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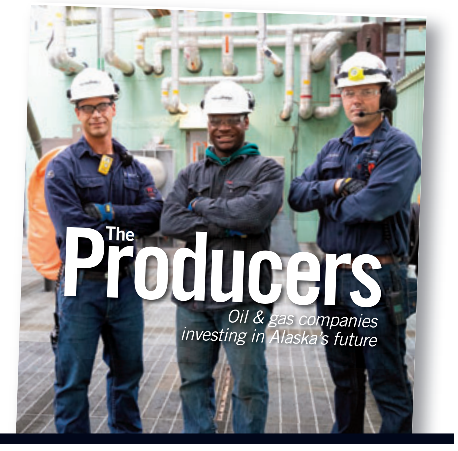


page 2 Producers preview: Crunch time at Nicolai Creek for Amaroq

Pikka Phase 1 70% complete, first oil expected 1st half 2026

Speaking at Santos Ltd.'s Investor Day in Sydney, Australia, on Nov. 19, Managing Director and Chief Executive Officer Kevin Gallagher said the company's Alaska North Slope Pikka Phase 1 project is now 70% complete with first oil expected in the first half of 2026, as compared to 67% complete per a third quarter Santos report released in October.

KEVIN GALLAGHER

On Nov. 19 Santos announced an updated capital allocation framework that will target returns to shareholders of at least 60% of all-in free cash flow from 2026, following a period of major capital investment to bring significant new production online from the Barossa and Pikka projects.

Gallagher said the Nov. 19 announcement confirms Santos' commitment to prioritize shareholder returns when new production comes online and to support the global energy transition while generating new revenue streams for the business.

"With Barossa and Pikka coming online, Santos' production is expected to increase by more than 30% by 2027 compared to 2024 … which will support strong free cash flow generation

see PIKKA UPDATE page 5

Wood Mackenzie details economics of phase 1 gas pipeline vs imports

Intent language in the state operating budget passed last spring asked for a third-party analysis from the Alaska Gasline Development Corp. of its proposed phased approach for the Alaska LNG project by Dec. 20, House Resources Committee Chair Tom McKay said at a Nov. 19 special meeting of House Resources.

TOM MCKAY

The language in the bill specifies that "if analysis shows a positive economic value to the state, all parties would work toward Front End Engineering and Design for Phase I of a pipeline project."

Wood Mackenzie has now presented that report, which does show positive economic value.

Wood Mackenzie's Costa Swift, vice president in upstream carbon management team based in Houston and Akari Takiguchi, a managing consultant for the gas and energy team, presented the

see GASLINE ANALYSIS page 4

Haul Road: raw; hard to maintain, political ping-pong is challenge

Alaska's Dalton Highway is legend, serving up white-knuckle challenges for intrepid truckers and spawning a long-running reality TV series.

The lonely ribbon of roadbed snakes over vast rugged wilderness from civilization to North Slope oilfields; a vital lifeline to the heart of Alaska's economic engine.

The "Haul Road" — the utilitarian handle by which it is locally known — was privately constructed and was once restricted but is now open to the public. Services along the highway are few. Rental car contracts typically forbid driving the road.

The challenge of maintaining the Haul Road falls to the state of Alaska. The Alaska Department of Transportation and Public Facilities routinely battles pavement-eating frost heaves, wind and water gravel erosion, blizzards, avalanches, ice, floods and earthquakes to keep the road open for safe passage.

According to Department of Natural Resources Commissioner John Boyle, the most vexing battle the state faces

see DALTON CONTROL page 6

FINANCE & ECONOMY

Ukraine war ups ANS

US crude inventory build offset by Russia/Ukraine war missile premium

By STEVE SUTHERLIN

Petroleum News

Alaska North Slope crude fell 47 cents Nov. 20 to close at $71.93 per barrel, as West Texas Intermediate fell 52 cents to close at $68.87 and Brent fell 50 cents to close at $72.81.

Oil futures rose in morning trading Nov. 20 but reversed after a reported surprise build in U.S. commercial crude inventories and gasoline supplies.

At the end of the five-day trading period ending Nov. 20, ANS held a 73-cent gain from its close of $71.20 Nov. 13 to close at $71.93 Nov. 20.

Losses Nov. 20 were held in check by a war premium, over concerns that the Russia/Ukraine war might escalate after reports emerged Nov. 18 that President Biden gave Ukraine the green light to use advanced U.S. long-range missiles to strike targets inside of Russia. Worries that a WWIII situation was imminent were soothed by reports that Vladimir Putin is open to discuss a Ukraine ceasefire with Donald

"Supermajors are accelerating investments in biofuels like HVO and SAF, recognizing their potential as low carbon 'drop-in' fuels that can be swiftly integrated into existing aviation, heavy transport and marine fuel systems," said Lars Klesse, Rystad bioenergy research analyst.

see OIL PRICES page 5

TECHNOLOGY PROJECTS

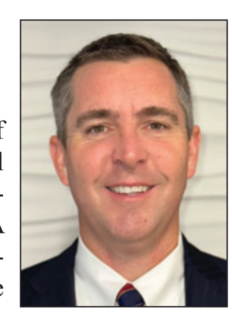
Testing bitcoin mining

Paving way for larger project; making use of plentiful ANS natural gas

By KAY CASHMAN

Petroleum News

On Nov. 5, the Alaska Department of Natural Resources' Division of Oil and Gas received a land use permit application from Austin, Texas-based TA Infrastructure Management LLC requesting to install a small data center module on a trial basis to utilize currently produced natural gas in the Hilcorp-operated Endicott oil field, which is part of the Duck Island unit.



JOHN BOYLE

The proposed data center site is the unit's Satellite Drilling Island, or SDI, a gravel oil and gas production facility pad. The data center module will contain 1.4 megawatts of bitcoin mining computers — a digital process that supports cryptocurrency.

The trial data center module will consume power from existing power generation equipment owned by Hilcorp Alaska LLC.

The purpose of this project, TA Infrastructure said, is to demonstrate the ability to operate data center infrastructure on the North Slope and identify any logistical or operational challenges that a larger project might have.

DNR Commissioner John Boyle told Petroleum News in a prepared statement: "We are very

see BITCOIN MINING page 7

UTILITIES

RRC CEO is announced

Ed Jenkin appointed to head organization overseeing Railbelt electrical system

By ALAN BAILEY

For Petroleum News

Ed Jenkin, currently chief energy transformation officer for Matanuska Electric Association, has accepted the role of president and chief executive of the Railbelt Reliability Council, the RRC announced on Nov. 13. Jenkin will join the RRC as CEO on Jan. 3.

COURTESY MEA

ED JENKIN

"I am thrilled that Mr. Jenkin is taking the helm of the Railbelt Reliability Council," said RRC Board Chair Joel Groves. "Ed's experience, leadership and clear vision will directly empower the RRC to advance its core mission, ultimately producing long-term benefits for electric consumers across the Railbelt."

The RRC says that it picked Jenkin after an extensive international search of highly qualified candidates. The organization's board cited, as key factors in making its decision, Jenkin's widely recognized expertise, his reputation for stellar integrity and his consistent leadership in addressing efforts to improve the Alaska Railbelt electric industry.

"I am excited for the opportunity to lead the RRC and realize the value provided through Railbelt-wide standards and regional planning,"

see RRC CEO page 8

● PRODUCERS PREVIEW

Crunch time for Amaroq at Nicolai Creek

Three-well program could extend field by decade; no drilling promises P&A; company has asked state for royalty relief at Amaroq

Editor's note: This story comes from the 2024 edition of The Producers magazine, which will be published in mid-January 2025.

By ERIC LIDJI
For Petroleum News

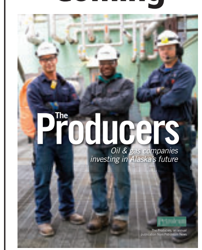
For a run of years now, operator Amaroq Resources Inc. has been public about the need for investment to ensure that the onshore field on the west side of Cook Inlet remains viable. And yet economics have persistently delayed those investments year after year.

"Nicolai Creek Unit has tremendous upside potential for conventional oil and gas, unconventional gas, and storage development," the small independent company wrote in its 50th plan of development, covering the year ending Dec. 31, 2024. "If the operator is successful in attracting the additional investment dollars to pursue any or all of these upsides, the field would likely remain in operation for years to come. The alternative will be to commence planning for field abandonment in 2-3 years' timeframe."

And yet, during that development year, the company conducted no development drilling or 3D seismic operations and delayed installation of a booster compressor unit. The compressor would connect the NCU No. 2 and NCU No. 11 wells, which would allow additional gas to be produced while maintaining existing production from NCU No. 9.

In its current 51st plan of development, though, Amaroq is proposing a three-well drilling program at Nicolai Creek — the most significant development at the field in years.

Coming



January 2025

The NCU No. 15 well would be "drilled from the south pad as a 'twin' to develop shallow reserves behind pipe in NCU No. 9 due to poor or no cement conditions at the target zones in the existing well," according to the company. Amaroq decided to drill a twin of NCU No. 9, rather than recompleting it, after a Petrotechnical Resources of Alaska analysis in early 2024 found shallow natural gas reserves behind pipe at NCU No. 9, estimating P50 reserves — meaning a 50% probability — of 1.2 billion cubic feet.

The NCU No. 16 well would be drilled from the north pad to drain most of the remaining reserves associated with NCU No. 3 — 2.8 bcf of P50 reserves. The NCU No. 17 well would be drilled from the NCU No. 13 pad and would target 2.8 bcf of P50 reserves.

Before fully committing to this program, though, Amaroq needs funding. In its plan, the company described its efforts to obtain this funding as "very active and ongoing."

Possible projects

Of the six active wells at the Nicolai Creek field, four need considerable work.

Of the six active wells at the Nicolai Creek field, four need considerable work.

The NCU No. 1B injector is experiencing increased pressure. NCU No. 2 produces intermittently, depending on reservoir pressure. The NCU No. 3 producer was shut-in with plugged tubing. The NCU No. 10 producer was shut-in following excessive water.

The NCU No. 11 producer was shut-in for insufficient pressure but was brought back online in August 2024 and "has performed better than expected," according to the company. That leaves the NCU No. 9 producer, which has been producing without issue.

Amaroq has discussed — but not sanctioned — several other projects.

The company is pursuing funding for a program to run a wireline unit at NCU No. 1B to determine the cause of the increased pressure at the well and possibly to resolve it.

The company has also been trying to decide whether to work over the NCU No. 10 well (and later NCU No. 3) or to drill a new well. These projects would serve a similar goal.

Amaroq brought the Nicolai Creek Unit No. 10 back online in May 2021 after some time offline, but it produced "excessive quantities of water," according to the company. In previous plans of development, the company proposed a rig workover for the well. The company has also previously proposed a coiled tubing cleanout of the NCU No. 3 well.

In its 50th plan of development, Amaroq said it had

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ON THE COVER

EXPLORATION & PRODUCTION

THE PRODUCERS PREVIEW

● EXPLORATION & PRODUCTION

Baker Hughes US rig count down 1 at 584

By KRISTEN NELSON
Petroleum News

The Baker Hughes' U.S. rotary drilling rig count was 584 the week ending Nov. 15, down by one from the previous week, down by 34 from 618 a year ago and down one from two weeks ago. Over the last eight weeks the rig count was unchanged in three weeks, down in four and up in one week with losses of five and a gain of one, continuing a downward trend dominant since the beginning of May. This is the lowest domestic rig count since December 2021.

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 Nov. 15 count includes 478 rigs targeting oil, down one from the previous week and down 22 from 500 a year ago, with 101 rigs targeting natural gas, down one from the previous week and down 13 from 114 a year ago, and five miscellaneous rigs, up one from the previous week and up by one from a year ago.

Forty-eight of the rigs reported Nov. 15 were drilling directional wells, 520 were drilling horizontal wells and 16 were drilling vertical wells.

Alaska rig count unchanged

New Mexico (102) was up two rigs from the previous week and Pennsylvania (15) was up one.

Texas (279) was down two rigs while Oklahoma (43) Utah (11) were each down by a single rig.

Rig counts in other states were unchanged from the previous week: Alaska (10), California (6), Colorado (11), Louisiana (33), North Dakota (34), Ohio (10), West Virginia (10) and Wyoming (18).

Baker Hughes shows Alaska with 10 rotary rigs active Nov. 15, unchanged from the previous week and up by one from a year ago when the count was nine.

The rig count in the Permian, the most active basin in the country, was unchanged from the previous week at 303 and down by eight from 311 a year ago. ●

Contact Kristen Nelson at knelson@petroleumnews.com

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PRODUCERS PREVIEW

completed a "tentative" work plan and authorization for expenditure for the NCU No. 10 workover but was intrigued by idea of drilling a new well, which "could produce most or all of the remaining reserves" associated with NCU No. 10 and produce most or all of the remaining reserves associated with the NCU No. 3 well. But drilling a new well would require third party funding.

Division's conditions

As part of its approval of the 50th Nicolai Creek plan of development, the state Division of Oil and Gas placed two conditions on Amaroq. Either the company could commit to restoring production from the NCU No. 3 well by working over the well, or the company could commit to working over or re-drilling the NCU No. 10 well by the end of 2025, to access some 1 bcf of proven undeveloped natural gas reserves.

In its 51st plan of development, Amaroq acknowledged those lapsed commitments: "Due to the fact that Amaroq's proposed drilling program for 2025 could develop significantly greater reserves of natural gas, possibly eliminate the need to workover NCU No. 3 and possibly result in a superior way to access the PUDs associated with NCU No. 10, Amaroq respectfully requests the Division's concurrence that Amaroq's proposed drilling program for 2025 should replace, or at a minimum defer the imposed conditions."

Amaroq has also formally asked the state for royalty relief at the Nicolai Creek field. The royalty relief combined with the booster compression planned for installation this coming winter "could potentially extend the field life a few years," according to the company.

Even so, the royalty relief and boosted compression "are not a long-term solution." The three-well program would extend estimated field life by a decade. "Absent the successful drilling of new wells, plans will commence to plug and abandon the field in a 1-2 year timeframe, or possibly pursue the conversion of the field to gas storage" Amaroq wrote.

History

Texaco Inc. discovered the Nicolai Creek field in 1966 and 1967. Union Oil Company of California operated the Nicolai Creek unit from its start-up in 1968 through the late 1970s, when operations were suspended following years of zigzagging production rates.

Amaroq has also formally asked the state for royalty relief at the Nicolai Creek field. The royalty relief combined with the booster compression planned for installation this coming winter "could potentially extend the field life a few years," according to the company.

The small, local independent Aurora Gas LLC revived the Nicolai Creek unit in 2000 and undertook additional drilling and fieldwork at the property for nearly two decades.

Over time, as the field matured, those earlier operators plugged and abandoned five wells at the unit: NCU No. 4, NCU No. 5, NCU No. 6, NCU No. 13 and NCU No. 14.

A legally unrelated but similarly named company called Aurora Exploration LLC acquired the Nicolai Creek unit after Aurora Gas filed for bankruptcy protection in early 2018. Aurora Exploration later changed its name to Amaroq Resources.

Under the operatorship of Amaroq, the unit has received investment. The company converted NCU No. 1B to injection and brought NCU No. 10 back into production.

The Nicolai Creek unit produced some 108 million cubic feet of natural gas in the year ending Aug. 31, 2023, down from some 114 million cubic feet the previous year and 120.5 million cubic feet the year before, according to figures from the company.

Deep oil

Amaroq acquired some 5,000 net acres of "deep rights" for oil and natural gas on the Kenai Peninsula and the west side of Cook Inlet from Apache Alaska Corp. in November 2021. The sale included access to proprietary 3D seismic over the Nicolai Creek unit.

In the 50th plan of development, Amaroq said it had developed a scope of work for analyzing this data. The company had previously seemed interested in deep oil potential but now plans to prioritize "identifying natural gas bearing formations as opposed to the deeper potentially oil bearing formations." The company was working to secure funding.

The project was not mentioned in the 51st plan of development. ●

Contact Eric Lidji at ericlidji@mac.com

EXPLORATION & PRODUCTION

Foothills stratigraphic test core viewing

On Dec. 11 and 12 the U.S. Geological Survey and Alaska's Division of Geological and Geophysical Surveys will hold public viewings of cores from two stratigraphic test boreholes that the agencies drilled in the Brooks Range foothills on the North Slope during the summer of 2024. The viewings will run from 9 a.m. to 12 p.m. and 1 p.m. to 4 p.m. on each day. The viewings will provide opportunities to look at the cores and to discuss preliminary interpretations, future analytical plans and implications for North Slope petroleum systems, DGGS says.

The first of the boreholes, Slope Mountain 1, targeted non-marine reservoir rocks of the Nanushuk formation. It recovered 522 feet of core, including rocks that are covered, poorly exposed or in adjacent outcrop. The cores provide sedimentological and stratigraphic information related to the deposition of the Nanushuk formation.

The other borehole, the Landslide 4, was drilled to evaluate source rocks from deepwater deposits in the Seabee and Torok formations. Oil stained sandstones were found in 733 feet of recovered core. There is some degree of stratigraphic uncertainty with the cores because of the lack of outcrop exposures of rocks that correlate with the subsurface rocks.

Information about the viewings can be obtained from Josh Long at josh.long@alaska.gov or 907-451-5010.

—ALAN BAILEY

Potential well, sidetrack at Deep Creek

In its 21st plan of development for the Deep Creek unit on the Kenai Peninsula, Hilcorp Alaska said it might drill one grassroots well at the unit, "pending results of reservoir field studies planned for spring and summer of 2024."

The Alaska Oil and Gas Conservation Commission has published notices of public hearings for spacing exception requests from Hilcorp for one grassroots well and one sidetrack at Deep Creek, Happy Valley B-18 and Happy Valley B-13A. The hearings are tentatively scheduled for Jan. 14 at 10 a.m. Requests for the hearings must be in writing and submitted by Dec. 6 at 4:30 p.m. The commission said if no timely requests are filed, it may issue an order without a hearing. Call 907-793-1223 after Dec. 10 to learn if the hearing will be held.

AOGCC said the spacing exceptions are required because the wells would be within 1,500 feet of an external property line where owners and landowners are not the same on both sides of the line.

In its 2024 POD, which covers Aug. 1, 2024, through July 31, 2025, Hilcorp said it did not have long-term activities planned, but "future wells will be evaluated based upon current risked resource and economics, market demand, pipeline capacity, and competitiveness within Hilcorp's gas project portfolio."

Deep Creek is one of the smaller Cook Inlet gas producers, averaging 3,078 thousand cubic feet per day in September, 1.61% of inlet gas production, down 4.25% from August and down 16.46% from September 2023. September production was from seven wells, with the majority from four wells on B pad, which is where the proposed grassroots and sidetrack are located.

—KRISTEN NELSON

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Kay Cashman	PUBLISHER & FOUNDER
Mary Mack	CEO & GENERAL MANAGER
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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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GASLINE ANALYSIS

analysis.

The focus was natural gas for Southcentral, and Wood Mackenzie noted the declining Cook Inlet gas supply, with only a 9% success rate at the 34 exploration wells drilled in the basin over the last 15 years, resulting in lack of a secure and affordable supply leading to declining gas demand, notably closure of the fertilizer plant in 2007 and mothballing of the Kenai LNG plant in 2017.

The pipeline alternative

Wood Mackenzie compared importing LNG with building phase 1 of the Alaska LNG project — just the pipeline — to bring natural gas south.

Building the pipeline would result in increased demand from Fairbanks, with increased demand from the Nikiski oil refinery and from additional industrial applications.

The baseload cost for a million British thermal units of gas would be $12.80, dropping gradually as more demand is added, first to $11.20 and then to $8.97 with more industrial demand resulting from the dependable resources. The big drop, of course, would come when the Alaska LNG project was completed and began exporting LNG, with the export volumes supporting a delivered cost of $2.23 to Alaskans.

The cost in Fairbanks would be higher as there would be an additional tariff for the spur line into that Interior city.

First gas is assumed in 2031.

Imported LNG alternative

Wood Mackenzie looked at four cost components for imported LNG: cost of the molecules; shipping; regasification; and onshore reception of the gas. Onshore reception was not calculated because of unknown variables. Wood Mackenzie said that based on other onshore sites, that cost could range from $50 million to $500 million.

Molecule cost would vary based on contractual terms, but Wood Mackenzie estimated costs ranging from $10.21 to $13.72 per million Btu, without the unknown onshore reception cost.

Economic impacts

Wood Mackenzie then looked at the economic impacts for the state of the alternatives, finding the impact of Alaska LNG Phase 1 to be seven to 10 times larger than that of LNG imports, based on construction, lifetime operations, multipliers and the potential savings with access to low-cost gas.

Another downside to imported LNG is the lack of upside demand for gas outside of the baseload.

In addition to increased gas demand generated by the pipeline, that project would also generate government income from corporate taxes and income from monetization of upstream gas.

Jobs along would be four times the number for construction and 4.6 times the number for operation for a pipeline over imported LNG.

The time to first gas for the pipeline is estimated at 2031, while time for LNG imports is put at 3-4 years after the final investment decision, but with the caveat that an LNG import project has not submitted any major applications.

AGDC: What's next

Frank Richards, president of the Alaska Gasline Development Corp., provided a timeline of work needed to secure first gas from Phase 1 of the Alaska Natural Gas Pipeline in 2031.

The third-party verification of phase 1 economics was completed.

Next on the list was executing a FEED backstop agreement with a pipeline operator.

FRANK RICHARDS

Richards said that for a pipeline operator to take on and execute the FEED phase, they needed surety that if the project didn't go forward, they would be repaid for the FEED cost — up to $150 million.

Funding the FEED backstop requires $50 million, he said.

Meanwhile, work has not stopped on advancing the full Alaska LNG project. AGDC has been working to raise capital, $150 million, as well as continuing to talk to LNG developers, financiers and countries about the opportunity in Alaska LNG.

Chairman McKay asked if AGDC could wait until the next legislative session for the $50 million.

Richards said the sooner AGDC has the $50 million, the sooner it can start engineering.

Once the pipeline operator funds and undertakes FEED, it will prepare a final cost estimate and construction contracts.

The next step is agreements with Alaska utilities for long-term gas supply, then raising debt and equity financing followed by a final investment decision and the start of construction. For first gas in 2031, construction would start in 2027.

—KRISTEN NELSON

Contact Kristen Nelson at knelson@petroleumnews.com

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OIL PRICES

Trump, but Putin nixed major territorial concessions and called for Ukraine to abandon notions of joining NATO, five sources with knowledge of Kremlin thinking told Reuters Nov. 20.

Despite the report that the Kremlin is open to work on a cease-fire deal, "there remains a great deal of uncertainty surrounding the near-term outlook for the conflict," Tyler Richey, co-editor at Sevens Report Research, told MarketWatch.

In a bullish demand development, Terence Hove of Exness told the Wall Street Journal that a rebound in China's oil demand is likely, which could propel crude imports to near-record levels by the end of November.

U.S. commercial crude inventories for the week ended Nov. 15 rose 0.5 million barrels from the previous week to 430.3 million barrels, 4% below the five-year average for the time of year, the U.S. Energy information Administration reported Nov. 20.

On average, analysts polled in a survey conducted by S&P Global Commodity Insights called for a decline of 800,000 barrels in U.S. commercial crude for the week.

Total motor gasoline inventories jumped 2.1 million barrels for the period to 208.9 million barrels, 4% below the five-year average for the time of year, the EIA said. Distillate fuel inventories fell 0.1 million barrels to 114.3 million barrels, 4% below the five-year average for the time of year.

The S&P Global Commodity Insights survey called for supply decreases of 2.5 million barrels for gasoline and 1.8 million barrels for distillates.

Oil inched higher Nov. 19 as ANS added 28 cents to close at $72.41, WTI added 23 cents to close at $69.39 and Brent gained a penny to close at $73.31.

Prices were boosted as Russian crude shipments hit a two-month low based on reduced loadings from Russia's Western ports, according to tanker-tracking data monitored by Bloomberg and released Nov. 19. Russian maritime crude oil exports fell to 3.28 million barrels per day in the month ending Nov. 17, off 150,000 bpd versus the preceding four-week average ending Nov. 10.

Daily Russian crude shipments in the week ending Nov. 17 slid some 740,000 barrels to 2.83 million, the lowest since the first week of July.

Also on Nov. 19, Ukraine launched at least six U.S.-made ATACMS missiles on a weapons depot in Russia's Bryansk region, the Russian Defense Ministry and Ukrainian officials said per a Washington Post report.

Crude prices surged Nov. 18 on reports of a production halt at Norway's Johan Sverdrup field caused by an onshore power outage. ANS leapt $2.10 to close at $72.13, WTI leapt $2.14 to close at $69.16 and Brent leapt $2.26 to close at $73.30.

The leap was preceded by a down day Nov. 15 which saw ANS drop $1.55 to close at $70.04, while WTI sunk $1.68 to close at $67.02 and Brent dropped $1.52 to close at $71.04.

ANS rose 39 cents Nov. 14 to close at $71.59, WTI rose 27 cents to close at $68.70 and Brent rose 28 cents to close at $72.56.

Oil majors such as BP, Chevron, Shell, TotalEnergies, ExxonMobil and Eni are investing in biofuels.

The six companies have announced 43 biofuel projects either already operational or targeted to start up by 2030, Rystad Energy said in a Nov. 19 release.

Investments include biodiesel and ethanol, but the focus is clearly on hydrotreated vegetable oil and sustainable aviation fuel — expected to make up some 90% of the projected biofuel production.

The investments could add a combined 286,000 barrels per day of production capacity, Rystad said, adding that 31 projects are greenfield developments, six involve co-processing — integrating bio feedstock into existing crude-oil refineries to produce a blended feedstock — while another six are full conversions of refineries to facilities dedicated exclusively to biofuel production.

"Co-processing stands out as a cost-effective option that allows companies to leverage existing infrastructure and reduce upfront investment, making it an appealing choice for oil majors entering the biofuels market," Rystad said.

"Supermajors are accelerating investments in biofuels like HVO and SAF, recognizing their potential as low carbon 'drop-in' fuels that can be swiftly integrated into existing aviation, heavy transport and marine fuel systems," said Lars Klesse, Rystad bioenergy research analyst. "As the energy transition progresses, these biofuels offer a practical, near-term solution to reduce emissions without requiring significant changes to current infrastructure." ●

Contact Steve Sutherlin at ssutherlin@petroleumnews.com

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PIKKA UPDATE

throughout the commodity price cycle," Gallagher said.

"Santos has been unrelenting in sticking to its strategy and implementing its disciplined operating model," he said.

The successful startup of Santos' 1.7 million tons per annum Moomba Carbon Capture and Storage project in October, with the technology and reservoirs performing as expected, demonstrates the potential for future phases to provide safe, low-cost, permanent carbon storage for customers and hard-to-abate industries, the company said.

The goal is equivalent to around 50% of Santos' 2023 equity Scope 3 emissions from the combustion and use of its products.

On its website Santos said the Nanushuk play in the Pikka unit, which is operated by its subsidiary Oil Search (Alaska) LLC, represents one of the largest conventional oil discoveries made in the United States in the last 30 years, and the Pikka Phase 1 project is the most significant development on Alaska's North Slope in more than 20 years.

Pikka has low emission intensity, placing it in the top quartile of oil and gas development projects globally for greenhouse gas emissions performance.

"Pikka is poised to play an important role in the energy transition and is aligned with our company goal of managing climate change risk," the website said.

Santos is committed to delivering a net-zero project (scope 1 and 2, equity share) from first oil and has entered into memorandums of understanding with Alaska Native corporations to deliver carbon offset projects, including a strategic alliance with ASRC Energy Services, a wholly owned subsidiary of Arctic Slope Regional Corp., on leading technology development for carbon solutions in the Arctic.

The project has strong fundamentals and is in a world-class oil producing province with significant existing infrastructure, has low unabated emissions intensity and is supported by key stakeholders, including the state of Alaska, the North Slope Borough, the landowner company Kuukpik Corp. and the Arctic Slope Regional Corp., the website said.

—KAY CASHMAN

Contact Kay Cashman at publisher@petroleumnews.com

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DALTON CONTROL

to maintain the Haul Road is political, frustratingly unnecessary, and fought with bureaucrats in faraway Washington D.C.

A very important corridor

The transportation corridor that holds the Dalton Highway also hosts the trans-Alaska pipeline, and it is the right of way for much of the proposed natural gas pipeline from the North Slope to the tidewater of Cook Inlet. The state manages these assets, but most of the corridor north of the Yukon River falls under jurisdiction of the U.S. Bureau of Land Management. South of the Yukon, the land falls under state jurisdiction.

The Haul Road is of vital importance, and the Trans-Alaska Pipeline System is the economic lifeline of the state, Boyle said in remarks to the Resource Development Council's 45th Annual Alaska Resources Conference Nov. 13 in Anchorage.

"Having management of those lands is critical," Boyle said. "In October it was announced that some consortium of environmental groups and others are actually challenging of BLM's authorizations for the Trans-Alaska Pipeline System, citing climate concerns and other things, so having that area under federal management — particularly federal management that is antithetical to the interests of the state of Alaska — is problematic."

Alaska remains entitled to nearly 6 million acres of additional land entitlement from the federal government that it has yet to receive, based on Alaska being admitted as the 49th state of the union, Boyle said. Of those acres, the Dalton Highway corridor — currently covered under Public Land Order 5150 — "represents the state's number one priority in terms of the lands that we're most interested in in getting our hands on."

Federal control complicates and delays even such basic tasks as obtaining gravel to improve and maintain the highway during the short summer construction season, Transportation and Public Facilities Commissioner Ryan Anderson told conference attendees.

Anderson said the state conducted a study that found that due to wind and heavy truck traffic, the highway loses 3/4 of an inch per year of surfacing during the season.

"On the Dalton, it's not easy to find good gravel sources in a lot of places and so we're really pushing out just to try to find those good materials and build that road that'll last," he said.

Boyle expressed frustration that the Secretary of the Interior had the opportunity to grant the state those lands within the 5150 corridor earlier in 2024 as Interior was working on its Central Yukon Resource Management Plan — a planning effort BLM had undertaken over the past decade.

"They were looking at alternatives from completely conveying the 2.1 million acres that the state has selected in that quarter to not conveying any element at all," he said.

A promising field trip

Boyle said he had reached out in good faith to BLM Director Tracy Stone-Manning in 2023 and was invited, along with DNR Deputy Commissioner Brent Goodrum, to join Stone-Manning for a ride up the Haul Road to a BLM camp north of Coldfoot.

Despite a vast divide in political philosophies, it was a good trip, Boyle said.

After crossing from state land over the Yukon River bridge to BLM land, Boyle had a chance to chat with Stone-Manning and make a point.

"We just spent the last couple of hours driving around the part of the Dalton Highway corridor that's managed by the state, and as you can see it's not some kind of hellscape that we've cut down all the trees, and we've stripped mined everything and it just looks like some kind of barren wasteland," he said. "It's beautiful pristine Alaska wilderness and so you know shifting from federal to state management isn't some kind of dramatic shift in how these lands are going to be managed.

Boyle said the state refined its proposal, instead of asking for 2.1 million acres it shrunk down its ask to its most important points: to have the Dalton highway; to have the Trans-Alaska Pipeline System right of way, and to have the right of way for the future Alaska LNG pipeline. In addition, the state requested material sites needed to maintain the highway; some placer mining deposits in the Wiseman area; and most importantly access corridors off the highway to places like the Ambler mining district, the Ray Mountains and other state land holdings that are currently isolated.

"I actually got a commitment from Director Stone-Manning and the team here in Alaska to work on analyzing the state's revised proposal and to work with us through that RFP process to actually arrive at a solution that would give the state titles," Boyle said. "But as was the common practice in the Biden/Harris administration, that decision making was sucked back into D.C., and it was pulled up into that unknown ethereal layer that didn't really rest with the Interior — that's somehow connected to the people in the White House that are that are calling all the shots and particularly calling the policy shots for Alaska."

—STEVE SUTHERLIN

Contact Steve Sutherlin at ssutherlin@petroleumnews.com

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BITCOIN MINING

encouraged that companies are pursuing opportunities like this in Alaska, and DNR hopes to continue to see more opportunities for computing and data center development using Alaska's abundant resources. The Division of Oil and Gas is currently adjudicating this permit application through the public process."

The term requested in TA Infrastructure's application is four years, from November 2024 to November 2028.

Installation

Installation of the data center module will be overseen by a Hilcorp team, including "logistics onto the site, placement of the module on the existing pad and the electrical connection from the transformer already in place to the data center module," TA Infrastructure said in its application.

Transportation to the site will be done by a single truck out of Deadhorse on existing roads.

Placement of the module at the site will involve a single crane to move the container from the truck onto the pad with no additional construction or surface disturbance necessary.

Electrical connections will be performed by Hilcorp and consist of five total cables running 60 feet each from the transformer to the data center module.

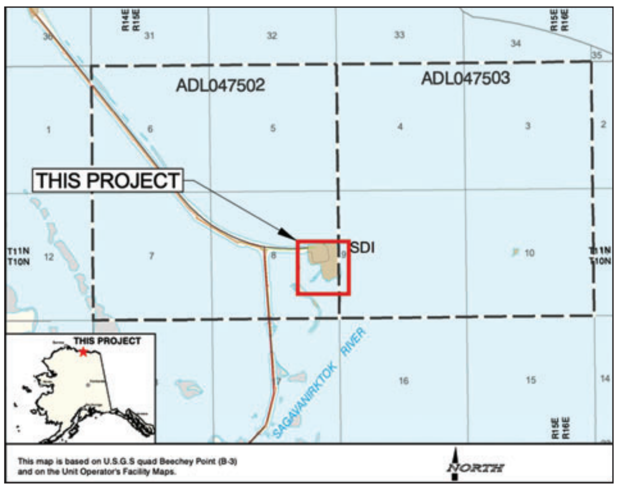
"We are estimating less than a week total to complete installation once the data center module arrives at the site," TA Infrastructure said.

"Overall, we have designed this pilot to have minimal impact to the existing pad site," the tech firm said.

Collaborating with Hilcorp

TA Infrastructure said it has been "collaborating with Hilcorp on strategic projects to monetize produced natural gas on the North Slope" that is associated with some oil fields and otherwise stranded from traditional sales markets.

"As part of those efforts, we have developed a business model whereby we can utilize currently produced natural gas to generate power and co-locate data centers to consume that power on the North Slope," TA Infrastructure said in its application.



STATE OF ALASKA

The pilot program will consist of a single 40-foot shipping container that will serve as a modular data center. Its computers will consume power from Hilcorp's already installed power generation equipment "on a continuous basis 24/7 for 4 years," TA Infrastructure said.

"Overall, we believe this project and future larger projects present significant opportunity to monetize natural gas on the North Slope and attract new high-tech industries to the state of Alaska," TA Infrastructure said.

Connected by causeway

The Duck Island unit was initially developed from two artificial gravel islands, the main producing island and the Satellite Producing Island, connected by a causeway to the mainland.

BP had proposed drilling ultra-extended reach wells to tap the Liberty oil reservoir, located on federal leases in shallow Beaufort Sea waters about 6 miles offshore and 15 miles east of Prudhoe Bay.

"Overall, we believe this project and future larger projects present significant opportunity to monetize natural gas on the North Slope and attract new high-tech industries to the state of Alaska," TA Infrastructure said.

A monster rig was to bore the wells from the SDI at BP's offshore Endicott field. In November 2010, however, BP announced it was suspending construction pending an engineering review, and the rig stood idle at Endicott for several years before eventually being removed.

Comments welcome

TA Infrastructure Management's application package is available for review at the Division of Oil and Gas' Permitting Section, 550 West 7th Avenue, Suite 1100, Anchorage, AK 99501, or online at http://dog.dnr.alaska.gov/Newsroom.

Send comments to dog.permitting@alaska.gov or to the division address above. All comments must be in writing. A copy of the final decision will be sent to any person who provides written comments. An eligible person affected by this decision may appeal or request the commissioner's reconsideration in accordance with 11 AAC 02.

All comments must be received by the comment deadline: 4:30 p.m., Alaska Standard Time, Nov. 29.

The Department of Natural Resources complies with Title II of the Americans with Disabilities Act of 1990. This notice will be made available in alternative communication formats upon request. Individuals with disabilities who may need auxiliary aids, services, or special modifications to participate may contact the address above or call 907-269-8411. ●

Contact Kay Cashman at publisher@petroleumnews.com

Oil Patch Bits

Lynden delivers relief supplies after Stebbins fire

As reported by Lynden News Nov. 14, Lynden is known for responsive service and flexibility when schedules and circumstances change. A scheduled Alaska Marine Lines barge delivery for a housing project took a sharp turn when a fire destroyed the village school and teacher housing in Stebbins, Alaska. Alaska Gov. Mike Dunleavy declared a disaster for the village after the fire. "Construction company and customer Tapraq Rock sent an email asking us if we could help get supplies there quickly so they could rebuild the school by August," explains Rick Kellogg, Alaska Marine Lines pricing logistics analyst.

Kellogg and the Alaska Marine Lines team pulled together a quote within 24 hours and located a barge in Dutch Harbor that was already positioned for fish season. "They had about a week to round up a barge worth of cargo. They were bringing things in on sail day, but we got it loaded, lashed and on its way." Cargo consisted of 17 modular units for use as classrooms and teacher housing, machinery, building materials and rolling stock.

Lynden Air Cargo also supported the effort with nine flights, moving over 300,000 pounds of construction materials, furniture and supplies for the school rebuild. "The Stebbins runway is too small for us to operate directly into, so we flew everything to nearby St. Michael's, where the loads were then trucked to Stebbins," says Nick Niziolek, commercial operations manager.

The air and marine assistance was a mad dash, Kellogg says, with a short window of time to get cargo into the village to prepare for the 230 students starting school in August. "Although we could not divert our scheduled barge, the operations team came up with a solution to locate another barge and move quickly for this important project. They are the heroes of this story." The Alaska Marine Lines team of Don Reid, TJ Vires, Brian Ward, Trevor Stephens and Bubba Miller put together the voyage of eight days from Anchorage to Nome for offloading, followed by five landing craft trips from Nome to Stebbins. For more information visit www.lynden.com.

Companies involved in Alaska's oil and gas industry

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

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RRC CEO

Jenkin said. "I believe the stakeholder-led organization is the right vehicle to bring enforceable standards and regionalized resource planning to the Railbelt to help achieve long-term reliability, sustainability, and affordability. I look forward to building on the progress the RRC has already made to deliver on our commitment to Alaskans."

Approved by the Regulatory Commission of Alaska in 2022 as the electric reliability organization for the Alaska Railbelt generation and transmission system, the RRC has a role to maintain and mandate reliability standards for the Railbelt's high voltage electrical system; administer rules for open access to the transmission grid; and conduct Railbelt-wide integrated resource planning. The idea is to achieve more unified management of the system, thus minimizing electricity costs while also maintaining an acceptable level of supply reliability.

In a presentation to the RCA on Nov. 13 Groves overviewed what the RRC has achieved this year and its upcoming plans.

Interim management team

In the absence of a CEO, earlier this year the organization hired an interim management team using a chief administrative officer and chief technical officer working under contract, so that work could begin towards achieving the organization's objectives. Subsequently, work on developing reliability standards began in June, Groves said. The first tranche of these standards will be presented to the board for approval in December, he commented. Following board approval, the standards will

Meanwhile, activities expected for 2025, now that a CEO is in place, will include the hiring of employees and a transition from interim to permanent management, together with the establishment of RRC office space.

require approval by the RCA.

Four further standards are under development and are anticipated to be presented at some time in the new year, with further standards being queued up for preparation.

Work on the reliability standards involved the formation of a technical advisory committee, operating under the chief technical officer, and with a working group developing each standard. The standards development is using, as a template, voluntary reliability standards that the utilities had approved in 2018. However, bringing these standards up to date and into compliance with the North American Electric Reliability Corp. templates that they are based on involves quite a bit of work, mainly at the working group level, Groves said.

A public oriented process

And the standards development requires a very public oriented process, involving consumer advocates and members of the public, Groves commented. He also commented that the technical advisory committee now has custody of the critical infrastructure protection standards that the Railbelt load serving entities have developed in the past — in 2025 these standards will be moved through the same process as the other standards that the committee is working on.

In the near future the RRC also anticipates making some refinements to its process for developing an integrated resource plan. The organization anticipates completing these refinements during the first quarter of 2025, so that work on an IRP can begin in the first or second quarter.

The RRC's role in overseeing the electricity transmission system has changed as a consequence of the formation this year of the Railbelt Transmission Organization within the Alaska Energy Authority. The Alaska Legislature passed a statute requiring formation of the RTO to develop and oversee a new Railbelt electricity transmission tariff arrangement that removes current impediments to competition in the bulk power market in the Railbelt. The RRC retains responsibility for the planning of the transmission system and the RRC board chair is a member of the board committee of the RTO.

The RRC's structure

In terms of the RRC's internal structure, the organization has been working on revisions to its rules and bylaws. For example, confidentiality concerns relating to some of the reliability standards require some clarification in the RRC rules, Groves said. The organization has also launched a new website that has improved capability to support product development, he said. Financial systems have also been implemented and are functioning well.

The RRC is governed by a 15-member board of directors, with 13 members appointed to represent specific stakeholder classes including electric utilities, independent power producers and electricity consumers. Two non-voting members represent the Regulatory Commission of Alaska and the Office of the Attorney General's Regulatory Affairs and Public Advocacy Section.

Groves said that monthly board meetings are coupled with monthly training or workshop sessions that focus on governance issues, the technical products that come before the board and current events that are relevant to the RRC, such as Cook Inlet gas supply problems and electricity transmission system plans.

Currently much of the RRC's outreach to stakeholders in the electrical system comes from the fact that its board of directors encompasses a broad spectrum of those stakeholders. In addition, as needed, the organization can conduct one-on-one communication with individual stakeholders such as the CEOs of Railbelt utilities or independent power producers. The RRC also emphasizes the importance of outreach to its stakeholders through its budget development process, Groves said. The organization will soon be presenting its 2025 budget to the RCA, he added. Furthermore, the RRC is developing an outreach plan that will enable a broader engagement with the public, he said.

The work program

Overall, the lengthy time required to find and appoint a CEO has resulted in some delays in the RRC's work program, relative to its originally conceived plan. The organization had anticipated completing the electrical system operating and planning standards in March 2025, Groves said. There is some difficulty in predicting exactly when these standards will now be finished, given unforeseen issues that can arise, but completion is anticipated in mid-2025, he said. However, the development of critical infrastructure protection standards is on track for completion in September 2025, he added. And work has yet to begin on standards for open access to the system, he commented.

The RRC anticipates completing an initial integrated resource plan for the Railbelt in June 2026, as originally envisaged, Groves said.

Meanwhile, activities expected for 2025, now that a CEO is in place, will include the hiring of employees and a transition from interim to permanent management, together with the establishment of RRC office space. ●

Contact Alan Bailey at abailey@petroleumnews.com