Petroleum news

page 6 EIA: US output 12.9 million bpd in '23, forecast at 13.2 million in 2024

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Jade, DNR meet on Sourdough; Pt Thomson producing into storage

THE EASTERN NORTH SLOPE Sourdough development is still on hold, with operator Jade Energy unwilling to spend more than the $20 million its already invested in the project until it can convince Alaska Department of Natural Resources officials to reverse their decision that put the acreage in default.

The parties are still talking.

On March 29, DNR Commissioner John Boyle, Deputy Commissioner John Crowther and DNR's Division of Oil and Gas Director Derek Nottingham met with Jade Managing Member Erik Opstad and his team.

In response to an email from Petroleum News about the outcome of the meeting, Crowther responded on April 8 confirming the meeting had taken place.

"We are reviewing their requests but cannot comment further at this time," Crowther said, promising to provide results when they were available.

A follow-up email sent by Opstad to the DNR meeting attendees said, "I hope we successfully conveyed that the conditions imposed by DOG for its approval of the 5th POD

see INSIDER page 10

Drought poses problem for water-intensive gas industry

Unless there is a sudden change in weather patterns, persistent drought conditions pose a big challenge for the natural gas sector in Western Canada says a report by Deloitte Canada.

The report, made public in early April, says the potential water shortage is a key risk facing gas producers in 2024.

It says some of the most extreme drought conditions are currently in the gas-dependent regions of northeastern British Columbia and northwestern Alberta where water use is critical to the development of gas that underpins the LNG facilities expected to come on stream in the next year.

Andrew Botterill, national oil, gas and chemicals leader at Deloitte Canada, said the upcoming availability of new processing and transmission infrastructure is "the moment the natural gas industry has been waiting for for 10 years," but the prospect of water restrictions means "we've now got another complication."

see DROUGHT POTENTIAL page 9

POD: Hilcorp continues to look at drilling into NTBU from Monopod

Hilcorp Alaska has been trying to reach gas reserves in the North Trading Bay unit by sidetracking wells from the Monopod in the Trading Bay unit, but so far without success.

In the company's 2024 plan of development for North Trading Bay, submitted April 1 to the Alaska Department of Natural Resources' Division of Oil and Gas, the company reviewed two failed attempts to sidetrack in 2022 and a third in 2023, and told the division that drilling into the NTBU is unlikely in the 2024 POD period, July 1 through June 30, 2025, "due to the need to refresh access options following the recent failed drill wells, as well as winter drilling constraints limiting the drilling season."

Hilcorp said it "needs time to further evaluate its options to develop the NTBU and will be able to provide additional insight in the 2025 POD."

Production ceased in 2005

In its May 25, 2023, approval of the 2023 POD for NTBU,

see HILCORP DRILLING page 10

FINANCE & ECONOMY

ANS hovers near $90

ANS, Brent back in low-$90s as Middle East tensions fan oil prices higher

By STEVE SUTHERLIN
Petroleum News

Alaska North Slope crude and Brent crude both jumped back into the $90s April 10 as traders contemplated the specter of a direct confrontation between Iran and Israel.

ANS lifted 96 cents to close at $90.57 per barrel, while West Texas Intermediate jumped 98 cents to close at $86.21 and Brent jumped $1.06 to close at $90.48.

ANS was up 86 cents for the trading week ending Wednesday, April 10, from a close of $89.71 April 3 to $90.57 on April 10.

Fears are that Iran may attack Israel in the wake of Israel's hit on the Iranian embassy in Syria in early April.

U.S. intelligence and U.S. allies believe drone or missile attacks by Iran on government and military targets in Israel is imminent, Bloomberg said, citing people familiar with the situation.

Prices were also fanned higher as a deadly air strike by Israel in Gaza killed three sons and other family of a senior Hamas official, complicating negotiations for a cease fire and hostage deal between Israel and Hamas.

"Bottom line, tensions remain elevated between Israel and Hamas and while ceasefire talks are as close as they have been yet, there remain risks of further escalation and a contagion effect in the region, particularly with Iran who recently threatened to

see OIL PRICES page 9

EXPLORATION & PRODUCTION

APA: Lagniappe update

Three-rig drilling operations continue on eastern North Slope

By KAY CASHMAN
Petroleum News


BILL ARMSTRONG

When asked for an update on the eastern North Slope drilling program operated by Bill Armstrong's Lagniappe Alaska, Alex Franceschi, a spokesperson for APA Corp.'s Apache Corp., sent Petroleum News the following statement on April 8: "The three rig drilling operation is ongoing and we have no results to report at this time. We plan to provide an update after we finish the drilling program and analyze the technical data."

Lagniappe, APA and Santos are partners in a two-year exploration program on a 148-lease block south of Badami. Their goal is to drill six wells in the 275,000 acres, three each winter season, starting with first quarter 2024.

Armstrong's work led to the discovery of Pikka, a billion-barrel new field now under construction west of Prudhoe Bay. He thinks there are new oil discoveries to be made east of Prudhoe Bay, also in the Brookian.

In a text to Petroleum News before the partnership deal was struck between APA, Santos and Lagniappe, Armstrong described the area as "defined off of high effort, reprocessed modern 3D. Really exciting stuff. Big targets," adding

see LAGNIAPPE UPDATE page 11

GOVERNMENT

Cook Inlet bills move

Legislation for encouraging new gas development reaches House Finance

By ALAN BAILEY
For Petroleum News


TOM MCKAY

Three bills designed to encourage natural gas exploration and development in the Cook Inlet basin have been passed from the House Resources Committee to the House Finance Committee for review. And on April 4 House Finance listened to presentations on the bills.

The bills consist of House Bill 257, to authorize the Alaska Department of Natural Resources to supply certain Cook Inlet seismic survey data free of charge to people qualified to use it; House Bill 223 to eliminate state royalties on newly developed Cook Inlet gas fields; and House Bill 387 that would award tax credits to a company that brings a jack-up rig to the Cook Inlet.

Four other bills aimed at encouraging Cook Inlet development remain in House Resources.

The bills come in response to growing concerns about pending shortages of natural gas supplies from the Cook Inlet basin. Natural gas is used to heat buildings and is the primary fuel for power generation in Southcentral Alaska.

see INLET BILLS page 8

● CANADA

Nuclear option resurfaces in Alberta

Could be 2035 before province sees first nuclear reactor; monies allocated to study conversion of fossil fuel electric generation

By GARY PARK
For Petroleum News

For the umpteenth time Alberta is hoping to utilize nuclear power — a target that Premier Danielle Smith says is still about a decade away despite frequent moves by government and industry in the direction of deploying the province's first small modular reactor, SMR.

"Our industry is anticipating it will take until 2035 to be able to get the first nuclear reactor rolled out in Alberta, but I hope we can do it a lot faster than that," Smith told reporters at an SMFR Summit in Calgary in early March.

Smith's government is allocating C$600,000 to SMR developer X Energy Reactor in partnership with Calgary-based TransAlta that is studying repurposing a fossil fuel electricity generation site for a nuclear reactor.

SMR potential for oil sands

The potential of nuclear power in the oil sands has gathered steam with Terrestrial Energy, based in Oakville, Ontario, forming a base in Alberta to offer an opportunity that is not available elsewhere in Canada to develop SMRs.

"The nuclear solutions for Eastern Canada are very much focused on a traditional nuclear system. This is an on-grid power generation idea," said Simon Irish, the CEO of Terrestrial Energy.

He said Alberta, with a C$1 trillion annual energy market, offers opportunity for private energy that is now available in some other parts of Canada, namely Ontario, Saskatchewan and New Brunswick, the three most active of Canada's 10 provinces who have all signed a memorandum of understanding to develop SMRs.

"The nuclear solutions for Eastern Canada are very much focused on a traditional nuclear system," said Irish. He said the new nuclear generation system will provide high quality heat for industry, which is "clean, cost competitive, secure and reliable."

The investment by Terrestrial will create 29 jobs over the next two years, targeting development of a zero-emission heat and power plant that will provide direct-use power in oil sands projects.

SMRs to reduce emissions

Brad Parry, CEO of Calgary Economic Development, said the SMRs have been identified as a key tool in reaching net zero emissions and an important part of the energy transition taking place in Calgary.

In January, X-Energy signed a memorandum of understanding with the government agency Invest Alberta to develop economic opportunities to support the potential deployment of the Xe-100 SMR in Alberta, while GE-Hitachi and ARC Energy have a foothold in other provinces.

Duane Bratt, a political science professor at Mount Royal University in Calgary, said public opinion in Canada on nuclear energy has changed dramatically over the past decade, moving from below 50% approval rate to 70%.

He said the understanding about SMR has grown as well. "Critics will say, 'Well, if it hasn't been licensed already it never should be,' which is a kind of a ridiculous argument." ●

Contact Gary Park through publisher@petroleumnews.com

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● EXPLORATION & PRODUCTION

Baker Hughes US rig count down 1 to 620

Texas gains 7 rigs; California, New Mexico each down 3; March worldwide rig count 1,793, down 20 from February, down 86 from '23

By KRISTEN NELSON

Petroleum News

The Baker Hughes' U.S. rotary drilling rig count was 620 the week ending April 5, down by one rig from 621 the previous week, and down by 133 from 151 a year ago, following a drop of three rigs last week. The rig count was down in five and up in three of the last eight weeks, with a loss of 18 against a gain of 15 over the period, following a downward trend dominant since the beginning of May.

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 2023, the count hit its low point Nov. 10 at 616, down from a high of 775 on Jan. 13, 2023. In 2022, the count bottomed out at 588 Jan. 1, reaching a high for the year of 784 on Nov. 23.

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 April 5 count includes 508 rigs targeting oil, up by two from the previous week and down 82 from 590 a year ago, with 110 rigs targeting natural gas, down two from the previous week and down 48 from 158 a year ago, and two miscellaneous rigs, down one from the previous week and down one from a year ago.

Fifty-one of the rigs reported April 5 were drilling directional wells, 557 were drilling horizontal wells and 12 were drilling vertical wells.

Texas (297) was up by seven rigs from the previous week and Pennsylvania (22) was up by a single rig.

California (3) and New Mexico (108) were each down by three rigs.

Louisiana (39) was down by two rigs and West Virginia (8) was down one rig.

Baker Hughes shows Alaska with 14 rotary rigs active April 5, unchanged from the previous week and up by four from a year ago when the count was 10.

Rig counts in other states were unchanged from the previous week: Alaska (14), Colorado (15), North Dakota (32), Ohio (12), Oklahoma (44), Utah (12) and Wyoming (11).

Baker Hughes shows Alaska with 14 rotary rigs active April 5, unchanged from the previous week and up by four from a year ago when the count was 10.

The rig count in the Permian, the most active basin in the country, was up by one from the previous week at 317 and down by 36 from 353 a year ago.

Baker Hughes' monthly international rig count for March, issued April 5, is up by 13 from February at 971, with land rigs up one to 736 and the offshore count at 235 up by 12. Compared to the March 2023 count of 930, the March 2024 international count is up by 41, with land rigs up by 34 and offshore rigs up by seven.

Baker Hughes began providing a monthly international rig count in 1975. The international count excludes North America, which is included in the company's worldwide figures.

The Middle East accounted for the most rigs in the international totals for March, 344, followed by Asia Pacific with 229, Latin America with 165, Europe with 118 and Africa with 115.

The U.S. rig count averaged 625 in March, up by three from February, and down 127 from March 2023, while the Canadian count for March averaged 198, down 36 rigs from February and up by one from March 2023.

Worldwide the rig count was 1,793 in March, down 20 from 1,813 in February and down 86 from 1,878 in March 2023. ●

Contact Kristen Nelson at knelson@petroleumnews.com

GOVERNMENT

State issues proposed carbon offsets regs

The Alaska Department of Natural Resources has a draft out for public comment of regulations for a portion of its carbon offset program.

In a March 28 press release, DNR said the regulations stem from Senate Bill 48, enacted last year. That bill created two pathways for developing carbon storage projects — the draft regulations apply to just one of those options, establishment by the state of a carbon offset program through DNR's Office of Project Management and Permitting.

Under that option, the state can develop carbon storage projects, generating revenue through sale of carbon credits issued by a registry for those projects.

The other option, with draft regulations expected out later this spring, covers the carbon leasing program in DNR's Division of Mining, Land and Water, which enables the state to lease lands to third parties to develop carbon projects, with the third party doing the work of identifying, planning and developing the project. The third party would compensate the state for use of the land.

"Regulations are a critical step in our goal to monetize the carbon-removal benefits of Alaska's vast natural resources by leveraging free-market demand for decarbonization," Gov. Mike Dunleavy said. "We have the opportunity to grow our economy while actively managing our forests and ensuring continued public access and use of State of Alaska lands."

The regulations, which include steps and criteria for identifying and evaluating projects, provide the framework for DNR to implement carbon projects on state lands. DNR would determine if projects are in the state's best interests, contract for project services and register projects.

"Carbon offsets can be a substantial new revenue stream for the people of Alaka," said DNR Commissioner John Boyle. "Through active management of the state's forests, we can improve forest health, mitigate our risk of wildfires, and grow our inventory of merchantable timber which will lead to future economic opportunities. The Carbon Offset Program is an innovative new program in line with DNR's overall mission to develop, conserve and maximize the use of Alaska's natural resources for the benefit of Alaskans."

DNR said the goal is to have regulations for both programs, the state carbon offset program and the carbon leasing program, in place by mid-2024.

For updates on the program go to: https://dnr.alaska.gov/carbon.

Comments on these regulations are due by April 29.

—PETROLEUM NEWS

● EXPLORATION & PRODUCTION

February Cook Inlet gas volumes down 4.7%

Average was 206,568 mcf per day, down month-over-month; also down 7.1% from February 2023; Ninilchik has steepest drop

By **KRISTEN NELSON**
Petroleum News

Cook Inlet natural gas volumes averaged 206,568 thousand cubic feet per day in February, down 10,117 mcf per day, 4.7%, from a January average of 216,684 mcf per day and down 7.1% from a February 2023 average of 224,618 mcf per day.

Volumes are calculated from Alaska Oil and Gas Conservation Commission data, reported on a month-delay basis. For natural gas AOGCC reports measurements in thousands of cubic feet, mcf.

Six large fields accounted for 81.4% of February production, 168,083 mcf per day: North Cook Inlet, Beluga River, Ninilchik, Kenai, McArthur River and Kitchen Lights; fifteen smaller fields accounted for the remaining 18.6%.

Larger fields

Hilcorp Alaska's North Cook Inlet, where AOGCC records show the company completed two grassroot wells and a sidetrack over the last year, averaged 45,148 mcf per day in February, 21.9% of the inlet total, down 1,295 mcf per day, 2.8%, from a January average of 46,483 mcf per day but up 20.4% from a February 2023 average of 37,501 mcf per day.

At Hilcorp-operated Beluga River — Chugach Electric Association holds the majority working interest in the field — where Hilcorp completed six wells in 2023, February production averaged 40,130 mcf per day, 19.4% of the inlet total, down 1,234 mcf per day, 3%, from a January average of 41,364 mcf per day, and down 2.3% from a February 2023 average of 41,061 mcf per day.

At Hilcorp's Ninilchik, where the company completed three wells in 2023, February production averaged 38,736 mcf per day, 18.8% of the inlet total, down 3,930 mcf per day, 9.2%, from a January average of 42,667 mcf per day and down 20.9% from a February 2023 average of 48,958 mcf per day.

No new wells were completed in 2023 by Hilcorp at its Kenai field, although three were permitted in late 2023 and early 2024. Kenai gas production averaged 19,087 mcf per day in February, 9.3% of inlet production, up 101 mcf per day, 0.5%, from a January average of 18,986 mcf per day but down 17.4% from a February 2023 average of 23,099 mcf per day.

Hilcorp's McArthur River, where no new wells were drilled in 2023, averaged 12,749 mcf per day in February, 6.2% of inlet production, down 227 mcf per day, 1.8%, from a January average of 12,976 mcf per day and down 17.7% from a February 2023 average of 15,488 mcf per day.

There were also no new wells drilled at Furie's Kitchen Lights in 2023. The field averaged 12,232 mcf per day in February, 5.9% of inlet volume, down 305 mcf per day, 2.4%, from a January volume of 12,537 mcf per day, but up 1.3% from a February 2023 average of 12,077 mcf per day.

Smaller fields

Several smaller Cook Inlet fields saw drilling in 2023 or have permits for 2024 drilling. All are Hilcorp fields. The company permitted a well at its Cannery Loop field early this year, drilled a sidetrack at Lewis River in 2023, drilled three new gas wells at Swanson River in 2023, did a redrill of a Trading Bay well in 2023 and currently has a new well permitted at that field.

These smaller fields have production ranging from 4.8% of total volume to less than 0.1%, from an average of 9,823 mcf per day to an average of 123 mcf per day.

Hilcorp's Beaver Creek averaged 9,823 mcf per day in February, down 1,280 mcf per day, 11.5%, from a January average of 11,103 mcf per day but up 11% from a February 2023 average of 8,849 mcf per day.

Hilcorp's Swanson River averaged 6,492 mcf per day in February, down 368 mcf per day, 5.4%, from a January average of 6,859 mcf per day and down 16% from a February 2023 average of 7,729 mcf per day.

Hilcorp's Cannery Loop averaged 5,172 mcf per day in February, down 100 mcf per day, 1.9%, from a January average of 5,272 mcf per day but up 8.6% from a February 2023 average of 4,762 mcf per day.

Hilcorp's Deep Creek averaged 3,402 mcf per day in February, down 135 mcf per day, 3.8%, from a January average of 3,537 mcf per day and down 15.7% from a February 2023 average of 4,033 mcf per day.

Hilcorp's Granite Point averaged 3,086 mcf per day in February, down 6 mcf per day, 0.2%, from a January average of 3,092 mcf per day and down 7.3% from a February 2023 average of 3,327 mcf per day.

AIX's Kenai Loop averaged 2,156 mcf per day in February, down 65 mcf per day,

see **INLET GAS** *page 5*

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Kay Cashman	PUBLISHER & FOUNDER
Mary Mack	CEO & GENERAL MANAGER
Kristen Nelson	EDITOR-IN-CHIEF
Susan Crane	ADVERTISING DIRECTOR
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Steve Sutherlin	CONTRIBUTING WRITER
Judy Patrick Photography	CONTRACT PHOTOGRAPHER
Forrest Crane	CONTRACT PHOTOGRAPHER
Renee Garbutt	CIRCULATION MANAGER

ADDRESS
P.O. Box 231647
Anchorage, AK 99523-1647

NEWS
907.522.9469
publisher@petroleumnews.com

CIRCULATION
281.978.2771
circulation@petroleumnews.com

ADVERTISING
Susan Crane • 907-250-9769
scrane@petroleumnews.com

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● THIS MONTH IN HISTORY

Commission conditionally OKs gas sales agreement

20 years ago this month: Regulatory Commission of Alaska calls for changes in gas sales agreement between Enstar, NorthStar Energy

Editor's note: This story first appeared in the April 11, 2004, issue of Petroleum News.

By KRISTEN NELSON

Petroleum News

The Regulatory Commission of Alaska has conditionally approved a gas sales agreement between Enstar Natural Gas Co. and NorthStar Energy Group Inc. that will bring natural gas to Homer at the southern end of the Kenai Peninsula in Southcentral Alaska.

The agreement provides for 20 years of natural gas delivery from NorthStar's North Fork field east of Anchor Point.

The commission, in a March 23, 2004, order, required some changes in the agreement.

In addition to amending the agreement, both companies have a lot of work to do before any pilot lights are lit on the lower end of the peninsula.

Dan Dieckgraeff, Enstar's manager of finance and rates, told Petroleum News in August when the companies announced the sales agreement that it would probably take a year and a half to two years to begin delivering gas. Approval of the contract and the proposed rate by the commission is the first step, he said.

There is a single well at the field, drilled in 1965. NorthStar has to drill at least one additional well before the gas sales agreement becomes effective and must raise proved reserves at the field from 12 billion cubic feet to 14.5 bcf.

Then there are the pipelines: NorthStar will build the 8 miles from North Fork to Anchor Point. Enstar will build the 11 miles from Anchor Point to Homer, and the local distribution lines.

NorthStar, for its part, hopes to do more than provide natural gas for Homer. Larry Snead, manager of land and contracts for NorthStar, said in August that building the pipeline from North Fork to Anchor Point is the most exciting part of the project for NorthStar, because that "allows us the opportunity to build a line north" later to hook up with the Kenai Kachemak Pipeline, allowing the company to move gas from the lower peninsula north.

Commission lowers floor price

Enstar and NorthStar proposed a floor price of $3 per thousand cubic feet for the gas but the commission found that floor to be too high, and is requiring the companies to reduce the floor to $2.75 per mcf, and also to modify the transportation rate to include a cap of 30 cents per mcf, and to limit arbitrage to not more than 15% of the total volume of gas sold under the agreement.

The commission approved a proposal to charge Homer customers a $1 per mcf surcharge to permit delayed recovery of the contribution customers must pay to Enstar to build its line extension to Homer, a charge which customers normally must pay up front before they receive service, the commission said. The surcharge would continue until actual capital costs of the pipeline from Anchor Point to Homer are recovered, estimated to be approximately 10 years.

Alaska Attorney General opposes pricing method

The Alaska Attorney General opposed the pricing method for the gas, a 36-month trailing average of Henry Hub natural gas futures prices. The commission disagreed, finding the use of Henry Hub futures prices consistent with customary language and practice of commerce, and noted that Enstar's current long-term gas supply

see HISTORY page 7

LAND & LEASING

Division issues call for new information

The Alaska Department of Natural Resources' Division of Oil and Gas has issued a call for new information for areawide oil and gas lease sales in the Beaufort Sea, North Slope and North Slope Foothills. The next sales, the division said, are planned for the second half of the year.

The division issues best interest findings every 10 years for each areawide sale area, and supplements as required.

The most recent best interest findings were issued for the Beaufort Sea in 2019, for the North Slope in 2018 and for the North Slope Foothills in 2021. The division said no supplements have been issued for these areas.

The division is requesting substantial new information. It will then determine, based on the information received, whether a supplement for an areawide BIF is justified.

The division said it "generally considers 'substantial new' information to be published research, studies, or data directly relevant to the matters listed in AS 38.05.035(g) that has become publicly available over the last year."

Substantial new information must be received by 5 p.m. May 6 to be considered.

—PETROLEUM NEWS

continued from page 4

INLET GAS

2.9%, from a January average of 2,221 mcf per day but up 9.8% from a February 2023 average of 1,964 mcf per day.

Vision Operating's North Fork averaged 1,995 mcf per day in February, down 14 mcf per day, 0.7%, from a January average of 2,008 mcf per day and down 26.5% from a February 2023 average of 2,712 mcf per day.

Hilcorp's Ivan River averaged 1,920 mcf per day in February, down 800 mcf per day, 29.4% from a January average of 2,720 mcf per day and down 72.3% from a February 2023 average of 6,928 mcf per day.

Hilcorp's Lewis River averaged 1,677 mcf per day in February, down 126 mcf per day, 7%, from a January average of 1,803 mcf per day but up 310.3% from a February 2023 average of 409 mcf per day.

Hilcorp's Trading Bay averaged 1,110 mcf per day in February, up 69 mcf per day, 6.6%, from a January average of 1,041 mcf per day but down 11.5% from a February 2023 average of 1,255 mcf per day.

BlueCrest's Hansen averaged 995 mcf per day in February, down 306 mcf per day, 23.5%, from a January average of 1,301 mcf per day and down 35.3% from a February 2023 average of 1,538 mcf per day.

Cook Inlet Energy's West McArthur River averaged 197 mcf per day in February, down 41 mcf per day, 17.2%, from a January average of 238 mcf per day but up 100.5% from a February 2023 average of 98 mcf per day. CIE is a Glacier Oil and Gas company.

CIE's Redoubt Shoal averaged 176 mcf per day in February, up 5 mcf per day, 2.9%, from a January average of 171 mcf per day and up 29% from a February 2023 average of 136 mcf per day.

Hilcorp's Nikolaevsk averaged 163 mcf per day in February, down 39 mcf per day, 19.3%, from a January average of 201 mcf per day and down 24% from a February 2024 average of 214 mcf per day.

Amaroq's Nicolai Creek averaged 123 mcf per day in February, down 21 mcf per day, 14.6%, from a January average of 144 mcf per day and down 56.3% from a February 2023 average of 281 mcf per day.

Cook Inlet natural gas production peaked in 1990 at more than 850,000 mcf per day. ●

Contact Kristen Nelson at knelson@petroleumnews.com

● FINANCE & ECONOMY

EIA: US production continues to grow

Domestic crude averaged 12.9 million bpd in ’23, forecast at 13.2 million in ’24, 13.7 million in ’25; LNG from 12 bcfpd to 14 bcf

By KRISTEN NELSON
Petroleum News

Domestic crude oil production continues to grow, the U.S. Energy Information Administration said in its April Short-Term Energy Outlook, released April 9. In 2023, U.S. crude production averaged 12.9 million barrels per day and is forecast to increase to 13.2 million bpd this year and to 13.7 million bpd in 2025.


JOE DECAROLIS

Global liquid fuels production is projected to increase by more than 800,000 bpd this year, down from a 1.8 million bpd increase last year, with voluntary production cuts by the Organization of the Petroleum Exporting Countries and associated countries offset by production increases outside of OPEC+ of 1.8 million bpd, increases coming primarily from the United States, Guyana, Brazil and Canada, EIA said.

EIA attributed increasing oil prices in March to “heightened geopolitical risk related to the attacks targeting commercial ships transiting the Red Sea shipping channel and general elevated tensions around the region,” coupled with the extension by OPEC+ of voluntary production cuts at a time when spring and summer driving typically increases demand in the Northern Hemisphere.

The agency is forecasting global liquid fuels production to increase by 2 million bpd in 2025, due to a combination of the end of OPEC+ voluntary cuts and supply growth outside of OPEC+.

Brent

EIA said the Brent spot oil price, which averaged $82 per barrel last year, is forecast to average $89 per barrel this year before dropping to $87 per barrel in 2025.

Brent averaged $85 per barrel in March, up $2 per barrel over February “and the third consecutive month when the average Brent price increased.” The agency is forecasting Brent to average $90 per barrel in the second quarter of this year, up $2 per barrel from its March forecast, reflecting an “expectation of strong global oil inventory draws during this quarter and ongoing geopolitical risks.”

EIA attributed increasing oil prices in March to “heightened geopolitical risk related to the attacks targeting commercial ships transiting the Red Sea shipping channel and general elevated tensions around the region,” coupled with the extension by OPEC+ of voluntary production cuts at a time when spring and summer driving typically increases demand in the Northern Hemisphere.

Bridge collapse impact

The collapse of the Francis Scott Key Bridge in Maryland March 26 led to a decrease in EIA’s forecast for U.S. coal exports, as it closed the Port of Baltimore, the second-largest U.S. hub for coal exports.

“We expect U.S. coal exports to recover toward the end of the summer or early fall, but there is significant uncertainty based on the timeline for the port reopening and how quickly exporters can adjust to export through alternative ports,” said EIA Administrator Joe De Carolis.

EIA said it reduced U.S. coal export forecasts for April by 33% and for May by 20%, and after previously expecting U.S. coal exports to increase by some 1% this year, it now expects total coal exports to drop by 6% from 2023 totals.

The agency said Baltimore accounted for 28% of U.S. coal exports last year.

LNG

EIA expects U.S. liquefied natural gas exports to average 12 billion cubic feet per day this year, up 2% from 2023. In the agency’s overview of U.S. energy market indicators, both 2023 and 2024 show 12 bcf per day of LNG exports.

In 2025, LNG exports are expected to increase by 2 bcf per day, up 18% to 14 bcf per day, as three of five LNG export projects under construction are expected to start operations and ramp up to full production, EIA said.

U.S. LNG export facilities are expected to run at utilization rates similar to last year, “adjusted for seasonality and annual maintenance on liquefaction trans,” the agency said. Plaquemines LNG Phase I and Corpus Christi Stage 3 are expected to begin production and load first cargoes by the end of 2024, with the first two of three trains at Golden Pass LNG expected to be in service in 2025.

Domestic gas is also exported by pipeline, with increased exports to Mexico expected to grow pipeline exports by almost 1 bcf per day over the forecast period as several pipeline in Mexico expected to reach full service this year and next.

Natural gas storage

EIA estimates that U.S. natural gas storage inventories were 39% higher at the end of the current withdrawal season, November to March, compared to the 2019-23 5-year average.

At the start of the winter heating season storage was 5% above the 5-year average, with that surplus and a mild winter resulting in below-average residential and commercial consumption of natural gas.

Natural gas prices were low in the first quarter of the year, which EIA attributed partly to the large storage surplus.

The Henry Hub spot price averaged less than $2 per million British thermal units in February and March and is forecast to average less than $2 in the second quarter and about $2.20 per million Btu for the year.

Lower U.S. natural gas production is expected in the second and third quarters, compared to the first quarter, EIA said, resulting in less injection into storage than typical. But the agency said it still expects the U.S. to have more than 4,120 bcf of natural gas in storage at the end of the storage season, 10% above the 5-year average and a new record. ●

Contact Kristen Nelson at knelson@petroleumnews.com

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HISTORY

agreements have typically included price adjustments based on various price indices, including the three-month average for light sweet crude futures and Henry Hub futures.

The Attorney General also said North Fork gas should be priced based on the Moquawkie contract, where a known field was developed for production through an existing well and where a second well was also drilled, with a flat $2.75 per mcf price, adjusted for inflation. That differs from the recent Unocal contract, which required Unocal to explore for gas in new areas, and which Enstar used as a model, proposing a $3 per mcf floor price and the use of Henry Hub pricing index, because NorthStar is required to drill a new well and create redundant gas supply.

The commission agreed with Enstar, noting that the Moquawkie contract did not require drilling a new well before deliveries could begin. It disagreed, however, on the floor price, saying the record did not support NorthStar's contention that the floor price should be 25 cents higher per mcf than the $2.75 Unocal floor, based on inflation, higher costs of capital and current elevated costs of gas.

Arbitrage, size of gas pipeline

The commission disagreed with Enstar on arbitrage and inserted a 15% limit — the same as the Unocal contract — on the amount of gas volume sold under the agreement that may come from third party sources.

The Attorney General argued against the 20-year term of the agreement, saying Enstar should have an opportunity to get out of the contract if it finds it can get gas more cheaply elsewhere. The commission said NorthStar argued that without the long-term contract, it would have no assurance that its investment would make financial sense, and that investors and financiers must be assured NorthStar "would obtain sufficient revenues over a long enough period to justify investment."

The commission concluded that 20 years was a reasonable term, both for the companies and for Homer consumers, who have to retrofit their current heating systems to accept natural gas.

The commission added a transportation cap of 30 cents per mcf, noting the Unocal contract had a cap of $1 per mcf, based on a pipeline about three times as long and about three times the diameter.

The commission also said that when it comes to approving a tariff, it "will not approve transportation rates on NorthStar's pipeline that are in excess of the charges necessary to support a 4-inch pipeline from North Fork to Anchor Point." The commission said it understands that NorthStar hopes to find enough gas to eventually sell into the Southcentral market, and said it agreed with Enstar: "if NorthStar is successful '…the vast majority of the gas going through that line may be for other purposes and other people.'" On that basis, the commission said, it is placing "NorthStar on notice that we will only approve transportation charges that recover the costs of a pipeline four inches in diameter from its leases to Anchor Point."

And, because Enstar's affiliate, Alaska Pipeline Co., could be asked to build the NorthStar pipeline, the commission said it is requiring that NorthStar's "transportation tariff filing must demonstrate that a valid, reasonably advertised, competitive procurement process was undertaken for the construction of the NorthStar pipeline." ●

Contact Kristen Nelson at knelson@petroleumnews.com

20 years ago this month: Commissioner disagrees with RCA decision

Commissioner Kate Giard of the Regulatory Commission of Alaska disagrees with the decision of the majority of the commission's members to approve the gas sales agreement between Enstar and NorthStar Energy Group for natural gas from the North Fork field proposed for delivery to Homer.

That sales agreement is based on the Enstar-Unocal gas sales agreement, includes a floor price and indexes the price paid by Alaska consumers to a 36-month Henry Hub futures index price.

Giard said in a dissenting statement dated April 5, 2004, that Enstar "failed to meet its burden of proof that this (gas sales agreement) is in the public interest." Girard agreed with the Alaska Attorney General's argument that Henry Hub natural gas futures include Lower 48 transportation and tax costs and said the Attorney General "provided evidence that the U.S. Average Wellhead Price Index is a more appropriate proxy, is nationally tracked and reported and linearly correlates to the prices of the Henry Hub Natural Gas Futures market."

The commissioner said the shift to a national pricing proxy "created a substantial increase in natural gas costs for Enstar's ratepayers," with natural gas price increases ranging from 12.44% to 13.93% between 2002 and 2003.

"To the extent these increases are necessary to assure future supply meets expected demand, they are a rational expression of economic policy," she said. "However, without adequate controls, this shift could create windfall profits and destabilize our economy."

In addition to using the U.S. Average Wellhead Price Index rather than Henry Hub, Giard also said the commission should establish a price cap, because as a consequence of the commission's approval of the Enstar-Unocal and Enstar-NorthStar sales agreements, "Alaska natural gas prices are utterly dependent on activities in the Lower 48.

"A series of events or a single dramatic event occurring in the Lower 48 could materially affect our economy."

If a terrorist attack in the Lower 48 put a gas pipeline out of commission for a period of time, or unusually cold weather occurred, the Henry Hub price would increase.

"The result is an increase in Alaskan prices completely unrelated to the supply or demand in Alaska," she said.

Giard said the commission should have required "a reasonable price cap" which would balance "the need to compete nationally for exploration and development dollars" with protection for Enstar's ratepayers.

Giard also said the commission should eliminate the floor price. Indexing Alaska's price to Henry Hub futures with no price cap "allows for unrestricted upward opportunity for price increases," she said, and coupled with an inflation-adjusted floor to secure against future decreases in the Henry Hub price, "is known in pejorative terms as having your cake and eating it too."

—PETROLEUM NEWS

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INLET BILLS

Free seismic data

HB 257 would make state-owned seismic data available free of charge to accredited domestic research institutions; anyone involved in Alaska oil, gas or minerals exploration; or to anyone in a situation where the provision of the data would serve the best interests of the state.

Rep. Tom McKay, chair of the House Resources Committee, told House Finance that making seismic data more accessible can stimulate more interest and investment in oil and gas development.

"This bill represents a pivotal step towards realizing the untapped potential of Cook Inlet, encouraging innovation, and fostering a competitive energy market," he said.

Trevor Jepsen, staff to Rep. McKay, said that the relevant seismic data had been relinquished to the state 10 years after it had been gathered by companies that had received state geological and geophysical tax credits. By giving out the seismic free of charge, rather than selling it, the state would forfeit a small amount of revenue. In return the state would encourage more interest in Cook Inlet exploration and development, Jepsen said.

Royalty reductions

HB 223 would eliminate state royalties for natural gas production and reduce royalties by 50% for oil production for 10 years from gas and oil fields in the Cook Inlet basin that start production after July 1, 2024. The reduced royalty rates would also apply to a field that has been shut in during 2024 but is later brought back into production, or to production from a prospect outside an area accessible to existing wells.

Rep. George Rauscher, vice chair of House Resources, told House Finance that the bill represents a crucial step in revitalizing the gas industry in the Cook Inlet basin. The bill aims to elevate Alaska's competitiveness for natural gas investments, he said. Rauscher said the bill resulted from the merger of the bill in its original form with a near identical bill that Gov. Mike Dunleavy had prepared.

Derek Nottingham, director of Alaska's Division of Oil and Gas, told the committee that at present Cook Inlet gas production is expected to fall below the anticipated 70 billion cubic feet per year annual demand level in 2027 and 2028. But, with appropriate development incentives, the timeframe for the shortfall could be extended out to around 2029 or 2030, he said. Moreover, the sale into storage of excess gas produced in that timeframe could potentially extend the adequacy of gas supplies through to 2037. Although this analysis is subject to uncertainties such as future consumer gas pricing, development incentives are anticipated to extend the timeframe within which gas production could meet demand levels, he indicated.

GEORGE RAUSCHER

More effective than existing procedure

Currently the Department of Natural Resources does have a procedure whereby it can authorize the reduction of royalties for a specific field. Asked why this arrangement would not suffice to achieve the objectives of the proposed legislation, DNR Deputy Commissioner John Crowther said that reducing a royalty level via this existing route is typically a complicated, very time consuming and expensive process.

"We think the legislation is much more effective at immediately promoting investment," Crowther said.

And rather than depending on the vagaries of the gas market to drive development decisions, a competitive royalty environment can induce companies to make the necessary investments, he said.

Nottingham presented data estimating the levels of gas supply cost reductions that a developer might gain from the enactment of the proposed legislation. Other data provided estimates of how the reduced royalty rate could potentially reduce the payback time on a development by several months to more than a year, while increasing the development's internal rate of return by around five percentage points.

Jack-up rig tax credit

HB 387 would enable the award of a state tax credit to any entity that installs a jack-up rig in Cook Inlet, provided that the rig is used, or contracted to be used, for at least three years in the inlet. Currently the only jack-up rig in the inlet is contracted by Hilcorp Alaska for its offshore drilling operations — the idea is to make a rig available to other operators for offshore exploration and development. The credit would equal the total cost, to a maximum of $75 million, of purchasing or leasing the jack-up rig and transporting the rig to Cook Inlet. The rig could operate in state or federal waters.

"If we wanted increased drilling activity in Cook Inlet, at least offshore, we would need another jack-up rig, because the current rig in the inlet is pretty much full up drilling wells for Hilcorp," McKay told House Finance. It is necessary to have another rig, to have any impact on increased gas production, he added.

Encourage further offshore drilling

Jepsen said that the current jack-up rig in the inlet, the Spartan 151, is primarily being used by Hilcorp to enable the company to meet the terms of its firm gas supply contracts. In addition, there are prospective areas of the Cook Inlet where the water is too deep for the Spartan rig to operate, he said.

"The state fully or partially subsidizing the purchase or transfer of another jack-up rig, to develop Cook Inlet offshore reserves, will offset the risk and increase the rate of return for a potential project," Jepsen said.

The credit would apply to any company that brings a rig to the inlet, and not necessarily to an oil and gas company, he commented. McKay commented that, although there are already land rigs for conducting land based drilling, some of the larger gas prospects are offshore.

Asked about a previous state jack-up rig tax credit, Jepsen said that, whereas that credit had only applied to drilling up to three exploration wells, the proposed credit would target having a rig available for non-stop drilling for at least three years for both exploration and development wells.

In response to a question about alternative ways of drilling offshore in the inlet, McKay commented that it would likely be impractical to use a dynamically positioned drill ship, in particular because of the high fuel costs involved in stabilizing the position of the ship in the tidal currents. ●

Contact Alan Bailey
at abailey@petroleumnews.com

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DROUGHT POTENTIAL

Poised to come on stream is the C$40 billion LNG Canada project at Kitimat that is scheduled to start exporting LNG and open up Asian markets to Canadian gas for the first time.

Much of the C$5 billion in capital spending projected to take place in gas fields this year is targeted at British Columbia according to the Canadian Association of Petroleum Producers.

Botterill said the threatened drought "is just going to mean some extra costs around water management."

In December the Alberta Energy Regulator warned the oil and gas industry it could face restricted access to water in the event of a severe drought in 2024.

The provincial government has already launched negotiations aimed at trying to get major water users to reach water-sharing agreements.

Meanwhile, the British Columbia Energy Regulator has issued advance warning of potential water restrictions for industrial license holders.

Botterill said that if restrictions are imposed gas developers will need to explore increased use of alternative water sources, such as recycled water previously used as fracking fluid.

In 2022 the Alberta Energy Regulator estimated that just over 1% of water used by hydraulic fracturing operations was recycled water, with the remaining 99% being primarily fresh water.

—GARY PARK

Contact Gary Park through publisher@petroleumnews.com

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OIL PRICES

close the Strait of Hormuz, which sees about one fifth of the world's seaborne oil trade flow through it," Sevens Report Research analysts said in an April 10 newsletter, MarketWatch reported.

Crude prices rose despite a surprise build in U.S. inventories, reported by the U.S. Energy Information Administration in its April 10 Weekly Petroleum Status Report.

U.S. commercial crude oil inventories for the week ending April 5 — not including Strategic Petroleum Reserve volumes — jumped by 5.8 million barrels from the previous week to 457.3 million barrels, 2% below the five-year average for the time of year, the EIA said.

Analysts answering a poll by The Wall Street Journal had predicted an 800,000-barrel increase in crude stocks.

Total motor gasoline inventories increased by 0.7 million barrels for the period to 228.5 million barrels, 3% below the five-year average for the time of year, the EIA said. Distillate fuel inventories increased by 1.7 million barrels over the week.

Oil prices were hit, along with other financial assets April 9, as investors hoping for the U.S. Federal Reserve to begin easing its benchmark interest rate saw hopes dashed on reports of higher U.S. inflation, which led to hawkish remarks from the Fed.

ANS plunged $1.02 April 9 to close at $89.61, as WTI plummeted $1.20 to close at $85.23 and Brent plunged 96 cents to close at $89.42.

Crude prices were off April 8 as well. ANS fell 42 cents to close at $90.64, as WTI fell 48 cents to close at $$86.43 and Brent fell 79 cents to close at $90.38.

Peter Andersen, CIO of Andersen Capital Management, said oil prices could affect the Fed in its interest rate policy decisions.

"This will present a speed bump to any of the Fed calculus that's out there," he said in an April 8 interview with FOX's "Mornings with Maria," adding, "As oil prices rise, certainly, you know, there is going to be an interpretation of that as inflation."

Oil prices had hit 2024 peak levels April 5, with ANS up 10 cents to close at $91.05, WTI up 32 cents to close at $86.91 and Brent up 52 cents to close at $91.17.

On April 4, ANS surged $1.24 to close at $90.95, WTI surged $1.16 to close at $86.59 and Brent surged $1.30 to close at $90.65.

Higher prices loom

Analysts saw continued higher prices ahead as tension in the Middle East melded with stronger economies in the United States, China and Europe, while the Organization of the Petroleum Exporting Countries and its allies constrict supply.

"It's supply-and-demand with geopolitics thrown in on top," Paul Horsnell, global head of commodities at Standard Chartered was quoted by Financial Times April 7.

Crude prices will likely range between $80 and $100 per barrel in 2024, according to Vitol Group, the world's largest independent oil trader.

Vitol expects consumption to grow by 1.9 million barrels per day in 2024, Vitol CEO Russell Hardy said April 9 at the Financial Times Commodities Global Summit in Lausanne, Switzerland, Bloomberg reported.

Oil prices over the next year are largely in the hands of OPEC+, according to Sebastian Barrack, head of commodities at Citadel hedge fund.

If OPEC+ carries its cuts beyond June, tightness in the market will be "very constraining" and high prices will have to "help destroy demand to solve that problem," Barrack said at the FT Commodities Global Summit, Oilprice.com reported. OPEC+ may not be willing to cripple demand, however.●

Contact Steve Sutherlin at ssutherlin@petroleumnews.com

Petroleum news — Oil Patch Bits

Lynden delivers rush shipments to rebuild school lost in Maui fire

As reported by Lynden News April 2, Maui continues to rebuild after last year's devastating wildfires. Lynden Logistics assisted in the recovery by coordinating two priority shipments of fragile electrical panels from Washington to the island to rebuild a school there. "We had them crated and flown to Maui from our Seattle office," explains Mary Kutscherenko, Hawaii trade lane sales manager. "The first shipment was for the temporary Lahaina School put in place after the fires, so you can imagine the urgency to finish it and get these kids back in school. The team at our Lynden Seattle service center is made up of top-notch people who care about customers and always deliver quality service," Kutscherenko says. "Kirk Knudson, Jen Aliiaana, Debbie Chervenak, Debbi Crain and others on the team gave us up-to-the-minute pickup and transfer info."

LYNDEN LOGISTICS

A dedicated truck was used to deliver the crates to the airlines for loading onto a wide-body plane direct to Maui from Seattle. The specialized crating was required to avoid a barge transfer from Oahu to Maui. The 7-foot by 5-foot panels were laid flat to fit on the plane safely to Maui. "The crates made it to Maui and the panels were quickly delivered for Alpha Electric who installed them at the school. We were happy to play a role in this important project," Kutscherenko says.

Companies involved in Alaska's oil and gas industry

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INSIDER

materially disrupted the advancement of a program that had been steadily gaining ground since the initial 3D seismic survey of the prospect, conducted by Jade stakeholders in 2018."

He added: "As to the 6th POD matter, I don't want to revisit the subject in detail, but a few high-level comments seem appropriate. Beginning with the initial collection of the Yukon 3D seismic data set covering the Sourdough prospect in 2018, Jade has demonstrated a continuous record of ongoing technical and field work to advance understanding of the reservoir and requirements for its potential development." Opstad listed some 30 examples, noting there were "dozens" of other reports, studies, analysis, presentation slide decks and so forth.

"I am sure you get the point that Jade has devoted a significant amount of time, money, and resources to thoroughly evaluate the Sourdough development opportunity," Opstad wrote in his email to the DNR/DOG March 29 meeting attendees.

Jade's takeaway? In response, Opstad listed the following, verbatim:

1. The Sourdough prospect, as confined to ADL 343112, Segment 2, represents a small development opportunity that could grow into a larger program if surrounding contiguous resources can be added to the development scenario. We don't see any operational hurdles to speak of. The Jade operations team just finished a 2-year program with a stakeholder that successfully delivered 2 exploration wells and 4 abandonment programs on federal lands in NPRA more than 100-miles off North Slope infrastructure. Given that, we don't think the Jade-1 well which is only 65-miles east of the Endicott causeway and less that 4-miles from PTU Central Pad, will pose much of a challenge operationally. Additionally, years of operating Badami has given us broad experience in high-pressure reservoir operations, so that is unlikely to be an issue either.

ERIK OPSTAD

JOHN BOYLE

JOHN CROWTHER

DEREK NOTTINGHAM

2. Sourdough development economics are problematic. I think one of our investors said it best when simply saying that "the state's take is too great." They got that right! The 40% Net Profit Share take materially impacts project economics and the other burdens just aggravate the situation further. Jade worked extensively with the DOG Commercial Analytical staff running numerous economic scenarios. The best outcome was that Jade might break even some day! Obviously, something needs to change that outcome, not just for Jade, but for everyone else with an interest in the project. In mid-2023 Jade was able to construct a development model that yielded a positive NPV and creatable IRR, but only by aggressively deferring typical North Slope project CAPEX way into the future. A dicey plan at best!

3. Then there is the 5th POD issue. The conditions of approval in that document, in our opinion, offered no benefits to anyone, not the State of Alaska, not Jade or its stakeholders, not our vendors or Native partners, not residents at large, NO ONE! More than enough has been said about that subject, so I'll just move straight to the ask.

The Ask

To get the Sourdough Development Program back on track, Jade is requesting that DNR/DOG approve the 6th POD.

"Such an approval will put all the angst and controversy surrounding the 5th POD conditions of approval in the rearview mirror, allowing us all to refocus on making Sourdough economics work and on attracting the investment capital needed to execute the project. Hopefully, approval of the POD would also be interpreted positively by all the local, national, and international folks that have taken such an interest in this subject," he wrote.

"By way of some related housekeeping, I would also suggest that the 6th POD be approved for a 2-year term. That would align Jade's POD cycle with that of the Point Thomson unit, which is also on a 2-year cycle. We don't coordinate our PODs in any way, but an alignment of the timeline can provide some planning synergies and it would cut out some near-term paperwork related to filing the 7th POD, the filing date for which is seemingly just around the corner."

Stay tuned….

PTU producing into storage

THE NORTH SLOPE POINT THOMSON unit is in production but not shipping its condensate, according to a Petroleum News source, who said production began in March with volumes going into storage on site subject to availability of the pipeline from Point Thomson to Badami.

The Point Thomson Export Pipeline was shut-in after a leak was discovered Jan. 13 by Harvest Alaska LLC, the pipeline operator. Harvest is a subsidiary of Hilcorp, which operates the field on behalf of itself and majority working interest owner ExxonMobil Production.

Alaska Oil and Gas Conservation Commission data show 14 days of oil production from the field in January, none in February. March data will not be available from AOGCC until late in April.

Situation reports from the Alaska Department of Environmental Conservation's Division of Spill Prevention and Response say Harvest received a leak detection alarm at 10:10 p.m. Jan. 13, and isolated the line, with visual confirmation observed from aircraft on Jan. 14 at 11:54 a.m., followed by confirmation by a ground survey crew shortly after.

DEC said the release was some 35 miles east of Prudhoe Bay and about 1 mile south-east of the Badami Pad.

From Badami Point Thomson crude moves in the Badami pipeline.

The last DEC situation report, issued Feb. 2, said the amount of condensate released was being determined, with maximum calculated by Harvest at 275 barrels, with investigation of the cause of the spill on-going.

Following the leak alarm the pipeline "was immediately shut-in and depressurized," DEC said, stopping any remaining condensate from leaving the line, with installation of a repair clamp completed Jan. 28.

In December, AOGCC data show Point Thomson production averaged 3,754 bpd.

—Oil Patch Insider is compiled by Kay Cashman

Contact Kay Cashman at publisher@petroleumnews.com

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HILCORP DRILLING

the division said there are three state oil and gas leases at NTBU.

Hilcorp became operator in 2013, acquiring NTBU and the Spark and Spurr platforms from then-operator Marathon Oil Co.

The platforms were installed in 1968, Spark by ARCO and Spurr by Texaco.

Alaska Oil and Gas Conservation Commission data show the platforms produced both oil and gas, with both coming online in 1968.

The last AOGCC report of production from the platforms was in 1992.

The division said Marathon ceased production at the North Trading Bay unit in 2005, and while it established a long-term abandonment plan in 2008, the plan was not implemented.

The Spark and Spurr platforms are in lighthouse mode, the division said, and while the crane and helidecks are functional, crew facilities are not and there are no active wells.

In its 2017 POD Hilcorp told the division that returning the platforms to production was not economically or technically feasible and said it had no plans to return either the Spark or Spurr platform to production.

The company did, however, plan to restore NTBU production by drilling from the Monopod in the Trading Bay unit during the 2018 POD — drilling which did not occur.

2019 POD denied

In its 2019 POD Hilcorp proposed to sidetrack from the A-10 on the Monopod rather than the well proposed in 2018, the A-04RD.

Based on what it described as a lack of diligent work to restore production, the division denied the 2019 POD and administratively terminated the unit.

Hilcorp appealed and the DNR commissioner, after a review, invited the company to submit a new POD including identification of drilling targets within 16 months and drilling in the subsequent POD.

Hilcorp submitted the 2021 POD, which was approved, requesting a 20-month length to align that POD with other Hilcorp offshore Cook Inlet units and committing to sidetracking the A-10RD from the Monopod into the Tyonek gas sands at NTBU.

The division said Hilcorp attempted to sidetrack the A-10RD but encountered mechanical issues; a second attempt to drill also encountered mechanical challenges.

In July 2022 the company notified the division that it was going to redesign the sidetrack for another drilling attempt in 2023.

That attempt was also unsuccessful.

2024 POD

In its 2024 POD, Hilcorp told the division sidetracking the A-10RD3 in 2023 did not result in production. The drill pipe failed, the company said, and the bottom-hole assembly was left in the hole "resulting in suspension of the well."

Hilcorp said it "is evaluating options to restore production from NTBU."

It said the failures in 2022 and 2023 warranted "a deeper look at the development plan and consideration of other wellbores for access," and said it plans to "study the subsurface and facility access options and propose a refreshed development strategy."

P&A

Hilcorp said it is committed to the plug and abandon program authorized by AOGCC, with focus on the Baker platform in the recently terminated Middle Ground Shoal unit in 2024.

The company said because of facility and structural work required to access Baker platform wells and because of higher risk posed by Platform C wells, also in MGS, P&A work on Spark and Spurr platforms has been pushed into 2026.

Fuel gas

Hilcorp's goal in producing the NTBU gas is to provide fuel gas for the Monopod, which currently receives fuel gas from the Steelhead platform, freeing up more Trading Bay unit gas for sale.

Because NTBU gas would cross a unit boundary into the Trading Bay unit, Hilcorp would have to pay royalty to the state on the gas, so the company's plan is that once there is sustained production of NTBU gas, it would apply to DNR to merge NTBU into TBU.

—KRISTEN NELSON

Contact Kristen Nelson at knelson@petroleumnews.com

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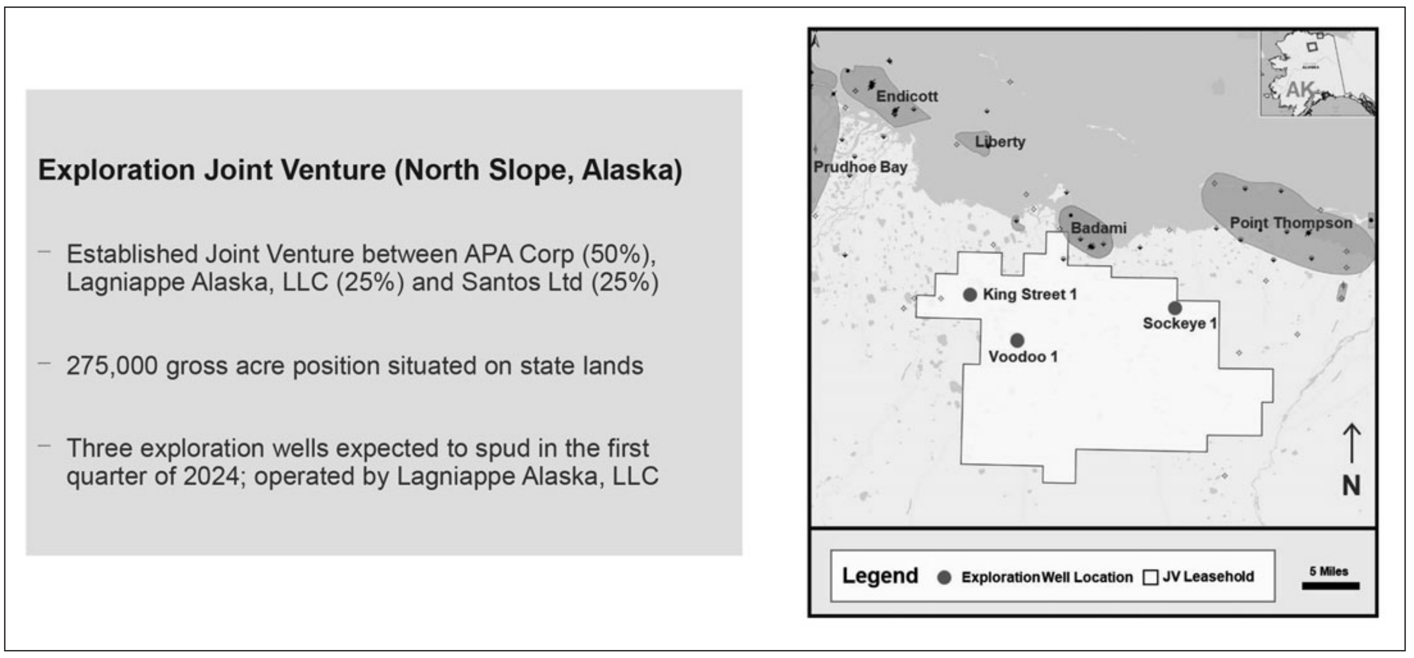
LAGNIAPPE UPDATE



APA CORP.

there has been "virtually no prior drilling in the area. The wells that have been drilled have great shows and some have bypassed pay on old logs."

On Feb. 22, when asked to provide more color on the risk profile for the exploration drilling program APA Corp. is invested in on Alaska's eastern North Slope, the company's CEO and President John J. Christmann said, "these are 3D and amplitude supported but this is a step-out in an area where there is risk associated with it so I'm not going to give you a number on a ratio. We're going to drill three wells and they are risky but they're high reward."

At the same Feb. 22 conference call covering fourth quarter and full year 2023 financial and operational results, Christmann asked Tracy Henderson, the company's exploration manager, to expand on his response and she said: "What interested us in the block was that we do see materiality with these prospects that warranted exploration."

He also turned to her when asked whether the partners were searching for Pikka lookalikes. Henderson said: "Yes, I would agree with that. We're looking at more play types like Pikka and Willow on the other side of Prudhoe Bay. And that is the Brookian play we're going to be exploring for in a younger sequence but it's absolutely the same geologic model and set up that we expect to see. Basically, just farther east than it's been explored for."

At the time the three partners made their deal in 2023, Santos Managing Director and CEO Kevin Gallagher said he was "pleased we've reached this agreement to farm down our exploration assets in Alaska. This transaction demonstrates the continued level of interest in exploration and development projects in the region, a tier one jurisdiction with supportive stakeholders and prospective undeveloped acreage."

Partner split

KEVIN GALLAGHER

APA holds a 50% working interest in the 148-lease block; Lagniappe and Santos each hold a 25% interest.

In 2024, APA had said it planned to invest $1.9 billion to $2.0 billion in upstream oil and gas capital worldwide. APA said it would invest for the long term by directing $100 million of the upstream budget toward exploration activities predominantly in Alaska.

"In Alaska it is a position that sits between Prudhoe Bay and ANWR in the Brookian play, so we've entered into the area where we have analogues there that have worked, but they are in an area where that play has not really been explored for. So we're testing in an under-explored region, As John said, we are drilling three wells in this winter season. All of those will spud in Q1," Henderson said.

We've "got good seismic control and they're fully supported so we feel good about them but it IS exploration," Christmann said.

The partners are looking at drilling three more wells next winter, so a total of six wells with three rigs drilling simultaneously. Under the terms of the deal between the three working interest owners, initial exploration activities during the two-year exploration phase will be undertaken without cost to Santos, which is concentrating on development of Pikka Phase 1 west of the central North Slope.

Better oil

All reports say the play concept in the Lagniappe-operated acreage to the east is very similar to the Brookian at Pikka. Multiple zones, onshore, good gravity oil, reasonably close to infrastructure.

But the targeted objectives are slightly younger than what Santos and partner Repsol have at Pikka et al but with better reservoir qualities — porosity and permeability — even though they are deeper.

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 of the wells bypassed good oil shows, Armstrong said in a 2021 interview.

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

Bad weather

In a Feb. 26, 2024, text Armstrong updated Petroleum News on Lagniappe drilling program where the company was using three drilling rigs to simultaneously drill three exploration wells.

The Doyon 141 drilling rig was delivered to the King Street-1 well location, the Nabors 105-E rig to the Voodoo-1 site and the Doyon Arctic Fox rig to Sockeye-1.

"Our drilling is just now starting," Armstrong wrote.

"Warm weather, then really windy weather has delayed our program a couple of weeks."

But more unusually bad weather followed and continued to plague drilling operations — more wind, snow and below normal temps.

What impact these conditions have had on drilling and possible flow-testing operations is unknown, but PN sources say all three wells will be completed this season. ●

Contact Kay Cashman at publisher@petroleumnews.com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