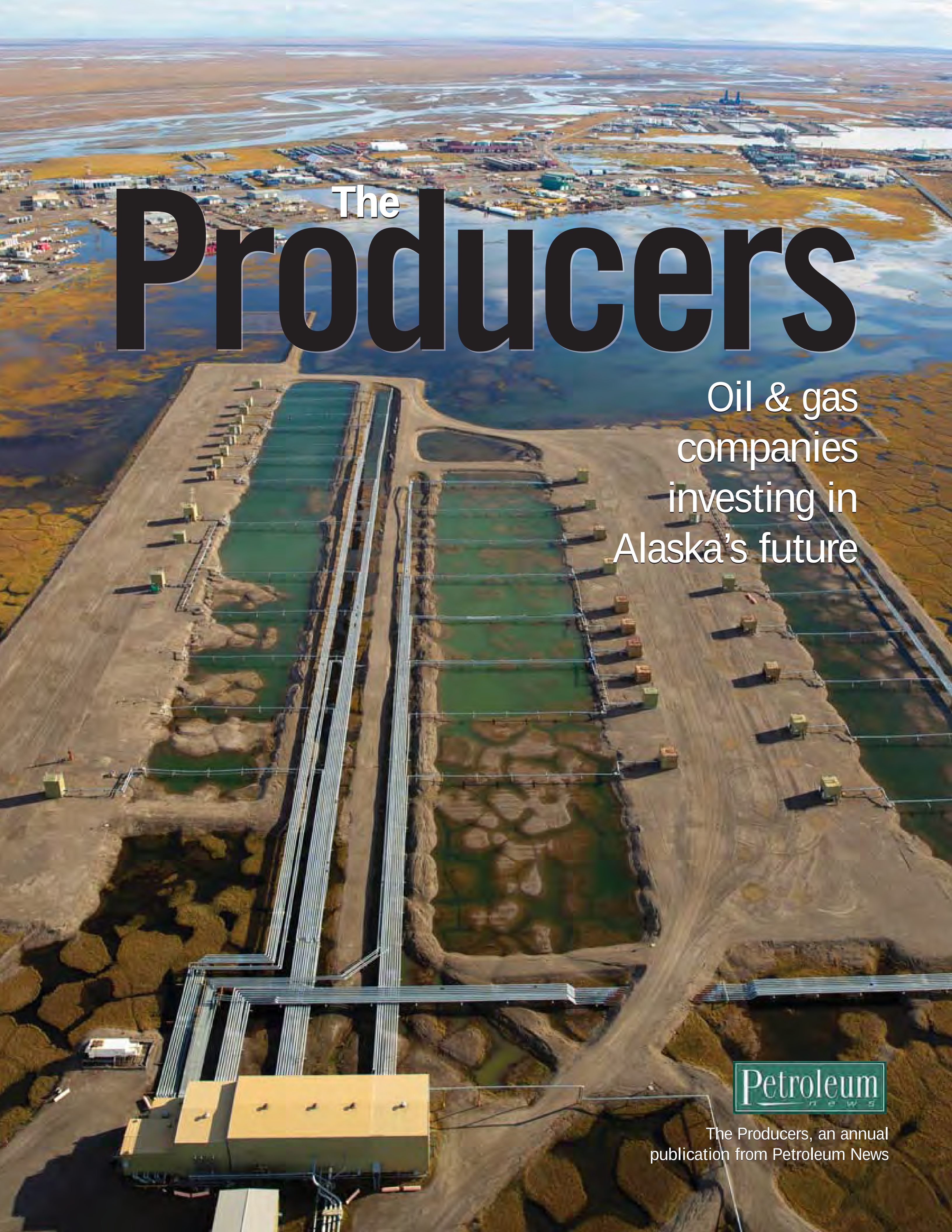

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The Producers, an annual publication from Petroleum News


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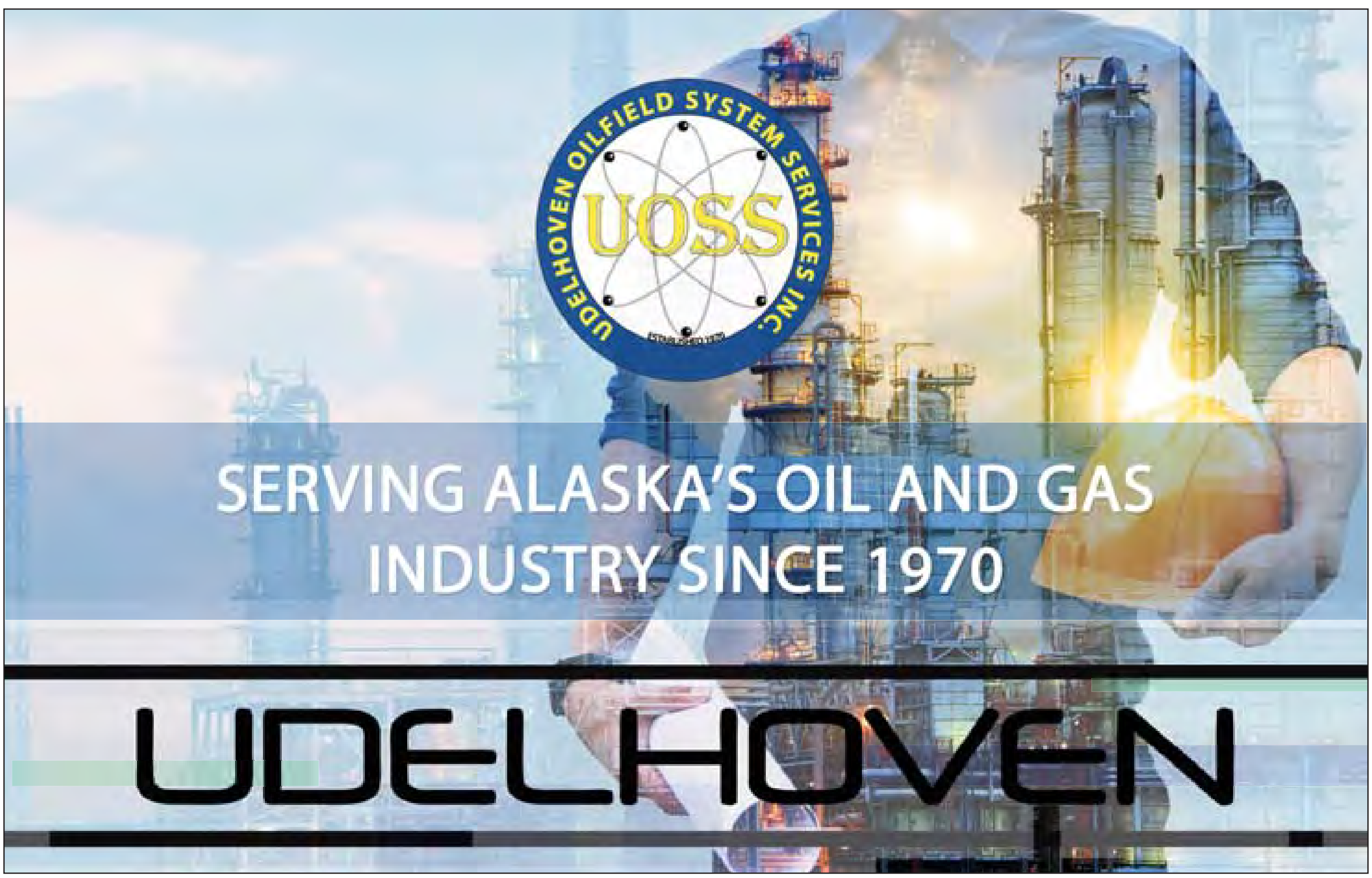
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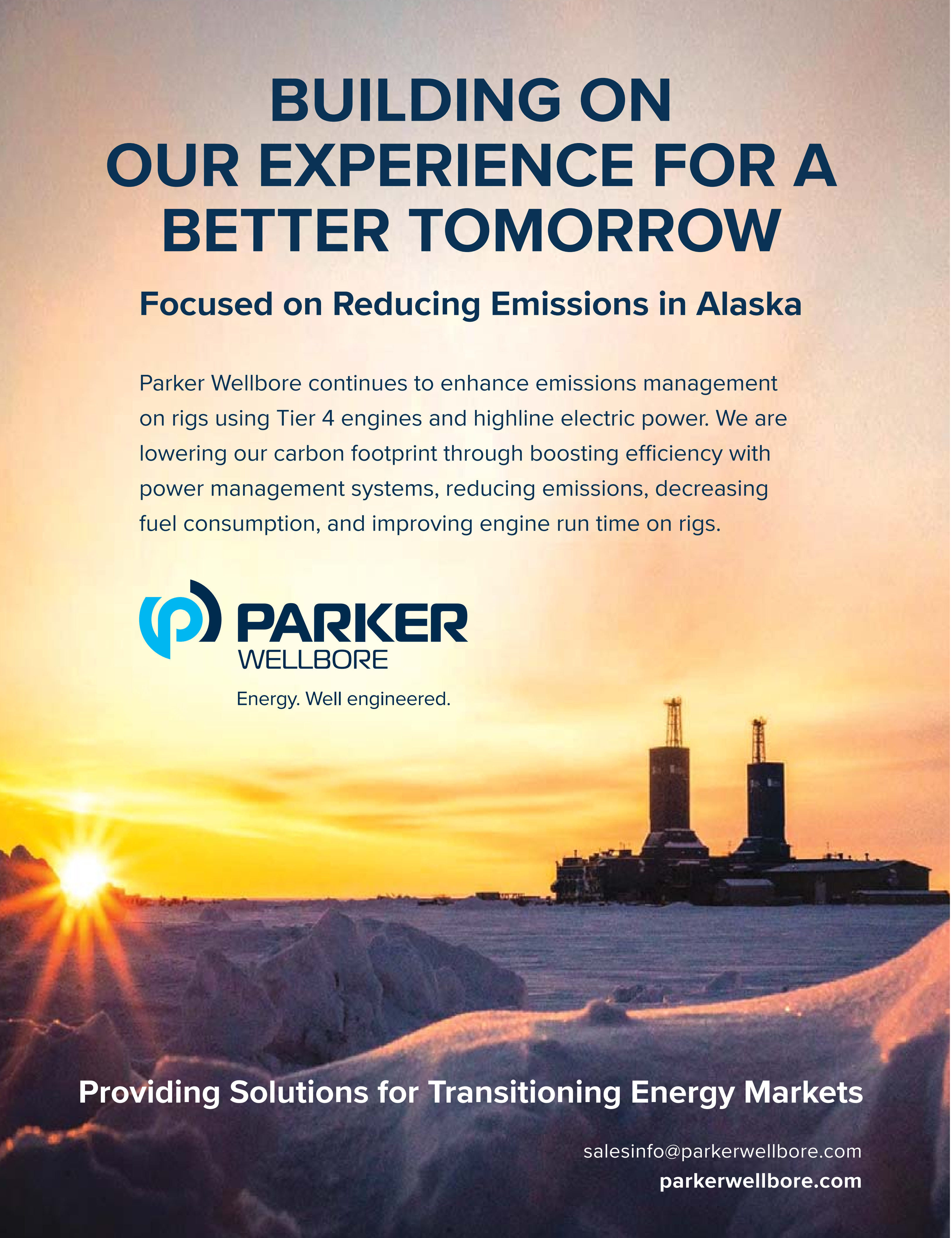
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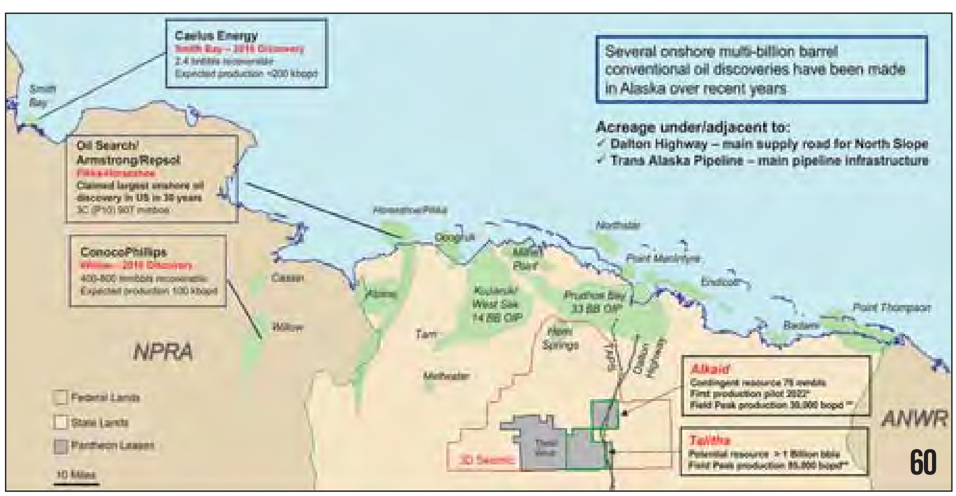

# The Producers

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*On the cover:*
*Drill Site 1 in Deadhorse.*

*Photo by Judy Patrick*

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# A global case for Alaskan oil and gas

**By AKIS GIALOPSOS**
Acting Commissioner, Alaska Department of Natural Resources

Geopolitical realities illustrate the merits of Alaskan oil and gas.

The Russian Federation is the third largest oil exporter in the world, following Saudi Arabia and the United States. However, the shocking invasion of Ukraine in February compelled swift and direct Western action; sanctions have pushed substantial Russian oil and gas to leave European and North American markets. What we are now witnessing is an abrupt tightening of supply for oil, natural gas and the petroleum products we depend on in the near term. Though necessary, this tightening has happened at the same time as limited global investment in upstream opportunities. As the world reemerges from what were historic destructions of demand for oil and gas due to government-imposed shutdowns, the demand for fossil fuel supplies that are also free of the coercive political actions of the home government will only climb.


AKIS GIALOPSOS

For current Alaskan producers and future exploration companies, this is an opportunity that borders on an obligation as demand for Alaska supplies rises. Supply and energy security mean national security — and meeting a societal necessity. We have the capacity to meet the West's demand as well as allies like Japan and South Korea, but there will be challenges. Investment in exploration and development is needed immediately to meet these challenges, as we push for policies that further support capital investment bringing new supplies to market.

## Cook Inlet today

Our challenges and needs are local in additional to global. Cook Inlet is the energy breadbasket for the Railbelt region of Southcentral Alaska, which supplies fuel and electricity for most Alaskans. Natural gas has been reliably produced to meet these energy needs since the late 1950s, which has allowed Anchorage, the Matanuska-Susitna valleys, and the Kenai Peninsula to grow with reliable power and heat to support the development of Alaska's industrial capacity.

Over the course of the last decade, however, major industrial customers such as Kenai LNG and Agrium's fertilizer plant have ceased or limited operations, complicating the balance of supply and demand in the Cook Inlet market. This imbalance paradoxically makes it harder for new projects to enter the market at the same time our need for new supplies increases. While our geology indicates there are significant hydrocarbon reserves remaining in the region, there is an increasing urgency to support decisions breaking through this challenge in both the near and long-term.

Cook Inlet also requires a steady supply of crude oil for our in-state refineries to meet our domestic demands for fuels. Anchorage's Ted Stevens International Airport, which is consistently one of the busiest cargo hubs on earth, relies on a stable supply of jet fuel.

This demand needs to be met, and we need to take action to ensure that it is met. Natural gas, especially, will be critical to the Southcentral energy mix for a long time to come, and we must secure additional supplies.

## Cook Inlet tomorrow

In the near term, further exploration and development is needed to meet domestic energy needs — to generate electricity for our grid, to keep our homes warm and to provide resources to our local commercial customers. The Alaska Department of Natural Resources (DNR) is already acting, with an additional Cook Inlet lease sale in December coinciding with BOEM's Cook Inlet lease sale. Japan, a legacy consumer of Kenai oil and gas, has seen its imports of Russian fossil fuels drop by half in the past calendar year; South Korea's have declined by nearly one-fifth. These legacy trading partners of Alaskan oil and gas represent an opportunity to reinvigorate a basin with known resources, established infrastructure (including a liquefaction facility), and a history of stable supply.

In the longer term, Cook Inlet's substantial pore space represents an opportunity for the state to pursue carbon capture, utilization and storage (CCUS). Unlike carbon taxes or offsets, a CCUS regime would literally monetize the storage of carbon molecules in now depleted reservoirs, and in some cases even utilize the carbon for indirect energy generation. Combined with federal tax credits and substantial market interest, CCUS can incentivize further oil and gas development, and create new vacant areas to store carbon from other parts of the world. Alaska is joining a process that other energy producing states such as Wyoming and Louisiana have already embarked upon, with promise of prolonging the oil and gas market in the Cook Inlet through this and other innovations.

## North Slope today

The North Slope is fortunate to host legacy fields, with committed and capable operators, that continue to generate significant production for Alaska and broader markets decades after startup. Our primary field, Prudhoe Bay, is now operated by Hilcorp after their acquisition of BP's Alaska assets closed in 2020. Over the last eight years, Hilcorp has assumed an increasing footprint on the North Slope and it is now the operator of five fields in addition to Prudhoe Bay (most recently becoming

*continued on page 10*


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**GIALOPSOS** *continued from page 8*

operator of Point Thomson in 2021). Hilcorp is the operator of fields representing more than two-thirds of all North Slope production, and they have shown impressive results in stemming overall decline, even raising year-over-year production levels in Prudhoe Bay, deploying new technologies to stimulate production at Milne Point and increasing reliability at Point Thomson.

ConocoPhillips operates the other two major legacy fields on the Alaska North Slope, the Kuparuk River and Colville River units, and is one of our most promising explorers with new prospects and developments on the Western North Slope. Their major potential developments in the National Petroleum Reserve-Alaska (NPR-A), building on their success with the Colville River developments and the Greater Mooses Tooth Unit, herald the promise of major new production in the years ahead. ConocoPhillips-operated fields contribute nearly the remaining third of all North Slope production.

Eni, a major Italian oil company responsible for nearly 8% of North Slope production, is planning to do field maintenance projects and infield drilling to optimize production at their two fields. Glacier Oil and Gas also continues work to reinvigorate the Badami Unit and bring more production from the East. Our North Slope oil production partners are doing great work to maintain and even find new ways to produce oil from the fields they operate, with these lessons supporting the new fields that are on the horizon.

## North Slope tomorrow

Alaska has been hampered by ignorant international calls for integrated oil companies and financial institutions to divest from the American Arctic. These efforts to stifle Alaskan oil and gas development on the North Slope are based on concern for the environment and a recognition of climate change. Governor Dunleavy has been clear in response to those claims: those who truly care about the environment, social justice and not benefitting totalitarian regimes should support Alaska producing its resources. Fortunately, the truth is gaining traction, both nationally and internationally. One of DNR's priorities in the months ahead is to amplify and magnify this truth: Alaska continues to demonstrate our long-standing values and protections for the environment and its peoples, and we have over 40 years on the North Slope to prove it.

Major new developments show us that, with continued investment, we have a bright tomorrow. Santos and Repsol — two

*We are looking at a new renaissance of oil exploration on Alaska's North Slope, backed by billions of dollars in capital investment by firms based in countries with some of the strongest environmental, social, and governance standards in the world.*

major international exploration and production companies — recently approved the $2.6 billion final investment decision to develop the first phase of their Pikka project, with production to begin in 2026 at a projected throughput of 80,000 barrels per day. These same owners received approvals for two new units (Quokka and Horseshoe) this year, with exploration drilling to follow. These potential successive developments represent a tremendous runway of opportunity for these companies to establish robust new production on the North Slope, and to bring significant revenues and economic activity to the people of Alaska.

The State of Alaska has also worked to support westward expansion into the federally managed NPR-A, where we believe the same kinds of responsible and small footprint developments as we see on state lands can unlock new resources. ConocoPhillips's Willow project promises to be a multi-billion-dollar investment and engine for Alaskan employment while potentially providing, at peak production levels, 180,000 barrels per day of throughput for the Trans Alaska Pipeline System. Developments in the NPR-A share revenues with the State of Alaska and support the communities of the North Slope via the NPR-A mitigation grant fund.

On other state land, Great Bear Pantheon has been making strides to explore, delineate, and test its unitized prospects at Alkaid and Talitha, with production tests ongoing and permitting underway for permanent production. Shell continues to explore ways to develop its West Harrison Bay unit. Accumulate Energy, affiliated with the Australian 88 Energy, and Burgundy Xploration are moving forward with drilling its Icewine prospect. We are looking at a new renaissance of oil exploration on Alaska's North Slope, backed by billions of dollars in capital investment by firms based in countries with some of the strongest environmental, social, and governance standards in the world.

We also see advanced research and technology that could unlock even more of the North Slope's previously untapped resources. An international inter-governmental research project led by the U.S. Department of Energy and the Japanese government's Japan Oil, Gas, and Metals National Corp. to demonstrate the long-term production viability of methane hydrates was just permitted and preparation for the test is underway. The University of Alaska, with funding from the Governor's budget, continues to progress the science behind successfully producing heavy oil and unlocking major new potential from our legacy fields.

## A sense of urgency

While geopolitical uncertainty presents an opportunity to Alaska's North Slope and Cook Inlet, its long lead times on development present an urgency to meet this demand as soon as possible. Our state needs significant capital investment in exploration and development now to fortify the foundation described above and provide longer-term benefit to the nation. We can see the need for energy now and the critical risks of shortage of energy in the years ahead. The time for aggressive investment, and for Alaska to act, is now. ●

# AIX keeps it simple at Kenai Loop

*No wells or workovers planned this year at Kenai Loop but reservoir management and recompletions could be on the docket*

**By ERIC LIDJI**
For Petroleum News

In its most recent plan of development for the Kenai Loop gas field, AIX Energy LLC wrote, "It is AIX's objective to maximize field recovery, and to align production capacity with commercial opportunities while maintaining operational integrity and reliability."

Produce as much as you can, but not more than the market can handle, without harming the hydrocarbon-bearing geology or the physical infrastructure designed to exploit it.

Simple enough.

That straightforward pragmatism has defined AIX Energy's tenure in Alaska.

The small independent AIX Energy acquired the onshore gas field on the Kenai Peninsula in late 2014, as part of the bankruptcy proceedings of Buccaneer Energy Ltd.

The companies have different temperaments. Buccaneer was expansive, always seeking new opportunities for growth and eventually overextending itself in the process.

AIX Energy has been practical and consistent, typically working within its means. In its eight years as operator, it hasn't drilled any wells or conducted any major workover campaigns. In fact, it shrunk the field by decommissioning an un-used drilling pad.

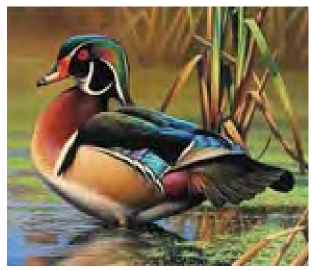
For the coming year, running through May 2023, the company is once again planning no drilling operations at the field or any major activities to workover its existing wells.

The biggest project on the agenda involves reservoir management. AIX is planning a 72-hour shutdown of the field to record static reservoir pressures on KL 1-1 and KL 1-3 wells. The goal is to update the material balance estimates of gas in place and reserves.

AIX undertook this perennial maintenance project under its sixth plan of development for the 2020-2021 development year, but it skipped the project during its 2021-2022 year.

The company said it would attempt to conduct the work during other planned pipeline and facility maintenance activities in order to reduce the amount of disruption at the field.

The company is also currently conducting a cost/benefit analysis of a plan to connect the shut-in KL 1-4 producer into the production system. The project would serve three purposes: increase deliverability, provide redundancy to ensure that the field can produce enough to meet firm gas sales obligations and possibly increase ultimate recovery.



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*AIX is planning a 72-hour shutdown of the field to record static reservoir pressures on KL 1-1 and KL 1-3 wells. The goal is to update the material balance estimates of gas in place and reserves.*

The project has been included in several recent plans of development for the field without moving forward. In early 2019, AIX Energy commissioned a new compression facility at the field, designed to improve production and deliverability at the aging field. The idea for the KL 1-4 project emerged out of that effort to install new compression at the field.

AIX said it is also looking into recompleting wells to provide additional deliverability.

Another major recent development at the field involves sales. The company mentioned a new agreement in its latest plan of development. As of April 2022, the company has been selling exclusively to a single purchaser under a one-year "Firm as Available" contract.

### History

Buccaneer Energy acquired the leases at the Kenai Loop field from the state of Alaska and the Alaska Mental Health Trust in late 2010 and early 2011. The company drilled the KL 1-1 discovery well in May 2011 and drilled the KL 1-2 dry hole in September 2011.

Buccaneer also commissioned a 3D seismic survey covering 23-square miles of the area and used the results to guide additional drilling activities. The company drilled the KL 1-3 producer in November 2012 and the KL 1-4 producer in October 2013. Although slightly shallower than the other two producing wells, KL 1-4 was found to be producing from the same reservoir, and so Buccaneer ultimately decided to keep the well disconnected from the existing production system and use it instead to monitor field pressure.

Through the end of March 2022, the Kenai Loop field has produced 26 billion cubic feet of natural gas, 10,178 barrels of water, and 2,836 barrels of condensate, according to AIX. Gas production peaked in early 2016 around 11.5 million cubic feet per day and declined sharply in late 2017. It currently produces some 4 million cubic feet per day. ●

*Contact Eric Lidji at ericlidji@mac.com*

# 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.

SCOTT PFOFF

**Amaroq Resources, LLC**

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*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.*

## 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. 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

*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.*

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. ●

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# Cosmopolitan still waiting for restart

*Regulatory hurdles and economic uncertainty have paused an ambitious multilateral campaign at Cosmopolitan*

**By ERIC LIDJI**
For Petroleum News

BlueCrest Alaska Operating LLC generally releases its annual development plan right as The Producers is going to print. One of the big questions that document will answer: whether the company will resume development at Cosmopolitan or wait another year.

As the coronavirus pandemic was upending the global economy in early 2020, the local subsidiary of Fort Worth-based BlueCrest Energy Inc. was developing its Cosmopolitan unit with a sequence of increasingly complex wells designed to cut time and save money.

J. BENJAMIN JOHNSON

The strategy emerged after the state withheld between $75 million and $100 million exploration tax credits from BlueCrest in early 2017. The company cancelled a proposed five-well program and used the time to envision a new approach to the offshore field.

BlueCrest ultimately proposed a multi-lateral well drilled in a “fishbone” pattern. The well would have a “spine” running through the Hemlock with seven lateral “ribs” drilled every 800 feet up through the Hemlock and Starichkof horizons. The ribs would drain to the spine well, which would flow back to shore, where oil would be trucked to market.

JOHN M. MARTINECK

The company drilled the H-12 well in this fishbone pattern in July 2018, re-drilled the H-16 well later that year using the same pattern, and drilled the H-4 well the following year.

In its plan of development for 2020, BlueCrest increased its ambitions. It proposed a “trident” well, which would have had three subsurface fishbones from one surface well.

Although the well was technically complex, the initial delays were regulatory. The well required 24 drilling permits from the Alaska Oil and Gas Conservation Commission, as well as a general exemption to standard well-spacing requirements covering the project.

BlueCrest made progress on those permits throughout 2019 and 2020, but it still lacked several permits by the time it submitted its next development plan in September 2020.

With the economy also uncertain, the company delayed plans for the well beyond 2021.

Even with the suspension on major drilling, BlueCrest completed a workover of the Hansen 1AL1 well, which brought the producer back online. The company also advanced permitting work on a proposed offshore natural gas development at Cosmopolitan.

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BLUECREST ALASKA OPERATING LLC

**BlueCrest’s Cosmopolitan onshore drilling and production facility at sunrise, Anchor Point, Alaska.**

## Recent work

In its eighth plan of development, for 2022, the company said it would continue to suspend drilling activities at Cosmopolitan “as long as the COVID pandemic, and the current market environment persist … There is a tremendous amount of uncertainty around Investors/Lenders extending funding to the oil and gas industry in Alaska considering the treatment the State of Alaska has given to the industry in its current obligation to pay the Tax Credits earned. We have run into increasing obstacles with existing and potential Investors/Lenders with the uncertainty of potential regulation changes midstream in the process. Investor/Lenders like stability and follow through.”

Even so, BlueCrest said it would continue to advance the offshore gas project. It also said it would evaluate maintenance projects to extend well life and would perform hot oil treatments on the Hansen 1AL1, Hansen H4, Hansen H12, Hansen H14 and

*continued on page 18*

**BLUECREST** *continued from page 16*

Hansen H16A wells to maintain production rates. The company also still wants to develop a Starichkof/Hemlock oil target at the unit, if market conditions become more favorable.

BlueCrest has not permitted any new wells at Cosmopolitan since 2019.

## History

BlueCrest was formed in 2011. It came to Alaska soon after to join Buccaneer Energy Ltd. as a minority partner at Cosmopolitan. It eventually took over as operator of the unit.

BlueCrest brought the Cosmopolitan unit online in early 2016 from an existing well. The company began a drilling program toward the end of the year using its custom-built BlueCrest Rig No. 1, which the company bills as the most powerful drilling rig in Alaska.

Even before it began proposing extreme multilateral wells, the company was facing technical challenges at the unit. The location of the offshore reservoir required either an offshore drilling solution or a rig capable of highly directional wells. The BlueCrest Rig was designed to drill three miles out and then a mile-and-a-half down to the reservoir and an additional mile-and-a-half horizontally through the sands, according to the company.

The point of the multilateral campaign was to reduce the number for these directional surface wells. "Each fishbone well contacts the same amount of reservoir rock as seven-nine individual horizontal wells, and each trident well should recover the same ultimate reserves as three fishbone wells since the reservoir

*The company also still wants to develop a Starichkof/Hemlock oil target at the unit, if market conditions become more favorable.*

contact is the same," CEO and President J. Benjamin Johnson told Petroleum News in 2019, adding, "so, each trident well provides the same amount of reservoir contact as 21-27 individual wells."

BlueCrest commissioned a mechanical refrigeration unit at Cosmopolitan in 2020. The unit can process up to 35 million feet per day of natural gas. The facility is primarily designed to accommodate natural gas contained in oil production. The proposed natural gas target is dry and is unlikely to require any additional refrigeration capacity.

Cosmopolitan produced 331,077 barrels of oil (183 barrels per day) in 2021 and 143,198 barrels (160 bpd) during the first half of 2022, according to the AOGCC. The unit also produced 954 million cubic feet of gas in 2021 and 313 million cubic feet in the first half of 2022. ●

*Contact Eric Lidji at ericlidji@mac.com*

## BlueCrest to resume drilling in 2023, pending funding

BlueCrest plans to resume development drilling at its Cosmopolitan unit in 2023, according to a plan of development filed as The Producers was going to print.

The plan calls for drilling the H10 Trident Fishbone Well "pending receipt of new investment funding," the company told state officials in a plan of development filed Sept. 27. The company said it would begin drilling within "several months" of receiving funding and would continue drilling based on information from the first well.

The company is also still evaluating an offshore natural gas project in the Tyonek.

In addition to the drilling plans, BlueCrest said it would "continue to make adjustments to our wells to maximize production levels and to extend our wells' lives" in the upcoming year. The company also plans to perform Hot Oil treatments on the Hansen 1AL1, H4, H12, H14 and H16A wells, sidetracks and laterals "to maintain production rates." The company has been performing those treatments every three to four weeks this past year.

The state Division of Oil and Gas has yet to approve the development plan.

In its recently completed development year, BlueCrest said it overhauled two high pressure gas compressors. "These compressors are not only used for compressing our natural gas for sale but are also used to gas lift all our wells and provide fuel for all our plant operations. This was a large undertaking but was critical work completed this year."

The company also upgraded the mechanical refrigeration unit used to remove unwanted liquids and impurities in natural gas to bring achieve pipeline sales specification.

—ERIC LIDJI

# ConocoPhillips Alaska state's largest oil producer

*As it continues to reduce its environmental footprint, the big independent increases output*

By **KAY CASHMAN**
Petroleum News

EREC ISAACSON

ConocoPhillips Alaska Inc., or CPAI, is Alaska's largest oil producer. With a history of more than 60 years in the state, the Alaska unit of the Houston-based independent has diligently pushed westward beyond Prudhoe Bay.

Going east to west on Alaska's North Slope, CPAI has four Central Processing Facilities: CPF 1-2-3 in the Kuparuk River Unit and the Alpine Central Facility in the Colville River Unit.

Kuparuk River has 48 drill sites with active wells flowing through CPF-1, CPF-2 or CPF-3.

The Colville River Unit has five drill sites — CD1-2-3-4-5. Those five drill sites and the Greater Mooses Tooth Unit drill sites MT6 and MT7 flow through the Alpine Central Facility.

**ConocoPhillips**

**COMPANY HEADQUARTERS:** Houston, Texas
**TOP ALASKA EXECUTIVE:** Ryan Lance
**ALASKA SUBSIDIARY:** ConocoPhillips Alaska
**TOP ALASKA EXECUTIVE:** Erec Isaacson, president ConocoPhillips Alaska
**ALASKA OFFICE:** 700 G St., Ste. 1950, Anchorage, AK 99501
**PHONE:** 907-276-1215
**COMPANY WEBSITE:** www.conocophillipsalaska.com

All are operated by CPAI.

The company also owns approximately a 36% working interest in the Prudhoe Bay Unit, which is operated by Hilcorp North

*continued on page 22*


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## CPAI July 2022 production

The Kuparuk River field averaged 81,489 bpd of oil in July 2022, up 2,394 bpd, 3%, from a June average of 79,095 bpd and down 8.6% from a July 2021 average of 89,170 bpd.

In addition to the main Kuparuk pool, Kuparuk produces from satellites at Meltwater, Tabasco and Tarn, and from West Sak.

CPAI's Colville River Unit averaged 34,374 bpd in July, down 530 bpd, 1.5%, from a June average of 34,904 bpd and up 222.7% from a July 2021 average of 10,651 bpd.

There was a 26-day maintenance turnaround at the field in 2021 from July 9 through Aug. 3. In July 2022, wells at CD1 began to come back online following a shutdown at that pad which began in March following discovery of a natural gas release.

In addition to oil from the main Alpine pool, Colville production includes the Nanuq and Qannik oil pools.

CPAI's Greater Mooses Tooth in the National Petroleum Reserve-Alaska averaged 16,952 bpd of oil in July, down 2,047 bpd, 10.8%, from a June average of 18,999 bpd and up 2,409.8% from a July 2021 average of 675 bpd.

In July 2021 the field was producing from just one pad, GMT1, the Lookout oil pool. ConocoPhillips began sustained production from GMT2 at the Rendezvous oil pool on Dec. 12. GMT2 currently accounts for 90% of GMT production.

All of the oil mentioned in this story is shipped to market via the 800-mile trans-Alaska oil pipeline.

—KAY CASHMAN



**CONOCOPHILLIPS** *continued from page 20*

Slope LLC.

"Through the coming decade, we anticipate making significant capital investments at Colville River Unit, GMT Unit, Kuparuk River Unit, and Prudhoe Bay Unit which should enable gross production from these four units to grow and exceed 450,000 barrels of oil per day," CPAI media director Rebecca Boys told Petroleum News in an early September 2022 email.

### What's new

In response to a query from Petroleum News about what was new in CPAI-operated North Slope fields, including what new production was expected to feed into their processing facilities in the next year or two, Boys said in the Kuparuk River Unit the Nuna and Coyote projects will be developed from drill sites 3S and 3T.

Also in Kuparuk, the Eastern NEWS, or North East West Sak, project, which will be developed in the CPF-1 area, will be a "continuation of our successful West Sak 1H NEWS development."

In the Colville River unit, "there are the Narwhal (Nanushuk) projects with CD4 expansion and the new CD8 drill site. And of course, continuation of ERD drilling at CD2 targeting the Fiord West reservoir," she said, something that Petroleum News sources say is expected by the end of the year.

"In addition, there will be continued coil tubing and rotary development drilling across these assets," Boys said.

### Fiord West ERD

In a May 18, 2022, update of an April 11 annual update to federal and state officials on the 24th Colville River Unit plan of development, CPAI said it had achieved first oil at the Fiord West satellite. The well, CD2-310, was a record-setting horizontal well drilled into the Kuparuk formation by Doyon Rig 26. The well was drilled to a total measured depth of 35,526 feet making it the longest North American land based well.

Given the "significant challenges seen" in the well that led to delays, the company said its "drilling plans for 2022 had been updated to include a drilling break" for Doyon Rig 26 to be able to "improve ERD drilling operations."

The extended reach drilling rig, also known as the "Beast" because of its immense size, had started drilling the Fiord West CD2-310 well in second quarter 2021; it wasn't finished until May 2022. The technologically advanced rig is capable of drilling in excess of 40,000 feet.

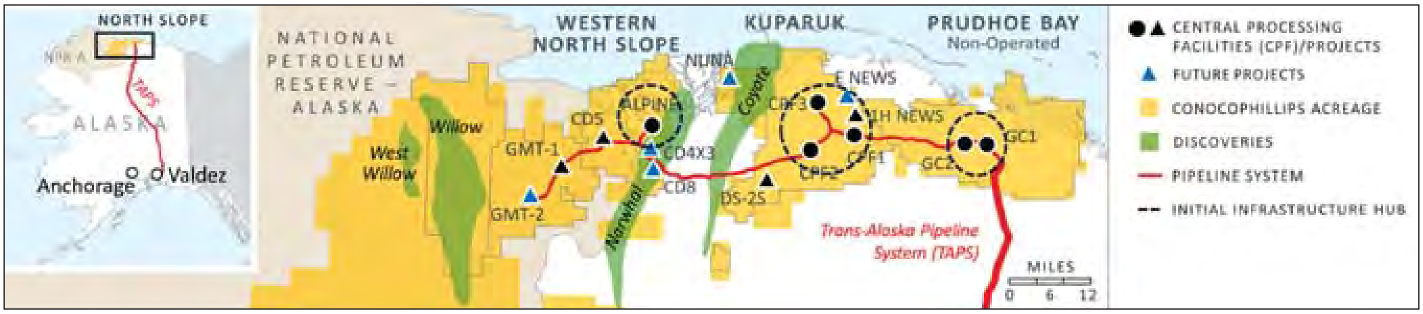
"This break in the ERD program," CPAI said, "will be used to incorporate the lessons learned from CD2-310 execution and make required engineering changes to the ERD well designs going forward."

While the well might not have been completed on time, it exceeded CPAI expectations in terms of output.

On May 20, 2022, CPAI said the well's flowrate was "being progressively increased and producing close to 10,000 barrels of oil per day, exceeding expectations."

On June 1, 2022, CPAI told Petroleum News that the company's Fiord West CD2-310 well had been "flowing steady" at 11,500 barrels of oil per day.

"The well choke is now fully open. A high rate was reached on May 25" of 12,000 barrels of oil per day, CPAI said in an email.




CONOCOPHILLIPS ALASKA

Initially, CPAI hoped to produce some 20,000 barrels of oil per day from the satellite, but that was from several wells.

At that time the company said the well will be "pre-produced for 5-6 months prior to being converted to permanent injection service." (CD2-310 was initially planned to be a development well, but its status was later changed by CPAI to that of an injector.)

Petroleum News sources said in mid-September 2022 that the Doyon 26 ERD rig was still in "warm stack" but remains under contract to CPAI. Expectations are that Rig 26 will start up again near the end of 2022.

The Colville River Unit is in both state of Alaska land and in federal land.

## Narwhal PA, CD8

Also in the Colville River Unit is the Narwhal Participating Area, covering some 3,360 acres, where sustained oil production began Dec. 14, 2021.

The Narwhal PA encompasses an area on the southeast edge of the unit where CPAI drilled the Putu 2 and Putu 2A wells. It is adjacent to the Pikka unit, where Santos subsidiary Oil Search (Alaska) and Repsol are working to develop the Nanushuk formation.

The company announced the Narwhal discovery based on the Putu wells, estimating between 100 million and 350 million barrels of oil equivalent.

Willow (in the National Petroleum Reserve-Alaska) and Narwhal are different sediment deposits within the Nanushuk formation, with Willow being older.

In its PA approval the division said the Narwhal sands "are broadly age equivalent to the Late Cretaceous Nanushuk Group." CPAI proposed defining the Narwhal reservoir as the accumulation that correlates with that found in the Oil Search (Alaska) Qugruk 3 well from 4,192 to 5,152 feet measured depth.

"The Narwhal sands extend for approximately 30 miles long by 3 miles wide," the division said.

Planning for development of a new drill site called CD8 will continue during 2022. This new drill site will develop the Narwhal reservoir in the Fifth Expansion area of the Colville River unit.

The company plans to drill one new Narwhal PA well by May 15, 2023.

## Nuna and Coyote

Per Boys' early September 2022 email, in the Kuparuk River Unit the Nuna and Coyote projects will be developed from drill sites 3S and 3T.

Here are some of the things CPAI executives have said, or CPAI state filings have revealed, about the Coyote and Nuna prospects.

• In 2015-16 the company drilled the Torok reservoir at Drill Site 3S (Nuna), drilling a well pair and contacting more than 4,000 feet of reservoir in a single lateral.

• Among CPAI's "notable activities" completed within the Kuparuk participating area in 2021 was the completion of a well

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**CONOCOPHILLIPS** *continued from page 23*

sidetrack into the "Brookian-age Coyote reservoir" from DS-3S. (Coyote had been identified from review of 2015 3D seismic.)

• In mid-2021, CPAI announced the Coyote discovery east of Nuna. At the time, company President Erec Isaacson said Coyote was in the Brookian topset above the Nuna Torok discovery, describing Coyote as shallow.

• In late 2021 and 2022 CPAI officials said that the primary Greater Kuparuk Area development projects included Coyote, Nuna and North East West Sak, also referred to as Eastern NEWS.

• Regarding the status of Nuna, the company told Petroleum News on May 4, 2022: "We continue to progress the project planning and approvals for the development at 3T, a planned future drill site where we plan to locate the Nuna development. It will be sited on the existing gravel pad within the Nuna acreage we acquired from Caelus. We plan to drill some wells in the same reservoir in the 3S area in Q3 2022 that will provide key learnings to help us further optimize the 3T development plans."

NICK OLDS

• Also on May 4, 2022, a CPAI spokesperson told Petroleum News that well test results from the Coyote prospect were "very successful," exceeding CPAI expectations and "providing key data to help us better understand the Coyote reservoir interval."

In CPAI's 2022 Kuparuk River Unit 2022 plan of development, which was approved in July 2022 and runs from Aug. 1, 2022, through July 31, 2023, the company said rotary drilling was planned to resume in the third quarter of 2022 with an injector-producer pair in the Torok (Moraine) reservoir (Nuna).

In addition to the completion of a well sidetrack into the Brookian-age Coyote reservoir from DS-3S, CPAI said it further continued to monitor the two existing Torok (Moraine) horizontal producer/injector well pairs at DS-3S, to determine long-term deliverability and waterflood performance of the reservoir.

Also, CPAI intends to apply for a separate participating area for the Torok

CONOCOPHILLIPS ALASKA

Doyon 26, also known as the "Beast," at Fiord West satellite.

(Moraine) reservoir ahead of the 2023 Kuparuk River Unit POD submission.

In addition to the Torok (Moraine) wells, CPAI also plans to pursue a well pair within the Coyote reservoir and an additional Kuparuk target during the 2022 POD period.

## Pilot EOR at Coyote

On Aug. 11, 2022, CPAI applied to the Alaska Oil and Gas Conservation Commission for approval of a pilot enhanced oil recovery project for the Coyote interval in the Kuparuk River unit.

In its application the company said since the feasibility of injection into the reservoir had not been established, this is considered a pilot project that "will aid in determining the commercial viability of developing Coyote as an enhanced oil recovery project."

The area is in the vicinity of DS 3S at Kuparuk, and includes an adjacent lease, ADL 392374, which is held by the Kuparuk working interest owners but is not currently in the unit.

"The 3S-24B exploration well was drilled to understand the ability to produce from the Coyote interval," the company told AOGCC. A horizontal producer-injector well pair is planned for the fourth quarter of this year with injection beginning about the first quarter of 2023.

The development design for Coyote is expected to be a line-drive water alternating gas flood with horizontal producers and injectors, the company said, with results from the pilot indicating whether that is the optimal development concept.

"If a commercially viable discovery is established and the development is sanctioned, then CPAI would apply at that time to the AOGCC to establish pool rules and an area injection order," the company said.

CPAI told AOGCC in its application that the first injector will be 3S-701 and be 1,000 to 3,000 feet southwest of the planned production well, the 3S-704, with optimum spacing for development of the reservoir still under analysis.

"Completion of the 3S-701 injection well will allow interference and injection testing of the Coyote reservoir to help establish the optimal pattern spacing and potentially support commerciality of the reservoir," the company said.

A second injection well may be drilled, depending on the outcome of the first injector and its testing, to continue "this long-term injection and production test with a fully supported producer centered pattern centered around the 3S-704."

The company is requesting a 3-year duration for the pilot to allow time for drilling, testing injector performance, analyzing results of the first injector and potentially drilling, testing and observing and analyzing results of a second injector.

Logs from the Palm 1 well — with a bottomhole immediately west of DS-3S — were used to define the "gross Coyote reservoir interval" at a measured depth range of 4,270 to 5,115 feet, the company said.

"The Late Cretaceous Coyote reservoir is a thinly bedded, shallow marine, west to east progradational system within the Nanushuk formation," ConocoPhillips said, with a thickness of approximately 650 feet in the DS-3S area.

"The interval has been penetrated by numerous wells targeting deeper stratigraphic intervals, both from Drill Site 3S, and vertical off-ice exploration wells in and surrounding the Kuparuk River Unit."

The DS-3S is currently on produced water service, but that could change, and part of the purpose of the pilot is to confirm compatibility, the company said, listing primary injection fluids as:

- Produced water and gas from oil pools within the Kuparuk River unit;
- Beaufort seawater from the Kuparuk seawater treatment plant; and
- Enriched hydrocarbon gas — a blend of KRU lean gas with indigenous and/or imported natural gas liquids.

CPAI said the proposed Coyote enhanced recovery injection order area is within the scope of an existing aquifer exemption, as the lease not currently in the Kuparuk River Unit was part of the unit in 1984 when the Environmental Protection Agency adopted the aquifer exemption and in 1986 when AOGCC incorporated the EPA aquifer exemption.

"Initial reservoir modeling and simulation estimate a primary depletion recovery factor of 5-10%, a cumulative recovery factor from waterflood operations between 20-30%, and an incremental 1-5% recovery for enriched gas injection (EWAG)," CPAI said.

### Willow on hold

When the U.S. Bureau of Land Management issued a draft supplemental environmental impact statement for CPAI's Willow project in the National Petroleum Reserve-Alaska, the agency added Alternative E.

RYAN LANCE

The company told Petroleum News in a July 2022 email that the new alternative was in response to an order from the U.S. District Court for Alaska.

BLM said in the draft SEIS that Alternative E is intended to reduce surface infrastructure in the Teshekpuk Lake Special Area and reduce impacts to yellow-billed loon nests near the original proposed location for the Bear Tooth 5 drill site — Willow is in the Bear Teeth unit in NPR-A.

In the company's second quarter earnings call on Aug. 4, 2022, Chairman and CEO Ryan Lance said ConocoPhillips looks forward to a record of decision on Willow later this year "so we can move forward on the project. We think we've satisfied all the concerns that the federal judge has had, and we're ready to move forward."

Nick Olds, ConocoPhillips' senior vice president, strategy and technology, called publication by BLM of the draft SEIS on July 8 "a key milestone," but said the company wouldn't make a final investment decision until BLM publishes a final SEIS and there is "a supportive record of decision by the BLM." That, he said, would allow ConocoPhillips to move forward with Willow construction.

As to when FID might occur, "we would probably see that at the earliest later this year and more likely early next," Olds said.

He said a winter 2022-23 construction season would occur "assuming we had a very favorable record of decision," allowing the company "to do civil construction and start putting roads in place for the project."

Olds said ConocoPhillips continues to do detailed engineering "to refine cost and schedule, as well as the final development modifications." Modifications are necessary, he said, because of Alternative E, which responds to the court order. "And that is to minimize or reduce the surface impact on the Teshekpuk Lake Special Area. So that alternative, we think, is a good path forward."

Olds said Alternative E "reduces the surface infrastructure and still maintains the estimated recoverable resources that we communicated in the market update of about 600 million barrels," 180,000 barrels per day gross before royalty.

ConocoPhillips remains committed to Willow, which "remains competitive in the portfolio," and continues to have, he said,

*continued on page 26*

## Greening of CPAI's oil fields

Technology has been at the heart of ConocoPhillips Alaska Inc.'s, or CPAI's, greening of its oil fields on the North Slope.

The Fiord West Kuparuk development "opens a new era we call 'growth without gravel' where we can use extended reach technology to access 60% more acreage from a single pad, dramatically reducing our footprint and enabling us to safely produce from environmentally sensitive areas," CPAI President Erec Isaacson said May 20. 2022.

"We are always seeking new and better ways to responsibly deliver Alaska's energy potential," Isaacson wrote in a recent editorial.

"Extended reach technology has been a game changer for ConocoPhillips," said Vincent Lelarge, vice president, Alaska Asset Development. "It's how we are able to responsibility develop fields like Fiord West Kuparuk with minimal footprint on the tundra and the surrounding environment."

Lelarge said CPAI has worked collaboratively on the Doyon 26 rig since 2011 when use of an extended reach drilling rig was being evaluated. From front-end engineering and design studies to ConocoPhillips Canada colleagues collaborating with Doyon Drilling during construction, the Doyon Rig 26 arrived on the North Slope of Alaska in 2020.

The technologically advanced rig is capable of drilling in excess of 40,000 feet, which substantially extends the reach from a single pad.

That means the rig will be able to develop 154 square miles of reservoir from a 14-acre drilling pad versus 55 square miles using today's conventional rigs. The Fiord West CD2-310 was the first well drilled by the rig.

—KAY CASHMAN

**CONOCOPHILLIPS** *continued from page 25*

"very strong stakeholder support, including the Alaska congressional delegation, the trades, and unions."

CONOCOPHILLIPS ALASKA

## Congressional delegation urges BLM

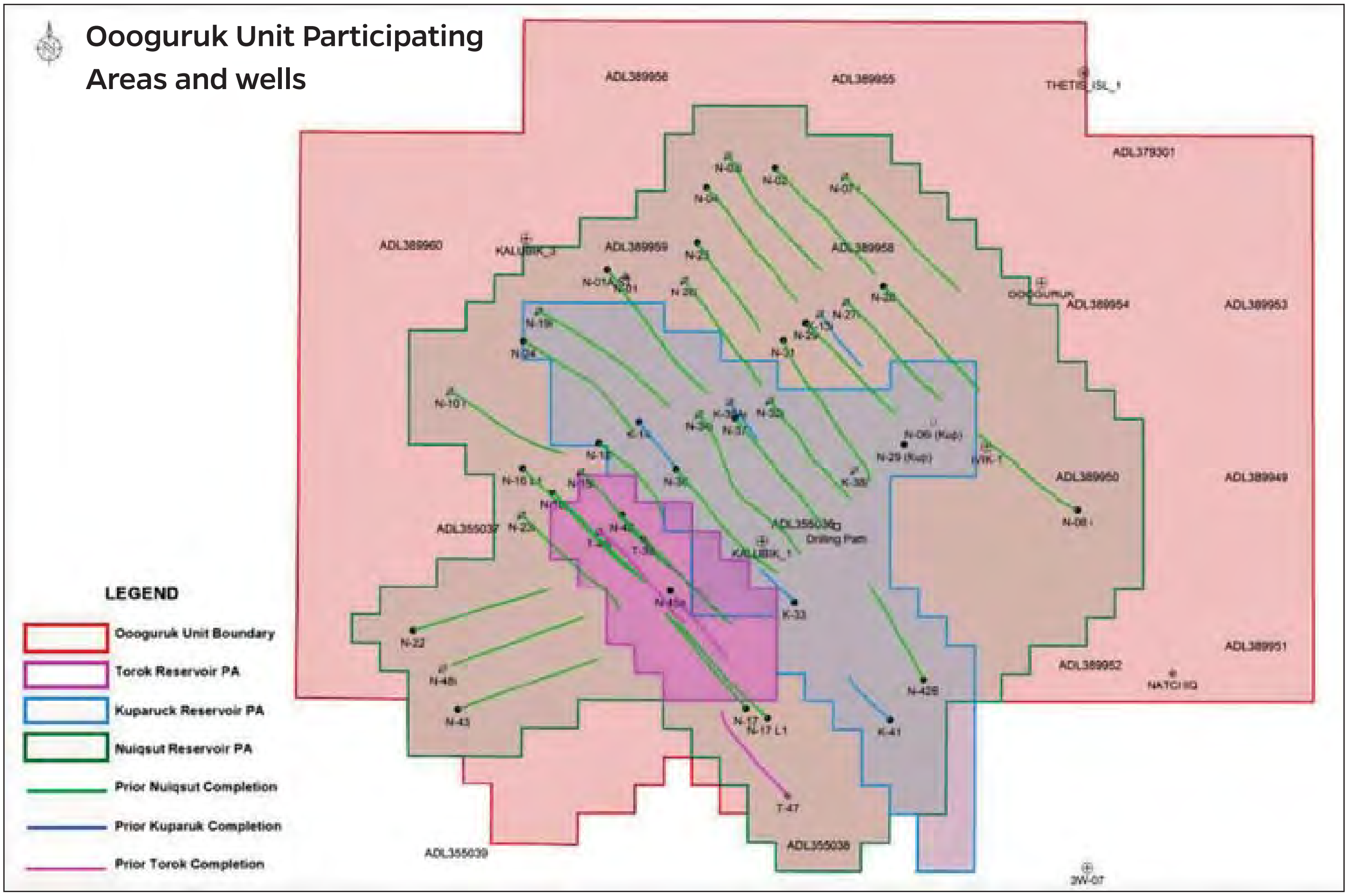
On Sept. 20, 2022, U.S. Senators Dan Sullivan, Lisa Murkowski (both R-Alaska) and Representative Mary Sattler Peltola (D-Alaska), sent a letter to Secretary of the Interior Deb Haaland urging BLM to complete the permitting process for the Willow Project in the National Petroleum Reserve in Alaska by the end of the year, in time for the winter construction season.

In their letter, the Alaska congressional delegation noted that the project has been developed under the strictest environmental standards in the world and is strongly supported by Alaska Native leaders, labor leaders, the state of Alaska, legislators from both parties, and President Joe Biden.

"The expeditious approval of this crucial project would greatly benefit Alaska, our nation, and the world, while demonstrating the Administration's commitment to addressing inflation, high energy costs, the need for greater energy security, and environmental justice initiatives," the delegation wrote. "After years of study and review, both the Administration and Alaskans can feel confident that the Project will abide by the strictest environmental considerations in the world, while being constructed and operated by a company with an impressive record of safe and responsible development on the North Slope.

"We believe the final SEIS should identify the preferred alternative; appropriately weight the purpose of energy production in the NPR-A; and recognize the public interest in supporting energy security and responsible resource development. The permitting process must be completed by the end of 2022 at very latest so the project's proponent can make a final investment decision and hire Alaskans in time for the winter construction season. That decision will not be possible, and none of those jobs will be created, in the absence of a clean and timely Record of Decision (ROD)." ●

*Contact Kay Cashman at publisher@petroleumnews.com*




ENI US OPERATING CO. INC.

# Eni overseeing neighboring offshore units

*American arm of Italian major is resuming drilling at Oooguruk and Nikaitchuq*

**By ERIC LIDJI**
For Petroleum News

ROBERT PROVINCE

Eni US Operating Co. Inc. might be the leading offshore player on the North Slope.

The American subsidiary of the global Italian major assumed the title unexpectedly. It started as a minority partner, then became an operator of one unit and then of two. And then, with the departure of several big offshore players and the cancellation of mega offshore projects, Eni became one of the most prolific offshore players in the basin.

Eni currently operates the Oooguruk unit and the neighboring Nikaitchuq unit in the nearshore state-owned waters of the Beaufort Sea north of the Kuparuk River unit.

## Eni US

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**TOP ALASKA EXECUTIVE:** Robert A. Province, manager – land, public relations & Alaska representative
**PHONE:** 907-865-3300
**PARENT COMPANY WEBSITE:** www.eni.it

Eni arrived in the region in the early 2000s to become the minority partner of Pioneer Natural Resources Alaska LLC at Oooguruk and the operator of Nikaitchuq. In the past few years,

*continued on page 28*

**ENI** *continued from page 27*

it acquired the remaining ownership and the operatorship of Oooguruk.

Those moves came during a decade when companies like Shell, ConocoPhillips, Statoil and others were pursuing major offshore projects in the Beaufort and Chukchi seas, opening what appeared to be the next phase of development in the basin. But following a string of regulatory and legal battles, economic frustrations and technical malfunctions, all of those major projects were set aside, at least for the time being, leaving Eni and Hilcorp as the only two companies operating offshore oil production on the North Slope.

Eni is the largest offshore producer on the North Slope and a major player for drilling and for infrastructure development. Until the day when Hilcorp brings the Liberty unit online, Eni has a strong case for make for its ascendancy.

Entering its second decade as an Alaska operator, Eni is overseeing two units at similar stages of their life cycle: shifting from initial development into a period of investment.

## Oooguruk

The Oooguruk unit marked a major turning point in the history of the North Slope.

The independent Armstrong Oil & Gas proved up the prospect in the late 1990s and early 2000s, formed the Oooguruk unit in 2003 and brought in Pioneer Natural Resources LLC.

The large Texas-based independent Pioneer oversaw startup in 2008 as operator and majority partner, with Eni taking a minority role. Pioneer developed the unit with man-made offshore drilling site (ODS) located in the nearshore waters of the Beaufort Sea. Oil is piped back to ConocoPhillips' Kuparuk River Unit CPF-3 facilities at Oliktok Point.

Oooguruk was the first North Slope unit brought into production by an independent, marking a new era in the development of the basin. Pioneer eventually sold the unit to Caelus Natural Resources Alaska LLC, which sold its interest to partner Eni in 2019.

The Oooguruk unit is currently developed from three pools: Oooguruk Nuiqsut, Oooguruk Kuparuk and Oooguruk Torok. The three operators have drilled 42 wells to date at the unit, and 37 are currently active: 24 oil producers (18 Nuiqsut, four Kuparuk, two Torok), 13 injectors (10 Nuiqsut, two Kuparuk, one Torok) and one disposal well.

In its development plan for the year ending September 30, 2022, Eni conducted several projects involving electric submersible pumps. The company recompleted the ODSN-02 well with an ESP and replaced failed ESPs at the ODSK-41 and ODSN-31 wells. The company also recompleted the ODSN-06 well, as well as work on seven other wells.

In its plan for the coming year, through September 2023, the company expects to conduct several drilling projects, as well as a major infrastructure project at the Oooguruk unit.

Eni is planning final engineering, fabrication and installation of a 20 million cubic-foot-per-day partial gas processing project, which is currently scheduled for startup in December 2023. The project would "mitigate gas processing constraints, reduce associated costs from KRU CPF-3, and unburden the CPF-3 gas compression system."

Gas constraints come largely from gas lift at production wells. Original design plans called for electric submersible pumps, but operators have shifted to gas lift instead. That comes on top of 4 million to 12 million cubic feet of gas production from the unit.

Eni is also planning a project to connect the Oooguruk and Nikaitchuq power systems, which would "allow a more robust and efficient power system sharing between the two development projects." The project represents an interesting infrastructure interconnection between the neighboring units, which are both wholly owned by Eni.

In addition to those facility projects, Eni is planning maintenance on several wells.

The company plans to replace ESPs at ODSK-41, ODSN-31 and ODSN-25 and plans to add ESPs at ODSN-02, ODST-39 and ODST 45A. High gas-to-oil ratios forced Eni to suspend Oooguruk-Torok production from the ODST-39 and ODST-45A production wells. The company plans to install electric submersible pumps at both wells and repair tubing at the ODST-46i injector. The company is also planning to work over ODSN-06 to isolate the Nuiqsut formation and to begin production from the Kuparuk formation.

The company is also planning to re-start development drilling after several years. The plan calls for drilling two wells next summer with completion and start-up in 2024.

Eni is evaluating two wells — ERD-N01 and ERD-N02 — in the northern Nuiqsut reservoir but within the proven drilling radius of the ODS. The wells would test the productivity and oil quality at ADL-379301, ADL- 389953 and ADL 389949 in several horizons.

There is still considerable room to grow at Oooguruk.

Eni said there are plans for as many as 12 additional development wells at the Oooguruk-Nuiqsut participating area — eight from available slots and four from reclaimed slots.

### Nikaitchuq

Eni joined the Nikaitchuq unit in 2005, became the operator and 100% working interest owner in 2007, and brought the unit into production in late January 2011 from two drill sites: the onshore Oliktok Point Pad and the offshore Spy Island Drillsite.

The unit had produced some 71.2 million barrels through May 2022, with average oil production between October 2021 and May 2022 totaling some 17,754 barrels per day.

Following a delay granted by the state Department of Natural Resources, some of the acreage at the Nikaitchuq unit was set to reach its automatic 10-year contraction at the end of September 2022, as this issue of The Producers was going to print. The company is planning to request an expansion of the Schrader Bluff participating area at the unit.

Under its plan of development running through September 2022, Eni conducted drilling and maintenance activities from both of its Nikaitchuq pads. The company completed a six-well workover program from the Oliktok Point Pad between December 2021 and May 2022. The company also drilled five wells from the Spy Island Drillsite: the injectors SI02-SE6, SI15-E1 and SI41-E3 and dual lateral producers SP09-E2 and SP40-E4 with plans for SP42-E2. It added a lateral to SP03-NE2 and completed two workover projects.

Eni has been developing the Nikaitchuq unit using waterflood. The company drills producers and injectors in side-by-side pairs with horizontal drains in the Schrader Bluff OA sands. A pilot project launched in late 2019 at the Oliktok Point I-2 well intended to study the efficacy of polymer injections but was cut short due in March 2020 to pandemic restrictions. The pilot project was resumed in April 2021 through the end of 2022.

*Eni recently announced the end of its exploration program at Nikaitchuq. The company spent several years planning a two-well program in the federal waters north of the unit.*

In the coming development year, through September 2023, Eni is planning a three-well and one-lateral program from the Spy Island Drillsite. The program includes the SP42-E2 dual lateral producer in late summer, the SI43-E3 injector planned for late 2022 to complete the northeast extension program, the SP05-FN7 second lateral also for late 2022, and the SI44-S5 injector planned for early 2023 to replace the suspended OI15-S4 well. Eni recently completed a six-well shelter at the pad to accommodate these projects.

At the Oliktok Point Pad, Eni is keeping the Nordic Calista Rig No. 4 in cold stack. The company has no drilling plans but expect to conduct workover starting in early 2023.

Eni recently announced the end of its exploration program at Nikaitchuq. The company spent several years planning a two-well program in the federal waters north of the unit.

The first well NN01 was suspended at 30,010 feet measure depth due to drilling complications. The second was cancelled after partner Shell backed out of the project.

Eni initially received a two-year deferral but ultimately allowed the leases to expire. ●

*Contact Eric Lidji at ericlidji@mac.com*

# Cook Inlet Energy analyzing options at WAMU and Redoubt

*Glacier Oil & Gas subsidiary still clearing fog from a pandemic suspension, looking for partners*

**By ERIC LIDJI**
For Petroleum News


STEPHEN RATCLIFF

A year after emerging from a pandemic induced hibernation, Glacier Oil & Gas Inc.is trying to understand its two offshore Cook Inlet units in a new economic environment.

The West McArthur River unit and the Redoubt unit are classic Cook Inlet properties: aging stalwarts in need of regular investment but also capable of significant growth.

In June 2020, with the delivered spot price of Alaska North Slope crude oil hovering around $30 to $40 per barrel, the state allowed the Glacier Oil & Gas subsidiary Cook Inlet Energy LLC to suspend operations at West McArthur River and Redoubt, as a response to the global economic upheaval brought about by the coronavirus pandemic.

Cook Inlet Energy brought the two units back online in the fourth quarter of 2021 and is now working under its second full development plan for the units since that restart.

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### West McArthur River unit

Stewart Petroleum Co. brought the West McArthur River unit online in the early 1990s. The offshore unit currently includes 6,970 acres and two participating areas: the Area No. 1 participating area and the Sword participating area. Operators came and went over the subsequent decades, until Cook Inlet Energy acquired the property in 2009.

Given the 16-month suspension, the state approved a one-year extension of the 29th plan of development for the West McArthur River unit, allowing it to run through April 2022.

Under that plan, Cook Inlet Energy performed a range of maintenance and evaluation projects. But “due to unfavorable economic conditions,” the company chose to defer planning activities for the long-discussed Sabre prospect, which had been on its plan.

Interest in Sabre goes back decades. Former operators Union Oil Company of California, Marathon Oil Co., Forcenergy Inc. and its successor Forest Oil Corp., and Pacific Energy Resources Ltd. all danced around the prospect during their years operating the unit.

Glacier subsidiary Cook Inlet Energy first discussed plans for a Sabre exploration well as early as late 2013 but delayed the project due to its complicated logistics and high cost.

Costs remain an issue, but logistics have eased some with the arrival of jack-up rigs in Cook Inlet. A jack-up eliminates the need for expensive extended reach drilling.

Even before the pandemic, Cook Inlet Energy was looking for partners to help develop the Sabre prospect. And now, in its current plan of development running through April 2023, the company is keeping Sabre “open for development” and looking for partners.

Even without Sabre, options exist for bolstering production.

Of the 11 wells at the West McArthur River unit, three have been plugged and abandoned (WF No. 1, WF No. 2U and WF No. 2L) and five are currently shut-in pending maintenance work (WMRU No. 1A, WMRU No. 2B, WMRU No. 7A, WMRU No. 8 and Sword No. 1). The WMRU No. 5 and WMRU No. 6 wells are both producing from the Area No. 1 participating area, and WMRU No. 4 is now a Class 1 disposal well.

As part of its current plan of development, Cook Inlet Energy plans to replace failed electric submersible pumps on the WMRU No. 2B and Sword No. 1 wells, although the project depends on the availability of a suitable rig, as well as economic conditions.

The company also plans to address high water production at the field, in part evaluating some of the other shut-in wells to find candidates for conversion to a disposal well.

## Redoubt

Pan American discovered the Redoubt Shoal field in the late 1960s. The Redoubt unit was formed in 1997 with production from the Hemlock participating area. Cook Inlet Energy acquired the Redoubt unit in 2009, as part of its initial acquisition in the region.

To accommodate the suspension, the state approved a six-month extension of the 20th plan of development for the Redoubt unit, allowing it to run through October 2021.

*Glacier subsidiary Cook Inlet Energy first discussed plans for a Sabre exploration well as early as late 2013 but delayed the project due to its complicated logistics and high cost.*

The overall program at Redoubt is similar to West McArthur River: maintenance on existing wells, plans to address high water volumes and prospects for expansion.

As part of its previous plan of development, the company undertook a range of maintenance projects. Before the shutdown, Cook Inlet Energy re-perforated and stimulated RU-6 to increase injectivity. It also completed a reservoir simulation study to see how produced water injections would impact secondary recovery rates at the unit.

The company also addressed near-term water disposal issues, in part by restarting the RU-D1 Class I disposal well and by maximizing injection at Class II disposal wells. The issue remains unresolved, though, and remains on Cook Inlet Energy's agenda.

As with the Sabre prospect at West McArthur River, Cook Inlet Energy deferred work on a proposed development at an expansion property called the Northern fault block. In its current plan, the company said it "plans to keep its options open" at both the Northern and Southern fault block by seeking partners to reduce the risk factors for development.

Cook Inlet Energy said that it might conduct a flow test on the RU-9 well in the Southern fault block to collect reservoir information this year. The well has a failed electric submersible pump, which would suggest the opportunity for future maintenance projects.

Of the nine wells at the Redoubt unit, four are producing (RU No. 1A, RU No. 2 A, RU No. 5B and RU No. 7B), two are in service for waterflood (RU No. 3A and RU No. 6A), two are shut-in (RU No. 4A for water loading issues and RU No. 9 due to a failed electric submersible pump) and the RU No. D1 is a recently reactivated Class I disposal well.

Associated with Redoubt are the Osprey platform and the Kustatan Production Facility.

The company recently installed a new subsea pig launcher on the pipeline to the platform. In its current plan, the company is planning inspections and upgrades at these two facilities. ●

*Contact Eric Lidji at ericlidji@mac.com*


HEX COOK INLET LLC

Onshore natural gas processing facility at Nikiski.

# HEX hanging in there with Kitchen Lights unit

*John Hendrix talks about Sterling evaluations, ongoing tax battle with Revenue*

**By KAY CASHMAN**
Petroleum News


JOHN L. HENDRIX

### Hex Cook Inlet LLC

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Long-time Alaskan John Hendrix is the only owner of an oil and gas company operating in the state. While other oil and gas companies establish local offices, they are based outside Alaska.

Via his newly formed HEX Cook Inlet, in July 2020 Hendrix acquired the natural gas producing company Furie Operating Alaska and its partners Cornucopia Oil & Gas Co. and Corsair Oil & Gas in bankruptcy proceedings. The centerpiece of the purchase was the offshore Kitchen Lights unit, its Julius R. production platform, a 15-mile subsea gathering line and an onshore natural gas processing facility at Nikiski on the Kenai Peninsula.

The Kitchen Lights unit, or KLU, is the largest unit in the Cook Inlet basin by acreage and has been seen as a source of growth for the basin.

Hendrix was raised in Homer, Alaska, and is an engineer. He has close to four decades of experience in the energy industry in Alaska, the Lower 48 and internationally with Apache, BP and Schlumberger.

That experience includes managing Apache's Cook Inlet operations from 2012 until 2016, when the company let its leases drop because of some of the same challenges HEX faces today.

## A few bad apples

In July and August 2022 interviews with Petroleum News, Hendrix talked about Furie's successes under his ownership along with the challenges the company has faced in the last two years.

Although Hendrix thinks the commissioners of Alaska's Department of Revenue and Department of Natural Resources are doing a good job to improve the business climate for oil and gas companies working in the state, he said some obstacles remain.

Alaska is an expensive place to operate, he said, likening the regulatory regime to a field spiked with land mines: “Yes, you can get across the field but you don’t know what kind of regulatory land mine you’re going to step on along the way that might cause your investment to go up in smoke,” he said, noting most of those ‘mines’ involve required federal permitting on federal and state acreage.

One of the mines HEX has run into was a property tax valuation by the Alaska Department of Revenue that was “more than four times what the IRS allowed the KLU assets to be depreciated from. … How can the state turn around and value it four times more than the IRS will allow me to depreciate? And it’s been audited. This is the kind of stuff that kills you. I must pay $1.6 million every year in property taxes until this is settled,” Hendrix said.

The company appealed Revenue’s decision to the State Assessment Review Board. SARB upheld Revenue’s decision so now the issue is headed to court in January 2023.

Estimating it will take about three years to reach a final decision in the courts, it means Hendrix will have “more than $5 million tied up in this matter, not including attorney fees.”

Hendrix said Revenue’s assessment was “unfair and excessive,” and money that should be used for well work to produce more natural gas for Southcentral Alaska’s residents that rely on gas to heat and electrify their homes and businesses.

“We had hoped the state of Alaska would come to the table and settle this through mediation that was recommended by the judge, but as of now they remain uncommitted. The Kenai Peninsula Borough is in favor of mediation.”

Until the lawsuit is settled, in or out of court, HEX cannot afford to invest in any more major capital improvements at Kitchen Lights.

“We’d hoped for a settlement, which would have saved everyone, including the state of Alaska money, but that hasn’t happened,” Hendrix said. And in September 2022 he confirmed that state officials would still not come to the table.

“The state of Alaska makes how many billions off oil and gas, yet the Department of Revenue has no definition for proved or proven or proven reserves. ... we’re hoping to help them get there some day,” Hendrix said.

## Production, court

In the meantime, HEX is trying to keep gas production level, although he’d prefer to be investing the money he’s paying in excess taxes into KLU improvements that would increase output.

He’s already proven he can boost production, although he is still working to prove up reserves in the unit:

Output data from the Alaska Oil and Gas Conservation Commission for the KLU averaged 13,946 thousand cubic feet of natural gas per day in July 2022 which is 7.5% of Cook Inlet basin production. In July 2020 KLU averaged 12,678 mcf per day.

A settlement could save a lot of time and money for all the parties involved.

“We are an Alaskan company. Out of every $100 made, we spend $30 in paying for royalties and property tax. On top of that we have payroll, daily operating expenses, so it is a challenge,” Hendrix said.

## Had to fix everything

At the time HEX acquired Furie, KLU was an underperforming field in need of fixing, but with considerable potential.

On Dec. 18, 2020, Hendrix said, “When we took over Kitchen Lights, we basically had to go in and fix everything.” This statement was confirmed by DNR’s Division of Oil and Gas.

“I took a gamble on buying KLU; I know that. But I figured I should be able to trust my state government to treat me fairly and help me navigate through the challenges of operating in the Cook Inlet,” he told PN.

## Most active bidder

Hendrix has been the most active bidder in Cook Inlet basin lease sales for the last two years.

He was one of two companies in the 2021 lease bid round. In the most recent state Cook Inlet basin lease sale in May 2022, Furie was the only bidder, winning two leases.

“Our predecessor had already relinquished those. I decided we needed to pick them up because they are close enough to where we want to produce in the future. It’s all about shoring up acreage surrounding our platform,” Hendrix said.

## Sterling opportunities

Furie under its previous owners brought the unit into production from a single well in November of 2015 and subsequently drilled three more production wells, with the last being the KLU A-4 well in October 2018.

By the time HEX took control, one of the four wells was offline, awaiting upgrades and repairs. And the three other producing wells were underperforming.

HEX’s goal was, and continues to be, having all four existing wells producing natural gas — hopefully from both the Beluga and Sterling formations, with much of the upside in the unproved Sterling.

As of Sept. 19, one of the four wells was producing from the Sterling. Two other wells are capable of producing from the Beluga, but one is shut-in from April to October because the utilities only want the gas in the winter months.

According to one natural gas producer, the utilities want producers to produce 350 million SCF of gas per day for them in winter and then they cut the Cook Inlet producers back to 50 million from April to October. So as a group the producers only sell 1/7 of what they make in the summer.

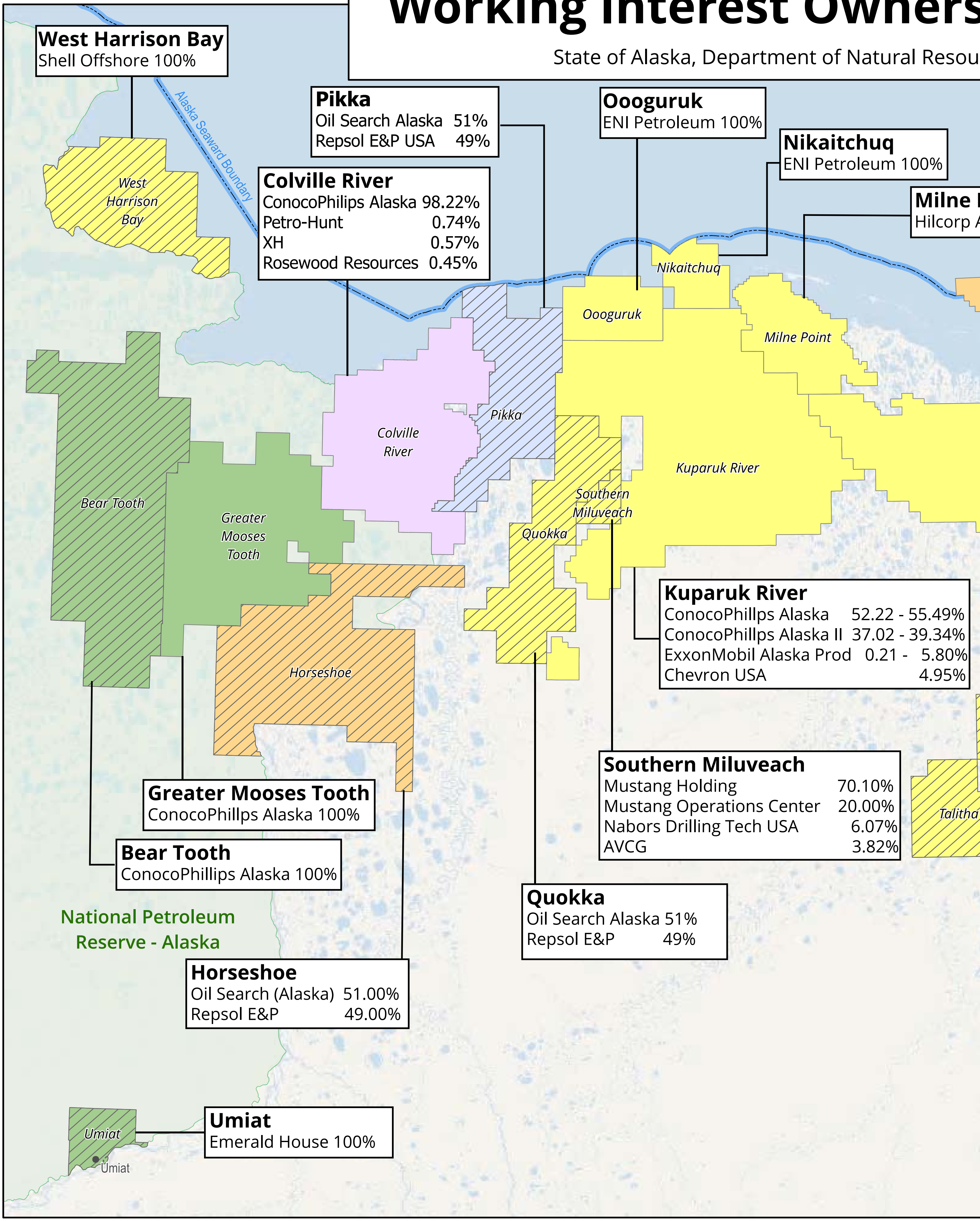
A produced water handling system was installed in 2021 primarily for the Sterling formation.

“We view the Sterling as a great opportunity; that is if we get this right and get it producing natural gas year-round, we might

*continued on page 37*

# Working Interest Owners

State of Alaska, Department of Natural Resou



# ship of North Slope Units

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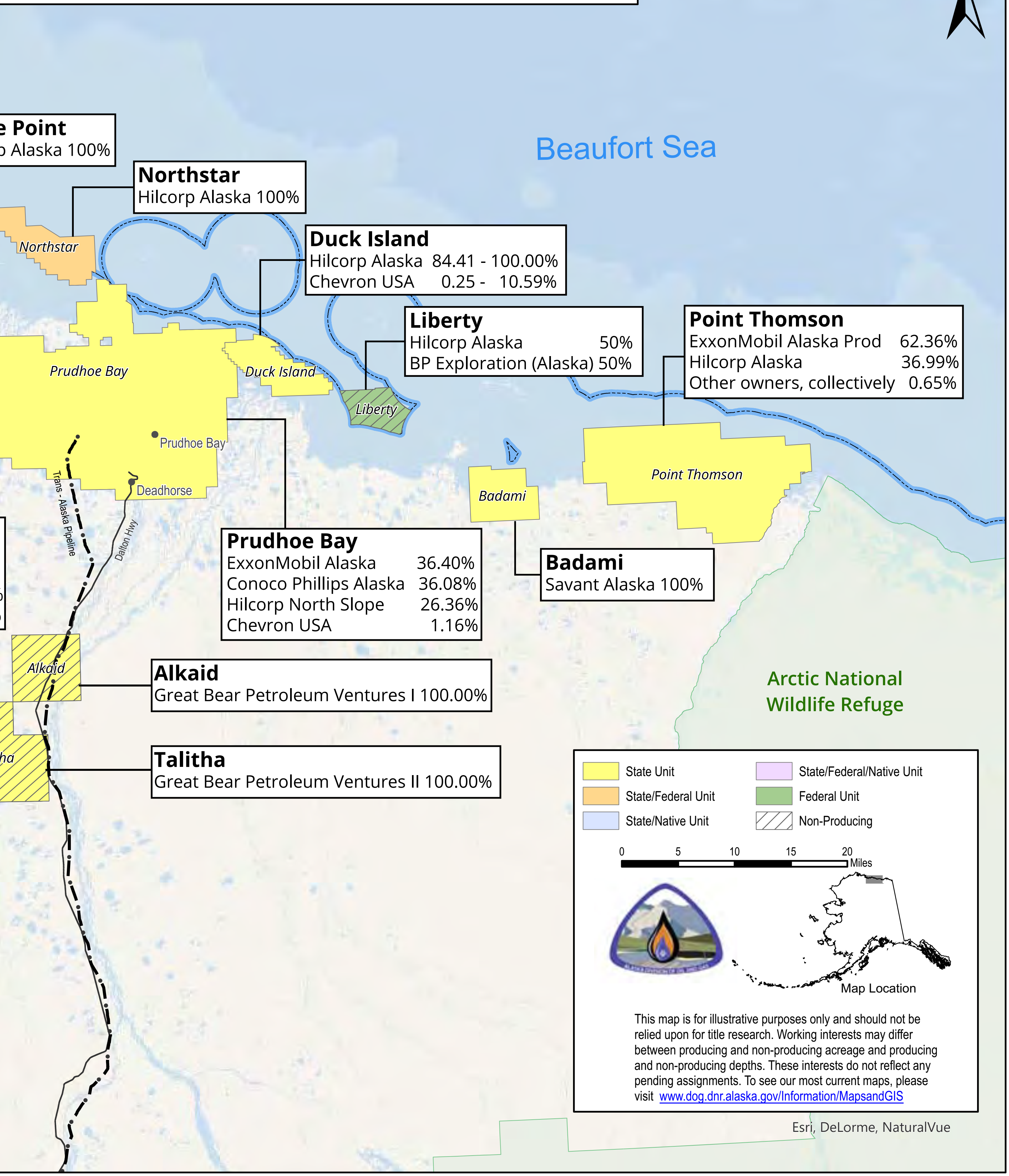
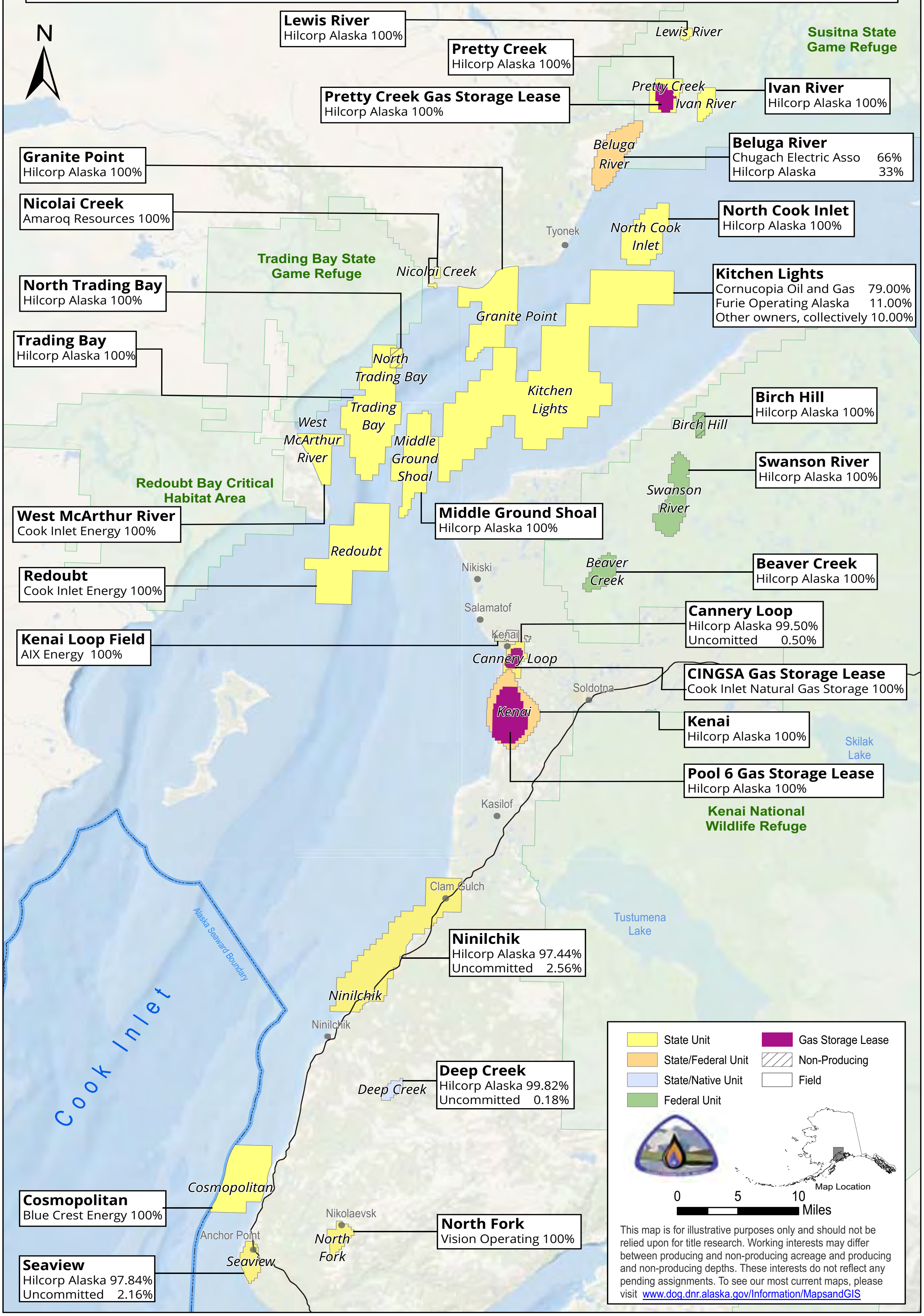


# Working Interest Ownership of Cook Inlet Units

State of Alaska, Department of Natural Resources, Division of Oil and Gas, as of September 2022



**HEX COOK INLET** *continued from page 33*

be able to add a year to the life to the field," he said.

"The big thing is, proved reserves have to be economical and right now we're testing to see if we can get it to that point."

The Sterling is what cost Furie's previous owners $17 million when they froze the flowline in the winter of 2019 due to excess water production.

"We spent about $1.8 million on it," Hendrix said, referring to the water handling system. "Udelhoven installed it," he said, pointing to the fact that unlike the previous Furie owners Hendrix's companies employ Alaskans — and use Alaska, not Outside, contractors.

Several months ago HEX's Furie put the A-1 Sterling well into test. The test has been "encouraging," Hendrix said.

Since then, KLU A-2A and KLU A-4 have also been tested and evaluations are ongoing.

Because of the inability to comingle Beluga and Sterling production, HEX is strategically placing individual zones in test to minimize any disruptions to overall production, he said.

Unfortunately, Hendrix told PN on Sept. 19 that the "KLU A-4 Sterling tests were disappointing." ●

*Contact Kay Cashman at publisher@petroleumnews.com*

HEX COOK INLET LLC

**Julius R. production platform with Denali in the background.**

# Hilcorp works mature fields in Cook Inlet

*Company is largest inlet producer of both oil and gas; facilities upgrades, expansions, as well as new wells planned*

**By KRISTEN NELSON**
Petroleum News

LUKE SAUGIER

Hilcorp began acquiring oil and gas assets in Cook Inlet in 2011 and began operating there in 2012. Hilcorp's focus is on extending the life of maturing fields where more oil and gas can be extracted and Cook Inlet, where oil and gas production began in the late 1950s, offered the company numerous opportunities.

Cook Inlet was the focus of exploration and development in Alaska until the discovery of Prudhoe Bay in the late 1960s drew companies and investment north.

Cook Inlet oil production peaked in 1970 at more than 227,000 barrels per day and natural gas production in the mid-1990s at more than 850 million cubic feet per day. Alaska Oil and Gas Conservation Commission data for July 2022 show Cook Inlet liquids production averaging 9,910 bpd and natural gas production averaging 187 million cubic feet per day.

Hilcorp acquired Chevron/Union Oil Company of California assets in Cook Inlet in 2012 and Marathon Oil's Cook Inlet assets in 2013. In 2015 it added inlet assets from XTO Energy and in 2016 it acquired ConocoPhillips' North Cook Inlet field and minority interests that company held in and around North Trading Bay and other small interests.

Hilcorp Alaska operates 17 Cook Inlet fields, split between the west side, fields produced from platforms and the Kenai Peninsula.

## HILCORP ON THE WEST SIDE

Hilcorp Alaska operates four natural gas fields on the west side of Cook Inlet, three of which is owns and one of which it operates on behalf of majority owner Chugach Electric Association.

Hilcorp became 100% working interest owner and operator at the smaller fields — Ivan River, Lewis River and Pretty Creek — effective Jan. 1, 2012, as part of its 2011 acquisition of Chevron's Cook Inlet assets, which included one-third ownership at Beluga River where ConocoPhillips Alaska was the operator.

Hilcorp took over as Beluga operator in 2016 when ConocoPhillips sold its interest to Anchorage-based electric utilities Municipal Light & Power and Chugach Electric (Chugach Electric purchased ML&P in 2020).

Beluga averages more than 15% of inlet production; Ivan River averages almost 6%; Lewis River is a small producer, less than 1%; and Pretty Creek currently has no production.

### BELUGA RIVER

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In its current plan of development and operations for Beluga River, dated March 1, 2022, Hilcorp told the U.S. Bureau of Land Management (Beluga includes federal, Cook Inlet Region Inc. and state acreage) that it anticipates drilling two grassroots wells and one sidetrack and is also evaluating one to two additional wells to add to the program. That plan covers April 1, 2022, through May 31, 2023.

Planned wells, using Rig 147, are BRU 244-27, BRU 220-34 and BRU 233-23 (the sidetrack).

Hilcorp said it also anticipates two de-completes with Rig 401 to prepare for sidetracking and two to four workovers using Rig 401. Workovers planned include BRU 212-24T (de-complete for sidetrack), BRU 211-03 (de-complete for sidetrack), BRU 232-26 (rig workover) and BRU 212-35T (rig workover).

Work completed under the 59th plan (April 1, 2021, through March 31, 2022) included a grassroots well drilled with Rig 147 targeting Sterling and Beluga gas sands and Tyonek sands. Hilcorp said that well, BRU 223-24, was drilled deep to test sands below 7,000 feet true vertical depth; the well was then plugged back and completed in the lower Beluga sands, which were brought online Dec. 23, 2021, with initial production of 6.3 million cubic feet per day.

Beluga production in January 2022, the first month of full production from the new well, averaged 28.36 million cubic feet of gas per day, up 18.3% from January 2021 production. In July AOGCC data show the field averaged 16.93 million cubic feet per day, down 14.2% from July 2021.

Under the 59th plan Hilcorp also did five through tubing rate adding intervention projects. One well was returned to production following a coil cleanout.

### K Pad expansion, pool rules

Hilcorp has filed a lease plan of operations with the Alaska Department of Natural Resources' Division of Oil and Gas to expand K Pad at Beluga by 4.5 acres. Additional infrastructure would be installed including a compressor package and a communications tower.

"This project is necessary to support additional resources development with BRU," the company said in its application, with additional wells planned for K Pad for 2023.

The company also applied to AOGCC for pool rules for Beluga. In the May 5 order establishing the rules, AOGCC described the Sterling-Beluga gas pool as "a mature development that has been in production for nearly 60 years and has produced approximately 1.4 trillion cubic feet of gas," with production in 2021 of some 8.6 billion cubic feet, a daily average of approximately 23.6 million cubic feet.

As a mature field, Beluga production has been on decline, with annual volumes in recent years dropping from 18.1 bcf in 2016 to 7.4 bcf in 2020, before increasing back to 8.5 bcf in 2021. The field peaked in the early 2000s, hitting 55.9 bcf, for example, in 2005.

The commission said Hilcorp plans four additional wells to develop the proposed Sterling-Beluga gas pool further. The company drilled three wells in 2020, demonstrating "that there is still significant potential for finding untapped gas accumulations which cannot be produced form existing wells due to the discontinuous nature of the sands."

In is application for pool rules, Hilcorp said Standard Oil Company of California, Richfield Oil Corp. and Shell Oil Co. established a joint operating agreement for exploration "of various state, federal and private lands" on the west side of Cook Inlet in 1962, followed by formation of the Beluga River unit, with each of the companies owning one-third.

Hilcorp said the first gas discovery at Beluga was in December 1962 and was made while exploring for a deeper oil objective, with regular gas production beginning in 1968.

## IVAN RIVER

The Ivan River unit was formed by Standard Oil Company of California in 1967, the Alaska Division of Oil and Gas said in approving the 52nd plan of development in May 2022.

The field averaged 12.15 million cubic feet per day in July, up 42.7% from a July 2021 average.

In its POD application Hilcorp said it began drilling a grassroots well, IRU 241-02, in the fourth quarter of 2021 but was not able to finish drilling due to ice conditions. It suspended the well and plans to begin drilling operations again in the third or fourth quarter of 2022. In the previous plan period the company completed a rig workover on the IRU 11-06, adding Beluga D sands.

For the new plan period, in addition to completing IRU 241-02, various non-rig well projects are planned, including coil cleanout operations and adding or isolating Sterling or Beluga sand perforations.

Planned facilities work includes installation of a tie-in pipeline and equipment upgrade on the IRU Pad after completion of the IRU 241-01 and installation of a heater/separator as needed following completion of the well.

The company also plans to upgrade the facility water disposal system on the IRU Pad.

## LEWIS RIVER, PRETTY CREEK

Hilcorp plans little activity at the smallest of its west side gas

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**HILCORP COOK INLET** *continued from page 39*

fields, Lewis River and Pretty Creek.

At Lewis River under the 2021 plan Hilcorp perforated Sterling A sands in the Lewis River A1 well but reported the work was unsuccessful. The division said production averaged 1,039 thousand cubic feet per day from June 1, 2021, through March 31, 2022.

Under the 2022 plan Hilcorp said it would continue to evaluate delineation drilling opportunities with the Sterling-Beluga and Tyonek participating areas, with various non-rig well projects planned.

At Pretty Creek, Hilcorp has been working to restore production which ceased in August 2019. The division said the company produced 1,807 thousand cubic feet, mcf, over a three-day period in January from the PC-02. Hilcorp said it continues evaluation of delineation drilling opportunities and plans various non-rig well projects.

## HILCORP PLATFORMS

There are 17 offshore oil and gas production platforms in Cook Inlet, 13 of them active, and Hilcorp Alaska operates 11.

The majority of Cook Inlet crude oil comes from these offshore platforms, 72% of the average 9,910 barrels per day in July, according to AOGCC data.

And of that 72%, 7,184 bpd in July, 6,233 bpd came from Hilcorp platforms — 87% of the platform volume (Hilcorp accounted for 79% of total Cook Inlet crude production in July).

The platforms account for a much smaller percentage of Cook Inlet natural gas production, just 32%, 59,450 thousand cubic feet per day in July out of a total of 186,922 mcf per day. Of that 59,450 mcf, Hilcorp platforms accounted for 76%, 45,264 mcf per day (overall, including its share of Beluga production, Hilcorp accounted for 82% of Cook Inlet natural gas production in July).

Hilcorp has five offshore units in Cook Inlet: Granite Point, Middle Ground Shoal, North Cook Inlet, North Trading Bay and Trading Bay.

PHOTO BY JUDY PATRICK, COURTESY OF HILCORP ALASKA LLC

**Hilcorp's Steelhead Platform (at the McArthur River field), first operated by Marathon Oil in 1986, rests atop four giant legs that house multiple wells. It's topped with a 150-foot derrick.**

### GRANITE POINT

AOGCC Pool Statistics show Granite Point 1, drilled by Mobil Oil Corp. in 1965, as the Granite Point discovery well. The unit is on the western side of Cook Inlet, west southwest of Tyonek.

In its June approval of Hilcorp's most recent Granite Point plan of development, the Alaska Division of Oil and Gas said Granite Point production began in 1967. There are three platforms at Granite Point, all installed in 1966: Anna, Bruce and Granite Point.

Granite Point produces both gas and oil. The division said that through April 30, 2022, cumulative production was 142.22 billion standard cubic feet of natural gas and 157.65 million stock tank barrels of oil.

In early 2016 the South Granite Point unit was expanded to include the Granite Point field and renamed the Granite Point unit. There are six state oil and gas leases in the unit, some 15,411 acres.

The GPU has two participating areas, the Hemlock PA and the Granite Point Sands PA, with production processed at the Granite Point Production facility.

In its POD for 2021, Hilcorp proposed sidetracking Granite Point St 31-23, but the division said the company was unable to do that work due to equipment incompatibility. Hilcorp also proposed mud acid workovers but told the division the mud acid jobs were contingent on concurrent mud acid work at Middle Ground Shoal "which is delayed indefinitely." MGS is currently shut-in following a 2021 leak in the fuel gas pipeline.

Hilcorp said it did complete field studies of the Anna and Granite Point platforms as part of its an evaluation of additional rotary development wells. "Prospects identified as part of this study require more subsurface and economic analysis to progress drilling," the company said.

For 2022, the POD for July 1, 2022, through June 30, 2023, Hilcorp said it would continue evaluation of additional rotary wells and access the feasibility of a reperforation campaign.

The company plans to perforate GP 24-13D2 to return that well to production.

### MIDDLE GROUND SHOAL

Hilcorp's Middle Ground Shoal — producing from the A and C platforms — is currently shut-in following a leak detected in April 2021 in the fuel gas pipeline of the Middle Ground Shoal

Fuel Gas System. All MGS production has been shut-in while Hilcorp determines whether to repair or replace the line, the division said March 22, in a decision approving an amendment and extension to the POD for MGS.

In March Hilcorp requested that the division extend the 2021 POD: "the MGSFGS repair project is now temporarily put on hold for the 2022 calendar year. Hilcorp analyzed the overall scope of the MGSFGS repair project and determined further studies are needed," the company said.

Hilcorp said it is assessing Southcentral Alaska's "gas needs to determine what part the Cook Inlet Offshore production will have in the overall supply plan" and said it will take six to nine months "to study alternatives and come up with a reasonable plan going forward."

Amoco Production's 1963 MGS State No. 1 Middle Ground Shoal discovery well "was the first offshore discovery in both Alaska and the Cook Inlet," the division said.

There are four platforms at MGS, two of which — A (installed in 1964) and C (installed in 1967) — are active. The Dillon Platform (installed in 1966) was lighthoused in 2003 and the Baker Platform (installed in 1965) in 2013.

In March 2021, prior to shut-in at MGS, its oil production averaged 1,226 barrels per day, 11.5% of Cook Inlet oil production, and natural gas averaged 218 mcf of natural gas, 0.1% of gas production.

In September 2021, Luke Saugier, senior vice president of Hilcorp Alaska, told the Cook Inlet Regional Citizens Advisory Council board that Hilcorp's efforts are going to focus on delivering natural gas to local markets, particularly from the Steelhead and Tyonek platforms where, he said, Hilcorp will be drilling for years to come.

## NORTH COOK INLET

Hilcorp's most productive gas platform is Tyonek at the North Cook Inlet unit, accounting for more than 12% of gas production in the basin in July and 50% of Hilcorp's production from its inlet platforms and is where the company has been the most active, using the Spartan 151 jack-up to sidetrack from shut-in wells at the field.

The platform was installed in 1968.

In a June POD approval the division said NCIU has been in production since 1969 and has produced 1,937 billion cubic feet of natural through the end of April 2022.

Hilcorp acquired the NCIU from ConocoPhillips in 2016.

The division said that during the 2021 POD period, Hilcorp drilled three sidetracks of existing shut-in wells as well as doing various rig and non-rig well projects, with the result that production in 2021 was 7,100.3 million standard cubic feet of gas, "a substantial increase from the 2020 production volume of 5,681.1 million standard cubic feet."

Hilcorp has been using the Spartan 151 jack-up at North Cook Inlet, both to plug and abandon a well dating from 1962 and for drilling from the platform.

In its 2022 POD Hilcorp said it has identified seven sidetrack and grassroot well prospects at North Cook Inlet, with some to be drilled in the 2022 POD period (July 1, 2022, through June 30, 2023) and some later. Wellwork and workover programs are also planned, as well as work on the Tyonek Platform.

*continued on page 42*

**HILCORP COOK INLET** *continued from page 41*

Hilcorp also said it planned further review of Beluga and Sterling gas potential accessible via rig workover or sidetracks of existing wells.

The company said the grassroots well will target Beluga and Sterling formations, as will the sidetrack operations.

In July, AOGCC data show 10 producing gas wells at North Cook Inlet

### NORTH TRADING BAY

Hilcorp is attempting to bring the North Trading Bay unit back into production by drilling from the Monopod at the Trading Bay unit.

North Trading Bay was produced from the Spurr and Spark platforms (both installed in 1968), but production ceased in 2005 and the platforms are in lighthouse mode. Hilcorp told the division in 2017 that it would not be economic or technically feasible to return the platforms to production. Instead, the company is attempting to restore North Trading Bay to production by drilling from the Monopod.

Wells were proposed for this purpose in both 2018 and 2019, but not drilled, after which the division denied the proposed POD and administratively terminated the unit. Then-DNR Commissioner Corri Feige reversed that decision on appeal, inviting Hilcorp to submit a new POD allowing the company 16 months to identify drill targets which it would have until the end of the subsequent POD period to drill.

If that drilling was not done, the NTBU would automatically terminate.

The division approved the 2021 POD in September 2021 for a period of Oct. 15, 2021, through June 30, 2023, requiring quarterly updates.

In early August the division responded to a second quarter update, noting that Hilcorp made two attempts to sidetrack the A-10RD2, both unsuccessful, but did install surface facility equipment and a production meter on the Monopod to accommodate production from the sidetrack.

The division said that met the obligations under a 2019 decision reversing termination of the North Trading Bay unit.

### TRADING BAY

The Trading Bay unit includes the McArthur River and Trading Bay fields.

In a June approval of Hilcorp's 2022 POD for the unit, the division said the unit was formed and began production in 1967.

There are five platforms: the Monopod, installed in 1966; King Salmon, Grayling and Dolly Varden, all installed in 1967; and Steelhead installed in 1986.

There are four participating areas in the McArthur River Field: Hemlock Oil Pool PA; West Foreland Oil Pool PA; Middle Kenai "G" Oil Pool PA; and Grayling Gas Sands PA.

In an expansion approved in 2013, the Trading Bay field was added to the TBU.

McArthur River is a major producer, averaging 18,006 mcf per day in July, 9.6% of Cook Inlet production, and 2,850 bpd of crude, 28.8% of Cook Inlet production. Trading Bay averaged 1,242 mcf per day of natural gas in July, 0.7% of inlet production, and 983 bpd of oil, 9.9% of inlet production.

Under the 2021 POD, Hilcorp did two workovers, replacing a failed electric submersible pump in one well and doing a fill cleanout and gravel pack in another well.

In addition to those planned rig workover projects, Hilcorp listed 18 other rig and non-related wellwork projects it completed, with three more projects planned for the remainder of the 2021 POD period.

The company also did planned work at the King Salmon, Steelhead and Monopod platforms — including completion of new crew quarters on the Monopod.

In the 2022 POD, which covers July 1, 2022, through June 30, 2023, long-range development activities include:

*Continuing evaluation of existing completions for rig workovers "to optimize the drawdown and lift mechanism at McArthur River Field wells."

*Continuing GGS field study work to identify additional subsurface opportunities.

*Continuing work on a Trading Bay field study "to identify additional rig workover, rotary sidetrack, perforation adds, fill cleanouts, and waterflood activation opportunities."

Various wellwork and workover projects are planned.

On the Monopod, Hilcorp said facility upgrades "to support gas stream A-10RD2 from NTBU are being installed," with repairs or replacement equipment to be installed as needed.

## KENAI PENINSULA

Hilcorp Alaska operates fields on the Kenai Peninsula including early discoveries and its most recent development. The largest gas producer is the Ninilchik unit, which Hilcorp acquired from Marathon Oil in 2013.

In addition to unitized production, Hilcorp has a tract operation at Nikolaevsk, which produced just 271 mcf of natural gas in July, making it among the lowest gas producers.

Hilcorp has also wrapped up work Birch Hill, a gas discovery in the Kenai National Wildlife Refuge with a single well drilled by Union Oil Company of California in 1965, but never put on production. Hilcorp acquired Birch Hill when it took over Chevron/Unocal's Cook Inlet assets in 2011, and under a plan approved by BLM put in a temporary gravel road and plugged and abandoned the well earlier this year.

### NINILCHIK

Hilcorp has been most active recently at the Ninilchik gas field, one of the largest in Cook Inlet and also one of the newest inlet fields to come on production.

AOGCC pool statistics show a discovery by Standard Oil Company of California in 1961 and various other early wells but the field was not developed until Marathon Oil formed the unit in 2001. Continuous production began in 2003.

Hilcorp acquired Ninilchik from Marathon in 2013. In its July approval of the 18th POD for Ninilchik, effective Aug. 1, 2022, through July 31, 2023, the Alaska Division of Oil and Gas said cumulative production through the end of 2021 was 248.2 billion cubic feet of gas, with 11.1 bcf produced in 2021 and average production in that year of 30.5 million cubic feet per day.

AOGCC records show the field averaged 31,903 mcf per day in July, 17% of inlet production and the highest producing gas field that month, up 4.7% from a July 2021 average of 30,483 mcf per day, 15.4% of inlet production, and the second highest producing gas field in that month.

During the 2021 POD Hilcorp drilled three rotary sidetrack wells, Paxton 11, Kalotsa 8 and Pearl 2A, with the Paxton and Kalota wells targeting the Beluga and Tyonek sands and the Pearl well targeting Tyonek sands.

The company also completed 30 workover and well projects at the unit.

Under the 2022 POD, the division said Hilcorp may drill as many as three wells — Paxton 6, Pearl 8 and Pearl 9 — with a perforation add possible at Blossom 1, a well drilled in 2015.

Hilcorp has also applied to expand the Paxton Pad and design a pad expansion and facilities at Pearl Pad. The Pearl Pad expansion would accommodate gas production from Pearl 2A and additional delineation wells. The company has permitted the Pearl 8 and Pearl 9 wells and said in an Aug. 22 application to the division that Pearl 8 was in progress.

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**HILCORP COOK INLET** *continued from page 43*

## KENAI

The Kenai gas field was discovered in 1959 by Union Oil Company of California with regular production beginning in 1961, AOGCC said in its pool statistics.

The Kenai unit has federal leases and is managed by BLM.

The 64th plan for the Kenai unit, filed by Hilcorp in March, was approved in April for the period April 1, 2022, through March 31, 2023.

AOGCC data show Kenai averaged 26,593 thousand cubic feet, mcf, per day in July, 14.2% of Cook Inlet gas production, down 20% from July 2021.

During the 2021 plan, Hilcorp said 15 projects were executed, including conversion of two wells from shut-in to producing. There were numerous facilities projects, including beginning of construction on 24-inch low pressure and 20-inch medium pressure flowlines, beginning of installation of new compressors on pad 34-31 and conversion of existing and installation of new flowlines, electrical and instrumentation to accommodate wells being returned to production.

During the 2022 plan, Hilcorp said its workover program includes up hole recompletions, perforation adds and rig workovers. Construction will be completed on the 24-inch low pressure and 20-inch medium pressure flowlines, the new compressor installation on pad 34-31 and 20-inch and 16-inch sales pig launcher/receiver installations.

## BEAVER CREEK

In the 55th plan of development and operations for Beaver Creek in the Kenai National Wildlife Refuge approved by BLM in April, Hilcorp said that a well in the 2021 54th plan, Beaver Creek unit 18RD, would be spud. AOGCC records show the well was spud in April and completed in May.

The company completed two planned workovers in 2021, both "reservoir and mechanical successes. As a result of the work, Beaver Creek now has two online oil wells and another productive gas well," Hilcorp said. The company also completed wellwork in addition to that in the 2021 plan.

In its plans for 2022, covering April 1, 2022, through March 31, 2023, Hilcorp said it anticipates one sidetrack well and will evaluate drilling another well, with workovers planned for two gas wells and one oil well.



*The 64th plan for the Kenai unit, filed by Hilcorp in March, was approved in April for the period April 1, 2022, through March 31, 2023.*

The company also plans to install a new crude oil storage tank "to assist with handling Beaver Creek's increased oil production following the 2021 workover at BCU-04RD."

AOGCC pool statistics show Marathon Oil discovered gas at Beaver Creek in 1967 and oil in 1973.

In July, Beaver Creek averaged 792 bpd of oil, 8% of Cook Inlet production, up 102% from July 2021, and 12,847 mcf per day of natural gas, 7% of inlet production, and up 47.5% from July 2021.

## SWANSON RIVER

Swanson River, discovered in 1957, is the oldest Cook Inlet field. AOGCC pool statistics say continuous production began at Swanson River in 1958 and peaked in 1967 at an average of 38,323 bpd.

AOGCC data show Swanson production in July was 801 bpd, 683 bpd of crude and 118 bpd of natural gas liquids, 8% of inlet liquids production, along with 8,032 mcf per day of natural gas, 4.3% of gas production.

Hilcorp's plan of development and operation for the unit, the 58th, was approved by BLM in May, covering April 1, 2022, through May 31, 2023.

In its summary of the 2021 POD, Hilcorp said it has a new subsurface team in place and will continue work to identify "remaining Sterling, Upper Beluga, and Tyonek gas in Blocks 3, 4, and 5; remaining oil reserves across the field in the Tyonek G-Zone; and potential oil prospects to target with CTD drilling."

Hilcorp said subsurface review led to drilling in the Central Fault Block, Block 5, in 2021, with a new gas well successfully drilled through the Sterling, Beluga and Tyonek formations, producing first gas in early October. The company said work by the subsurface team will inform targets for 2022 drilling, while further study of the Tyonek G-Zone is required before it launches a coil tubing drilling program.

Two planned workovers were completed in 2021, as well as six additional workovers.

For the 2022 plan, Hilcorp said it will continue reviewing to identify remaining reserves with the potential for a coiled tubing drilling campaign in 2023.

A well is planned for the Northern Fault Block in 2022 and a well will be evaluated as a CTD sidetrack for Hemlock and G-zone oil play with another being evaluated as a CTD sidetrack for Hemlock and G-zone oil pay during the second quarter of 2023.

Hilcorp has a substantial list of planned workovers and also a substantial list of facilities/other operations.

## CANNERY LOOP

In its approval of 43rd plan for Cannery Loop the Alaska Division of Oil and Gas July 8 said the field's annual production in 2021 was 1.7 bcf, compared to 1.9 bcf in 2020. That plan covers Aug. 1, 2022, through July 31, 2023.

In July, AOGCC data show the field averaged 6,521 mcf per day, 3.5% of inlet gas production, up 58% from July 2021, when it averaged 4,135 mcf per day, 2.1% of inlet production.

In Hilcorp's plan of development, submitted in April, the company said that during the 2021 POD it added perforations to two wells and planned to complete additional rig and non-rig workovers prior to the end of the 2021 plan.

In the 2022 POD Hilcorp said it is evaluating drilling additional wells for Beluga and Tyonek sands, depending on "current risked resource and economics, market demand, pipeline & compressor capacity, and competitiveness within Hilcorp's gas project portfolio."

One grassroots well would target the Beluga and Tyonek formations, the company said, "pending results from initial sidetrack drill well results." Up to three sidetracks are also anticipated.

The company plans to install a sales compressor on one of the Cannery Loop pads to handle increased throughput from the facility. That work is planned for the third quarter of 2022. The division approved the compressor installation in a May amendment to the POD.

### DEEP CREEK

Hilcorp Alaska's Deep Creek unit is managed by the Alaska Division of Oil and Gas and Cook Inlet Region Inc. It was formed in 2001 and the division said in its July 8 approval of the 19th POD for the unit that sustained production began from the Happy Valley participating area in November 2004. Hilcorp took over as operator in January 2012 and in July 2019 the unit was contracted to the PA and has 1,240 acres.

Cumulative production through the end of 2021 was 40.9 bcf of gas.

AOGCC data show an average daily production of 3,233 mcf in July, down 13.4% from July 2021 production averaging 3,734 mcf per day.

The division said that under the 2022 POD, effective Aug. 31, 2022, through July 31, 2023, Hilcorp will evaluate either drilling a sidetrack from the HVB 16 well or drilling the HVB 18 well; both would target the Tyonek formation. Wellwork opportunities will be evaluated and executed as they arise.

### SEAVIEW

Seaview is Hilcorp's newest gas field and the farthest south production on the Kenai Peninsula. The division said in a June plan approval that the unit was approved in August 2020. In the previous, 2021 POD, Hilcorp proposed completing a pipeline to the Seaview 8 well and beginning production, drilling the Seaview 9 and an additional well adjacent to the Seaview unit, Whiskey Gulch 1.

The division said those operations were completed.

During the 2022 plan of operation, approved in June and covering Aug. 1, 2022, through July 31, 2023, the division said Hilcorp plans to continue evaluating results from the Seaview 9 and possibly complete additional perforations. The compressor currently at the Seaview 1 pad will be exchanged for a smaller model. Hilcorp said in its plan that the current compressor was needed at the Cannery Loop unit.

Seaview began production in June 2021. In July 2022, AOGCC data show production averaged 238 mcf per day, down 78.1% from a July 2021 average of 1,085 mcf per day. ●

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PHOTO BY JUDY PATRICK, COURTESY OF HILCORP ALASKA LLC

Hilcorp's Innovation Rig drilling Milne Point Unit – S Pad.

# Hilcorp in the Arctic

*Company operates Prudhoe, Slope's largest field, Milne, where it has substantially upped production, Endicott, Northstar, Point Thomson*

**By KRISTEN NELSON**
Petroleum News

Hilcorp started operating in Southcentral Alaska's Cook Inlet in 2012 and moved onto the North Slope in 2014.

It took over operatorship at Prudhoe Bay, the North Slope's original and largest producing field, in mid-2020 after acquiring BP Exploration (Alaska)'s remaining Alaska assets. In addition, it operates Milne Point and Northstar, where it has 100% working interest ownership, and the Duck Island unit (Endicott) where is holds a majority WIO. Most recently, Hilcorp took over as operator at Point Thomson, where ExxonMobil Production holds the majority WIO.

## PRUDHOE — ALASKA'S LARGEST OIL AND GAS FIELD

### INITIAL PARTICIPATING AREA

The Prudhoe Bay unit was formed in June 1977 and currently includes 254,235 acres with average ownership of 26.36% Hilcorp North Slope, 36.4% ExxonMobil Alaska Production, 36.08% ConocoPhillips Alaska and 1.16% Chevron U.S.A., the Alaska Department of Natural Resources' Division of Oil and Gas said in its June 2022 approval of the 2022 plan of development for the IPA, the Initial Participating Area.

(Note: Chevron is reported to have its North Slope assets, including its share of Prudhoe, up for sale.)

There are 12 participating areas at Prudhoe, including the Oil Rim PA and Gas Cap PA — the IPA — the focus of the division's June decision on the 2022 POD.

Operator Hilcorp North Slope reported production of an average of 161,203 barrels per day of oil in calendar year 2021 from the IPA, which the division said was down from an average of 166,578 bpd in 2020.

In its March 2022 POD, covering July 1, 2022, through June 30, 2023, Hilcorp said development of the Permo-Triassic reservoir at Prudhoe began with the Prudhoe Bay State No. 1 exploratory well in 1968, with regular production in June 1977. Produced water injection began at production with large-scale waterflood for secondary recovery installed in August 1984 and miscible gas for water-alternating-gas injection, WAG, for tertiary recovery

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**HILCORP NORTH SLOPE** *continued from page 46*

beginning in June 1987.

Hilcorp said 830 producers and 223 injectors contributed to IPA production or injected water and gas in calendar year 2021. Returning idle wells to service, optimizing production through existing infrastructure and improved operational efficiency were the focus, Hilcorp said, with an increase in fluid handling from 2020 to 2021.

A rig workover program optimized and/or returned to service 13 IPA wells in 2021, and there was also an improvement in natural gas liquids volumes "from successful crude cooling project execution and amendment to the Pump Station 1 crude volatility restrictions."

There was an overall increase of 18 IPA wells online from 2020 to 2021, Hilcorp said.

There were initially no plans to drill in the IPA in the 2021, but Hilcorp said that when the oil price recovered in mid-2021, the working interest owners approved a drilling plan, with two coil tubing sidetracks likely to be completed in the POD period. The company said earlier IPA drilling programs had "focused on coil tubing sidetracks to advance infill opportunities."

Hilcorp said it anticipated completing as many as 15 workovers or recompletes during the 2021 POD, with nine wells worked over to date, six producers to restore tubing integrity and two wells to install autonomous inflow control device retrofit liners to control high gas-to-oil ratio. One well was recompleted from the IPA to the Polaris pool in the Western Satellites area.

Eleven workovers are planned during the remainder of the 2021 POD, nine producers and two gas injectors.

The company said non-rig well intervention activity increased in 2021, with 855 interventions in the IPA to date during the 2021 POD, 501 IPA wells with annular communication work and surveillance drifts for subsidence monitoring excluded.

The 2021 POD included major facility projects, including seawater treatment plant maintenance and upgrade; a Flow Station 2 turnaround including multiple inspections, valve replacements, gas conditioning improvement and crude cooler install; continuing the 69kV power upgrade to increase power reliability fieldwide; pig launch/receiver valves installed in common lines 12B and 9A; continued subsidence related repairs/improvements to pipelines and facilities; and field testing and full implementation of internal automated digital radiographic testing crawler inspection technology "to comprehensively evaluate the integrity of pipelines in PBU that cannot undergo an In-Line Inspection." Hilcorp said more than 53,000 feet of internal pipeline crawler inspections have been completed since July 1, 2021.

## IPA 2022 POD

Up to 11 new wells are planned during the 2022 POD, with candidates at W, H and N pads and drill sites 11, 3 and 9 targeting the Ivishak or Sag River formations, Hilcorp said.

Flat to slightly increasing well intervention activity is anticipated, with the focus on maintaining existing well stock and increasing production through non-rig rate enhancement.

A number of major facility projects are planned.

- A seawater treatment plant process heater upgrade is planned to lower STP emissions and improve process reliability.
- Gathering Center 2 C and D slug catcher sand jetting system reinstatement and upgrade to improve solids and water handling capabilities.
- GC2 lower pressure compressor major overhaul to improve reliability.
- Previously planned turnaround activities at Flow Station 3 and Gathering Center 3 have been segregated into 2022 and 2023 work scopes for each facility, with 2022 work to include electrical preventative maintenance, wet gas corrosion inhibitor quills and delivery system installation, FS3 bank slug catcher cleanout, inspection and repairs and pressure safety valve testing and other repairs and maintenance at both facilities.
- FS1 C Train vessel cleanouts and repairs.
- Lisburne Production Center rich gas compressor install was planned for the 2022 POD period, "but supply chain constraints may cause execution to slip into the 2023 POD period," Hilcorp said.

There will also be ongoing maintenance and integrity management.

Long range, Hilcorp said, it continues to evaluate future drilling opportunities as well as evaluating potential undeveloped resources.

## GREATER POINT MCINTYRE AREA

Greater Point McIntyre area PODs for 2021 and 2022 show drilling, workovers and facility projects.

GPMA, the eastern area of the Prudhoe Bay unit, has six participating areas: Combined Niakuk, Lisburne, North Prudhoe Bay, Point McIntyre, Raven and West Beach.

In its Aug. 18 approval of the 2022 plan of development for Greater Point McIntyre, effective Oct. 1, 2022, through Sept. 30, 2023, the Alaska Division of Oil and Gas said initial production began in the GPMA in December 1986 at the Lisburne PA, currently producing from the Wahoo and Alapah formations.

The Combined Niakuk, West Beach, North Prudhoe Bay and Point McIntyre PAs began sustained production between 1993 and 1994.

West Beach briefly produced in 2009, the division said, but other than that, both West Beach and North Prudhoe Bay have been shut-in since 2000 and 2001, respectively.

Point McIntyre and Combined Niakuk continue to produce from the Cretaceous Kuparuk River formation, while the most recently formed PA, Raven, began production from the Ivishak and Sag River formations in 2005.

The division said cumulative GPMA production through June 2022 was 828.67 million barrels of hydrocarbon liquids, and from April 1, 2021, through March 31, 2022, production was 9.364 million barrels, "a slight decrease from the same period over the previous year."

## GPMA PODS

In its 2022 POD for GPMA, submitted in June, Hilcorp North Slope said production from April 1, 2021, through March 31, 2022, was 9,564,000 barrels of oil and 1,312,000 barrels of natural gas liquids, with average production of oil 29,797 barrels per day.

The company said since it took over as operator at GPMA it "has focused on returning idle wells to service, optimizing production through the existing surface infrastructure, targeting reservoirs that had been under-developed, improving voidage

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**HILCORP NORTH SLOPE** *continued from page 48*

replacement, and improving operational efficiency," leading to a 0.5% year-on-year increase in oil production from April 1, 2020-March 31, 2021, to April 1, 2021-March 31, 2022.

Under the 2021 POD, four coil tubing sidetracks were completed — two in the Lisburne PA and two in the Point McIntyre PA, with three additional CTD wells planned to be completed during the 2021 POD period which ends Sept. 30, two at the Lisburne PA and one at the Point McIntyre PA.

Those PAs are the most productive at GPMA, Lisburne accounting for 3.262 million barrels and Point McIntyre 5.367 million barrels between April 1, 2021, and March 31, 2022.

As many as three well workovers with the Thunderbird 1 workover rig were proposed, but none had been completed when the POD was submitted, although two were expected to be completed prior to the end of the 2021 POD period.

Long-lead materials were ordered and engineering completed for the Lisburne Production Center Rich Gas to CGF, with completion expected in the 2022 POD period.

During the 2021 POD Hilcorp completed the L5 Pipeline replacement project, with an initial increase of 700 bpd from debottlenecking the L5 and NK drill sties.

A project to route L2 production to drill site 18 is in construction and expected to be completed by the end of June 2022, Hilcorp said, debottlenecking LPC's gas compression and resulting in an increase of some 400 bpd.

In the 2022 POD, Hilcorp said it anticipates drilling as many as four new wells, with potential CTD sidetracks in the Lisburne and Point McIntyre PAs and an additional rotary well planned for the Raven PA.

Up to four well workovers with the Thunderbird 1 are contemplated in the Lisburne and Combined Niakuk PAs.

Under facility projects, Hilcorp said the LPC Rich Gas to CGF is expected to be completed during the 2022 POD.

Long range projects include evaluating future drilling opportunities and additional facility capacity expansions.

## WESTERN SATELLITES

There are five participating areas in the Western Satellites area at Prudhoe: Aurora, Borealis, Midnight Sun, Orion and Polaris. In its December 2021 approval of the 2022 POD (Jan. 1, 2022, through Dec. 31, 2022) for the area the Division of Oil and Gas said Aurora, Borealis and Midnight Sun produce primarily from the Kuparuk River formation while Orion and Polaris produce from the Schrader Bluff formation.

Through October 2021 the Western Satellites have cumulatively produced 239.4 million barrels of oil and 450.42 billion cubic feet of gas, the division said.

While Hilcorp did not initially propose a drilling program in its 2021 POD, it did plan up to 10 workovers or recompletions. In July 2021 the company amended the 2021 POD to include up to six wells at the Orion PA.

Hilcorp said that since taking over as operator it has focused on returning idle wells to service, optimizing production, targeting under-developed reservoirs, improving voidage, maximizing miscible injection utility and improving operational efficiency.

The company said there was a 43% year-on-year production increase, 2.837 million barrels, July 2019-June 2020, to July 2020-June 2021, a total of 9.417 million barrels in the latter period: Polaris, 2.71 million; Borealis, 2.59 million, Aurora, 2.18 million, Orion, 1.48 million and Midnight Sun, 0.46 million.

One well at Orion was spud in September 2021 and Hilcorp said it planned to drill five additional wells in the remainder of the 2021 POD period.

Two Borealis PA workovers were completed, a well repaired at Orion, along with two rig workovers at that PA; at Polaris three rig workovers were planned for additional injection.

For the 2022 POD, Hilcorp said it anticipated completing up to 10 new wells, with candidates at Aurora, Borealis, Orion and Polaris; no drilling was planned at Midnight Sun.

As many as three workovers or recompletes were also planned, along with evaluation of facility work.

Long-range activities included continued evaluation of future drilling opportunities and a polymer pilot at Polaris; the company is also conducting front-end engineering studies on L Pad expansion and V Pad gas separation.

Hilcorp proposed, and the Alaska Oil and Gas Conservation Commission approved, amendments to existing AOGCC orders to remove well spacing requirements within the Aurora, Borealis, Midnight Sun and Polaris oil pools. In its approvals the commission said the change reflected current drilling and completion practices and would allow for optimal development of the pools.

## MILNE POINT

Milne Point is the North Slope field where Hilcorp has had the greatest impact, taking over as operator in 2014 when it acquired 50% of BP Exploration (Alaska)'s working interest ownership in the field and acquiring the other 50% when it acquired all of BPXA's Alaska assets in the deal which closed in mid-2020.

Milne Point development began in the 1980s under Conoco. The field has had two surges of development, the first in 1994 after BP took over and the second 20 years later, after Hilcorp became operator.

Milne Point produced 7.1 million barrels of oil in calendar year 2014; in 2021 it produced 13 million barrels, according to Alaska Oil and Gas Conservation Commission data, with 393.1 million barrels of oil produced from 1985 when production began through July 2022.

## PLANS OF DEVELOPMENT

Recent plans of development for Milne Point indicate the work Hilcorp is putting into the field.

In its November 2021 approval of the 2022 POD, the Alaska Department of Natural Resources' Division of Oil and Gas said there are some 50,000 acres in the Milne Point unit, which was formed in 1979.

For September 2020 through August 2021, production averaged 35,329 barrels per day, an increase of 12% from a September 2019 through August 2020 average of 31,592 bpd, the division said.

The field averaged 38,321 bpd in July 2022, AOGCC data show, up 9.9% from a July 2021 average of 34,861 bpd.

## WORK DONE DURING 2021 POD

The division said that in its 2021 POD, Hilcorp proposed drilling as many as 17 wells and doing up to 20 workovers, with an amendment in February 2021 for five wells, 11 workovers and a coil tubing drilling program of seven wells.

The division said that through November 2021, Hilcorp had drilled 12 wells in the Schader Bluff formation with additional wells deferred; 12 workovers had been completed; and five coil tubing wells drilled.

Hilcorp said it completed all five wells anticipated at S Pad, three Schrader Bluff Nb sand injectors and two Schrader Bluff Nb sand producers.

Fourteen wells were anticipated on I Pad, Hilcorp said, of which five were completed, a vertical Schrader Bluff sands injector, two horizontal Schrader Bluff Oa sand producers and two Schrader Bluff Oa injectors.

Hilcorp said the remaining nine wells "were put on hold due to completion equipment availability and desire to observe results from the first two producer/injection patterns in each sand."

At J Pad, three wells were anticipated and Hilcorp said it drilled two, a horizontal producer and horizontal injector, both into the Schrader Bluff Nb sand. Due to complications with running completions in the completed wells, the third well was deferred.

Hilcorp planned workovers using the ASR1 workover rig and the Doyon 14 workover rig, but those scheduled for the Doyon 14 were cut from the schedule after work to install a 4-1/2-inch screened liner inside an existing 6-5/8-inch liner on the M-26 well was unsuccessful.

As many as 20 workovers were anticipated using the ASR1, Hilcorp said, but budgetary constraints and fewer electric submersible pump failures resulted in just 11 workover operations being executed.

Seven coiled tubing drilling operations were anticipated. At C Pad, two wells were successfully sidetracked. At L Pad, four sidetrack were anticipated and two were competed. One of the four was deferred on complexity issues and one was

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**HILCORP NORTH SLOPE** *continued from page 51*

deferred due to prior well results.

The company said it anticipated sidetracking an L Pad well in December 2021.

### 39TH POD FACILITY PROJECTS

Eight facility projects were completed during the 2021 POD.

Three polymer facilities were installed and started up, one each on Moose, I and E pads.

At S pad the company did polymer engineering/procurement and header expansion and polymer facility.

A fuel gas compressor was installed and started up, a transformer was replaced on Tract 14 and at L Pad the polymer systems were upgraded.

A number of facility projects anticipated during the 39th POD were deferred, Hilcorp said:

•2020 shutdown for A Train process vessel inspections and upgrades was deferred because historical data and external inspections suggested the work could be delayed another year.

•At B Pad, internal economic evaluation was not completed so a gas injection compressor installation and startup was not done.

•A project tied to A Train shutdown, V-5304 Grid replacement, was deferred.

•Replacement of test separator at S Pad was deferred to 2022 and a G Pad test separator was replaced instead.

•Solar Titan 130 power generator engineering/procurement was not done because power demand did not increase as anticipated.

•Diesel tank to slop oil tank conversion was deferred in favor of other projects.

### 40TH POD

In the 40th POD, Jan. 13, 2022, through Jan. 12, 2023, Hilcorp said it anticipates drilling as many as 17 new wells, with potential drilling candidates including 10 I Pad Schrader Bluff wells, six producers and four injectors, and seven M Pad or B Pad Schrader Bluff wells, four producers and three injectors.

In February the division approved a POD amendment request from Hilcorp to drill a development well at B Pad and in April the division approved an amendment to the POD for five development wells at B Pad.

The proposed sidetrack drilling program includes six wells: B-16 at B Pad; C-02 and C-19 at C Pad; E-17 at E Pad; and K-02 and K-17 at K Pad.

Hilcorp said key facility projects many include:

•F Pad power fluid separation system installation — in August the division approved an amendment to the POD for a separator unit at F Pad.

•B Pad polymer unit installation.

•M Pad upgraded polymer unit installation.

•S Pad multiphase meter replacement.

•E Pad production header replacement.

•J Pad water softening system installation — for polymer make down and dilution.

•Installation of new produced water treatment equipment at the CFP.

•Solar Titan 130 power generator engineering/procurement.

Hilcorp said other projects may include but are not limited to:

•B Pad gas injection compressor installation.

•E Pad power fluid booster installation.

•L Pad second polymer unit installation.

•Shutdown for A Train process vessel inspections and upgrades.

•Diesel tank to slop oil tank conversion.

•Tract 14 production heater installation.

•M Pad water softening system installation.

•S Pad produced water treatment equipment installation.

Hilcorp said it is evaluating several potential long-term activities:

•Future drilling opportunities on undeveloped acreage in the northwest of the unit, particularly net profit share leases, and on previously developed acreage from I, H and S pads in the Schrader Bluff participating area.

•Evaluation of continued performance from Ugnu horizontal producing well S-203.

•Continuing evaluation of infill drilling opportunities in the Kuparuk sands.

### UGNU

Hilcorp requested approval of a pilot polymer injection program for the Ugnu at S Pad from AOGCC. The commission approved the request in April.

Hilcorp said the project builds on work begun by BP in 2003 and is for a subset of the S Pad development area.

The company began using polymer injection for Schrader Bluff oil at Milne Point in 2018 and said in that year that it expected polymer to increase Schrader recovery from 10% to 15% of oil in place at Milne to as much as 50%.

In its April approval AOGCC said the first well in the Milne Point unit, drilled and suspended in 1969, found oil in the Ugnu and Schrader Bluff intervals and also discovered the underlying Kuparuk River oil pool.

The commission said Ugnu production at Milne began in November 2003 and continued sporadically until 2013 from five wells. Since 2019 there has been a single Ugnu producer at Milne, MPU S-203, with cumulative production of 185,408 barrels, the commission said in April (its data records through July show cumulative production of 217,128 barrels from that well) in addition to cumulation production of 122,062 barrels from the five earlier wells.

## POINT THOMSON

Hilcorp Alaska took over as operator at the Point Thomson unit effective Jan. 1, 2022, following an agreement by the working interest owners in October 2021 and regulatory approval by the state.

ExxonMobil Production, the former operator, retains its working interest ownership at Point Thomson, where it holds the largest ownership position, 63.36%. Hilcorp Alaska holds 36.99%, while combined others hold 0.65%. ExxonMobil also holds the largest WIO position at Prudhoe Bay, 36.4%, where Hilcorp North Slope operates.

Point Thomson has two-year plans of development, so the current plan, approved in November 2021 by the Alaska Division of Oil and Gas, covers Jan. 1, 2022, through Dec. 31, 2023. That plan, approved when ExxonMobil Alaska Production was still operator, committed to the continuation of production from current facilities and the continued evaluation and communications with third parties concerning potential major gas sales.

The Point Thomson unit was approved in August 1977, the division said, although sustained production did not begin until April 2016 following litigation resulting in the 2012 PTU Settlement Agreement, modified in September 2018 by the PTU Letter Agreement, which provided, among other things for biennial PODs.

### LETTER AGREEMENT

The September 2018 Letter Agreement is focused on an Alaska LNG Project and suspends work on evaluation and selection of a PTU expansion project until the Department of Natural Resources provides notice to all parties in the Settlement Agreement that either there is a final investment decision on an Alaska LNG Project, or work on the Alaska LNG Project is no longer progressing.

If there is a final investment decision for an Alaska LNG Project, the Point Thomson owners "will provide to DNR work plans and project activities to develop Point Thomson Reservoir for Major Gas Sales through the Alaska LNG Project" and if that project is suspended, then the PTU WIO will have 30 months to resume work on suspended portions of the Settlement Agreement, including to commit to a Point Thomson expansion project.

### AOGCC ON IPS

In Conservation Order 719 the Alaska Oil and Gas Conservation Commission required that ExxonMobil, then the Point Thomson operator, provide a report on Initial Production System results by Nov. 1, 2023. In April 2021, ExxonMobil requested that requirement be amended, a request AOGCC granted in January 2022.

The commission said CO 719 had required the Thomson Oil Pool operator to submit IPS results 5 years after the beginning of sustained production or 12 months before gas sales from Point Thomson were scheduled to begin, whichever came first.

The commission said in its January decision that while Thomson Oil Pool production began in Aril 2016, "during the first two and a half years of production and plant commissioning, the plant was rarely able to produce at full capacity for any length of time and was often offline completely."

By November 2018, AOGCC said, "the plant was fully commissioned and operating stably for extended periods of time," but because of frequent production upsets prior to that, "the data from April 2016 through October 2018 does not provide an accurate means by which to determine the reservoir performance, and in turn the viability of the gas cycling project in the TOP."

A results report from the first 5 years after stable production was achieved, "will provide a more accurate depiction of reservoir performance than to have it based on 2.5 years of erratic production followed by 2.5 years of steady production," AOGCC said.

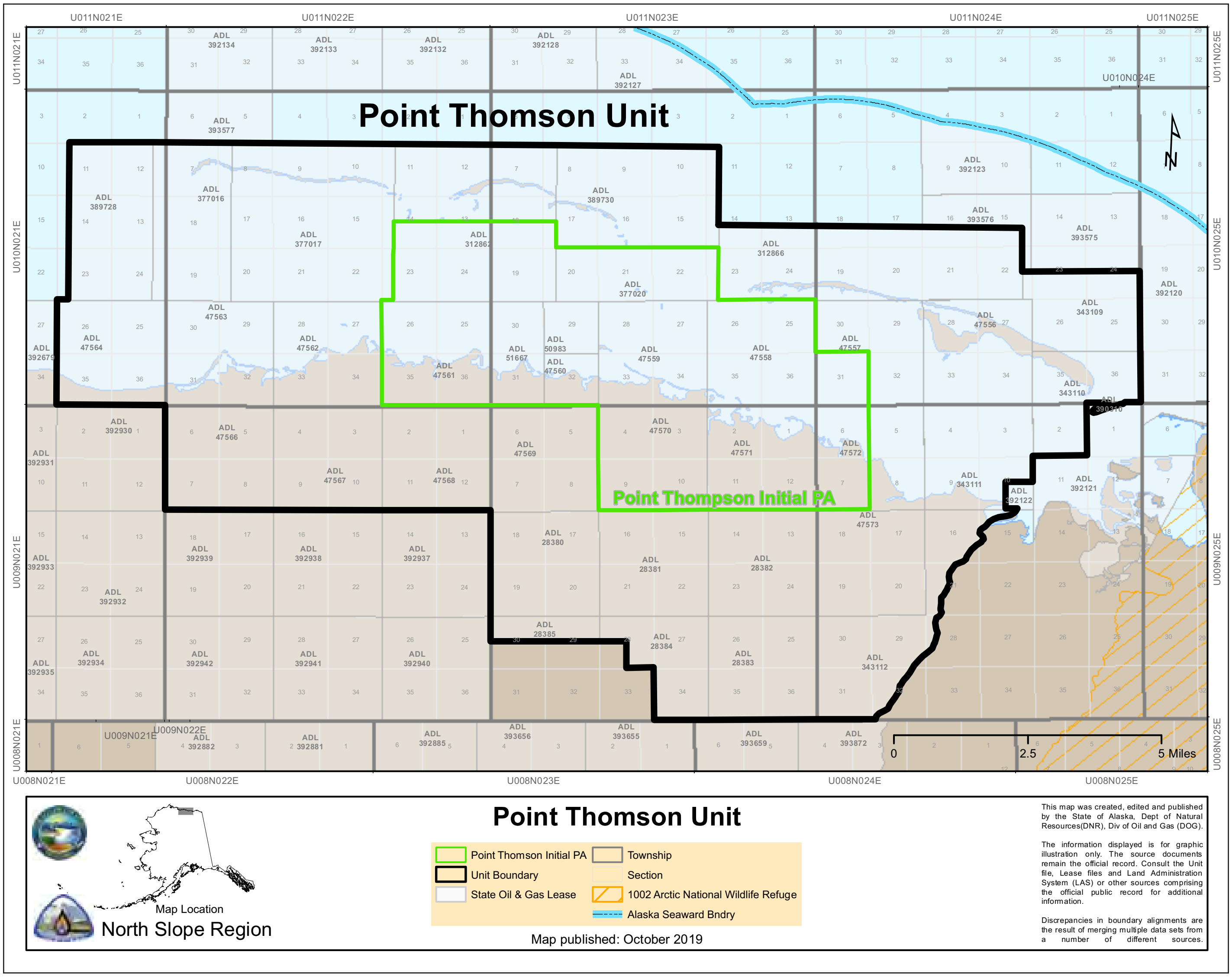
The new requirement says the IPS results report is due: "By November 1, 2023, or 12 months before gas sales from Pt. Thomson are scheduled to begin, whichever comes first."

That report is required to contain:

"A description of what the operator expected the IPS to show about the performance of the Thomson Oil Pool and the fluids contained within before the IPS project began producing."

The report also requires information on what the IPS actually showed about TOP performance and the fluids in the pool; a discussion, with supporting data, on whether the IPS showed the TOP was compartmentalized; a discussion, with data, on what the IPS

*continued on page 54*




**HILCORP NORTH SLOPE** *continued from page 53*

showed about properties of the reservoir fluids; and a discussion on whether "the development method proposed in this order is still the best method to optimize ultimate recovery and prevent waste."

## CURRENT PRODUCTION

AOGCC data shows Point Thomson averaged 9,143 barrels per day in July 2022, down 0.5% from a June average of 9,187 bpd and down 3.1% from a July 2021 average of 9,435 bpd. Maximum production over the last calendar year was in August and September of 2021 when production averaged 9,575 bpd and 9,524 bpd respectively.

## DUCK ISLAND

The Duck Island unit in the Beaufort Sea east of Prudhoe Bay is one of the smaller North Slope units, accounting for just under 1% of North Slope liquids production in July 2022 according to Alaska Oil and Gas Conservation Commission data. It produces from three participating areas, Endicott, Sag Delta and Eider, the Alaska Division of Oil and Gas said in approving the 40th plan of development for the unit in January 2022.

Hilcorp acquired BP's interest in Duck Island in 2014, along with BP's interest in Northstar and a 50% interest in Milne Point and Liberty, taking over as operator of all four.

Division records show Hilcorp Alaska holds between 84.41% and 100% of working interest in DIU leases while Chevron USA holds from 0.25% to 10.59%.

The Endicott oil pool was discovered by Sohio Alaska Petroleum Co. in 1978, AOGCC said in its pool data. That pool was developed from two artificial gravel islands, the Main Producing Island and the Satellite Producing Island, some 4 miles offshore, connected by a causeway to the mainland.

The unit was formed in 1978 and currently has some 17,588 acres. AOGCC said production began from the Endicott oil pool in a limited fashion in July 1986, with full production in October and November of 1987.

The field also produces from the Sag/Ivishak undefined oil pool, the Ivishak oil pool and the Eider oil pool, but in 2021 the majority, 91% of DIU production, was from the Endicott Oil Pool.

In calendar year 2021 DIU produced 2,029,291 barrels of oil and 286,105 barrels of natural gas liquids, down from 2020 production of 2,265,939 barrels of oil and 335,834 barrels of NGLs.

AOGCC said that at peak production from November 1987 to

October 1993, the Endicott pool averaged some 104,000 barrels of oil per day. AOGCC production data shows that for one month in that peak period, January 1992, combined crude and NGL production for all the pools at the DIU averaged 115,675.

In January 2022 production from all DIU pools averaged 6,942 bpd, crude and NGLs combined.

### PODS FOR ENDICOTT

In its January approval of the 40th plan of development for the Duck Island unit, the division said November 2020 through October 2021 production was 2.34 million barrels of oil and NGLs, "slightly increased from the 39th POD."

In the field overview in its 40th POD submittal, dated Nov. 15, 2021, Hilcorp said DIU production "is associated with the Kekiktuk Reservoir" in the Endicott PA, the Ivishak and Sag River reservoirs in the Eider PA; "and the Sag River Reservoir in the Minke Tract Operation."

Work at the DIU is focused on wellwork and workovers and on surface facilities.

In the 39th POD Hilcorp said it added perforations in five wells; performed well surface excavations on two wells; and returned one long term shut-in well to service.

Facilities work included a summer turnaround for maintenance on surface facilities.

The conversion of one well to a gas injector was delayed as the company evaluated converting another well.

In its 40th POD, covering Feb. 13, 2022, through Feb. 12, 2023, Hilcorp said under long-range activities it planned a "tracer study to understand injector/producer response to target potential future drilling targets."

No grassroots or sidetrack drilling is planned.

Rig workovers are planned on two wells to return them to production and two wells will be converted "to gas injection for enhanced gravity draining recoveries."

Other planned work would increase water injection on current wells and/or convert wells to water injection; additional workover operations as needed; and various non-rig wellwork operations.

Major facility projects may include upgrading/repairing Satellite Drilling Island low flow test separator intervals and installation of propane turbine demister. A turnaround would allow for vessel cleaning and inspection; LACT meter upgrades; rotating equipment overhaul and repairs; retraying condensate stabilizer; and flare inspection and repair.

## NORTHSTAR

Northstar is one of the newest fields that Hilcorp took over from BP, producing a 1984 discovery from an island constructed beginning in the winter of 1999-2000, with first regular production beginning in November 2001. Hilcorp acquired BP's interest in the field and took over as operator in 2014; it holds 100% of working interest in Northstar.

One of the North Slope's smaller fields, Northstar has the largest volume of natural gas liquids of any field in Alaska, 44.7% of its production in July 2022.

The 5-acre manmade gravel island at Northstar is in the Beaufort Sea 6 miles offshore and is connected to onshore processing facilities by a pipeline, the Alaska Oil and Gas Conservation

*continued on page 56*

**HILCORP NORTH SLOPE** *continued from page 55*

Commission said in its pool statistics. The Northstar oil pool was discovered in 1984 by Shell Island BF-47 No. 1 (Seal No. A-1) and a BP well, the 2002 Northstar Unit NS-08, discovered the Kuparuk C undefined oil pool.

Northstar oil pool production exceeded 50,000 barrels per day in June 2002 and 70,000 bpd by June 2003, AOGCC said, while the Northstar Kuparuk oil pool, which produces gas condensate and oil, peaked in 2018 at 4,549 bpd.

AOGCC data for July 2022 show Northstar averaging 6,903 bpd, 3,816 bpd of crude and 3,088 bpd of NGLs.

In its January 2022 approval of Hilcorp Alaska's latest plan of development for Northstar, the unit's 18th, the Alaska Division of Oil and Gas said the unit was formed in January 1990 and is jointly managed by the division and the U.S. Department of the Interior's Bureau of Safety and Environmental Enforcement. There are four state and three federal leases, totaling some 20,135 acres, with three participating areas, Northstar, Fido and Hooligan.

The division said production from November 2020 through October 2021 increased from the previous, 17th POD, totaling 2.97 million barrels of oil and natural gas liquids and 200 million cubic feet of natural gas.

## CURRENT POD

In its 18th POD for Northstar, submitted in November 2021, and covering Feb. 13, 2022, through Feb. 12, 2023, Hilcorp Alaska said there are three oil sand accumulations in the unit: Ivishak sands in the Northstar participating area, Ivishak sands in the Fido PA and Kuparuk sands in the Hooligan PA.

The company said production from Jan. 1, 2021, through Oct. 31, 2021, was 197.5 million cubic feet of gas and 3.227 million barrels of oil, with average daily production of 8,841 bpd.

During the 17th POD Hilcorp said it completed planned summer maintenance, installed "45 heat pipes around modules to enable active ground refrigeration in order to reduce ground settlement" and "continued ongoing repair of island's coastal defenses."

The company had anticipated converting the NS-15 well from a Kuparuk oil producer to an injector, but that work was delayed "due to update in injection management strategy."

In its 18th POD Hilcorp listed three long-range proposed development activities: exploring importing gas from Prudhoe for pressure maintenance for the Kuparuk reservoir; determining "if coil tubing drilling operations are economically viable, or even mechanically feasible, on Northstar Island" and reviewing potential CTD candidates; and researching the economic viability of Sag River development. "The reservoir is of very low permeability and porosity, likely requiring stimulation techniques to unlock production."

Hilcorp said it is not planning any grassroots wells, sidetracks or workovers, but said it would do workover operations as needed to maintain production.

Surface facility work will continue, with active refrigeration to be installed on the "45 newly installed heat pipes and 41 converted thermosyphons" along with continued work to repair the island's coastal defenses. ●

*Contact Kristen Nelson at knelson@petroleumnews.com*

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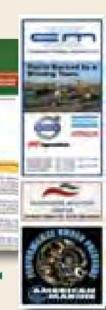

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# Barrow gas field keep powering Utqiaġvik

*Decades old project remains a unique story for North Slope natural gas*

By ERIC LIDJI
For Petroleum News

HARRY K. BROWER, JR.

It's a uniquely Alaska anomaly. While the wider North Slope region has been trying for years to monetize its extensive natural gas resources for decades, one small community has been benefitting for years.

Under the operatorship of the North Slope Borough, the Barrow gas fields have been the foundation of affordable and relatively secure energy for the city of Utqiaġvik for years.

The program subverts the usual paradigm for Alaska. Remoteness is usually a leading factor preventing development of known resources. But Utqiaġvik's remoteness has made it nearly impossible to develop the nearby gas fields for anything but local use.

The Barrow gas fields emerged from federally sponsored exploration in the National Petroleum Reserve-Alaska after World War II to improve domestic energy security.

Federal contractors discovered the fields on separate expeditions between the late 1940s and the 1980s. The fields have generally required minimal development work, aside from a $92 million rejuvenation program launched in 2011 to combat declining production.

With that effort, the city commissioned the Savik 1 and 2 wells at the East Barrow field and the Walakpa 11, 12 and 13 wells at the Walakpa field. By improving deliverability, the city of Utqiaġvik can now rely on natural gas for its energy needs even during cold snaps or during maintenance activities, instead of switching to diesel as an alternative.

## North Slope Borough

**HEADQUARTERS:** P.O. Box 69 Barrow, Alaska 99723
**TELEPHONE:** 907-852-2611
**TOP ALASKA EXECUTIVE:** Mayor Harry K. Brower, Jr.

### South Barrow

The U.S. Navy discovered the South Barrow field with the 2,505-foot South Barrow No. 2 well in 1948, during its initial wave of NPR-A exploration following World War II.

Production began the following year. Drilling continued through 1987 with 13 new wells drilled and one existing well — South Barrow No. 7 — deepened, according to the AOGCC. Production began in November 1981 at 3.5 million cubic feet per day.

The South Barrow field produced consistently from 1950 through 1990, at which point operators began to suspend production sporadically. The field was shut-in with increasing regularly through the 2000s, often being used only to increase supplies in winter.

After nearly six years of inconsistent production, South Barrow has now been producing regularly since May 2018. The field produced 99.3 million cubic feet in 2021, up considerably from 56.1 million cubic feet in 2021, according to the AOGCC.

*Cumulative production through June 2022 was nearly 9.9 billion cubic feet, well above the 6.2 billion cubic feet in place originally estimated for the East Barrow field. The city of Utqiaġvik attributes the productivity to the presence of methane hydrates at the field.*

The South Barrow field is producing from three wells: S. Barrow Test Well No. 6, South Barrow NSB No. 1 and South Barrow No. 9. The field produced exclusively from S. Barrow Test Well No. 6 from January 2020 through July 2020, when it went offline. It was back online from April 2021 through June 2021 and again in November and December 2021. South Barrow NSB No. 1 came online in February 2021 and went offline in June 2021, which accounted for increased production in 2021. It returned from December 2021 through March 2022. South Barrow No. 9 produced in July 2021.

Cumulative production at South Barrow passed 24 billion cubic feet by June 2022, according to the AOGCC. Early forecasts estimated some 32 billion cubic feet in lifetime production at the field, suggesting the potential of ongoing production for years to come.

## East Barrow

The U.S. Geological Survey discovered the East Barrow field with the South Barrow No. 12 well in 1974, during the second wave of oil and gas exploration in the NPR-A.

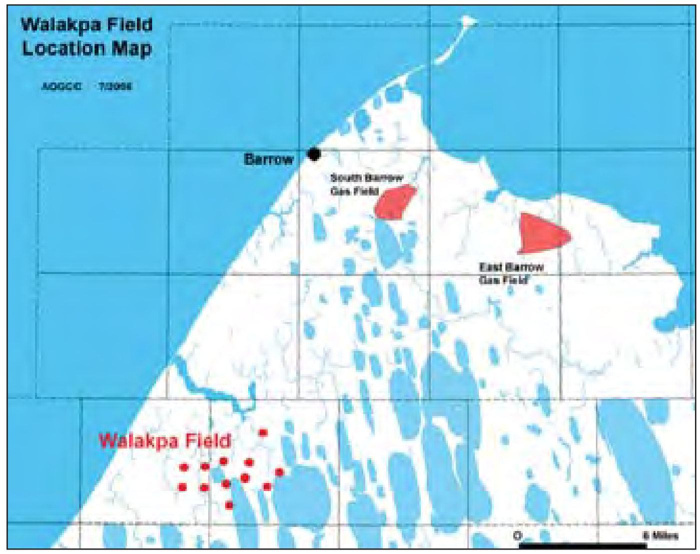
Production began in December 1981. Drilling continued through 1990, with eight wells total. The North Slope Borough more recently returned with the Savik drilling program.

Gas production peaked in early 1983 at some 2.75 million cubic feet per day.

The East Barrow field produced nearly 47 million cubic feet from the South Barrow No. 14 and Savik No. 1 wells in 2021, down considerably from 139.1 million cubic feet in 2020 according to the AOGCC. The decline started in spring 2021 and culminated in a shutdown of production through the latter half of the year before resuming in December.

Production was restored somewhat this year. The field produced nearly 60 million cubic feet through the first half of the year, down somewhat from 2020 but well above 2021.

Cumulative production through June 2022 was nearly 9.9 billion cubic feet, well above the 6.2 billion cubic feet in place originally estimated for the East Barrow field. The city of Utqiaġvik attributes the productivity to the presence of methane hydrates at the field.




ALASKA OIL & GAS CONSERVATION COMMISSION (AOGCC)

**Although dated, this map is still accurate except for the fact that it refers to the city of Utqiagvik as Barrow. (Barrow was its name from 1901 to 2016.) Utqiagvik, Alaska is the northernmost city in the United States, the borough seat and the largest community in the North Slope Borough. The Barrow gas fields — South Barrow, East Barrow and Walakpa — are operated by the North Slope Borough.**

## Walakpa

Working under a U.S. Navy contract, Husky Oil discovered the Walakpa field with the 3,666-foot Walakpa No. 1 well in the 1980s. Production began in the late 1992. The field has peaked above 5 million cubic feet per day numerous times in the decades since.

Walakpa is the most productive of the three Barrow gas fields, currently producing from 11 wells — Walakpa No. 3 through Walakpa No. 13. The field produced 1.4 billion cubic feet in 2021, up from 1.3 billion cubic feet in 2020, according to the AOGCC. The field produced 746 million cubic feet in the first half of 2022, on pace with 2021 rates.

Cumulative production through June 30, 2022, was 37.3 billion cubic feet.

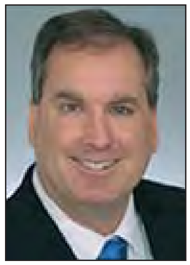
The South Barrow and East Barrow reservoirs have a stratigraphic setting similar to the Alpine oil field. Walakpa is in the Pebble Shale unit, a major North Slope source rock. ●

*Contact Eric Lidji at ericlidji@mac.com*

# Great Bear Pantheon from explorer to producer

*By September 2021 Pantheon talking billions of barrels of oil in its acreage*

**By KAY CASHMAN**
Petroleum News



PAT GALVIN

On Sept. 23, 2022, when this annual edition of The Producers magazine closed, Pantheon Resources' operating arm in Alaska, Great Bear Pantheon, was close to flow testing what it hopes will be its first oil and gas production well on the North Slope.

The London-based oil and gas company with a 100% working interest via its Great Bear Pantheon-operated North Slope oil assets, said Sept. 6 the Nabors 105 rig that was used to drill the Alkaid 2 well had been fully demobilized, and wireline and completion equipment was on location.

Alkaid 2 will be perforated, stimulated and plugged off in sections prior to the commencement of flow testing, which Pantheon anticipates in early October 2022.

In regard to procurement and mobilization of production facilities, Great Bear Pantheon, or GBP. had upgraded the capacity of the production facilities, which were enroute to the North Slope. The increased capacity of these modular facilities was "sufficient to process oil production from multiple wells," Pantheon said in its Sept. 6 operational and corporate update.

## Entered Alaska in 2019

On Jan. 21, 2019, London-based Pantheon, which was founded in 2005, first entered Alaska with its acquisition of two wholly owned subsidiaries of Great Bear Petroleum Operating — Great Bear Petroleum Ventures I and II.

Pantheon's operating subsidiary immediately re-entered and tested the Alkaid 1 vertical test well, which Great Bear had drilled in 2015. It was conveniently located just west of the Dalton Highway, south of the Prudhoe Bay unit. Great Bear had been unable to flow test the well because of flooding on the highway.

Pantheon said March 25, 2019, that the first of the three targeted horizons in its re-entry and flow testing of the Alkaid 1 well confirmed an oil discovery,

The company said a six-foot section "from a 240 foot interval of net pay" in the "Brookian ZOI" was perforated and flow tested at 80-100 barrels of oil per day, yielding light oil.

"Such flow rates are considered to be an excellent result and indicate the potential for materially higher flow rates when wells are drilled in the typical manner for Brookian wells in Alaska — horizontally, stimulated and with larger intervals perforated," Pantheon said.

## Talitha prospect

In July 2020, Pantheon said it would drill an exploration well in its Talitha prospect in the winter of 2020-21 followed by an Alkaid producer, Alkaid 2 sometime in the year that followed.

### Great Bear Pantheon LLC

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Talitha 1 would be a re-drill of the 1986 ARCO Alaska discovery well, Pipeline State No. 1.

Alkaid 2 had the potential to be completed as a producer via the "installation of an Early Production Unit facility," Patrick Galvin, chief commercial officer and general counsel for Great Bear Pantheon, or GBP, told Petroleum News at the time.

In the meantime Pantheon continued to acquire North Slope acreage via state lease sales and drill. But COVID-19 negatively impacted the availability of rigs, equipment and supplies, not to mention it lowered demand for oil, reducing oil prices.

## Billions of barrels

By September 2021 Pantheon was talking billions of barrels of oil in its acreage, with prospects Alkaid, Talitha and Theta West all close to one another along the Dalton High and the trans-Alaska oil pipeline.

Its Theta West 1 well — to be drilled in the 2021-22 winter season — was incredibly significant for Pantheon if the company's expectations for the well were met.

The Theta West ice pad would be 10 miles west of the Talitha pad where operator GBP's Talitha A exploration well struck light oil the previous winter.

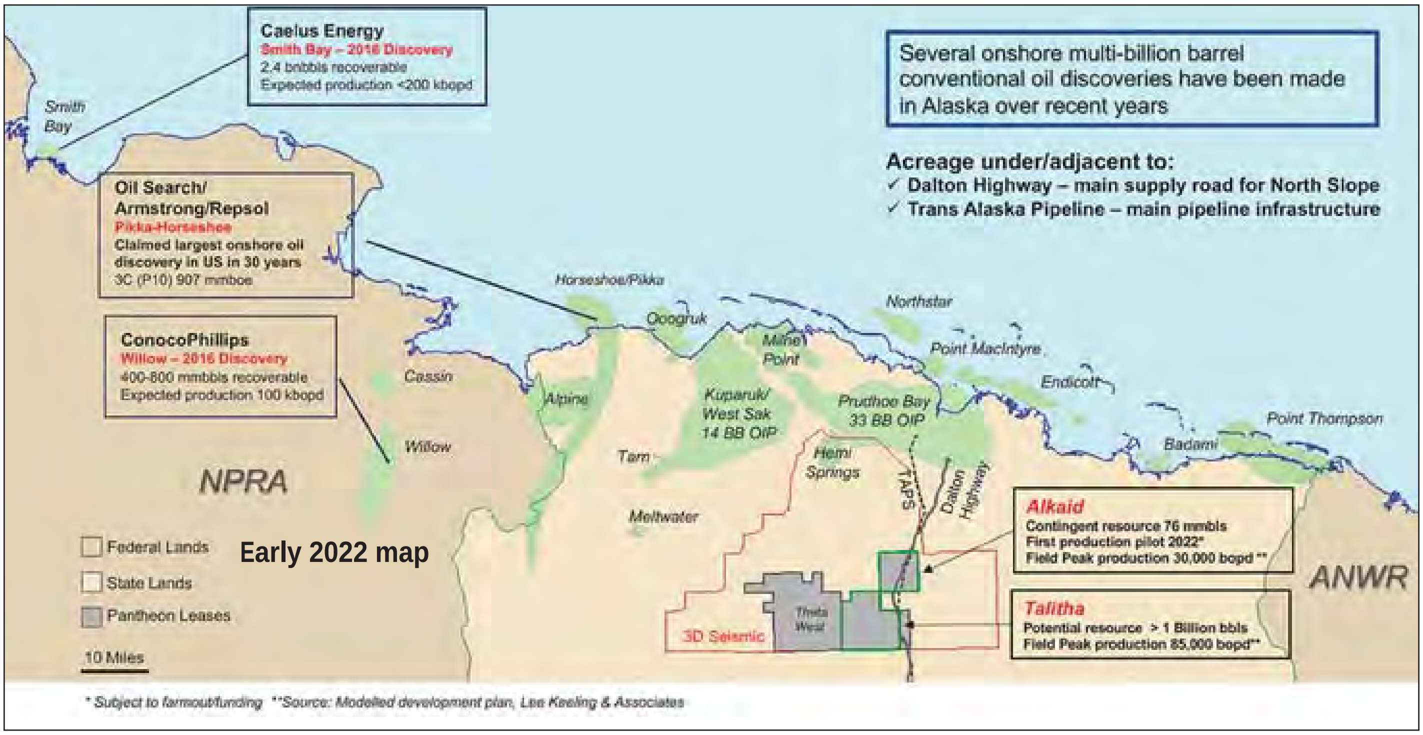
GBP also planned to reenter the Talitha well to resume testing of zones it ran out of time for as the winter exploration season ended in the spring of 2021, Pantheon's CEO Jay Cheatham told Petroleum News in a Nov. 5, 2021, interview The company expected to see the same zones and more in the Theta West well, with recoverable resource amounts gargantuan for the $770 million market cap Pantheon.

Cheatham said Pantheon would be a big part of Alaska's future.

"At least a billion" barrels, Bob Rosenthal, Pantheon's technical director said. "We think we've got one of the largest discoveries made in the world in the last year."

GBP considered Theta West 1 to be an appraisal well of the previous winter's Talitha discovery, he said.

"This discovery would be significant anywhere in the world,




GREAT BEAR PANTHEON

whether in 5,000 feet of water, or Alaska or Texas; it would have a massive, major impact," Rosenthal said. "Its proximity next to infrastructure just magnifies that impact."

By December 2021 Pantheon announced results of an equity fundraising, saying the funds allowed it to fully execute its 2022 program which included reentry of Talitha A and drilling of the Theta West and Alkaid 2H wells.

## Pleased with Theta West

Pantheon said March 24, 2022, that its Theta West 1 well flowed high quality light oil (35.5-38.5 degree API gravity) to the surface at rates that averaged more than 57 barrels of oil per day with peak rates exceeding 100 bpd over 2.5 days before testing was suspended due to extreme weather conditions.

The company thinks the Theta West 1 test results support, and likely exceed, its pre-drill resource estimates of 1.2 billion barrels of oil recoverable for the Theta West prospect.

## Alkaid 2 spud in July

GBP spud its first production well on Alaska's North Slope the evening of July 6, 2022.

Alkaid 2, a horizontal long-term test well, marks the company's possible transition from explorer to producer.

The first horizontal wells drilled on the North Slope were drilled by BP Exploration (Alaska) starting in the 1990s, and the technology has been used and improved ever since on the Slope.

PAT GALVIN, GREAT BEAR PANTHEON

**Nabors 105AC rig drilling Alkaid 2 well.**

Pantheon has 100% working interest in all of its oil projects spanning 153,000 acres adjacent and near to the Dalton Highway and Trans Alaska Pipeline System, or TAPS.

Because of its close proximity to infrastructure, Pantheon said the Alkaid accumulation is ideal for a phased development, which would minimize upfront capital expenditure and allow for future capital needs to be partly funded through production revenues, yielding higher internal rates of return. ●

*Contact Kay Cashman at publisher@petroleumnews.com*

# Savant looking to drill at Badami

*Economic conditions will guide decision of Glacier Oil and Gas subsidiary*

**By ERIC LIDJI**
For Petroleum News

STEPHEN RATCLIFF

The Badami unit has been perplexing and pleasantly surprising the oil patch for decades.

Its complex geology has forced operators to be patient and resourceful. But in recent years, the unit has proven to be an important infrastructure link for the North Slope basin.

BP Exploration (Alaska) Inc. brought the eastern North Slope oil field into production in 1998. Badami was much smaller than historic giants like Prudhoe Bay, Kuparuk and Alpine, but it was seen as an important first step toward developing the 70-mile stretch between Prudhoe Bay and the ANWR 1002 Area — the beginning of a "string of pearls."

Almost immediately, though, geology muddied those visions.

The reservoir at Badami was compartmentalized, making it difficult to develop in the usual manner. BP had to frequently suspend operations to let reservoir pressure recharge.

BP developed the unit with a processing facility capable of handling 38,500 barrels per day of oil. But by the mid-2000s, average production was down to 876 barrels per day.

Taking a different approach, BP partnered with the small independent Savant Alaska in 2008 and then sold the field. Savant then became a subsidiary of Glacier Oil & Gas Inc.

In its decade overseeing the unit, Savant has stabilizing production with two successful development wells: B1-38 and the B1-07 Starfish well. With production averaging around 1,100 barrels per day, Badami production remains well below original estimates, but remains much healthier than the stop and start days of the turn of the century.

In its development plans, Glacier Oil and Gas has often mentioned opportunities around its existing property — prospects just beyond the unit boundaries or just outside existing participating areas. And the past two decades have also seen renewed interest in the broader eastern North Slope, including start-up of the long-delayed Point Thomson unit.

And yet, during the crazed uncertainty of late 2020 and early 2021, Badami was briefly on the market, appearing and then disappearing from various asset marketing websites.

With its current plan of development, running through July 15, 2023, the Glacier Oil and Gas subsidiary Savant Alaska is proposing a range of development projects that indicate some energy and enthusiasm but that also depend upon favorable market conditions.

## Current plans

In its last development year, Savant completed several maintenance projects at Badami.

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**TOP ALASKA EXECUTIVE:** Stephen Ratcliff, president
**WEBSITE:** www.glacieroil.com

*For several years, Savant has been evaluating prospects in the Badami and Killian sands at the unit. The company has identified several prospects in these two sands.*

Savant conducted gas lift optimization on the Starfish B1-07 well, which improved production by 15%, according to the company. The company also conducted production logging on the B1-36 well, which help identify and mitigate water intrusion into the well. In April 2022, it added 47 feet of perforations to the B1-36 well. As of this past summer, testing was underway to determine the efficacy of these perforations.

In the current plant, Savant proposed a similar range of projects at the Badami unit.

The company plans to log the B1-38 well and possibly add perforations in the Brookian section of the reservoir, in addition to the existing production from the Killian. Any co-mingling would require Alaska Oil and Gas Conservation Commission approval.

Savant also plans to log fluid movement in the B1-01 Class I injection well to test the existing injections zones, as well as the mechanical integrity of the existing wellbore.

## Badami East

The eastern North Slope is generally thought to be under-explored and under-developed, with many notable prospects waiting for the right economic and technical conditions.

For several years, Savant has been evaluating prospects in the Badami and Killian sands at the unit. The company has identified several prospects in these two sands. Of those prospects, three could be drilled from the existing Badami pad but the remainder would require construction of a new drilling pad, currently being called the Badami East pad.

The proposed Badami East pad would be a satellite, connected back to the main Badami pad by an 8-inch three-phase production pipeline and a 2-inch gas supply pipeline.

*continued on page 64*

# Gardes' Vision takes over North Fork pipeline

*Plans to inject produced water to grow CI field's natural gas production*

**By KAY CASHMAN**
Petroleum News

Bob Gardes of Lafayette, Louisiana, entered Alaska in September 2020 with the purpose of becoming a natural gas producer by acquiring bypassed and/or underdeveloped gas deposits in the Cook Inlet basin.

At that time Gardes purchased the southern Kenai Peninsula North Fork unit from Cook Inlet Energy, or CIE, a Glacier Oil and Gas company. The 2,602-acre unit produces from a single participating area and is one of Cook Inlet's smaller gas fields.

Gardes is first and foremost looking for natural gas, not oil. He told Petroleum News that he views the Cook Inlet basin as one of four top gas regions in the world.

"We think the future in the U.S. is gas. It burns 98% cleaner than oil and coal. It is a transformational resource," Gardes said. "There is a lot of bypassed gas here because the deposits weren't big enough" for companies to bother with them.


BOB GARDES


MARK LANDT

On May 1, 2021, Gardes-owned Vision Operating took over as operator of the North Fork unit, which consists of five state leases that are held by another Gardes company, Vision Resources.

While Gardes, per its website, is "currently negotiating" additional "potential acquisitions in the Cook Inlet region," its operations crew on the ground, led by Mark Landt, has had its attention focused on enhancing production from the company's North Fork unit.

## RCA issues final order

Recent news from Gardes is that effective July 27, 2022, the Regulatory Commission of Alaska issued a final order transferring CIE's controlling interest in Anchor Point Energy, owner of the North Fork unit's 16-mile pipeline, to Gardes Holdings.

North Fork was first brought online in 2011 by a Bill Armstrong joint venture, even though the field was first unitized by Standard Oil Co. of California in 1965.

In February 2021 Vision Resources entered into a five-year natural gas sales and purchase contract with Alaska Pipeline Co. that resulted in APC's utility affiliate Enstar Natural Gas continuing to distribute gas from North Fork after CIE's contract expired on May 10, 2021.

## Could be largest CI producer

On Dec. 21, 2021, Vision Operating applied to the Alaska Oil and Gas Conservation Commission, or AOGCC, for a Class 2 underground injection control well permit at its North Fork unit.

The application indicated that Vision has plans to expand natural gas production from North Fork.

The application, signed by Vision Operating President Stephen Hennigan, said there are eight existing North Fork unit wells, with as many as 22 producing and pressure maintenance wells possible, up to two disposal wells and ancillary equipment and production processing and handling facilities for oil, gas and water.

Vision said at the time that the unit averaged some 3 million cubic feet per day of natural gas, and production with their planned activities could be as much as 60 million cubic feet per day, a volume which would make the field the largest current producer in the Cook Inlet basin.

With the larger volume of gas, water production was projected at 5,000 barrels of water per day.

## Lots of untapped gas

North Fork is accessed by a 12-mile road from Anchor Point, at the end of which is a 5-acre gravel pad bounded by fencing and gates. North Fork gas is transported through two fiberglass pipelines to Anchor Point where it ties into the Enstar line.

Hennigan also told AOGCC he had been involved at the field since Armstrong brought North Fork online in 2011. He said a lot of zones were left because they started to produce water. There was significant gas in those zones, he said, and if the water could be disposed of, the company could go back and produce the gas.

Hennigan also said the company has identified as many as 23 natural gas prospects in the area.

At that hearing, Vision told AOGCC that produced water from gas production would be an estimated 73.1% of the total injected, with well workover fluids some 21.4%, other exempt fluids some 2.3% and drill cuttings, mud and completion fluids some 1.1%.

Vision said it has plans for additional production at the field

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### Gardes Holdings, Inc.

GARDES HOLDINGS INC.

**NAME OF COMPANY:** Vision Operating, LLC (Gardes Holdings, Inc. parent company)
**COMPANY HEADQUARTERS:** 301 Fairlane Dr., Lafayette, LA 70507
**TOP COMPANY EXECUTIVE:** Robert Gardes, CEO
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**TOP ALASKA EXECUTIVE:** Mark Landt, VP, Land & Business Development
**TELEPHONE:** 214-738-6945

**SAVANT** *continued from page 62*

Savant initially intended to advance the project last year as part of a multi-well drilling program in the Lion and Rhino Killian prospects. But given the uncertainty of economic conditions in 2020 and 2021, the company deferred the drilling, as well as the pad.

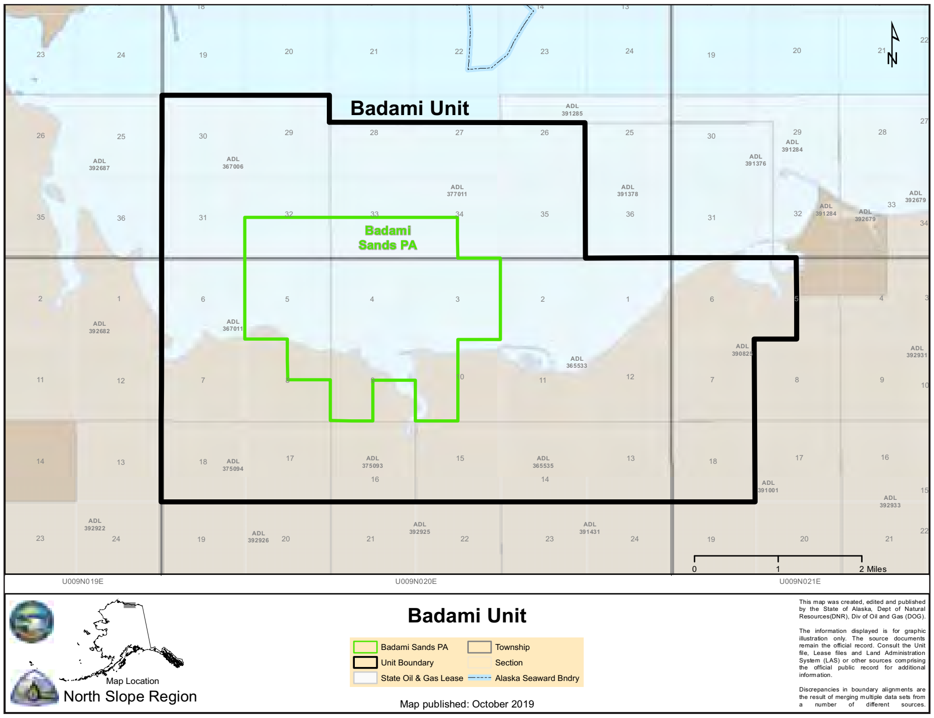
"Raising capital to drill exploration wells in Alaska continues to remain a challenge for growth and expansion at Badami," the company wrote in its current development plan.

In considering the likelihood of advancing the Badami East project this year, Savant wrote, "Due to the significant capital cost of the endeavor, it is highly dependent upon an extended period of stable oil prices and ability to raise capital at reasonable terms."

## Drilling plans

Those economic factors will also determine whether and when Savant pursues a proposed two-well program in the Badami sands using the existing Badami main drilling pad.

The company is somewhat optimistic that it can drill at least one well into the Killian 28 reservoir this coming winter. The project would aim to prove the Killian play outside the existing participating area to better obtain investment capital for future drilling activities.




The company also plans to conduct geologic evaluations to identify potential drilling targets on 1,280-acres of newly acquired property south of the existing Badami unit.

The current plan also includes some facility work.

Savant plans to relocate a newly installed wastewater treatment plant to improve access and operations at the Badami main pad, to upgrade a communications system, and to convert some of its propane-powered thermoelectric generators to run on natural gas. ●

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**VISION** *continued from page 63*

and plans to drill over the next 7 years.

## Plan of development

Alaska's Division of Oil and Gas signed off Feb. 24, 2022, on the 2022 plan of development for the North Fork unit, or NFU. The POD, the 57th for the unit, covers March 31, 2022, through March 30, 2023.

On Feb. 24, Landt explained, the division approved Vision's proposed 57th POD because Vision was "committed to enhancing and extending existing NFU production" by drilling additional wells in the existing participating area and "also outside of the current PA boundaries."

The NFU Gas Pool No.1 PA, or GPA, consists of some 800 acres.

Since Vision Operating took over as North Fork operator May 1, 2021, the division said the unit averaged 3,058 thousand cubic feet per day of gas production through November 2021. More recent AOGCC data for June 2022 shows the NFU averaged 3,058 mcf per day.

In April 2022 the company got AOGCC approval to use an existing, but non-producing well, for Class II oil field waste fluids underground disposal.

## Aquifer exemption

In a July 20, 2022, order approving an aquifer exemption for North Fork, AOGCC said the well proposed for injection, NFU 23-25, is perforated in two sands within the deeper planned injection zone, Zone 1.

"Vision will perforate and inject wastes into the Zone 1 sands until capacity is reached," and after that overlying sands in Zone 2 will be perforated and used for further injection, the commission said.

Vision estimates the maximum radius for injection is 1,200 feet from the injection point, with the capacity in Zone 1 of 12.5 million barrels and the combined capacity of Zones 1 and 2 some 47 million barrels.

AOGCC disagreed with the size of the aquifer exemption Vision requested, saying it was some 3 square miles or about 1,920 acres. The 3 square mile area "is not warranted," the commission said, approving instead an area with a radius of 2,000 feet from the NFU 23-25 wellbore, saying the extent of the affected area can be re-evaluated and amended in the future, if necessary.

## Drilling expensive

But drilling for new pockets of gas requires more money, generally bank financing.

In more than one filing with the division since acquiring the North Fork unit and its assets, Vision has inserted a qualifying statement about drilling depending on favorable economic and/or market conditions in its work plans for exploration and development drilling in the North Fork unit. ●

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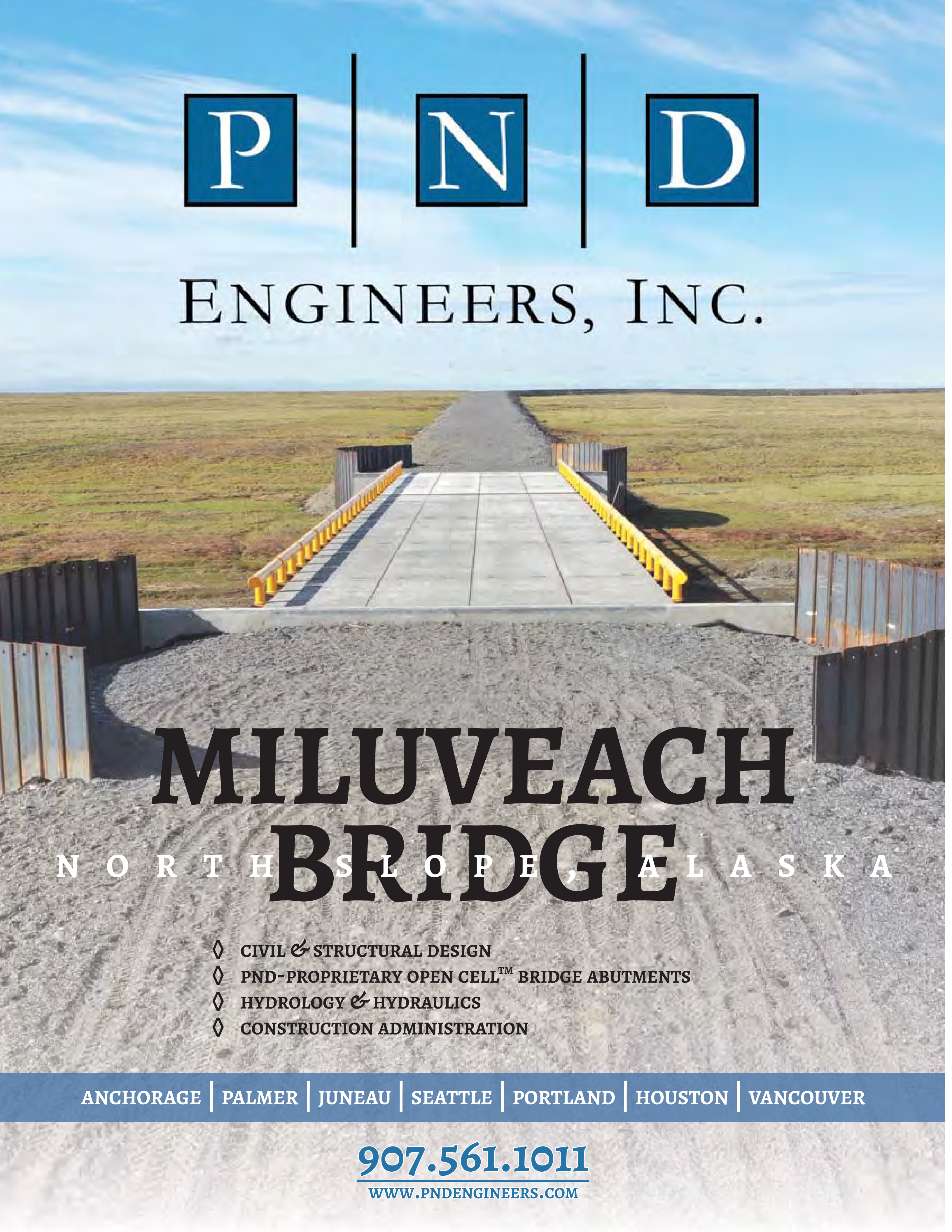
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