now being appraised.

Ataruq next

Kerr-McGee's 2005 drilling season program includes the two appraisal wells at Nikaitchuq and the exploration well at the Tuvaaq prospect. The Nikaitchuq No. 4 horizontal appraisal well tested the Schrader Bluff interval, while the Nikaitchuq No. 3 horizontal appraisal well currently is being drilled to test the Sag River formation, the company said.



PETROLEUM NEWS FILE

In 2004, Kerr-McGee announced successful exploration and appraisal wells on the Nikaitchuq prospect, with the vertical Nikaitchuq No. 1 testing at rates of more than 960 bpd of 38 degree API from the Sag River formation. The Nikaitchuq No. 2 was drilled 9,000 feet southeast of the discovery well and successfully extended the accumulation down dip.

Earlier this year, Kerr-McGee acquired a 50% working interest in the Ataruq prospect onshore Alaska and is the operator. Kerr-McGee said it plans to drill the initial Ataruq exploration well following the Nikaitchuq appraisal drilling.

Hager said that once drilling is finished at Nikaitchuq, Kerr-McGee will drill an exploration well at the Ataruq prospect onshore. Ataruq is the prospect Armstrong assembled and called Two Bits on the western edge of the Kuparuk River unit.

"This is a project that's south of the Nikaitchuq field," Hager said. "They're going to test the Kuparuk C and the Tarn formations."

The slide accompanying Hager's remarks described Ataruq as a potential extension of Kuparuk and Palm fields, and said Kerr-McGee, with a 50% working interest, plans one to two exploratory wells in the 2005 drilling season. ●

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GAS PIPELINE BILLS

The Legislature provided funding for permitting that project and to do design work including a lateral line to Fairbanks, some 32 miles, with the main line connecting to the Enstar line in Southcentral, work the corporation did from 2012 through 2015. Front-end engineering and design work was completed, Richards said, and rights of way were granted for both the mainline and the lateral to Fairbanks.

In 2014, he said, the Legislature also gave AGDC responsibility to represent the state in the LNG project, so it had both projects in 2014 and 2015, but in the 2015-17 timeframe, the Legislature directed that all funds available were to be directed to the Alaska LNG project, so the in-state project was put on the shelf.

Richards said AGDC is now working with Glenfarne on taking over as private developer for Alaska LNG. AGDC has also had a lot of interest from Alaska pipeline companies in developing the lateral line to Fairbanks, he said.

Asked why the work done on the in-state line couldn't be rolled into the Alaska LNG project, Richards said the in-state work was done under an Army Corps of Engineers environmental impact statement, while the AKLNG project includes the plant on the North Slope, the pipeline and the liquefaction facility and that work has been done under the Federal Energy Regulatory Commission. To include the in-state line would potentially open up the environmental process again.

That, he said, is why AGDC is looking at two entities, one developing the Alaska LNG project and the second the lateral line.

As to why the lateral wasn't part of the original AKLNG project, Richards said that work was begun when ExxonMobil, BP and ConocoPhillips were joint development partners with AGDC, and that project allowed for offtake points. It was not a choice made by AGDC, he said, but by the lead developer at the time. ●

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EXPLORATION & PRODUCTION

Upper foothills opened to tundra travel

The Alaska Department of Natural Resources' Division of Mining, Land and Water, said March 19 that it has opened the upper foothills area of the North Slope to winter off-road tundra travel.

The division said soil temperatures and snow cover within the upper foothills have met the criteria for opening — 9 inches of snow and soil temperatures colder than -5 degrees C at 30 centimeters depth.

The opening applies to operators with valid off-road vehicle travel permits for state-owned North Slope lands.

The division said snow cover may be thin in some areas and those areas should be avoided or special construction methods used to protect the tundra.

The lower foothills area remains closed to winter off-road travel.

The eastern coastal area opened for tundra travel Dec. 23; the western coastal area opened Dec. 30.

—PETROLEUM NEWS

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SANTOS UPDATE

"We are pleased with the Sockeye-2 well exploration discovery and its confirmation of resource potential over our Lagniappe leasehold. In addition, we are now 80% complete at our Pikka phase 1 project. Pipeline installation is progressing well and set to be completed in two winter seasons, putting us in a good position to pursue acceleration to first oil around the end of 2025. This will be dependent on logistics and weather allowing for the mobilization of key production models by barge up the Hay River."

Until the company has more certainty, guidance remains unchanged with first oil in mid-2026, Dingeman said.

Pikka phase 1 is expected to deliver 80,000 barrels of oil per day at full production shortly after start-up.

Santos said it remains committed to disciplined investment in the Alaska assets to deliver value for shareholders, delivering safe and efficient operations while advancing key development milestones.

—KAY CASHMAN

Contact Kay Cashman at publisher@petroleumnews.com

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REVENUE FORECAST

Total state revenues, restricted and unrestricted, were $16.298 billion in FY24 and are forecast to be $17.388 billion in FY25 and $15.901 billion in FY26.

Production, price forecast changes

In FY24, the department said, ANS oil production averaged 461,000 barrels per day and is expected to average 466,800 bpd in FY25 (up 200 bpd from the fall forecast) and 464,000 bpd in FY26 (down 5,400 bpd from the fall forecast).

Comparing the fall and spring forecasts, the largest production decreases are at the Slope's largest and oldest fields, Prudhoe and Kuparuk. Prudhoe is now forecast at 181,300 bpd, down from 187,200 bpd in the fall forecast, with Prudhoe satellites up slightly from 86,300 bpd in the fall forecast to 87,100 bpd in the spring forecast. Since the department includes Milne Point with the Prudhoe satellites and production from that field has been on a steady increase, the increase is probably from Milne. Kuparuk production is down from 48,000 bpd in the fall forecast to 44,700 bpd in the spring, and, as with Prudhoe, Kuparuk satellites show a slight increase from 49,200 bpd in the fall to 49,600 bpd in the spring. Kuparuk satellites include Coyote and Nuna, both currently under development.

The ANS oil price averaged $85.24 per barrel in FY24 and is now projected to average $74.48 bpd in FY25 (up 62 cents per barrel from the fall forecast) and $68 per barrel in FY26 (down $2 per barrel from the fall forecast). The department's oil price forecast is based on futures market predictions for Brent crude as far into the future as those are available and thereafter an inflation-based increase.

"The Spring 2025 Revenue Forecast comes during a time of continued uncertainty due to recent geopolitical and financial events, causing volatile market conditions," Revenue Commissioner Adam Crum said in a cover letter to the spring forecast. "It is important to note this forecast represents one plausible scenario within a range of potential outcomes."

In the spring forecast the department attributed the changes in forecast petroleum revenue to a combination of a lower price forecast and "adjustments to expected production and higher expected lease expenditures."

Allowable lease expenditures

The department said allowable oil and gas lease expenditures were an estimated $7.5 billion statewide in FY24, with $7.1 billion of that on the North Slope, and are expected to increase in FY25 to $8.6 billion statewide, $8.2 billion on the North Slope. In FY26 allowable lease expenditures are expected to be $8.5 billion statewide, $8 billion on the North Slope, with North Slope lease expenditures expected to average $7.2 billion annually over the following decade, led by new developments but including continued investments in the Slope's existing fields.

Transportation costs for North Slope oil averaged $10.53 per barrel in FY24, are forecast to average $10.92 per barrel in FY25 and $10.31 per barrel in FY26. Costs are expected to remain at some $10 per barrel over the coming decade, with inflationary pressures offset by higher production.

—KRISTEN NELSON

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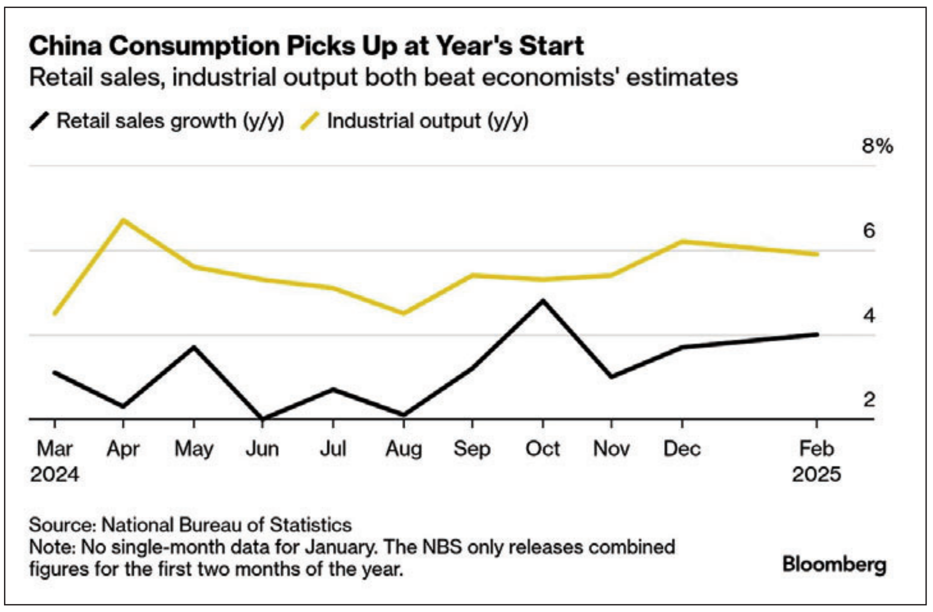

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OIL PRICES

On March 19, ANS held a $2.40 premium over Brent, versus a $2.57 premium over Brent on March 12.

In that time, ANS slid to a thin 34-cent loss — from its March 12 close of $73.52 per barrel, to close at $73.18 on March 19.

ANS gained 6 cents on March 19, while West Texas Intermediate rose 26 cents to close at $67.16 and Brent rose 22 cents to close at $70.78.

Prices closed in the green March 19 despite a bearish build in U.S. commercial crude inventories.

China explanation for ANS boost

Traders were at a loss to explain an extraordinary development March 6 as ANS skyrocketed $2.77 upward to close at $71.72, flipping positions with Brent to trade at a premium — of $2.26 — over the North Sea benchmark.

Stronger demand in Asia is one reason that Pacific cargo values might rise, but on March 6, analysts saw China as a weak spot for oil demand,

The crude-oil market "finds itself in the worst of all worlds right now," Michael Brown, Pepperstone senior research strategist said in a note, reported March 5 by MarketWatch.

China continues to struggle, while OPEC+ hikes production as the U.S. economy stalls, Brown said.

But government data released later in March has shown Chinese demand didn't crash despite moribund economic activity in country — instead, Chinese refiners managed to keep run rates high despite notching a 26-month import low in January.

Seaborne crude flows were poised to rebound strongly in March after Beijing adapted to U.S. sanctions on Russia and Iran, rising by 700,000 barrels per day month-over-month to 10.6 million bpd, the data said.

China has unveiled a $41 billion government subsidy to prompt buyers to replace old consumer goods with new, while allocating $27 billion to subsidize equipment upgrades.

Industrial output has risen by 5.9% year-over-year in January-February, exceeding consensus expectations, the data said.

The industrial activity creates an internal spike for demand, but China also has a history of buying, storing and refining extra oil to serve outside customers, particularly in Asia, with finished petroleum products.

China has been known to have increased its crude storage capacity in recent years, however, hard data on the country's actual stockpiling capabilities are not accurately known outside of China.

Crude inventories rise

U.S. commercial crude oil inventories for the week ended March 14 increased by 1.7 million barrels to 437.0 million barrels, 5% below the five-year average for the time of year, the U.S. Energy Information Administration said in its March 19 weekly petroleum products report.

The data were in line with a rise of 1.2 million barrels on average, according to an analyst survey by Platts S&P Global Commodity Insights.

Total motor gasoline inventories slid by 0.5 million barrels for the period to 240.6 million barrels — 2% above the five-year average for the time of year, the EIA said. Distillate fuel inventories were drawn down by 2.8 million barrels to 114.8 million barrels — 6% below the five-year average for the time of year.

The Platts survey forecast supply decreases of 2.3 million barrels for gasoline and 370,000 barrels for distillates.

A smaller-than-expected drawdown in gasoline inventories might indicate a "more healthy U.S. appetite for air travel," especially considering a larger-than-expected draw in distillates, which include jet fuel, Gary Cunningham, director of market research at Tradition

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DATA CENTER PROJECT

The commission said Hilcorp does not have the ability to segregate gas used for power generation for the third-party data center from gas used to generate power for Endicott facilities.

Relevant AOGCC regulations refer to the 1998 revision of the American Petroleum Institute Manual of Petroleum Measurement Standards which does not recognize venturi meters for custody transfer. The commission said venturi meters were recognized in the 2023 edition of the API MPMS, but said "venturi tube measurement equipment at Endicott does not meet AOGCC custody transfer measurement requirement nor the provisions of" the 2023 edition of API MPMS.

Circumstances at Endicott

The commission said Hilcorp has estimated that less than 0.15% of total gas produced at Endicott will be used for power production at the data center during the pilot. The company has informed the commission that the data center has been installed but is not yet connected to the power supply.

The company proposes to indirectly measure the gas consumed to provide data center power by calculation based on "the measured total volume of gas consumed at Endicott for power generation and a ratio of the measurements of the electricity consumed by the third-party data center and total electricity produced at Endicott."

There are electrical meters to measure power consumed at each Endicott facility power generating turbine and at the third-party data center. The data center will provide Hilcorp with weekly power consumption reports.

The Endicott pilot project is the first such application under AOGCC's jurisdiction, the commission said, and it "has no experience nor jurisdiction regarding electrical meters."

The commission concluded that because the data center was a temporary pilot project and involves a small volume of gas it warrants "conditional approval of a waiver to use non-custody transfer meters."

Conditions

The commission imposed numerous conditions:

•The pilot project will not exceed 5 years;

•The equipment must be as described in Hilcorp's application and the company must obtain commission approval before making changes to equipment or measurement methodology;

•Numerous inspections and calibration checks are required;

•24-hour notification to the commission is required for witness opportunities of "function checks, calibrations and inspections of the venturi measurement system prior to start/restart of the third-party data center and any equipment changes";

•Equipment and records that must be available for inspection are specified;

•Copies of calibration reports required within 7 days of completion, with contents of reports specified; and

•Electrical power consumption reports must be available upon request.

—KRISTEN NELSON

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HILCORP INLET WELLS

incidental take authorization shall be granted if NMFS finds that the taking will have a negligible impact on the species or stock(s)," the agency said in a Federal Register notice published March 13 requesting comments and information on the application by April 14.

In its application Hilcorp said the proposed "activities produce sound in the marine environment that has the potential to affect local marine mammals."

Exploration wells

Hilcorp said it plans to drill one exploration well between the Anna and Bruce platforms near the northern border of Trading Bay and two exploration wells in the Middle Ground Shoal unit in middle Cook Inlet, with the drilling based on 2D and 3D seismic and historical well information.

The first well, in Trading Bay, is proposed for 2026, between April and December; the MGS unit wells are proposed for drilling in 2028, but Hilcorp said the wells may occur in any year in the 5-year period.

The wells would be drilled by Hilcorp's Spartan 151 jack-up rig, which would have to be mobilized to middle Cook Inlet and then demobilized back to Rig Tenders Dock.

"The exact start dates for drilling the wells are currently unknown and are dependent upon availability of the jack-up rig," Hilcorp said. Drilling and testing are expected to take some 40 to 60 days for each well, with two days of tugs towing the jack-up and six days of pile driving. The wells will be plugged and abandoned after drilling.

"Acoustic sources associated with exploratory drilling for which incidental take authorization is requested include tugs towing, holding, and positioning a jack-up rig and pile driving," the company said.

Production drilling

The company did not include a proposed number of development wells, saving it "routinely conducts production drilling activities to meet production needs," and said all its platforms have the potential for production drilling, which is done with conventional drilling equipment through existing well slots or wellbores in the legs of existing platforms.

Production drilling in middle Cook Inlet and Trading Bay is planned for the open water season, generally April to November, activities spanning up to 240 days, with drilling by the Spartan 151 or a similar jack-up which will be towed by three ocean-going tugs, with a fourth tug on standby in the event of mechanical issues.

At the Tyonek platform in the North Cook Inlet unit, drilling activities are expected to span 240 days, with varying days with sound-producing activity from tugboats towing, holding or position a jack-up.

In addition to drilling at Tyonek, Hilcorp said 10 drilling conductor pipes — also described as piles — will be driven into the sediment to support future well slots for production well drilling, not to exceed installation of two per year.

Pipelines

Hilcorp also plans two pipeline replacement or installation projects between 2025 and 2029, using either a lay barge method or a pipe pull method, with both methods installing or replacing 7,500 feet of pipeline.

"Each project's scope entails the installation or replacement of pipeline in either middle Cook Inlet or Trading Bay or a combination of both," the company said.

The replacement and installation of pipelines is to ensure pipelines meet requirements of the Pipeline and Hazardous Materials Safety Administration or, in the case of new pipelines, to address growing consumer demand for natural gas in Southcentral.

Hilcorp said timelines for pipeline projects are subject to weather and equipment readiness. ●

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SOCKEYE-2 WELL

Lagniappe Alaska, a Bill Armstrong company and Oil Search (Alaska), a subsidiary of Santos Limited, announced preliminary results of the Sockeye-2 exploratory well on the eastern North Slope, in which Apache holds a 50% working interest and operator Lagniappe and partner Santos each hold 25%.

The Sockeye-2 well, approximately 8 miles southeast of Badami, was drilled to a depth of some 10,500 feet and successfully encountered a high-quality reservoir with approximately 25 feet of net oil pay in one blocky, Paleocene-aged sand with an average porosity of 20%. As compared to recent regional field analogues in the Brookian play, the porosity and permeability are both better than expected, with the permeability to be confirmed through an upcoming flow test, which will be done by the first of May.

Additional zones of potential pay were also encountered in the shallower Staines Tongue formation.

In a March 18 interview with Petroleum News, Bill Armstrong described the discovery as "Alaska-like" in that it appears to stretch under "some 30,000 acres of the 350,000 Lagniappe block but be relatively thin at 25 feet unlike big discoveries elsewhere in the world which can be hundreds of feet thick but be substantially smaller in aerial extent."

COURTESY ARMSTRONG

Key individuals on the exploration program: From left to right: Bill Armstrong, Liz Armstrong, Colby Vandenburg, Jessica Schmidt, Kevin Dorrington, Ed Teng, Nate Lowe

The Sockeye prospect is AVO supported across 30,000 acres, and confirms the partners' geologic and geophysical models, de-risking numerous additional prospects in the area.

Wireline logging is complete and additional data collection is underway.

"The Sockeye-2 test is the second successful exploratory well drilled by the partnership on the Lagniappe position on state lands. The first well, King Street-1, was a new field discovery with oil in two separate Brookian zones. The Sockeye-2 well further demonstrates the potential of the play, presenting an exciting opportunity in an active area of the North Slope with significant existing infrastructure," said Bill Armstrong, who is CEO of Armstrong Oil & Gas and owner and CEO of Lagniappe.

"We are very encouraged by the results at the Sockeye-2 well, which further proves our geologic and geophysical models and confirms a working hydrocarbon system. We look forward to the results of the flow test and sharing more information about the broader opportunity in Alaska," said John J. Christmann, APA Corp. CEO.

There have been very few wells drilled in and near Lagniappe's South Badami area — and most of those wells were drilled in the 1970s trying to find another Prudhoe Bay, but almost all the wells had good oil shows, Armstrong said.

Prior to finding all that oil in the Nanushuk formation west of Prudhoe Bay most people were saying Alaska's North Slope had very little remaining potential. The Nanushuk at Pikka changed all that.

Armstrong interview

In a March 18 interview with Petroleum News, Armstrong said the Sockeye prospect was "based off of reprocessed 3D seismic. The trap is very similar to what we found at the Pikka field; a top-set stratigraphic trap. This discovery extends the North Slope top-set play 94 miles east of our Pikka discovery. A big trend!"

The ultimate size of the field still needs to be appraised, he said, "but as currently mapped it appears to be around 30,000 acres. The Sockeye field, if that's what we call it, is very Alaska-like. A good/very good oil saturated sand that covers a big area. Due to the North Slope's structural quiescence — a lack of faults, anticlines, etc. —fields can be and are commonly large in aerial extent such as Pikka, Prudhoe Bay, Kuparuk River, Milne Point, Willow and Alpine."

The Sockeye pay, Armstrong said, "looks very similar to the pay sands at Willow and Alpine, except the permeabilities at Sockeye appear to be substantially better —maybe 10-times better. The oil is medium gravity, low viscosity, sweet oil."

Last year, Armstrong said, was a rough year for all the operators on the North Slope due to a late start to winter and then all the operational shutdowns due to high winds.

"We intended to drill three wells last year: King Street, Sockeye and Chinook (formerly known as Voodoo). Only the King Street well was drilled to TD. That well found oil in two zones.

"This year's Sockeye well replaced last year's well which didn't get through a difficult shallow drilling issue —an issue that we were able to solve this year with a few drilling adjustments.

"Our primary objective came in as mapped. We also have additional pay shallower in the well. Seismic indicates that there are multiple look-alike anomalies nearby to Sockeye. Again, very Alaska-like.

"Our biggest prospect on our Lagniappe block, Chinook, will be located and drilled once we have finalized our seismic processing," he said, referring to a new seismic shoot by SAE.

What else?

What else is Armstrong up to?

An Armstrong affiliate was recently awarded a 100% stake in a 3.5 million acre area for offshore exploration in Aruba, amidst the hot Latin America oil plays (Guyana, Suriname, Columbia).

"We are really enthusiastic about Aruba's opportunities. It is truly exciting," Armstrong said in a text to Petroleum News.

"We have two to three world class prospects that could hold super-giant reserves for oil and gas. We're finalizing the reprocessing of a 3500 square kilometer 3D seismic shoot, and the data is showing very clear DHIs," he said. ●

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OIL PRICES

Energy, told MarketWatch.

Oil prices fell March 18 as U.S. President Donald Trump and Russian President Vladimir Putin discussed an end to the three-year-old war in Ukraine, which potentially could lead to easing of sanctions on Russia's fuel exports, boosting world crude supplies.

Putin stopped short of endorsing a full 30-day cease-fire sought by the White House, but Putin and Ukraine President Volodymyr Zelenskyy did agree to a moratorium on energy facilities and infrastructure.

ANS fell 34 cents March 18 to close at $73.12, while WTI dropped 68 cents to close at $66.90 and Brent dropped 51 cents to close at $70.56.

On March 17, ANS added 44 cents to close at $73.46, WTI added 40 cents to close at $67.58 and Brent added 49 cents to close at $71.07.

ANS rose 53 cents March 14 to close at $73.02, as WTI rose 63 cents to close at $67.18 and Brent rose 70 cents to close at $70.58.

Prices slid March 13. ANS slid $1.03 to close at $72.50, WTI dropped $1.13 to close at $66.55 and Brent slid $1.07 to close at $69.88.

Peace deal will determine Russian gas exports

Natural gas volumes from Russia to Europe have collapsed since the Ukraine invasion, from almost 150 billion cubic meters per year in 2021 to only 15 bcm per year, Wood Mackenzie's Simon Flowers said in the Edge March 19.

The terms of any future deal peace deal with Russia will determine the willingness of both the United States and Europe to re-establish political and economic ties with Russia, Flowers said, adding, "We expect that the removal of sanctions on its LNG projects will be the very least of Russian demands as it looks to reaffirm its position as a global player."

Based on early-stage dynamics of negotiations, a peace deal effectively forced on Ukraine by the U.S. and Russia looks most likely, he said. This widens the U.S./ Europe rift and allows for only a limited return of Russian piped gas and LNG into the market.

More war would mean more sanctions on Russian gas, Flowers said. A scenario where all parties sign a mutually acceptable peace agreement looks least likely at this stage, but it would "open the door to material volumes of Russian gas into Europe." ●

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