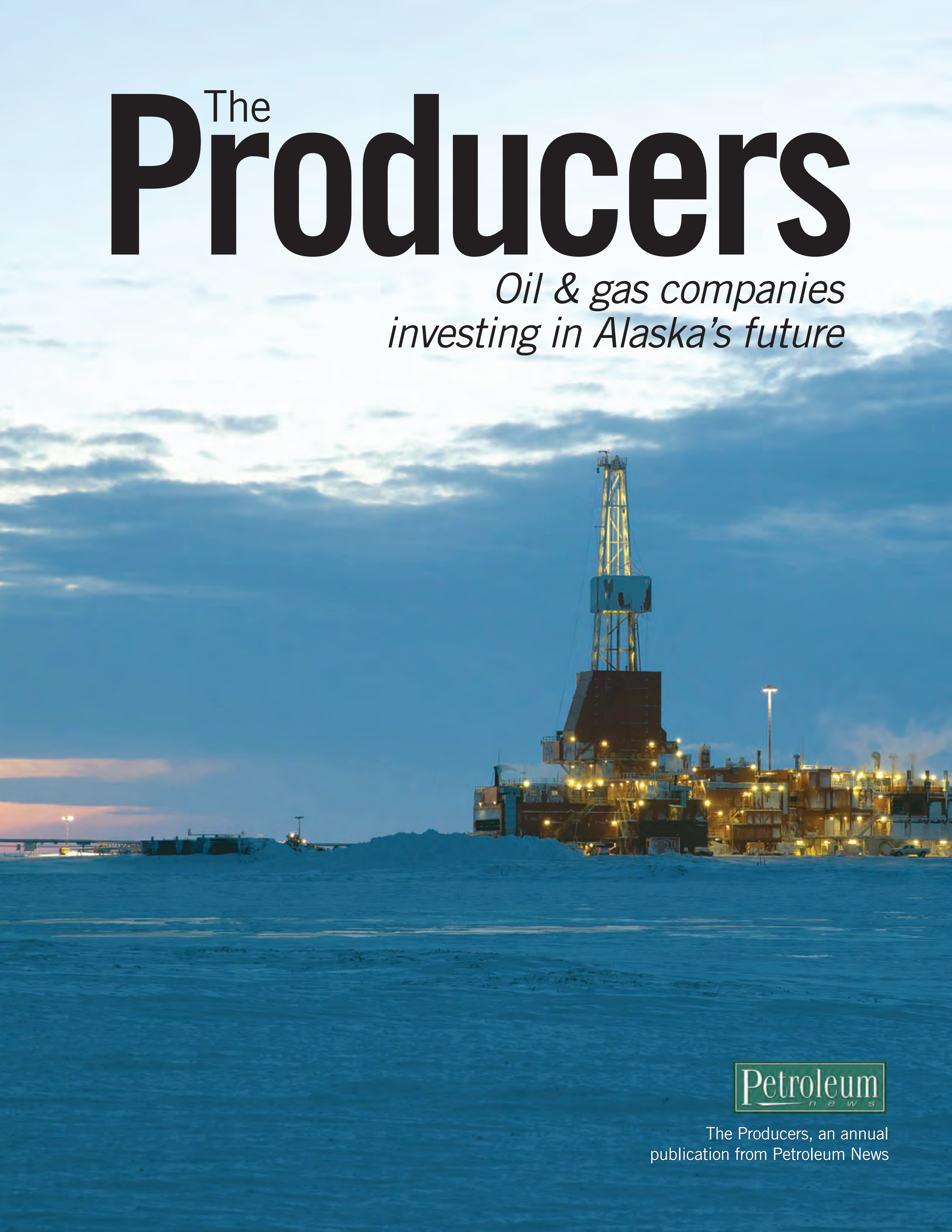
The Producers

Oil & gas companies investing in Alaska's future



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The Producers

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On the cover:
ConocoPhillips Alaska, Alpine Field

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Production surge coming

Alaska holds gold standard in environmental stewardship

By **KAY CASHMAN**
Petroleum News Publisher


KAY CASHMAN

An oil production surge is around the corner for the North Slope of Alaska.

The first surge will come from Santos' Pikka Phase 1 project, scheduled to begin producing oil in the first half of 2026 with 80,000 barrels per day, followed by Pikka Phase 2. Its pads and roads may be built as early as 2025-26 winter season, followed by other nearby discoveries, such as Quokka. Pikka Phase 2, Quokka and others are expected to be in the 80,000 bpd range.

And then in 2029, ConocoPhillips Alaska will bring on its giant Willow project in the National Petroleum Reserve-Alaska with some 180,000 bpd from three drill sites. And if the incoming Trump administration is able to open more of the petroleum reserve, Willow might get the original five drill sites it had requested for the project.

There are also smaller projects underway on the North Slope, such as ConocoPhillips' Nuna, which will bring Kuparuk's 49th drill site online in 2025. It will tie back to existing processing facilities at Kuparuk's Central Processing Facility 3, boosting Kuparuk's production some 20,000 net barrels of oil equivalent per day.

Prime area

Alaska is a prime place to develop oil because it is a longtime leader in environmental stewardship, ranking lowest in ESG metrics among all energy producing states. ESG, which stands for environmental, social and governance, affects the capital allocation decisions of many oil and gas companies.

Finally, and notably, Alaska is the LOWEST in carbon emissions from fossil fuels of all the states.

After all, companies have been investing in northern Alaska and producing oil safely and responsibly for more than 40 years.

The northern part of the state offers world class basins with large land positions ready to explore and there are major exploration projects already underway that may result in new production in 7 to 8 years, such as a Bill Armstrong venture on the eastern North Slope, whose targets include Nanushuk look-alikes.

Another advantage for companies looking to produce in Alaska is the fact that it has an experienced industry service sector; firms that have technological expertise to offer.

The North Slope's 40-plus years of production touts technological advancement and the reduction of the environmental footprint in oil and gas projects.

Factoid: Alaska's wildlife stocks remain strong in number; higher than at start-up of the trans-Alaska pipeline system in 1977.

Finally, and notably, Alaska is the LOWEST in carbon emissions from fossil fuels of all the states.

Cook Inlet basin

This issue of the annual Producers magazine also covers oil and gas companies doing business in Southcentral Alaska's Cook Inlet basin, which currently supplies natural gas for heating homes and commercial buildings all over the state.

Today the focus in the Cook Inlet basin is natural gas, although the basin still produces a small amount of crude: 8,183 bpd. ●

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AIX Energy closes out first decade in Alaska

Small operator remains diligent and conservative at Kenai Loop field in Cook Inlet

By ERIC LIDJI
For Petroleum News

AIX Energy LLC marked 10 years in Alaska in 2024. In its first decade in the state, the independent company has sometimes behaved more like a Lower 48 operator.

Over the past 70 years, Alaska has become accustomed to an oil patch led by several large or midsize operators who pursue ongoing campaigns to develop large or midsize fields. And while that dynamic exists "outside" Alaska, too, the Lower 48 is also home to many smaller operators working to maintain daily profitability at small, marginal fields.

In its decade in Alaska so far, AIX Energy LLC has rarely conducted a development campaign, never drilled an exploration well, never farmed-out work and rarely traded assets. After an initial burst of acquisitions, it has rarely expanded its holdings. The private company doesn't issue press releases or holds investor conferences, preferring to speak through its required regulatory filings. For 10 years now, the company has been steadily focused on one simple goal: maintaining production to meet contracted demand.

In fact, AIX has been more likely to shrink than expand. Since taking over the field in 2014, the company has removed one well from service and forfeited two leases.

The approach is a stark contrast with its predecessor.

Australian independent Buccaneer Energy acquired the leases at the Kenai Loop field in late 2010 and early 2011. The acquisition was part of an ambitious strategy of growth, perpetually focused on new opportunities. These included many undeveloped properties, as well as interests in an offshore jack-up rig during basin-wide efforts in the 2000s and 2010s to expand offshore exploration in Cook Inlet and also an onshore drilling rig.

Buccaneer eventually became overextended. AIX Energy acquired Buccaneer's debt in April 2014. Buccaneer ultimately filed for bankruptcy protection in late May 2014, and AIX Energy was listed as the largest secured creditor. AIX Energy agreed to be a stalking-horse bidder, but those plans changed through the course of the bankruptcy proceedings. In an October 2014 bankruptcy auction, AIX acquired nearly all of Buccaneer's assets in Alaska with a $44 million credit bid (the process by which a creditor can bid the value of the debt it is owed against cash offers from other bidders).

Kenai Loop

Kenai Loop was the most successful property in the Buccaneer portfolio throughout its tenure in Alaska. The company drilled four wells and commissioned a seismic survey.

Buccaneer drilled the KL 1-1 discovery well in April and May 2011 using the Glacier No. 1 rig. The 10,680-foot well tested at 10 million cubic feet per day in June 2011.

Ralph E. Davis Associates Inc. later estimated that the prospect contained some 31.5 billion cubic feet of natural gas and some 3.9 million barrels of oil equivalent in proven reserves. Buccaneer drilled the 11,000-foot KL 1-2 dry hole that fall. (The wells at the Kenai Loop field originally had a different naming convention but were later changed.)

Buccaneer brought the Kenai Loop field online in early 2012 and commissioned a 3D seismic survey over a 25-square-mile region to guide future drilling. Based on the results of the seismic survey, the company drilled the 13,000-foot KL 1-3 producer well in late 2012. The well flowed at 3 million cubic feet per day in January 2013. Buccaneer brought the KL 1-3 well online in February 2013 at 2 million cubic feet per day.

Buccaneer started drilling the 10,700-foot K-L 1-4 well in August 2013, targeting what "appears to be a fault separated from the current producing zones in the Kenai Loop No. 1-1 and Kenai Loop No. 1-3 wells," as the company explained during the drilling process. The well flowed at 5.9 million cubic feet per day during a test in October 2013.

Those final two wells came amid regulatory challenges. The Alaska Department of Natural Resources denied a request to unitize

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AIX ENERGY *continued from page 10*

Kenai Loop, arguing that Buccaneer was using the process to preserve leases rather than maximize development. Buccaneer said that unitization would simplify operations in a crowded area with many landowners.

One of those landowners later accused Buccaneer of using the KL 1-4 well to drain resources from neighboring properties. The complaint drew the attention of other landowners, leading to legal complications that carried into the bankruptcy proceedings.

AIX work history

In its first year as operator, AIX Energy resolved some outstanding issues from its predecessor and began evaluating some of the maintenance projects it could pursue.

AIX Energy quickly increased its leasehold nearly eight-fold to 8,882 acres in May 2016, up from 1,049 acres in April 2015 — not counting Alaska Mental Health Trust leases.

It also focused considerable attention on contracts.

AIX Energy secured a short-term supply contract with Chugach Electric Association in late 2014 and resolved a pre-existing contract dispute with Cook Inlet Energy LLC in mid-2015. The company later secured a supply contract with Enstar Natural Gas Co.

Toward the end of 2015, Chugach Electric Association asked regulators to extend its existing natural gas supply agreement with AIX Energy by eight years, to March 31, 2024, with the possibility of an additional extension through March 31, 2029.

The flexible contract allowed the parties to negotiate sales on a case-by-case basis with a price cap rising by approximately 2% each year and volumes up to 3 billion cubic feet annually.

Through the end of June 2024, the Kenai Loop field had produced 27.8 bcf, according to the Alaska Oil and Gas Conservation Commission.

By early May 2017, AIX Energy had at least four supply contracts: a non-firm contract with Tesoro, a non-firm contract with an un-named company (likely Chugach Electric Association), a firm contract with Tesoro and a firm contract with Enstar Natural Gas Co. By that fall, AIX Energy had renewed its agreement with Enstar Natural Gas Co. through March 2021, calling for firm gas supplies that would increase slightly each year.

In an early 2022 filing, AIX Energy revealed it was selling its volumes exclusively to a single, unnamed purchaser under a one-year "Firm as Available" contract.

As these agreements were being negotiated and executed, AIX Energy was also reckoning with declining production at the aging field. In early 2019, in a bid to improve deliverability, AIX Energy commissioned a new compression facility at the field. The project appears to be the single largest investment the company has made at Kenai Loop.

Kenai Loop production began declining in 2016 and increased around 2018, leading to uncertainty around the long-term viability of the prospect. In its 2023 plan of development, AIX Energy stood behind its original gas in place estimate but asked to keep the figure confidential. Through the end of June 2024, the Kenai Loop field had produced 27.8 bcf, according to the Alaska Oil and Gas Conservation Commission.

Plans

Its 10th plan of development, covering the year ending May 6, 2025, amounted to a single sentence: "AIX will focus on aligning gas sales with field deliverability." (At the time The Producers went to print, the state had yet to rule on this plan of development.)

In its ninth plan, ending May 2024, AIX Energy had "focused on obtaining reservoir information to better understand field reserves and deliverability, identifying operational efficiencies, maximizing gas sales, and maintaining a safe operating environment." As reported in previous plans, AIX Energy currently sells "all gas volumes to a single purchaser," under a three-year, "firm as available" contract approved April 1, 2023. ●

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Crunch time for Amaroq at Nicolai Creek

Three-well program could extend field by decade; no drilling promises P&A

By ERIC LIDJI
For Petroleum News

SCOTT PFOFF

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

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

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

Amaroq Resources, LLC

Amaroq Resources, LLC

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

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

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

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

Possible projects

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

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

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

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AMAROQ *continued from page 14*

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

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

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

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

In its 50th plan of development, Amaroq said it had completed a "tentative" work plan and authorization for expenditure for the NCU No. 10 workover but was intrigued by idea of drilling a new well, which "could produce most or all of the remaining reserves" associated with NCU No. 10 and produce most or all of the remaining reserves associated with the NCU No. 3 well. But drilling a new well would require third party funding.

Division's conditions

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

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

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

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

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

History

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

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

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

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

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

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

Deep oil

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

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

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

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BlueCrest pins Cosmo financing on HB 50 funding

BlueCrest and DOG trade summer correspondence over future of Cosmo unit

By ERIC LIDJI
For Petroleum News


J. BENJAMIN JOHNSON


JOHN M. MARTINECK

The Cosmopolitan project neatly captures the challenges of the Cook Inlet basin.

The offshore field is the largest proven and undeveloped oil and gas reserve in the Cook Inlet basin and is therefore crucial for maintaining supplies in the region. It is also a technically challenging project, requiring offshore drilling or extended reach drilling to access. And it exists in an unusual marketplace, where most supplies stay local.

To make the project work, operator BlueCrest Operating Alaska LLC wants some assurances, specifically upfront supply contracts and state backing to spur investment.

Under its 10th plan of development for the unit, covering calendar year 2024, the Texas-based independent company made two commitments for 2025: drilling the H-10 Trident Fishbone well and providing a plan for bringing the Tyonek Gas Project online in 2027.

The H10 Trident Fishbone is an innovative well that is designed to maximize subsurface recovery while minimizing surface drilling. A single wellbore branches into three subsurface "fishbone" wells with eight laterals each — 24 individual wells altogether.

BlueCrest would drill the well directionally from an onshore pad. The custom-built BlueCrest Rig No. 1 can drill 3 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. Even with the rig, the desire to minimize surface drilling led to the complex well design. In addition to the technical challenge, it poses new permitting challenges.

The Tyonek Gas Project sits even farther out, beyond the reach of the rig. The project would require a new offshore platform and a new pipeline system back to shore.

According to the company, the field contains 235 billion cubic feet of proven gas reserves, enough to support as much as a quarter of Cook Inlet demand. The company estimated in February 2024 that the project required some $400 million in financing.

Summer update

In approving the plan of development, the state required an update by June 30, 2024.

With a few weeks remaining toward that deadline, Division of Oil and Gas Director Derek Nottingham took the uncommon step of publicly telling the company about the pending due date. In a letter dated June 17, 2024, Nottingham reminded BlueCrest's John Martinek of the need to file a letter by the end of the month addressing four questions:

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Did the company have enough money to drill an oil well at Cosmopolitan in 2025? Did it have enough money to advance its Tyonek gas development? Did the company have a "fully defined plan and schedule for Tyonek Gas development?" And were the existing financing and development plans enough to bring sustained gas production by 2027?

"The current Cook Inlet market environment demands operators marshal all available resources and ensure enough natural gas is available for citizens of Alaska. The Division (of Oil and Gas) accordingly expects BlueCrest to develop its proven oil and gas resources in time to meet this critical need, consistent with its (10th plan of development) commitments. Delay is not an option and the Division must fulfill all of its constitutional, statutory, and contractual duties in this context," Nottingham wrote in the letter.

In its official update, dated June 28, BlueCrest listed some of the challenges of Cook Inlet. It described the basin as "a closed gas market" with 70 billion cubic feet of annual demand and declining supplies, presaging an energy shortage in the Alaska Railbelt.

The company said that it needed upfront sales contracts to justify the hundreds of millions of dollars of investment required to bring additional natural gas supplies online.

AIDEA partnership

In arranging financing, BlueCrest has depended heavily on the Alaska Industrial Development and Export Authority, a public corporation created in the late 1960s to spur economic activity in the state. The recent passage of House Bill 50 gave AIDEA the authority to loan funds to a company based on its proven undeveloped or developed oil and gas reserves. "It will be important for the legislators now to appropriate the funds necessary to fund this loan program to the producers," Martinek wrote to Nottingham.

AIDEA's involvement in the project dates to 2015, when it provided a loan to bring an onshore drilling rig to the Cosmopolitan unit for an extended-reach drilling program.

A series of internal and external issues — construction delays on the rig, the state suspending its tax credit program, and the drop in oil prices during the early months of the coronavirus pandemic — led to various modifications, most recently in August 2023.

In his letter, Martinek said BlueCrest was working with AIDEA on a loan to fund drilling of the H10 well and to finish preparatory work on the Tyonek Gas Project. "There is also a possibility that other lenders will join in on the loans given to BlueCrest now that the State has taken an interest in the development of these oil and gas projects. We continue to work with two other groups outside of AIDEA to jointly fund this project," he wrote.

Plans of development

The Division of Oil and Gas was unsatisfied with the response. In a letter dated Aug. 26, Nottingham asked BlueCrest for more details about its financing and supply contracts.

"January 2027 is now 29 months, or a little less than two and a half years away — a very short timeframe for the execution of significant development activity. Based on the information above, please also share how the contingencies or uncertainties in the current funding opportunities affect this delivery date," Nottingham wrote in the August letter.

In its 11th plan of development, for calendar year 2025, BlueCrest said it was "working with a large investment firm" to secure funding for Cosmopolitan. Combined with AIDEA funding, these third party funds would "totally fund" drilling of the H10 Trident Fishbone Well in 2025 and bringing the Tyonek Gas Project online by mid-2027.

According to the plan of development, BlueCrest had already completed long lead-time permitting for 2025 operations and was working on permits for the 2027 program. The company said it still needed to complete final permitting for the 2025 program. The state had yet to approve the plan by the time The Producers went to print in November 2024.

History

BlueCrest came to Alaska in the early 2010s as a partner of Buccaneer Energy Ltd., which operated Cosmopolitan. As part of bankruptcy proceedings, BlueCrest took over as sole owner and operator and brought the unit online in early 2016 from an existing well.

COURTESY BLUECREST

BlueCrest Rig #1 at the Cosmopolitan onshore drilling and production facility located in Anchor Point, Alaska.

The company commissioned a mechanical refrigeration unit at Cosmopolitan in 2020 capable of processing as much as 35 million cubic feet of natural gas per day. The two current Cosmopolitan projects have been on the docket for years, delayed by a global pandemic, oil price fluctuations, and uncertain financial markets and tax regimes.

The Cosmopolitan unit produced nearly 260,000 barrels of oil and 465 million cubic feet of natural gas in 2023, according to the Alaska Oil and Gas Conservation Commission, down from 281,000 barrels of oil and 587 million cubic feet of natural gas in 2022. The unit has produced 2.3 million barrels of oil and 9.2 billion cubic feet of gas cumulatively. ●

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ConocoPhillips enthusiastically expanding

Alaska's most consistent operator pursuing three major growth initiatives

By ERIC LIDJI
For Petroleum News


EREC ISAACSON

After several slow pandemic years, ConocoPhillips Alaska is firmly in a period of growth.

The largest and most consistent Alaska operator in the 21st century is undertaking three long-term expansion projects over the next five years. The company is adding two participating areas at its Kuparuk River unit to target new intervals, adding a pad at its Colville River unit to target the prolific Nanushuk formation and actively developing the Willow prospect at its Bear Tooth unit in the National Petroleum Reserve-Alaska.

That leaves the Greater Mooses Tooth unit, which is producing around 14,000 barrels per day and serves as a crucial infrastructure link connecting Bear Tooth back to the grid.

These projects come on top of existing daily operations at those units represent approximately $17 billion in upcoming investment in Alaska, according to the company.

ConocoPhillips

ConocoPhillips Alaska

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Kuparuk River unit

ConocoPhillips expanded the Kuparuk River unit this past

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CONOCOPHILLIPS *continued from page 20*

year. The company successfully added two new participating areas: Torok and Coyote. And the company is currently working toward expanding the existing West Sak participating area.

The Torok participating area is associated with the Moraine interval at the Nuna satellite, while the Coyote participating area is associated with the Nanushuk formation.

The Torok participating area covers 16,102 acres in the northwest of the unit, beyond the current boundaries of the Kuparuk participating area. Previous exploration efforts by Sinclair Oil and Gas in the mid-1960s, Texaco in the 1980s, and ARCO in the 1990s discovered oil in the area. High water cuts rendered the area uneconomic at the time.

A breakthrough came in the 2010s, when Pioneer Natural Resources successfully tested horizontal multi-stage frac wells in a similar horizon at the Oooguruk unit to the north.

Additional testing provided more data, leading to the 3S-19 and Nuna No. 1 wells in the Torok participating area boundaries. ConocoPhillips followed those test wells with three producer/injector pairs: 3S Phase 1 (2015), Phase 2 (2018) and Phase 3 (2023).

The acreage in the Torok participating area was previously known as the Nuna satellite of the Oooguruk unit. Pioneer Natural Resources and Caelus Natural Resources each pursued the project as operators of Oooguruk. ConocoPhillips acquired the property from Caelus Natural Resources in 2019, including a preliminary drillsite and associated road.

ConocoPhillips sanctioned a $900 million project in 2023, began a 29-well development program this year. It expects first oil in early 2025 toward peak production of 20,000 barrels per day with cumulative recoverable oil estimated around 100 million barrels.

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Top: Nuna module at Drillsite 3T in the Kuparuk River Unit. Middle: Module offloaded at Oliktok dock in early August. The Oliktok dock is used for offloading sealift modules transported by barge to the North Slope. Above: The Nuna module leaves the Port of Alaska July 24, 2024.

CONOCOPHILLIPS *continued from page 22*

The Coyote participating area covers 16,278 acres at the western end of the unit. The area also saw previous exploration from Sinclair in the mid-1960s and Texaco in the 1980s.

The 3W-07 development well passed through Coyote toward a target in the Kuparuk in the early 1990s. ConocoPhillips drilled the Palm No. 1 exploration well in 2001. The vertical 3S-24B produced about 97,000 barrels over about 12 months in 2022. The 3S-704 producer and 3S-701A injector pair have been operating since the middle of 2023, while the 3S-718 and 3S-722 producer/injector pair from 2024 are awaiting completion.

In its plan of development for the year ending July 31, 2025, ConocoPhillips committed to building the new 3T drillsite to accommodate eight new Torok participating area wells and a portion of the estimated 30 and 40 new wells planned for the Coyote participating area. The majority of the Coyote wells are being planned for the existing 3S drillsite.

In that plan, ConocoPhillips proposed a 17-well development program this year at the Kuparuk River unit: eight at Torok, six at Coyote, and three at West Sak. The company completed a 12-well program this past year focusing on the same three areas, in addition to the regular slate of maintenance projects across all seven participating areas.

According to the company, the Kuparuk River unit produced 79,700 barrels of oil per day (29 million barrels total) in 2023, down from 81,700 barrels per day (29.8 million total) in 2022, down 2.4% year over year. The unit produced 13.8 million barrels in the first half of 2024, according to the Alaska Oil and Gas Conservation Commission.

Colville River unit

The Nanushuk continues to be the driving force behind Colville River unit growth.

The Colville River unit includes eight participating areas, three oil pools, and eight distinct reservoirs within those pools. In the current development year, ConocoPhillips is planning no major development work at the Alpine, Fiord Kuparuk, Fiord Nechelik, or Fiord West Kuparuk, Nanuq Nanuq, Qannik or Narwhal participating areas. The company announced one producer planned for the Nanuq Kuparuk participating area.

In early 2024, ConocoPhillips drilled the Titan No. 1stratigraphic test well in the Fiord West Kuparuk participating area to guide future drilling in the area. The company also drilled the CD5-32X exploration well to test the Brookian Nanushuk interval. While previous wells have penetrated this interval, no fluid data had yet been collected.

In an amendment in September 2024, ConocoPhillips added three more wells, both attached to new participating areas created to target the Nanushuk formation.

The CD4-5XX well would be a producer in the recently approved Narwhal participating area. It would be drilled by May 15, 2025, as "part of continued development of the Brookian Nanushuk Narwhal reservoir from CD-4 pad," according to the company.

The two CD5-6XX wells would be a producer and injector pair in the Minke participating area, which the company proposed in an application to regulators in September 2024. The two horizontal wells would be drilled from existing CD-5 slots by May 15, 2025.

None of the three wells had been fully permitted as The Producers went to print.

In addition to these projects, ConocoPhillips plans to advance required work commitments required for its fifth expansion area in the south of the Colville River unit.

The company is planning to build a CD8 pad in the expansion area to access Narwhal resources that lay beyond the comfortable reach of extended-reach drilling from the CD4 pad. The current plan envisions 20-40 wells from CD8, "dependent on ongoing reservoir studies and learnings from CD4 Narwhal drilling and production to determine final spacing and optimum wellbore designs and trajectories," according to the company.

In its 2023 plan, ConocoPhillips drilled five CD4 wells, two producer-injector pairs and one "opportunity" well. These wells provided "additional data on reservoir performance and provide insights to optimize the CD4 and CD8 development concepts, including ultimate well spacing, waterflood performance, and surface facility design for CD8."

The company is also using the 2020 Narwhal 3D seismic survey and a 2022 survey by SAExploration, which will provide additional insights into the 5th expansion area.

Under the current timeline, ConocoPhillips would build CD8 between 2027 and 2029 with first oil around 2030. In addition to CD8, the CD4X3 pad expansion from 2022 will allow the company to eventually drill as many as 12 Narwhal wells from CD4.

The Narwhal participating area has gone by many names over the years. ConocoPhillips called the prospect Titania in the early 2000s. Brooks Range Petroleum Corp. called it Tofkat in the mid-2000s. ConocoPhillips called the prospect Putu in the late 2010s and later announced a 100 million to 350 million barrel Nanushuk discovery at Narwhal.

NPR-A

The CD5 pad at the Colville River unit was transformational, allowing ConocoPhillips to cross the Nigliq Channel and access prospects in the National Petroleum Reserve-Alaska, including the Greater Mooses Tooth unit and the Bear Tooth unit Willow prospect.

At the Greater Mooses Tooth unit, the company brought the Lookout project online from the GMT-1 pad in 2018 and the Rendezvous project online from the GMT-2 pad in 2021.

The company began pursuing Willow at Bear Tooth in 2018 following an exploration program and sanctioned the project in late 2023, following years of permitting and legal challenges. The $7.5 billion project would develop some 600 million barrels of recoverable oil, estimated to start in 2029 and peak at around 180,000 barrels per day.

In a November 2024 earnings call, ConocoPhillips SVP Kirk Johnson said, "the team is really sharpening the pencil right now on preparing for our 2025 winter construction season… In 2025, we'll resume those critical activities that … you have to do from ice roads. And so that consists of gravel placement for roads and paths. We'll resume pipeline installations, and then we'll also start to begin placing camps out at Willow."

With the completion of ice road construction, the company can begin moving operation enter modules into place. Those

continued on page 26

Incurs $341M in taxes

On Oct. 31, 2024, in connection with ConocoPhillips' quarterly 2024 earnings presentation, ConocoPhillips Alaska reported a net income of $267 million in the third quarter of 2024.

During the quarter, ConocoPhillips Alaska incurred an estimated $341 million in taxes and royalties, which includes $251 million to the state of Alaska and $90 million to the federal government.

Additionally, in the third quarter, ConocoPhillips Alaska invested $691 million in capital.

"Continued progress on projects like Willow and Nuna, along with our agreement to acquire certain Chevron oil and gas assets in Alaska, underscores our commitment to Alaska and demonstrates the effectiveness of the stable fiscal regime," said Erec Isaacson, president of ConocoPhillips Alaska.

"Year to date, we've invested more than $2 billion in Alaska projects, which surpasses our total 2023 capital expenditures. This investment creates jobs and promotes economic opportunities for Alaskans," Isaacson added.

Since 2007, the company has incurred approximately $45 billion in taxes and royalties to the state of Alaska and the federal government. Of that amount, about $35 billion went directly to the state. In that same period, ConocoPhillips Alaska's earnings were over $27 billion.

In the Q&A session for ConocoPhillips, SVP Kirk Johnson, global operations, said this about Alaska operations: "Most importantly, the team is really sharpening the pencil right now on preparing for our 2025 winter construction season. ... And we do recognize that the scope here next year is going to be larger than the past winter season that was really quite successful for us."

"In 2025, we'll resume those critical activities that ... you have to do from ice roads. And so that consists of gravel placement for roads and paths. We'll resume pipeline installations, and then we'll also start to begin placing camps out at Willow."

"And then lastly, and very importantly, again, now that we have those operation center modules — they're up on the North Slope of Alaska. Once we have ice roads constructed, we'll begin moving those modules into the Willow development area."

—KAY CASHMAN

CONOCOPHILLIPS *continued from page 25*

modules arrived on the North Slope in August 2024.

Buying Chevron assets

Another 2024 event: ConocoPhillips Alaska said Oct. 3 that it signed a purchase and sale agreement to acquire Chevron U.S.A. Inc.'s and Union Oil Company of California's non-operated interest in the Kuparuk River unit and a portion of its non-operated interest in the Prudhoe Bay unit for approximately $300 million, subject to customary adjustments at closing.

The transaction is expected to close by the end of 2024.

Upon closing, ConocoPhillips Alaska's working interest will increase approximately 5% to a range of 94-99% in the Kuparuk River unit, inclusive of satellite fields, and will increase 0.4% to approximately 36.5% in the Prudhoe Bay unit.

The transaction is expected to add an estimated 5,000 net barrels of oil equivalent per day to the company's portfolio going forward.

"This transaction once again demonstrates our investment in the state," said Isaacson. "In the first half of 2024, our investments in Alaska projects have exceeded $1.4 billion, underscoring our sustained commitment to Alaska for more than 50 years."

Expanding KIC entrance

And there is one other thing.

On Oct. 1, 2024, ConocoPhillips Alaska applied to the division for a unit plan of operations amendment to cover a 3.5-acre expansion at the north entrance of the Kuparuk Industrial Center pad.

In its project overview the company said the work would involve placing some 20,140 cubic yards of clean gravel fill between the KIC laydown yard and the existing northern entrances.

Because the existing gravel infrastructure has inconsistent thickness, a 3-inch-thick blue board insulation will be laid under the gravel for thermal protection of underlying permafrost and allowing a smoother transition to existing grade.

"Extending the northern entrances increases laydown space and safety for large vehicles and emergency equipment utilizing the existing KIC gravel pad," ConocoPhillips said.

Discussing the purpose and need for the work, the company said it "will increase safety and support the transportation and storage of heavy equipment, emergency equipment, piping, modules, and other materials on the KIC gravel pad" maintaining safe and reliable operation of existing infrastructure needed to support ongoing and planned activities in the Greater Kuparuk Area.

KIC work plan

The schedule calls for gravel mining, hauling, placement and compacting from Jan. 15, 2025, through June 1, 2025, which is the anticipated date for project completion.

Construction equipment involved may include graders, front-end loaders, dump trucks, excavators and compactors.

Gravel will be from Mine Site C or other permitted sources in the Greater Kuparuk Area, with gravel to be placed by existing maintenance contractor work force at Kuparuk.

There will be permanent impacts to 3.5 acres of jurisdictional wetlands, ConocoPhillips said, noting that "wetlands proposed for impact have experienced indirect impacts from surrounding development which have decreased their overall function." ●

Contact Eric Lidji at ericlidji@mac.com

Eni hands over the reins to Hilcorp

Oooguruk and Nikaitchuq will fall under the auspices of Alaska's top producer

By ERIC LIDJI
For Petroleum News

ROBERT PROVINCE

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Eni US Operating Co. Inc. is in an unusual position. The domestic subsidiary of the Italian major recently submitted its annual plans of development for the two North Slope units it operates — Oooguruk and Nikaitchuq.

Earlier this year, Eni negotiated a sale of those two units to Hilcorp Alaska LLC. As this edition of The Producers was going to print, it appeared that the sale had closed. If that's true, Oooguruk and Nikaitchuq plans of development would almost certainly be revised.

Under those plans, Eni would have drilled five new wells and one lateral at the two units.

At the Oooguruk unit, Eni would have drilled the ODSN-05 and ODSN-09 producers and would have worked over the ODSDW-44 disposal well. The company would have also advanced its Oooguruk Tie-in Pad Partial Gas Processing project. Delays associated with the Partial Gas Processing project prevented Eni from completing the wells in 2024.

At the Nikaitchuq unit, Eni would have drilled three new wells and one lateral from the offshore Spy Island drillsite and would have expanded the Schrader Bluff participating area. The program calls for an N-sand pair, the SI44-S5 injector to support production from the existing OP14-S3 and OP10-09, and the SP05-FN7 lateral well.

In addition to these drilling plans, Eni would have advanced its Electrical Power Sharing project between Oooguruk and Nikaitchuq. The company had expected to conduct a major review in the coming year after completing engineering and receiving bids.

Now, all those plans are up in the air.

Since arriving in Alaska more than a decade ago, Hilcorp has been in this position several times: inheriting plans that are quickly suspended and revised to reflect a new strategy.

Given the uncertain short-term outlook for Oooguruk and Nikaitchuq, it makes the most sense to use this space to review the two-decade history of these landmark properties.

Oooguruk

A headline in the July 28, 2002, edition of Petroleum News read: "A winning package."

The article described efforts by Armstrong Resources LLC to advance its three-well Kuparuk-Thetis exploration prospect, following an Exxon lead from the mid-1990s. The company had acquired the acreage in a statewide lease sale the previous October.

The arrival of the small Denver-based independent seemed at the time to mark the beginning of a new era of North Slope operations. In the immediate aftermath of the Charter for the Development of the Alaska North Slope, here was a nimble, ambitious independent eager to explore a promising play considered too small for the Big 3.

(Longtime readers of Petroleum News might recall that our annual publication "The Explorers" actually began in November 2002 under the name "The Independents.")

A ballot agreement at the Kuparuk River unit in July 2002 gave Armstrong access to some existing North Slope infrastructure. It was seen at the time as a major validation of the Charter but proved to be much more complicated over time, as the project developed.

By that fall, Armstrong had convinced the large Dallas-based independent Pioneer Natural Resources Co. to join the project. Pioneer acquired a 70% interest in the 14,000-acre prospect, which it began describing as the Northwest Kuparuk prospect.

Pioneer talked about bringing an "independent model" to Alaska.

"The independent model is to quickly turn investment into cash flow," Executive Vice President of Worldwide Exploration Chris Cheatwood said in early 2003. The idea was to reduce to "cycle time" of acquisition, exploration, development, and production.

The Alaska oil patch is naturally wary of big promises, but this one worked out.

The state approved the Oooguruk unit in July 2003. The 20,394-acre unit covered 11 leases (and part of a 12th) in the nearshore waters of Harrison Bay of the North Slope.

Subsequent exploration drilling justified a $500 million project, including construction of a 6-acre gravel island and pipeline connections back to the Kuparuk River unit, as well as new drilling. The state provided royalty relief to improve the economics of the project, although a major run-up in oil prices above $130 per barrel also helped the project.

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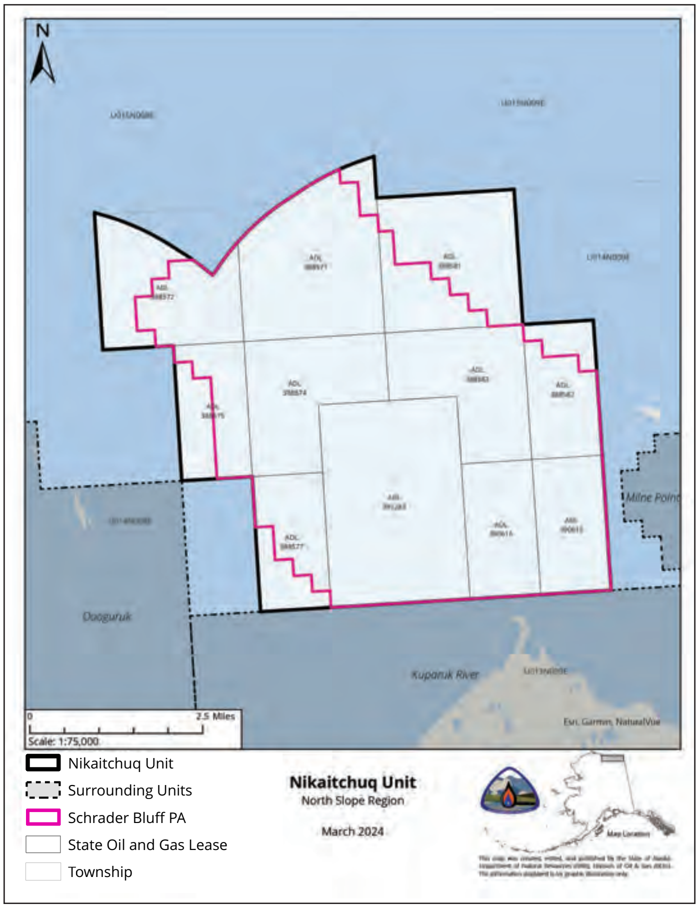

ENI *continued from page 27*

Over the next few years, Pioneer became a symbol of industry frustration with the perpetual changes in the Alaska fiscal regime for oil productions. Those accusing the state of instability noted that Pioneer had started exploring at Oooguruk under one tax structure, permitted the project under a second and developed the project under a third.

Pioneer brought Oooguruk online in June 2008, becoming the first independent operator in North Slope history. Almost immediately, the company had to suspend production to accommodate planned maintenance at Kuparuk River Unit Central Processing Facility 3.

At the time, Pioneer estimated that Oooguruk would produce between 70 million and 90 million barrels of oil equivalent over 25 to 30 years of field life. After more than a year of development, the company upped the estimates to between 120 million and 150 million.

Despite general enthusiasm about Alaska, Pioneer quickly shifted its priorities toward development. The company dropped nearly 150,000 exploration acres in 2009. In early 2011, the company also sold its Cosmopolitan project in the southern Kenai Peninsula.

Throughout the remainder of 2011 and into 2012, Pioneer focused on expanding the Oooguruk unit, first through the addition of a third pool — Torok, in addition to the existing Kuparuk and Nuiqsut — then by pursuing the 50 million barrel Nuna satellite.

By focusing on Oooguruk, and expanding its holdings there, Pioneer made the unit attractive. In the first quarter of 2014, the company sold its Alaska subsidiary to Caelus Energy Alaska LLC for $300 million. The players behind Caelus had a track record of entering complex basins, making notable discoveries, and selling to larger players.

Caelus spent much of its first year pursuing royalty relief for the Nuna project. The company received that relief in January 2015 and sanctioned the project that April, beginning activities that summer. The following April, though, the company suspended Oooguruk drilling, postponed Nuna, and laid off 25% of its workforce, blaming "the prolonged depression in oil prices and uncertainty in Alaska's oil tax system."

Although it investigated acreage in other areas of the state, Caelus never bounced back from the suspension at Oooguruk. The company sold its share of the unit to minority partner Eni in early 2019 and sold the Nuna project to ConocoPhillips in June 2019.

Nikaitchuq

In some ways, Eni was the logical operator of Oooguruk.

For the previous decade, Eni had a front-row seat for the story of Oooguruk.

In the summer of 2003, a year after announcing its Kuparuk-Thetis prospect, Armstrong announced plans for a three-well exploration program at its nearby Northwest Milne prospect offshore near Spy Island — also known as the proposed Nikaitchuq unit.

In early 2004, Armstrong brought the large Oklahoma-based independent Kerr-McGee Oil & Gas onto the project, just as it had brought Pioneer onto the Oooguruk project the previous year. The companies drilled two exploration wells that winter, announced a notable oil discovery, and formed two neighboring units: Tuvaaq and Nikaitchuq.

Kerr-McGee and Pioneer flirted with the idea of forming a joint venture to cover all their discoveries but ultimately decided to operate independently. For a time in the summer of 2005, a race was underway: which would be the first independent producer on the North Slope? Even though Kerr-McGee was second to start, it was proposing a faster schedule.

Eni joined the conversation in August 2005 when it acquired Armstrong Alaska's assets, including its 30% minority stakes in the Oooguruk and Nikaitchuq units.

Progress on Nikaitchuq was complicated in late 2006, when Anadarko Petroleum acquired Kerr-McGee for $24.3 billion. The acquisition was focused on opportunities in the deepwater Gulf of Mexico and the Rockies. Anadarko CEO Jim Hackett said at the time, "There are no sacred cows," meaning the company would sell non-core properties.

Taking advantage of the opportunity, Eni acquired the remaining majority 70% interest in Nikaitchuq in early 2007, giving it total ownership of the offshore unit.

After spending the rest of the year expanding Nikaitchuq to include the neighboring Tuvaaq unit and successfully requesting royalty modification from the state, Eni officially sanctioned a $1.45 billion Nikaitchuq development project in early 2008.

The project envisioned two drilling pads, one onshore at Oliktok Point and the other on an artificial offshore island near Spy Island. In a notable change from the Kerr-McGee proposal, Eni announced it would build a 40,000-barrel-per-day standalone production facility rather than negotiate access to existing BP or ConocoPhillips facilities.

Eni estimated that Nikaitchuq contained 180 million barrels of recoverable reserves and announced plans to drill 73 development wells by 2011 with first oil planned for 2009.

Eni became a producer in June 2008 through its minority stake in Oooguruk. Amid a historic downturn in Alaska North Slope crude oil prices in late 2008 and early 2009, Eni announced a slow down to its Nikaitchuq timeline, delaying start-up to 2010 or later.

While low oil prices were cited at the time, the explanation was unsatisfying, given the royalty modification at the unit. It was later revealed that the company had missed the winter barge season on the North Slope due to Hurricane Ike work delays in Louisiana.

Eni announced start-up at Nikaitchuq in February 2011. The company said at the time that it expected the unit to produce for more than 30 years, peaking at 28,000 barrels per day, and estimated that the field contained 220 million barrels of recoverable reserves.

In the decade since completing its initial development program at Nikaitchuq in late 2014, the company has been working on Phase II to expand production at the unit.

The expansion efforts included numerous initiatives.

Eni added dual laterals to select wells and later drilled the first multilateral well at the unit. The company looked beyond the reach of its existing drilling pattern with the West Extension Project and East Extension Project and later with the more ambitious North Nikaitchuq project in the Arctic OCS. Eni appraised the potential of the Schrader Bluff N sands at the unit after restricting Phase I development to the Schrader Bluff OA sands and floated the idea of conducted a Sag River formation development at the unit.

With its acquisition of the majority stake in the neighboring Oooguruk unit in 2020, Eni seemed to be reuniting the two units that had emerged from the same exploration wave in the early 2000s. In addition to new drilling, the company was beginning to undertake infrastructure projects design to improve efficiency and reduce redundancy at the units.

Hilcorp

When they were first discussed in the early 2000s, Oooguruk and Nikaitchuq were promoted as a new era in North Slope operations: midsize fields for midsize players.

The reality was winding, involving two large independents, a small independent, and one of the largest majors in the world, before arriving in the portfolio of Hilcorp.

In some ways, Hilcorp makes sense. The company has always been most interested in maximizing existing development projects, rather than pursuing wildcat adventures.

The difference here is age.

Until now, Hilcorp has largely pursued legacy Alaska projects, including some of the oldest and most enduring oil and gas plays in the state. Oooguruk and Nikaitchuq were discovered less than 20 years ago and brought online only about 15 years ago. ●

Pioneer brought Oooguruk online in June 2008, becoming the first independent operator in North Slope history. Almost immediately, the company had to suspend production to accommodate planned maintenance at Kuparuk River Unit Central Processing Facility 3.

Contact Eric Lidji at ericlidji@mac.com

Glacier maintains Cook Inlet properties, ponders expansion

West McArthur and Redoubt remain viable but future may depend on exploration

By ERIC LIDJI
For Petroleum News


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Earlier this year, the state officially approved a major ownership shuffle involving Glacier Oil & Gas Co. and its two subsidiaries: Cook Inlet Energy and Savant Alaska.

Under the plan approved by the Division of Oil and Gas, SEP Alaska LLC transferred some of its 100% interest in Glacier to The Smith Bay Company Alaska Inc. and JPD Family Holdings LLC. Glacier owns 100% interest in Cook Inlet Energy, which owns 100% interest in Savant Alaska. Under the new proposal, Cook Inlet Energy and Savant Alaska retained their existing working interest in 15 state leases.

Pontem Energy and Sweat Equity Partners acquired Glacier Oil & Gas in early 2023, picking up 100% working interest in the Cook Inlet Energy LLC-operated West McArthur River unit, Redoubt unit and associated Kustatan Production Facility in Cook Inlet as well as the Savant-operated Badami unit on the eastern North Slope.

(Editor's note: See update on Badami in the North Slope section of The Producers.)

As with other smaller fields throughout the Cook Inlet basin, Cook Inlet Energy is balancing practical and relatively affordable projects with a desire for new drilling at the West McArthur River unit and the Redoubt unit. The company is reporting significant increases at the West McArthur River and a significant decline at the Redoubt unit.

West McArthur River

The state formed the West McArthur River unit in 1990. Cook Inlet Energy assumed operatorship in 2009. The unit has 6,970 acres over parts of three offshore leases.

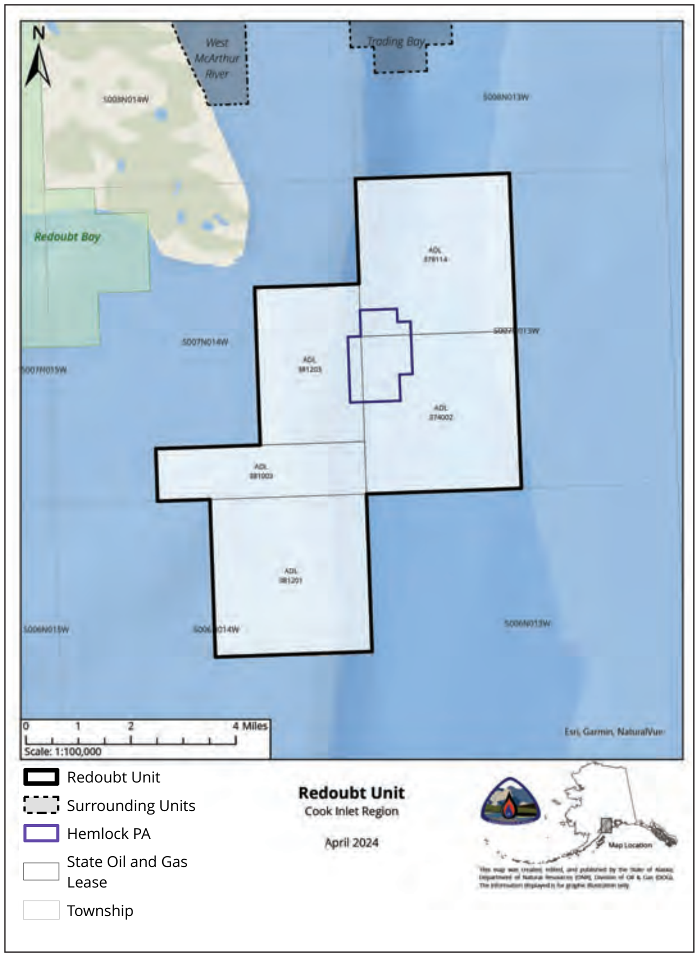
West McArthur River includes two participating areas: Area No. 1 and Sword.

The West McArthur River unit has eight wells. The unit produces from WMRU-2B, WMRU-5, WMRU-6 and Sword No. 1, producing 55.8 million cubic feet of natural gas, 230,992 barrels of oil, and 1.7 million barrels of water in calendar year 2023, according to the company. This represents a 138% increase in production over the prior year.

WMRU-4D is a Class I disposal well, currently online. The WMRU-1A and WMRU-7A producers have been shut-in since late 2010 and late 2012, respectively, due to failed jet pumps. The WMRU-8 disposal well was taken offline in August 2023 pending work.

Redoubt

The state formed the Redoubt unit in 1997. Cook Inlet Energy assumed operatorship in 2009. The unit has 9,668.5 acres over parts of five offshore leases. Redoubt has one participating area: Hemlock. A proposed contraction of the unit is under consideration.



The Redoubt unit has nine wells. The unit produces from RU-1A, RU-5B, and RU-7B, producing 40.9 million cubic feet of natural gas, 164,203 barrels of oil, and 142,747 barrels of water in calendar year 2023, a 47 percent decline over the previous year.

RU-3A and RU-6A are injectors. RU-D1 is a Class I disposal well.

The RU-2A and RU-9 producers have been offline since 2023 and 2014, respectively, due to downhole issues. The RU-4A gas producer was suspended in 2014 due to water loading issues.

Acid Test

In May 2023 — at the start of its previous development year that ended April 2024 — Cook Inlet Energy continued an acid stimulation project it had started the previous year.

The company conducted a pilot test on the WMRU-5 and WMRU-6 wells in June 2022 and the RU-2A well in December 2022 and reported that the test had "proved beneficial to ESP pump performance by eliminating scale buildup from high water cuts and aided in enhancing production from the Hemlock formation" at West McArthur River.

A subsequent failure of an ESP at the RU-2A well, unrelated to the stimulation, kept the company from fully determining the impact of the project at Redoubt. A workover in July 2023 was abandoned "after discovering that a major portion of the tubing and ESP assembly had parted in the hole," requiring special intervention, possibly this year.

Following those positive results, the company conducted additional acid stimulation at the WMRU-2B and the Sword No. 1 wells, before working over both wells in May and June 2023 to replace failed electric submersible pumps. The new ESP at WMRU-2B stopped working after 18 days, requiring a second workover in September 2023 to replace a failed penetrator. The well was brought back online following that intervention.

Workovers

A reservoir study at the Redoubt unit in March 2023 included a project to determine whether to convert the RU-5B producer into a water injection well, following an ESP failure. The company instead decided to replace the ESP in August 2023 and keep the well as a producer. Following the operation, the company conducted a weak acid stimulation in December 2023 to increase productivity. The results are being evaluated.

Following a failed ESP at the RU-7B well in May 2023, Cook Inlet Energy conducted an unplanned workover and acid stimulation in August. The company was unable to retrieve the failed pump but said the remaining pieces had no adverse impact on production. This work forced the company to defer some activities that had been planned for RU-9.

FWKO

Cook Inlet Energy completed its Free Water Knock Out project in September 2023. The project was launched to simplify disposal at West McArthur River and Redoubt.

Before the project, the company processed produced water from both fields at the Kustatan Production facility and injected the waste at Redoubt. The FWKO project allows the company to extract produced water from the three-phase stream before it leaves West McArthur River for Kustatan, making it available for local uses at West McArthur River.

As part of a pilot project launched in December 2022 and carried into 2023, the company identified the shut-in WMRU-7A and WMRU-08 wells as candidates for injection.

Through the FWKO project, Cook Inlet Energy converted the WMRU-4D Class I disposal well to produced water disposal and is now considering the same for WMRU-08.

The company is working on a phased project to increase injections at RU-3A.

The state formed the West McArthur River unit in 1990. Cook Inlet Energy assumed operatorship in 2009. The unit has 6,970 acres over parts of three offshore leases.

Cook Inlet Energy completed in-line inspection on its three-phase 8-inch pipeline connecting West McArthur River to Kustatan and now plans to replace 1 mile of the pipe. The company also discontinued Rig 37 after evaluating the unit for repairs. A substitute rig brought to the site is also being used at Redoubt instead of Rig 35.

Exploration projects

Those are the maintenance projects. The bigger project at West McArthur River is the Sabre prospect. The bigger projects at Redoubt are the Northern and South fault blocks.

Several former operators looked at Sabre. Cook Inlet Energy considered a well as early as late 2013 but ultimately delayed the project due to logistics and costs. The company previously drilled the RU-9 well in the Southern fault block, but a failed electric submersible pump subsequently hampered the well. Cook Inlet Energy has continued to include both expansion projects in development plans over the year. Its 2023 plan cited "capital constraints coupled with geologic and drilling risk" as well as the ownership change and a focus on Badami drilling as current reasons for deferring these projects. ●

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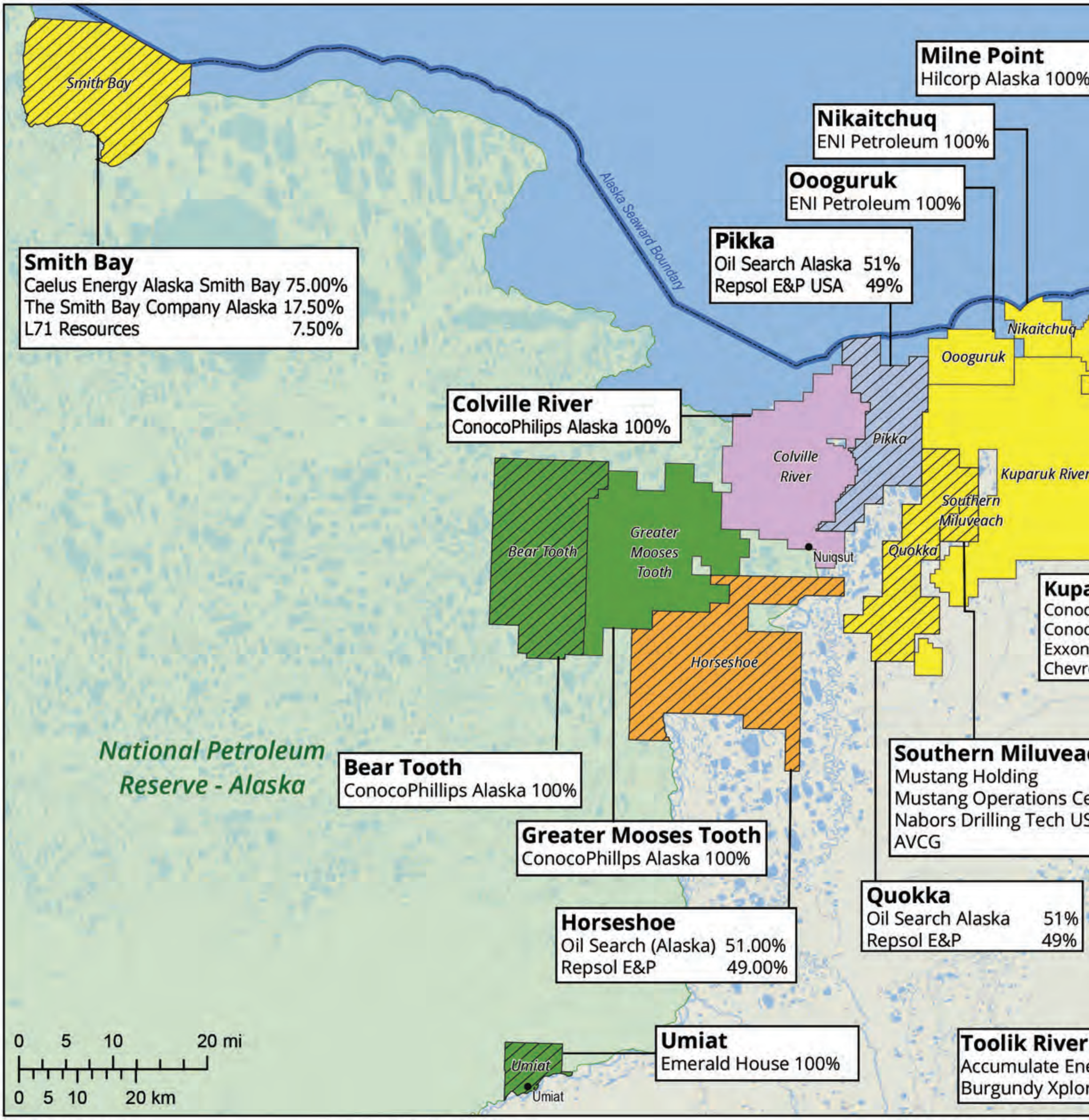

State Unit
State/Federal Unit
State/Native Unit
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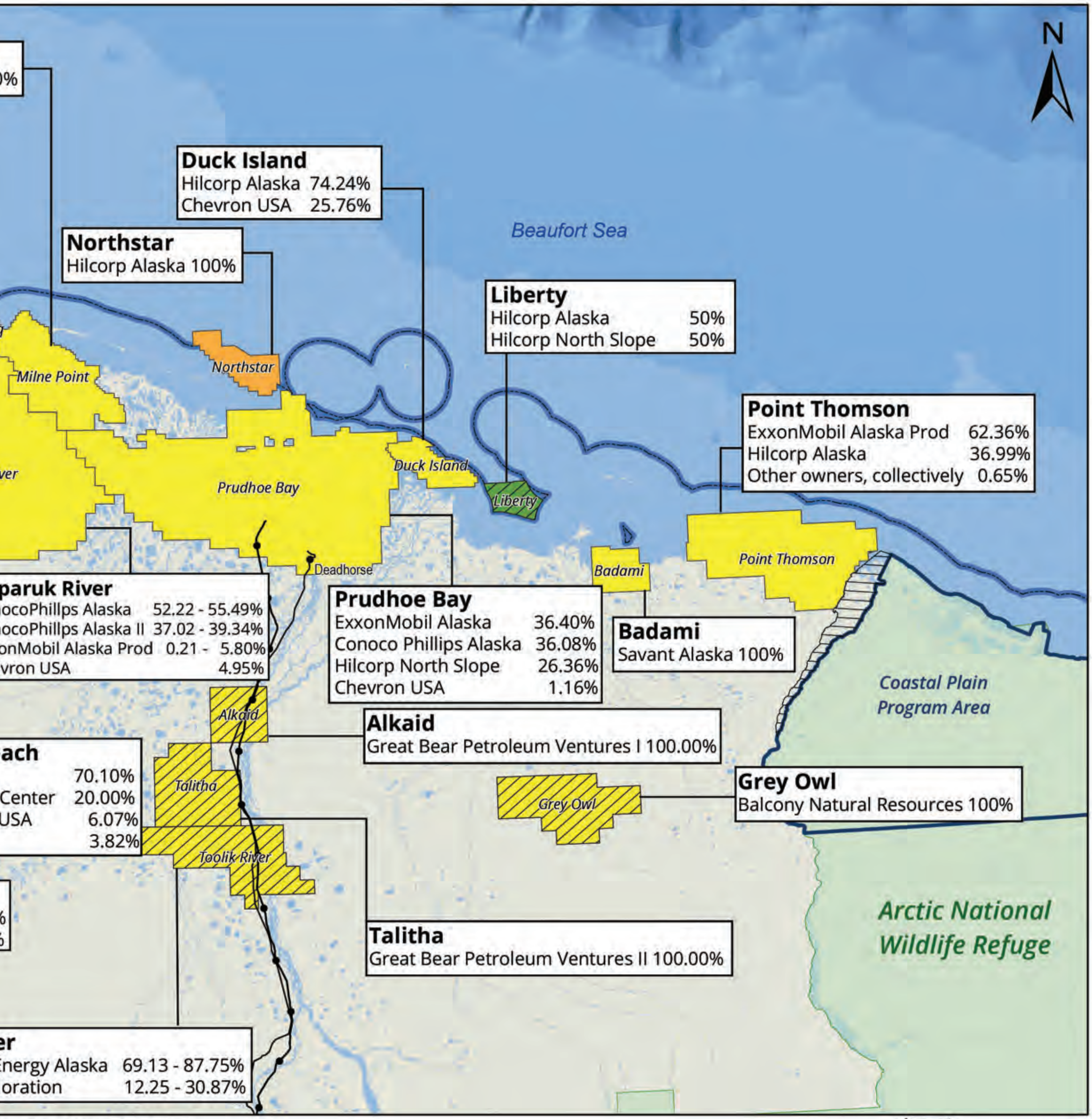
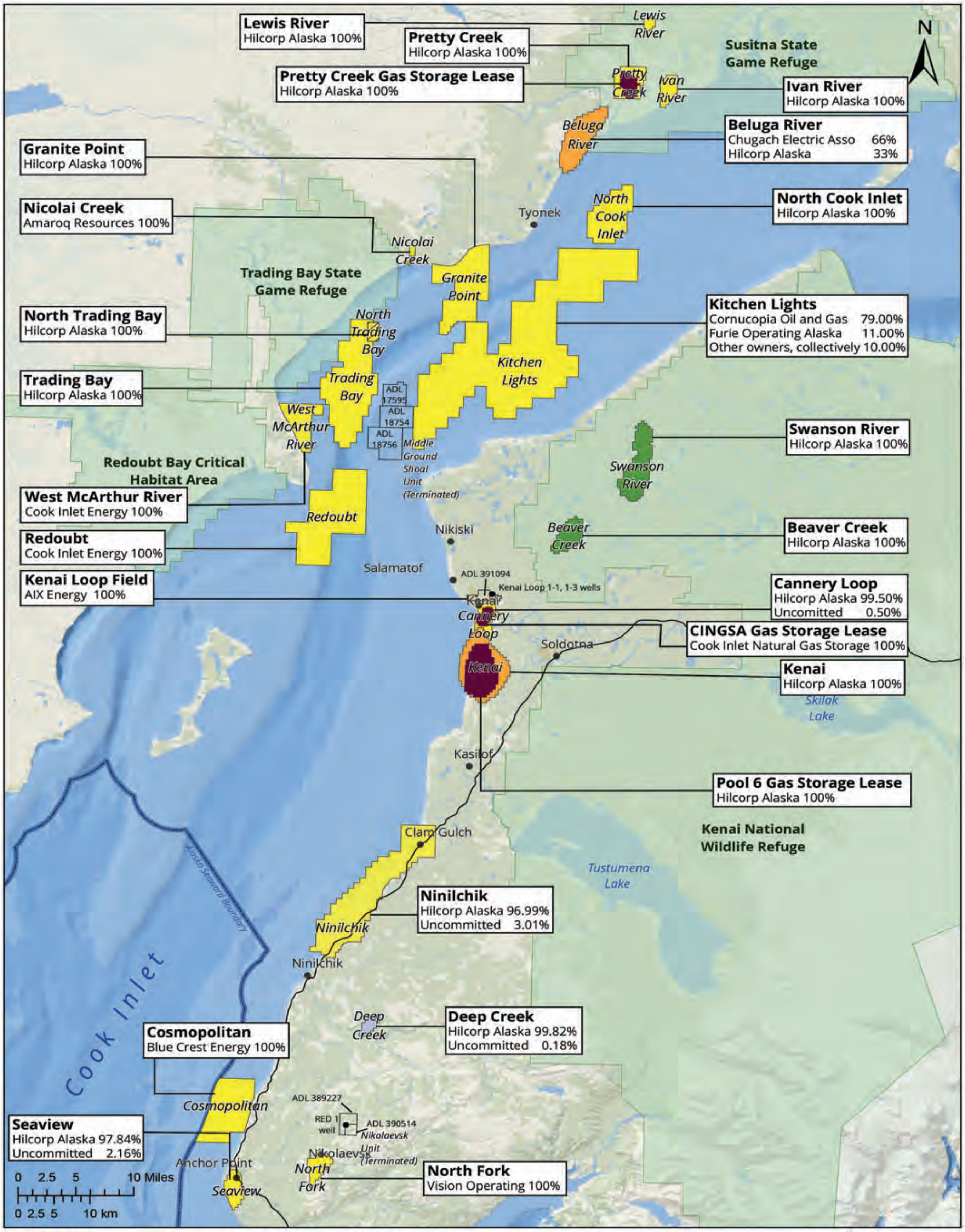


rest Ownership
Slope Units

of Alaska
Natural Resources
f Oil and Gas

ber 2024

This map is for illustrative purposes only and should not be relied upon for title research. Working interests may differ between producing and non-producing acreage and producing and non-producing depths. These interests do not reflect any pending assignments. To see our most current maps, please visit: www.dog.dnr.alaska.gov/Information/MapsandGIS



State Unit
State/Federal Unit
State/Native Unit
Federal Unit
Gas Storage Lease
Non-Producing
Field
Sterling Highway
Well(s)

Working Interest Ownership of Cook Inlet Units

State of Alaska
Department of Natural Resources
Division of Oil and Gas
August 2024

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HEX/Furie moves on gas

Jack-up rig at Kitchen Lights platform drilling for more natural gas for Alaskans

By **KAY CASHMAN**
Petroleum News


JOHN L. HENDRIX

John Hendrix's message on Oct. 3, 2024, to his fellow Alaskans: "Great day for HEX/Furie and Alaska. Jack-up rig on our platform today at 10 am!! Drilling local natural gas for Alaskans!"

The Enterprise 151, formerly named the Spartan 151, is the jack-up.

The platform is the Julius R Platform, or JRP.

The field is the 83,000-acre Kitchen Lights unit.

And long-time Alaskan John Hendrix is the owner of HEX, the parent of HEX Cook Inlet. HEX Cl is the only 100% Alaskan-owned oil and gas company currently operating in the state.

Hendrix formed the HEX companies for the purpose of purchasing Furie Operating, its sister companies and their Cook Inlet assets — principally to switch the Cook Inlet Kitchen Lights unit from foreign and Outside ownership to Alaska ownership. He accomplished this on June 30, 2020, making the purchase from a Delaware bankruptcy court.

In addition to the Kitchen Lights unit, the assets he acquired include the JRP, a 15-mile subsea gathering line and an onshore natural gas processing facility at Nikiski on the Kenai Peninsula.

While the platform is the newest and smallest in Cook Inlet, the unit is the largest by acreage and is considered to have undeveloped potential for natural gas.

Drilling for natural gas from the JRP meets the mandatory drilling conditions of the 10th plan of development that were written into the POD by the Alaska Department of Natural Resources' Division of Oil and Gas, which stated "Furie will drill a grassroots well or sidetrack well targeting additional gas resources during the 2024 POD," which runs from Jan. 4, 2024, to Jan. 3, 2025.

HEX risked drilling even though the division had not given final approval on HEX's application for royalty reduction, which was essential to help make the unit economic. HEX risked drilling because the jack-up rig was available and there was urgent need for natural gas in Alaska.

Hendrix, owner and top executive for both Furie and HEX, told Petroleum News on Oct. 30, that "we're taking a leap of faith by drilling this well. We're just trying to prove we are committing ourselves. We're here for Alaskans. ... We're doing our part."

The Kitchen Lights platform, the Julius R, is the smallest in the inlet with space for just four well slots; that is until HEX employed the latest technology.

"We currently have … six conventional 30-inch slots that with new technology we can put two wells in each," Hendrix told PN on Oct. 31.

"We have also contacted the original builders, engineers and divers to add additional slots to grow our well count to 12 wells," he said.

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The new sidetrack, KLU A-1A, was sidetracked off one of the original four well slots.

Hilcorp owns jack-up

Purchased for approximately $40 million from Enterprise Offshore Drilling by Hilcorp Alaska on May 31, the Enterprise 151 is a 150 H class independent leg, cantilevered jack-up that can drill to 25,000 feet and operate in water depths up to 151 feet.

It is the only jack-up in the region and Hilcorp said it would make the rig available to other companies operating in Cook Inlet, presumably when Hilcorp is not using it on its own properties/leasehold.

AIDEA financing

On Oct. 23, 2024, the board of the Alaska Industrial Development and Export Authority, or AIDEA, passed a resolution approving a "revolving line of credit for a HEX Cook Inlet development project to increase Cook Inlet natural production and supply."

HEX had applied to AIDEA for the $50 million revolving line of credit to finance a "multi-year Julius R platform based offshore and a land-based North Kenai exploration development program and associated infrastructure development for the Kitchen Lights unit ... and on other oil and gas leases held by Furie or HEX."

In its resolution, AIDEA said that HEX has proposed "substantial

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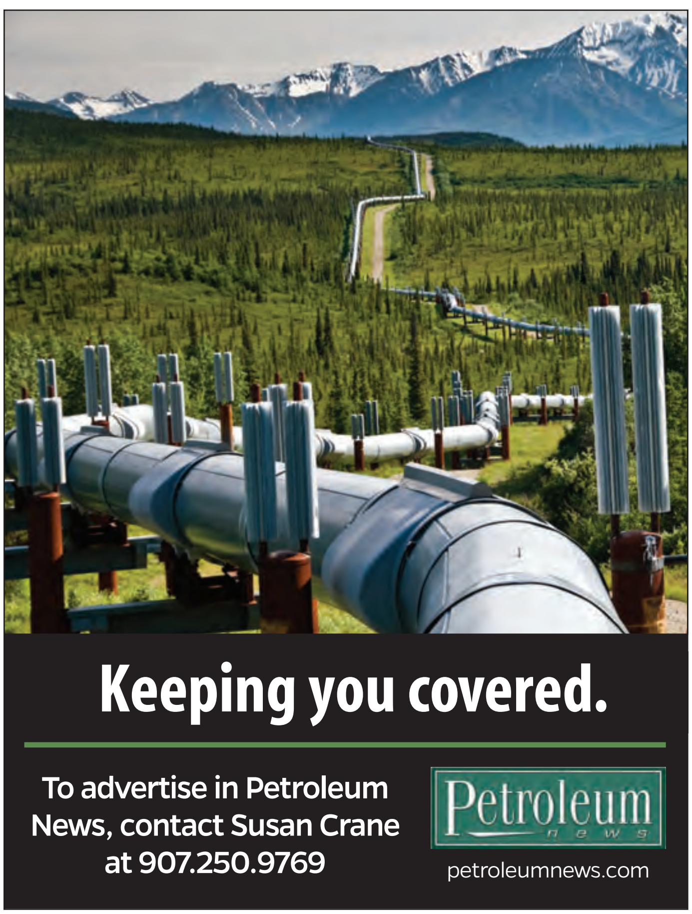
FURIE OPERATING ALASKA



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new investments in drilling, including the KLU A-1A (drilled in October 2024) and A-4A sidetracks, which would bring additional gas to market, but these projects are contingent on royalty relief at commercially reasonable terms that incentivize increased production of Cook Inlet natural gas for south central Alaska."

In its resolution AIDEA said there was a "forecast supply deficit of natural gas in the Cook Inlet" and "transmission outages will happen during January and February, the highest electrical load time. Unimpeded natural gas delivery to central and northern regions for electrical generation is critical to prevent blackouts."

In an Oct. 23 memo to AIDEA board members, Executive Director Randy Ruaro said the new funding is under AS 44.88.172, the Economic Development Account, over a 5-year period.

He said economic and development benefits for Alaska include:

—Enhancing the competitiveness of Alaska's natural gas markets by broadening access and resources.

—Increase jobs to five new permanent jobs and up to 100 during development operations.

—Retention of a resident skilled workforce in Alaska's oil and gas industry.

—Increased production of essential natural gas supply from the Cook Inlet.

—Possible future expansion.

In keeping with AIDEA's mission, Ruaro said HEX is an

Alaska owned company with a focus on hiring and training Alaskans for Alaska's oil and gas sector.

He noted that HEX successfully paid off the 2020 $7.5 million AIDEA loan early and has provided evidence of sufficient collateral.

Identifying gas zones

In its 10th POD Furie said G&G evaluations will continue with the priority of identifying additional gas zones that are potentially reachable from the Julius R platform.

The company is continuing to monitor production from existing producing wells and to identify mechanical additions that could extend economic gas production.

In the 10th POD period, the company intends to do wireline interventions as necessary with its own wireline equipment to maintain production levels from existing wells.

Timing of drilling

The timing of HEX CI Furie Operating's drilling plans were included in the two incidental harassment authorizations, or IHAs, the company received from the National Marine Fisheries Service, or NMFS.

These authorizations are effective from Sept. 13, 2024, through Sept. 12, 2025, for year 1 activities, and Sept. 13, 2025, through Sept. 12, 2026, for year 2 activities.

Per NMFS Furie is planning to conduct the following natural gas activities:

In year 1, Furie will relocate the Enterprise 151 jack-up production rig to the JRP site and conduct production drilling of up to two natural gas wells with the Enterprise 151 across 45-180 days.

On Oct. 23, 2024, the board of the Alaska Industrial Development and Export Authority, or AIDEA, passed a resolution approving a "revolving line of credit for a HEX Cook Inlet development project to increase Cook Inlet natural production and supply."

During year 2, Furie will again relocate the Enterprise 151 rig to the JRP site and conduct additional production drilling.

Furie proposes to conduct the rig towing activities between April 1 and Nov. 15 each year, but if favorable ice conditions occur outside of that period, it may tow the rig outside of that period.

Permits, production

The Alaska Oil and Gas Conservation Commission currently lists two drilling permits for Furie Operating in the Kitchen Lights unit: KLU A-4A permitted June 25, 2024, and KLU A-1A permitted Sept. 13, 2024.

In August 2024, Furie averaged 9.745 million cubic feet per day of natural gas from two wells at Kitchen Lights, according to recent data from AOGCC — 5.21% of inlet gas production in that month. ●

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Hilcorp focuses on large Cook Inlet fields

Beluga, North Cook Inlet, focus of development gas well drilling; some smaller fields also see attention

By **KRISTEN NELSON**
Petroleum News

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Hilcorp Alaska is the dominant oil and gas producer in Cook Inlet, with the company's focus on natural gas, which provides heat and electrical power for Southcentral Alaska.

Hilcorp's Houston-based parent, Hilcorp Energy, is one of the largest U.S. privately held exploration and production companies, the company says on its website. Founded in 1989, the company operates in Alabama, Alaska, Colorado, Louisiana, New Mexico, Ohio, Pennsylvania, Texas and Wyoming.

"We deploy new resources to increase production and expand cashflow," Hilcorp says, allowing the company "to reduce debt and opportunistically acquire additional fields, beginning a new cycle. By adopting this approach, we have proven our ability to revitalize mature and often overlooked properties."

Hilcorp Alaska became an operator in Cook Inlet in 2012, taking over Chevron/Union Oil Company of California's Cook Inlet assets, primarily mature fields dating to the beginning of Cook Inlet production in the late 1950s and early 1960s. In early 2013, Hilcorp acquired Marathon Oil's Cook Inlet assets, also primarily mature fields, but including the majority working interest in one newer large field, Ninilchik, which Marathon developed and brought online in the early 2000s.

In 2015, Hilcorp acquired XTO Energy's Cook Inlet assets, and in 2016 took over several of ConocoPhillips Alaska's Cook Inlet assets, primarily the North Cook Inlet field but also minority interests in and around North Trading Bay and other small interests.

Hilcorp took over as operator at the west side Beluga gas field in 2016 when ConocoPhillips sold its interest in that field to Anchorage-based electric utilities Municipal Light & Power and Chugach Electric Association (Chugach Electric purchased ML&P in 2020 and now has a two-thirds working interest in Beluga).

Focus on gas

Alaska Oil and Gas Conservation Commission production data for August show Hilcorp Alaska's most productive gas fields are Beluga River, where it holds a 33.33% working interest ownership and operates on behalf of itself and majority WIO Chugach Electric Association, North Cook Inlet, in which Hilcorp holds 100% working interest in producing intervals and Ninilchik, in which Hilcorp has 100% WIO.

In August, Hilcorp's share of produced Cook Inlet natural gas was 74.9% and its share of produced Cook Inlet oil was 73.8%.

Hilcorp's focus is on extending the life of mature fields where more oil and gas can be extracted, and after acquiring Cook Inlet properties the company initially focused on maximizing production from existing facilities.

It has also worked to expand production at existing fields, primarily large natural gas fields, with current focus on Beluga and North Cook Inlet.

Beluga

The Beluga River gas field on the west side of Cook Inlet was discovered in 1962 in a well targeting deeper oil. Sustained production didn't begin until the late 1960s after Chugach Electric Association built a power plant at Beluga, using natural gas from the field to generate electricity. In the 1980s, Enstar built a pipeline connecting to Anchorage, and began providing Beluga gas for heating.

Hilcorp holds a one-third working interest in the field and is the operator; Chugach Electric Association holds a two-thirds interest.

The Beluga River unit is primarily managed by the federal Bureau of Land Management with the state managing the subsurface of the northern half of the leases. The field produces from a number of onshore pads on the west side of Cook Inlet.

In its 62nd plan of development and operations for Beluga River, covering June 1, 2024, through May 31, 2025, and submitted to BLM in March, Hilcorp said that during the 2024 POD period it anticipated drilling as many as six grassroots wells with Rig 147, each targeting Sterling and Beluga gas.

In reviewing work completed during the 2023 POD, Hilcorp said it drilled five grassroots wells targeting Sterling and Beluga gas sands, did seven workovers and performed facility work including

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moving a compressor from C Pad to K Pad to provide compression at the pad which previously had no permanent on pad compression, and installing facilities at the DW-02 Pad allowing for disposal of drill cuttings and drilling mud.

AOGCC drilling permit data over the last calendar year show Hilcorp permitted eight Beluga River wells, completing six — the most wells completed at any Cook Inlet field in that period.

AOGCC production data for August 2024 show Beluga River averaged 42,771 thousand cubic feet per day, 22.87% of inlet gas production in that month, and a volume which was up 7.71% from July and up 25.17% from August 2023.

North Cook Inlet

Currently the second most productive gas field in Southcentral, the North Cook Inlet unit has been in production since 1969, the Alaska Department of Natural Resources' Division of Oil and Gas said in a May 2024 approval of the current plan of development which covers July 1, 2024, through June 30, 2025. Cumulative production was 1.963 billion cubic feet of natural gas through March of this year.

Hilcorp acquired the North Cook Inlet unit from ConocoPhillips effective Oct. 31, 2016, the division said and holds 100% working interest in producing intervals in the unit, which is operated from the Tyonek platform.

In the 2023 POD period Hilcorp mobilized jack-up Rig 151 to the platform and drilled two grassroots wells, sidetracked one well and completed plugging and abandonment of the Cook Inlet State 17589, an exploration well drilled in 1962.

In the 2024 POD period, Hilcorp told the division it planned as many as three grassroots wells targeting Beluga sands and up to two sidetracks, although the division said that in the technical meeting on the POD, the company said it was not working on plans for the second sidetrack due to the limited drilling season.

AOGCC records for the preceding calendar year show Hilcorp received eight drilling permits for North Cook Inlet and completed five wells.

August AOGCC production data show North Cook Inlet averaged 38,510 mcf per day, 20.59% of inlet gas production, down 1.92% from July but up 11.6% from August 2023.

Ninilchik

Ninilchik, which was the most productive natural gas field in Cook Inlet in August 2023, is currently third, averaging 29,134 mcf per day in August 2024, 15.58% of inlet production in that month, down 5.46% from July and down 25.64% from August 2023, AOGCC production data show.

Hilcorp Alaska has a 100% working interest in Ninilchik, a unit formed by Marathon Oil in 2001 and expanded in 2003 and again in 2016. Hilcorp acquired the share of Ninilchik owned by Union Oil Company of California when it acquired that company's Cook Inlet assets in 2012 and acquired a majority interest and operatorship in 2013 as part of its acquisition of Marathon Oil's Cook Inlet assets.

Marathon began sustained production in 2003, and while contraction to approved participating areas and acreage supporting production is required after 10 years of sustained production, Ninilchik contraction has been delayed several times, as field expansion and development continues. Last year Hilcorp applied to expand the unit to the south where it has confirmed natural gas in the Pearl Structure, and to establish the Pearl participating area.

AOGCC records show no wells permitted or completed at the unit in the past 12 months.

The unit, produced from onshore pads, includes onshore and offshore acreage.

Ninilchik produces natural gas from three participating areas, Falls Creek, Grassim Oskolkoff and Susan Dionne-Paxton, the Division of Oil and Gas said in a June approval of Hilcorp's 20th plan of development for the unit, covering Aug. 1, 2024, through July 31, 2025.

Hilcorp did not drill or complete any development wells in the previous 19th POD but did various well work projects and completed Pearl Pad compressor installation.

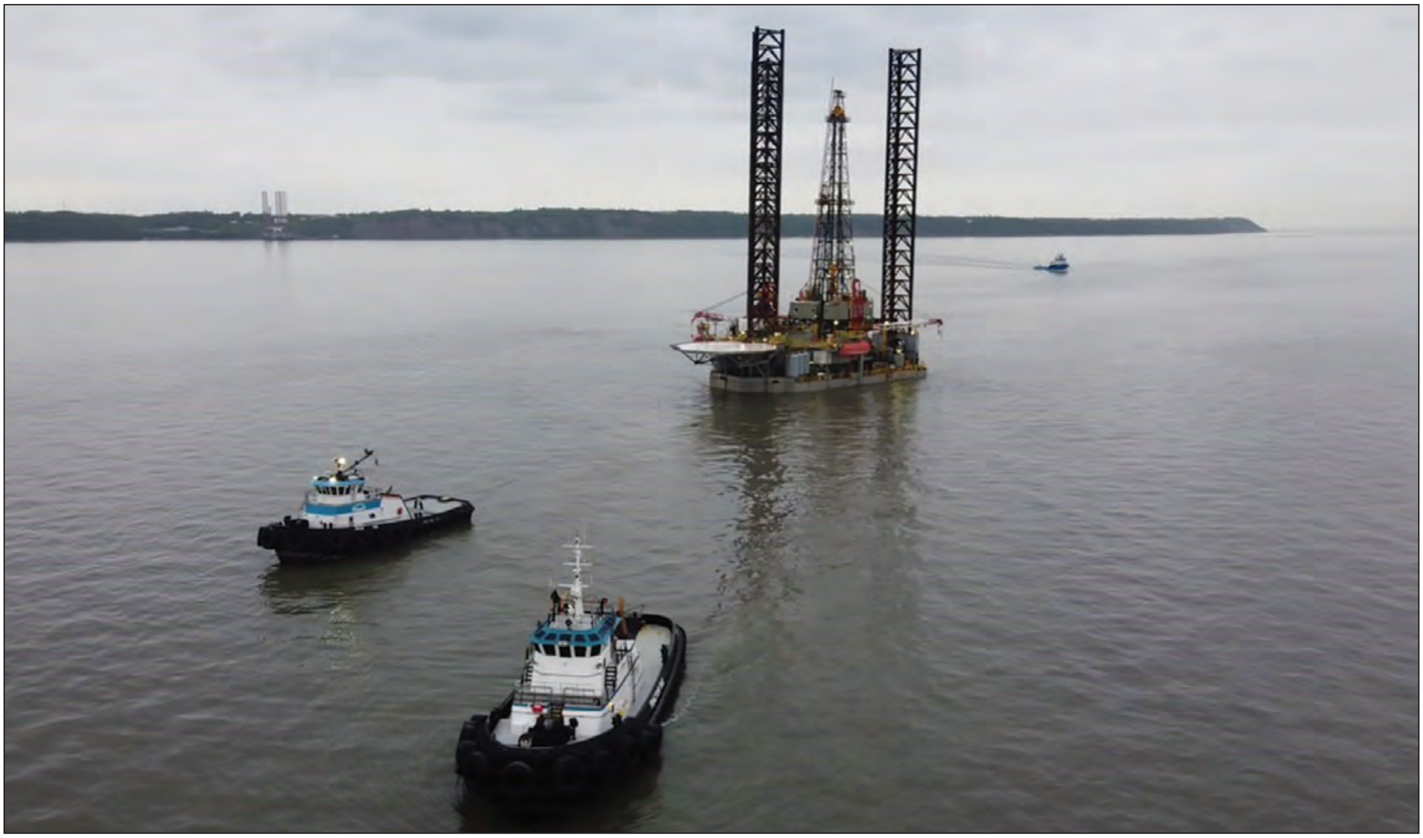
Proposed 2024-25 POD work includes various well work and facility projects

Kenai

The field currently ranking fourth in Cook Inlet gas production is Hilcorp Alaska's Kenai gas field, which AOGCC data show averaged 19,292 mcf per day in August 2024, down 2.55% from July and down 0.59% from August 2023. The field went into production in 1960.

AOGCC drilling data show that Hilcorp permitted four wells in the field over the last 12 months, completing three.

Kenai is a federally managed field, onshore on the Kenai Peninsula, and in the 66th plan of development and operations for the field, effective June 1, 2024, through May 31, 2025, submitted to BLM in March of this year, Hilcorp said that under the previous POD it completed two wells, with a third planned to


HILCORP

The Spartan 151 jack-up rig.

spud in March.

Hilcorp also worked over several wells in the 65th POD, completing all plans approved for that POD.

In its 66th POD Hilcorp said that pending results of drilling under the 65th POD, it planned to drill two wells during the 66th POD in the fall of 2024 and winter of 2024-25. A workover program is also planned, along with planning and designing phase 1 of storage and processing for contaminated gravels at the field.

Trading Bay

Hilcorp's Trading Bay unit produces both oil and natural gas from the McArthur River and Trading Bay fields. Platforms, north to south, are Monopod, King Salmon, Grayling, Steelhead and Dolly Varden.

In its May 22 approval of the 2024 plan of development for Trading Bay the Division of Oil and Gas said the unit was formed and began sustained production in 1967, with current production from four participating areas in the McArthur River field: the Hemlock oil pool PA, the West Foreland oil pool PA, the Middle Kenai "G" oil pool PA and the Grayling

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gas sands PA.

Hilcorp took over as operator in January 2012, and in August 2013 the division approved the second expansion of the unit to include the 5,280-acre Trading Bay field.

The division said cumulative production from the Trading Bay field of March 31, 2024, was 110.6 million barrels of oil and 91.2 billion cubic feet of natural gas, while cumulative production from the McArthur River field was 660.2 million barrels of oil and 1,552.3 bcf of natural gas.

Under the 2023 plan Hilcorp completed five rig workovers and multiple non-rig operations, as well as attempting to drill the A-10RD3 sidetrack from the Monopod into the North Trading Bay unit, but the division said that "mechanical issues prevented the well from reaching the intended subsurface target."

The 2024 plan of development covers July 1, 2024, through June 30, 2025, and includes two grassroots wells from Steelhead, with one of the wells begun prior to the 2024 POD. Various rig and non-rig drilling activities are planned.

AOGCC reports McArthur and Trading Bay production separately. On the gas side, McArthur River accounted for 6.12% of inlet production in August, 11,438 mcf per day, while Trading Bay averaged only 705 mcf per day. Combined the fields accounted for 6.5% of inlet production in that month. Compared to August 2023, McArthur River was up 1.38%, while Trading Bay was down 8.8%.

On the oil side, McArthur River averaged 2,391 barrels per day in August, 28.53% of inlet production — the field is the inlet's largest current oil producer — while Trading Bay averaged 787 bpd, 9.39%, a combined 37.92%.

North Trading Bay

The North Trading Bay unit formerly produced natural gas from the Spurr and Spark platforms, built in 1967. Production ceased in 2005; the platforms are maintained in lighthouse mode. The division said in a June 2024 conditional approval of a 2024 plan of development that the crane and helidecks on Spurr and Spark are functional, but crew quarters are not; no wells are active.

Hilcorp took over as operator in 2013 and in 2017 told the division it would not be economically or technically feasible to return the Spark and Spurr to production, but proposed drilling from the Monopod in the Trading Bay unit into the North Trading Bay unit.

By 2018, the company was proposing a sidetrack of the A-10 Monopod well into acreage not in the NTBU but geologically connected to acreage in that unit and said it would petition for expansion of the NTBU if that drilling was successful.

So far attempts to drill that sidetrack have not been successful.

The division said Hilcorp has committed to evaluate options to restore production from NTBU during the 2024 POD, and told the division that "the repeated failures of the A-10RD2 an A-10RD3 warrants a deeper look at the development plan and consideration of other wellbore for access" as well as studying subsurface and facility options and proposing "a refreshed development strategy."

In its June 4, 2024, conditional approval of the 2024 POD the division said it was approving the POD only through May 2; requiring a plan of refurbishment by Feb. 1, 2025, if Hilcorp decides to refurbish the platforms; requiring a presentation on remaining resources in place and plans for production from NTBU; requiring discussions on future of platforms if production targets within NTBU determined not to be economic; and requiring the company to provide the division with all relevant permits and applications.

AOGCC drilling permit data over the last calendar year show Hilcorp permitted eight Beluga River wells, completing six — the most wells completed at any Cook Inlet field in that period.

The division said that if the company determines it is not economically viable to pursue resources within the unit, it will automatically terminate and certification of any wells within the unit will be rescinded.

Swanson River

Hilcorp acquired the Swanson River unit on the Kenai Peninsula from Union Oil Company of California, becoming operator in 2012. Swanson, site of the 1957 Cook Inlet discovery well, has been in production since 1958, producing both oil and gas. In August AOGCC production data show the field averaged 729 bpd of oil, 8.7% of inlet total, and 7,530 thousand cubic feet per day of gas, 4.03% of inlet total for that month. Gas production was up 55.92% from July but down 15.51% from August 2023.

The field is managed by the federal Bureau of Land Management, and the 60th plan of development and operations for the field, submitted March 1, 2024, shows cumulative gas production for 2023 of 2,480 million standard cubic feet of gas and 274,000 barrels of oil.

During the 2023 POD, effective April 1, 2023, through May 31, 2024, Hilcorp drilled three gas wells and numerous workovers.

For the 2024 POD, Hilcorp planned to continue work to identify remaining gas reserves in the North and Central Fault Blocks and remaining oil reserves across the field.

One gas well is planned for the 2024 POD period and numerous workovers, along with facilities work.

Cannery Loop

Alaska Oil and Gas Conservation Commission data show Cannery Loop was the highest gas producer among Hilcorp's smaller fields in August. The Cannery Loop unit was formed in 1978, with Union Oil Company of California as operator, the Alaska Division of Oil and Gas said June 27 when it approved the 2024 plan of development for the unit from Hilcorp Alaska, which took over as operator in 2012 after it acquired Union's Cook Inlet assets.

Production at the unit totaled 2.1 billion cubic feet of gas in calendar year 2023, down from 2.3 bcf in 2022, the division said, an average of 5.8 million cubic feet per day compared to 6.3 million cubic feet per day in calendar year 2022.

AOGCC production data for August 2024 show Cannery Loop averaged 4,941 thousand cubic feet per day, 2.64% of inlet production in that month, down 3.02% from July and down 4.81% from an August 2023 average of 5,191 mcf per day.

The division said that during the 2023 POD period, Aug. 1 through July 31, 2024, Hilcorp did two workovers and began drilling a grassroots well, CLU 16. AOGCC records show that well was completed in June, with production beginning in that same month.

For the 2024 POD the division said Hilcorp proposed evaluating the potential for drilling up to two grassroots wells, based on results from the CLU 16.

"Depending on the subsurface locations of potential follow-up grassroots drill wells, Hilcorp intends to expand the CLU 1 Pad and/or install additional compressor capacity at the CLU 3 Pad," the division said. Also during the 2024 POD, Aug. 1 through July 31, 2025, various rig and non-rig projects may include preparing for potential sidetracks, coil cleanout operations, additional perforations and setting plugs or patches for potential water shutoffs.

Beaver Creek

Another top natural gas producer among Hilcorp's smaller Cook Inlet fields, Beaver Creek, accounted for 2.42% of inlet production in August. AOGCC production data for that month show the field averaged 4,525 mcf per day, a drop of 43.61% from its July volumes and a drop of 14.87% from its August 2023 average of 5,315 mcf per day. Beaver Creek also produces oil, averaging 242 bpd in August, 2.88% of inlet production, and down 4.7% from July and down 21.99% from August 2023 when the field's production averaged 310 bpd.

The Beaver Creek discovery well, Marathon's Beaver Creek No. 4, was drilled in 1972 and production of both oil and gas began late that year.

Hilcorp purchased the field from Marathon and became operator in 2012, AOGCC said in its pool statistics. Beaver Creek is on the Kenai Peninsula southwest of Swanson River.

The field is managed by the Bureau of Land Management and Hilcorp submitted the 57th plan of development and operations for the field to BLM in March 2024.

During the 2023 POD Hilcorp reported workovers on five wells, studies of the gas reservoirs on three wells and installation of a vapor recovery unit.

For the 2024 POD, effective June 1 through May 31, 2025, Hilcorp said that pending results of an upcoming field study, it would drill up to one well targeting the Upper Beluga, likely a sidetrack, in the fourth quarter of 2024 or the first quarter of 2025.

AOGCC data show Hilcorp permitted two development wells at Beaver Creek in September, both sidetracks.

Ivan River

Ivan River is one of three small Hilcorp gas fields on the west side of Cook Inlet, north and northeast of the much larger Beluga River field.

Ivan River became a Hilcorp asset when the company took over Chevron/Union Oil Company of California's Cook Inlet assets in 2012.

The Ivan River unit was formed in 1967 by Standard Oil Company of California and produces from an undefined gas pool.

Through the end of August, AOGCC data show cumulative gas production from Ivan River of 96.881 billion cubic feet.

In August the field averaged 3,320 thousand cubic feet per day, 1.78% of inlet production, up 78.36% from July but down 41.9% from August 2023 production of 5,715 mcf per day.

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In its May 8 approval of Hilcorp's 2024 POD for Ivan River, the field's 54th, the division said that in the 53rd POD Hilcorp continued evaluating opportunities for rig workovers, subsurface opportunities and delineation wells, along with wellwork, upgrading the water disposal system and optimizing compression. The 2024 POD covers June 1, 2024, through May 31, 2025.

Company plans during the 54th POD included evaluating rig and non-rig workover opportunities; reviewing and evaluating opportunities to drill delineation wells; doing pad and facility work to support potential grassroots well drilling in 2025; installation of coalescer for compressor; and routine facility repair and replacement as needed.

On Oct. 15 the division approved a Hilcorp unit plan of operations amendment to expand the Ivan River pad by 2.1 acres.

In an August application for the operations amendment, the company said additional development wells are planned for 2025 with the pad expansion would provide space for the drill rig for the new wells and "allowing safe access and uninterrupted facility operations." Subject to application approval, the company said pad expansion work would begin this fall.

Lewis River

The unit at Lewis River, a small onshore gas field on the west side of Cook Inlet, was formed in 1977 with Cities Service Oil Co. as the original operator. Hilcorp took over as operator from Union Oil Company of California Jan. 1, 2012, the Alaska Division of Oil and Gas said May 8, in its approval of the 49th plan of development for the unit. AOGCC data show cumulative production through August 2024 of 17.86 billion cubic feet. The field averaged 3,450 thousand cubic feet per day in August, 1.84% of inlet gas production, down 13.65% from July but up 893.65% from August 2023, when the field averaged 347 mcf per day. In August 2023, there was just a single well on production at the field.

The division said that in the 48th POD Hilcorp brought the LRU C-02 well online with initial production of 2 million cubic feet per day and installed a line heater and a separator to accommodate the new production. Production is now from two wells at the field.

Hilcorp's plans for the 49th POD, which covers June 1, 2024, through May 31, 2025, include continuing evaluation of drilling delineation wells, evaluating potential coil cleanout operations and installing a condenser for the Lewis River compressor.

Deep Creek

The Deep Creek unit was formed in 2001 and is jointly managed by the Alaska Division of Oil and Gas and Cook Inlet Region Inc. Sustained production began from the Happy Valley participating area in late 2004. Hilcorp took over as operator in January 2012 after acquiring Union Oil Company of California's Cook Inlet assets.

AOGCC data show cumulative production of 44.5 billion cubic feet of natural gas from Deep Creek. In August 2024 the field averaged 3,215 thousand cubic feet per day, 1.72% of inlet gas production, down 2.22% from July and down 10.26% from an August 2023 average of 3,582 mcf per day.

The division approved the 21st Deep Creek plan of development June 27, covering Aug. 1, 2024, through July 31, 2025.

During the 2023 POD, Hilcorp added perforations from three wells.

In the 2024 POD, the division said Hilcorp planned wellwork as opportunities arise, evaluate the potential to drill one grassroots well, pending reservoir field study results planned for spring and summer 2024 and make improvements and repairs as needed.

Granite Point

Hilcorp's Granite Point unit, producing from the Granite Point, Anna and Bruce platforms in Cook Inlet, is one of the company's smaller gas fields, averaging 3,043 thousand cubic feet per day in August, 1.63% of inlet production, but its second largest Cook Inlet oil producer, averaging 2,037 bpd, 24.3% of inlet oil, AOGCC production data show. The 3,043 mcf per day average this August was down 1.67% from July and down 7.91% from August 2023, when gas production averaged 3,304 mcf per day. Oil production was unchanged from July to August, but down 7.73% from an August 2023 average of 2,208 bpd.

In its May 22 approval of Hilcorp's 2024 POD for Granite Point, the Alaska Division of Oil and Gas said Granite Point production began in 1967. AOGCC data show cumulative production through August of 145 billion cubic feet of gas and 159.55 million barrels of oil.

Hilcorp purchased Chevron/Union Oil Company of California's working interests in late 2011 and became operator in early 2012. In mid-2012 Hilcorp acquired the remaining 75% working interest in the unit from ExxonMobil Production Co.

The unit was originally called South Granite Point; it was expanded in 2015 to include the Granite Point field and renamed the Granite Point unit.

The division said that Hilcorp had committed in its 2023 POD to drilling up to three grassroots wells from the Bruce Platform, using the 151 jack-up, but did not drill the wells, telling the division that with only one jack-up available in Cook Inlet, it chose to defer the Granite Point wells in favor of wells within the North Cook Inlet unit because it had higher confidence in bringing North Cook Inlet gas to market.

The division said that in its 2024 POD, Hilcorp committed to drilling up to one grassroots well targeting Tyonek format gas from the Bruce Platform. If commercial qualities of gas are found, Hilcorp told the division it would "evaluate production facility and pipeline capacity constraints to optimize delivery of gas between existing platforms and the Granite Point Tank Farm." The company also plans various non-rig activities.

Pretty Creek

Pretty Creek is an onshore gas field on the west side of Cook Inlet. It was unitized in 1998 by Union Oil Company of California and acquired by Hilcorp, which became the operator effective Jan. 1, 2012. Through August, AOGCC production data show the field has produced cumulatively 9.617 billion cubic feet of gas.

Recent production from the field has been sporadic: just 78 thousand cubic feet so far in 2024; 1,252 mcf in 2023; 2,081 mcf in 2022; 345 mcf in 2021; no production in 2020. The last production of any significance was in 2013, when production totaled 25,217 mcf for the year. There is a single well.

In its May 8 approval of the 46th POD for Pretty Creek, the division said Hilcorp has not committed to specific exploration or delineation activities, but "is evaluating the possibility of drilling up to two development wells targeting Sterling, Beluga, and Tyonek sands," and anticipates "uphole recompletes, perforation adds and rig workovers to existing wells to help maintain and increase productivity."

As this edition of The Producers was wrapping up, activity at Pretty Creek was ramping up, with a sidetrack drilled in September and an application filed with the division to expand the Pretty Creek pad, with development drilling from the expanded pad set for 2025.

Nikolaevsk

The unit at Nikolaevsk on the Kenai Peninsula, which produces from a single well, was terminated in 2021 at operator Hilcorp's request. Two of the former unit tracts are allocated from the Red No. 1 well and Hilcorp continues to operate production as a lease operation.

In August, AOGCC data show the field averaged 210 thousand cubic feet per day, 0.11 % of inlet gas production, down 11.91% from July and down 10.04% from August 2023 production of 233 mcf per day.

Seaview

Hilcorp discovered and developed Seaview, the most southerly and the newest of the Kenai Peninsula gas fields, including drilling two development wells, Seaview 8 and Seaview 9, and installing production facilities and a pipeline.

AOGCC data show the field produced from Seaview 8 from June 2021 through August 2022, a cumulative total of 181,837 thousand cubic feet. There has been no production since.

In its June 27 approval of the fifth, 2024, plan of development for Seaview, the Alaska Division of Oil and Gas said that in the 2023 POD, Hilcorp has proposed evaluating adding perforations in the Seaview 9 well but elected not to because of "the proximity of the surface casing to the proposed perforation." The company also did not do an injectivity test for coalbed methane opportunities. It did not replace the compressor at the Seaview Pad 1 "because other compression opportunities took precedence."

"Depending on the subsurface locations of potential follow-up grassroots drill wells, Hilcorp intends to expand the CLU 1 Pad and/or install additional compressor capacity at the CLU 3 Pad," the division said.

The company did acquire a north-south seismic line from Seaview north to Ninilchik, looking to enhance its understanding "of the overall structure in the Seaview and Whiskey Gulch region for future development and exploration."

For the 2024 POD period, Aug. 1, 2024, through July 31, 2025, Hilcorp is planning "a shallow stratigraphic drill test to understand the structural relation between Seaview and Whiskey Gulch." It will evaluate drilling a test well to sands shallower than accessible in current wellbores and evaluate adding perforations in the existing wells.

It is also exploring potential to collect data and test coalbed methane potential at Seaview. ●

Contact Kristen Nelson at knelson@petroleumnews.com

Hilcorp a major North Slope producer

Operates Prudhoe Bay, Point Thomson, Endicott; owns and operates Northstar and Milne Point; adding Nikaitchuq, Oooguruk

By KRISTEN NELSON
Petroleum News

Hilcorp came to Alaska in 2011 with acquisitions in Cook Inlet, becoming an operator there in 2012, and began working on the North Slope in 2014, acquiring BP Exploration (Alaska)'s working interest in the Duck Island and Northstar units, and 50% of BP's interest in Milne Point, where Hilcorp took over as operator.

In mid-2020, with finalization of a sale announced in 2019, Hilcorp took over BP's remaining North Slope assets, including its interest in Prudhoe Bay, where Hilcorp became operator. The acquisitions included BP's remaining 50% interest in Milne Point and its interest in Point Thomson, where ExxonMobil holds the majority working interest. Hilcorp Alaska took over as operator at Point Thomson in 2022, with ExxonMobil retaining its majority working interest.

PRUDHOE BAY

The unit at Prudhoe Bay, Alaska's largest oil field, was formed in 1977, following the discovery of oil in the Ivishak and Sag River sandstones in 1968 at Prudhoe Bay State No. 1 and currently includes 254,235 acres. Hilcorp took over as operator of the Prudhoe Bay unit on June 30, 2020, after acquiring BP Exploration (Alaska) from the Standard Oil Co. and changing the name to Hilcorp North Slope.

The share of Prudhoe that Hilcorp acquired from BP is not the largest in the unit. Information on the Alaska Department of Natural Resources' Division of Oil and Gas website shows Hilcorp with an average working interest of 26.36% at Prudhoe, while ExxonMobil Alaska Production holds 36.4%, ConocoPhillips Alaska 36.08% and Chevron U.S.A. 1.16%.

Alaska Oil and Gas Conservation Commission production data for September, the latest available when this section of The Producers was compiled, show Prudhoe averaging 246,803 barrels per day, 55.08% of Slope production, with 81.57% of that volume from crude oil and 18.43% from natural gas liquids. Compared to September 2023, Prudhoe production was up 3.31% this September. There are 12 participating areas at Prudhoe, with drilling activity largely focused in the Initial Participating Areas — the oil rim PA and the gas cap PA — and in the newest development area, the western satellites.

PRUDHOE IPA

In its April 2024 initial participating areas plan of development, covering July 1, 2024, through June 30, 2025, submitted to the Division of Oil and Gas April 1, Hilcorp North Slope said development began in the IPA in 1968 with the Prudhoe Bay State No. 1 exploration well, with regular production beginning in June 1977 and the beginning of produced water injection that same month, followed by large-scale waterflood for secondary recovery in August 1984 and use of miscible gas for water-alternating-gas injection for tertiary recovery in June 1987.

In its May 2024 approval of the 2024 POD for the IPA, the division said IPA production for calendar year 2023 was some 2,759 billion cubic feet of gas, 53.62 million barrels of black oil and 16.56 million barrels of natural gas liquids — with the NGLs mixed in with and sold with the black oil.

Daily production in 2023 averaged 146,906 barrels of black oil and 45,355 barrels of NGLs, down from 2022 daily averages of 156,487 barrels of black oil and 48,507 barrels of NGLs.

During calendar year 2023, 827 producers (up from 825 in 2022) and 213 injectors (unchanged from 2022) contributed to production in the IPA, Hilcorp said in its proposed IPA 2024 POD.

"Fluid handling and production in 2023 were affected by significantly increased levels of planned maintenance and downtime compared to 2022," the company said.

IPA 2023 POD

Hilcorp had anticipated drilling up to 38 wells in the IPA during the 2023 POD.

The division said that by the April 23, 2024, technical meeting on the 2024 POD, Hilcorp had drilled only 11 wells, nine coil tubing drilling sidetracks and two grassroots wells, with five more scheduled to be drilled by the end of the 2023 POD June 30, 2024.

Hilcorp said in the 2024 POD that the difference was "primarily rig scheduling and availability" and told the division in the technical meeting that the deviation in drilling "was due to not securing an additional CTD rig" and said it anticipated that a second CTD rig would be operational in the IPA by mid-June 2024.

Workovers were completed on an as-needed basis during the 2023 POD, Hilcorp said, with six IPA wells worked over and five more planned by the end of the 2023 POD period.

The company said non-rig well interventions remained relatively high in 2023, with some 426 IPA wells experiencing interventions "excluding annular communication work and subsidence drifts," with most of the work aimed at maintaining well stock or increasing production through enhancements.

Large facility projects included CCP compressor upgrades, GC2 B-Bank slugcatcher internals redesign, Drill Site 18 pipeline construction and H Pad pipeline construction.

IPA 2024 POD

During the 2024 POD Hilcorp said it planned "a continued increase in drilling activity" with up to 36 IPA wells "dependent upon rig availability, rig utilization within the PBU, an economic viability."

The company said it has continued to work through the backlog of broken IPA wells and anticipates a reduction in workovers in 2024.

Flat well intervention activity is anticipated.

Major facility projects include the 2024 scope of the CCP compressor upgrades, CCP air inlet housing replacement, FS-2 de-oiler and Eileen West End pipeline.

PRUDHOE WESTERN SATELLITES

The Prudhoe Western Satellites are the fields' newest development area.

There are five participating areas in the Western Satellites: Aurora, Borealis, Midnight Sun, Orion and Polaris, with Aurora, Borealis and Midnight Sun producing primarily from the Kuparuk River formation and the Orion and Polaris PAs producing from the Schrader Bluff formation.

Development began at Aurora in 2000, with production starting that year, water injection in 2001 and miscible gas for water-alternating-gas, WAG, injection for tertiary recovery in late 2003.

Borealis development began in 2001 with production that same year, water injection in 2002 and a pilot project for miscible injectant for WAG in 2004 for tertiary recovery.

Midnight Sun development began in 1997 with production in 1998, water injection in 2000 and miscible injectant in 2016.

Orion development began in 2001 with production startup in 2002, water injection in 2003 and Prudhoe Bay MI for WAG for tertiary recovery in October 2006.

Polaris development began in 1997 with production in 1999, water injection in 2003 and Prudhoe Bay MI for WAG used briefly in 2006 and then beginning in 2009 for tertiary recovery.

Western Satellites 2025 POD

Hilcorp North Slope's proposed 2025 POD for the Western Satellites, covering calendar year 2025, submitted to the division Oct. 2, breaks out 2023 calendar year production by PA, with Orion accounting for 49.52% of the area's 13.953 million barrels of oil, followed by Polaris at 18.66%, Borealis at 18.32%, Aurora at 11.12% and Midnight Sun at 2.4%.

In its Nov. 27, 2023, approval of the 2024 POD for the western satellites (the division's decision on the 2025 POD had not been released when this issue of The Producers was completed), the division said Hilcorp had completed 14 new drill wells during the 2023 POD, with another four pending, out of its proposal to drill up to 26 new wells and do four rig workovers. The division said the company deferred drilling the remaining wells as it "turned its focus to the drilling of other wells within the PBU based on production efficiency and economics." Hilcorp said this October it had completed five additional wells by the end of the 2023 POD period.

Hilcorp had completed one new well to date under the 2024 POD, with an estimated four pending execution, and said Western Satellite drilling was reduced from the proposed activity of up to 19 wells "due to alternative opportunities identified in the Oil Rim

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HILCORP NORTH SLOPE *continued from page 47*

and Gas Cap Participation Areas."

There were also workovers and recompletes of four wells at Aurora and three at Borealis.

Major facility projects under the 2024 POD included beginning construction of the Eileen West End Twin Pipeline Phase 1.

During 2025 Hilcorp said it anticipates completing seven wells, with up to eight additional possible at Orion "depending on rig availability."

Major facility work includes expected completion of the EWE LDF Twin Pipeline Phase 1 and various projects at Gathering Center 2.

The company will also be evaluating new pad development options in 2025, including permitting for construction of Omega Pad, and is evaluating additional pipelines to reduce header pressure and increase gas lift pressure at four pads: L, V, W and Z.

Opportunities for polymer flood and foam WAG flood in the Schrader Bluff formation are being evaluated, along with a project to improve injected water quality to increase injectivity and oil recovery.

GREATER POINT MCINTYRE AREA

The Alaska Division of Oil and Gas approved the 2024 POD for the Greater Point McIntyre area Aug. 22, covering Oct. 1, 2024, through Sept. 30, 2025.

GPMA includes six participating areas, the division said: Combined Niakuk, Lisburne, North Prudhoe Bay, Point McIntyre, Raven and West Beach. Initial production from GPMA began in 1986 with Lisburne producing from the Wahoo and Alapah formations.

Combined Niakuk, West Beach, North Prudhoe Bay and Point McIntyre began producing between 1993 and 1994. West Beach produced briefly in 2009, but West Beach and North Prudhoe Bay have been shut-in since 2000 and 2001, respectively.

Point McIntyre and Combined Niakuk produce from the Kuparuk River formation.

Raven began production in 2005 from the Ivishak and Sag River formations. There are also tract operation wells.

The division said GMPA produced 10.333 million barrels of oil and NGLs between April 1, 2023, and March 31, 2024, a slight decline from the same period in the previous year.

Hilcorp had committed to drilling six wells at the GMPA during the 2023 POD period, the division said, including five coil tubing drilling sidetracks and one rotary well at Raven, however no drilling was completed within the GMPA during the 2023 POD period.

The division said sidetracks were deferred in favor of work elsewhere in Prudhoe, while the Raven well was "deferred due to issues following warming up the rig from cold stack," with that well deferred to the four quarter of 2024 or the first quarter of 2025.

No workovers were planned, but the company told the division two were expected to be completed before the end of the 2023 period.

The 2022 POD also saw no wells drilled, although three wells planned for the 2022 POD were drilled in the 2021 POD period after the 2022 POD was submitted, the division said.

Hilcorp said that since taking over operatorship at GPMA, it "has focused on returning the wells to service, optimizing production through the existing surface infrastructure while investing in capacity-expanding and debottlenecking projects, targeting reservoirs that had been under-developed, improving voidage replacement and optimizing the water and MI floods, improving operational efficiency and drilling new sidetracks from underperforming wellbores."

The company's proposed 2024 POD program includes two rotary wells at Raven, and four potential CTD sidetracks at Point McIntyre, a rotary well at Lisburne and two track operation wells targeting the Brookian.

Hilcorp has a list of long-range activities at GPMA evaluating development potential, including in the Brookian; in the Lisburne; in the Niakuk Kuparuk; in the Point McIntyre Kuparuk, Sag River and Ivishak; potential of existing tract operations and other Sag River accumulations offsetting Raven; and continuing to evaluate facility debottlenecking projects.

MILNE POINT

Hilcorp Alaska acquired a 50% working interest in the Milne Point unit from BP Exploration (Alaska) and became operator in 2014. In 2020 Hilcorp acquired BP's remaining assets in Alaska, including the other 50% of Milne, and became 100% working interest owner at the unit.

Milne Point is the largest of the North Slope units in which Hilcorp has 100% or at least a majority working interest ownership and is where the company has had the greatest impact, almost doubling production.

Milne Point development began in the 1980s under Conoco, with Alaska Oil and Gas Conservation Commission production data showing a 0.7 million barrel total for 1985, rising to 7.5 million barrels by 1991, and then dropping to 6.8 million barrels in 1993.

BP took over in 1994, with production at 6.7 million barrels for the year, and grew that to a peak of 20.4 million barrels in 1998, with production leveling off in the range of 18.8 million to 19.7 million barrels per year through 2004, and then dropping off to 7.1 million barrels by 2014.

Hilcorp has been growing Milne Point production since it took over as operator — growth reflected in the 43rd plan of development for the field which the company filed with the Alaska Department of Natural Resources' Division of Oil and Gas in mid-October.

In its recent PODs Hilcorp has reported average production per day for the calendar year to date based on when the POD is submitted — Jan. 1 through Sept. 30 for PODs submitted in mid-October.

For the POD submitted in 2021, Milne production averaged 35,757 barrels per day; for the 2022 POD, the average was 37,466 bpd, up 4.78% from the previous year. In 2023 the average was 39,944 bpd, up 6.61% from the previous year, and the most recent POD, using 2024 volumes, shows an average of 43,474 bpd for that same period, up 8.84%.

43rd POD

Milne produces from the Kuparuk reservoir in the Kuparuk participating area, the Schrader Bluff reservoir in the Schrader Bluff PA and the Sag River reservoir in the Sag River PA. There are also multiple wells on tract operation production.

In the 43rd Milne POD, Jan. 13, 2025, through Jan. 12, 2026, Hilcorp said it anticipates drilling 19 rotary wells, with 18 potential candidates in the Schrader Bluff formation — half producers, half injectors — and one in the Kuparuk producer.

The company also expects to do coiled tubing drilling operations on three wells.

It will continue to use the ASR1 rig for well work and workovers "as required to maintain and enhance production."

Major facility projects include H Pad power fluid separation; return gas injection to F and L pads through existing gas injection lines; L and H pad polymer expansion; return water injection to K Pad; CFP A train internals upgrade; and CFP PL 5 upgrade.

Long range the company said it continues to evaluate additional Schrader Bluff drilling opportunities; evaluate performance from the existing S-203 and planned S-204 Ugnu wells to help determine future Ugnu development; evaluate infill drilling opportunities in the Kuparuk formation; and target facility upgrades to increase the production capacity of the unit.

42nd POD

In the 42nd POD Hilcorp said it originally anticipated drilling 20 wells, and then amended that to 24, with the majority Schrader Bluff wells, and two Kuparuk formation wells and two Ugnu formation wells being considered.

The company said in its Oct. 14 POD submittal that it has drilled 16 of the wells with an additional six anticipated to be completed by the end of the POD period Jan. 12.

Fifteen of the wells drilled to date are in the Schrader Bluff formation, seven producers and eight injectors, with an additional five — four producers and one injector — anticipated to be completed by the end of the 42nd POD.

One Kuparuk formation well was drilled, a horizontal producer, and one Ugnu well was anticipated to be drilled by the end of the POD period.

Hilcorp said it anticipated coiled tubing drilling operations on six wells and six, five producers and one injector, were drilled.

There were no planned workover operations, but 20 workovers were completed with an additional 12 planned before the end of the POD period.

Hilcorp said not all of the facility projects anticipated during the 42nd POD have been completed, but two — E Pad power fluid separation and reactivation of the D Pad transmission line to B Pad — are expected to be completed before the end of the POD period, while two others are expected to be initiated during the 42nd POD and continued through the 43rd POD — H Pad power fluid separation and return of gas injection to F and L pads through existing gas injection lines.

Three unanticipated projects were begun under the 42nd POD and will be completed before the end of the period: Solar Titan 130 power generation install at L Pad; CFP B-Train internals upgrade; and J Pad polymer injection expansion.

Operations that deviated from or did not conform to the 42nd POD include R Pad Drillsite construction; CFP 3rd train oil separation; Solar Titan 130 power generation install at L Pad; CFP B Train internals upgrade; and J Pad polymer injection expansion.

POINT THOMSON

Hilcorp Alaska's most recent North Slope operatorship is at

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HILCORP NORTH SLOPE *continued from page 49*

Point Thomson, the most easterly of the Slope units. The company took over from ExxonMobil Production, developer of the field, effective Jan. 1, 2022, following agreement by working interest owners in October 2021 and regulatory approval by the state.

ExxonMobil retains its majority working interest in the field, 62.36%. Hilcorp has a 36.99% working interest, with others holding a combined 0.65% interest.

The Point Thomson unit was approved in 1977, although sustained production did not begin until 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 the biennial PODs.

The September 2018 letter agreement is focused on an Alaska LNG Project and suspends work on evaluation and selection of a PTU expansion project — a requirement of the 2012 PTU Settlement Agreement — until the Department of Natural Resources provides notice to all parties in the 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.

A final investment decision for an Alaska LNG Project would require Point Thomson owners to provide work plans and project activities to develop the reservoir for major gas sales. If, on the other hand, the LNG project is suspended, owners would have 30 months to resume work on suspended portions of the settlement agreement, including a Point Thomson expansion project.

Point Thomson POD

Point Thomson differs from other units in that its plans of development cover two years.

The most recent plan, submitted by Hilcorp in October 2023 and approved by the division in December 2023, covers calendar years 2024 and 2025.

Hilcorp said the initial participation area at Point Thomson consists of the Thomson reservoir, with gas and condensate produced from the PTU-17 well on West Pad and the PTU-15 and PTU-16 on Central Pad used for gas reinjection.

In reporting on the previous POD, for 2022-23, Hilcorp said no drilling was planned during that period.

Condensate production from Jan 1, 2022, through Aug. 30, 2023, averaged 7,300 barrels per day, with 4.4 million barrels delivered to the trans-Alaska pipeline during that period, while gas production averaged 130.3 million cubic feet per day, with 126.3 million cubic feet per day reinjected and the remainder used as fuel gas for unit operations.

For the 2024-25 POD, Hilcorp said it anticipated reviewing and evaluating internal data for “Area F” of the PTU.

Area F, the state said in its approval, was created by terms of the 2012 settlement agreement and requires submittal of a POD for Area F.

Jade Energy LLC acquired a working interest in a portion of Area F, ADL 343112, in 2018 and submitted a POD in late 2018. The division said that while Jade is not a party to the settlement agreement, the division determined that the Jade POD satisfied the obligation in the settlement agreement, although the settling parties retain an “obligation to maintain an approved POD for Area F or relinquish the acreage.”

The Jade POD is on hold pending an agreement with the Alaska Department of Natural Resources and the division. (See coverage of Area F issues in Petroleum News, most recently in April of 2024.)

PTU production issues

In the 2024-25 POD Hilcorp proposes continuing production from current facilities.

The company said it “anticipates that current oil and gas production from the PTU will be maintained in line with historical decline.”

The most recent AOGCC production figures, for September 2024, show Point Thomson averaging 4,678 barrels per day, down from an early peak of 10,725 bpd in December 2018. The facility’s rated capacity is 10,000 bpd.

Hilcorp told the division it would continue to evaluate drilling opportunities at Point Thomson, and said that, pending results of internal review, it would convert injector PTU-15 to production.

The company evidently tested this possibility, as AOGCC production data show that in September 2023 Point Thomson production was from the PTU-15, rather than the PTU-17.

In discussing long-range potential at the field, Hilcorp noted declining production from PTU-17 and said “current operable wellstock at Point Thomson is unable to cycle 200 MMSCFD gas and fill the IPS facilities to capacity”

Filling the IPS to capacity would require additional wells, and the company said it “will continue to evaluate drilling opportunities during the 2024-2025 POD Period.”

DUCK ISLAND

The Duck Island unit, Endicott, is one of the smaller fields Hilcorp Alaska operates on the North Slope, an offshore producer with a causeway connecting the main production island and the satellite production island to shore. Endicott accounted for less than 1% of North Slope production in September 2024 at 4,168 barrels per day, the latest month for which Alaska Oil and Gas Conservation Commission production data was available when this issue of The Producers was finalized.

In its Jan. 8, 2024, approval of the latest plan of development for Duck Island, the 42nd, the Alaska Division of Oil and Gas said the unit was formed in 1978. It was developed by BP Exploration (Alaska). Hilcorp, which took over BP’s interest in 2014, holds 74.24% working interest and is operator; Chevron USA holds the remaining 25.76% working interest.

In its November 2023 POD submittal for the 42nd POD, Hilcorp said Duck Island unit production is associated with the Kekiktuk reservoir in the Endicott participating area, the Ivishak and Sag River reservoirs in the Eider PA and the Sag River reservoir in the Minke tract operation.

Hilcorp said 2023 production from Jan. 1 through Sept. 30 averaged 5,588 bpd.

Endicott is one of three areas on the North Slope — along with Northstar and Prudhoe Bay — with natural gas liquids production. For September 2024, AOGCC data show total Endicott production averaged 4,168 bpd, 95% of that crude and 5% NGLs, with the total down 32.94% from September 2023.

In its current POD, covering Feb. 13, 2024, through Feb. 12, 2025, Hilcorp said long-range development activities include converting “LSZ of Kekiktuk to gravity drainage to increase oil production” and exploring the unit for “remaining Ivishak and Alapah opportunities.”

The company said a grass roots well is planned, MPI 2-72, with a second, MPI 2-74, possible dependent on results from the first well. AOGCC records show both wells permitted, with MPI 2-72 completed in July 2024, although AOGCC September production data do not yet show any production from MPI 2-72.

For the previous 41st POD, Hilcorp completed eight rig and non-rig wellwork operations and a number of surface facility operations.

NORTHSTAR

Northstar is the newest of the North Slope units Hilcorp Alaska took over from BP Exploration, formed in 1999, with four state leases and three federal leases jointly managed by the Alaska Division of Oil and Gas and the federal Bureau of Safety and Environmental Enforcement.

The discovery well was drilled in 1984 by Shell. BP began island construction in the winter of 1999-2000, with regular production beginning in late 2001.

The 5-acre manmade gravel island in the Beaufort Sea is 6 miles offshore, connected to onshore processing facilities by a pipeline.

Hilcorp acquired BP's 100% working interest in Northstar in 2014 in the same deal that gave it BP's share of Endicott and 50% of BP's interest in Milne Point.

The current POD for Northstar, as with Duck Island, covers Feb. 13, 2024, through Feb. 12, 2025.

There are three oil sand accumulations: Ivishak in the Northstar participating area, Ivishak in the Fido PA and Kuparuk in the Hooligan PA.

Northstar is one of three North Slope units reporting both crude and natural gas liquids production to the Alaska Oil and Gas Conservation Commission — and has the largest percentage of NGL production of the three.

For September, the latest month for which Alaska Oil and Gas Conservation Commission production data was available when The Producers went to print, Northstar averaged 5,159 barrels per day, 52.61% of that in crude, 2,714 bpd, and 47.39% in NGLs, 2,445 bpd, with the total down 2.93% from September 2023.

19th, 20th PODs

Hilcorp said no grass roots wells, no sidetracks and no workovers were planned in the previous, 19th POD, and while the company did not drill any wells or sidetracks, it did half a dozen workovers, including recompletions, re-perforations, adding perforations and began work on converting an Ivishak producer to gas injection.

Planned facilities work included completing commissioning remaining heat pipes in a ground refrigeration expansion project and continuing repair of the island's coastal defenses; Hilcorp said both projects have been completed.

In the 20th POD, approved by the division in January, Hilcorp said it would explore downdip water injection in the Kuparuk reservoir and review potential coil tubing drilling candidates and determine if CTD "operations are economically viable, or even mechanically feasible, on Northstar Island."

No drilling or workover operations are planned, but surface work includes modifying surface equipment to allow produced water to be routed to the NS-19 well, expanding existing gas lift systems and continuing to repair coastal defenses. ●

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Mustang moving to production

Company looking to bring Southern Miluveach unit back online by end of 2024

By KRISTEN NELSON & KAY CASHMAN
Petroleum News


HARRY BOCKMEULEN

Mustang Holding LLC, the current operator of the Southern Miluveach unit on the North Slope, is aiming to bring it back online by the end of the year, according to the 10th plan of development for the unit the company filed with the Alaska Department of Natural Resources' Division of Oil and Gas Nov. 27, 2023.

Ownership of Mustang passed from the Alaska Industrial Development and Export Authority to Finnex Operating LLC on Oct. 27, 2023, the division said in a Dec. 15, 2023, approval of the POD. Mustang Holding is the operator. AIDEA had taken over from the field's developer, Brooks Range Petroleum Corp., in 2020 after BRPC defaulted on a loan agreement with AIDEA.

So far BRPC has had the only production at Mustang, producing its North Tarn 1A well from the Kuparuk River pool for one month in 2019, a total of 10,999 barrels over a 23-day period.

10th POD

In its approval of the 10th plan of development for the Southern Miluveach unit the division said work commitments by Mustang included moving the facility out of cold storage by applying for necessary environmental and operating permits and fulfilling state bonding requirements; installing either new or repurposed early process facilities with the capacity to handle expected oil and gas production, processing or reinjecting "from the existing NT-1A, M-02 well, completion of the M-01B well" and reconnecting the pipeline connection to the Alpine pipeline.

Mustang Holding LLC

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Phase 1 would include completion of drilling and well work operations for North Tarn 1A; SMU M-02 — reperforation and possible stimulation; and SMU M-01B — drilling lateral extension, possible stimulation.

Phase 2 would include drilling M-03 and up to two additional wells in 2025 or 2026 "to further demonstrate reservoir productivity and lateral continuity."

The division said Mustang was targeting resumption of production in the late fourth quarter of 2024.

Alaska Oil and Gas Conservation Commission records current as of late November show Mustang Holding has completed two sidetracks at SMU: M-01B on Sept. 6, 2024, and M-03A on Sept. 13.

The company also has AOGCC approval to flare for up to 180 days in conjunction with pre-production well testing.

Pad expansion

On Sept. 13, 2024, the division approved an application from Mustang Holding to expand the Mustang Pad by some 5 acres at the southeast corner of the pad, requiring 70,000 cubic yards of gravel.

The company said material from the Mustang Mine was used for original pad construction, and said the pad "has experienced some settling and erosion" which will be addressed by using "methods for gravel placement that were not used during the initial construction of the pad," including screening the gravel to remove excess fines and using geotextile on the tundra. Gravel will be placed on the geotextile "in one-foot lifts until design grade elevation is reached."

The work will occur before winter so material can be appropriately compacted and an additional foot of gravel will be placed on top of the design grade "and left until the following season, when the pad will be graded to design elevation."

The pad expansion will provide space for camps to be placed "at an appropriate distance from current and planned well sites."

The pad work was scheduled to begin Sept. 1, 2024.

> *Phase 2 would include drilling M-03 and up to two additional wells in 2025 or 2026 "to further demonstrate reservoir productivity and lateral continuity."*

Mustang history

Mustang was the first oil field on Alaska's North Slope to have been taken from discovery to production by a small independent — Brooks Range Petroleum Corp., or BPRC.

BRPC was formed in 2004 as the operating arm of the Kansas-based Alaska Venture Capital Group, or AVCG, to pursue large or mid-sized oil fields passed over during the first decades of North Slope development. The lead individual was Bart Armfield.

The small independent spent 8 years looking for the right North Slope play before drilling the North Tarn No. 1A discovery well in 2012. The resulting Mustang field was estimated to hold some 21.2 million proven barrels of oil in place.

BRPC then spent the next several years responding to a series of technical, economic, political and logistical challenges at the Mustang field. While some of those complications were inherent to the field and to the company, others were external, such as the crash in oil prices in 2014, as well as the 2017 veto by then-Gov. Bill Walker of previously approved oil and gas tax credits designed to offset exploration expenses for companies such as BRPC.

Despite these challenges, BRPC succeeded in putting Mustang online in early November 2019. Per the Alaska Oil and Gas Conservation Commission the field produced 10,999 barrels of oil that month, averaging 478 barrels a day for the 23 days it was in production.

BRPC conducted an extended production test from the North Tarn No. 1A well using its temporary processing facilities and exported oil to the Alpine Pipeline System. By the time a flaring permit for the unit expired on Nov. 27, 2019, the company had produced 11,944 barrels of oil, according to its estimates.

Although Mustang production was small by North Slope standards, it was a sign that the basin was at least theoretically accessible to players beyond multinational majors and even beyond large and mighty independents with strong balance sheets.

But the challenges that had plagued earlier years continued apace.

As the production test was proceeding, a private sector backer failed to meet its financial obligations on the project. BRPC and working interest owners began refinancing a major loan with the Alaska Industrial Development and Export Authority, their main financial backer.

According to BRPC, AIDEA issued a notice of default on that debt in early October, and then, in early November exercised its rights to accelerate debt repayments.

BRPC suspended operations.

The story continues from there, but BRPC was not able to restart the field without AIDEA's backing.

The division approved change of control to Finnex on Feb. 29, 2024, with an effective date of Nov. 1, 2023. ●

Contact Kristen Nelson at knelson@petroleumnews.com

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The Barrow gas field remains a reliable source of local fuel

Last major investment at Utqiaġvik-area gas fields came in 2011

By ERIC LIDJI
For Petroleum News


JOSIAH PATKOTAK

The Barrow gas fields are a local resource for local use. The federal government discovered the field as part of a sporadic post-war exploration campaign in the National Petroleum Reserve-Alaska to improve domestic energy security

Big, but not big enough to justify the massive cost of transport back to the grid, the fields were just the right size for the nearby city of Utqiaġvik. Under the operatorship of the North Slope Borough, the three Barrow gas fields — South Barrow, East Barrow and Walakpa—have provided affordable and predictable energy for Utqiaġvik for decades.

The biggest intervention at the Barrow gas field came in 2011, when the North Slope Borough launched a $92 million program to improve production and deliverability.

The program included 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 at those two fields, 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

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TOP ALASKA EXECUTIVE: Mayor Josiah Patkotak

South Barrow

The U.S. Navy discovered the South Barrow field in 1948, during its initial wave of NPR-A exploration. Drilling continued through 1987 with 13 new wells drilled and one deepened, according to the Alaska Oil and Gas Conservation Commission. Production began in November 1981 at 3.5 million cubic feet per day and continued 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. Even so, the field has reported some dramatic swings in recent years: from 56.1 million cubic feet in 2020, up to 99.3 million cubic feet in 2021, down to 37.5 million cubic feet in 2022, up to 61.4 million cubic feet in 2023. As of July 2024, the field was producing from S. Barrow Test Well No. 6 and South Barrow NSB No. 1.

Cumulative production at South Barrow is approaching 24.1 billion cubic feet, according to the AOGCC. Early forecasts had 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.G.S. discovered the East Barrow field in 1974, during the

continued on page 56

Santos steams ahead

Twenty percent cost bump offset by first production 6 months earlier than planned

By **KAY CASHMAN**
Petroleum News


BRUCE DINGEMAN

According to a third quarter report released Oct. 17, 2024, by Santos Ltd., the company's Alaska North Slope Pikka Phase 1 project is now 67% complete and "focused on accelerating pipelay activities to two programs following increased realized productivity over the 2023 winter season."

Twelve wells have been drilled, with seven stimulated and six flowed back.

"Well tests continue to de-risk subsurface, with well results in line with expectations," Santos said.

Following the "post 50% review, the combination of accelerated pipelay activity costs and inflation experienced since FID means we now expect development capital for Pikka Phase 1 (including D&C sustaining capex post first oil) to increase approximately 20%," Santos said.

Around 70% of this projected increase has already been incurred in 2024 with the remainder still to be incurred over 2025 and 2026.

In its operating highlights Santos said the Alaska Department of Natural Resources approved Santos' application to expand the joint venture's Pikka unit acreage in September by approximately 25%. (Joint venture partners are Santos approximately 51% and Repsol 49%.)

Santos Managing Director and CEO Kevin Gallagher was quoted as saying the "Pikka project is progressing well .... High productivity across all scopes of work ... The team are now focused on delivering another high productivity winter season, weather permitting, which could create the potential for first oil production up to six months earlier than originally planned. This would be a great result and

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Santos

COMPANY HEADQUARTERS: Adelaide, South Australia
TOP EXECUTIVE AND TITLE: Kevin Gallagher, Managing Director and CEO
TOP ALASKA EXECUTIVE AND TITLE: Bruce Dingeman, EVP and President Alaska
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NORTH SLOPE BOROUGH *continued from page 54*

second wave of NPR-A exploration. Drilling continued through 1990, with eight wells total, followed by the 2011 campaign. The field recently produced from South Barrow No. 14 and Savik No. 1.

The East Barrow field has also reported some dramatic swings in production in recent years: 139.1 million cubic feet in 2020, down to 47 million cubic feet in 2021, up to 99.3 million cubic feet in 2022, and down to 83.1 million cubic feet in 2023. The field appears to have been taken offline in July or August 2023, according to AOGCC records.

Cumulative production through June 2024 was more than 10 billion cubic feet, well above the original gas-in-place estimate of 6.2 billion cubic feet for East Barrow. The city of Utqiaġvik attributes the productivity to the presence of methane hydrates at the field.

Walakpa

Working under a U.S. Navy contract, Husky Oil discovered the Walakpa field in the 1980s, followed by the 2011 Walakpa program. Walakpa is the most extensive and most productive of the three Barrow gas fields, currently producing from 11 wells.

The Walakpa field produced 1.34 billion cubic feet in 2023, down slightly from 1.388 billion cubic feet in 2022 and 14.13 billion cubic feet in 2021, according to the AOGCC. Cumulative production through June 30, 2024, was more than 40 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. ●

SANTOS *continued from page 55*

help offset increased project costs. At a consensus oil price of US$75/bbl, the IRR of the project is 20%, so Pikka is set to deliver significant value for our shareholders."

What is six months earlier? Santos most recently said Pikka Phase 1 would come online in the first half of 2026.

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

Pikka has low emission intensity, placing it in the top quartile of oil and gas development projects globally for greenhouse gas emissions performance. "Pikka is poised to play an important role in the energy transition and is aligned with our company goal of managing climate change risk," the website said.

Santos is committed to delivering a net-zero project (scope 1 and 2, equity share) from first oil and has entered into Memorandums of Understanding with Alaska Native corporations to deliver carbon offset projects, including a Strategic Alliance with ASRC Energy Services, a wholly owned subsidiary of Arctic Slope Regional Corp., on leading technology development for carbon solutions in the Arctic. The project has strong fundamentals and is located in a world-class oil producing province with significant existing infrastructure, has low unabated emissions intensity and is supported by key stakeholders, including the state of Alaska, the North Slope Borough, the landowner company Kuukpik Corp. and the Arctic Slope Regional Corp. ●

Glacier/Savant working Badami

Small eastern North Slope field sees dramatic increase in production year over year

By KRISTEN NELSON
Petroleum News

The small Savant-operated Badami field on the eastern North Slope has seen a dramatic turnaround in production following new ownership and a successful well.

Savant is a Glacier Oil and Gas company. That company was acquired by Pontem Energy and Sweat Energy Partners in January 2023. Then in March 2024 the Alaska Division of Oil and Gas approved a change of control, with SEP Alaska LLC transferring partial ownership in Glacier to The Smith Bay Company Alaska Inc. of Anchorage and JPD Family Holdings LLC of Georgetown, Texas.

STEPHEN RATCLIFF

The division said SEP Alaska owns 100% membership of Glacier, which owns 100% membership of Cook Inlet Energy, which owns 100% membership of Savant. The division's approval was effective Dec. 1, 2023.

Badami B1-33

On the production side, successful drilling of B1-33 earlier this year changed the economic picture at Badami.

Glacier Oil & Gas Corp.

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With new ownership and an improved economic outlook for exploration, Savant was able to pursue a Killian well after years of deferrals, with the Alaska Oil and Gas Conservation Commission permitting the Badami B1-33 Jan. 26, 2024, the unit's first exploration well since Badami B1-07 in early 2018. Three of the unit's most productive wells — B1-07, B1-38 and B1-33A — all produce from what AOGCC calls undefined oil.

This is what the company calls the Killian sands, the target of the Badami B1-33, which the company told the division in its 21st plan of operation, submitted by David Pascal, chief operating officer of Glacier Oil and Gas, was intended to prove up the Killian

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GLACIER / SAVANT *continued from page 57*

play beyond the existing participating area "and aid in securing capital for overall development."

In December 2023, the division approved activities associated with the well. It said the well would be drilled by Doyon 19 or a similar rig and require a 26.6-mile ice road from the Endicott/Duck Island Unit Road to the Badami Main Pad.

Drilling began with a pilot hole, B1-33PH, completed in April 2024, followed by the original well, B1-33, plugged and abandoned in June and a sidetrack, B1-33A, completed in early September, which while it only produced for 18 days in the month accounted for 68% of the field's September production, 52,458 barrels out of 77,011.

The B1-33A made a significant impact on Badami production, which averaged 2,567 barrels per day in September, up 214% from an August average of 818 bpd and up 184% from a September 2023 average of 903 bpd.

Those low production averages were behind a September 2023 decision by the commissioner of the Alaska Department of Natural Resources who determined that the Badami field qualified for royalty reduction based on how close it was to closing down due to economics.

Killian

Savant has identified prospects in the Badami and Killian sands, including some within reach of the existing pad and others which would require construction of the Badami East pad, although the company has recently been considering extended reach drilling in lieu of the East Pad.

In the 21st POD, Pascal said the company had temporarily suspended East Pad development plans and is "evaluating the risk and execution of drilling extended reach wells from the Badami Main pad along with economics that help with the case of tie-in into existing production facilities" on the main pad.

In its June 20 approval of the 2024 POD for Badami, the division said the company previously committed to drilling two Badami sand wells from the main pad but deferred those wells as a result of the Killian B 1-33 exploration well. The division said the company did confirm at a technical meeting on the POD that "the Badami wells remain integral to its multi-well development strategy," but indicated it could prioritize Killian projects depending on results from the Billian B 1-33 and the prospectivity of that play.

Marginal production

Badami was discovered in 1991 by Conoco and Petrofina; BP Exploration (Alaska) Inc. acquired a 70% interest in the field in 1993. The unit was formed in 1995, field development began in 1996 and production in 1998.

Facilities at Badami were designed for a production rate of 35,000 barrels per day of liquid hydrocarbons and 22.5 million standard cubic feet per day of produced gas, along with 13,600 bpd of produced water and 30,000 bpd of source water.

BP drilled eight wells in the first year of operation and production began in August 1998, but the company temporarily suspended production in early February 1999, saying at the time that throughput was so low that there was a risk the waxy Badami oil would plug the pipeline under the extremely cold North Slope conditions. Flow had been averaging less than 3,000 bpd, down from an average of 4,000-5,000 bpd in October, when the company said it had expected production at that stage to be more than 10,000 bpd.

BP again suspended operations from 2003-05 and 2007-11.

By the mid-2000s, average production was less than 900 bpd.

BP partnered with Savant in 2008 and then sold Savant the field; Savant later became a Glacier Oil and Gas subsidiary.

Starfish

In 2018 Savant drilled the B1-07 exploration well outside the existing Badami sands participating area, using Nabors 27E to target what the company called the Starfish prospect, at a time when field production was averaging some 1,000 bpd.

The well tested at rates above 2,500 bpd, the company said, targeting the Killian sand, a reservoir interval immediately above the oil source rock and below the Badami sands. The well proved the geologic and commercial viability of the new reservoir, the company said. B1-07 was the first new well brought into production at Badami since 2010 and the first to produce from Killian.

In discussing the company's request for royalty reduction DNR said that had the B1-07 not been drilled in 2018, the field may have been at the end of its field life earlier. The company requested royalty reduction in 2021, and DNR concluded in the fall of 2023, based on production averages to that time, that without royalty modification, the "increasing per barrel costs at Badami would likely result in the unit reaching the end of its economic field life." ●

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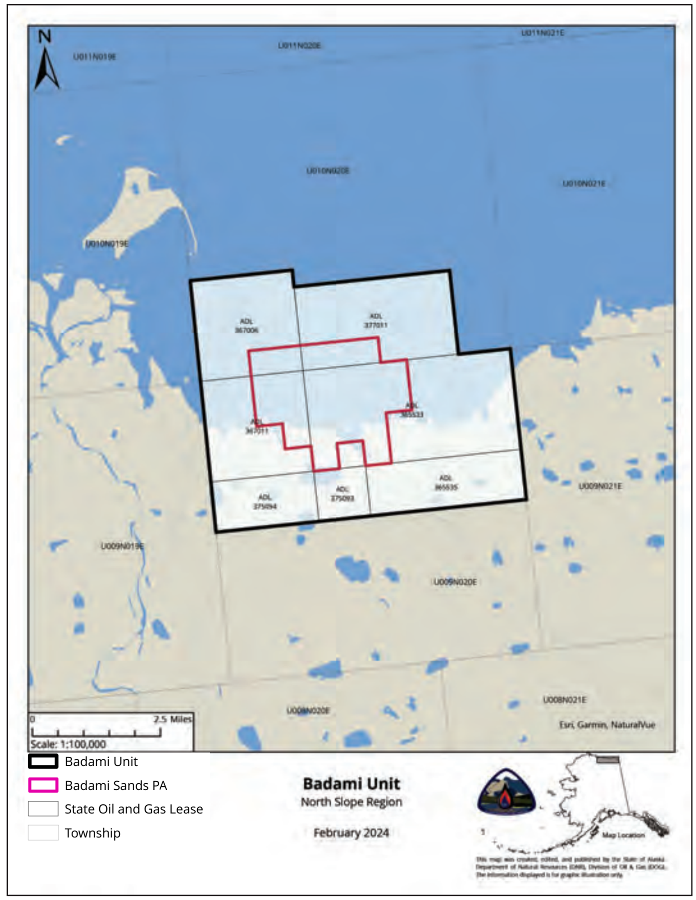

Vision hanging in there

Meets first requirement of modified POD, might lead to new North Fork well by end 2025

By **KAY CASHMAN**
Petroleum News

BOB GARDES

MARK LANDT

Vision Operating made its first report deadline of July 1, 2024, with the Alaska Department of Natural Resources' Division of Oil and Gas regarding the modified North Fork unit plan of development approved on March 5, 2024.

The POD was filed by unit operator Vision Operating LLC, a fully owned subsidiary of Louisiana-based Gardes Holdings Inc.

The onshore, natural gas producing North Fork unit, or NFU, is on the southern Kenai Peninsula. The division's approval letter was sent to Gardes and Vision executive Mark Landt.

In its 2024 POD Vision proposed to enhance production from existing NFU wells, convert a well to water disposal and drill additional wells. However, all Vision's proposed operations are contingent on market conditions and the ability to raise capital and secure a drilling rig.

The division approved Vision's POD, setting these conditions: "Vision will begin drilling a well in the NFU by the end of the calendar year 2025 and maintain operations to bring that well into production. Based on these conditions, the NFU 59th POD is approved through the end of 2025. Updates to this POD are due July 1, 2024, Jan. 1, 2025, and July 1, 2025."

Petroleum News asked Landt on Aug. 19 whether Vision Operating filed its July 1 update. And if so, what it said. Also, PN asked whether Vision/Gardes acquired any other acreage in Southcentral Alaska.

Here is what Landt had to say in response to the July 1 filing: "We have verbally responded. Nothing new."

In response to acquiring new acreage, which Bob Gardes initially suggested he would be doing when his company entered Alaska in September 2020: "No, we have not acquired any new acreage."

As of Nov. 15, 2024, all that remains the same, except for production.

Vision Operating's North Fork unit averaged 1,765 thousand cubic feet per day in September 2024, down 50 mcf per day, 2.74%, from an August average of 1,814 mcf per day and down 20.45% from a September 2023 average of 2,218 mcf per day.

The same six wells were in production at North Fork, but production was lower at all those wells.

NFU advantages

In an Aug. 23, 2023, interview with Landt, PN asked him what Vision Operating and its 2,601.84-acre North Fork unit in Alaska's Cook Inlet basin offers investors.

Gardes Holdings, Inc.

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Vision Operating, LLC
(Gardes Holdings, Inc.
parent company)
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TOP COMPANY EXECUTIVE: Robert Gardes, CEO
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TOP ALASKA EXECUTIVE: Mark Landt, VP, land & business development
TELEPHONE: 214-738-6945

"We can put new wells online almost immediately," Landt said.

"Also, the potential Southcentral Alaska natural gas market is very attractive in terms of current pricing and potential future pricing. According to recent utility reports addressing the long term — 2027 and beyond — one alternative is importing LNG at $12 to $32 per mcf. That puts natural gas pricing in the long-term in the $10-20 per mcf range," Landt told PN.

Another advantage, he said, is that that the onshore North Fork unit has all its infrastructure in place, is accessible by road, and is located on state, not federal land.

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 natural gas is transported through two fiberglass pipelines to Anchor Point where it ties into the Enstar line.

Brought online by Armstrong

A Bill Armstrong joint venture first brought the North Fork unit online in 2011, even though the field was first unitized by Standard Oil Co. of California in 1965. North Fork produced from six Tyonek sandstones.

In March 2009, Armstrong Vice President of Land and Business Development Ed Kerr told the Alaska House Resources Committee that North Fork held between 7.5 billion and 12.5 billion cubic feet of natural gas reserves and said it was "realistic" the prospect could hold between 20 billion and 60 billion cubic feet.

"There is some potential that it could be substantially larger than that," Kerr said.

That same year Armstrong hired PGS Onshore to shoot a 3D seismic campaign over some 20 square miles around North Fork to help guide future drilling decisions.

The seismic acquisition "greatly improved the regional structural definition of the four-way anticlinal North Fork closure," Armstrong Cook Inlet said in state filings.

The trick at North Fork is to find productive patches within the sandstones.

"Depositionally, these are lenticular sands, so they come and go," Kerr told Petroleum News, referring to layers of sands and mud. "We're drilling through a package of sands."

Initially formed as a federal unit in1965, in 2006 the feds waived administration rights and transferred their North Fork unit leases to the state of Alaska.

Gardes takes over

In late 2014, Armstrong sold the North Fork unit to Cook Inlet Energy LLC for nearly $65 million in order to concentrate his efforts on the oil-rich North Slope.

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.

Gardes was first and foremost looking for natural gas, not oil. He told Petroleum News at the time 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.

Gardes' first, and so far, only acquisition in the Cook Inlet basin was the North Fork unit from Cook Inlet Energy by that time a Glacier Oil and Gas company.

Effective May 1, 2021, Vision became unit operator. ●

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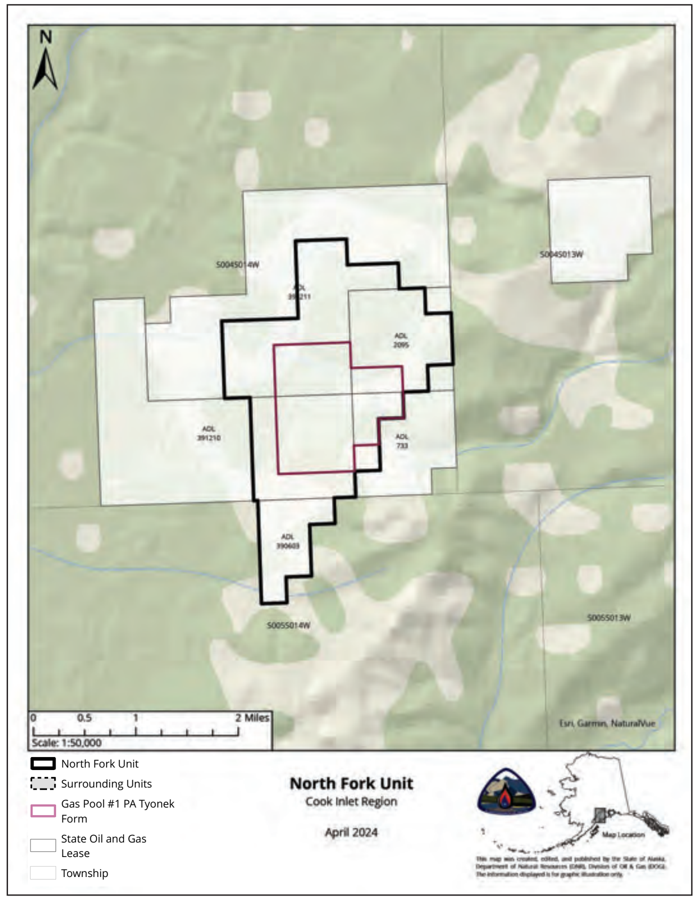

Saluting Alaska's Producers

Sunrise over Flow Station Three in Prudhoe Bay

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Anchorage Daily News, Friday, September 12, 1975

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