Petroleum news

page 4 This week in history: BP wants fair, simple predictable terms for gasline

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## AOGCC changes: Price, Seamount leaving, Wilson new commissioner

There are big changes underway at the Alaska Oil and Gas Conservation Commission, with turnovers in two of the three commissioner seats.

Chair Jeremy Price is leaving the commission for a job with HF Sinclair in Anacortes, Washington, effective Sept. 23, and Dan Seamount, who has been AOGCC geology commissioner since 2000, is retiring, with his place on the commission being taken by Greg Wilson, who started Sept. 19.

JEREMY PRICE

Price told Petroleum News in a Sept. 21 email that he is moving to a position as government and public affairs manager with HF Sinclair, which bought Shell's Anacortes refinery late last year. "They refine Hilcorp's Alaska North Slope crude," Price said, calling the new position "an opportunity to promote a favorable business climate where ANS gets refined, a great way to help my home state of Alaska in a different way."

In a Sept. 12 resignation letter to Gov. Mike Dunleavy Price said that during his three years on the commission, "I focused on

*see* **AOGCC CHANGES** *page 12*

## GBP needs lengthy Alkaid 2 flare approval; AOGCC sets hearing

The Alaska Oil and Gas Conservation Commission has scheduled a hearing on a request by Great Bear Pantheon for approval for nine months of flaring of gas associated with long-term testing of the Alkaid 2 oil well.

In an Aug. 22 request, Michael Duncan, Great Bear Pantheon's chief operating officer, said that following completion of the Alkaid 2, "Great Bear intends to conduct a long-term pilot production test to determine if the well, and more specifically the target formation, will be capable of producing at sufficient sustained volumes to support a development program of the target formation."

During that production test, the company "will need to flare non-utilized natural gas," he told the commission.

Duncan said Alkaid 2 is a horizontal well with the target formation, the Alkaid production zone, "considered a tight sand." He said the well will use horizontal multi-stage completion,

*see* **FLARE APPROVAL** *page 12*

## Oct. 20 opening, Nov. 3 close for online state fall lease sale bids

The Alaska Department of Natural Resources' Division of Oil and Gas said Sept. 15 that bidding will open Oct. 20 for the state's fall areawide oil and gas lease sales — the Beaufort Sea, North Slope and North Slope Foothills. The deadline to submit bids is Nov. 3 and results will be available online Nov. 9 on the division's website at https://dog.alaska.gov.

MIKE DUNLEAVY

DNR said this will be the 25th North Slope areawide sale. All unleased acreage in the North Slope region is offered each fall and since 1998 the sales have brought in more than $310 million in cash bonuses for the state.

There are 1.9 million acres on 1,125 leases currently under lease within the North Slope areawide sale area and more than 700,000 acres on 255 leases in the Beaufort Sea sale area, with 355 of the leases in production and paying royalties to the

*see* **FALL LEASE SALE** *page 10*

EXPLORATION & PRODUCTION

# He's back at it!

*Bill Armstrong leads exploration team; this time, West Castle in NPR-A*

**By KAY CASHMAN**
*Petroleum News*

A Bill Armstrong company, North Slope Energy LLC, is planning a multi-year onshore oil and gas exploration drilling program in the National Petroleum Reserve-Alaska. He's pursuing what he describes as "a perfect look-alike to Willow and Pikka," meaning Nanushuk reservoirs.

BILL ARMSTRONG

Starting with two wells in the first year, North Slope Energy will drill into a 92,000-acre lease block purchased from Anchorage-based Borealis Alaska Oil in early 2020.

"West Castle is a gorgeous prospect. We identified it off of 3D seismic," Armstrong told Petroleum News in mid-September.

Shortly after acquiring the acreage, Armstrong told PN his leases lie to the immediate west of ConocoPhillips' Harpoon prospect.

Drilling is expected to start Feb. 15, 2023, using All American 111 drill rig.

Wells are planned as single, vertical wellbores. Well formation evaluations via open and cased hole logs will be performed during the drilling at both wells.

At completion of formation evaluation in terms of commercial viability, wells will be plugged and

*see* **WEST CASTLE** *page 11*

FINANCE & ECONOMY

# Risk-off bias reigns

*Fed rate hike sends oil prices near 2-week low; ANS hovers above $90*

**By STEVE SUTHERLIN**
*Petroleum News*

Alaska North Slope crude clung precipitously to the $90-plus range Sept. 21, sliding by 87 cents to close at $90.55 per barrel. West Texas Intermediate fell $1.51 to close at $82.94 and Brent slid 79 cents to close at $89.83.

Bears continued to claw support away from oil prices under a decisive risk-off bias pervading financial markets in the lead up to a Sept. 21 rate hike decision by the U.S. Federal Reserve. The Fed raised its target interest rate by 75 basis points, and although the move was widely anticipated, oil prices neared a two-week low on the day.

The U.S. dollar rose, dealing more pain to economies that must convert local currencies to pay dollar-denominated oil prices.

*As has been shown in the recent past, when China and its Asian neighbors step up crude purchases, they hoover up Pacific cargoes that would otherwise have competed against ANS on the West Coast.*

News from Asia blew headwinds as well.

The Asian Development Bank downgraded its 2022 growth forecast for developing Asia, citing COVID-19 lockdowns in China, conflict in Ukraine and economic friction from efforts to

*see* **OIL PRICES** *page 10*

PIPELINES & DOWNSTREAM

# Pikka in great detail

*Part 1 of 2: Santos Alaska subsidiaries lay out pipeline-related plans to RCA*

**By KAY CASHMAN**
*Petroleum News*

1 2 SERIES

Remember the estimate of 160,000 barrels of oil per day possible from the Pikka unit? Well, it is real over time if additional Pikka Unit development is sanctioned according to information provided by Santos Limited Alaska subsidiaries in a mid-September public hearing held by the Regulatory Commission of Alaska, or RCA.

As previously reported. Pikka Phase One (Drill Site B) has been sanctioned by the unit's working interest owners; it will produce 80,000 bpd of oil starting in 2026. If sanctioned the additional 80,000 bpd would come from within the Pikka Unit, specifically from two additional drill sites (A and C), and "some possibilities" in the northern part of the unit. None is likely to come from nearby discoveries in the Horseshoe unit (Horseshoe and Stirrup wells) or the Mitquq well in the Quokka unit, although at one point in the hearing the Mitquq discovery was mentioned as a possible tie-back to Pikka.

### Purpose of hearing

The Sept. 16 hearing was about Oil Search

*see* **PIKKA DETAIL** *page 6*

● PRODUCERS PREVIEW

# Amaroq keeps Nicolai Creek alive

*Aging field continues to produce 133 million cubic feet per year and could have lasting life with additional investment*

**By ERIC LIDJI**
*For Petroleum News*

Being a producer doesn't always mean drilling, especially in a legacy basin.

The small local independent Amaroq Resources LLC has managed to keep the Nicolai Creek unit alive in recent years, despite marginal economics, without drilling new wells.

First came a successful conversion project to address water-handling issues at the onshore natural gas field on the west side of the Cook Inlet basin. Then came a desirable verdict in a recent legal case over its bonding requirements, saving the company millions.

More maintenance and administrative projects like those exist, if the company chooses to pursue them. But the long-term future of the unit probably lies in drilling for deep oil.

### History

Union Oil Company of California oversaw startup in 1968 and operated the unit through 1977. With declining production, the unit went offline for decades. The small, local independent Aurora Gas LLC revived the west side Cook Inlet property in 2000 and undertook additional drilling and fieldwork at the property for nearly two decades.

Aurora Gas filed for bankruptcy protection in early 2018. As part of the proceedings, a similarly named but legally unrelated company called Aurora Exploration LLC acquired the Nicolai Creek unit. Aurora Exploration later changed its name to Amaroq Resources.



Unocal and Aurora Gas drilled 11 wells at the Nicolai Creek unit. Today, five of those wells have been abandoned — NCU No. 4, No. 5, No. 6, No. 13 and No. 14 — and another five are capable of producing — NCU No. 2, No. 3, No. 9, No. 10 and No. 11.

In a plan of development from 2020, Amaroq said that the Nicolai Creek unit would become uneconomic within a few months without several important investments.

One of those investments was finding a better disposal method for produced water. The company ultimately converted the depleted NCU No. 1B well to a water disposal well.

The project was undertaken in mid-2020 and completed by the end of the year and came online in mid-2021, following weather-related delays. It now handles 250 barrels per day.

### Production

Of the five wells capable of production, only a few are producing consistently.

The Nicolai Creek unit produced 133 million cubic feet of natural gas in the year ending Aug. 31, 2021, up 43% over the previous year, according to Amaroq. The unit produced 45.7 million cubic feet of natural gas in the first six months of this year, down from 67.8 million cubic feet in the first six months of 2021, according to the AOGGC.

The decline came largely from lower production at the NCU No. 9 well, which currently accounts for the majority of unit production, and to a lesser extent at NCU No. 11. NCU No. 11 has been perennially shut-in during recent years due to low reservoir pressure.

The remaining production wells are all candidates for investment, to varying degrees. The leading candidate at the moment is NCU No. 10, which currently produces sporadically.

The well was returned to production in May 2021 after some time offline. It produced nearly 4.8 million cubic feet through October 2021 before coming offline again.

*see* **PRODUCERS PREVIEW** *page 3*

## contents

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# EXPLORATION & PRODUCTION

## US rotary rig count up by 4 to 763

The Baker Hughes' U.S. rotary drilling rig count was 763 on Sept. 16, up by four from the previous week and up 251 from 512 a year ago.

When the count dropped to 244 more than two years ago, 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, where it remained through mid-March, 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 Sept. 16 count includes 599 rigs targeting oil, up by eight from the previous week and up 188 from 411 a year ago, with 162 rigs targeting natural gas, down by four from the previous week and up 62 from 100 a year ago, and two miscellaneous rigs, unchanged from the previous week and up by one from a year ago.

Forty-five of the rigs reported Sept. 16 were drilling directional wells, 699 were drilling horizontal wells and 23 were drilling vertical wells.

### Alaska rig count unchanged

The rig count in Texas (364) was up by five from the previous week. The Louisiana rig count (65) was up by one.

New Mexico (108) and North Dakota (38) were each down by one rig week over week.

Rig counts in other states were unchanged from the previous week: Alaska (10), California (7), Colorado (21), Kansas (1), Ohio (11), Oklahoma (64), Pennsylvania (23), Utah (13), West Virginia (13) and Wyoming (20).

Baker Hughes shows Alaska with 10 rotary rigs active Sept. 16, unchanged from the previous week and up by five from a year ago, when the state's rig count stood at five. Nine of the rigs in Alaska were onshore, up by one, and one was offshore, down by one from the previous week.

The rig count in the Permian, the most active basin in the country, was up by three from the previous week at 343 and up by 84 from 259 a year ago.

—KRISTEN NELSON

*continued from page 2*

## PRODUCERS PREVIEW

The well was returned to production in June 2022 at a rate roughly matching its May 2021 re-start.

The complication is water production. The well produced more than 17,000 barrels in 2021, with gas-to-water ratios increasing notably during early months of production.

"Once the well has stabilized and water production can be accurately projected, Amaroq will evaluate the economics associated with a gravel pack and/or rig workover during 2022, which would facilitate production at much higher rates," Amaroq wrote in its plan.

Another possible investment opportunity is NCU No. 3, which has been shut-in for some time due to "formation sand and silt plugging the tubing," according to Amaroq. The company is proposing a coiled tubing cleanout but has not yet sanctioned that project.

### Bonding

Earlier this year, Amaroq won an important court case against the Alaska Oil and Gas Conservation Commission over bonding requirements on its Nicolai Creek wells.

The AOGCC requires operators to post large monetary bonds to ensure that funding is available to eventually plug and abandoned all oil and natural wells drilled in the state.

The state agency increased the bonding amount in 2019. Under the previous schedule, companies had to post $100,000 for a single well and $200,000 for multiple wells. The new schedule instituted a formula based on the number of wells a company maintained: companies with one to five wells would pay $400,000 per well; companies with six to 20 wells would pay $2 million, plus an additional $250,000 per well for each well above five; companies with 21 to 40 wells would pay $6 million; companies with 41 to 100 wells would pay $10 million; and companies with 101 to 1,000 wells would pay $20 million.

Under that formula, Amaroq would have had to pay $2.25 million to cover the six wells at the Nicolai Creek unit. Amaroq appealed, based on the going rate to plug and abandon wells in the area. The AOGCC agreed in 2020 to lower the bonding rate to $900,000, but Amaroq appealed to state superior court, citing an earlier 2017 agreement at $200,000.

The judge ultimately sided with Amaroq, noting that the 2017 agreement contained a clause that made it difficult for the AOGCC to change the rate at a point in the future.

### Deep oil

Amaroq Resources LLC is also chasing one of the big prizes of Cook Inlet.

For many years, industry watchers have discussed and debated the potential of deeper horizons within the basin, leading to various exploration proposals and activities.

In its most recent plan of development, filed with state officials in September 2021, Amaroq announced plans to acquire 100% working interest in "the 'deep rights' below certain geologic markers in Nicolai Creek Unit." A previous operator at the west side Cook Inlet natural gas field had previously sold these deeper rights to a third party.

That sale closed in November 2021 when Amaroq acquired some 5,000 net acres of "deep rights" on the Kenai Peninsula and the west side of Cook Inlet, including deep oil and natural gas rights underlying the Nicolai Creek unit, from Apache Alaska Corp.

The zones included in the purchase are below the Upper Tyonek formation underlying onshore acreage. The sale granted Amaroq access to proprietary 3D seismic data commission by Apache over the Nicolai Creek unit on the west side of Cook Inlet. ●

*Contact Eric Lidji at ericlidji@mac.com*

● THIS MONTH IN HISTORY

# Let's make a deal

*BP says it wants fair, simple and predictable fiscal terms for gas pipeline from state; briefs DNR, Revenue officials on proposal*

*Editor's note: The following is a reprint from the Sept. 22, 2002, issue of Petroleum News Alaska*

**By KRISTEN NELSON**

*Petroleum News*

BP Exploration (Alaska) Inc. has been saying for some time that one of the things required to make a North Slope gas pipeline project viable is state fiscal predictability. The state asked what that would involve, and in July BP began what it describes as a conversation with the state about fiscal predictability.

Bob Reynolds, manager of Alaska taxes and royalties for BP Exploration (Alaska), made the July 24 presentation to commissioners and staff of the Department of Natural Resources and the Department of Revenue. He and told PNA Sept. 12 that BP's concerns about fiscal predictability for gas are grounded in the state's oil history.

"The history of our relationship with the state on oil was that we spent well over a decade in very acrimonious litigation over essentially the tax and royalty terms," he said. The companies ended up paying an additional $2 billion-$3 billion.

The gas project, Reynolds said, "cannot withstand that kind of risk."

## Fiscal certainty just one leg

But state fiscal certainty is only one leg of a "four-legged stool," said Dave MacDowell, director of external affairs-gas for BP Exploration (Alaska).

Four things are needed to progress the project, he told PNA, and state fiscal predictability is only one. The others are federal enabling legislation, an efficient regulatory process in Canada and a reduction in cost for the project, now pegged at some $20 billion.

Since BP's July 24 presentation to the state, the company has "been having conversations with people who have an interest in this topic", MacDowell said, to inform people about BP's view of fiscal predictability prior to the next session of the Legislature and the new administration.

## BP asking for simplification

In evaluating fiscal predictability, Reynolds said, BP looked at all of the components of the state's take — royalty, production tax, property tax, net profit share and state income tax — and asked how those elements of take could be changed to make them "more fair and simple and predictable" for gas.

The discussion BP had with the state was based on suggested ways to simplify the state's "take regimes" for gas by using common terms between the different regimes and by calculating the value of gas just once for all of the regimes. In the present tax regime, different values are calculated for royalty and for production tax.

"In the new world we propose calculating one value to be used for both regimes, both the production tax regime and the royalty regime," he said.

A lot of the conversation is about simplicity, Reynolds said, and "about taking areas that have historically been contentious either because they're not well defined or not well understood" and agreeing in advance on "what we think are viable terms and then determining ways that we can test those terms over time."

This was not a conversation about incentives or tax holidays or changes in royalty rate, he said: "This is just about trying to nail down what the existing take would be."

## Common terms

Simplicity is the primary thing BP is looking for in common terms, Reynolds said. With five different regimes in the state for taxes and royalty, "we have a large body of statutes or law and regulations that control each one." In addition to that complexity, he said, there are also some omissions.

Reynolds said BP talked to the state about establishing an algorithm or formula to establish the value for gas based on available price markers.

And BP is also suggesting a different type of audit. Instead of auditing for compliance, Reynolds said, BP wants audits to validate the agreement between the producers and the state. "And if it doesn't work, then we go out and we change the basic agreement."

The test for clarity "will probably be whether we've minimized the areas of dispute," he said. "If we can come away with an agreement that has some durability in terms of parties not wanting to break it, then we've succeeded."

*On property tax, Reynolds said, BP is "not looking for a change in the municipalities' take" but wants to see if it can reach agreement with the state on some of the components going in. It would make it a simpler task, he said.*

As for certainty, Reynolds said BP needs to run the economics on a 20-30 year project, and has to ask: "What degree of comfort do you have that those assumptions that you're using are actually going to last that long?"

## Determining a value

Common terms for taxes and royalty means one formula to value the product — for both tax and royalty, Reynolds said. What BP wants, he said, is "a value that reflects what we actually get for selling the gas."

And that amount, MacDowell said, would be arrived at through an algorithm or formula, not by counting up each and every transaction. "And you could test that to make sure the formula was behaving as you expected it would."

"We'd like to have our tax and royalty paid at what we get for our product," Reynolds said. An algorithm or formula would be used to determine those net proceeds, he said: "Or at least approximate that."

The algorithm would approximate reality, MacDowell said, without "the time, energy, effort and potential disputes" of measuring multiple transactions.

A "worst-case formula could be comprised of a hundred different markers," Reynolds said. "What we're saying is, let's pick the most viable, most liquid, the most … transparent liquid markers and let's use those.

"As long as they're representative of what we think the real value of the Alaska gas is."

"And choosing those, the most appropriate marker or markers, is the subject of the conversation that needs to occur with the state. That's a critical part," said MacDowell.

## Deductions

Also on BP's list are allowable deductions.

The gas treatment plant will be an "enormous multi-billion dollar facility" that is "essential to getting the gas to market" and

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## HISTORY

JUDY PATRICK

**BP managers Dave MacDowell, left, and Bob Reynolds**

BP wants the cost of operating that facility to be a deduction, Reynolds said. The gas treatment plant will be a regulated facility, he said, and will have a tariff, "and we would like to just make sure that that tariff is deductible."

Another deduction, he said, would be for moving the gas from the North Slope to market. There will be a tariff for the pipeline, he said, and BP wants to use the regulated tariff as the basis for the deduction.

There have been many years of litigation over the tariff on the trans-Alaska oil pipeline, Reynolds said, and there are ongoing challenges even today to those tariffs.

"And what we want to do is make sure that we do not repeat that in the gas environment because the tariffs for gas are even more important to gas than the tariffs are to oil," he said. The tariff on the trans-Alaska oil pipeline is about $4 a barrel and the value of oil is between $20 and $25 a barrel, so the tariff is 20 percent or less of the value of oil.

But, Reynolds said, a tariff on the gas pipeline could be $2 and the value of the gas $3 to $3.50 — a tariff of 50 percent or more of the value of gas.

BP wants to make sure that the state and industry don't end up at odds over this, he said.

"We spent 10 years arguing about a cost that was less than 20 percent of the value of a product, oil. Without a change, what would that mean if you're talking about a cost that was over 50 percent of the value of a product?" MacDowell asked.

To make sure that the state and industry don't end up at odds over costs, "an agreement with the state will be required up front," Reynolds said.

### Fuel gas also an issue

Tax and royalty treatment of fuel gas — the gas used to run the treatment plant and the pipeline — is another issue that Reynolds said needs to be resolved. The normal practice in the gas industry is that the shipper donates a portion of his gas to the carrier for treatment and transportation.

"And we're basically saying let's do the same thing for Alaska. And that that gas that's consumed doesn't have any kind of tax or royalty associated with it." Reynolds said that would be consistent with Lower 48 practice and also simplifies the process: the quantity of gas that is sold is the quantity of gas that is taxed.

BP also wants confirmation from the state that the carbon dioxide removed at the gas treatment plant and reinjected would be tax and royalty free.

### Binding arbitration: winner take all

Resolution of future disputes is an important issue for the producers, Reynolds said, and the solution they propose is baseball-style (winner-take-all) binding arbitration.

"If we have a dispute, we call in some neutral third parties, present our cases and let them decide."

The arbitration panel doesn't get to split the difference in this kind of arbitration, he said: "It's one side is right and one side is wrong."

Oil royalty for the major producers is subject to baseball arbitration now, Reynolds said: "So we've been down this road and as far as we're concerned it works."

BP wants to see both tax and royalty for gas subject to baseball arbitration.

### Only one check?

There is something else BP would like the state to consider, Reynolds said, something that is already done in Alberta.

If the terms for tax and royalty are common — same value, same deductions — "do we need to write two different checks? Why don't we just write one check that covers both?"

That would be a big change, he said, but one the producers hope the state will consider.

Looking at an Alaska royalty of 12.5% and a production tax of around 10% for gas, an average would be 22-24%, factoring in some leases with a higher royalty.

In Alberta producers already write just one check: for 25%.

This would further simplify the state's fiscal regime, and wouldn't even be breaking new ground, Reynolds said.

### Average weighted royalty?

BP is also proposing a single royalty rate for every molecule of gas.

Instead of saying so much gas comes from leases with 12.5% royalty, so much from leases with 16 2/3% and so much from leases with a 20% royalty, Reynolds said the idea would be to do a weighted average and charge all gas at one royalty rate.

BP is also proposing a uniform field cost allowance. Some lease forms allow the producers to charge field costs against the state's royalty gas, he said, and some don't. As with the royalty, BP is proposing a weighted average field cost applied to all gas.

### Binding arbitration for property tax

On property tax, Reynolds said, BP is "not looking for a change in the municipalities' take" but wants to see if it can reach agreement with the state on some of the components going in. It would make it a simpler task, he said.

BP also wants to replace the State Assessment Review Board with binding arbitration.

Reynolds said he doesn't think either the producers or the state are in a position to deal with the income tax issue yet, but "it needs to be part of the final agreement" once more work is done.

The producers also want a moratorium on municipal taxes for the life of the project.

"We need to make sure on a project of this size that we don't have municipalities applying things like sales taxes or transfer taxes or etc.," Reynolds said.

### Vehicles for delivery of terms

There are different "vehicles" to deliver these terms, Reynolds said.

One would be a contract negotiated with the administration and enacted by the Legislature. The constitutionality of such a contract would have to be tested in the Alaska Supreme Court, he said, because the contract would have to bind subsequent Legislatures.

Another possibility is something used elsewhere in the world: a compensatory royalty contract. Such a compensatory contract would say "if taxes go up by a dollar, royalty goes down by a dollar." ●

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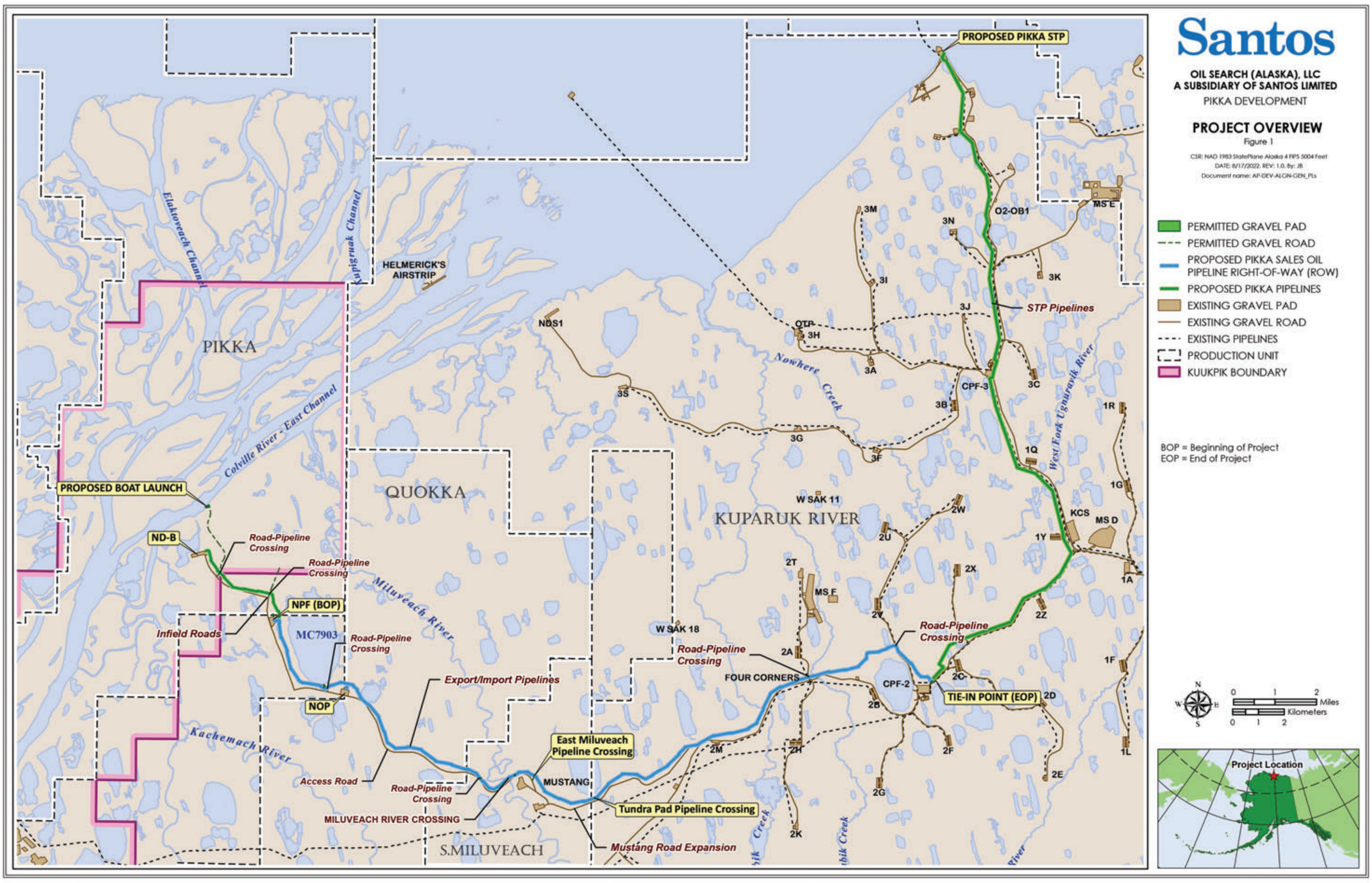


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## PIKKA DETAIL

(USA)'s application to RCA for a certificate of public convenience and necessity, or CPCN, to operate the Pikka Sales Oil Pipeline, for permits to build the pipeline and connect it to the Nanushuk Processing Facility, and for the authority to operate the interconnect facilities, as well as for approval of the connection agreement.

Quite a mouthful, but in essence it was Oil Search (USA)'s compliance filing in response to an RCA order.

Individuals from Santos subsidiaries Oil Search (USA), or OSU, and Pikka leaseholder and operator Oil Search (Alaska), or OSA, gave detailed presentations about their plans at the Sept. 16 public hearing in Anchorage, which included a slideshow and a Q&A session.

Some of their testimony and most of the information from the Q&A will appear in next week's Petroleum News as part 2 of this article.

> *If sanctioned the additional 80,000 bpd would come from within the Pikka Unit, specifically from two additional drill sites (A and C) and "some possibilities" in the northern part of the unit.*

### Fencil, Herrera, Anglen and Knecht

Those making presentations in the RCA hearing were as follows:

- Kollin S. Fencil
- Troy H. Herrera
- Ben Anglen
- Charles H. "Chuck" Knecht

In this part of the story, Part 1, Kollin S. Fencil's testimony will be featured. Fencil is senior vice president of operations for OSA and president of the Pikka Sales Oil Pipeline construction project for OSU.

But it seems appropriate to insert one piece of information from Anglen at this point in the story. Lead pipeline engineer for OSA and acting secretary and technical manager of the Pikka Sales Oil Pipeline construction project for OSU, Anglen noted the current design of the pipeline is expected to deliver 80,000 bpd during the initial phase of operations, with subsequent development phases the maximum throughput capacity could increase to 160,000 bpd.

Capacity can be increased, he said, up to 160,000 bpd of oil by injection of drag reducing agent at the Nanushuk Processing Facility or adding a booster pump at the tie-in pad, or TIP: "The design pressure is 1,480 psig and the normal operating pressure will vary from 1,400 to 800 psig," Anglen said, "depending upon rates and tie-in pressure at the Kuparuk Pipeline tie-in location."

Returning to Fencil, he told hearing attendees that his "current managerial responsibilities include supporting concurrent exploration and pipeline projects, including appraisal activities, and managing production operations."

*see* **PIKKA DETAIL** *page 8*

## FINANCE & ECONOMY

### Chevron has its Slope interests for sale

Reuters reported Sept. 19 that Chevron Corp. has its North Slope interests up for sale.

Alaska Division of Oil and Gas records indicate Chevron holds non-operating interests in three North Slope fields:

•Duck Island unit (Endicott) — working interest ownership ranging from 0.25% to 10.59% in the various leases in that unit.

•Prudhoe Bay unit — 1.16% WIO.

•Kuparuk River unit — 4.95% WIO.

The Reuters report said Chevron is marketing its interest is more than 2,000 oil and gas wells in Alaska.

Chevron, an early explorer in Alaska, previously exited the state in 1992, Reuters noted, returning when it acquired Union Oil Company of California. Unocal held primarily Cook Inlet operated assets which Chevron sold to Hilcorp in 2011. Division records show Chevron held 23,169.82 acres of state oil and gas leases as of Sept. 4.

Reuters said Chevron estimates proved and developed portions of the assets to be worth $655 million and with future developments, the value could be $926 million.

The marketing document says interests in pipelines in the Kuparuk and Endicott fields are included in the sale, Reuters said.

—PETROLEUM NEWS

### Oil & gas jobs up 5.9% from August '21

The Alaska Department of Labor and Workforce Development said Sept. 16 that jobs in the state in August were up by 3.1% from August 2021, an increase of 10,200. The August count was 338,500, down from 340,500 in July, but a gain of 10,200 from 328,300 in August 2021. The total is down by 13,700 from an August 2019 count of 352,200 jobs.

In the oil and gas sector, the August job count was 7,200, unchanged from July, but up 400 from August 2021, an increase of 5.9%. In August 2019, however, there were 10,100 oil and gas jobs, leaving the current total 2,900 below the pre-pandemic number. The department said the August count for oil and gas jobs was about 1,000 above a late 2020 pandemic low.

Several job sectors have fully recovered since the pandemic: construction, health care, federal government and local government. Major sectors with the most ground left to make up are leisure and hospitality and oil and gas.

The seasonally adjusted unemployment rate in the state was 4.5% in August, compared to a U.S. rate of 3.7%.

—PETROLEUM NEWS

## GOVERNMENT

### AOGCC schedules CD1 gas release hearing

The Alaska Oil and Gas Conservation Commission said Sept. 20 that it is calling a public hearing to address the release of natural gas from ConocoPhillips Alaska's Alpine CD1 drillsite.

The hearing will be Oct. 25 at 10 a.m. in the commission's Anchorage offices; audio call-in information is 907-202-7104 conference ID 617 160 570#.

In a hearing notice Commissioner Jessie Chmielowski said the AOGCC has conducted an internal investigation into the gas release discovered on the CD1 drillsite March 4. ConocoPhillips said in an Incident Investigation Report that the gas originated from Colville River unit well WD-03 during drilling operations. The company identified findings and causal factors.

Following AOGCC's internal investigation, Chmielowski said, the hearing will address:

•Casing and cementing program for the well "as it relates to confining fluids to the wellbore, preventing the migration of fluids form one stratum to another and protecting significant hydrocarbon zones."

•Gas disposition from the drillsite as it relates to waste of resources.

•Conduct of operations for the well as it relates to ConocoPhillips's internal section plan for the well and communication of pressure limits.

•Well safety valve systems related to producing natural gas up the outer annulus of the well.

•Change of an approved program related to an Application for Sundry Approvals form following oral approval from AOGCC.

Written comments may be submitted to AOGCC at 333 W. 7th Ave., Anchorage, AK 99501 or to samantha.carlisle@alaska.gov and must be received no later than the conclusion of the Oct. 25 hearing.

—PETROLEUM NEWS

# Pikka Phase 1 roads and pads complete

Constructed key infrastructure to facilitate field development

- 11.5 miles of gravel roads constructed
- 56 acres of gravel pads constructed (4 pads)
- 5 miles of existing Mustang Road upgraded
- 192-foot bridge fabricated/installed
- 68 miles of ice roads constructed
- 111 acres of ice pads constructed
- **~2.24 MM cubic yards from 2 gravel mines**
- **>50,000 truck loads**
- **Miles driven equal to 3 moon missions**




*continued from page 6*

## PIKKA DETAIL

In his capacity as president of the Pikka Pipeline Project, Fencil's duties include "management of the planning and construction of the pipeline, and management of its operation once it is completed and in service."

Fencil also manages the "functional capabilities of health, safety, and environment, and Alaska supply chain matters," working closely with various OSA, OSU and Santos departments, including the projects, exploration, subsurface, environmental, finance, commercial, legal, people and culture, and external affairs departments, to advance Alaska development and deliver production and pipeline transportation operations.

*Capacity can be increased, he said, from 80,000 up to 160,000 bpd of oil by injection of drag reducing agent at the NPF or adding a booster pump at the tie-in pad, or TIP.*

"I ultimately drive the implementation of strategic plans for OSA and have direct accountability for operational activity for OSA and OSU in Alaska," Fencil said, adding "I also manage community relationships, assure organizational readiness for production and pipeline operations, and manage safe, reliable, and legally compliant operations in Alaska."

Fencil has worked in the oil industry for 26 years in various technical, commercial, and engineering capacities, including being vice president or senior vice president for OSA for nearly three years.

Prior to that Fencil worked for BP for more than 14 years in eight managerial and engineering positions in Indiana, Texas and Alaska. Before that he worked nearly six years for ExxonMobil.

### OSU role, partners

As to OSU's role as applicant, the company will be the owner and operator of the Pipeline — and the leaseholder under the Pikka Pipeline Right-of-Way Lease pending issuance by the State Pipeline Coordinator's Section, Fencil said.

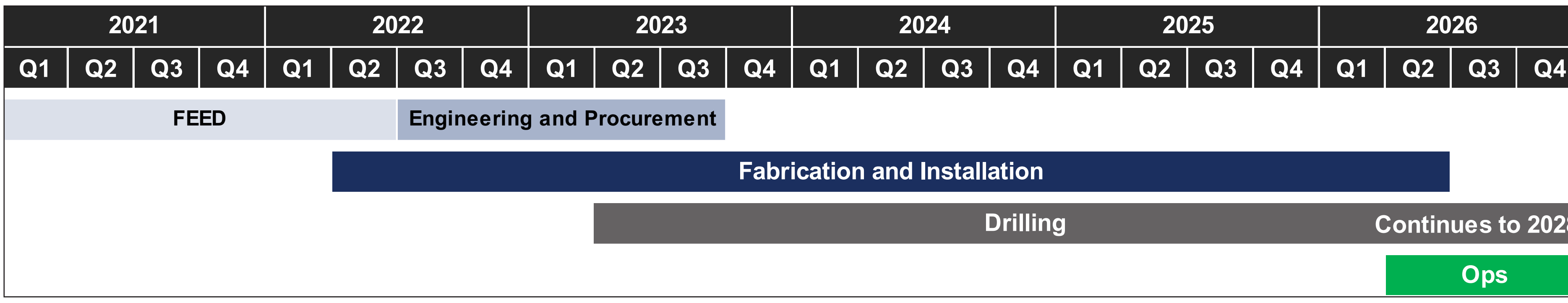
One of the more interesting topics RCA asked Fencil to address was the possibility of potential partners in the project that would change the financial structure of how the pipeline will be financed.

"As stated in the application, the construction of the pipeline is expected to be financed by equity of OSU and through contributions of equity from its parent companies. Santos has been meeting all financial obligations of its subsidiaries, including POSL, OSU and OSA, through net operating cash flows from its producing assets in Australia and PNG and from a mix of debt facilities," Fencil said. (POSL stands for parent Papuan Oil Search Ltd.)

"However, as noted in the application, the pipeline is eventually expected to be owned by an entity that will be owned by affiliates of the parties to the Pikka Unit — currently OSA (51%) and Repsol E&P USA LLC (49%)," Fencil said. "Transfer of the CPCN and the pipeline would occur upon the future creation of such a pipeline company entity," he said.

OSU and the "future pipeline entity would file a transfer application with the RCA at that time," Fencil said, adding

*see* **PIKKA DETAIL** *page 9*




*continued from page 8*

# PIKKA DETAIL

that "no prospective partner in the Pikka Pipeline Project is expected at this time."

Fencil's testimony also addressed the important roles of OSA, Santos and other Santos affiliates in the Pikka Pipeline Project.

### Pipeline schedule

OSU currently expects to begin construction of the vertical support members, or VSMs, and/or horizontal support members, or HSMs, on which the pipeline will be placed in or around the fourth quarter of 2023.

Pipe installation is slated to begin in 2024, Fencil said, with construction of the Pikka Project infield pipelines and the Pipeline occurring "over multiple seasons beginning in 2023."

The current Pikka Sales Oil Pipeline completion date is expected to be the third quarter of 2025, Fencil said.

### Common carrier line

OSU submitted the application for a new CPCN to construct and operate the pipeline, which is a proposed common carrier line needed to transport oil produced from the Pikka Unit to market, in April 2022, Fencil said.

The proposed pipeline will originate at the Nanushuk Processing Facility in the Pikka Unit at its west end and terminate at a proposed connection with the Kuparuk Sales Oil Pipeline on its east end (collectively, the "Interconnect Facilities"). From there, oil will be transported via the Kuparuk Pipeline to the Trans-Alaska Pipeline System, or TAPS, for ultimate transportation to market.

The Nanushuk Processing Facility, or NPF, will support oil production activities as well as processing facilities to prepare the oil for shipping on the pipeline.

| Key milestone | Proposed Dates |
|---|---|
| FID | 3Q 2022 |
| Gravel hauling and construction of roads and pads | 2023 |
| Installation of facilities (ND-B, NOP, NPF, TIP, & STP) | 2023 - 2026 |
| Pipeline construction | 2023 - 2025 |
| Spud first well | Mid 2023 |
| Pipelines and NPF ready for start-up | Mid 2026 |
| First Oil | 2026 |
| Continued drilling | Through 2028 |

The pipeline, Fencil said, will be approximately 22.2 miles long (the distance from the NPF tie-in to the proposed Kuparuk Pipeline tie-in), will "consist of 16-inch diameter pipe from NPF to the TIP, and 12-inch diameter pipe from the TIP to the Kuparuk Pipeline."

The minimum engineering design life of the Pipeline is estimated to be 30 years, Fencil said.

### Need for pipeline, interconnect facilities

"As explained in the application, the Nanushuk oil field in the Pikka Unit is one of the largest conventional oil discoveries made in the United States in the last 30 years," Fencil said.

"However, there is currently no facility to transport oil produced and processed from the Pikka Unit to TAPS. The proposed pipeline will provide safe, affordable, and compliant transportation to market for oil produced from the Pikka Unit, thus ensuring the marketability," he said.

*"However, as noted in the application, the pipeline is eventually expected to be owned by an entity that will be owned by affiliates of the parties to the Pikka Unit — currently OSA (51%) and Repsol E&P USA LLC (49%)," Fencil said.*

"The pipeline is also expected to support throughput in both the Kuparuk Pipeline and TAPS, slowing or offsetting throughput declines and keeping transportation rates lower on those pipelines than they would otherwise be without the Pikka Unit production throughput. Lower transportation rates would very likely help extend the life of other fields which use those pipelines," Fencil said, noting "all of this would benefit the state of Alaska through higher economic activity, jobs, and revenue."

The Pikka Unit is on state of Alaska and Alaska Native corporation land. The "state and the Arctic Slope Regional Corp. are expected to receive royalties from development of the Pikka Project. Because a portion of the Pikka Project is on Kuukpik Corp. land, it would receive payments associated with surface use," Fencil said.

Furthermore, he said, the "interconnect facilities will prevent redundancy in North Slope infrastructure and thereby reduce costs and environmental hazards and increase safety and operating efficiency. Like the pipeline itself, the interconnect facilities will also stimulate economic activity in the area and help extend the life and economic viability of other North Slope oil fields. The proposed connections will make more efficient use of rights-of-way, and existing infrastructure will be put to its highest and best use." ●

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## FALL LEASE SALE

state, DNR said.

Gov. Mike Dunleavy said Alaska "is committed to making millions of prospective acres in Alaska available for lease. Alaska's resources are a national security asset and can help our domestic energy needs and the needs of our allies around the world."

"We're encouraged by the major new sanctioned developments in the region and the ongoing exploration and development efforts we see across the North Slope," said Acting DNR Commissioner Akis Gialopsos.

Details of the sales are available on the division's website.

### EnergyNet Services

The division said it has contracted with EnergyNet Services LLC for the online bidding system for the sale, with bidder registration and bid submission on the EnergyNet Government Listings site at https://www.energynet.com.

AKIS GIALOPSOS

Minimum bid amounts, royalty rates and annual rental rates vary by sale area. All tracts have primary 10-year lease terms.

Beaufort Sea tracts have a minimum bid of $25 per acre, a 16.66667% royalty rate and an annual rental rate of $10 per acre.

North Slope state/Arctic Slope Regional Corp. tracts and north sub-region tracts have a minimum bid of $25 per acre, a 16.66667% royalty rate and an annual rental rate of $10 per acre. North Slope south sub-region tracts have a $25 per acre minimum bid, a 12.5% royalty rate and an annual rental rate of $10 per acre.

North Slope Foothills tracts have a minimum bid of $5 per acre, a 12.5% royalty rate and rent of $1 per acre for year 1, $1.50 per acre for year 2, $2 per acre for year 3, $2.50 per acre for year 4 and $3 per acre for years 5-10. In instructions to bidders the division said the first day to view the lease sale on EnergyNet is Oct. 14, with Oct. 20 the first day to submit bids.

Oct. 31 at 4 p.m. is the deadline to qualify to bid with the division.

The deadline to submit bids to EnergyNet is Nov. 3 at 4 p.m. and the deadline to submit signed bid forms to EnergyNet is Nov. 8 at 2 p.m.

Bidding results will be available to the public Nov. 9 at 9 a.m. and the deadline to settle bid deposit wire transfers is Nov. 9 at 2 p.m.

—KRISTEN NELSON

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## OIL PRICES

combat inflation, The Straits Times reported Sept. 21.

The forecast — covering the 46 members of the ADB stretching from the Cook Islands in the Pacific to Kazakhstan in Central Asia — was cut to 4.3% versus the ABD's April forecast of 5.2%. The region grew 7% in 2021.

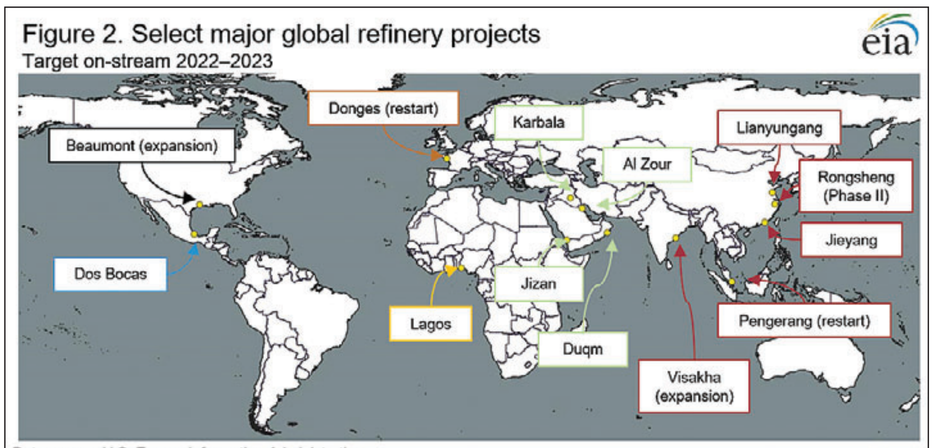
China's growth forecast for 2022 was reduced to 3.3% from 5%, as Beijing pursues its punishing zero-Covid-19 strategy, The Strait Times said.

ADB Chief Economist Albert Park said, "risks loom large" for the region, adding, "A significant downturn in the world economy would severely undermine demand for the region's exports."

Demand reduction fears for Asia and China have been a recurring theme in bearish oil price action.

Traders for now are discounting the fact that China's lockdowns will eventually be lifted, and that domestic mobility on the ground and in the air will bounce back, while international air travel to

**Figure 2. Select major global refinery projects**
Target on-stream 2022–2023




Data source: U.S. Energy Information Administration

China will rise from its current low levels.

The skies are wide open. Even New Zealand, which was notably isolationist in its initial response to the coronavirus epidemic, has dropped requirements for international arrivals to test for COVID-19 before departure, and international visitors are no longer required to present proof of vaccination for the virus.

### Demand in China

The U.S. Energy Information Administration, in its September Short-Term Energy Outlook, forecast that China's petroleum consumption will increase in 2023 to record highs.

China has completed projects to expand refining capacity this year, and it has projects under development that will expand domestic refining capacity next year to support increased consumption, the EIA said. To meet expected increased consumption, China will likely continue to import crude oil imports and increase domestic production.

On the other hand, EIA forecast Russia's oil production to decrease in 2023 once the EU economic sanctions are in full effect.

China's total crude oil imports decreased in recent months, however, crude oil imports from Russia have increased, the EIA said in a Sept. 21 release.

"Russia is typically China's second-largest source of crude oil imports, slightly behind Saudi Arabia, and imports from Russia have generally increased over time, both in volume and share of imports," the EIA said.

China's crude imports from Russia increased from 8% of crude oil imports in 2011 (slightly less than 400,000 bpd) to about 16% of imports in 2021 (1.6 million bpd) and to as much as 21% in August 2022 (2.0 million bpd), the EIA said, adding that the share of total imports from Russia was 20% in June and 19% in July.

As China's thirst for crude oil grows, and if Russia's production drops as the EIA expects, China will be casting about for new sources of oil.

In a June 2022 release, the EIA said new projects, particularly in China and the Middle East, could add more than 4.0 million bpd of new capacity over the next two years.

"Many of these new refineries are located in coastal areas and have easy access to export refined products that are not consumed domestically," it said.

The scenario is bullish for North Slope crude. As has been shown in the recent past, when China and its Asian neighbors step up crude purchases, they hoover up Pacific cargoes that would otherwise have competed against ANS on the West Coast. ●

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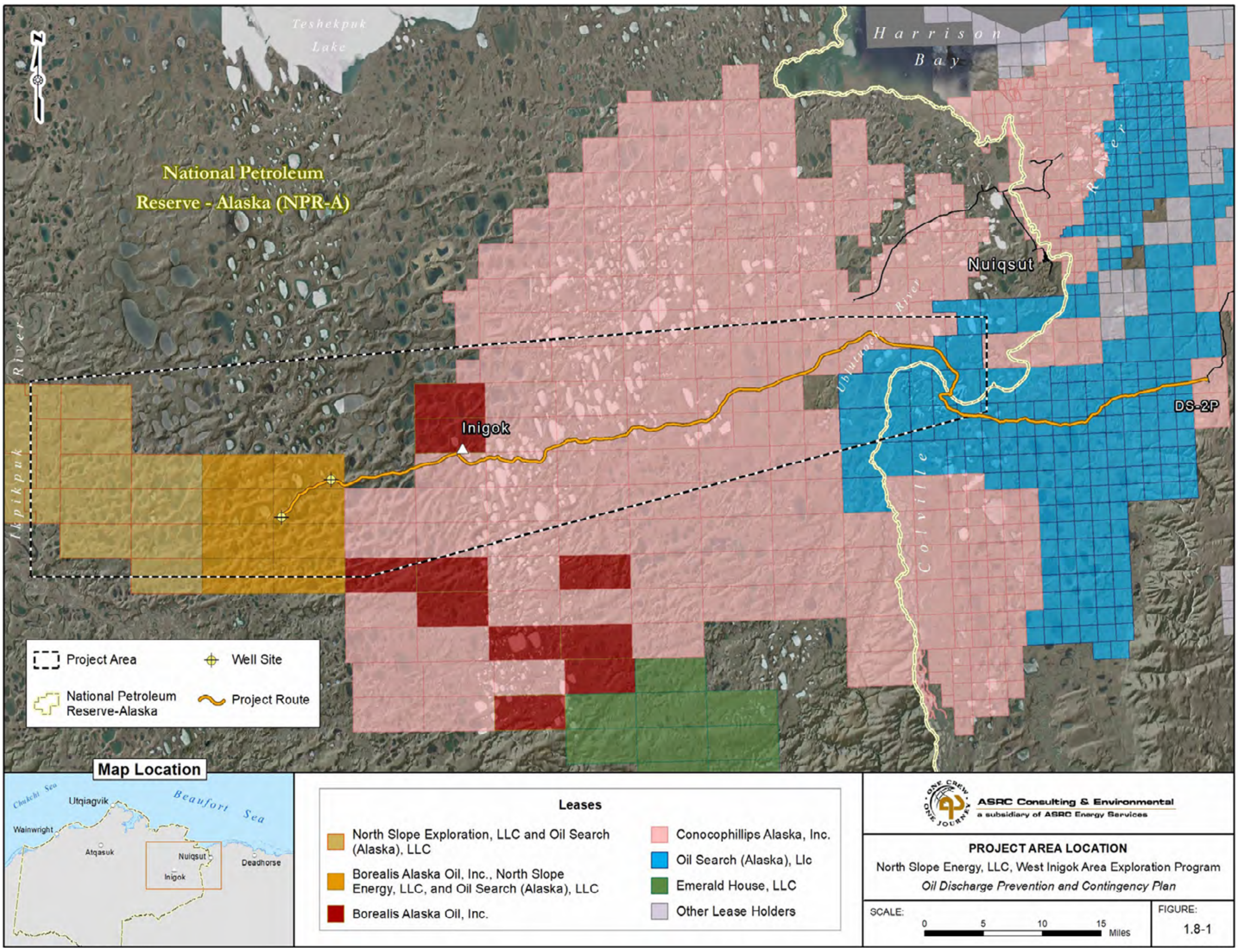


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# WEST CASTLE

abandoned.

## West Inigok Exploration Area

Armstrong's plans became public after North Slope Energy applied to the Alaska Department of Environmental Conservation for an Oil Discharge Prevention and Contingency Plan, or ODPCP, as part of its "West Inigok Exploration Area Exploration Program." DEC posted a public notice on the application on Sept. 15, as first reported by PN's News Bulletin Service.

The ODPCP was signed by Armstrong, president of Armstrong Oil &Gas Inc., manager of North Slope Energy LLC, on Aug. 12, 2022.

The ODPCP was prepared for North Slope Energy by ASRC Consulting & Environmental, a subsidiary of ASRC Energy Services.

The 200-plus-page document said the "primary target reservoir objectives are Nanushuk sand."

An existing 7.5-acre gravel pad will be used as an operations base. It is connected to the Inigok Airstrip by an all-season gravel road that can be accessed using ice or snow roads from the wells that will be drilled this winter. The pad and the airstrip's 6,500-foot runway improve the logistics of exploratory drilling in the area.

All planned exploratory drilling will be conducted on ice pads using overland packed snow roads originating from Drill Site 2P and extending west across the Colville River to the West Inigok Area exploration drill sites.

A 500 foot by 400 foot ice pad will be built adjacent to Drill Site 2P to provide space for storage and fuel storage and transfer.

The objective of the ODPCP is to prevent and/or limit the spread of a spill, minimize potential environmental impacts, and provide safety for personnel.

## Castle Prospect trend

In early 2020 Borealis, a June 2019 re-brand of Nordaq Energy, held an NPR-A lease position amounting to 206,966 acres, referred to as the Castle Prospect Trend, directly southwest of ConocoPhillips' Willow oil discovery. There were six individual lower Nanushuk prospects, including the Castle West prospect, within the trend.

The Inigok No. 1 test well, drilled in the trend area in the 1980s by Husky Oil for the U.S. Geological Survey, indicated a strong possibility of finding oil. Although the well was drilled deep, in search of oil in the Ellesmerian sequence, the host sequence for oil in the Prudhoe Bay field, the upper part of the well found gas with compositions indicative of the presence of light oil in the Brookian sequence, the rock sequence that includes the Nanushuk.

And testing the Brookian prospects only requires relatively shallow drilling, to depths of around 4,000 to 5,000 feet.

## Bill Armstrong's impact

When William "Bill" D. Armstrong first arrived in Alaska more than 20 years ago, he predicted the "best days of Alaska oil and gas were yet to come" — a bold statement considering North Slope oil production was in decline, with the 800-mile trans-Alaska oil pipeline carrying half the oil it had at peak production in 1988.

> *"West Castle is a gorgeous prospect. We identified it off of 3D seismic. It is a perfect look-alike to Willow and Pikka."*
> *—Bill Armstrong*

Armstrong has since made believers of many Alaskans. He was responsible for the discovery of the North Slope Oooguruk field, Nikaitchuq field and the still expanding Pikka field complex which includes the Pikka, Horseshoe, Stirrup and Mitquq discoveries.

Through these exploration efforts Armstrong brought in multiple entrants to the North Slope — Eni, Pioneer, Kerr McGee, Repsol and Oil Search (now part of Santos).

"The Nanushuk discoveries at Pikka were a big surprise to the industry as it was a shallow horizon in and amongst deeper developments in the Alpine and Kuparuk River field areas," Armstrong said.

"The size of the Nanushuk fields was the biggest surprise with several of the new fields estimated to be in excess of 1 billion barrels of recoverable oil."

Armstrong said the Nanushuk play is still in its infancy and Pikka-size oil discoveries are likely repeatable across Alaska's North Slope, stretching 350 miles from the western edge of the state near the Chukchi Sea, through the bourgeoning Pikka/Willow complex, all the way to the eastern edge of Alaska state lands. ●

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## AOGCC CHANGES

updating and streamlining policies, where appropriate, modernizing AOGCC's authorizing statute, and being responsive to industry concerns while still holding them accountable."

DAN SEAMOUNT

Price, who was born in Fairbanks, told PN it was a tough decision to leave the state.

### Dan Seamount

Seamount is retiring after more than 20 years as geology commissioner and is longest serving commissioner in AOGCC history. There have been 16 public members of the commission over the years and 14 petroleum engineering members, but only six geologist members.

His bio on the AOGCC website notes that he served as commission chair from 2008 to 2012, and as a commissioner worked on many issues including regulation of Alaska's more than 50 oil and gas fields, North Slope natural gas, Cook Inlet energy supply challenges, hydraulic fracturing, statute and regulations modifications, investigations of minor and major incidents and advances of energy sources such as coalbed methane, geothermal and underground coal gasification.

Appointed to fill the geologist seat in 2000, Seamount was reappointed to full six-year terms in 2005, 2011 and 2017. His current appointment expires next March.

Prior to joining AOGCC, Seamount was senior advising geologist for Unocal in Anchorage and previously worked for Marathon Oil and Chevron U.S.A.

JUDY PATRICK

GREG WILSON

### Greg Wilson

Wilson, who was appointed effective Sept. 19 for a term which expires March 1, 2023, will need to be confirmed by the Alaska Legislature.

The governor's office provided Wilson's resume.

He retired from ConocoPhillips Alaska in 2021 and has 31 years as a petroleum geologist in Alaska. He earned a Ph.D. in geology from the University of Wisconsin-Madison and was hired by ARCO Alaska that same year, serving as a senior geologist from 1990-2000. With Phillips Alaska, Wilson was a staff geologist, becoming principal exploration geologist with ConocoPhillips Alaska in 2002, and director, Arctic exploration and services, for the company in 2011. From 2014-21 he was manager of exploration operations and technology for the company.

In 2021 he was recognized by the Alaska Oil and Gas Association, AOGA, with the organization's Marilyn Crockett Lifetime Achievement Award.

AOGA cited Wilson for spending "his career supporting and leading Alaska exploration teams with ARCO, Phillips, and ConocoPhillips." The organization noted he was recruited by ARCO for its Anchorage office in 1990 "and has spent decades since then working in Alaska exploration."

—KRISTEN NELSON

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*continued from page 1*

## FLARE APPROVAL

"similar to those successfully used in the Permian, Anadarko, and Williston basins."

A long-term pilot production test will "establish the production profile and characteristics of the Alkaid Production Zone," forming "the basis for understanding formation and field deliverability, processing facility design, takeaway capacity needs, and overall project economics and financial viability," Duncan said.

The pilot production test will likely last up to nine months, he said and if the initial production rate is low or production decline is significant, "the project may never evolve to regular production."

Adequate initial production and a modest decline curve are necessary for the project to be considered for regular production, he said.

### Use of gas onsite

Duncan said Great Bear Pantheon will deploy a gas-fired turbine during testing, initially fueled by compressed natural gas.

"Once the well begins to flow, Great Bear Pantheon is hopeful that the production stream will include enough natural gas to fully power the turbines," Duncan said, reducing the amount of natural gas that will need to be flared. The company also plans to use excess natural gas for gas lift.

The company estimates that at production rates of 500 to 1,000 barrels per day, gas production could be 150-500 mcf per day, of which infield uses could consume up to 150 mcf per day, "which could represent the entire gas production stream and eliminate any flaring."

### Duration of test

Duncan said wells using a horizontal multi-stage completion technique, HMSC, such as that at Alkaid 2, "are known for high initial production with rapid decline that eventually transition to steady production at a lower rate."

Properly understanding the decline curve at the Alkaid 2 will take months, he said, because wells with identical initial production can have very different ultimate rates which won't be evident for nine months or more.

Determining estimated ultimate recovery, EUR, takes many months with HMSC wells, Duncan said, and uncertainty over EUR in the first few months means uncertainty in the economics which may mean the project won't be able to attract capital due to "perceived uncertainty in the economics." Also, facilities designed based on incomplete data may be over-built or under-built for actual production.

"A two million barrel well compared to a well that produces half of that are materially different investments, that require materially different facilities," Duncan said. Predicted EUR narrows as the pilot production test is carried out. "The confidence in whether the project will prove economic or not significantly increases as the range of potential EUR narrows," he said, and terminating the pilot production test too early "will result in a very risky prediction of EUR that will be backed by little confidence."

"Great Bear Petroleum anticipates that the PPT will need to proceed for up to nine months before we reach the level of certain necessary to fund the project and design the facilities," Duncan said.

### Unusual length

In a public notice issued Sept. 14, Jeremy Price, AOGCC chair and commissioner, said typical requests for flaring authorization for testing are for a few weeks and the Great Bear Petroleum request is for longer than any approval the commission has ever granted.

"Due to the unique nature of the request the AOGCC has decided to hold a public hearing on this matter before rendering a decision."

The hearing will be Oct. 27 at 10 a.m. in the commission's Anchorage offices. Audio call-in information is 907-202-7104, conference ID no. 673 632 073#.

Written comments may be submitted to the commission at 333 W. 7th Ave., Anchorage, A 99501 or samantha.carlisle@alaska.gov and must be received no later than conclusion of the Oct. 27 hearing.

—KRISTEN NELSON

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