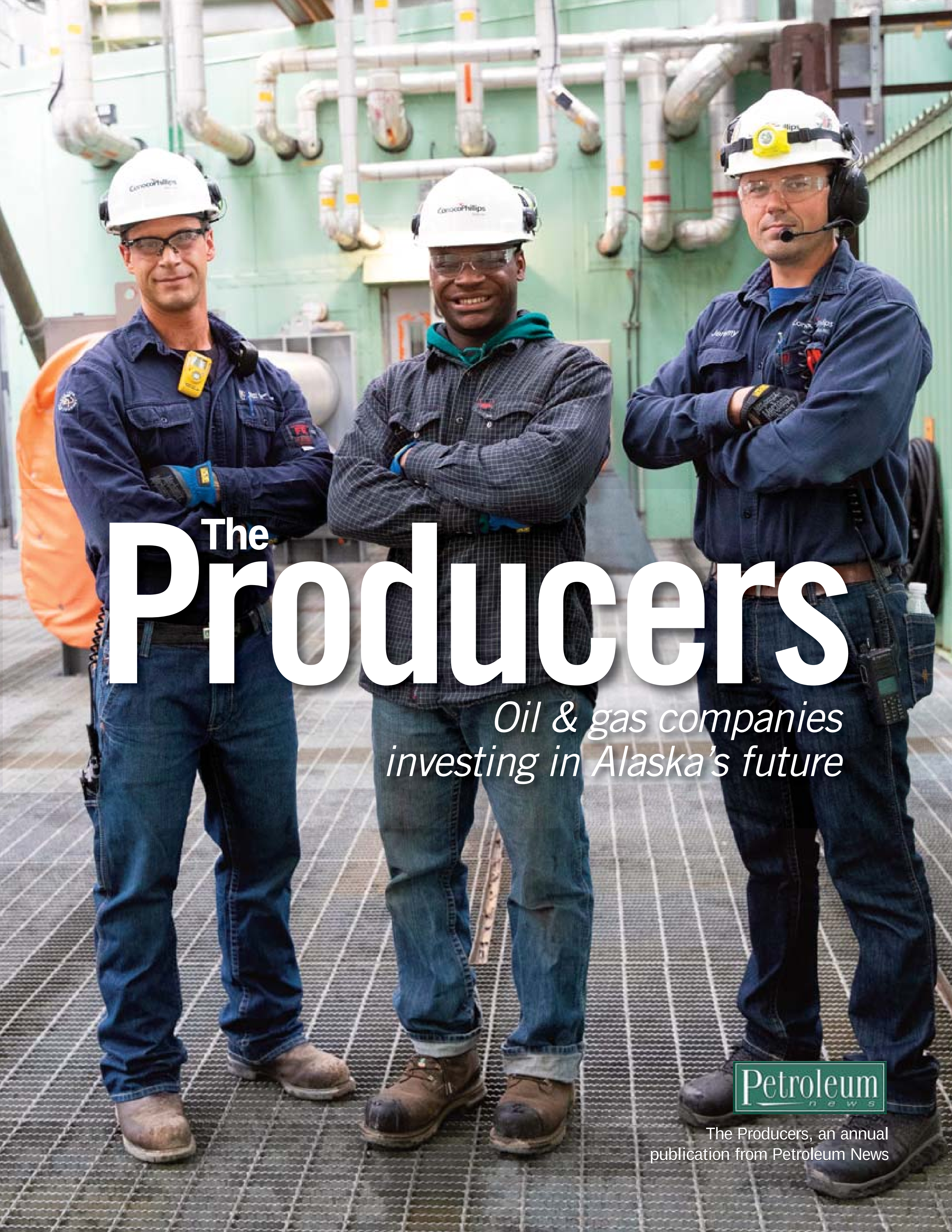

The Producers

Oil & gas companies investing in Alaska's future

Petroleum news

The Producers, an annual publication from Petroleum News

Petroleum news

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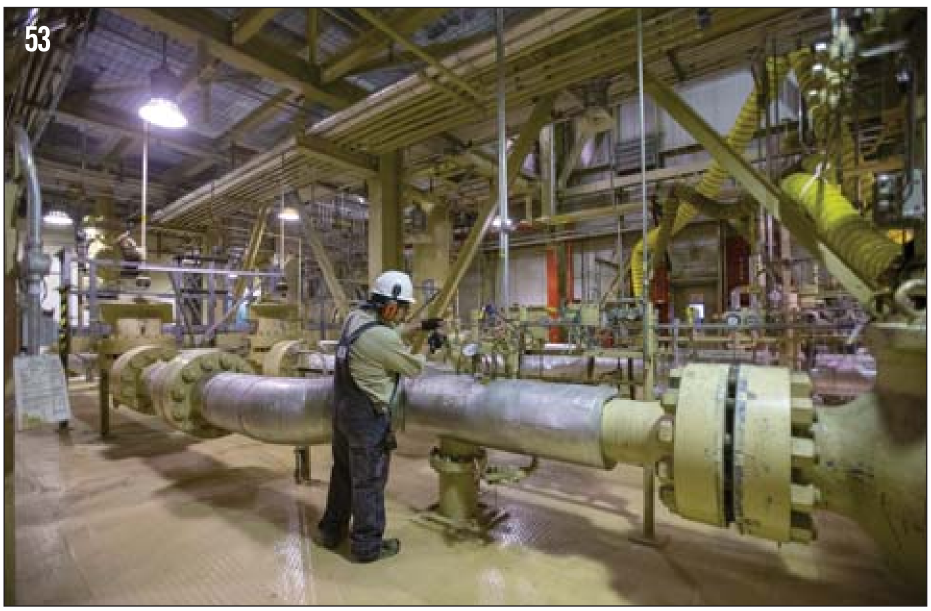

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On the cover:
ConocoPhillips Alpine Operators, from left, Justin Nusunginya (intern), Samking Germain and Jeremy Anderson.

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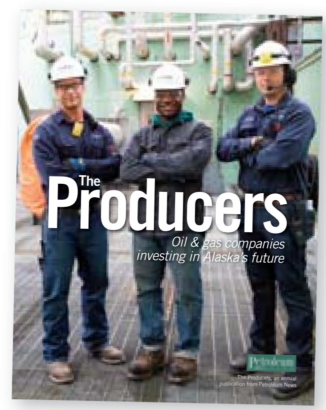
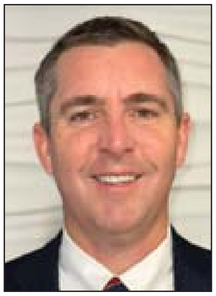


Alaska's promise

By JOHN BOYLE
Commissioner of the Alaska Department of Natural Resources

Activity levels are high on the North Slope and are trending in an exciting direction for Alaska. The investment and hard work that is occurring to make these developments happen is impressive as the state is entering an era of exploration and development more promising than any time since Prudhoe Bay nearly 50 years ago. As Gov. Mike Dunleavy would say, Alaska is open for business.

There is also increasing recognition that Alaska's resources are fundamentally necessary to meet still-growing global demand for hydrocarbons, and that efforts to restrict or diminish activity in the state are misguided. When environmental protection, carbon intensity, community support and benefit, indigenous participation, or return on capital are assessed, Alaska quickly stands out amongst competing jurisdictions. Simply put, we do things better in Alaska, practices that Governor Dunleavy refers to as the "Alaska Standard."


JOHN BOYLE

As we look at opportunities across the state, Prudhoe Bay is a natural starting point. Alaska's legacy field has a new operator, Hilcorp, who took the reins during the challenging 2020 lockdown year. Their activity — backed by partners ExxonMobil, ConocoPhillips and Chevron — has roared forward with major facility de-bottlenecking, surface piping upgrades and a new drilling program with amazing results. Nearly 50 years in, Prudhoe Bay may see sustained, if incremental, production increases. Hilcorp is also replicating that model on other legacy fields it operates. Milne Point, for example, has seen its production more than double since Hilcorp assumed operatorship. This means core North Slope assets will play an even more significant role in maintaining production than assessed even a few years prior.

Down the road from Deadhorse, there are exciting exploration efforts at the Talitha and Alkaid Units led by Great Bear Petroleum, and at the Toolik River Unit by 88 Energy. Both operators are looking to develop their plays with the benefit of proximity to the Dalton Highway. Further east, Badami has a new owner and partner who are diligently working to prolong the life of that useful asset.

South of Badami, we have seen the formation of the Grey Owl Unit and are eagerly anticipating the three well exploration drilling program led by wildcatter Bill Armstrong this winter season. And as another indication of interest in the state, Apache has returned to Alaska through a farm-in of the Lagniappe leases held by Armstrong and Oil Search. Further east, Point Thomson continues to cycle liquids as larger scale gas commercialization comes together.

Significant developments in the west

Our most significant new developments are in the west. This year has seen major progress on two mega-projects that are defining the next generation of opportunity for Alaskans: Pikka and Willow. The final investment decision on Phase I of the Pikka project by Santos and partner Repsol is ushering in an active construction season over the next few years with first oil of 80,000 barrels per day anticipated in 2026. With an exploration and development runway for Santos and Repsol of Pikka Phase II, Quokka, Horseshoe, and other prospects, the promise of the Nanushuk play is being tapped at a scale and potential production rate that will rival or exceed any development since Kuparuk.

When environmental protection, carbon intensity, community support and benefit, indigenous participation, or return on capital are assessed, Alaska quickly stands out amongst competing jurisdictions.

We also have reason for cautious optimism with ConocoPhillips's Willow project receiving its federal Record of Decision earlier this year. While litigation against the project continues, early rulings on preliminary injunctions have been favorable and a robust suite of Alaskan stakeholders continues to make the project's massive public benefits known through their filings in support. In addition to Willow, ConocoPhillips is continuing robust investment and new drilling across its eastern North Slope portfolio, which is a key driver of total Alaskan production.

All this activity means Alaska Division of Oil and Gas internal production forecasts — even with conservative risking on volumes and timelines — show our contribution to domestic energy security and global supply increasing over the decade ahead. We as Alaskans should seize this opportunity by continuing to support investment through sound policy and advocacy, and maintaining a stable and predictable fiscal environment. The Dunleavy Administration is committed to these principles, and eager to promote Alaska as a premier investment destination.

Russia's invasion of Ukraine and the upending of global energy markets are leading many to believe that Alaska's resources are a solution to the problems of reliability, scale and dependability. To that end, Gov. Dunleavy, the Department of Natural Resources (DNR) and the Alaska Gasline Development Corp. are working hard to bring in project developers and offtakers to make the AKLNG project a reality. While there are challenges inherent in developing one of the largest LNG projects in the world, we will continue to do everything we can to facilitate progress on the project to develop North Slope gas for the benefit of Alaskans. Alaska's energy security interests are aligned with our national interests as a clean energy exporter and the international market's demand for reliable energy from stable jurisdictions; the critical alignment that we believe will drive the project forward.

Cook Inlet natural gas

North Slope resources are also a potential solution to the critical issue of potential shortfalls in Cook Inlet natural gas production. Cook Inlet natural gas has long been a core energy source for Alaskans stretching back to statehood in 1959. Accordingly, many of the major fields in the region — some of which have been producing since that time — are seeing significant declines in their

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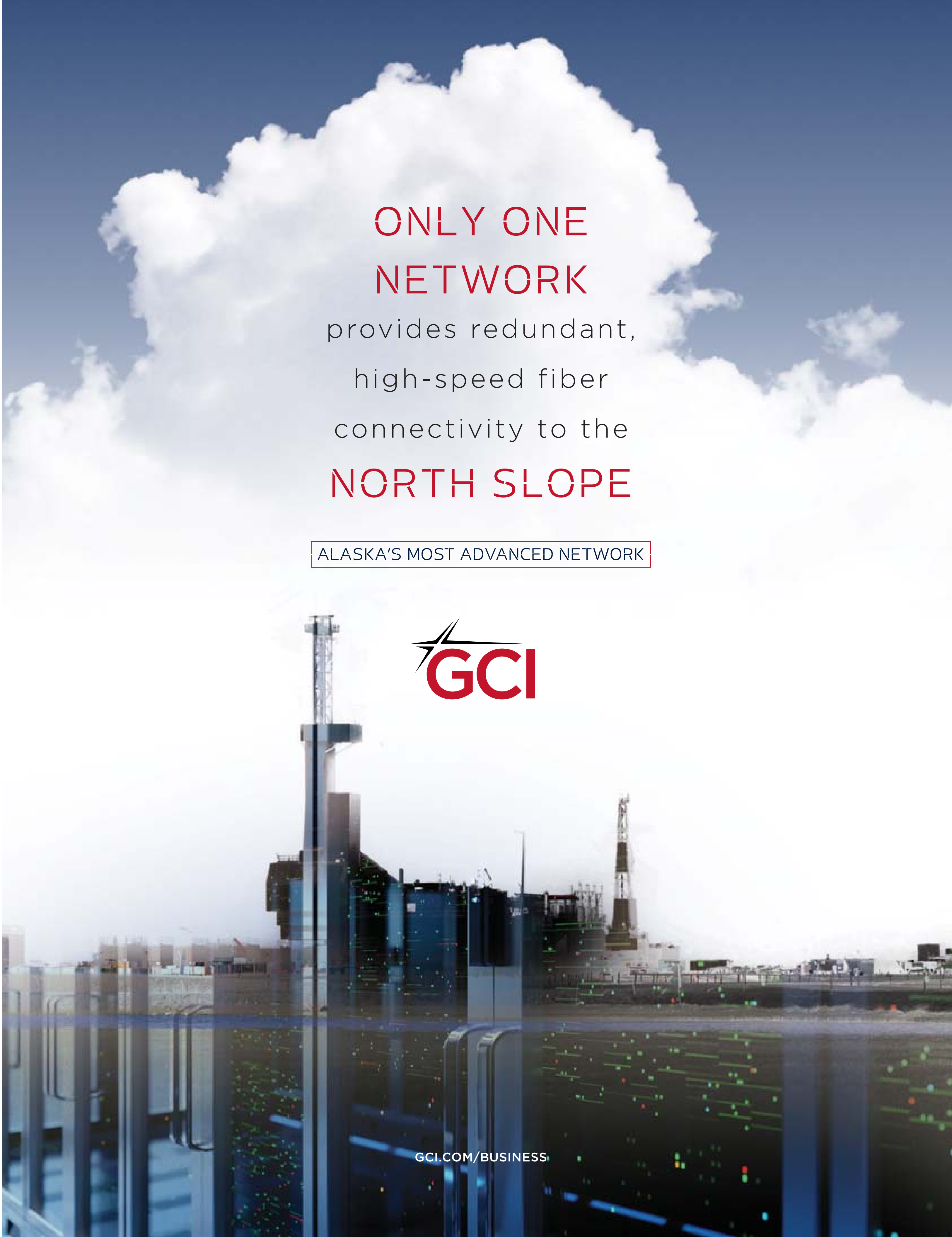
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BOYLE *continued from page 8*

production. While identified reserves continue to be produced, Hilcorp, as the largest operator in the Inlet, announced last year that they do not have line of sight on additional supplies to provide extensions to utility contracts as they have in prior years. Although significant volumes are already covered by contracts over the next decade, a "gap" in contracted demand is emerging in the years ahead, particularly at the end of this decade.

All this activity means Alaska Division of Oil and Gas internal production forecasts — even with conservative risking on volumes and timelines — show our contribution to domestic energy security and global supply increasing over the decade ahead.

The Dunleavy Administration is taking this issue seriously, with a coordinated and comprehensive approach to boost contractable volumes of gas in the Inlet while we look for longer-term, all-of-the-above solutions to expand energy availability. As we learned a decade ago, when similar market and supply issues developed in the Cook Inlet, it takes policy leadership and action to address this kind of critical situation. We are incorporating lessons from the past while seizing on potential changes to our development regime to make a better tomorrow.

DNR is working to provide flexibility focused on increasing production and continuing to find efficiencies in our permitting process. We are also making available geological and geophysical data gathered a decade ago under previous tax credit programs that are now eligible for publication, with significant releases expected this year and early next.

The department is taking even more novel steps to incentivize new leasing, with our ongoing offering of highly competitive leases for all available state-owned Cook Inlet acreage. The bid variable for these leases is a "net profit share" term, where a developer owes lease-based payments to the state when they recoup capital costs and reach profitability — rather than a fixed royalty rate. This approach draws on similar terms offered in other jurisdictions around the world and provides a powerful framework for developers to earn back their investment as quickly as possible without a fixed royalty burden, and the state sharing in the profits when they do.

There are major hydrocarbon prospects in Cook Inlet on existing leases that have not yet seen development for a variety of reasons. In addition to active management under our existing authorities, Gov. Dunleavy is evaluating a variety of options to pull these resources into the market. Existing royalty adjustment provisions could be expanded to cover different categories of new production to secure new supplies. A new package of proposals the administration is planning to bring before the Legislature will make new supplies attractive to develop and promote Alaskan energy security without driving up consumer prices, incentivizing activities that do not directly lead to new supplies or forgoing state return for resources that are already in production.

A new package of proposals the administration is planning to bring before the Legislature will make new supplies attractive to develop and promote Alaskan energy security without driving up consumer prices, incentivizing activities that do not directly lead to new supplies or forgoing state return for resources that are already in production.

Cook Inlet oil

While much of the public discussion has focused on natural gas, Cook Inlet oil remains a vital source of in-state fuel supply. Most of Alaska's gasoline is produced at the Nikiski refinery, along with diesel fuel, aviation fuel and asphalt for construction. This local industrial capacity is vital to the health of our economy and keeping high-paying jobs in our communities. Measures the Dunleavy Administration considers for boosting natural gas production will also create correlative, positive potential for oil development.

Other stakeholders are also working on these issues, and it is going to take initiative across different sectors of our economy to tackle this challenge. That is why the Dunleavy Administration is taking an all-of-the-above approach looking at everything from tidal, solar, wind, hydro, biomass, nuclear and geothermal resources to diversify supply and lower the cost of energy for Alaskans. DNR is supporting all these efforts and ensuring that project developers have a welcoming business environment to evaluate this potential.

Alaska has the resource base to provide affordable and abundant energy for its citizens and the world. Our motto of "North to the Future" is more relevant than ever as we look at the landscape before us. And I am confident that Alaskans' can-do spirit, coupled with smart policy, will help us solve our most vexing challenges and position us for a bright and prosperous future. ●

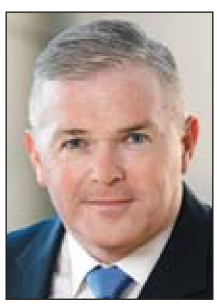
PHOTO BY JUDY PATRICK, COURTESY OF SANTOS

Members of the Santos Board of Directors and senior leadership team along with board members of the Kuukpik Corporation tour the Pikka project drill site on the North Slope in June.

Next big North Slope oil field

Santos' Pikka Phase 1 development getting greener; first oil expected in 2026 with daily gross of 80,000 barrels a day

By **KAY CASHMAN**
Petroleum News



KEVIN GALLAGHER

On Aug. 16, 2022, Santos Ltd. (51%) and its joint venture partner Repsol (49%) took a final investment decision to proceed with the US$2.6 billion Phase 1 of their Pikka development project west of Alaska's central North Slope. (Santos' share is $1.3 billion.)

The Pikka unit operator is Santos subsidiary Oil Search (Alaska), or OSA.

First oil is expected in 2026 with a daily gross of 80,000 barrels a day from Phase 1, which represents approximately 17% of the Alaska North Slope's entire output.

The Pikka Phase 1 project is progressing as planned and remains on schedule and on budget, Santos told Petroleum News July 30, 2023.

Santos also released a short, summary statement about Pikka Phase 1 in its second quarter report on July 20, 2023, saying that "all major drilling, fabrication and construction contracts are in place. On-site 2022/23 winter construction activities, including gravel work for road, pad and pipeline crossings, has been completed. All pipeline orders have been placed, materials are being delivered and fabrication is underway for the upcoming 2023/24 winter construction season."

Most recently, in Santos' Aug. 23, 2023, presentation of its first half year results, which ended June 30, CEO and Managing Director

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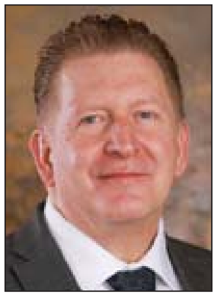
Kevin Gallagher said the company has progressed carbon solution opportunities, including "executing agreements with Alaska landowners to support the generation of nature-based carbon credits for our Pikka project."



BRUCE DINGEMAN

And in the Alaskan Business Unit clip: "Santos is committed to delivering a net-zero emissions project (Scope 1 and 2, equity share) and has executed an agreement with an Alaska Native corporation to deliver carbon offsets, with additional carbon solution opportunities being evaluated."

Santos has not yet said which Native corporation or provided additional details on nature-based carbon credits or the additional carbon solution opportunities.

The two big buckets

The two big buckets of carbon offsets recognized today are the government/regulatory schemes and voluntary/market schemes that are in place nationally and internationally. They set out the things a company must do in order to demonstrate they are mitigating or offsetting their CO2 emissions.

The first category includes technology-based offsets. These are interventions in the combustion/emissions process that have the effect of limiting or eliminating the emissions. For example, Santos is participating in a consortium that is pursuing these sorts of offsets and recently took a step forward in the federal Department of Energy process to look at Direct Air Capture, or DAC, technologies in the Arctic. DAC removes CO2 from the atmosphere which can then be used or stored. It is very expensive and inefficient but the Biden administration offers significant tax breaks for doing it.

Nature-based offsets are those that take advantage of naturally occurring processes to capture more CO2 or reduce the amount of CO2 put into the atmosphere. In many cases, this is some sort of forestry-related process. Either a given stand of timber is managed differently to cause the timber to capture and store more CO2 than it would if managed under the status quo — or it is not harvested at all so as to leave the CO2 in the trees. Additional opportunities exist in the maricultural space but the point is that these are naturally occurring rather than mechanical/artificial processes.

Phase 1 18% complete

In its operational highlights for Pikka in the first half of 2023, Santos said it spud and completed its first well (for cuttings disposal) in June and remains on track for production in 2026.

Anthea McDonell, chief financial officer for Santos, said that as of the end of the first half of 2023, Pikka Phase 1 is 18% complete.

Her overheads showed that major contracting has been completed, module fabrication initiated and community projects in progress.

In its July 30, 2023, interview with Petroleum News, Santos said the Pikka modules are "under production in both Alaska and Canada. Worley is building the G&I facility in Anchorage and NANA is building the camps in Big Lake. The modular processing facility is being built in Canada. First modules are expected to arrive at Pikka before the end of the year." ●

Contact Kay Cashman at publisher@petroleumnews.com

AIX maintains discipline at Kenai Loop

Steady approach has kept Kenai Loop viable, despite declines

By ERIC LIDJI
For Petroleum News

AIX Energy LLC is a steady operator. Over the past nine years, the small independent has been disciplined at its onshore Kenai Loop field in the northern Kenai Peninsula.

The company generally focuses on securing short-term, immediate sales contacts, and it usually puts most of its resources toward required maintenance activities at the field.

"AIX's marketing goals are to continue to pursue value added, near term gas sales opportunities (to align with existing and future production capacity), while maintaining pricing discipline," the company wrote in its most recent plan of development.

Under a three-year, "firm as available" contract approved April 1, 2023, AIX Energy currently sells "all gas volumes to a single purchaser," according to the company.

During its eighth plan of development, for the year ending May 6, 2023, AIX tested emergency systems, as required by schedules. It also conducted audits of its control room with Pipeline and Hazardous Materials Safety Administration personnel with no issues.

The company also obtained static reservoir pressures on the KL 1-1 and KL 1-3 wells.

Early in 2023, the state Division of Oil and Gas automatically terminated two AIX Energy leases — ADL 393033 and ADL 393035 — for failure to pay rental.

Plans

In the coming year, AIX plans to evaluate the feasibility of tying the shut-in KL 1-4 well into the production system "to provide increased deliverability, to provide redundancy to meet firm gas sales obligations and to possibly increase ultimate recovery. AIX will also evaluate recompleting wells to provide additional deliverability," the company wrote.

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

According to its most recent plan, AIX has not identified any drilling opportunities for the coming year. That fact and others — the desire to improve deliverability, the three-year "firm as available" contract, production rates on the decline since early 2016 and especially since early 2018, and the decision to allow two leases at the field to expire — combine to raise questions about future of Kenai Loop, especially in regard to reserves.

In its most recent plan, AIX Energy said that its existing original gas in place estimate still remains "accurate" but asked that the figure be kept confidential. Through the end of March 2023, the Kenai Loop field had produced 27.1 billion cubic feet of natural gas.

Natural gas production peaked in early 2016 around 11.5 million cubic feet per day and declined sharply in late 2017. It currently produces some 2.5 million cubic feet per day.

History

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

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

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Amaroq anticipates investments at Nicolai Creek

West side Cook Inlet field needs investment; operator Amaroq need capital

By ERIC LIDJI
For Petroleum News


SCOTT PFOFF

In recent years, the Nicolai Creek unit has stood on the edge of precipice of capital.

The onshore field on the west side of Cook Inlet continues to produce sufficient quantities of natural gas to justify its existence, but operator Amaroq Resources Inc. has frequently acknowledged that essential investments will be needed in the near future.

In its current plan of development, the 49th for the unit, Amaroq once again proposes no drilling activities at Nicolai Creek but continues to inch toward investments: working over the Nicolai Creek Unit No. 10 well, resolving issues at the Nicolai Creek Unit No. 1B injection well and improving its knowledge of deeper oil horizons at the field.

All these plans, though, are beyond what Amaroq can afford on its own. The company told regulators that its long-range plans for the unit are "highly dependent on (its) ability to attract the additional capital necessary to effectively further develop the field."

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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.

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

The Nicolai Creek unit produced some 54.2 million cubic feet of natural gas in the first six months of this year, up from 45.7 million cubic feet in the first six months of 2022, according to the AOGCC.

The unit has shrunk, as wells have been taken offline.

Nicolai Creek unit No. 4, No. 5, No. 6, No. 13 and No. 14 have since been plugged and abandoned, while Nicolai Creek No. 2, No. 3, No. 9, No. 10 and No. 11 remain capable of producing. But of those five wells, only one is consistently producing at the moment.

The Nicolai Creek unit produced some 114 million cubic feet of natural gas through July 1, 2023, down 5.4% from 120.5 million cubic feet over the previous 12-month period, according to figures from the Alaska Oil and Gas Conservation Commission.

The Nicolai Creek unit produced some 54.2 million cubic feet of natural gas in the first six months of this year, up from 45.7 million cubic feet in the first six months of 2022, according to the AOGCC. The unit produced entirely from Nicolai Creek Unit No. 9 during that time, and the well posted some of its best months on record,

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RESPONSIBILITY | SAFETY | JOBS | COLLABORATION | ENERGY
Responsibility goes beyond compliance. At ExxonMobil, we deeply value the wisdom, culture, and vision of Alaska Natives. We must learn from and collaborate with all Alaskans to develop our great state's resources responsibly.

AMAROQ *continued from page 16*

most notably 15.6 million cubic feet or 742,000 cubic feet per day over 21 days in March 2023.

In previous years, the Nicolai Creek Unit No. 11 well also provided small, supplementary production, but the well has been perennially shut-in during recent years due to low reservoir pressure and only produced during three months of 2022, last in November.

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

Amaroq brought the Nicolai Creek Unit No. 10 online in May 2021 after some time offline. The well produced nearly 4.8 million cubic feet through October 2021 but also produced "excessive quantities of water,' according to the company. The well was returned to production in June 2022, with similar rates of gas and water production.

The solution is "most likely" a rig workover, according to Amaroq. In its latest plan of development, the company told regulators that it was beginning to develop a work plan and cost estimates. Those efforts will continue under the current plan of development.

In a previous plan of development filed in September 2021, Amaroq said it planned to acquire 100% working interest in "deep rights" below parts of the Nicolai Creek Unit, specifically the Upper Tyonek formation underlying its onshore acreage.

In previous years, Amaroq noted development opportunities at the Nicolai Creek Unit No. 3 well, which has been shut-in due to "formation sand and silt plugging the tubing," according to the company. The company has previously proposed a coiled tubing cleanout of the well but did not include the project in its current plan of development.

Between mid-2020 and mid-2021, Amaroq converted the depleted Nicolai Creek Unit No. 1B well to water disposal. The current plan calls for remediation at the well.

Deep oil

In a previous plan of development filed in September 2021, Amaroq said it planned to acquire 100% working interest in "deep rights" below parts of the Nicolai Creek Unit, specifically the Upper Tyonek formation underlying its onshore acreage.

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

The sale granted Amaroq access to proprietary 3D seismic data commissioned by Apache over the Nicolai Creek unit on the west side of Cook Inlet. Having now analyzed that data, Amaroq has concluded that "additional data extending onto its offshore acreage is needed. Amaroq therefore currently is in the process of obtaining this additional data for (analysis) and incorporation into its existing model. Should Amaroq be able to 'high grade' the prospect into a drillable opportunity, then it will seek third-party funding to move forward with an exploratory well," according to a summary from the state. ●

Contact Eric Lidji at ericlidji@mac.com

COURTESY BLUECREST

Loading a Carlile truck to haul oil to the Marathon refinery. This is one of over 7,100 trucks that have been loaded from the BlueCrest Cosmopolitan onshore drilling and production facility located in Anchor Point, Alaska.

BlueCrest returning to Cosmo drilling

Hiatus could end this year pending permitting and financing

By ERIC LIDJI
For Petroleum News

BlueCrest Alaska Operating LLC expects to soon resume drilling operations at its Cosmopolitan unit after a three-year pause. The reasons for the pause are known: a pandemic, oil price fluctuations, and uncertain financial markets and tax regimes.

The thin silver lining is easy to overlook. With that extra time, BlueCrest has already designed the well it wants to drill. All it needs is financing and final regulatory approval.

The regulatory approval is more challenging than usual, given the nature of the well.

The Alaska subsidiary of the Texas-based independent is looking to restart its drilling program at Cosmopolitan with the H10 Trident Fishbone, a technically complex well intended to maximize the reach of a surface well with numerous subsurface laterals.

The innovative well design has a single wellbore that branches into three subsurface "fishbone" wells, each with eight distinct laterals. All told, that means 24 individual wells, each requiring separate drilling permits from various state agencies, particularly the Alaska Oil and Gas Conservation Commission. "AOGCC has been really responsive and good to work with. They're keen on new technology," BlueCrest Alaska President and Chief Executive Officer John M. Martineck told Petroleum News in late 2022.

In its most recent plan of development, the company said it

continued on page 22

J. BENJAMIN JOHNSON

JOHN M. MARTINECK

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Santos
At Santos, we are proud to develop the world-class Pikka Project on the North Slope. Phase 1 will develop about 400 million barrels from a single drill site with first oil expected in 2026. And we are even prouder that our interest in Pikka will be net-zero on Scope 1 & 2 emissions!
Santos
Santos

BLUECREST *continued from page 20*

hoped to begin drilling this year and believed it could spud the well "within several months" of receiving funding.

Permitting

In early 2023, BlueCrest filed an amendment to its Oil Discharge Prevention and Contingency Plan, announcing its expectation of increased oil production rates in expectation of the additional wells. A C-plan is a crucial early permitting document.

As this issue of The Producers was going to press in mid-September 2023, the AOGCC had not posted any new drilling permit applications at Cosmopolitan on its website.

With those regulatory matters underway, BlueCrest also needed to resolve financing.

"The challenge to get financing is largely because of the way the State handled the tax credits," Martineck told Petroleum News, adding, "Companies, including BlueCrest, spent millions on exploration but then could not collect from the State. … Some sold tax credits at a drastically reduced price to other companies to get funds to stay afloat… the State also cancelled the tax credit program we were counting on from the start."

The H10 Trident Fishbone is primarily targeting oil accumulations but is expected to encounter natural gas, as well. BlueCrest plans to sell associate gas into the local market.

Beyond that immediate project, though, BlueCrest is also interested in a distinct gas play in the Tyonek formation at Cosmopolitan. Martineck described the play as "the largest known underdeveloped structure in the Inlet." Developing the prospect would require a new offshore platform with a new pipeline back to shore, meaning that any gas production would be at least two-to-three years beyond the start of development work.

History

The offshore Cosmopolitan unit sits just off the coast of the southern Kenai Peninsula.

One of the essential decisions facing any operator of the unit was whether to develop it through some offshore drilling solution — like a new platform or a jack-up rig — or whether to attempt to reach the reservoir from an onshore pad using directional drilling.

BlueCrest came to Alaska in the early 2010s as a minor partner of Buccaneer Energy Ltd., which was then operating Cosmopolitan. BlueCrest eventually took over as sole owner and operator and brought the unit online in early 2016 from an existing well.

BlueCrest chose the onshore option. The company commissioned the custom-built BlueCrest Rig No. 1, which it billed as the most powerful drilling rig in Alaska. The rig was designed to 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 a powerful rig, drilling from the shore was expensive and technically challenging. The multilateral campaign is a way to drill fewer directional surface wells.

"Each fishbone well contacts the same amount of reservoir rock as seven-(to)-nine individual horizontal wells, and each trident well should recover the same ultimate reserves as three fishbone wells since the reservoir contact is the same," then-CEO and President J. Benjamin Johnson told Petroleum News in 2019, adding, "so, each trident well provides the same amount of reservoir contact as 21-27 individual wells."

Work

As part of its activities for 2022, BlueCrest overhauled the two gas compressors at the unit. The company described the compressors as "the lifeline of the facility." The compressors handle natural gas for sale as well as for injection at the facility to improve oil production and also provide fuel for operations. "This was a large undertaking but was critical work completed this year," the company wrote in its plan of development.

During the year, BlueCrest also completed upgrades to the mechanical refrigeration unit at Cosmopolitan. BlueCrest commissioned the unit in 2020. The unit can process up to 35 million feet per day of natural gas for sales. The facility is primarily designed to accommodate natural gas contained in oil production at Cosmopolitan, which is wet.

Also during the 2022 development year, BlueCrest performed hot oil treatments on its wells every three to four weeks to maintain production levels at Cosmopolitan. The company plans to perform similar treatments on the Hansen 1AL1, Hansen H4, Hansen H12, Hansen H14, and Hansen H16A wells in the coming year to maintain production.

Cosmopolitan produced 281,223 barrels of oil in 2022 and 130,853 in the first half of 2023, down from 331,077 barrels of oil in 2021 and 143,198 barrels during the first half of 2022, according to the AOGCC. The unit also produced 587 million cubic feet of natural gas in 2022 and 272 million cubic feet during the first half of 2023, down from 954 million cubic feet in 2021 and 313 million cubic feet in the first half of 2022. ●

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ConocoPhillips still Alaska's Largest oil producer

Plans $1B annual spend in legacy fields alone; continues to develop prospects In or near existing infrastructure

By KAY CASHMAN
Petroleum News

EREC ISAACSON

ConocoPhillips Alaska is the state's largest crude oil producer, with current output of approximately 200,000 barrels a day of high margin oil with Brent-link pricing.

Since 2007, the company has incurred more than $43 billion in taxes and royalties to the state of Alaska and the federal government. Of that amount, about $33 billion went directly to the state.

In that same period, ConocoPhillips Alaska's earnings were approximately $25 billion.

"Alaska's existing fiscal regime provides stability for continued industry investment in the state. ConocoPhillips Alaska has spent more than $700 million in the first half of 2023, an increase in capital activity from 2022," Erec Isaacson, president, ConocoPhillips Alaska, said in August 2023.

Since the 2013 transition between ACES and SB 21 ConocoPhillips Alaska produced first oil at GMT1 in 2018 and at

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ConocoPhillips

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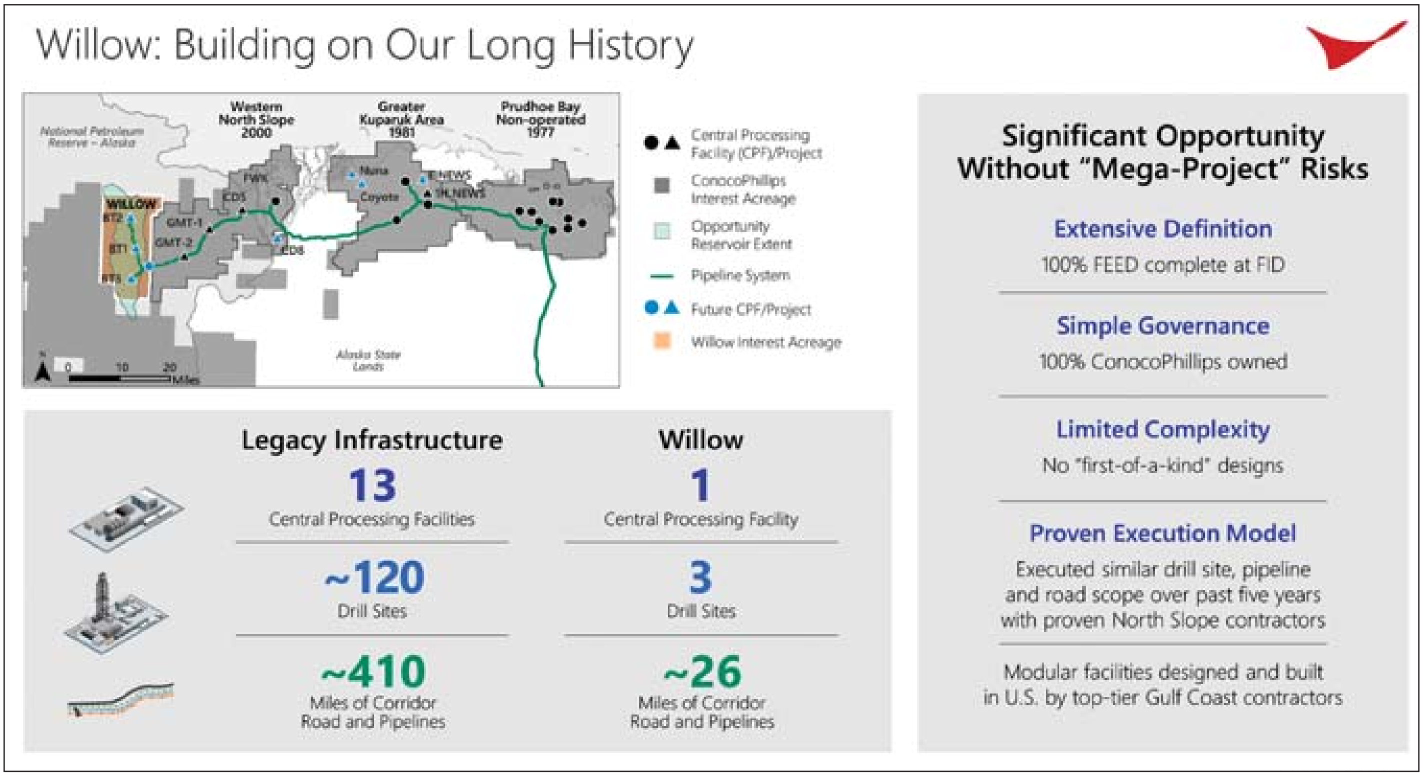

CONOCOPHILLIPS *continued from page 24*

GMT2 in 2021. Willow has also been described as a SB 21 success story.

"For more than 50 years, ConocoPhillips Alaska has invested in Alaska and developed meaningful community partnerships. We look forward to future decades of progress through continued growth and investment," Isaacson said.

As it has moved from east to west across Alaska's North Slope the company has amassed major ownership interests in two of North America's largest legacy conventional oil fields, both located on the central North Slope: the Kuparuk River unit, which the company operates, and the Hilcorp-operated Prudhoe Bay unit.

Additionally, ConocoPhillips operates several fields west of the central North Slope and has already begun spending on its $7 billion to $7.5 billion Willow development which was nearing its final investment decision, or FID, in September 2023 as this issue of The Producers magazine was headed to press.

The Colville River unit, which is west of the central North Slope, is the other major legacy oil field operated by ConocoPhillips.

$1B annual legacy capex

ConocoPhillips has said it will continue to invest about $1 billion a year to grow its Alaska legacy business.

This amount includes the company's Greater Kuparuk Area prospects such as Nuna, Coyote and Northeast West Sak, as well as Fiord West and CD8, which are in the Alpine field of the Colville River unit.

Nuna first oil early 2025

On Aug. 31, 2023, ConocoPhillips applied for a Torok participating area in the Kuparuk River unit, a move that followed its June 1 announcement that funding had been approved for developing the Nuna project from Drillsite 3T, or DS 3T, on the northwestern edge of the unit.

Development of Nuna through existing Kuparuk River unit facilities will minimize environmental impacts because "the tract owners will not have to build stand-alone processing facilities solely for the benefit of these areas," the company said.

Nuna drilling is scheduled to start in fourth quarter 2024. First oil is anticipated by early 2025, with an expected peak oil rate of some 20,000 barrels per day.

On Feb. 6, 2023, Alaska's Division of Oil and Gas approved ConocoPhillips' proposed development plan of operations for Kuparuk River unit DS-3T, including pad and road expansions.

The work includes expansion of the southeast side of the existing gravel pad, expansion of the existing 2.9-mile access road to the pad and expansion of the access road intersection near DS 3S.

The division said the expansion is to allow transport and installation of the 140-foot by 40-foot single production module, or SPM, and the larger drilling rig required for directional extended reach drilling of the 29 new wells proposed for the project.

There will also be some 3 miles of new pipelines from DS 3T to DS 3S, with power to be supplied by a messenger cable connected to the new pipeline.

The single production module "is an advanced self-contained unit that consolidated numerous other modules that would traditionally be found on a pad and controls the functionality of the drill site," the division said, with multiple modules in one unit which can be assembled and tested off site.

Coyote a Nanushuk reservoir

In mid-2021, ConocoPhillips announced the Coyote discovery east of Nuna. At the time, Isaacson said Coyote was in the Brookian topset above the Nuna Torok discovery, describing Coyote as shallow, i.e. a Nanushuk play.

Coyote had been identified from review of 2015 3D seismic.

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

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

On Jan. 4, 2023, the Alaska Oil and Gas Conservation Commission, or AOGCC, approved an application from ConocoPhillips for a 3-year enhanced oil recovery pilot at the Coyote reservoir on the western edge of the Kuparuk River unit.

The project will be both within the Kuparuk River unit and in an adjacent area, non-unitized lease ADL 392374, AOGCC said.

The pilot EOR will occur at the Kuparuk River unit 3S Pad drill site.

The commission said the Nanushuk formation was first discovered near the proposed pilot project area in 1965-66 in

A truck lays ice chips for construction of an ice pad for the Willow project. April 2023.

Sinclair's Colville 1 well, some 3 miles south-southwest of 3S Pad.

Phillips Alaska's Palm 1 exploration well, drilled in 2001 from what is now DS-3S, encountered oil shows in Nanushuk sandstone. The commission said seven development and service wells drilled to deeper reservoirs have penetrated the Coyote interval in or near the planned project area.

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CONOCOPHILLIPS *continued from page 27*

Exploratory, redrilled well 3S-24B, drilled in 2021, penetrated and tested the Coyote interval, AOGCC said.

A formal pool has not been established and for the purposes of this order, the commission said, ConocoPhillips defines affected sediments of the Nanushuk, informally named Coyote sands, as correlating with the reference Palm 1 between 4,270 and 5,115 feet measured depth.

Coyote oil

AOGCC said Coyote is primarily a stratigraphic trap, with oil in the interval averaging about 32 degrees API.

ConocoPhillips has estimated 31 million barrels of oil within the proposed pilot area, with primary recovery estimated at 5-10%, waterflood recovery 20-30% and an additional 1-5% from potential injection of enriched gas.

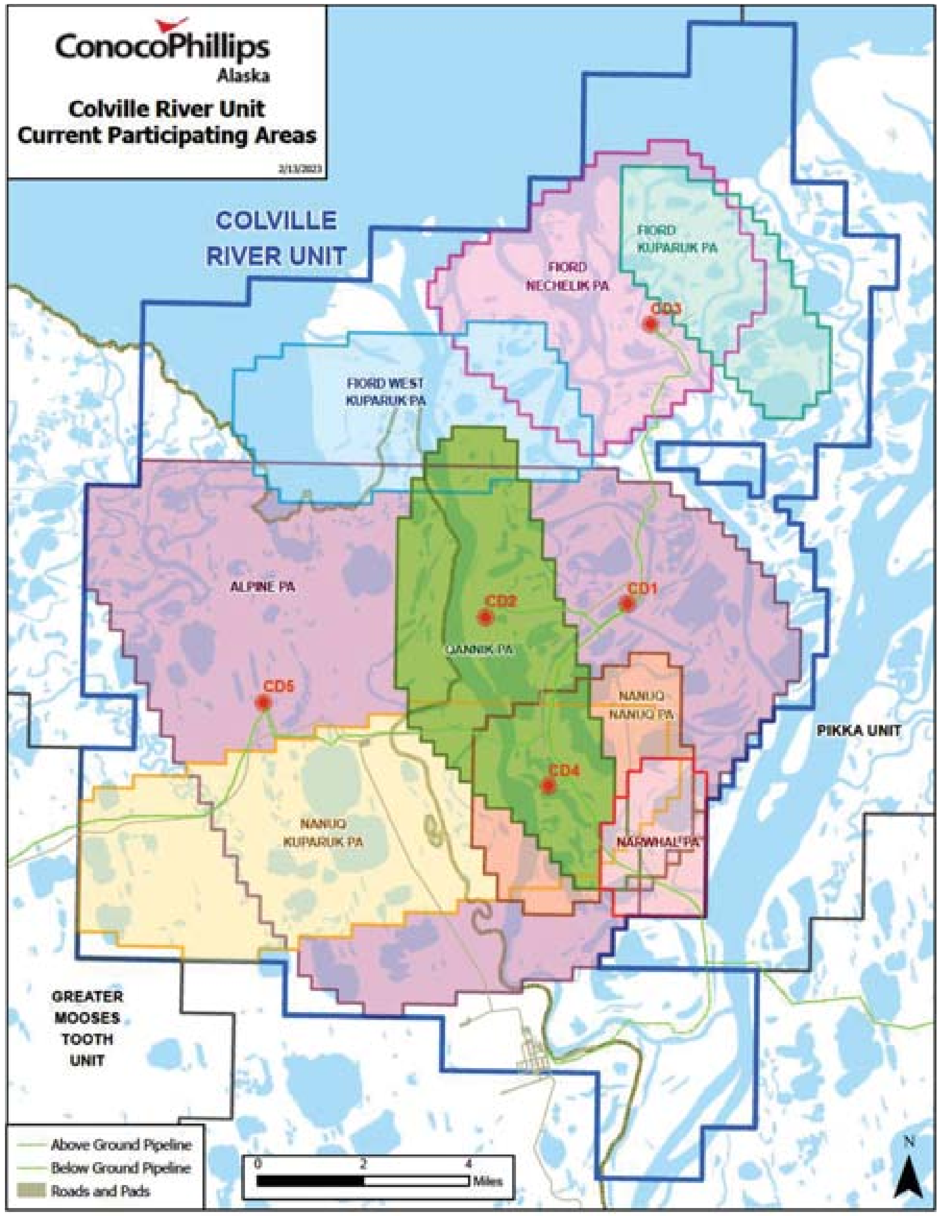
The original scope of the 3-year pilot includes a central horizontal producer with one offsetting horizontal injector west of the producer, and, depending upon initial results, a second horizontal injector east of the producer.

The commission said ConocoPhillips plans to fracture stimulate the proposed pilot project wells. Two wells, KRU 3S-03 and KRU 3S-21, are within a quarter mile radius of the pilot and are currently open to the Coyote interval. ConocoPhillips will isolate he Coyote interval in KRU 3S-21 with cement prior to fracture stimulation of the proposed pilot wells and will monitor the more distant KRU 3S-03 for pressure changes during Coyote fracture stimulation.

The commission said planned injection fluids include produced water from Kuparuk River oil pools, Beaufort seawater from the Kuparuk seawater treatment plant, hydraulic fracture fluids, tracer survey fluids, wellbore injectivity improvement fluids, freeze protection fluids and standard oil field chemicals such as corrosion and scale inhibitors. The company also proposes potential injection of produced gas from Kuparuk River oil pools and enriched hydrocarbon gas - informally termed miscible injectant.

AOGCC said waterflood injection into Coyote "should substantially improve oil recovery, but the technical and economic feasibility of conducting such an operation has not been demonstrated."

"Uncertainties including rock-strength estimates, unproven reservoir and confinement performance, and potential pressure effects on nearby wells that are currently open to the Coyote interval preclude injection of produced or enriched gas at this time," the commission said.



Kuparuk POD, Northeast West Sak

On July 6, 2023, the division approved ConocoPhillips' proposed 2023-24 annual plan of development for the Kuparuk River unit, covering the period from Aug. 1, 2023, through July 31, 2024.

Although a single horizontal well, 3H-36, was drilled in Q2 2023, the company has no plans to drill additional wells in the Kuparuk participating area during the 2023-24 POD period.

The wells drilled in the Kuparuk PA under the previous POD included the following:

—Two rotary wells into the Coyote reservoir from DS-3S;

—Two rotary wells into the Torok (Moraine) reservoir from DS-3S;

—Ten coiled tubing drilling wells that added approximately 0.9 MBOPD in 2023; and

—Nineteen workovers that restored approximately 5.8 MBOPD in 2022.

The Meltwater PA is shut-in indefinitely, so there are no plans for it other than monitoring and inspection of drill site facilities until all wells can be plugged and abandoned and abandonment of all pipelines to and from the 2P drill site can be executed.

There are also are no plans for drilling activity within the Tarn PA during the 2023-24 POD period, although ConocoPhillips plans to maintain production from Tarn through operations ranging from using miscible injectant at Tarn targets with low enhance oil recovery maturity, or those targets that were developed after cessation in 2022 of natural gas liquid imports from the Prudhoe Bay unit, recompletion of wells by adding perforations, or through isolation of high water cut zones, consideration of fracking or refracking Tarn wells, and completion of a new full field model for long-term identification of potential drilling opportunities in the Tarn PA.

There are also no plans for drilling activity within the Tabasco PA during the 2023-24 POD period, but production will be continued.

During the 2023-24 POD period, ConocoPhillips plans to conduct the following operations in the West Sak PA:

—Resume rotary drilling within the WSAK PA beginning in Q2 2023 with core area development program at DS-1C. This plan includes one water source well in the water leg of the Ugnu reservoir, one producer well and two injector wells;

—Begin drilling 1H NEWS (Northeast West Sak) Phase 2 in Q2 2024. This program will include two dual-lateral producers and two dual-lateral injector wells;

—Evaluate additional viscous oil development opportunities in the West Sak including 3R Phase 2, DS-3K and DS-3N, and Eastern NEWS;

—Continue evaluation of West Sak wells for workovers, including artificial lift conversion from gas lift, or jet pump to rigless ESP, remediation of annular communication problems and reconfiguration of wellbores for future coiled tubing sidetracks (the sidetrack candidates are Kuparuk donor wells, which after drilling, will be converted to West Sak wells)

—Drill a water source well into the water leg of the Ugnu reservoir from DS-1C (to provide clean water injection to 5 existing DS-1C West Sak injection wells); and

—Evaluation of potential solutions for sand control within West Sak.

CRU plan of development

Moving west to the Colville River unit, or CRU, the division approved ConocoPhillips 25th proposed plan of development for the unit on April 13, 2023. The POD period runs from May 16, 2023, through May 15, 2024.

The CRU was formed in 1998 and included 37 leases consisting of state, Arctic Slope Regional Corp. (ASRC), and joint state and ASRC lands.

The CRU has been expanded nine times since 1998, and now covers more than 134,000 acres of state, ASRC, joint, and federal lands. The CRU currently covers eight participating areas and eight distinct oil reservoirs.

The Alpine central facility also processes production from the Greater Moose's Tooth unit's GMT-1 and GMT-2 pads in NPR-A, before passing combined production into the Alpine pipeline. ConocoPhillips' Greater Mooses Tooth unit averaged 12,772 barrels of oil per day in April 2023, up 561 bpd, 4.6%, from a March average of 12,211 bpd, but down 26.9% from an April 2022 average of 17,480 bpd, with 76.5% of production from the GMT-2 pad (Rendezvous pool) and 23.5% from the GMT-1 pad (Lookout pool).

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CONOCOPHILLIPS *continued from page 29*

Production from the Colville River unit, excluding Greater Mooses Tooth output, averaged 40,990 barrels of oil per day during the 2021 calendar year and declined to an average 35,136 barrels of oil per day during the 2022 calendar year, representing an 14% year-on-year decline.

In June 2023, ConocoPhillips' Colville River unit averaged 35,950 bpd.

The company plans to drill a Fiord West Kuparuk PA well, CD2-320, and four Narwhal wells from CD4 during the 2023 POD period. Additionally, up to four rig workovers may be performed to increase CRU gas injection capacity. Ongoing scale inhibition treatments will continue during 2023.

In the previous 12-month 2022 period ConocoPhillips planned to drill two wells within the CRU. One well was planned to target the Narwhal participating area and another would be a waste disposal well drilled from the CD1 pad, with the possibility of additional wells based on rig availability. Planning for development of a new drill site called CD8 was planned during 2022. This new drill site will develop the Narwhal reservoir in the Fifth Expansion area of the CRU. These two wells were drilled, and a third was started in Q4 2022 and completed in Q2 2023.

Narwhal prospect

Through a series of acquisitions, followed by negotiations with the state, ConocoPhillips returned to an old prospect at the southeast corner of the Colville River unit.

The Narwhal participating area is the current name of the prospect. ConocoPhillips called it the Titania prospect in the early 2000s and 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.

ConocoPhillips initially developed the Narwhal prospect from the existing CD4 pad in the Colville River unit, bringing the participating area online in early 2022.

Longer-term Narwhal development plans include the previously mentioned new CD8 pad. The current timeline calls for sustained production by 2028 with a peak of 32,000 barrels per day.

Fiord West Kuparuk

ConocoPhillips' first Fiord West Kuparuk ERD well CD2-310 was "flowing steady" at 11,500 barrels of oil per day, as of June 1, 2022.

Alpine CD 1

"The well choke is now fully open. A high rate was reached on May 25 of 12,000 bpd," Anchorage-based company spokesperson Rebecca Boys said in an email to Petroleum News.

On May 18, 2022, ConocoPhillips officially achieved first oil at the North Slope Fiord West Kuparuk satellite, which is in the Alpine field of the Colville River unit. The well, CD2-310, was a record-setting horizontal well drilled by Doyon Rig 26, an extended reach drilling rig nicknamed the "Beast" because of its immense size.

The largest mobile land rig in North America, Doyon Rig 26 drilled CD2-310 to a total measured depth of 35,526 feet on April 11, 2022, making it the longest North American land based well.

Doyon Rig 26 is a technologically advanced rig, capable of drilling in excess of 40,000 feet, which substantially extends the reach from a single pad.

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

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

Technology has been at the heart of ConocoPhillips' greening of its oil fields on the North Slope.

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

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

ConocoPhillips said the well will be "pre-produced for 5-6 months prior to being converted to permanent injection service."

As previously mentioned, during the 2023 CRU development plan period from May 16, 2023, through May 15, 2024, ConocoPhillips will drill a second Fiord West Kuparuk PA ERD well, CD2-320.

Willow an extension

ConocoPhillips 2023 Analyst & Investor Meeting held on April 12, 2023, involved updates on the company's 10-year plan. The Alaska highlights came from Andrew O'Brien, ConocoPhillips SVP of Global Operations, and Ryan Lance, chairman and CEO of ConocoPhillips, who emphasized that the 600 million barrel Willow project in the National Petroleum Reserve-Alaska is located just 8 miles from ConocoPhillips' existing infrastructure:

"It's an extension of our Alaska business. We have successfully developed over 120 drill sites connected to 13 central processing facilities across the North Slope, from east to west. Willow is simply three new drill sites connected to one new central processing facility," O'Brien said.

In various other public statements and filings the company has said that by the end of 2023, ConocoPhillips will already have invested about $1.8 billion in the Willow project.

ConocoPhillips said that it anticipates the Willow project to generate $7.6 billion in federal revenues, $2.6 billion of which will be available to North Slope communities. State production, property and income taxes would amount to a further $2.3 billion. And the North Slope Borough would gain $1.2 billion in ad valorem taxes to help fund local services.

The primary message delivered in ConocoPhillips' Aug. 3, 2023, second quarter earnings conference call about Willow was that the capital spending range of $7 billion to $7.5 billion to first production in 2029 remains the same.

About one-third of the capital is for processing facilities and two-thirds is for drilling and infrastructure.

"By pre-drilling our initial wells we can maximize our cash flows and we'll quickly reach production of 180,000 barrels a day," O'Brien said.

As of mid-September 2023, ConocoPhillips has not made the financial investment decision, or FID, for Willow. ●

Contact Kay Cashman at publisher@petroleumnews.com

Eni integrating Oooguruk and Nikaitchuq

Power-sharing project would connect electricity systems at the nearby fields

By ERIC LIDJI
For Petroleum News

On the surface, the biggest development at the neighboring Oooguruk unit and Nikaitchuq unit in the nearshore state waters of the Beaufort Sea is renewed drilling.

After the uncertainty of the worst of the pandemic years, operator Eni US Operating Co. Inc. is planning another active year of drilling and maintenance activities at both units.

ROBERT PROVINCE

But for those in the oil patch who have been following the story of those two units over the past two decades, a more intriguing development might be underway: infrastructure.

Oooguruk and Nikaitchuq emerged from similar circumstances in the late 1990s and early 2000s. In the immediate aftermath of the Charter for the Development of the Alaska North Slope, the small Denver-based independent Armstrong Oil & Gas proved up both nearshore plays and brought on larger partners to oversee development and start-up.

The large Texas-based independent Pioneer Natural Resources took over Oooguruk, bringing the unit into production in mid-2008. The project was remarkable in several ways. Pioneer was the first independent to bring a North Slope oil field into production, and it completed the task in about five years, notably quicker than the basin average.

Pioneer worked on Oooguruk with minority partner Eni US Operating Co. The American arm of the large Italian multinational company, Eni also became the owner and operator of the neighboring Nikaitchuq unit. It brought that unit into production in early 2011, marking another expansion beyond the "Big 3" players: BP, ConocoPhillips and Exxon.

Despite all those similarities, there were some notable differences, too.

Eni was a much bigger company than Pioneer. Nikaitchuq was a bigger discovery, too. Early estimates for Nikaitchuq put primary recovery at 220 million barrels, compared to an estimate of 90 million barrels proposed during the early years of the Oooguruk unit.

The scale of the developments also differed.

Pioneer developed the Oooguruk unit from a single pad: the six-acre man-made Oooguruk Island built off the coast of Oliktok Point. Eni developed Nikaitchuq from two pads: the onshore Oliktok Point Pad and the offshore Spy Island Drillsite.

Even more consequentially, Eni was able to afford standalone processing facilities to handle production from Nikaitchuq. Pioneer negotiated a facility sharing agreement with ConocoPhillips Alaska Inc. to utilize spare capacity at Kuparuk River Unit facilities.

Eni US

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With both units now approaching the midpoint of their original life expectancy, perhaps it was inevitable that the need for efficiency would warrant some administrative changes.

Pioneer sold the unit to Caelus Natural Resources Alaska LLC, which sold it to Eni in 2019. By the end of May 2023, Eni reported cumulative oil production of 77.3 million barrels from 62 wells at Nikaitchuq and 48 million barrels from 42 wells at Oooguruk.

With both units now approaching the midpoint of their original life expectancy, perhaps it was inevitable that the need for efficiency would warrant some administrative changes.

Eni took the first step in that direction recent years by acquiring the Oooguruk unit, and now the company is increasingly integrating the two units. The company is currently working to interconnect the power supply for both units, in a project set for 2025.

Whether this marks the beginning of a wave of infrastructure projects at the units — including midstream and processing infrastructure — still remains to be seen.

Oooguruk

Going into its most recent development year for the Oooguruk unit, Eni US Operating Co. planned seven rig workovers and one new well toward the end of the year.

The aging unit had other plans.

By the time Eni filed its current development plan for the year ending Sept. 30, the company had completed 12 workovers on eight wells and had deferred the new well for a year.

The original program had called for recompleting one well (ODSN-06), installing electric submersible pumps in three wells (ODSN-02, ODST-45A, and ODST-39) and replacing electric submersible pumps in three wells (ODSN-31, ODSK-41, and ODSN-25).

The program expanded due to "premature equipment failures and supply limitations," as Eni explained in filings with state regulators. The company started the year in January by recompleting the ODSN-06 well and then conducted replacement activities at the ODSN-31, ODSK-41, and ODSN-25 wells, as planned, through the summer and into early fall.

By October 2022, the program had changed.

First the company isolated the Kuparuk formation at ODSN-29. Then it returned to ODSN-31, ODSK-41, and ODSN-25 for unplanned maintenance, such as replacing cables or re-replacing an electric submersible pump. The company had to remove a stuck subsurface safety valve from the ODSN-10 well and then tend to a failed cable at the ODSN-02 well. Supply delays for that cable prompted the company to put the rig on standby for 10 days in February, followed by regularly scheduled work on ODSN-04.

The program not only involved more work but also took longer. The original schedule was supposed to finish in October 2022. The actual schedule finished in April 2023.

Now, Eni plans to drill two new wells this year (ODSN-05 and ODSN-09) and conduct one workover on the ODSDW-44 disposal well, with other workovers a possibility.

The company is also planning two major infrastructure projects.

The first is the Partial Gas Processing (PGP) project. The project would install 20 million cubic feet per day of natural gas processing and compression equipment at the unit.

According to the company, "Engineering is complete and nine processing and pipe rack modules are currently in shop fabrication with selected modules planned to ship to Eni's Oooguruk Transfer Point (OTP) in August 2023." Start-up is scheduled for January 2024.

The second is the Electrical Power Sharing project. The project would create a power sharing system between Oooguruk and the neighboring Nikaitchuq unit, which are both owned and operated by Eni. According to the company, "Engineering is complete and preliminary procurement activities have been initiated." Start-up is set for mid-2025.

Pool data

The Oooguruk unit covers some 35,285 acres across 16 leases and is developed from a man-made offshore drilling site (ODS) in the nearshore waters of the Beaufort Sea. The unit has three participating areas: Nuiqsut, Kuparuk and Torok. Oil is commingled on the surface and piped to ConocoPhillips' Kuparuk River Unit CPF-3 at Oliktok Point.

At the end of September 2023, the Oooguruk unit had been developed through 42 wells, including 27 producers in the Oooguruk Nuiqsut participating area, five producers in the Oooguruk Kuparuk participating area, three producers in the Oooguruk Torok participating area, two ONPA-OKPA dual completion wells, one Class I & II disposal well, and four other well completions outside of existing participating areas.

The Oooguruk Torok participating area was offline during the year ending Sept. 30, 2022, "due to the high total gas-oil ratio required to produce the wells utilizing the gas lift and recurring tubing hydrate blockages in ODST-45A," according to Eni. The company had planned to install electric submersible pumps at ODST-45A and other wells in the participating area but deferred the project "to complete higher-priority Oooguruk wells during the rig workover campaign. Ultimately, the timing of the OTPA ESP recompletions will be constrained to future budget approvals

In the current development year, Eni is planning a similar program to this past year: workovers from the Oliktok Point Pad and new drilling from the Spy Island Drillsite.

and equipment availability."

Nikaitchuq

At the nearby Nikaitchuq unit, Eni conducted drilling and maintenance from the Oliktok Point Pad and from the Spy Island Drillsite under its 15th plan of development.

Between December 2022 and May 2023, the company completed workovers at the OP10-09, OI06-05, OI07-04, OP03-P05, OI20-07 and OI13-03 wells from the Oliktok Point Pad before cold stacking Nordic Rig 4. Workover projects included replacing electric submersible pumps, replacing injection packers, and running new injection packers.

Between September 2022 and May 2023, Eni drilled two producers — the SP41-E3 and SP42-NE4 production wells, each with an associated lateral — and the SI43-NE3 injector from the Spy Island Drillsite using Doyon Rig 15. The company also completed workovers at the SP31-W7, SP03-NE3, SD37-DSP1, SP21-NW1, SP36-W5, and SP10-FN05 wells. The workovers at Spy Island mostly involved replacing completions.

This year

In the current development year, Eni is planning a similar

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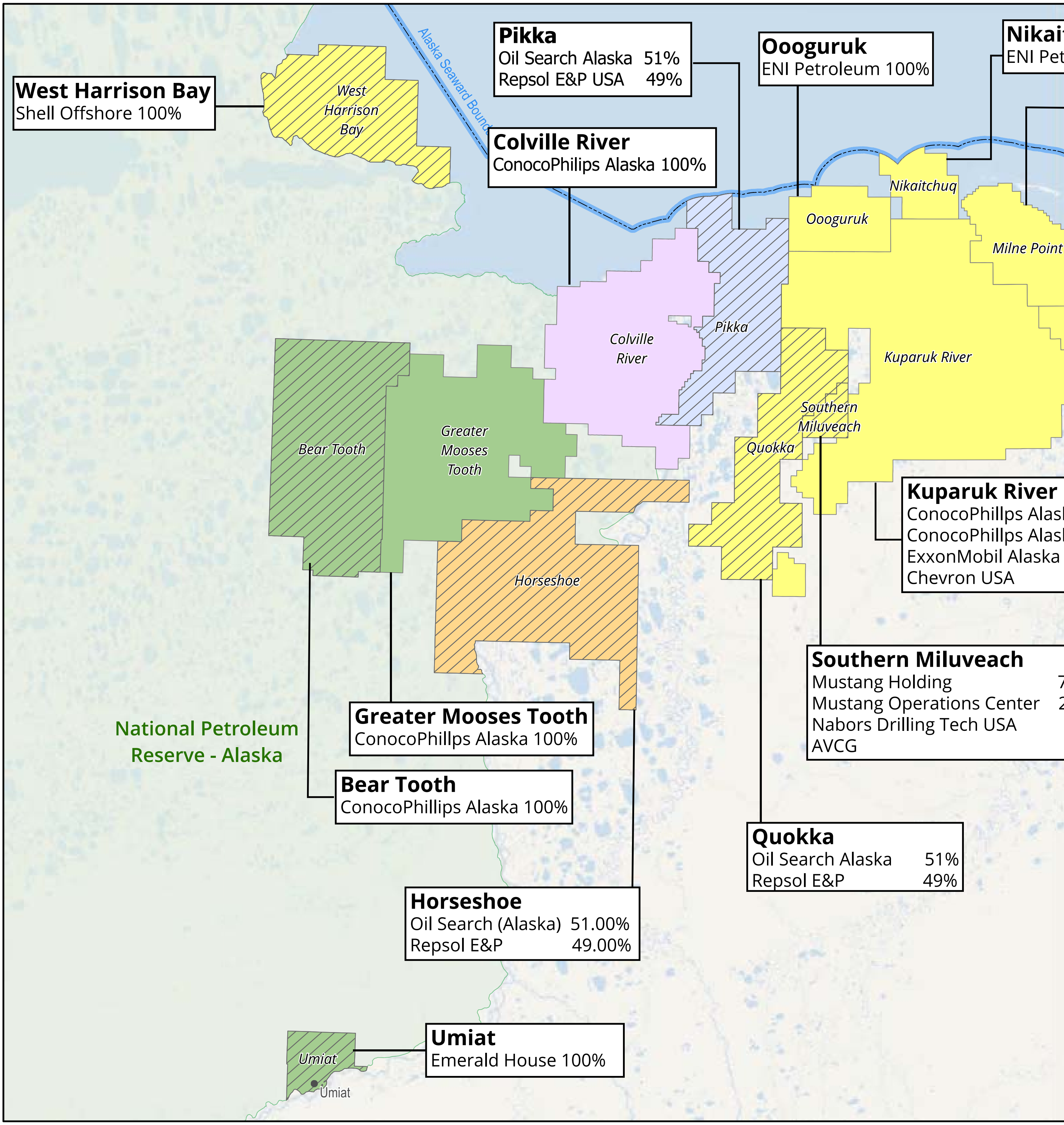

State Unit
State/Federal Unit
State/Native Unit
State/Federal/Native Unit
Federal Unit

Non-Producing
Disputed Ownership

0 5 10 15 20
Miles
Scale: 1:725,000

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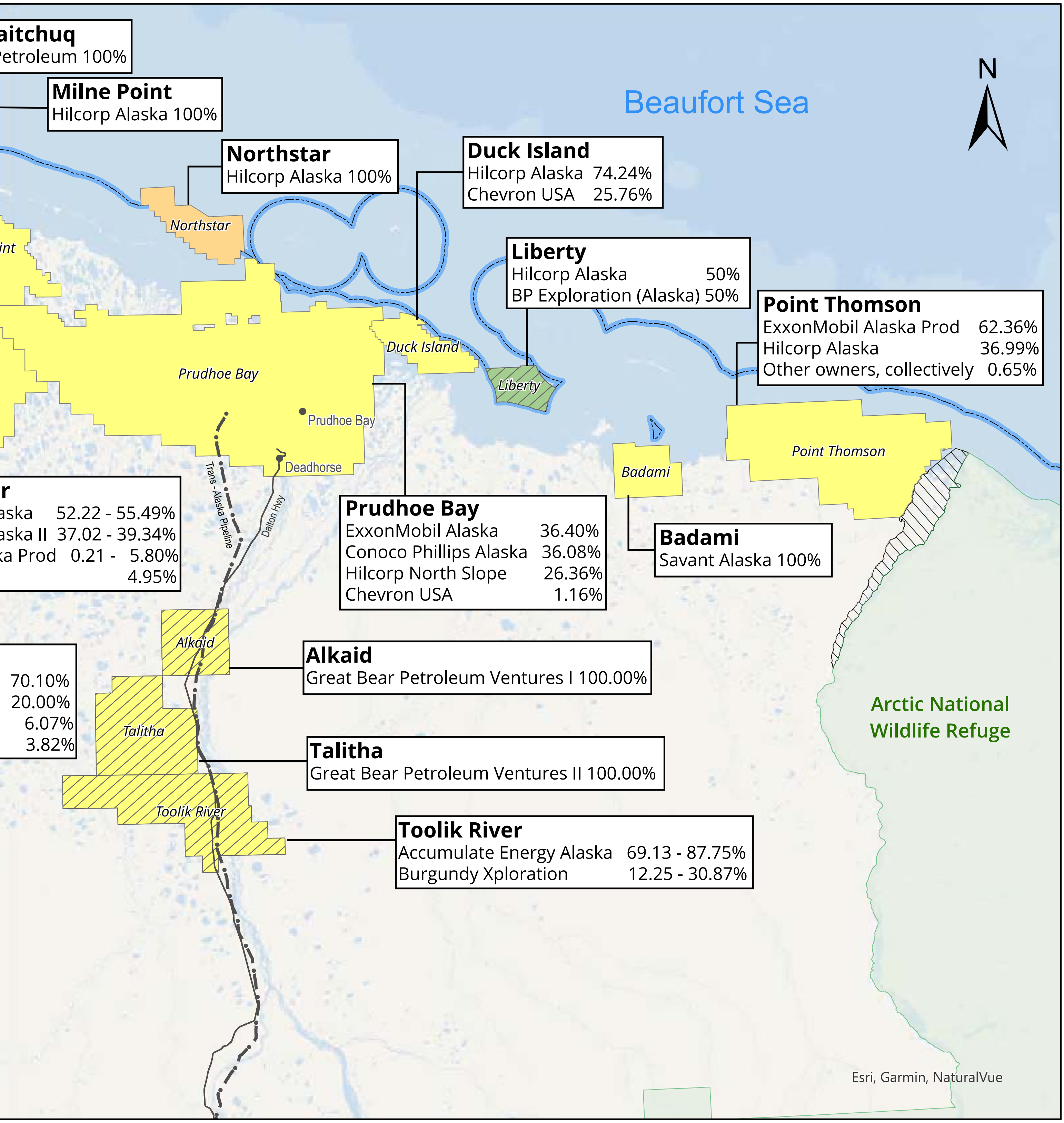

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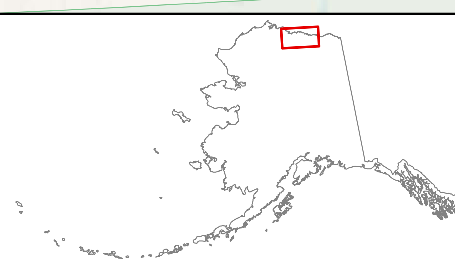

of Alaska
Natural Resources
Oil and Gas

st 2023

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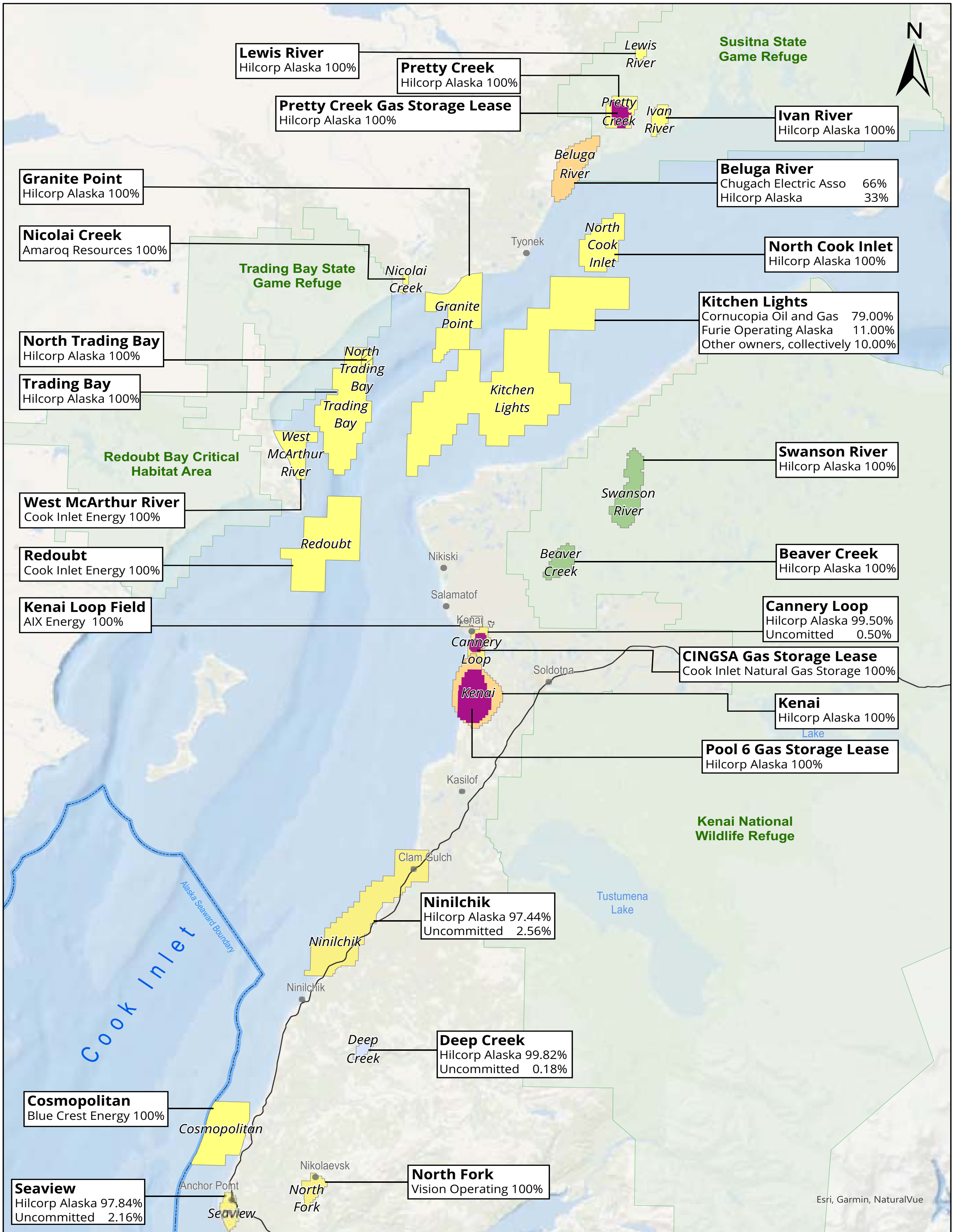


- State Unit
- State/Federal Unit
- State/Native Unit
- Federal Unit
- Gas Storage Lease
- Non-Producing
- Field

0 2 4 6 8 10 Miles

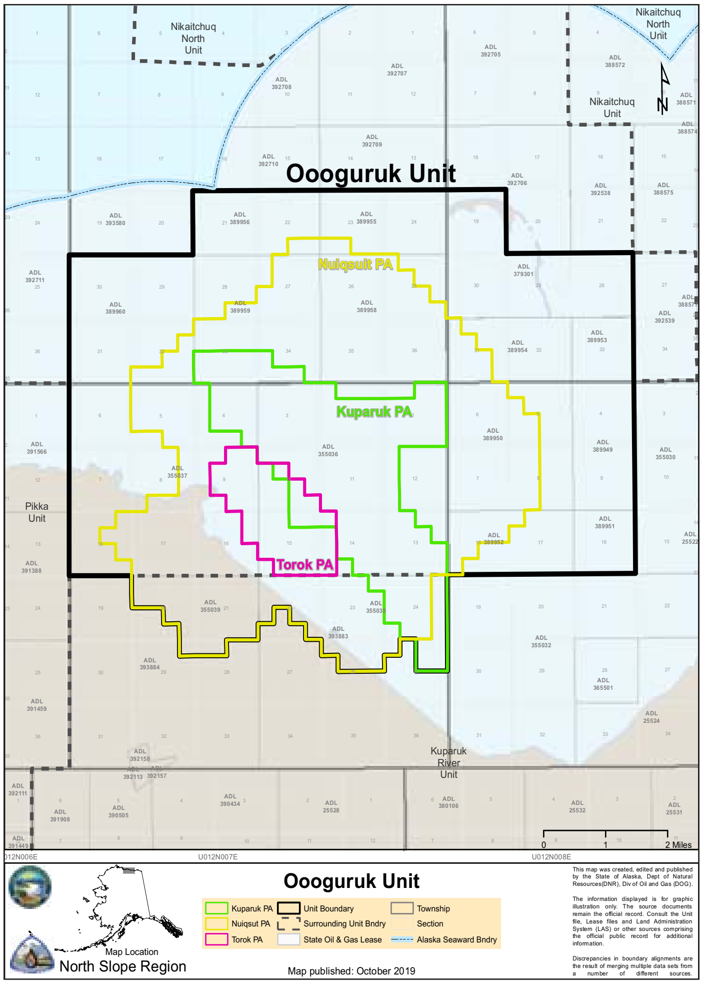
Scale: 1:500,000

Working Interest Ownership of Cook Inlet Units

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

August 2023

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



ENI *continued from page 33*

program to this past year: workovers from the Oliktok Point Pad and new drilling from the Spy Island Drillsite.

The company expects to warm up Nordic Rig 4 in January 2024 for an as-yet-determined workover program designed to "restore, sustain, and increase" Nikaitchuq production.

The company also expects to warm up Doyon Rig 15 in January 2024 to drill three new wells and a lateral from an existing well from the Spy Island Drillsite. The company also plans to "reclaim the NN01 Slot for future Nikaitchuq Development use" during the year.

The company is not planning any workover activities from Spy Island.

The NN01 well is a remnant of an exploration program Eni undertook in 2018 targeting offshore acres in federal waters north of the existing state unit. The company planned a two-well campaign but suspended the NN01 well shy of target depth due to drilling complications and cancelled the NN02 well after partner Shell backed out of the project.

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

Nikaitchuq currently includes 62 wells — 34 producers and 25 injectors. The production wells include 23 from the Spy Island Drillsite and 11 from the Oliktok Point Pad. The unit also includes two disposal wells (one at each pad) and three water source wells.

continued on page 38

ENI *continued from page 37*

Expansion

Over the past decade, Eni has been looking at several strategies for expanding production at the unit: dual laterals, N sand development and drilling beyond unit boundaries.

Dual laterals provide access to more of the underground reservoir without requiring additional surface wells. To date, the company has completed dual laterals on 29 wells at the Nikaitchuq unit — 21 from the Spy Island Drillsite and eight from the Oliktok Point Pad. These wells all target the OA sand of the Schrader Bluff oil pool at Nikaitchuq.

Eni previously drilled the OP19-T1N well to test the potential of the N sand. The well is currently inactive. The company plans to drill an N sand producer/injector pair sometime in the first half of 2024 to assess the prospects of future development in that stratum.

Other projects planned this year include drilling the SP05-FN7 L1 lateral, drilling the SP44-S5 injector to replace OI15-S4 and converting the SP40-E4 producer into an injector. All these injection wells support enhanced oil recovery at Nikaitchuq.

The company primarily uses waterflooding to improve recovery at Nikaitchuq, with most wells drilled in producer/injector pairs that drain into horizontal laterals.

The company launched a one-year polymer injection test at the Oliktok Point I-2 well in late October 2019 but cut the program short in late March 2020, after 154 days, due to logistical complications arising from the early days of the coronavirus pandemic. The results of the shortened test were inconclusive, leading the company to try again at Oliktok Point I-2 with a second test running from mid-March 2021 to mid-December 2022.

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"The successful execution of this pilot test allowed Eni to gather important information about the effectiveness of polymer injection into the Schrader Bluff OA sands in the Nikaitchuq field," the company wrote in its plan. "Key results of the study included the effects of polymer injection on the neighboring production wells, indications about polymer injectivity over time, and tracer arrival times. These findings provided valuable expertise in developing a case to support a future full-field polymer injection project."

According to the company, the test yielded approximately 120 barrels per day of additional oil production. The company is now considering full field implementation.

In addition to N sand development, dual laterals, and enhanced oil recovery, Eni expects to apply for an expansion of the existing Schrader Bluff participating area boundaries. ●

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Glacier adjusting to new ownership

Subsidiaries looking to expand West McArthur River, Redoubt, and Badami

By ERIC LIDJI
For Petroleum News


STEPHEN RATCLIFF

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The biggest news for Glacier Oil & Gas this year had nothing to do with the oil patch.

In early January 2023, the independent with operations on the North Slope and in Cook Inlet announced it had been purchased by Pontem Energy and Sweat Equity Partners.

The sale gave those two companies 100% working interest in the Cook Inlet Energy LLC-operated West McArthur River unit, Redoubt unit, and associated Kustatan Production Facility in Cook Inlet and the Savant-operated Badami unit on the eastern North Slope.

"We are excited by the opportunities that lie ahead for Glacier, its employees, and its new financial backers, Pontem and SEP," Glacier President Stephen Ratcliff said in a statement at the time. "Over the last couple years, we have remained committed to building Glacier during the pandemic while working diligently on production enhancement operations, plans for drilling additional wells, evaluating capital enhancement options, and better alignment through vested ownership. We are excited that this acquisition aligns our vision of growth through development drilling and increased production, maintains our strong corporate culture and our team, and provides an avenue to develop the Glacier brand as a sustainable and long-term player in … Alaska."

Glacier Oil & Gas operates the neighboring offshore West McArthur River unit and Redoubt unit in Cook Inlet through its subsidiary Cook Inlet Energy Inc. and operates the Badami unit on the North Slope through its subsidiary Savant Alaska LLC.

Editor's note: See Badami discussion in North Slope section of The Producers.

West McArthur River

Cook Inlet Energy is currently facing two options for improving production at the West McArthur River unit. One is simple but practical. The second is exciting but risky.

Cook Inlet Energy is currently facing two options for improving production at the West McArthur River unit. One is simple but practical. The second is exciting but risky.

The first involves small maintenance projects at the unit. Under its 30th plan of development running through April 2023, the company undertook many of these projects.

These include an acid simulation on the WRMU-5 and WRMU-6 wells, a pilot injection test to identify suitable wells to convert to water disposal and capture data with wireline operations, engineering work for a water knock out project, pipeline inspections and repairs, and repairs on the 15KV power cable connecting the WMRU and shore facilities.

The second option is the Sabre prospect.

Sabre has teased several former operators, including Union Oil Company of California, Marathon Oil Co., Forcenergy Inc. and its successor Forest Oil Corp., and Pacific Energy Resources Ltd. Cook Inlet Energy considered a Sabre exploration well as early as late 2013 but ultimately delayed the project due to its complicated logistics and high cost.

A logistical hurdle had been securing a jack-up rig to eliminate the need for expensive extended reach drilling. For years, this was a seemingly insurmountable challenge in Cook Inlet. Now, with jack-up rigs in the basin, costs are a more pressing issue.

In its most recent plan of development, Glacier said it "was not able to advance development on the Sabre Prospect due to capital constrains coupled with geologic and drilling risk associated with some of these prospects." Also an issue was a "an ownership change process at the corporate level," which led to delays on projects like Sabre.

In the coming year, Glacier told the state it plans to "keep its options open for the high-risk Sabre Prospect" and "work with new ownership on access to capital and avenues reduce the risk factors associated with exploration and development of this prospect."

Instead, the company plans to stick to maintenance projects.

These include conducting wireline operations on shut-in wells to collect additional reservoir data to aid in choosing a suitable disposal well, replacing failed electric submersible pumps, converting one shut-in well into a produced water disposal well, and performing pipeline inspections.

Converting an existing well at West McArthur River to production would ease operations at the nearby Redoubt unit. Produced water from both units is currently processed at the associated Kustatan Production Facility and then injected entirely at the Redoubt unit.

In early September 2023, Cook Inlet Energy protested an existing permit for the Kustatan facility, saying that the permit "does not authorize the discharge of any wastewater from onshore facilities directly, or commingled at a shore-based coastal facility." Without the ability to co-mingle, the company would have to provide separate solutions for each field.

The West McArthur River unit produced 21.6 million cubic feet of natural gas and 99,906 barrels of oil in 2022, according to the Alaska Oil and Gas Conservation Commission. The unit produced 17.9 million cubic feet of natural gas and 71,691 barrels of oil in the first half of 2023. The increase in both natural gas and oil production seems to be attributable to a strong summer at the WMRU No. 5 and WMRU No. 6 wells.

Redoubt

Under the operatorship of Cook Inlet Energy, the Redoubt unit has often faced similar projects to the nearby West McArthur River unit. That's the case this year, as well.

The expansion opportunity at the Redoubt unit involves two adjacent plays called the Northern and Southern fault blocks. While the company has perennially listed these opportunities in its plans of development, it has yet to pursue development at either.

In its most recent plan of development, Glacier cited "capital constraints coupled with geologic and drilling risk" for its inability to pursue these projects for the year ending April 30, 2023. The company said it would "keep its options open" for the projects this coming year and would "work with new ownership on access to capital and avenues to reduce the risk factors associated with exploration and development of those prospects."

Glacier previously drilled the RU-9 well in the Southern block. The well has been hampered by a failed electric submersible pump. In its current plan of development, Glacier said it would conduct a flow test on RU-9, pending "obtaining approvals."

Without those projects on the agenda, Glacier devoted its resources to maintenance projects at its existing wells at Redoubt.

The expansion opportunity at the Redoubt unit involves two adjacent plays called the Northern and Southern fault blocks. While the company has perennially listed these opportunities in its plans of development, it has yet to pursue development at either.

Along the lines of the pilot projects it undertook at the WMRU-5 and WMRU-6 wells, Glacier conducted an acid simulation pilot on the RU-2A well, but "due to ESP failure resulting from unrelated issues on the RU-2A post acid job, the results on the RU are yet to be fully vetted," the company told regulators.

In the coming year, Glacier also plans to replace the failed electric submersible pump at the RU-2A well and finish vetting of the effectiveness of the acid simulation test from last year. The company also plans to use reservoir modeling to evaluate the future of the RU-5B well as an injector or producer. The company plans to use its existing Osprey Platform to undertake both the RU-2A work and the proposed RU-5B workover.

The workover campaign could require a new well at the platform. The company plans to evaluate the existing Rig 35, which has been dormant at the platform since 2019.

The Redoubt unit produced 76.1 million cubic feet of gas and 337,267 barrels of oil in 2022, according to the Alaska Oil and Gas Conservation Commission. The unit produced nearly 22 million cubic feet of gas and 87,970 barrels of oil in the first half of 2023. ●

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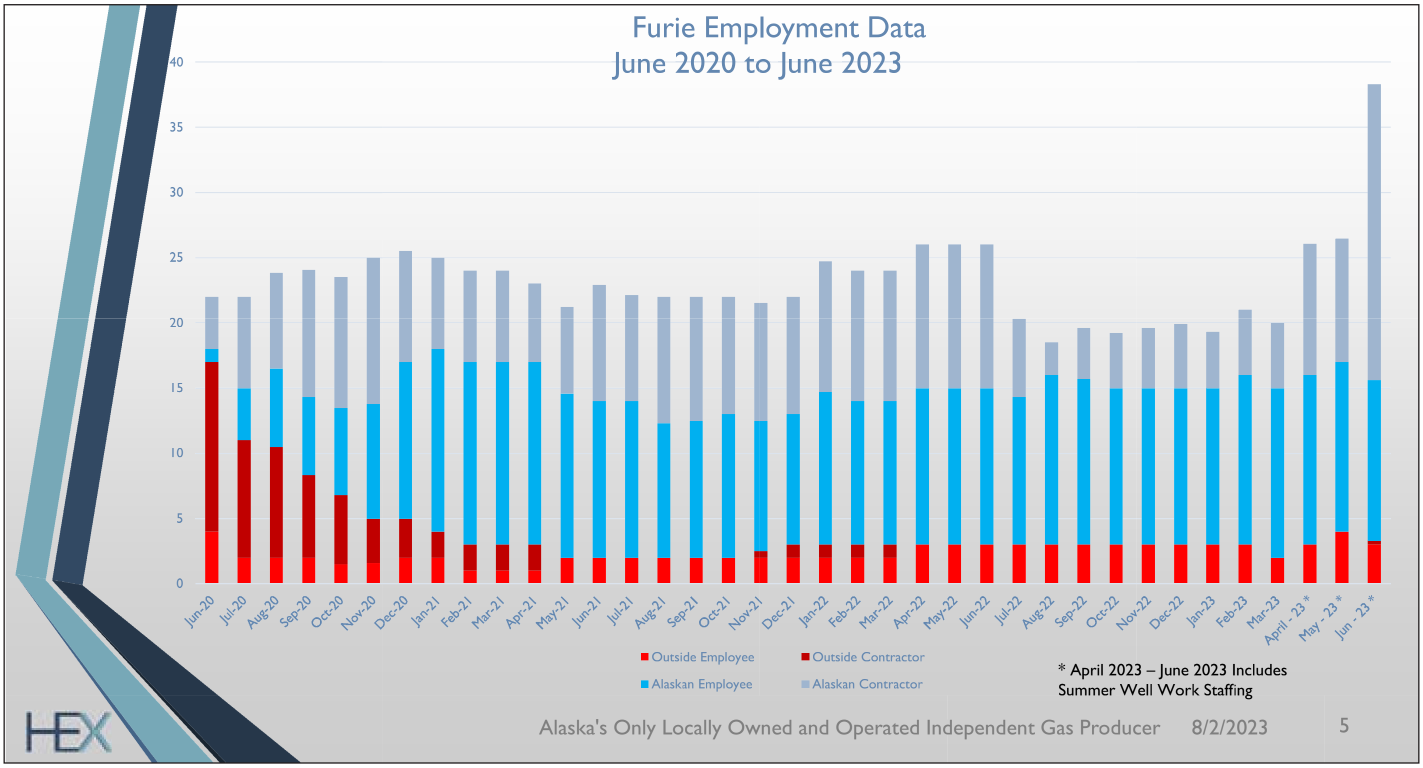

HEX, AIDEA allies in worst of times

Rescue bankrupt Cook Inlet unit, switch to local hire, boost gas output; Hendrix now fighting Alaska Department of Revenue in court

By KAY CASHMAN
Petroleum News

In the Aug. 2 public portion of the Alaska Industrial Development & Export Authority's meeting in Anchorage, HEX Cook Inlet LLC made a presentation to AIDEA's board of directors, highlighting the company's accomplishments since HEX CI acquired the Cook Inlet Kitchen Lights unit on June 30, 2020. The presentation to AIDEA also included present activities and future plans.


JOHN L. HENDRIX

HEX CI's acquisition of Furie Operating Alaska and Cornucopia Oil & Gas Co. and Corsair Oil & Gas along with the Kitchen Lights unit was through Delaware bankruptcy proceedings. Hendrix was restricted by the court from talking with the state of Alaska on a number of foundational issues.

The total purchase price was $34 million, of which $19 million were fixed assets subject to property tax. The state valued the fixed assets at $81 million — more than four times what Hendrix paid for them, requiring him to write a check for $1.6 million every year (which he does under protest), instead of the $400,000 he would be paying if the value was set at the actual market value of $19 million. If Hendrix doesn't pay the $1.6 million, it opens him up to fines that could double the amount due over time.

It is important to note that the IRS only allows him depreciation on $19 million.

HEX CI's acquisition was facilitated with a $7.5 million term loan from AIDEA. "All payments were made on time, some early," an AIDEA employee said prior to HEX CI's presentation.

HEX LLC, which owns 100% of HEX CI, is owned by longtime Alaskan John Hendrix, who formed the HEX companies for the purpose of purchasing Furie, its sister companies and their Cook Inlet assets — principally to switch the upper Cook Inlet

Hex Cook Inlet LLC

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Kitchen Lights unit from foreign and Outside ownership to Alaska ownership.

On June 30, 2020, HEX CI became the only producing Alaskan-owned oil and gas company in the state.

The assets

In addition to the 83,000-acre Kitchen Lights unit, those assets include the Julius R. production platform, 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.

HEX CI's Aug. 2 presentation was made by Mark Slaughter, director of marketing for Furie. Hendrix was unable to deliver the presentation because he was in an Alaska Superior Court trial that he initiated to fight what he argues are "unfair and excessive" property taxes levied by the Alaska Department of Revenue (some of which go to the Kenai Peninsula Borough).

Originally from Fairbanks, Slaughter has worked for Furie since November 2015. He was Furie's only Alaskan employee prior to the June 30, 2020, acquisition by HEX CI.

HEX CI's Furie is the operating company that runs the offshore platform, gathering line and onshore gas processing facility.

Challenging times

Although it was the early days of the COVID-19 pandemic and a challenging time to take over a natural gas producing field that was underperforming and needed major repairs, Hendrix and AIDEA's shared vision for Kitchen Lights yielded results.

In the first two months alone Outside employees and contractors (mainly from Louisiana and Texas) dropped by half, being replaced by Alaskans and Alaska contractors. As of June 30, 2023, per Slaughter, there are only three Outside employees (including a geologist, a geophysicist and an operator that have been with Furie for several years) — the rest are Alaskans (see employment chart in the pdf and print versions of this story).

Another shared goal of Hendrix and AIDEA was stabilizing and then increasing natural gas production — hopefully from both the Beluga and Sterling formations, with much of the potential upside thought to be in the unproved Sterling.

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

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

There are six slots for wells on the Julius-R platform.

In August 2020, Furie reentered and successfully restarted production from KLU A-4 well.

In a Dec. 18, 2020, presentation in Anchorage to Commonwealth North, Hendrix said, "When we took over Kitchen Lights, we basically had to go in and fix everything." This statement was confirmed by Alaska's Division of Oil and Gas.

In the next three years the company supplied natural gas, mainly in colder months. to several industrial users, including Enstar, Marathon Petroleum, Matanuska Electric Association, Homer Electric Association and Chugach Electric Association.

continued on page 44

HEX *continued from page 43*

Summer work, jack-up

Furie kept all four wells online from August 2020 through February 2023, when the "KLU A-1 well sanded up," Slaughter said, meaning it started to produce sand. The well had to be shut in, requiring repairs.

In the summer of 2023 Furie reworked two of the four KLU wells, including KLU A-1, with a hydraulic workover rig at a cost, Slaughter said, of some $8 million, noting their Alaska contractor had to bring the workover rig in from Canada because there were none available in Alaska that could work on the platform.

"The platform floor is very small. Currently we have 25 people working out there and we have beds for 26," he said in his presentation to AIDEA.

"The workovers are really designed to get us through the winter, get us poised for next summer," Slaughter said.

"This past year we have been reprocessing seismic, identifying drilling targets," he said, in hopes of "securing time on a jack-up rig for next summer … to drill a sidetrack or possibly a grassroots well."

"You're talking $30-$40 million for a new grassroots well," Slaughter said.

"We'll have to secure financing for that, so we anticipate being back in front of the AIDEA board for what we want to do with the Kitchen Lights unit," he said.

But first, he said, the property tax issue has to be resolved. Hendrix has said the $1.2 million a year he is spending on excess property tax would be better spent on well work to produce more natural gas for Southcentral Alaska's residents who rely on gas to heat and electrify their homes and businesses.

Most active bidder

In pursuit of his goal to increase natural gas production, Hendrix's companies have been active bidders in state of Alaska Cook Inlet basin lease sales since 2020.

HEX CI was one of two companies in the 2021 bid round. In the May 2022 sale, Furie Operating was the only bidder, winning two leases.

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

Produced water handling system

One of the reasons for Furie's bankruptcy was a lengthy closure of the field in the winter of 2019 because of hydrate blockages in Kitchen Lights subsea pipeline and in the onshore facility — hydrate formation that resulted from the freezing of a combination of gas and excess water in the line, costing the company $17 million in lost production and penalties to their utility customers.

To remediate this issue, when Hendrix acquired Kitchen Lights he had a produced water handling system installed primarily for the Sterling formation, and he obtained the appropriate permits to allow production of gas zones with higher water content.

"We spent about $1.8 million on it," Hendrix said. "Udelhoven installed it."

Alaska-based Udelhoven Oilfield Services was founded in Kenai in 1970 by Jim Udelhoven. Hendrix said he was "one of those men whose word you can trust with a handshake."

History of unit formation

Following a series of battles over work commitments involving several small players in Cook Inlet, the state formed the 83,394-acre Kitchen Lights unit in 2009 to prevent a legal battle and encourage exploration and development activities at a time of dwindling local gas supplies.

The unit combined the Escopeta Oil & Gas Co.-operated Kitchen unit, the Renaissance Alaska LLC-operated Northern Lights prospect and the Pacific Energy Resources Ltd.-operated Corsair prospect.

So, the state took three previously distinct prospects that were unitized and then administratively divided them into four exploration blocks: Corsair, North, Central and Southwest.

All development activities to date have occurred within the Corsair block.

About John Hendrix

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

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

Contact Kay Cashman at publisher@petroleumnews.com

Hilcorp works mature Cook Inlet fields

Company is dominant gas and oil producer in inlet; Ninilchik, North Cook Inlet, Beluga inlet's largest gas fields

By KRISTEN NELSON
Petroleum News


LUKE SAUGIER

Hilcorp is a major oil and gas producer in Alaska, active both in Cook Inlet and on the North Slope, and while Cook Inlet accounts for only a minority of the oil Hilcorp produces in Alaska, it accounts for all its natural gas production, sold to Southcentral utilities and used for heating and generating electricity. The demand for natural gas in Southcentral keeps the company busy at fields both large and small. maintaining production and, where possible, drilling wells into new accumulations or sidetracking wells for additional production.

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 one large newer field,

continued on page 46

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HILCORP COOK INLET *continued from page 45*

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 2/3 working interest in Beluga).

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 — Beluga, Ninilchik and North Cook Inlet.

While Hilcorp is the dominant producer of both oil and natural gas in Cook Inlet, Luke Saugier, senior vice president of Hilcorp Alaska, told the Cook Inlet Regional Citizens Advisory Council in September 2021 that the company's Cook Inlet efforts were going to focus on delivering natural gas to local markets. He said the focus would be particularly on the Steelhead and Tyonek platforms where the company will be drilling wells for years to come. Steelhead is in the Trading Bay unit while the Tyonek platform is in the North Cook Inlet unit.

NINILCHIK

Ninilchik, currently the most productive natural gas field in Cook Inlet, is the focus of much of Hilcorp Alaska's inlet work. Hilcorp recently 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.

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

The Ninilchik unit was formed in 2001 by Marathon Oil and expanded in 2003 and again in 2016, the Alaska Division of Oil and Gas said in an August approval of delayed contraction for the unit.

Ninilchik produces natural gas from three participating areas, Falls Creek, Grassim Oskolkoff and Susan Dionne-Paxton.

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, most recently this year, as field expansion and development continues.

Hilcorp acquired a share of Ninilchik owned by Union Oil Company of California when it acquired that company's Cook Inlet assets in 2013 and acquired a majority interest and operatorship in 2013 as part of its acquisition of Marathon Oil's Cook Inlet assets. Hilcorp has drilled both development and exploration wells, with exploration most recently leading to what the division described as a "significant" natural gas discovery in the Pearl structure, currently the focus of a requested unit expansion and participating area formation.

Ninilchik produces natural gas from both the Beluga and Tyonek formations.

Contraction delay

In approving a one-year delay in contraction of the unit to areas under production, the division cited Hilcorp's continuing development work, including:

- Five grassroots wells drilled May 2020-May 2023, along with workovers and other projects;
- Four Pearl prospects wells drilled during 2022 — Pearl A, 8 and 9 and Paxton 6 — first production in December 2022;
- Submission of an application to expand the unit and form the Pearl participating area;
- Paxton 12 and Pearl 10 and 11 wells drilled and completed with 11 wells now targeting gas sands in the Pearl structure;
- Evaluation and planning for a potential new drill pad between the Paxton and Pearl pads; and
- Preliminary plans for the first quarter of 2024 for additional well work on the existing Blossom 1 exploration well, originally planned for September 2022 but delayed due to the Pearl discoveries.

Proposed work during Hilcorp's 2023 plan of development for Ninilchik includes:

- Evaluation of one to two potential wells — Paxton 13 and 14;
- Various rig and non-rig well projects:
- Continued evaluation of a new drill pad;
- Installation of a compressor at Pearl pad; and
- Evaluating potential of additional compression at Paxton pad.

Alaska Oil and Gas Conservation Commission data show Ninilchik produced an average of 45,027 thousand cubic feet per day in July, 22.7% of inlet gas production in that month.

NORTH COOK INLET

The North Cook Inlet unit has been in production since 1969, the division said in a May approval of the current plan of development, with cumulative production of 1,949 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 April, when it submitted its 2023 plan of development, Hilcorp told the division that during the 2022 POD it mobilized Rig 151 to the Tyonek platform, sidetracking four wells targeting

Beluga sands west, northeast, north and southwest of the platform, and completing plug and abandonment of Cook Inlet State 17589 1A.

In the 2003 POD, Hilcorp said it anticipated drilling as many as three grassroots wells with Rig 151, which may include NCIU A-17 and NCIU A-18 targeting Beluga sands and other grassroots drilling opportunities as they arise.

AOGCC data show North Cook Inlet averaged 36,240 thousand cubic feet per day in July, 18.3% of inlet production in that month.

BELUGA

The west side Beluga River gas field 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 managed by the federal Bureau of Land Management; the state manages the subsurface of the northern half of the leases.

In its 61st plan of development and operations for the Beluga River unit, submitted to BLM in March, Hilcorp reviewed work accomplished under the 60th, 2022 plan, and described work proposed for the April 1, 2023, through March 31, 2024, 61st plan.

Hilcorp said it drilled three grassroots wells and one sidetrack with Rig 147, targeting Sterling and Beluga gas sands.

•BRU 214-13, drilled to the Beluga sands.

•BRU 233-23 was drilled to the lower Beluga.

•BRU 244-27, drilled to the Beluga sands.

Hilcorp also did workovers, three de-completions to prepare for sidetracks, two rig workovers adding perforations and two through-tubing workovers to add perforations.

For the 2023 plan, Hilcorp said it anticipates drilling as many as five wells at Beluga with Rig 147 targeting Sterling and Beluga gas sands and a rig workover using Rig 401.

AOGCC data show Beluga averaged 33,174 thousand cubic feet of natural gas per day in July, 16.7% of inlet production in that month.

KENAI

Hilcorp is working to maintain production at its federally managed Kenai gas field, the company told the Bureau of Land Management in its 65th plan of development and operations for the unit, submitted March 1. That field went into production in late 1960.

The company said that under the 2022 plan, the 64th for the unit, it focused on maximizing gas recovery through drilling and workovers, including up-hole recompletions, adding perforations and doing rig workovers.

In an idle well status report submitted with the 2023 plan, the company cited depleted gas zones as the reason for non-production in 30 of the 34 wells on the report. Twenty-nine of the wells are listed as under evaluation for future utility, with three in the 2022 workover queue.

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HILCORP COOK INLET *continued from page 47*

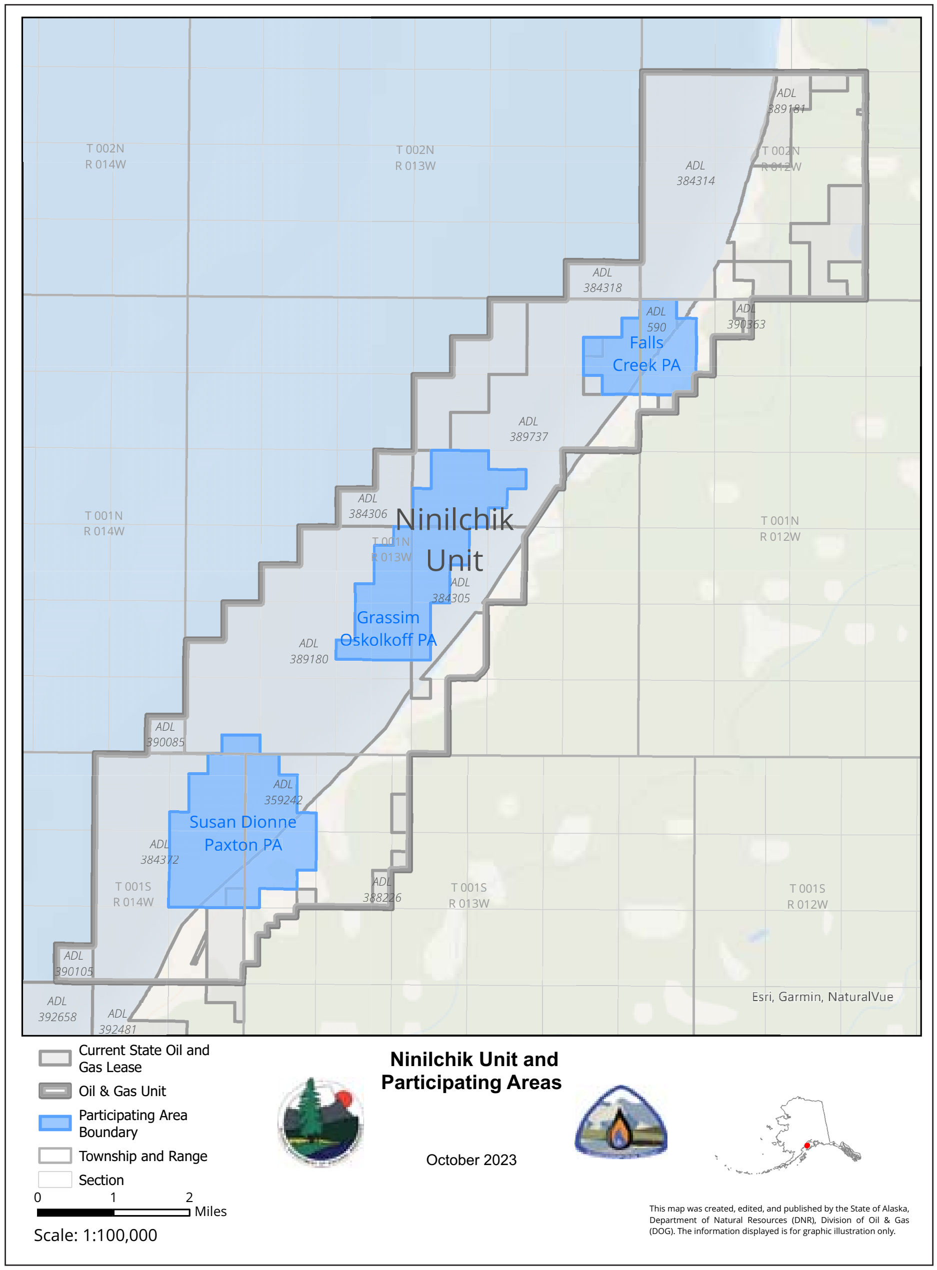
A permit application to AOGCC for KBU 11-07, one of the wells in the 2022 workover queue, shows the type of work Hilcorp is doing to maintain production: In 2021 the company added perforations in the Beluga/Upper Tyonek gas pool but that was unsuccessful. Its 2022 permit application was to plug and abandon the Beluga/Upper Tyonek and perforate sands in Sterling gas pools.

AOGCC's latest production report, for June, shows the well as producing from the Sterling 4 gas pool.

In its 2023 plan, as in the 2022 plan, Hilcorp listed uphole recompletions, adding perforations and rig workovers.

On the facilities side, the company plans to convert existing and install new flowlines, electrical and instrumentation equipment to accommodate wells which are returned to production.

AOGCC data show the field averaged 19,598 thousand cubic feet per day in July, accounting for 9.9% of inlet natural gas production.



STATE OF ALASKA

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 25 approval of the 2023 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 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. As of March 31, 2023, Trading Bay field has produced 109.9 million barrels of oil and 90.8 billion cubic feet of natural gas, while the McArthur River field has produced 650.3 million barrels of oil and 1,547.3 bcf of natural gas, the division said.

Under the 2022 plan Hilcorp did rig workovers and rig and non-rig related well work projects, including replacing failed ESP completions on four wells, replacing failed tubing on another well and adding perforations on two wells.

The company also did facility upgrades on the Monopod to support gas production from its attempted sidetrack of A-10RD2.

Rig and non-rig well projects are included in the 2023 plan, including replacements of failed ESPs; additional ESP repairs or replacements; coil cleanout operations; adding perforations; and well gas lift optimizations.

Work on the platforms may include simplifications on the King Salmon and Grayling platforms; gas and oil riser replacement on the Grayling; waterflood reactivation, riser replacement and fuel gas line repair on the Dolly Varden; and inline inspection on the King Salmon gas pipeline.

On the Monopod, repairs or replacement equipment will be installed as needed.

AOGCC data for July show the fields in the Trading Bay unit — McArthur River and Trading Bay — accounted for 41.2% of Cook Inlet crude oil and 7.6% of its natural gas in that month.

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 and the platforms are maintained in lighthouse mode. The division said in a May approval of a 2023 plan of development that the crane and helidecks on Spurr and Spark are functional, but crew quarters are not and 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.

The division denied the 2019 POD and terminated the unit, a decision overturned by the commissioner. Hilcorp then had 16 months to submit a new POD identifying targets for drilling.

In a proposed 2021 POD, Hilcorp committed to sidetracking the A-10RD into the Tyonek gas sands within the NTBU. The company encountered mechanical challenges, and in 2022, notified DNR of alternative plans to drill the well.

That sidetrack was drilled into NTBU acreage this year using Rig 56 on the Monopod. Alaska Oil and Gas Conservation Commission records show the sidetrack, A-10RD3, was completed in early June.

Hilcorp said in its April 2023 POD that it anticipates production from the North Trading Bay unit will be restored by the third quarter. The company put an $8 million price tag on the well, which it said, "represents a significant investment towards the recovery of otherwise stranded NTBU reserves that cannot otherwise be recovered."

The Monopod is gas deficient, Hilcorp said, and gas produced from A-10RD3 will provide fuel gas for Monopod operations, eliminating the need to transport gas from Steelhead to the Monopod, resulting in a net increase in natural gas sales from the Trading Bay unit.

Hilcorp said it would be required to pay royalties on fuel gas from the NTBU leases as that gas is moved across the Trading Bay unit boundary and said after sustained production from A-10RD3 is confirmed, it anticipates submitting a formal proposal to DNR to merge the North Trading Bay unit into the Trading Bay unit.

GRANITE POINT

Hilcorp's Granite Point unit, produced from the Granite Point, Anna and Bruce platforms, is one of the company's smaller gas fields, averaging 3,275 thousand cubic feet per day in July, but its second largest Cook Inlet oil producer, averaging 2,254 bpd, AOGCC production data show.

In its 2023 plan of development the company said it planned to look for more gas with new wells off the Bruce platform.

In its May 25 approval of the 2023 POD for Granite Point the Division of Oil and Gas said production began in 1967.

South Granite Point was unitized in 1998 and operated by Union Oil Company of California. Hilcorp purchased Union'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.

In 2015 the South Granite Point unit was expanded to include Granite Point field and renamed the Granite Point unit.

In its 2023 POD Hilcorp said that production in calendar year 2022 was 875.6 thousand barrels of oil and 1,267.5 million cubic feet of gas.

During the 2022 POD, Hilcorp said it added perforations to the GP 24-13RD2 in an attempt to return the well to production. (July AOGCC production data show no production from this well.)

For the 2023 POD, Hilcorp said it expects to drill as many as three grassroots wells from Bruce platform in the fourth quarter using Rig 151 targeting the Tyonek formation. If commercial quantities of gas are found, the company said, it "will evaluate production facility and pipeline capacity constraints to optimize deliverability of gas between existing platforms and to the Granite Point Tank Farm."

No sidetracks are planned for the 2023 POD, but Hilcorp said it will evaluate current wells for various rig and non-rig projects.

The company said it would prepare the Bruce platform for potential gas sales, pending success of the planned wells, and for possible pipeline work.

SWANSON RIVER

Hilcorp acquired the Swanson River

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HILCORP COOK INLET *continued from page 49*

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 July, the most recent month for which AOGCC production data are available, the field averaged 742 bpd of oil, 9.1% of inlet total, and 9,196 thousand cubic feet per day of gas, 4.6% of inlet total for that month.

The 59th plan of development and operations for the field, approved by the federal Bureau of Land Management Sept. 1, shows cumulative gas production for 2022 of 1,220 million standard cubic feet of gas and 284,000 barrels of oil.

Under the 2022 POD, Hilcorp told BLM, a new gas well, SRU 224-10, was drilled through the Sterling, Beluga and Tyonek formations. The company said planned coiled tubing drilling directed at the Tyonek G-Zone oil reservoir was delayed due to the focus on gas.

The company also performed numerous workovers, including a number in addition to those listed in the 2022 POD, and facility maintenance, including overhauls, repairs, replacements and upgrades.

For 2023, Hilcorp said it would continue to review the unit to identify remaining gas in the Sterling, Beluga and Tyonek in Blocks 1, 2, 3, 4 and 6, and remaining oil reserves across the field, with two gas wells planned, one each in the central and north fault blocs.

A number of workovers are planned, along with facility and infrastructure projects, including two pad expansions, with timing to be determined for those expansions.

SMALL WEST SIDE FIELDS

Ivan River, Lewis River, Pretty Creek

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

The three — Ivan River, Lewis River and Pretty Creek — became Hilcorp assets when the company took over Chevron/Union Oil Company of California's Cook Inlet assets in 2012.

IVAN RIVER

Ivan River, the most easterly of the three, is also the largest and the oldest, its unitization dating back to 1967.

In its May 8 approval of the 53rd plan of development for the field, the Division of Oil and Gas said that through the end of March, Ivan River had cumulatively produced 94.687 billion cubic feet of natural gas.

The division said that during the 52nd POD, Hilcorp completed drilling the IRU 241-01 well and brought it online in January 2022. Following completion of the well, the company installed a heater-separator on the IRU pad and upgraded the water disposal system on the pad.

Alaska Oil and Gas Conservation Commission records show the field averaged 5,016 thousand cubic feet per day in January 2022, the month the IRU 241-01 came online, increasing 57% to 7,874 mcf per day in February and peaking in September 2022 at 14,018 mcf per day.

In the 53rd POD the division said Hilcorp planned various non-rig workovers, and also planned to optimize IRU pad compression, "which may include connecting a trailer mounted temporary compressor and restaging existing compressors to meet the demand and lower tubing pressures of current wells."

AOGCC records for July, the most recent available, show Ivan River averaging 5,419 mcf per day.

LEWIS RIVER

In its May 8 approval of the 48th POD for Lewis River, the division said the field was unitized in 1977 and through March had cumulatively produced 16.839 billion cubic feet of natural gas.

In the 47th POD, the division said Hilcorp did various well, infrastructure and facility repairs, "including evaluation of shut-in wells for potential return to service or utility."

In the 48th POD Hilcorp planned to drill the LRU C-02 targeting the Sterling, Beluga or Tyonek sands. AOGCC records show permitting underway for LRU C-02 in July.

The company also planned various non-rig well operations, along with pursuing various well, infrastructure and facility repairs.

AOGCC production data for July show Lewis River averaged 357 thousand cubic feet of gas in that month.

PRETTY CREEK

In its May 30 approval of the 45th POD for Pretty Creek the division said the unit was formed in 1997 and through the end of March this year has cumulatively produced 9.616 billion cubic feet of natural gas.

AOGCC records show that Pretty Creek last produced in January 2022.

The division said that during the 44th POD, Hilcorp did not perform coil cleanout operations or add perforations. The company said the work commitments at Pretty Creek were not done because they were "uncompetitive with Hilcorp's other work, primarily with the focus being on Ivan River Unit."

For the 45th POD, June 1, 2023, through May 31, 2024, the company said the coil cleanout or perforation add referred to in the 2022 POD are "planned for next year as needed," but said "it will likely again focus its resources on Lewis River Unit primarily from a westside standpoint."

SMALL KENAI PENINSULA FIELDS

Hilcorp has several small fields, primarily gas producers, on the Kenai Peninsula: Beaver Creek, Cannery Loop, Deep Creek, Nikolaevsk and Seaview.

Nikolaevsk, which produces gas from a single well, is no longer unitized. In 2021, the unit was terminated, at Hilcorp's request. Two of the former unit tracts are allocated production from the Red No. 1 well and Hilcorp continues to operate the production as a lease operation.

In July, AOGCC data show production from Nikolaevsk averaged 263 thousand cubic feet of natural gas per day.

BEAVER CREEK

The Bureau of Land Management approved the 56th POD for Beaver Creek on Sept. 1, covering April 1, 2023, through March 31, 2024.

In its POD Hilcorp said that during the 2022 POD it sidetracked a gas well out of the BCU-18, but is still trying to establish production, as both Tyonek and Lower Beluga intervals were unproductive; uphole opportunities are being pursued. BCU-18B was drilled and completed and gas is online. An oil well, BCU-05RD2 was reperforated to boost oil rate.

Following an unexpected dry hole at BCU-18RD, Hilcorp said additional work is being done to understand gas reservoirs in the northern part of the unit, with further work planned for 2023.

Unsuccessful perforations of the Sterling at BCU-11 led to cancellations of work at BCU-09 BCU-10 pending a broader Sterling field study planned for 2023.

Work was done at a number of other wells.

No wells are planned for the 2023 POD. Hilcorp said workover plans include two gas wells and evaluation of plans for three offline gas wells. Other wellwork includes a fill clean out and added perforations and completion of a field study of gas reservoirs in the vicinity of BCU-06, 09, 10 and 18RD.

AOGCC production data for July show Beaver Creek production averaging 346 bpd of oil and 5,508 mcf per day of natural gas.

CANNERY LOOP

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 30 when it approved the 2023 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 averaged 6.1 million cubic feet per day of gas in 2022, up from an average of 4.7 million cubic feet per day in 2021, the division said. Alaska Oil and Gas Conservation Commission production data for July, the most recent available, show Cannery Loop averaged 5.4 million cubic feet per day in that month.

During its 2022 POD, Hilcorp sidetracked two wells, the division said, targeting lower Beluga sands.

Hilcorp anticipated drilling one grassroots well during the 2022 POD, "pending results from initial sidetrack drill well results."

The company did sidetrack two wells, but did not install an additional sales gas compressor, and said it currently does not plan to install additional compression at Cannery Loop.

For the period of the 2023 POD Hilcorp said it is evaluating additional wells into the Beluga and Tyonek sands but does not have any drilling plans at Cannery Loop during 2023. No sidetracks are planned, but various rig and non-rig well projects during the 2023 POD may include: preparation for potential sidetracks; coil cleanout operations; adding perforations of additional gas sands; setting plugs or patches for potential water shutoff activities; and evaluating and executing additional well work opportunities that may arise.

DEEP CREEK

The Deep Creek unit was formed in 2001, with sustained production beginning 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.

In a June 30 approval of the 20th Deep Creek plan of development the Division of Oil and Gas said the average gas production rate for 2022 at Deep Creek was 3.6 million cubic feet per day.

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HILCORP COOK INLET *continued from page 51*

The division said that during the 2022 POD, Hilcorp sidetracked one well.

In its May 1 POD submittal covering Aug. 1, 2023, through July 31, 2024, Hilcorp said it has no drilling plans for the 2023 POD period but would "evaluate and execute well work opportunities as they arise."

AOGCC production data shows eight wells in production at Deep Creek in July, with production averaging 3,808 thousand cubic feet 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.

The field produced from Seaview 8 from June 2021 through August 2022, a cumulative total of 181,837 thousand cubic feet.

In its fourth Seaview plan of development, filed in May, Hilcorp said it had moved the compressor at the Seaview pad to Cannery Loop to accommodate increased production at that field, but did not replace the compressor at Seaview with a smaller compressor "due to other compression opportunities taking precedence at this time."

Production was from Seaview 8, and Hilcorp said it was evaluating additional perforations in Seaview 9, the other well at the field, targeting a coalbed methane injectivity test during the 2023 POD, "which could include perforating and testing."

The company said it would continue to evaluate a new compressor at the Seaview pad "against other compression opportunities during the 2023 POD period."

MIDDLE GROUND SHOAL

Hilcorp's Middle Ground Shoal in Cook Inlet has been shut-in since April 2021, is no longer a unit and the company is studying the remaining leases for further natural gas development.

MGS was the first offshore discovery in Cook Inlet and in Alaska, with Amoco Production Co.'s MGS State No. 1 in 1963. The unit was formed in 1967 and produced oil and gas from four platforms: Baker, Dillon, A and C. Baker and Dillon were lighthoused in 2013 and 2003, respectively.

The shut-in occurred after Hilcorp discovered a leak in the Middle Ground Shoal Fuel Gas System. In March 2021, the last full month of MGS production, crude averaged 1,226 bpd, 11.5% of inlet production in that month, and gas averaged 218 mcf per day, 0.1% of inlet production.

Following the shut-in, the Division of Oil and Gas approved a suspension of production while the company considered whether to repair or replace the fuel gas pipeline.

When it submitted its 2023 plan of development for MGS in April, Hilcorp told the division it had determined the cost to repair or replace the pipeline was not economic as a standalone project and would not be pursued. It also said platform C had reached its economic unit and would not be returned to production, while platform A had potential for future reactivation, but only following a successful exploration program. Hilcorp committed to plugging and abandoning all the Dillon and Baker platform wells but said the platforms would be maintained as unmanned lighthoused facilities as the company explored potential utilization for commercial-scale alternative energy projects.

On May 31, Hilcorp withdrew the 2023 POD, asked for termination of the MGS unit, voluntarily relinquished two leases associated with the Dillon platform, requested a suspension of production for three leases associated with the C, A and Baker platforms, requested a land use permit for the Dillon platform structure and requested modification of existing pipeline easements associated with MGS.

On June 30 the division approved the request.

Hilcorp is evaluating whether there is commercial gas in the area that could be developed from an area north of the Baker platform which could be drilled from that platform, currently lighthoused, or whether a new platform would be required.

The division said it determined a 3-year suspension of operation for the three leases "is an appropriate amount of time to develop exploration prospects, drill, appraise, and ultimately determine whether the leases can be brought back into production." ●

Contact Kristen Nelson at knelson@petroleumnews.com

Hilcorp major North Slope player

Company started with small fields in 2014; took over as Prudhoe operator in 2020; has made most dramatic changes at Milne

By KRISTEN NELSON
Petroleum News

LUKE SAUGIER

Hilcorp Alaska started operating in Cook Inlet in 2012, after acquisitions in 2011, and moved onto 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 — as Hilcorp North Slope — 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.

The company said during calendar year 2022, 825 producers and 213 injectors contributed to production in the IPA and cited improved operational efficiency of 0.9% for contributing to increased fluid handling in 2022.

PRUDHOE BAY

Hilcorp took over as operator of the Prudhoe Bay unit, the North Slope's largest, on June 30, 2020, after purchasing BP Exploration (Alaska) and changing the name to Hilcorp North Slope. Taking over BP's share of Prudhoe, not the largest, Hilcorp North Slope holds an average working interest of 26.36%. 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 July, the latest available when The Producers went to press, show Prudhoe averaging 230,816 barrels per day, 53.5% of Slope production, with 82.6% of that volume from crude oil and 17.4% from natural gas liquids. Compared to July 2022, Prudhoe production was down 10% this July.

Drilling and wellwork continues across the 12 participating areas at Prudhoe, with activity largely focused in the IPA, the initial participating areas — the oil rim PA and the gas cap PA — and in the newest development area, the western satellites.

The Alaska Division of Oil and Gas has approved an expansion of the unit, adding four tracts in the Gwydyr Bay area, with exploration plans for the fourth quarter of 2023.

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One well is planned for the expansion area within 3 years, and preparation of a comprehensive drilling plan for the Gwydyr No.1 appraisal/development well is underway, along with a regional analysis of the Sag formation reservoir and the Kuparuk formation reservoir.

PRUDHOE IPA

The Prudhoe Bay unit was formed in 1977, following the discovery of oil in the Ivishak and Sag River sandstones in 1968 at Prudhoe Bay State No. 1.

In its May approval of the 2023 plan of development for the IPA, the division said IPA production for calendar year 2022 was some 2,836 billion cubic feet of gas, 57,118,000 barrels of black oil and 17,705,000 barrels of natural gas liquids, with the NGLs mixed and sold with the black oil. Average daily production was 156,487 barrels per day of black oil and 48,507 bpd of NGLs.

In reviewing the previous, 2022 POD, the division said Hilcorp had planned up to 11 new wells targeting the Ivishak and Sag River formations, more than 20 workovers and recompletes, continued evaluation of future drilling opportunities and facility projects.

Six wells were completed, the division said, with one additional well planned for the 2022 period.

"Other wells initially planned in the IPA were deferred for more favorable drilling opportunities in the Western Satellite Area of the PBU." Hilcorp performed 11 workovers with another four planned before the end of the 2022 POD, which covered July 1, 2022, through June 30, 2023.

In its 2023 proposed POD for the IPA, Hilcorp North Slope said regular production began in June 1977, with produced water injection that same month and large-scale waterflood in August 1984, followed by miscible gas for water-alternating-gas

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HILCORP NORTH SLOPE *continued from page 53*

injection, for tertiary recovery, in June 1987.

The company said during calendar year 2022, 825 producers and 213 injectors contributed to production in the IPA and cited improved operational efficiency of 0.9% for contributing to increased fluid handling in 2022. Gas cap water injection, GCWI, again increased significantly, due to "excellent plant reliability and the continuation of the Sea Water Optimization Plan" rerouting Flow Station 1 seawater injection to GCWI which began in 2020, Hilcorp said. During the 2022 POD a number of major facility projects were completed, including upgrades at the Seawater Treatment Plant, Gathering Center 2, Flow Station 3 and the Lisburne Production Center.

During the 2023 POD, July 1, 2023, through June 30, 2024, Hilcorp said it "anticipates an increase in drilling activity and plans to complete up to 38 drill wells in the IPA."

The company said it has worked through the backlog of broken wells in the IPA and anticipates a reduction of that activity, with workovers to be completed as needed. Flat well intervention activity is planned, with focus on maintaining the existing well stock and "increasing existing production through non-rig rate enhancement work."

Anticipated facility projects include CCP compressor upgrades; GC2 B bank slug catcher internals redesign; drill site 18 pipeline construction; and H pad pipeline construction.

Long-range activities include evaluating future drilling opportunities and facility projects "to pull through undeveloped resources." In the SWOP (seawater optimization plan) area, several shut-in injectors will be converted to production to capture vapor borne liquid hydrocarbon.

WESTERN SATELLITES

For the 2022 POD period, more wells were drilled in the western satellites than in the IPA, up to 23 in the western satellites vs. up to seven in the IPA.

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.

Hilcorp committed to drilling as many as 10 wells and completing three rig workovers in the 2022 POD (Jan. 1, 2022, through Dec. 31, 2022), the division said in approving the 2023 POD in November 2022, and as of November had drilled 13 wells "with an additional ten to be drilled before the end of the 2022 POD period." The company also completed two rig workovers, with an additional two planned for the 2022 POD.

Hilcorp provided an overview of the PAs in its proposed 2023 POD.

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.

PHOTO BY JUDY PATRICK COURTESY OF HILCORP

Central Gas Facility at Prudhoe Bay.

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.

Hilcorp said the wells completed during the 2022 POD included four at Aurora, five at Borealis, 10 at Orion and four at Polaris. Workovers included one at Orion and three at Polaris.

Facilities work included evaluation of additional sand jetting improvements at GC-2 in the C and D slug catchers, with work spread between 2022 and 2023, and an expansion of L pad to accommodate 2023 POD drilling.

Hilcorp said it anticipates up to 26 wells in the 2023 POD, with candidates in the Aurora, Borealis, Orion and Polaris PAs. As many as four workovers or recompletions are anticipated in the Orion and Polaris PAs.

Additional sand jetting improvements are being evaluated, and Hilcorp said it "plans to continue evaluating opportunities to improve the western area gathering infrastructure."

The company is also continuing to evaluate future drilling opportunities and potential undeveloped resources, along with evaluation of new pad development options and polymer injection, with a three well polymer pilot ongoing at Polaris to "determine polymer's impact on injectivity, MI utility, oil rate, and reserves." Hilcorp said it will use the data "to determine whether polymer expansion is economic at Orion and Polaris PAs."

The company is also evaluating additional pipelines to reduce header pressure and increase gas lift pressure.

GREATER POINT MCINTYRE AREA

The Alaska Division of Oil and Gas approved the 2023 POD for the Greater Point McIntyre area Aug. 21, covering Oct. 1, 2023, through Sept. 30, 2024.

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 10.369 million barrels of oil and NGLs between April 1, 2022, and March 31, 2023, a slight decline from the same period in the previous year.

During the 2022 POD Hilcorp completed the Lisburne Processing Center Rich Gas to the Central Gathering Facility project, adding 50 million cubic feet per day of capacity at LPC and significant NGL and miscible injectant benefits fieldwide.

The company did not drill any rotary or coil tubing wells during the 2022 POD, but three wells planned for 2022 were actually drilled in the 2021 POD period after the 2022 POD was submitted, the division said.

As many as four new coil tubing wells had been planned, with one failing pre-drilling screening. The division said that well will be sidetracked once it is repaired, while another well was deemed non-viable after reservoir data analysis and two other candidates were deferred pending further analysis of the wells drilled during the 2021 POD.

A rotary well had been planned at Raven but was not drilled.

In its 2023 proposed POD, Hilcorp provided an overview of the PAs. GPMA also produces from tract operations.

Development of the Niakuk reservoir began in 1994 from the Niakuk PA and then from the West Niakuk PA in 1995; the two PAs were combined in 2007. Waterflood began in 1995.

Lisburne was discovered in 1968 at Prudhoe Bay State No. 1. Development drilling started in 1985 and the field came online in 1986.

Lisburne gas cap water injection began as a pilot in 2008.

North Prudhoe Bay, a small satellite north of Prudhoe, produced from the Sag River and Ivishak, with the most recent production in 2005.

Point McIntyre produces from the Point McIntyre and Stump Island reservoirs and has been developed from two drill sites, PM1 and PM2.

Raven produces from the Sag River and Ivishak, with production processed at LPC.

West Beach produced most recently in 2009, with surface facilities remediation required before it can be returned to production.

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 anticipates drilling as many as six wells, with potential candidates including up to five coil tubing sidetracks with the Point McIntyre PA, and an additional rotary well at Raven being evaluated.

No major facility projects are planned.

Hilcorp has a list of long-range activities, evaluating future drilling opportunities: development potential in the Lisburne; in the Point McIntyre Kuparuk, Sag River and Ivishak; in the Niakuk Kuparuk; in West Beach and North Prudhoe Bay; potential of existing tract operations and other Sag River accumulations offsetting Raven; and continuing to evaluate facility debottlenecking projects.

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HILCORP NORTH SLOPE *continued from page 55*

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.

AOGCC production data show Milne produced 13.7 million barrels in calendar year 2022, not up to the field's 1998 peak, but still almost double what it was when Hilcorp took over as operator in 1994.

Annual production ranged from 6.5 million barrels in 2015 to 7.6 million barrels in 2018, before beginning to climb, to 9.3 million barrels in 2019, 12.2 million in 2020, 13 million in 2021 and 13.7 million in 2022.

Through July 2023, the latest AOGCC production data available when The Producers went to print, production for the year was at 8.3 million barrels, potentially on track to exceed 14 million barrels for the year.

Consistent drilling

In December 2022 the Alaska Division of Oil and Gas approved the 41st plan of development for the Milne Point unit, noting an increase in production of 5% from Jan. 1, 2022, through Sept. 30, 2022, compared to the same period in 2021.

There are three participating areas at Milne Point: Kuparuk, Schrader Bluff and Sag River, the division said, in addition to multiple wells on tract production.

In the previous POD, the 40th, Hilcorp proposed 17 new wells targeting the Schrader Bluff formation, including 10 wells from I pad and seven from M pad or B pad. Six coil tubing sidetracks were also proposed.

No workover operations were proposed, but there were significant facility improvement projects, the division said.

As of December, the division said Hilcorp had drilled 10 new wells with four more to be completed before the end of the 40th POD, covering Jan. 13, 2022, through Jan. 12, 2023.

The division said only two wells were drilled on I pad, with focus instead on M pad development, where three wells had been drilled and four more were planned. Three wells were drilled from B pad.

The coil tubing rig was relocated to Prudhoe Bay, so no coiled tubing wells were drilled at Milne.

Twenty-five well workovers were done, and some but not all of the proposed facility improvements were completed, with those not completed "deferred as a result of unanticipated projects that occurred during the POD period," the division said.

More drilling planned

In its proposed 41st POD, submitted in mid-October 2022 (for Jan. 13, 2023, through Jan. 12, 2024), Hilcorp discussed work completed under the 40th POD and said one producer and one injector were drilled at I pad. "Remaining anticipated wells were deferred due to a shortened rig schedule" and the shift to M pad focus.

On M pad, two injectors and one producer were completed, with an additional two injectors and two producers expected to be drilled by the end of the 40th POD period. Three wells were drilled at B pad, two injectors and one producer.

Extensive well work included 21 workovers done by the ASR1 workover rig and four workovers done by the Doyon 14 workover rig.

The rig planned for sidetrack drilling was moved to Prudhoe prior to any of that work being done.

Facility projects completed included: B pad polymer installation; M pad upgraded polymer unit installation; S pad multiphase meter replacement; and E pad production header replacement.

Hilcorp said it expected to begin two other projects prior to the end of the POD: F pad power fluid separation system installation and E pad power fluid booster installation.

Four projects not included in the 40th POD were executed during the POD period: J pad PW1 header replacement; S pad W1 header replacement; E pad polymer equipment installation; and I pad polymer equipment installation.

Nine projects expected to be done during the 40th POD were deferred.

41st POD plans

During the 41st POD Hilcorp said it anticipated drilling as many as 16 new wells, with potential candidates including: 12 Schrader Bluff wells (seven producers, five injectors); two Kuparuk wells (one producer, one injector); and two Ugnu wells (one producer, one injector).

The company anticipates doing coiled tubing drilling operations on six wells: two at C pad; one each at F pad and K pad; and two at L pad.

Workovers will be performed as needed.

Hilcorp said facility projects may include tract junction heater installation and production header replacements at the B, F and I pads.

Long-range activities being evaluated include:

- Future drilling opportunities on undeveloped acreage in the northwest of the unit, particularly on net profit share leases, and on previously developed acreage from I, H and S pads in the Schrader Bluff PA.
- Ugnu: evaluation of continued performance from horizontal producing well S-203.
- Continued evaluation of infill drilling opportunities in the Kuparuk sands.

POINT THOMSON

Hilcorp Alaska's most recent North Slope operatorship is at 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.

Point Thomson has two-year plans of development, so the most recent plan, approved by the Alaska Division of Oil and Gas in November 2021, and running through the end of 2023, was submitted by ExxonMobil.

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.

Letter agreement

The September 2018 letter agreement is focused on an Alaska LNG Project and suspends work on evaluation and selection of a PTU expansion project — 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.

If there is a final investment decision for an Alaska LNG Project, the Point Thomson owners "will provide to DNR work plans and project activities to develop Point Thomson Reservoir for Major Gas Sales though the Alaska LNG Project," the letter agreement said, and if that project is suspended, then the PTU working interest owners will have 30 months to resume work on suspended portions of the settlement agreement, including commitment to a Point Thomson expansion project.

In another regulatory decision, in January 2022 the Alaska Oil and Gas Conservation Commission amended an order which had required a report on the initial production system at Point Thomson five years after the beginning of sustained production, which would have been in 2021.

ExxonMobil, then operator, requested, and AOGCC granted, an extension until Nov. 1, 2023, based on production issues the company had faced during the first two and a half years of production, as ExxonMobil dealt with frequent production upsets.

"By November 2018, the plant was fully commissioned and operating stably for extended periods of time," the commission said, in extending the required date for the initial production system by two and a half years.

The report is to contain a description of how the Thomson oil pool was expected to perform before production began and information about the actual performance and fluids in the oil pool; a discussion on whether the oil pool was shown to be compartmentalized; a description of the properties of the reservoir fluids; and a discussion of whether the development method the commission approved "is still the best method to optimize ultimate recovery and prevent waste."

Recent production

The story at Point Thomson in the last year has been one of declining production, from an average of 9,143 barrels per day in

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HILCORP NORTH SLOPE *continued from page 57*

July 2022, to an average of 2,659 bpd this July, the most recent month for which AOGCC data was available when this issue of The Producers went to press.

This has been illustrated by regular filings with the Regulatory Commission of Alaska requesting approvals of tariff reductions — three such filings this year.

The tariff rate for 2023 for barrels moving through the PTE Pipeline from the Point Thomson central processing facility to a connection with the Badami Sales Oil Pipeline was set at $7.86 per barrel.

In May, PTE Pipeline filed for a tariff increase to $12.49, effective July 1, telling RCA that actual 2023 throughput in the line had been "significantly lower than originally projected."

Facilities at the field can handle up to 10,000 bpd and beginning in 2020, Point Thomson production began to exceed an average of 9,000 bpd for at least part of the year. But by 2022, only five months met that mark, and in 2023 the field never hit a monthly average of 9,000 bpd.

A second tariff increase, to $25.05 per barrel, was effective Aug. 1.

A third request is for an increase to $36.94 per barrel, effective Oct. 1.

In this most recent filing PTE Pipeline told RCA it expects the current throughput decline to continue through the end of 2023.

There is a single producing well at Point Thomson and Hilcorp Alaska said in filings with AOGCC for permits to work on the well that production has declined over time and it is working to determine the cause.

The requests for increases in the tariff are based on the 2019 settlement agreement between the state and PTE Pipeline, which provides that the maximum tariff rate may be changed during the year if new or additional data would result in at least a 10% increase or decrease in the maximum rate for the year.

DUCK ISLAND

The Duck Island unit, frequently referred to as Endicott, is one of the smaller fields Hilcorp Alaska operates on the North Slope, accounting for just 1.4% of North Slope production in July, 6,502 barrels per day, the latest month for which AOGCC production data was available when this issue of The Producers went to press.

There are three participating areas, Endicott, Sag Delta and Eider.

In its January approval of the latest plan of development for Duck Island, the 41st, the Alaska Division of Oil and Gas said the unit was formed in 1978. 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 2022 POD submittal, the 41st 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.

A causeway connects the main production island and the satellite production island to shore.

Hilcorp said production in calendar year 2022 was some 102,978 million cubic feet of gas and 1,954,000 barrels of oil.

Endicott is one of three areas on the North Slope — along with Northstar and Prudhoe Bay — to report natural gas liquids production to AOGCC. Production as reported for July was an average of 5,904 bpd of crude, 90.8% of the total, and 599 bpd of natural gas liquids, 9.2%.

For the previous, 40th POD, Hilcorp completed four non-rig wellwork operations:

•Tubing string install and return to production of DIU SDI 3-11;

•Production casing leak and return to production through use of hyposeal of DIU MPI 1-29;

•Conversion to gas injection of DIU MPI 1-09A; and

•Returned DIU SDI 3-17F to production.

A number of planned surface facility operations were associated with a summer turnaround, including: vessel cleaning and inspection; LACT meter upgrades in progress; rotating equipment overhaul and repairs; retraying condensate stabilizer; and flare inspection and repair.

For the 41st POD, covering Feb. 13, 2023, through Feb. 12, 2024, Hilcorp listed two long-range proposed activities: converting LSZ of Kekiktuk to gravity drainage to increase oil exploration and exploring remaining Ivishak and Alapah opportunities.

Planned wellwork and workovers include:

•Completing up to three rig workover operations;

•Additional workover operations as needed; and

•Various non-rig wellwork operations.

Hilcorp said major facility projects may include:

•Upgrading/repairing SDI low flow test separator intervals;

•Propane turbine demister install; and

•Turnaround for: LACT meter upgrades; upgrading/repairing SDI low flow test separator internals; ad propane turbine demister install.

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.

In its January 2023 approval of the 19th plan of development for the unit, the division said there are three participating areas representing three separate oil accumulations: Ivishak sands in the Northstar PA; Ivishak sands in the Fido PA; and Kuparuk sands 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.

The July, the latest month for which AOGCC production data was available when The Producers went to print, Northstar averaged 5,364 barrels per day, 59.9% of that in crude, 3,212 bpd, and 40.1% in NGLs, 2,152 bpd.

Hilcorp said the 19th POD, submitted in November 2022, covers Feb. 13, 2023, through Feb. 12, 2024.

During the 18th POD, Hilcorp said it worked on surface facilities, completing ongoing repairs of the island's coastal defenses and working on the ground refrigeration expansion project, with surface piping supporting 86 heat pipes nearing completing, and the first group of heat pipes expected to be in service by the end of the 18th POD.

In describing work done during the 17th POD, Hilcorp said the installation of heat pipes around modules enabled active ground refrigeration, reducing ground settlement.

For the 19th POD, Hilcorp listed three long-range activities:

•Exploring importing gas from Prudhoe Bay for pressure maintenance in the Kuparuk reservoir;

•Reviewing potential candidates for coil tubing drilling and determining "if coil tubing drilling operations are economically viable, or even mechanically feasible, on Northstar Island"; and

•Researching the economic viability of Sag River development. "The reservoir is of very low permeability and porosity, likely requiring stimulation techniques to unlock production," the company said.

No workover operations are planned but will be performed as needed.

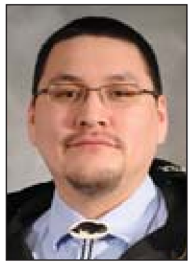
Hilcorp said it would complete commissioning of remaining heat pipes for the ground refrigeration expansion project and would continue ongoing repair of the island's coastal defenses. ●

Contact Kristen Nelson at knelson@petroleumnews.com

North Slope Borough keeps going at Barrow

Longstanding municipal project provides local energy for local use

By **ERIC LIDJI**
For Petroleum News


JOSIAH PATKOTAK

Alaska is a big place with a lot of rugged individualists. Within the oil patch, that's always fostered a tension between the ambitions of small players and big players.

The North Slope Borough is different. It is not a multinational oil company, not a well-financed independent and not a lone wildcatter hoping to hit pay. It is a municipal entity doing something relatively unique in the state: developing local resources for local use.

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

The federal government discovered the Barrow gas fields as part of a large exploration initiative in the National Petroleum Reserve-Alaska to improve domestic energy security.

The Barrow gas fields include three subfields: South Barrow, East Barrow and Walakpa.

Following years of steady production, the North Slope Borough launched a $92 million rejuvenation program launched in 2011 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.

South Barrow

The U.S. Navy discovered the South Barrow field with the 2,505-foot South Barrow No. 2 well in 1948, during its initial wave of NPR-A exploration. Drilling continued through 1987 with 13 new wells drilled and the South Barrow No. 7 deepened, according to the AOGCC. Production began in November 1981 at 3.5 million cubic feet per day.

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

After nearly six years of inconsistent production, South Barrow has now been producing regularly since May 2018. The field produced 37.5 million cubic feet of natural gas in 2022, down considerably from 99.3 million cubic feet in 2021 and 56.1 million cubic feet in 2020, according to the AOGCC, due largely to shut-in wells throughout the summer.

As of July 2023, South Barrow was producing from four wells: S. Barrow Test Well No. 6, South Barrow NSB No. 1, South Barrow No. 9, and South Barrow 10. South Barrow 10 flowed in July 2023 for the first time since June 2021 and before that November 2015.

Cumulative production at South Barrow is approaching 25 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. Geological Survey discovered the East Barrow field with South Barrow No. 12 in 1974, during the second wave of oil and gas exploration in the NPR-A. Drilling continued through 1990, with eight wells total, followed by the 2011 Savik campaign.

The East Barrow field produced nearly 99.3 million cubic feet in 2022, up considerably from 47 million cubic feet in 2021 and down notably from 139.1 million cubic feet in 2020. The field currently produces from the South Barrow No. 14 and Savik No. 1 wells.

Cumulative production through June 2023 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 with the 3,666-foot Walakpa No. 1 well 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 — Walakpa No. 3 through Walakpa No. 13. The field produced 1.388 billion cubic feet in 2022, down slightly from 14.13 billion cubic feet in 2021 and up slightly from 1.356 billion cubic feet in 2020, according to the AOGCC.

Cumulative production through June 30, 2023, was more than 38 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. ●

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Glacier adjusting to new ownership

Subsidiaries looking to expand West McArthur River, Redoubt, and Badami

By ERIC LIDJI
For Petroleum News


STEPHEN RATCLIFF

The biggest news for Glacier Oil & Gas this year had nothing to do with the oil patch.

In early January 2023, the independent with operations on the North Slope and in Cook Inlet announced it had been purchased by Pontem Energy and Sweat Equity Partners.

The sale gave those two companies 100 working interest in the Cook Inlet Energy LLC-operated West McArthur River unit, Redoubt unit, and associated Kustatan Production Facility in Cook Inlet and the Savant-operated Badami unit on the eastern North Slope.

"We are excited by the opportunities that lie ahead for Glacier, its employees, and its new financial backers, Pontem and SEP," Glacier President Stephen Ratcliff said in a statement at the time. "Over the last couple years, we have remained committed to building Glacier during the pandemic while working diligently on production enhancement operations, plans for drilling additional wells, evaluating capital enhancement options, and better alignment through vested ownership. We are excited that this acquisition aligns our vision of growth through development drilling and increased production, maintains our strong corporate culture and our team, and provides an avenue to develop the Glacier brand as a sustainable and long-term player in … Alaska."

Glacier Oil & Gas operates the neighboring offshore West McArthur River unit and Redoubt unit in Cook Inlet through its subsidiary Cook Inlet Energy Inc. and operates the Badami unit on the North Slope through its subsidiary Savant Alaska LLC.

Editor's note: See Cook Inlet section of The Producers for story on Glacier's Cook Inlet activities.

Glacier Oil & Gas Corp.

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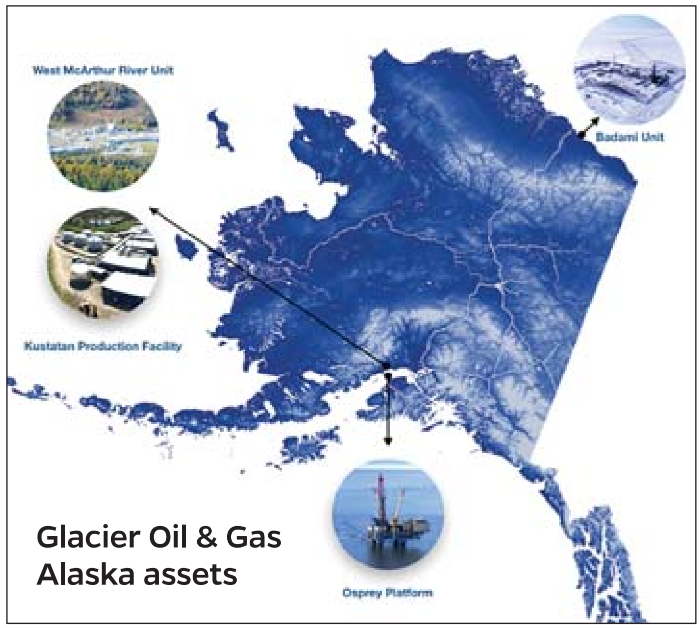

GLACIER OIL & GAS

Badami

Glacier is active on the North Slope through its subsidiary Savant Alaska LLC.

Under its current plan of development for the year ending July 15, 2024, Savant is planning to work on three wells, in addition to other projects to improve production.

One project involved a workover of the B1-07 well to restore production. A stuck fish took the well offline in July 2022. ("Fish" is oil field lingo for anything stuck in a well bore.) An attempt to workover the well in September 2022 was abandoned due to "catastrophic rig issues and timing of the barge season," according to the company.

Savant appears to have successfully completed the workover around April 2023, which is when the well began producing again, according to the Alaska Oil and Gas Conservation Commission. The B1-07 well produced one day in April, five days in May, 30 days in June, and 31 days in July, averaging more than 500 barrels per day for most of that time.

Also in the development plan this coming year is a study to consider opportunities for comingling at the B1-38 well. The well currently produces from the Killian. The company wants to add perforations in the Brookian reservoir to increase production. The project would require approval from the Alaska Oil and Gas Conservation Commission.

Through its parent company Glacier, Savant officially made the request with the state agency in late July 2023. In its application, the company said that the production from the well had been steadily declining since 2010 and would benefit from Brookian production.

The B1-38 well was drilled in 2009, targeting the Kekiktuk formation. The Kekiktuk was a bust, but the well produced uphole in the Killian. Daily oil production during the first year averaged between 300 and 400 barrels but is now between 130 and 150 barrels.

Under the proposal, Savant would perforate about 80 feet of Badami sands located about 1,100 feet uphole from the Killian and comingle the production with existing production.

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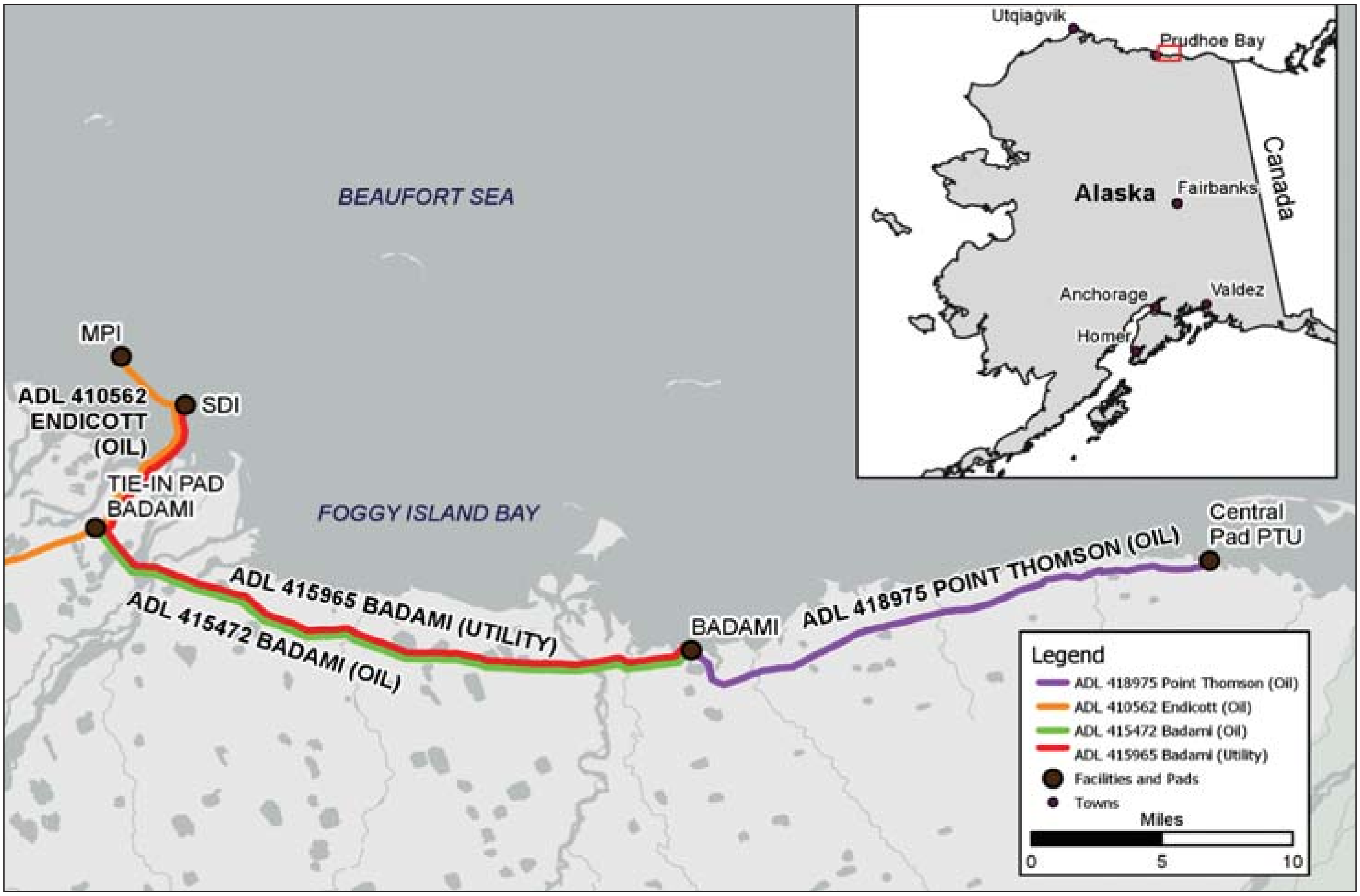
STATE OF ALASKA



GLACIER *continued from page 61*

The company planned the project for the second half of 2023.

Aspects of the project were originally planned to occur last year but were deferred.

Savant is also planning three projects to expand development opportunities at Badami in an effort to attract investors. The first is an exploration well planned for this coming winter. The well would "prove-up the extensive Killian plan beyond the (participating area) at Badami and aid in securing capital for overall development," the company wrote.

Following that well, Savant hopes to drill two wells from the Badami pad targeting the Badami sands. Both wells are currently classified as proved undeveloped reserves, pending favorable economic conditions and the ability to raise capital at favorable terms.

The second project is an ongoing effort to "refine, characterize, and de-risk the prospects related to the Killian sands outside of the participating area." The third is a geological and geophysical campaign over 4,267 acres to the south, west, and a bit north of the unit.

The state also gave a boost to these efforts in July 2023 when it granted a request from Savant to modify the royalty structure on seven leases at the Badami unit.

"Savant provided sufficient technical and financial information to substantiate its application - clearly showed that the per-barrel cost increase was sufficient to make future production no longer economically feasible without royalty modification," Alaska Department of Natural Resources Commissioner John Boyle wrote in his decision.

While he approved of some form of modification, Boyle rejected the scheme proposed by the company, which was indexed to daily production rates. State statute allows royalty modification to be based partly on production, but not entirely. Instead, the state approved modification "on a sliding scale incorporating both oil price and production."

(Editor's note: DNR issued a final findings and determination regarding the royalty modification request on Sept. 13 as The Producers was going to press. See story in Sept. 24 issue of Petroleum News.)

BP Exploration (Alaska) Inc. brought Badami online in 1998 with a wave of optimism, hoping to have a mid-size field that would close the 70-mile stretch between Prudhoe Bay and the ANWR 1002 Area. Almost immediately, though, geology muddied those visions.

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

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

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

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

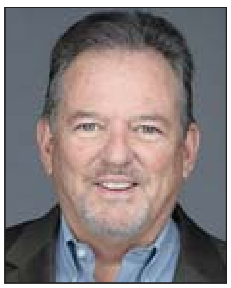
Contact Eric Lidji at ericlidji@mac.com

Gardes' Vision looking for drilling capital

Company can rapidly put new Cook Inlet basin wells online; Landt says Alaska natural gas market pricing is enticing

By **KAY CASHMAN**
Petroleum News

BOB GARDES



MARK LANDT

Gardes Holdings, Inc.

GARDES HOLDINGS INC.
VISION RESOURCES

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On March 3, 2023, Vision Operating LLC was given an 18-month delay in the mandatory contraction of its North Fork unit on the southern Kenai Peninsula by Alaska's Division of Oil and Gas.

The division had received a request in February from Vision Resources LLC and Vision Operating, both wholly owned subsidiaries of Gardes Holdings Inc., requesting a two-year delay. The 18-month period they were allowed goes through Oct. 6, 2024.

According to the approval letter, which was sent to Gardes and Vision executive Mark Landt by division Director Derek Nottingham, the 18-month respite provides Vision time to drill and evaluate potential resources outside the current participating area, or PA, which is the 800-acre NFU Gas Pool No. 1 in the 2,601.84-acre unit. (Contraction is required after a unit has been in production for 10 years, at which point it is contracted to areas that are producing.)

But drilling costs money.

In an Aug. 22, 2023, interview with Landt, Petroleum News asked whether Vision has any new wells planned outside the PA during 18-month period, and he said: "We have proposed locations that extend beyond our current PA, but the bottom line is drilling capital is hard to find. We are continually meeting with potential investors extolling the virtues of low risk development drilling in the Cook Inlet basin, a commodity short market that supports $7.50/thousand cubic feet, or mcf-plus pricing. Fundamentally, there is a lack of drilling capital for the smaller players in the Cook Inlet basin. Unfortunately, we're not seeing the level of private equity funding in oil and gas as many investors are focused on consolidating positions and ignoring new niche plays, especially in the Permian basin."

Quick return on investment

So what can Vision Operating and its North Fork unit in Alaska's Cook Inlet basin offer investors?

"We can put new wells online almost immediately," Landt, who is vice president of land and business development for Gardes Holdings, replied.

"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 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 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.

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GLACIER *continued from page 63*

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.

Currently, the unit is made up of five state oil and gas leases totaling 2,601.84 acres.

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 PN 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, or CIE, by that time a Glacier Oil and Gas company.

Effective May 1, 2021, Vision became unit operator.

Focused on North Fork

Vision is "focused on North Fork," Landt told PN on March 10, 2021. "We see some definite opportunities to pursue there," he said, noting the company has a "full G&G staff" working on the unit.

"Now that we have our plan of development for the unit approved with the Division of Oil and Gas and have purchased 3-D seismic — we are going to be working the 3-D data and generating our own ideas going forward."

"We can put new wells online almost immediately," Landt, who is vice president of land and business development for Gardes Holdings, replied.

Landt said Vision sees "additional gas to be recovered" at North Fork, mentioning the possibility of tapping "additional sands" in the field and more workovers.

The plan of development approved by the division was the 56th POD for North Fork.

Also in March 2021, then-operator CIE requested and received on behalf of Gardes a one-year delay in contraction of the North Fork unit to allow the new owner time to assess opportunities for additional drilling targets outside the PA.

Gardes' contract to distribute gas from North Fork went into effect May 11, 2021, at a starting price of $7.30 per thousand cubic feet, eventually increasing to $7.60 per mcf.

There has been a revised contract requested by Vision: to allow for North Fork's declining production: see story titled "RCA accepts revised Vision-Enstar contract" in the June 25, 2023, issue of PN.

RCA issues final order

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

Since Vision took over as North Fork operator May 1, 2021, the division said the unit averaged 3,058 mcf per day of gas production through November 2021. In 2023, Alaska Oil and Gas Conservation Commission data showed the unit averaged 2,378 mcf per day in May, down 101 mcf per day, 4.1%, from an April average of 2,479 mcf per day and down 22.8% from a May 2022 average of 3,080 mcf per day. ●

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A pipe rack destined for Santos' Pikka project is one of the first loads to arrive in Deadhorse in early August. The modules will be installed at the Nanushukk Process Facility in the 2023/24 winter construction season.

PHOTO BY JUDY PATRICK, COURTESY OF SANTOS

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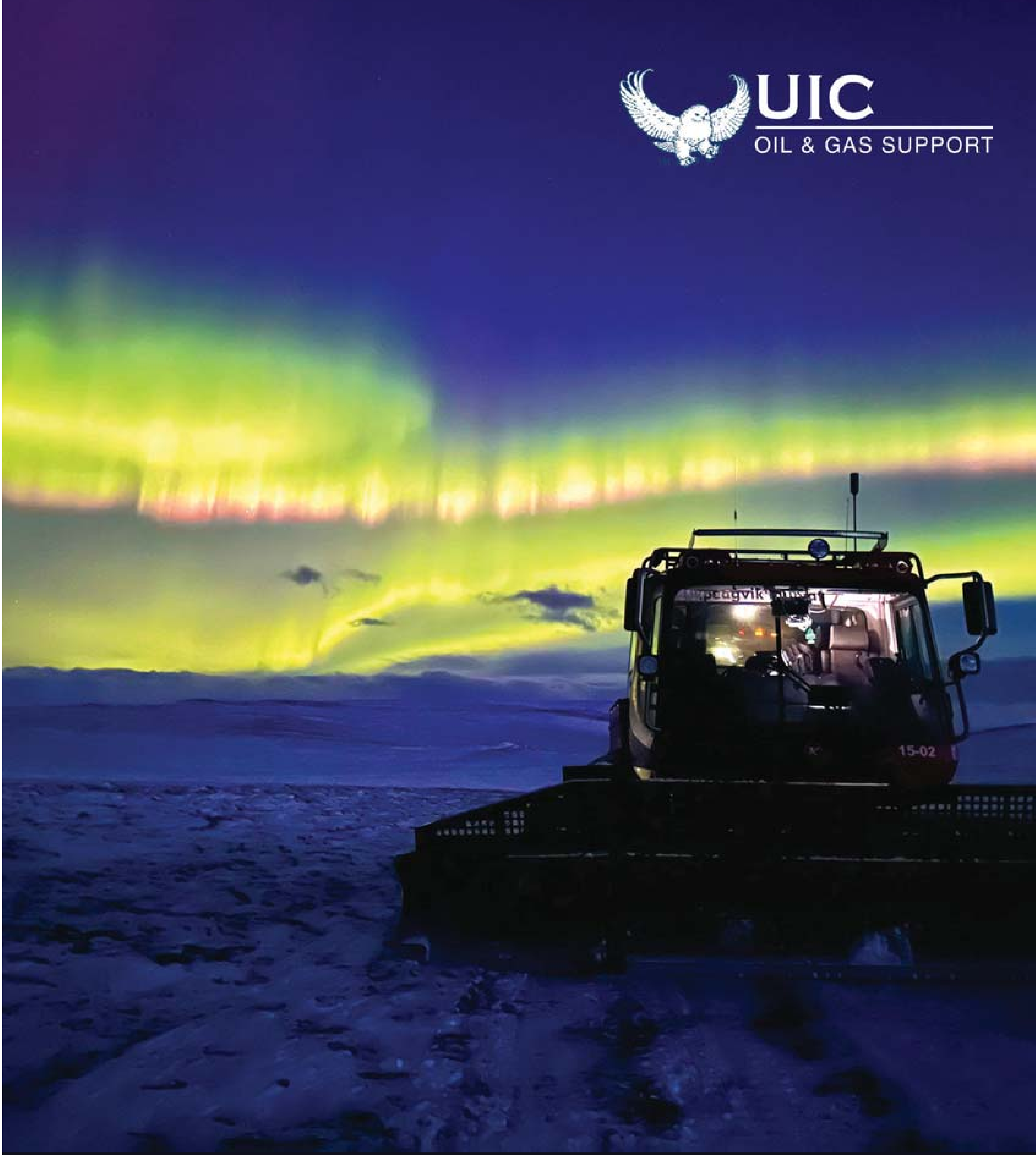
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