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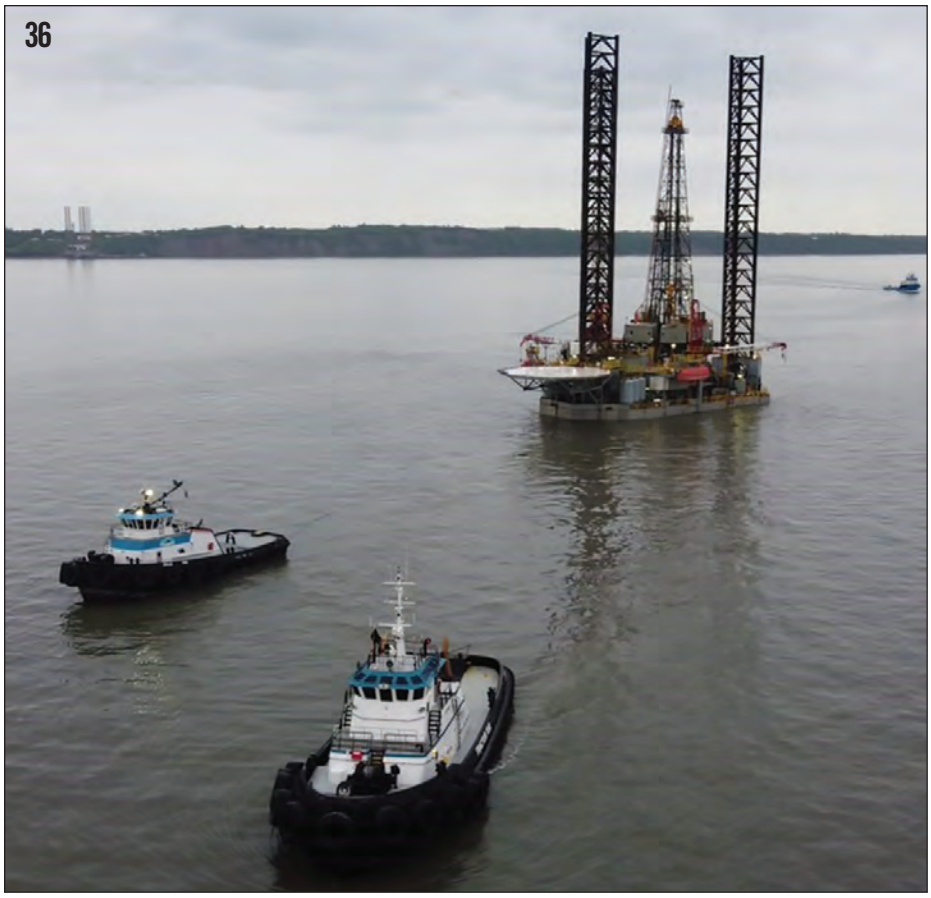

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On the cover:
151 Jack-up rig on location at Kitchen Lights Unit in Cook Inlet.

Photo courtesy Furie Operating Alaska, LLC

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A North Slope renaissance is underway

By KAY CASHMAN
Petroleum News Publisher


KAY CASHMAN

Alaska is experiencing an upcoming oil production surge driven by the Pikka and Nuna oil projects, with Pikka expected to begin production in early 2026 and Nuna already online.

This will mark the first significant increase in the state's annual crude oil production since 2002, as these new developments offset the decline of mature oil fields and aim to boost economic activity and State of Alaska revenues.

A major development on the North Slope that will begin producing oil in the first quarter of 2026, is Pikka with its first phase expected to yield 80,000 barrels per day within three months after start-up. Pikka Phase 1 is operated by a subsidiary of Santos Limited.

The smaller Nuna project, operated by ConocoPhillips on the North Slope, started producing oil in December 2024.

The combined efforts from these two new projects are forecast to increase Alaska's annual crude oil output: the first significant year-over-year growth in many years.

In particular, the Pikka Phase 1 development is projected to generate significant revenue for the state.

Alaska's overall oil production has seen a long-term decline from its peak in 1988, largely due to the depletion of older, more productive fields.

The new developments are crucial for counteracting the ongoing decline.

The oil industry accounts for one-quarter of Alaska jobs and about one-half of the overall economy when the spending of State revenues from oil production is taken into account. In other words, without oil, Alaska's economy would be half its size.

In 2018, the industry accounted for more than 77,600 direct and indirect jobs and $4.8 billion in Alaska wages.

Alaska residents represent 84 percent of primary company total employment in the state. For every primary company job, another eight are supported by primary company activity in Alaska and seven more jobs are supported by oil-related taxes and royalty payments to the State of Alaska. Cleary, when the industry prospers, so does Alaska's economy.

Alaska Governor Mike Dunleavy delivered his seventh State of the State address on Jan. 28, 2025, maintaining an optimistic view on Alaska's resources, highlighting oil and gas development and progress on a natural gas pipeline.

Pikka Phase 2 is projected to produce another 80,000 barrels per day at peak production; construction is expected to begin shortly after Phase 1 is online.

The Willow project by ConocoPhillips is anticipated to produce at peak production 180,000 barrels per day starting in 2029, with overall investment is anticipated to be more than $8 billion dollars.

Daniel Donovan, Hilcorp Asset Team Leader, recently talked about the company's new Point Thomson well; the first to be drilled in Point Thompson since 2017

Donovan said Hilcorp will end up spending more than $180 million by the time the Point Thomson well is drilled, completed, and online in 2026, bringing daily condensate and natural gas production to 10,000 barrels per day. ●

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1959 Alaska becomes the 49th state.

1968 ARCO discovers oil in the Prudhoe Bay field.

1969 Sinclair Oil Co. discovers the Kuparuk River field.

2000 ConocoPhillips Alaska Inc. begins developing the Alpine field using horizontal well technology.

2023 Final Investment Decision is made to develop the Willow project.

2024 The Nuna project produces first oil.

AIX faces declining production

Kenai Loop field showing signs of maturity as in 13th year of production focus on aligning gas sales with deliverability

By ERIC LIDJI
For Petroleum News

As it begins its second decade in Alaska, AIX Energy LLC continues to be a quiet and reliable presence in the Cook Inlet basin as operator of the Kenai Loop field.

Its 11th plan of development for the onshore field (effective for the period from May 7, 2025, through May 6, 2026) consists of a single sentence. "AIX will focus on aligning gas sales with field deliverability," per Chief Operating Officer Ronald C. Nutt.

In a slightly more expansive description of the activities for its 10th plan of development, Nutt had written that the company was "focused on obtaining reservoir information to better understand field reserves and deliverability, identifying operational efficiencies, maximizing gas sales, and maintaining a safe operating environment."

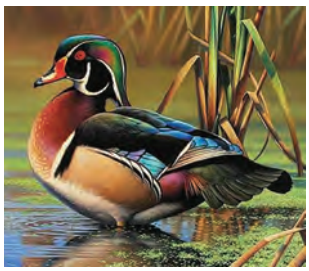
The note about "field reserves and deliverability" points to the inevitable changes underway at the maturing natural gas field.

Kenai Loop produced 1.24 billion cubic feet in 2022, 736 million cubic feet in 2023, 725 million cubic feet in 2024, and 311 million cubic feet through the first half of 2025.

The large drop between 2022 and 2023 can be traced directly to the Kenai Loop 1-3 well, which scaled back production in December 2022 and was suspended in October 2023.

Since then, the Kenai Loop field has been producing from a single well: Kenai Loop 1-1, the field's discovery well.

This well is also showing signs of age. It produced 2.44 million cubic feet per day in 2022. Production dropped to around 1.98 million cubic feet per day in 2023 and remained flat through 2024. It is down to around 1.71 million cubic feet per day through the first half of 2025.



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Since then, the Kenai Loop field has been producing from a single well: Kenai Loop 1-1, the field's discovery well.

Kenai Loop came online in 2012. Production began declining in 2016 and accelerated around 2018. AIX Energy installed a new compression facility at the field in 2019, which appears to be the largest investment AIX Energy has made in its time as operator.

Through the end of June 2025, the Kenai Loop field had produced 28.4 bcf, according to the Alaska Oil and Gas Conservation Commission. A Ralph E. Davis Associates Inc. report from the early 2010s estimated the field contained some 31.5 bcf of natural gas.

AIX history

AIX Energy arrived in Alaska in early 2014 when it acquired Australian independent Buccaneer Energy's debt. In a subsequent bankruptcy auction later that year, following Buccaneer drilling an 11,000-foot dry hole, AIX acquired nearly all of the Buccaneer Energy assets in Alaska through a credit bid.

The acquisition made AIX Energy the operator of the Kenai Loop field.

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

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

Alaska had become accustomed to an oil industry led by several large or mid-sized operators who pursue ongoing campaigns to develop large or mid-sized fields. And while that dynamic exists "outside" Alaska, too, the Lower 48 is also home to many smaller operators working to maintain daily profitability at small, marginal fields.

In its first decade in Alaska AIX Energy rarely conducted a development campaign, never drilled an exploration well, never farmed-out work and rarely traded assets. After an initial burst of acquisitions, it had rarely expanded its holdings. The private company doesn't issue press releases or hold investor conferences, preferring to speak through its required regulatory filings.

For 10-plus years now, the company has been steadily focused on one simple goal: maintaining production to meet contracted demand.

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AIX ENERGY *continued from page 10*

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

The approach is a stark contrast with its predecessor.

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

Buccaneer eventually became overextended and filed bankruptcy.

In its first year as operator, AIX Energy resolved some outstanding issues from its predecessor and began evaluating some of the maintenance projects it could pursue. It also began working to establish various gas sales agreements throughout the basin.

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

For 10-plus years now, the company has been steadily focused on one simple goal: maintaining production to meet contracted demand.

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

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

By early May 2017, AIX had at least four supply contracts: a non-firm contract with Tesoro, a non-firm contract with an unnamed company (likely Chugach Electric Association), a firm contract with Tesoro and a firm contract with Enstar Natural Gas Co.

By the fall of 2017, AIX Energy had renewed its sales agreement with Enstar Natural Gas Co. through March 2021, calling for firm gas supplies that would increase slightly each year.

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

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Amaroq gets royalty relief at Nicolai Creek

Decision buys company one year to figure out financing for development

By ERIC LIDJI
For Petroleum News

Just as this edition of The Producers went to press, the Department of Natural Resources' Division of Oil and Gas granted royalty relief for the Amaroq Resources LLC-operated Nicolai Creek unit, although there is some unfinished paperwork that both the division and Amaroq will have to complete.

With the decision, the royalty rate on five leases at the west side Cook Inlet unit was reduced to 3% until cumulative gross revenues from the unit totals $25.3 million.

The royalty relief is a highly targeted effort with a specific goal in mind.

According to estimates from the division, the terms of the royalty reduction would likely extend the life of the Nicolai Creek unit by only one year. It would generate some 80 million cubic feet of natural gas for the region while reducing state revenue by $154,000.

The idea is to give Amaroq one year to secure the financing required to conduct a long-delayed development campaign at the unit. The two-well program would increase the life of the unit by four years. This would generate an estimated 1.9 billion cubic feet of gas, which would generate $523,000 in direct royalty revenues, according to the State.

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In making the decision, the State also considered the immediate needs of the Southcentral Alaska utility market, which is eager for any and all natural gas supplies to meet demand.

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

Despite that urgency, Amaroq was unable to secure financing for any drilling at Nicolai Creek. It also delayed installation of a booster compressor unit that would have connected the NCU No. 2 and NCU No. 11 wells. This connection would have allowed additional natural gas to be produced while maintaining existing production from NCU No. 9.

In its plan for 2025, Amaroq proposed a three-well program but said the work would depend on funding. The company described its fundraising efforts as "very active and ongoing."

Amaroq did not secure the needed funding and did not drill the wells.

The Producers went to print before Amaroq submitted its plan of development for 2026, and therefore it is unclear whether the company will pursue the same development plan it proposed for 2025 or whether it will revise the plan based on the royalty modification.

Under the original plan for 2025, Amaroq would have drilled the NCU No. 15 well "from the South Pad as a 'twin' to develop shallow reserves behind pipe in NCU No. 9 due to poor or no cement conditions at the target zones in the existing well," according to the company.

A Petrotechnical Resources of Alaska analysis from early 2024 found 1.2 billion cubic feet of P50 shallow natural gas reserves behind pipe at NCU No. 9.

The NCU No. 16 well would have been drilled from the north pad to drain some 2.8 Bcf of remaining P50 reserves associated with NCU No. 3.

The NCU No. 17 well would have been drilled from the NCU

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AMAROQ RESOURCES *continued from page 14*

No. 13 pad and would have targeted 2.8 Bcf of P50 reserves.

Unit profile

The Nicolai Creek unit has five production wells. NCU No. 9 is the largest and most consistent producer.

NCU No. 2 and NCU No. 11 have produced intermittently in recent years. The NCU No. 3 and NCU No. 10 producers have been shut-in for several years.

By issuing the royalty relief, the state is trying to spur development drilling that would offset the losses of those two non-producing wells.

In recent years, Amaroq has considered different approaches. It has sometimes favored working over NCU No. 3 and NCU No. 10 and sometimes favored new drilling. A workover might be more affordable. A new well "could produce most or all of the remaining reserves," according to the company, but would require third party funding.

Recognizing the importance of those projects to the sustainability of the unit, the Division of Oil and Gas has required Amaroq in recent years to either work over NCU No. 3 or to work over/re-drill the NCU No. 10 well. The company leaned toward drilling instead of working over existing wells and asked the State to waive the requirements.

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

History

Texaco Inc. discovered the Nicolai Creek field in 1966 and 1967. Union Oil Company of California operated from start-up in 1968 until operations were suspended in the late 1970s.

Aurora Gas LLC acquired and revived the Nicolai Creek unit in 2000. A legally unrelated but similarly named company called Aurora Exploration LLC acquired the Nicolai Creek unit after Aurora Gas filed for bankruptcy protection in early 2018.

Aurora Exploration later became Amaroq Resources. Amaroq has converted NCU No. 1B to injection and temporarily brought NCU No. 10 back into production.

Nicolai Creek produced some 100 million cubic feet of natural gas in 2024, down from 102 Mmcf in 2023, according to the Alaska Oil and Gas Conservation Commission.

Deep oil potential

While the initial focus is natural gas, the Nicolai Creek unit also has oil potential.

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

In its 50th plan of development for 2024, Amaroq said it was prioritizing natural gas over oil at the leases. The project was not included in the 51st plan of development for 2025. ●

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Cosmo brings hope, frustration in Cook Inlet

Tensions between the state and BlueCrest have increased over the past year

By ERIC LIDJI
For Petroleum News

When the New York Times profiled the Cook Inlet gas situation in August 2025, it mentioned a number of possible solutions, including a North Slope gas line, development projects from HEX, liquefied natural gas imports, coal, and renewable energy projects.

Absent was a long-delayed but nearly complete project in the southern Kenai Peninsula.

BlueCrest Operating Alaska says it has been working to develop natural gas resources at the Tyonek field of the Cosmopolitan unit since 2017. Over the 50 years prior, Pennzoil, ARCO, ConocoPhillips, Pioneer, and Buccaneer all pursued the Cosmopolitan unit.

J. BENJAMIN JOHNSON

JOHN M. MARTINECK

With looming shortfalls in Cook Inlet, BlueCrest and Alaska's Division of Oil and Gas have been going back and forth on efforts to expand gas production at the unit.

By the end of summer 2025, BlueCrest said Cosmopolitan was mired in administrative complications. The division had placed the unit in default, and it was holding a plan of development for the unit in abeyance while it considered a request from the company to reconsider the default.

Central to the issue were two projects. The first would drill the H-10 Trident Fishbone oil well. The second would create a plan for bringing the Tyonek Gas Project online.

The H10 Trident Fishbone is an innovative concept designed to maximize subsurface recovery while minimizing surface drilling. Drilling with a powerful extended-reach rig from an onshore pad, a single directional wellbore would branch into three subsurface "fishbone" with eight laterals each for 24 individual wells into an offshore prospect.

For this specialty well, BlueCrest would use the custom-built BlueCrest Rig No. 1 to drill as far as three miles out and then a mile-and-a-half down to the reservoir and an additional mile-and-a-half horizontally through sands, according to the company.

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

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

The figures are likely higher today, given the uncertainties around global supply chains.

A great deal of the engineering work on these two complicated projects has been completed. What has delayed both projects for several years now is the financing.

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Four questions

Frustrations between BlueCrest and the State have emerged in filings surrounding the annual plans of development BlueCrest must file for its work at the Cosmopolitan unit.

In approving a Cosmopolitan unit plan of development for 2024, the DOG required a mid-year update and publically reminded the company a few weeks before the deadline.

The update posed four questions for BlueCrest: Did it have the funds to drill an oil well at Cosmopolitan in 2025? Did it have the funds to advance the Tyonek project?

Did it have a "fully defined plan and schedule for Tyonek Gas development?"

And were the existing financing and development plans enough to bring sustained gas production by 2027?

In its update, BlueCrest described Cook Inlet as "a closed gas market" with 70 billion cubic feet of annual demand and declining supplies. The company said it needed upfront sales contracts to justify the investment required to bring additional supplies online.

The division deemed BlueCrest's response "insufficient."

Following closed-door talks with the division, BlueCrest filed its 2025 plan of development at the end of September 2024.

Five conditions

In early December 2024, the division approved a conditional plan of development running through March 2025. (A plan of development typically covers a full 12-month period.)

In its conditional approval, the division imposed five conditions:

- BlueCrest would secure a loan from the Alaska Industrial Development and Export Authority, or AIDEA, covering the Tyonek gas project.
- BlueCrest would secure private funding for the Tyonek project.

continued on next page

BLUECREST ENERGY *continued from page 17*

• Once funding was secured, BlueCrest would submit a realistic project schedule.

• Throughout 2025, BlueCrest would provide monthly financing updates.

• BlueCrest would contract the Starichkof Sand and Hemlock Formation Participating Area, or SHPA. With only three wells drilled since the state approved the participating area in 2017, the division felt "BlueCrest has been given a reasonable amount of time and has not continued drilling efforts required to maintain the entirety of the SHPA."

A decade of work

In mid-December 2024, BlueCrest formally accepted the conditional three-month approval. In its response, it challenged some of the assumptions underlying the five conditions. BlueCrest also summarized its work at Cosmopolitan since 2013, including the following:

• investing $450 million,

• drilling Cosmopolitan State No. 1 to confirm potential of Hemlock and Starichkof,

• drilling more than 25 new vertical well stratigraphic penetrations throughout the Hemlock and Starichkof zones, and at least five new horizontal well penetrations,

• drilling four long-reach wells accessing every geologic zone to the Hemlock formation,

• designing and building the record-breaking BlueCrest #1 land drilling rig,

• building a gas sales pipeline system for future sales,

• and completing various imagining, infrastructure, and logging projects.

Southcentral gas

BlueCrest also offered its perspective on the Tyonek gas project.

The company said it had "completed the necessary long-lead-time steps to accelerate gas development at the appropriate time when there is a market for the gas."

According to BlueCrest, the big impediment toward bringing the field online was market constraint.

Here is how BlueCrest analyzed the situation:

After decades of stable supply, Southcentral utilities were expecting a natural gas shortfall as soon as 2030. Tyonek could help meet demand but faced a kink in the market.

According to BlueCrest, the Southcentral market could not currently accept the 20 billion cubic feet per year of natural gas expected from Tyonek. Existing storage in the Cook Inlet could not handle such volumes either.

"Based on BlueCrest's discussions with local utilities, the first Tyonek gas sales contract would not be required to meet local demand until January 2030," the company wrote in its filing. "Without a clear and current market at the time of first production, no investor could be expected to invest hundreds of millions of dollars and then wait years to begin to realize a return on this investment."

If the Tyonek field were an onshore prospect, BlueCrest could likely design incremental development that would gradually grow with unmet demand. Developing an offshore prospect requires building an expensive platform upfront. "Consequently,

premature development of Cosmopolitan gas that cannot be immediately sold would be imprudent."

In a response on Dec. 31, the division challenged BlueCrest on several points.

On storage: Division Director Derek Nottingham said staff had spoken with multiple Cook Inlet operators who were interested in converting depleted gas fields into storage within the next two or three years. Additionally, Hilcorp Alaska had begun working with regulators to permit a 38 billion cubic foot storage facility at the Kenai gas field. These proposed projects would have enough capacity to store the volumes expected at Tyonek.

On demand: Nottingham said Enstar had recently projected shortfalls as soon as 2028 but could delay the issue until 2032 with additional production and storage. By bringing Tyonek online in mid-2027 as committed, BlueCrest would not face any timing issues.

This year

In late 2024 and early 2025, BlueCrest submitted applications with AIDEA to fund the H-10 and the Tyonek projects.

The application flipped the order of the projects. Instead of starting with oil and moving to gas, it would use an extended reach rig to drill three wells into the eastern portion of the Tyonek A sand in 2025 with the hopes of easing Southcentral supply concerns.

Once that stopgap project was complete, BlueCrest would return to the H10 Trident Fishbone oil project. It would then return to the offshore Tyonek project by mid-2027.

In a pair of decisions on May 23, 2025, Nottingham approved the new plan of development through the end of 2025 and also placed the Cosmopolitan unit in default.

Both decisions came with the same conditions. BlueCrest must obtain financing for both projects within 90 days and must agree to regular updates over the intervening period.

In an update to the division in late July 2025, John M. Martineck, president and chief operating officer of BlueCrest Alaska Operating, revealed that BlueCrest and the division had a positive meeting with an unnamed company interested in investing in the project.

The update also included a proposed plan of development for Cosmopolitan running through August 2026. "BlueCrest anticipates commencing drilling of the H10 well ten months after finalizing the commercial structure with Party A; engineering work for the Tyonek gas development would begin within a short period after funding is secured."

COURTESY BLUECREST

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

What about the proposed onshore extended-reach gas project?

Given the high mechanical risk of the project, and announcements of gas developments by other Cook Inlet operators, BlueCrest was deferring proposed onshore plans.

In late August 2025, the division announced it would hold the proposed plan of development in abeyance while BlueCrest worked to cure the default on the unit and while the division considered a request from BlueCrest to reconsider the default.

No official action or response by the division had been taken as of Sept. 28, 2025. ●

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ConocoPhillips growing multiple ways

Alaska's legacy operator is advancing expansion at all its major properties

By ERIC LIDJI
For Petroleum News


EREC ISAACSON

Where are the areas of growth for ConocoPhillips on the North Slope?

The longest-serving operator in Alaska is finding new oil resources in several ways: through a steady regimen of workover activities, through new horizons at legacy fields, and through the steady westward expansion dating back more than 40 years.

ConocoPhillips Alaska Inc. produced 46.2 million barrels of oil from its operated Alaska properties in 2024, down about 2.7 percent from 47.5 million barrels of oil in 2023. The figure includes production from the Kuparuk River unit, the Colville River unit, and the Greater Mooses Tooth unit. The ConocoPhillips-operated Bear Tooth unit is not yet online. ConocoPhillips also maintains a non-operating stake in the Prudhoe Bay unit.

Considering the slate of projects currently on deck, it is entirely possible that the company will report year-over-year oil production growth in the coming years.

The primary activities at the Kuparuk River unit involve ongoing efforts to develop the Torok and Nanushuk through work at Drill Site 3S and 3T, as well as continuing work at the West

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CONOCOPHILLIPS *continued from page 20*

Sak participating areas. Colville River expansion is anchored to the proposed CD8 pad, which would improve access to the Nanushuk at the south of the unit.

Greatest growth area

The greatest area of growth for ConocoPhillips is the National Petroleum Reserve-Alaska. It has been 10 years since the company commissioned the CD5 pad and crossed the Nigliq Channel into the federally managed reserve. In that decade, the company has completed some preliminary development work from two pads at the Greater Mooses Tooth unit and is currently pursuing the Willow project at the Bear Tooth unit.

The success of those two projects is creating conditions for ConocoPhillips to consider further NPR-A expansion to the south and to the west of its existing properties.

Kuparuk River unit

At the Kuparuk River unit, ConocoPhillips continues to develop the Torok and Coyote participating areas, as well as ongoing development work at the West Sak participating areas. The plan for the year ending July 2026 calls for 15 wells at these three areas, down from 19 wells drilled at those three areas in the development year ending July 2025.

The Torok and Coyote participating areas are being developed from the existing 3S Drill Site and from the new 3T Drill Site that was commissioned in December 2024.

Torok is a Moraine play associated with the former Nuna satellite. The participating area covers 16,102 acres in the northwest of the Kuparuk River unit. Oil discoveries by earlier operators in the mid-1960s, 1980s, and 1990s were uneconomic due to high water cuts.

Successful tests of horizontal multi-stage fracs at the Ooguruk unit to the north suggested new approaches. ConocoPhillips drilled 3S-19 and Nuna No. 1, followed by three producer/injector pairs: 3S Phase 1 (2015), Phase 2 (2018) and Phase 3 (2023).

ConocoPhillips sanctioned a $900 million 29-well development in 2023. The company initially expected to bring the participating area online in 2025. Peak production is estimated at 20,000 barrels per day with cumulative recovery of around 100 million barrels.

In the development year ending July 31, 2025, ConocoPhillips drilled seven wells into the Torok participating areas from Drill Site 3S and Drill Site 3T, one less than it had forecasted. The company is planning a 10-well program at the Torok PA in the development year ending July 31, 2026.

ConocoPhillips produced 3,600 barrels of oil and 6.7 million cubic feet of natural gas per day from the Torok participating area in 2024, according to the company.

The Coyote participating area is associated with the Nanushuk formation. The Coyote participating area covers 16,278 acres at the western end of the unit. Earlier exploration in the mid-1960s, 1980s, early 1990s, and early 2000s yielded no oil production.

In its plan of development, ConocoPhillips said it had drilled two of nine planned wells by early July 2025 with the remaining seven expected by the end of that month. Alaska Oil and Gas Conservation Commission records confirmed all nine wells were drilled. The company is planning only one Coyote participating area well in the coming year.

ConocoPhillips produced 1,700 barrels of oil and 800,000 cubic feet of natural gas per day from the Coyote participating area in 2024, according to the company.

West Sak is a legacy participating area that continues to provide new opportunities. ConocoPhillips drilled three West Sak wells by the end of 2024 and has completed seven workovers in the combined West Sak participating areas through the end of April 2025.

In the coming year, ConocoPhillips is planning four West Sak wells. In its current plan of development ConocoPhillips said it plans to apply to expand the West Sak Participating Area before July 2026 but provided no additional details about the expansion project.

In addition to the work at these three areas, ConocoPhillips completed as many as 42 workover projects at the Kuparuk, Tarn, and Tabasco participating areas last year.

According to the AOGCC, the Kuparuk River unit produced 76,500 barrels of oil per day (28 million barrels total) in 2024, down from 79,700 barrels of oil per day (29 million barrels total) in 2023. The unit produced 15.4 million barrels in the first half of 2025, suggesting growth from 3S and 3T and the potential for a year-over-year increase.

Colville River unit

ConocoPhillips originally envisioned a three-well program at the Colville River unit in the development year ending May 15, 2025, including the Titan No. 1 well, the CD5-32X exploration well, and a development well in the Nanuq Kuparuk participating area. In an amendment, the company added a Narwhal PA

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CONOCOPHILLIPS *continued from page 22*

well and two Minke PA wells.

ConocoPhillips completed the Titan No. 1 well and the CD5-32X wells.

ConocoPhillips expanded the Colville River unit this past year by establishing the Minke participating area in February 2025 and drilled the CD5-629 producer and CD5-697 injector pair. The company ultimately deferred the Nanuq Kuparuk well to accommodate the Minke program and deferred the Narwhal well "due to a capital reevaluation."

In addition to these projects, ConocoPhillips finished reprocessing the Narwhal Merge 3D seismic survey to support the development of the CD8 pad. The project combined the 2020 Narwhal 3D seismic survey and the 2022 SAExploration 3D seismic survey.

The CD8 pad would access Narwhal resources beyond the CD4 pad. ConocoPhillips has already drilled eight Narwhal wells from CD4. The CD8 region is known as the 5th expansion area and is managed under special reporting requirements from the state.

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

ConocoPhillips began permitting in early 2025. As currently envisioned, the Narwhal project includes "a new gravel pad connected by a gravel access road with associated pipelines and power tied back into CD4 for processing and eventual sales at Alpine processing facilities. The current plan envisions 20-40 wells from CD8 with first oil by 2030.

As currently envisioned, the Narwhal project includes "a new gravel pad connected by a gravel access road with associated pipelines and power tied back into CD4 for processing and eventual sales at Alpine processing facilities. The current plan envisions 20-40 wells from CD8 with first oil by 2030.

The Colville River unit includes nine participating areas, four oil pools, and nine distinct reservoirs within those pools. In the current development year, ConocoPhillips is planning no development work at any of the participating areas: Alpine, Fiord Kuparuk, Fiord Nechelik, Fiord West Kuparuk, Nanuq Nanuq, Qannik, Narwhal, and Minke.

Colville River produced 12.7 million barrels of oil in 2024, up from 12.4 million barrels of oil produced in 2023. The unit produced 6.1 million barrels in the first half of 2025.

Greater Mooses Tooth

It's been 10 years since ConocoPhillips brought the CD5 pad online, allowing the company to cross the Nigliq Channel and access the National Petroleum Reserve-Alaska, OR NPR-A.

The 23-million-acre Naval Petroleum Reserve No. 4 was created in 1923 as an emergency oil supply. The U.S. Navy managed the area until 1976, when Congress shifted responsibility to the Department of the Interior's Bureau of Land Management and renamed the area the National Petroleum Reserve-Alaska. Following a planning process in the late 1990s, BLM held its first NPR-A lease sale in 1999.

Following exploration, Phillips Alaska announced discoveries in May 2001: Spark No. 1, Spark No. 1A, Moose's Tooth C, Lookout No. 1, Rendezvous A, and Rendezvous No. 2.

Those discoveries were inaccessible without some plan to cross the Nigliq Channel. The project prompted extended legal and regulatory battles before being resolved in 2015.

ConocoPhillips now operates two NPR-A units: Greater Mooses Tooth and Bear Tooth.

Greater Mooses Tooth is producing from two pads. ConocoPhillips brought Lookout online from GMT-1 in 2018 and brought Rendezvous online from GMT-2 in 2021.

According to the Alaska Oil and Gas Conservation Commission records, Greater Mooses Tooth has 33 active wells. There are nine active wells at Lookout (four producers and five injectors) and 24 active wells at Rendezvous (13 producers and 11 injectors).

The company drilled nine Rendezvous wells at Greater Mooses Tooth in 2024: GMTU-MT7-03A, GMTU-MT7-15, GMTU-MT7-83, GMTU-MT7-83PH1, GMTU-MT7-88, GMTU-MT7-89, GMTU-MT7-91, GMTU-MT7-92, and GMTU-MT7-93.

The company had no permitted or drilled any new Greater Mooses Tooth wells by August 2025.

ConocoPhillips produced 513,309 barrels of oil from the Lookout field in 2024, down from 594,976 barrels produced in 2023. The company produced 4,942,582 barrels of oil from the Rendezvous field in 2024, down from 5,350,571 barrels produced in 2023.

continued on page 26

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CONOCOPHILLIPS *continued from page 24*

Bear Tooth

The prospects ConocoPhillips discovered in 2001 became the center of the Greater Mooses Tooth unit and accommodated exploration to the south and the east.

The territory west of Greater Mooses Tooth was opened by an exploration campaign 15 years later. The two-well Tinmiaq exploration program in early 2016 lead to an announcement of a major discovery in the Nanushuk formation called Willow.

Willow was initially estimated to contain some 300 million barrels of recoverable oil and to have the potential to produce as much as 100,000 barrels per day at its peak. In subsequent documents, the company increased the resource estimate to 600 million barrels of recoverable oil and the peak production estimate to 180,000 barrels per day.

Efforts to delineate Willow from 2018 onward were slowed by legal and regulatory challenges, as well as the obstacles of the pandemic era.

ConocoPhillips sanctioned a $7.5 billion development in late 2023 with the goal of reaching first oil by 2029.

By early 2025, ConocoPhillips had some 2,400 workers working at the Willow project on 350 miles of ice road, 30 miles of pipeline, 1,101,000 cubic yards of gravel, and two bridges, not to mention two Willow Operations Center modules at the 30-acre pad.

This activity is accommodating year-round construction. In a first-quarter earnings call in May 2025, ConocoPhillips Senior Vice President Kirk Johnson said, "So on ... winter construction, we're now roughly 50 percent, if not slightly better, on completion of all of our civil scopes — roads, pads, bridges — and we've got about 80 miles of pipeline installed."

And "very importantly," Johnson added, the project team executed a horizontal directional drill underneath "one of the key waterways and that allows us to connect east-west pipelines... Again, we continued build out of that infrastructure."

By the second quarter call in August 2025, ConocoPhillips Alaska President Erec Isaacson said, "The Willow Operations Center remains on schedule for year-end commissioning and permanent camp occupancy, and the Willow Construction Camp is operational, enabling year-round construction activities."

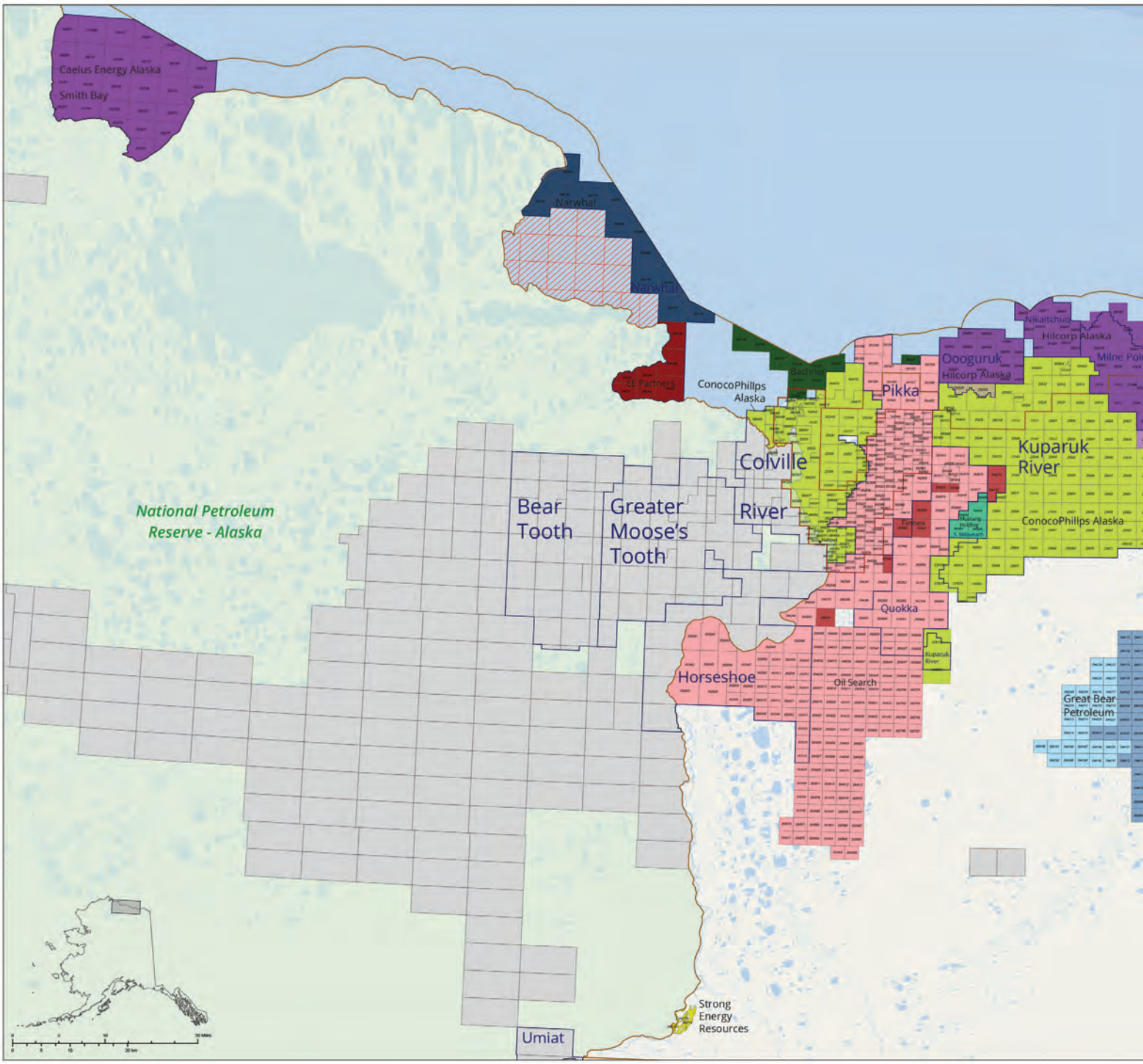
Speaking at the AOGA Conference in late August 2025, ConocoPhillips Asset Development Manager Donald Allen said, "Engineering and fabrication of the modules continues with delivery expected to the North Slope in 2027, and in 2027 we also expect to start up the predrilling."

The progress at Willow is allowing ConocoPhillips to consider opportunities to the west and to the south. The company has applied for a seismic program south of Greater Mooses Tooth and Bear Tooth and a one-well exploration program at Greater Mooses Tooth. The company has also requested authorization for a three-well exploration program with one well in the Bear Tooth unit and two wells to the west of Bear Tooth.

With these projects, Allen said, "You can expect us to follow our same disciplined development approach. We'll continue to look for ways to leverage our existing infrastructure and gravel for low capital intensity tieback projects where they exist." ●

Contact Eric Lidji at ericlidji@mac.com

The Nuna project achieved first oil under budget and ahead of schedule on Dec. 17, 2024.



- Accumulate Energy Alaska, Inc.
- Arctic Circle Exploration, LLC
- Bachner, J. Andrew
- Brooks Range Petroleum Corporation
- Cade, Samuel H
- Caelus Energy Alaska Smith Bay, LLC
- Captivate Energy Alaska, Inc.
- ConocoPhillips Alaska, Inc.
- Donkel, Daniel K
- EE Partners Corporation
- ExxonMobil Alaska Production, Inc.
- Finnex, LLC
- Glacier Oil & Gas Corp.
- Great Bear Pantheon, LLC
- Great Bear Petroleum Ventures II, LLC
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- Lagniappe Alaska, LLC
- Mustang Holding, LLC
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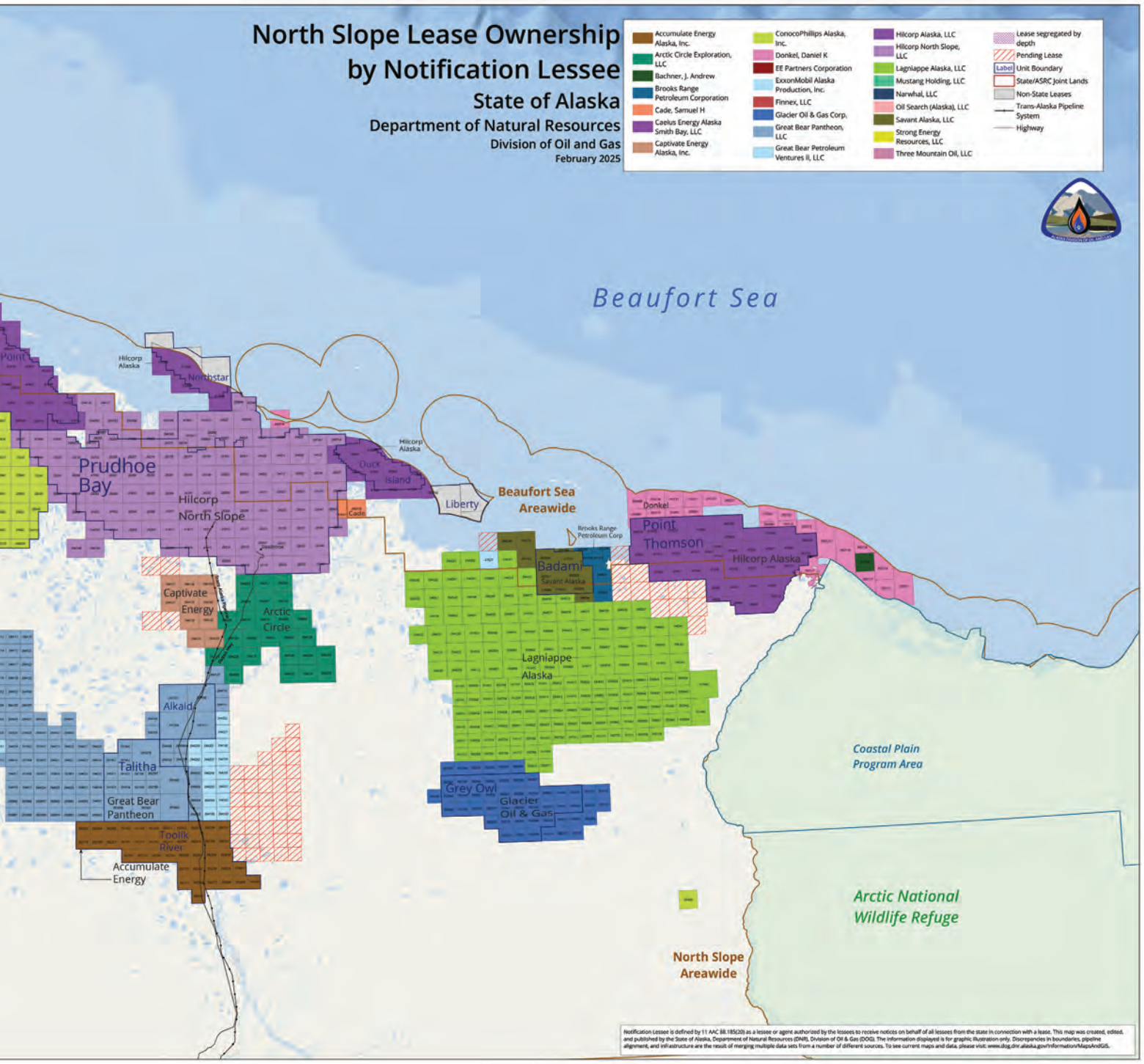
- Oil Search (Alaska), LLC
- Savant Alaska, LLC
- Strong Energy Resources, LLC
- Three Mountain Oil, LLC
- Lease segregated by depth
- Pending Lease
- Label Unit Boundary
- State/ASRC Joint Lands
- Non-State Leases
- Trans-Alaska Pipeline System
- Highway



North Slope lease ownership

Cook Inlet Lease Ownership by Notification Lessee

State of Alaska

Department of Natural Resources

Division of Oil and Gas

February 2025

N

Lewis River
Susitna Flats State Game Refuge
Pretty Creek
Ivan River
Beluga River
Hilcorp Alaska
Cook Inlet Areawide
North Cook Inlet
Nicolai Creek
Trading Bay State Game Refuge
Granite Point
North Trading Bay
Furie Operating Alaska
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Trading Bay
W. McArthur River
Redoubt Bay Critical Habitat Area
Cook Inlet Energy
Redoubt
Swanson River
Beaver Creek
Kenai National Wildlife Refuge
AIX ENERGY
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Hilcorp Alaska
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Storage Lease Inset Map
Cook Inlet Natural Gas Storage Alaska
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Kenai National Wildlife Refuge
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Amaroq Resources, LLC
BlueCrest Energy, Inc.
Cook Inlet Energy, LLC
Cook Inlet Natural Gas Storage Alaska, LLC
Furie Operating Alaska, LLC
Gremillion, Anne L
HEX, LLC
Hilcorp Alaska, LLC
Rhoades, Stina A
Strong Energy Resources, LLC
Vision Resources, LLC
Lease segregated by depth
Pending Lease
NonState Lease
Label
Unit Boundary
Areawide Boundary
Highway

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Glacier subsidiary CIE posts notable gains

West side Cook Inlet properties West McArthur River and Redoubt see growth thanks to maintenance work

By ERIC LIDJI
For Petroleum News


STEPHEN RATCLIFF

In the old days, increasing production usually required some increase in drilling. Today, though, technology can sidestep the need for new wells, especially in maturing fields.

Cook Inlet Energy, or CIE, reported double-digit percentage point production increases last year at its West McArthur River and Redoubt units — without any additional production wells.

Instead, the Alaska-based Glacier Oil & Gas Co. subsidiary implemented a range of technological interventions at the two offshore fields on the west side of Cook Inlet.

The state formed the West McArthur River unit in 1990. Cook Inlet Energy became operator in 2009. The unit currently covers 6,970 acres over parts of three offshore leases and includes eight wells within the Area No. 1 and Sword participating areas. The unit produces from four wells — WMRU-2B, WMRU-5, WMRU-6 and Sword No. 1.

West McArthur River produced 84.8 million cubic feet of natural gas and 330,776 barrels of oil in 2024, according to the Alaska Oil and Gas Conservation Commission, up from 55.8 MMcf of gas (up 52 percent) and 230,992 barrels of oil (up 43 percent) in 2023.

Cook Inlet Energy traces these increases to "optimizing [electric submersible pump] pump frequency, expanding water handling capacity and adding new injection wells."

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

The state formed the Redoubt unit in 1997. Cook Inlet Energy became operator in 2009. The unit covers 9,668.5 acres over parts of five offshore leases and has nine wells with the Hemlock participating area.

The unit produces from RU-1A, RU-5B, and RU-7B.

Redoubt produced 52.8 MMcf of gas and 199,523 barrels of oil in 2024, up from 40.9 MMcf of gas (up 29 percent) and 164,203 barrels of oil (up 21 percent) in 2023.

RU-3A and RU-6A are injectors. RU-D1 is a Class I disposal well. The RU-2A and RU-9 producers are offline for downhole issues. RU-4A is suspended for water loading issues.

Following recent deal making, the Smith Bay Company Alaska Inc. and JPD Family Holdings LLC now own Glacier Oil & Gas Co. and its two subsidiaries: Cook Inlet Energy and Savant Alaska.

Cook Inlet Energy operates West McArthur River unit, Redoubt unit and the Kustatan Production Facility.

Glacier Oil & Gas Corp.

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PHONE: 907-868-1258
TOP ALASKA EXECUTIVE: Stephen Ratcliff, president
WEBSITE: www.glacieroil.com

Savant operates the Badami unit on the eastern North Slope, which is profiled in the North Slope section of The Producers magazine.

Projects

The most significant intervention was the Free Water Knock Out

continued on next page

GLACIER OIL & GAS *continued from page 31*

(FKWO) project.

FWKO allows Cook Inlet Energy to extract produced water from the three-phase stream at West McArthur River. The company had previously processed produced water from both offshore fields at the Kustatan Production facility and injected waste at Redoubt.

Following a pilot project launched in December 2022 and carried into 2023, the company completed the project in September 2023. Through the project, it has converted the WMRU-4D Class I disposal well and the WMRU-08 at West McArthur River into water disposal wells.

A proposed phased project to increase injections at RU-3A was deferred because "the well was deemed to have sufficient injectivity in its current condition."

In addition to improved water handling, other important interventions were "proactive [electric submersible pump] frequency adjustments" and "acid stimulation jobs."

Cook Inlet Energy launched its acid stimulation project in 2022 with work at the WMRU-5, WMRU-6, and RU-2A wells. According to the company, the tests "proved beneficial to ESP pump performance by eliminating scale buildup from high water cuts and aided in enhancing production from the Hemlock formation" at the West McArthur River unit.

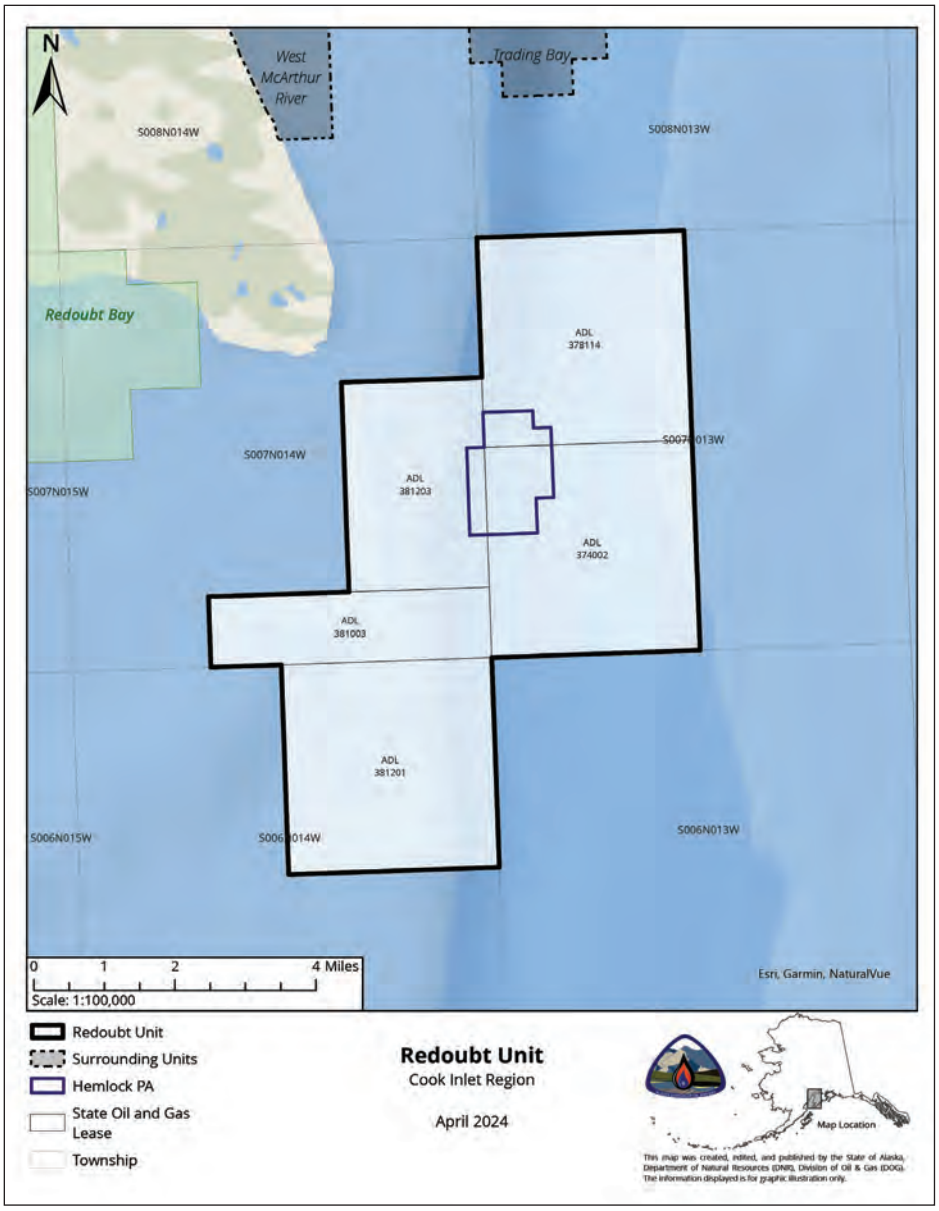
The Redoubt test results were complicated by an unrelated ESP failure. A workover to resolve the issue was abandoned after encountering downhole complications. A special intervention at the well has been on the docket ever since but has yet to be completed.

According to the company, "the workover is currently prohibitively expensive and could become a viable option if conducted in conjunction with another rig involved operation."

With the positive results at West McArthur River, Cook Inlet Energy conducted testing at WMRU-2B and the Sword No. 1 wells and replaced failed electric submersible pumps.

In the past year, Cook Inlet Energy resumed acid testing at Redoubt. An assessment of an earlier weak acid stimulation at RU-5B yielded a doubling of stable oil production at the well. A test at RU-1A was inconclusive due to an ESP failure soon after the procedure.

Cook Inlet Energy also replaced a mile-long section of its 8-inch three-phase pipeline at West McArthur River using FlexSteel. While the project was not directly related to increasing production, it represented the first use of the material in the Alaska oil patch.



Cook Inlet Energy traces these increases to "optimizing [electric submersible pump] pump frequency, expanding water handling capacity and adding new injection wells."

Exploration projects

While these projects have yielded important gains for Cook Inlet Energy, a larger prize potentially awaits if the company is able to conduct new drilling at the units.

In its current plan of development, Cook Inlet Energy is again non-committal about the Sabre prospect at West McArthur River, saying it "plans to keep its options open" as it works to obtain financing and reduce risk associated with the prospect.

Several former operators attempted to explore the Sabre prospect. Cook Inlet Energy considered a Sabre well as early as late 2013 but ultimately delayed the project due to logistics and costs.

In its current plan of development, Cook Inlet Energy also said it would maintain flexibility at the Northern and South fault blocks of the Redoubt unit while it looked for financing. The company also blamed delays on exploration work at the Badami unit. ●

Contact Eric Lidji at ericlidji@mac.com

HEX CI advances Alaska energy independence

Subsidiary Furie Operating has two new Kitchen Lights Unit wells producing 3,000 mcf a day each, plans four wells in 2026

By KAY CASHMAN
Petroleum News Publisher


JOHN L. HENDRIX

On July 24, 2025, HEX Cook Inlet's wholly owned subsidiary Furie Operating Alaska brought online two new gas wells in the Kitchen Lights Unit at the successful completion of its 2025 summer drilling program.

The wells are performing as designed at more than 3 million cubic feet of natural gas per day each.

Furie used Hilcorp's Spartan 151 jack-up for its 2025 $40 million program.

In addition to expanding Alaska's natural gas supply, the summer drilling program enhanced the competitiveness of local gas markets by broadening access to resources and reducing reliance on imported energy.

Additionally, the KLU A-2A well was successfully worked over in late June 2025 and has returned to production, further strengthening HEX Cook Inlet's operational capacity in the Cook Inlet basin.

The Julius R. Platform in the Kitchen Lights Unit, or KLU, has been renamed the Allegra Leigh Platform, honoring the first granddaughter of John and Candace Hendrix -- a fourth generation Alaskan.

Born and raised in Alaska, Hendrix is the owner of HEX, the parent of HEX Cook Inlet.

Hendrix formed the HEX companies for the purpose of purchasing Furie, its sister companies and their Cook Inlet assets -- principally to switch the Cook Inlet Kitchen Lights field from foreign and Outside ownership to Alaskan ownership.

He accomplished this on June 30, 2020, making the purchase from a Delaware bankruptcy court.

Furie is the only 100% Alaskan-owned oil and gas production company in Alaska. Furie and its parent HEX Cook Inlet are headquartered in Anchorage, Alaska, and are passionate about developing Alaska's resources for Alaskans.

Furie operates only in Cook Inlet and only produces natural gas for Alaskans.

More surface well slots

On March 21, 2025, Hendrix told Petroleum News that contractors working for Furie Operating have completed the implementation of surface well slots and conductor tubing on platform, which will enable up to 12 wells to be operated from the platform.

Before this the platform was only able to handle up to six wells. The platform, offshore in the Cook Inlet, is used to produce gas from the Kitchen Lights gas field.

The platform upgrade will enable a significant increase in the gas production capacity and reliability from the Kitchen Lights field.

Hex Cook Inlet LLC

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TOP ALASKA EXECUTIVE: John L. Hendrix, president/CEO
PHONE: 907-277-3726
EMAIL: Admin@furiealaska.com

Hendrix said that operating more wells from the platform gives his company greater confidence in signing long-term gas supply contracts, given the potential to have backup wells in support of gas production.

In its most recent plan of operations Furie had indicated an intent to increase the well capacity from six to eight wells, but it has now proven possible to double the capacity to 12 wells.

"It gives us options ... the more options you have, the better chances you have," Hendrix said.

Having more wells also enables the operating costs for the platform to spread across the additional wells, he added.

Hendrix's plan with the additional well capacity is to drill more field development wells, directionally drilled within a 3-mile radius of the platform.

Four wells in 2026

At that time Hendrix said if the drilling of two wells was successful in 2025 (and it was), Furie would like to move forward with the drilling of four wells in 2026.

The company is also looking at additional drilling in 2027.

The Kitchen Lights Unit has gas resources in two pools: the Sterling pool and the Beluga pool. However, given that production from the Sterling pool tends to contain large amounts of water,

continued on next page

HEX COOK INLET *continued from page 33*

Furie has been focusing its development on the Beluga pool.

In early 2019, before Hendrix took over Furie, the gas pipeline from the platform to the shore became plugged by ice given the high level of water production from the field. Under Hendrix Furie installed a water treatment facility on the platform to enable clean water to be discharged into the sea rather than be passed down the pipeline.

Hendrix said that the recent drilling of an additional well has increased the Kitchen Lights gas production from 5% to 7.5% of the total gas production from the Cook Inlet basin. The drilling of two further wells should then increase this to somewhere in the range of 10% to 12%. Hendrix said the company hopes to eventually further increase its production to a 25% level.

This comes at a time when there are increasing concerns about the future adequacy of Cook Inlet gas production.

Multiple drilling targets

Hendrix said that the Kitchen Lights field reservoir rocks are very fractured, with gas resources acting rather like streams meandering through the subsurface. And the "streams" operate at different depths.

Essentially, he said, it is a question of drilling into these resources, while gradually stepping out from the location of the platform.

"We've identified 27 well targets within a 3-mile radius of our platform," Hendrix said.

With a maximum of 12 wells that could be drilled from the platform, the drilling strategy involves first targeting gas that is relatively distant from the platform and then drilling sidetrack wells to access resources that are closer to the platform.

HEX COOK INLET

The Allegra Leigh Platform

At this time, Furie is focused on development drilling and gas production, rather than exploration drilling, Hendrix said. When people need gas, the question becomes whether to risk a month or two drilling an exploration well, versus drilling a couple of development wells and then bringing the wells online for gas production, he said.

Slap in the face

With firm contracts for natural gas supplies to Southcentral Alaska gas and electricity utilities expected to fall short of gas demand in the next three years, the utilities and the gas producers will need to make some critical decisions over how best to ensure the continuity of energy supplies to Alaska residents and businesses.

In a May 20, 2025, meeting of Commonwealth North, several experts on the subject presented their assessments of the situation. Hendrix was one of those experts. He argued for more production, for the feasibility of bolstering gas supplies through more drilling in the Cook Inlet basin.

"We should not be having this conversation. There's gas there. We just have to develop the gas," Hendrix said.

With regard to discussions about future gas supplies from outside the Cook Inlet, he said: "Bringing gas from the Lower 48 is, to me, a kind of slap in the face ... but we're kind of pushing ourselves in that direction."

On the other hand, given the isolated gas market in Alaska, there is a cap on how much gas can be produced and sold, he added.

Hendrix emphasized the distinction between the upstream gas producers, like Furie, and the utilities that sell energy products. While the producers risk capital to bring energy sources online, the utilities can move forward based on Regulatory Commission of Alaska approval of what they are doing, he said.

And decisions on how much capital to put at risk from drilling wells are impacted by issues such as renewable energy replacing gas use, the potential for a future North Slope gas line and the possibility of importing LNG.

Hendrix cited property taxes on gas producer facilities and state royalties as impediments to drilling for more gas production.

Hendrix also questioned assumptions that Cook Inlet gas is

HEX COOK INLET

Furie used Hilcorp's Spartan 151 jack-up for its 2025 drilling program at the company's Julius R. Platform, which has been renamed the Allegra Leigh Platform.

expensive, arguing that the gas is actually the fourth cheapest in the country at the meter.

Thumbs up from AIDEA

On July 25, 2025, lender AIDEA, the Alaska Industrial Development and Export Authority, congratulated Kitchen Lights Unit operator Furie Operating "for the successful completion of its 2025 summer drilling program and its continued leadership in advancing Alaska's energy independence."

In early May 2025, AIDEA and HEX Cook Inlet had announced the successful signing of loan documents supporting Furie's multi-year $50 million Revolving Line of Credit.

This agreement marked a key milestone in securing the financing necessary to advance new drilling operations and expand energy infrastructure to meet the growing demand for locally produced natural gas in Alaska and contributed to reducing the forecasted Cook Inlet natural gas supply gap.

Established by the Alaska Legislature in 1967, AIDEA is an independently governed public corporation tasked with promoting the economic welfare of Alaskans. Through flexible financing solutions, AIDEA has invested more than $3 billion in projects that drive economic development and job creation across the state. ●

Contact Kay Cashman at publisher@petroleumnews.com

Hilcorp Alaska's new drilling

Gas development and new drilling in Cook Inlet will help cushion projected regional supply deficit

By TIM BRADNER
For Petroleum News


LUKE SAUGIER

Hilcorp Alaska, the major producer in Cook Inlet, is investing in new drilling and natural gas development to cushion the effects of production declines expected in "legacy" producing fields, which are aging.

The latest is Hilcorp's work to expand drilling and development of smaller gas prospects, mainly onshore, in Southcentral Alaska along with new work at the offshore Tyonek Platform North Cook Inlet field, which produces approximately a third of Hilcorp's gas supplies for the region.

There is also new work being done at the Beluga River onshore gas field on the Inlet's west side, where Hilcorp is the field operator and joint owner with Chugach Electric Association.

Modifications at the Tyonek platform is a major undertaking this year. Hilcorp presented details of the company's plans at the 2025 Alaska Oil and Gas Association conference held in late summer.

The platform was built in 1968 and operates in challenging conditions in Cook Inlet in about 100 feet of water with a 30 ft. to 40 ft. tidal range and tidal currents of 10 knots. The platform produces 35 million to 40 million cubic feet of gas daily, or approximately 14 billion to 15 billion cubic feet yearly.

It has 24 producing wells that were drilled and now operate through the platform's large legs that support it.

The North Cook Inlet field is one of the Inlet's legacy fields and although it is over 50 years old there is more gas that could

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be developed. The problem is that there is not enough space in the existing platform legs to drill more wells.

Hilcorp has been studying the problem and considering options like structurally expanding the platform to add more legs, building a new platform or installing subsea well tie-backs, or wells drilled with sub-sea flow lines to the platform

Those are costly alternatives and pose environmental issues because of permitting challenges with any new work in the water, which is habitat of threatened Beluga whales.

The company's creative solution to this is to install new conductor pipe, through which wells can be drilled and operated, on the sides of the platform legs. Each conductor pipe can accommodate two wells, so installing one conductor pipe allows for two more producing wells, or two conductor pipes for four new wells. Hilcorp's project installs two conductor pipes.

However, an additional challenge is to protect the new external conductor pipe from the crushing force of winter ice that moves with the tidal currents.

To solve this, Hilcorp has built an "icebreaker," a steel structure that is 50-feet tall and 10-feet wide built with 1-inch steel plate and would be installed to protect the new conductor pipe from the ice forces.

The structure was built in Anchorage. moved to the Tyonek platform and has now been installed. The next step is installation of the conductor pipe.

Drilling is planned to begin in spring, 2026. It's an example of a creative solution to a challenge, Hilcorp said at the AOGA conference.

The company's creative solution to this is to install new conductor pipe, through which wells can be drilled and operated, on the sides of the platform legs.

Other new projects

In other new projects, Alaska's Division of Oil and Gas gave Hilcorp approval on Sept. 9, 2025, to build new infrastructure and drill new wells at the company's Happy Valley gas field on the Kenai Peninsula.

Work is to begin at Happy Valley on Oct. 20 and be completed in April 2026, the company told the division. What will be built is a new 300 ft.-by-400 ft. gravel pad, the "Happy Valley Middle Pad," as well as a new 3-mile gravel access road, two gas wells drilled from the new pad.

To solve this, Hilcorp has built an "icebreaker," a steel structure that is 50-feet tall and 10-feet wide built with 1-inch steel plate and would be installed to protect the new conductor pipe from the ice forces.

An additional well will be drilled to supply fresh water.

There will also be related facilities such as gas flowlines, electrical instrumentation, separators and other equipment to support production.

On a nearby project Hilcorp also received approval to install a pipeline to produce gas from its new Whiskey Gulch gas project near Anchor Point, also on the Kenai Peninsula.

A 4,000-foot, 6-inch diameter will connect the Whiskey Gulch production pad to a nearby Enstar Natural Gas Co. pipeline.

A third new gas development by Hilcorp will be at the small Pretty Creek gas field on the Inlet's west side. At Pretty Creek Hilcorp will build its new "Diamond" production pad that will support five new production wells, the company said in information supplied to the Division of Oil and Gas.

The location is about nine miles northeast of the Beluga airport.

All three of these projects involve drilling into known gas deposits, which are relatively small, but Hilcorp also plans to drill two new exploration wells to test newly acquired state leases near Kenai on the Inlet's east side. Success at these projects could help bring the small nearby Sterling gas field back into production, the company has said.

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HILCORP COOK INLET

The Spartan 151 jack-up rig.

The idea of having to import energy to an energy-rich state rankles most Alaskans but electric utilities like Chugach are required by government regulators to be able meet regional consumers' needs.

HILCORP COOK INLET *continued from page 37*

Hilcorp also plans new gas exploration in the small North Fork field area east of Anchor Point. Hilcorp purchased assets in the area from two small companies, Vision Resources and Anchor Point Energy. The North Fork gas deposit has seen limited drilling and production and has produced gas through a pipeline built to connect with Enstar's pipeline near Anchor Point. Hilcorp believes North Fork has additional potential.

Hilcorp is also continuing to drill in its larger existing "legacy" gas fields in Cook Inlet to add incremental reserves. In a presentation to the state Legislature in January 2025, Hilcorp said it drilled 21 new wells in 2024 following 18 new wells in 2023.

The company plans a steady program of 15 to 20 wells per year going forward, Hilcorp told the legislators.

Overall, Hilcorp has invested approximately $1 billion in Cook Inlet after purchasing the Inlet's aging gas fields from Chevron Corp. and Marathon Oil Co. in 2012 and 2013. Since that time has drilled 174 wells and produced 700 billion cubic feet of gas.

Despite the new activity there are still concerns for an annual gas supply deficit beginning in 2027. Regional utilities are preparing to import liquefied natural gas, or LNG, to cover the deficit and meet consumers' needs for electricity and heating for buildings.

Hilcorp affiliate Harvest Alaska is involved in that, with a plan to purchase the mothballed former ConocoPhillips LNG export plant at Nikiski and convert it to an LNG import terminal.

Chugach Electric Association, the state's largest electric utility, is working with Harvest with a plan to purchase imported LNG to meet Chugach's gas supply needs for power generation.

The idea of having to import energy to an energy-rich state rankles most Alaskans but electric utilities like Chugach are required by government regulators to be able meet regional consumers' needs. Harvest would help do that along with plans by Hilcorp to make additional underground gas storage available for utilities and others. Having additional storage will be a key part of meeting regional energy needs.

The regional gas supply deficit is fairly modest in 2027 and 2028, according to studies by the Division of Oil and Gas, and new incremental drilling by Hilcorp and other companies could meet the short-term need. But by 2029 and 2030 the supply deficit will be much larger, according to the division's estimates.

Whether new drilling will be enough to substantially reduce imported LNG is unknown, however. New Cook Inlet gas wells tend to decline rapidly in production after first being drilled with decline rates of 30% per year not uncommon, Hilcorp told legislators in a briefing in January 2025.

SomeAlaskans hope that a North Slope natural gas pipeline project will move forward, bringing the large "stranded" gas reserves known on the North Slope. But the big project faces financing challenges and is another major unknown. ●

Editor's note: Tim Bradner is publisher of the Alaska Economic Report and Alaska Legislative Digest. Contact him at timbradner@pobox.alaska.net

Hilcorp doing what it does best

Plans major west-end development at Prudhoe Bay and new producing well at Point Thomson

By TIM BRADNER
For Petroleum News

Hilcorp Alaska is doing what it does best on the North Slope, investing aggressively and applying new technologies in mature oil and gas fields to boost production.

So far Milne Point is Hilcorp's greatest success on the North Slope, but more is coming.

Production at Milne Point has tripled since Hilcorp bought into and became operator of the field from BP in 2014. It was then producing about 17,000 barrels of oil per day. But production has steadily increased after taking full control of the field in 2020, a $2.5 billion investment in drilling, construction of new facilities – including both the Moose and Raven Pads -- and application of a polymer flood, the first on the North Slope.

Earlier this year, Milne reached more than 50,000 bpd and Hilcorp says it's optimistic it can reach 60,000 bpd in the next few years. That's according to Daniel Donovan, Hilcorp's Western North Slope Asset Team Leader, who spoke at the Alaska Oil and Gas Association's annual conference in Anchorage Sept. 27.

At the large Prudhoe Bay field, Hilcorp stabilized production after taking over as co-owner and operator from BP in 2020.

Under BP's operatorship, production at Prudhoe had been declining gradually, as aging oil fields do, but through major investments into the field Hilcorp has mostly stopped the decline.

Earlier this year, Milne reached more than 50,000 bpd and Hilcorp says it's optimistic it can reach 60,000 bpd in the next few years.

Taiga project

Now Hilcorp is planning a major new project in the underdeveloped west end of Prudhoe that could actually boost field or at least continue to minimize production decline. This project, being called "Taiga" by Hilcorp. includes the development of two new pads on the west of Prudhoe Bay to develop the Schrader Bluff oil.

Hilcorp is proceeding with what Donovan describes as "greenfield development" on previously untapped tracts of Prudhoe subsurface. Phase one – projected to deliver peak production of 25,000 bpd – centers on the construction of a new drill site called "Omega Pad"and 51 development wells, with first oil expected in 2028.

A second phase would add another site "I-Pad," potentially bring on an additional 15,000 bpd as early as the 2030s.

A substantial part of the reservoir to be tapped in the Prudhoe west end project, is viscous oil similar to that in the Schrader Bluff viscous oil at Milne Point.

Viscous oil is cooler than conventional crude oil mainly because it is typically found at shallower depths than the large conventional oil reservoirs on the North Slope, which are deeper and at warmer temperatures so that the oil flows more easily.

Hilcorp now has substantial experience with viscous oil because of its work in developing Milne Point. The Schrader Bluff oil at the field is also found at Prudhoe Bay's west end and it similar to the West Sak viscous oil found in the Kuparuk River field, except that West Sak is even shallower and cooler and has presented its own technology challenges for ConocoPhillips and, earlier, ARCO Alaska.

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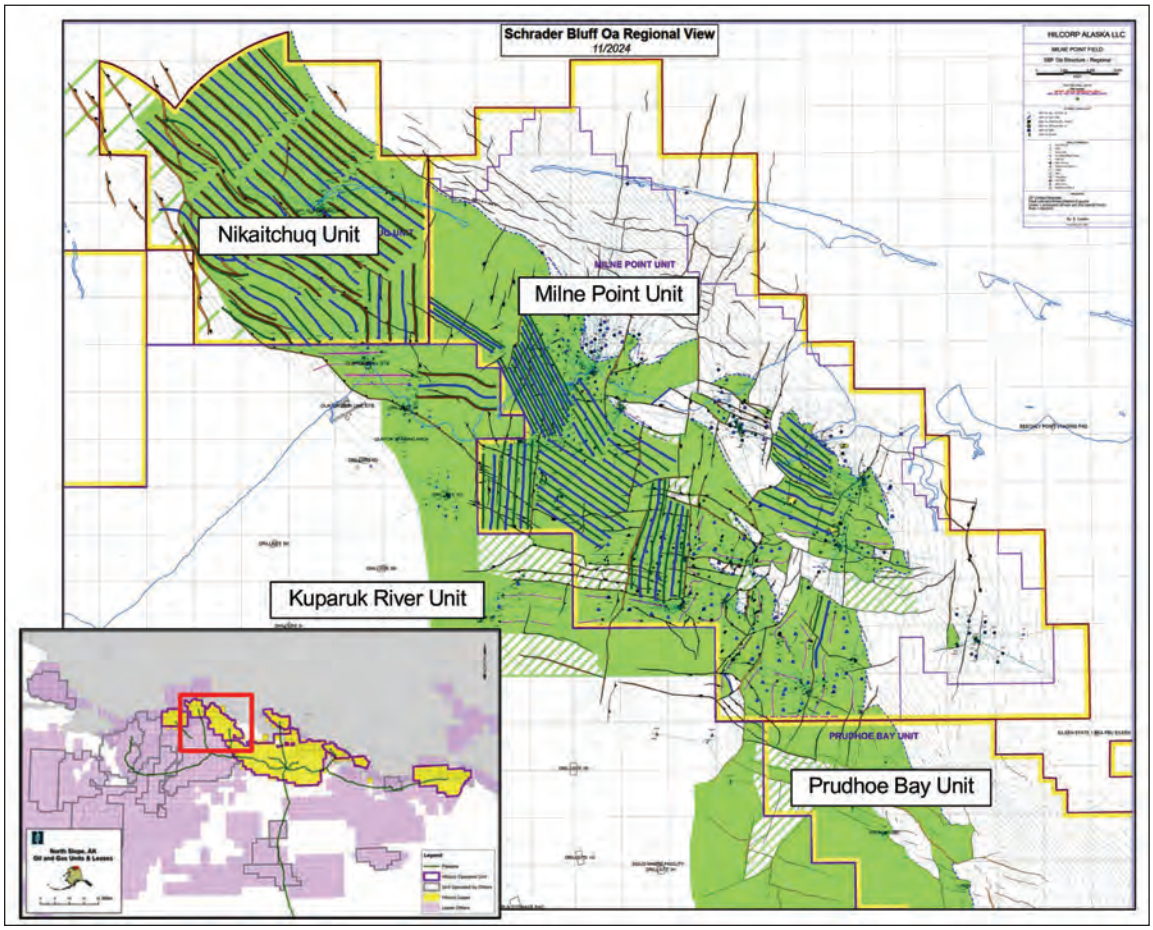
HILCORP NORTH SLOPE



Hilcorp is planning a major new project in the underdeveloped west end of Prudhoe that could actually boost field or at least continue to minimize production decline. This project, being called "Taiga" by Hilcorp. includes the development of two new pads on the west of Prudhoe Bay to develop the Schrader Bluff oil.

HILCORP NORTH SLOPE *continued from page 40*

The polymer injection at Milne Point was developed in cooperation with the University of Alaska Fairbanks' Institute of Northern Engineering. The project now involves injection of 58,000 bpd of the polymer, which is done in a pattern alternating with water.

Hope for Ugna

Hilcorp is also now producing a limited amount of oil from the Ugnu formation that underlines large parts of Milne Point. Ugnu is true heavy oil that is denser and colder, because it is even shallower than the viscous oil in the Shrader Bluff deposit.

The deposit is a very large oil resource with some estimates exceeding 20 billion barrels of oil in-place or locked in the reservoir rock. Producing it, and getting the oil to flow, is the main challenge. Where producing companies typically see 40 percent or more recovery of oil from conventional North Slope fields the estimates for heavy oil accumulations like Ugnu are much lower, at 10 percent or even less.

Polymer at Nikaitchuq

UAF's Institute of Northern Engineering has also been working with new processes to produce the heavy oil and have found that a technique of injecting a solvent alternating with water and polymer has promising results, at least as shown in laboratory studies.

Hilcorp is also actively working to boost its to-do list, and may be boosting two smaller North Slope fields the company acquired from the Italian state-owned company Eni S.p.A last year, Nikaitchuq and Oooguruk.

Doyon Drilling's Rig 15, previously now on Spy Island in the Nikaitchuq field was recently moved by barge in a major sealift earlier this month to Point Thomson.

These are offshore fields in shallow Beaufort Sea waters just north of the Alaska coast. Nikaitchuq produces viscous as well as conventional oil and Hilcorp hopes its polymer production technology successfully used at Milne Point may be equally successful there.

"We have hopes that this can produce Milne Point typo results," Donovan said.

New well at Point Thomson

Hilcorp also has plans for Point Thomson, the large gas and condensate field east on the eastern North Slope, about 60 miles east of Prudhoe Bay. A new gas and condensate production well at a new drill-site is planned for 2026 that is expected to add production and bring Point Thomson production to near 10,000 bpd.

It is the first new well drilled at Point Thomson since 2016-2017 and it's an expensive project budgeted at $180 million. Logistics are a major part of what makes it expensive, Donovan said. Doyon Drilling's Rig 15, previously now on Spy Island in the Nikaitchuq field was recently moved by barge in a major sealift earlier this month to Point Thomson. Preparations are underway for drilling to commence this winter and will require an approximately $40 million ice road to be built to the location.

The field is now producing about 4,000 b/d and has been short

A new gas and condensate production well at a new drillsite is planned for 2026 that is expected to add production and bring Point Thomson production to near 10,000 bpd. The Point Thomson assets also include a 22-mile pipeline that connects the field with the 25-mile Badami pipeline at that small oil field essentially half-way between Point Thompson and Pump Station One of the Trans Alaska Pipeline System at Prudhoe Bay.

of its production goal because of technical challenges in producing and injecting produced gas back into a high-pressure reservoir. The new well will bring liquid condensate production to 10,000 bpd, the target for Point Thomson. First oil from this new well is anticipated for the second half of 2026.

Hilcorp's acquisition of BP's Alaska assets included its share of Point Thomson, which is 32.6%. ExxonMobil, which also owns a significant part of Point Thomson, about 62.5% and there are also some small owners. ExxonMobil was previously the Point Thomson field operator but has passed that responsibility to Hilcorp, who is known for its ability to bring aging assets back to life through efficiency and investment.

The Point Thomson assets also include a 22-mile pipeline that connects the field with the 25-mile Badami pipeline at that small oil field essentially half-way between Point Thompson and Pump Station One of the Trans Alaska Pipeline System at Prudhoe Bay.

Meanwhile, major maintenance is at the top of the list for any field operator, and this summer Hilcorp did a major "turnaround" project at Prudhoe Bay. The project involved taking Gathering Center-2, or GC-2, on Prudhoe Bay's west end, off-line for period for about a month, which temporarily reduced Prudhoe Bay production by 60,000 b/d. It has since been restored.

The Prudhoe turnaround was a major project, that involved about 125,000 man-hours or labor and 500 people who performed 385 "work items," Donovan told the AOGA conference.

The resulting work will improve gas quality going to the gas plants, upgrade gas dehydration systems will allow more oil to be produced from production pads on Prudhoe's west side.

Hilcorp Corporate Manager of Government and Public Affairs Matt Shuckerow said, "Hilcorp is proud to reach completion of its largest ever turnaround at Prudhoe Bay, which was supported by our team of employees and hundreds of contractors and operators working around the clock this summer. This 5-week planned turnaround was completed safely and ahead of schedule, and underscores Hilcorp's deep commitment to the field."

Hilcorp owns 27.1% of Prudhoe Bay, the portion previously held by BP. ConocoPhillips and ExxonMobil are working interest owners in the field, with 36.5% owned by ConocoPhillips Alaska, 36.4% held by ExxonMobil Alaska. ●

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FINNEX LLC / MUSTANG HOLDING LLC

The sun rises on the Southern Miluveach unit connection to the Alpine pipeline.

Southern Miluveach status unknown

Operator Mustang Holding, a Finnex company, has not reached goal of 4,000 barrels of oil per day — yet

By KAY CASHMAN
Petroleum News Publisher

HARRY BOCKMEULEN

With the 12th plan of development, or POD, due Oct. 2, 2025, little was known about Finnex's progress in the North Slope Southern Miluveach unit on Sept. 25 as the latest Producers magazine was headed to press.

The company's goal in its 11th POD filed Oct.2, 2024, was to bring more wells online and get daily oil production to 4,000 barrels.

The most recent production numbers supplied by the Alaska Oil and Gas Conservation Commission, or AOGCC, for July 2025 showed that goal had not been reached.

The following three wells were online in July 2025:

•North Tarn 1A produced 13,902 barrels in July for 31 days at an average of 448.45 barrels per day.

•M-018 produced 15,831 barrels in July for 23 days at an average of 688 bpd.

•M-03A produced 1,732 barrels in July for 22 days at an average of 78.7 bpd.

All production was Kuparuk River oil.

The field is operated by Mustang Holding, a Finnex company.

The 11th POD said it was submitted by Mustang Holding on behalf of the working interest owners, specifically Mustang Holding, Mustang Operations Center 1, Mustang Investment Holdings and AVCG.

A phone message to Harry Bockmeulen, listed as the registered agent in Anchorage in last year's Producers magazine (per paperwork submitted to the State of Alaska by Mustang Holding) was not returned; but to be fair he was given only two days to meet our deadline.

Mustang Holding LLC

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The Southern Miluveach unit, or SMU, began continuous production in December 2024, producing one day each month, December through February. All production came from the North Tarn-1A, the discovery well.

The SMU lies between the Kuparuk River and Colville River units.

Unit history

The SMU was formed on March 31, 2011, and currently contains five tracts covering approximately 8,960 acres.

On Dec. 4, 2020, Alaska's Division of Oil and Gas approved Mustang Holding as operator of the SMU, after the previous operator and field developer Brooks Range Petroleum Corp. defaulted on its loan agreement with the Alaska Industrial Development and Export Authority, or AIDEA.

Despite the default initiated by AIDEA, Brooks Range was the first small independent to bring an oil field online on Alaska's North Slope, producing its North Tarn-1A well from the Kuparuk River pool for one month in 2019, a total of 10,999 barrels over 23 days.

Mustang Holding was a wholly owned subsidiary of AIDEA, but ownership of Mustang passed to Finnex on Oct. 27, 2023. (Specifically, Division of Oil and Gas Director Derek Nottingham approved change of control to Finnex on Feb. 29, 2024, with an effective date of Nov. 1, 2023.)

The most significant work done in 2024 during the 10th POD was the successful drilling and completion of the M-03A and M-01B wells. Additionally, the North Tarn-1A well that was completed in 2012 was prepared to return to production.

Oil production from the SMU began flowing into the Alpine Pipeline on New Year's Eve, Dec. 31, 2024, Bockmeulen told Petroleum News that day.

During the 10th POD period, and continuing into the 11th POD period, the company reported that early process facilities, or EPFs, were being refurbished when possible, and new equipment was being installed as necessary.

The Kuparuk oil pool in the SMU is a continuation of Kuparuk C and Kuparuk A sands "adjacent to the southwest portion of the Kuparuk River Unit," Mustang Holding told AOGCC.

Phase 1, which was completed in the 10th POD period, included re-installation of the production facilities, re-entering existing wells, reconnecting the Mustang Pipeline and returning the field to production.

Additional wells were to be drilled in Phase 2 to keep production in the target range of 4,000 barrels per day, and were to include expansion of waterflood operations, Mustang Holding told AOGCC.

Depending on results from earlier phases, additional wells were to be drilled to bring the total to as many as 11 horizontal or vertical producers and 10 horizontal or vertical injectors. The company said the EPFs would be "debottlenecked or replaced by additional facilities modules if warranted by longer term production results, reservoir performance, and potential third party or multi-horizon Mustang field development." ●

Editor's note: Watch for news on the status of the SMU in Petroleum News, assuming the 12th POD is filed on Oct. 2, 2025, as scheduled.

Contact Kay Cashman at publisher@petroleumnews.com

Barrow gas field growth possible

Far north natural gas fields entering fifth decade of local use; could grow at a cost

By ERIC LIDJI
For Petroleum News


JOSIAH PATKOTAK

The Barrow Gas Transfer Act of 1984 might be the most underappreciated piece of federal legislation in Alaska oil patch history. Although rarely discussed today, the law changed the way one Alaska community accessed natural resources for local benefit.

The Naval Petroleum Reserves Production Act of 1976 is best remembered today for transferring the National Petroleum Reserve-Alaska to the Department of Interior and launched a second wave of exploration in a large tract of North Slope property. The statute also required the Department of Interior to supply gas to Utqiaġvik at fair rates.

Once the federal NPR-A exploration program was finished in the early 1980s, the Barrow Gas Transfer Act was proposed to "get Interior out of the utility business by transferring the gas fields and facilities to that village," according to a 1984 memo from John Roberts, who was a White House Counsel at the time. In the memo, Roberts argued that the move essentially privatized a government function, consistent with administration policy.

Shepherded through Congress by Rep. Don Young and Sen. Frank Murkowski, and signed by President Ronald Reagan in July 1984 amid a presidential campaign, the law gave 19 wells in the three Barrow gas fields and associated subsurface rights to the North Slope Borough. As much as $30 million in appropriated exploration funds would be redirected to the North Slope Borough to cover maintenance activities at the field.

The bill also gave associated sand and gravel rights to the Ukpeagvik Inupiat Corporation. And the law made various changes to existing statutes and regulations to give those entities the ability to produce from existing wells and to expand development.

While one can argue whether transferring gas fields from federal to local control constitutes "privatization," the bill effectively moved the project off the federal books and created a model for local control of energy resources — a perpetual Alaska subject.

The federal government discovered the Barrow gas fields as part of post-war exploration campaigns in the National Petroleum Reserve-Alaska to improve domestic energy security. With the 1984 transfer, the South Barrow, East Barrow and Walakpa fields have since provided affordable and predictable energy for the city Utqiaġvik for decades.

Even with these benefits, the full impact of the legislation remains unfulfilled. The law empowered the North Slope Borough to deliver natural gas to surrounding villages.

Utqiaġvik had nearly 3,000 people when the law passed, while the villages of Wainwright and Atqasuk combined for some 600 people. Today, Utqiaġvik has more than 5,000 people and the other two cities combined have nearly 1,000 people. Adding the village of Point Lay could potentially bring another 350 or so customers onto the grid.

North Slope Borough

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TOP ALASKA EXECUTIVE: Mayor Josiah Patkotak

In its most recent comprehensive plan looking forward through 2039, the North Slope Borough noted this opportunity. "Developing pipelines from Utqiaġvik to nearby communities of Atqasuk, Point Lay, and Wainwright is consistent with the Barrow Gas Field Transfer Act and would provide a sustainable source of energy," the report wrote.

In its most recent comprehensive plan looking forward through 2039, the North Slope Borough noted this opportunity. "Developing pipelines from Utqiaġvik to nearby communities of Atqasuk, Point Lay, and Wainwright is consistent with the Barrow Gas Field Transfer Act and would provide a sustainable source of energy," the report wrote.

Of course, all North Slope construction is easy to describe and hard to execute. Extending the current Utqiaġvik grid to include Atqasuk, Wainwright, and Point Lay could require perhaps 250 miles of pipeline, costing hundreds of millions or even billions of dollars.

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

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

In terms of cost, a pipeline system along the coastline would be several orders of magnitude greater than the 2011 program but could potentially yield wide benefits.

Beyond the direct assistance to nearly 1,350 people living in these remote communities, a regional pipeline system could improve the economics of development in the National Petroleum Reserve-Alaska by pushing the existing grid far beyond its western extent.

A half-century of step-out development on the North Slope has the pipeline grid to the Greater Mooses Tooth unit. Hundreds of miles of NPR-A lie beyond it.

Through the decades, companies have drilled promising wildcats

in western Alaska, only to abandon the projects in the face of the impossible economics of remote Arctic development.

With a pipeline system connecting villages along the Chukchi Sea coastline, step-out development could potential proceed in two directions through the NPR-A.

South Barrow

The U.S. Navy discovered the South Barrow field in 1948. Drilling continued through 1987 with 13 new wells and one deepened well, according to the Alaska Oil and Gas Conservation Commission.

The field came online in November 1981 at 3.5 million cubic feet per day and continued consistently from 1950 through 1990, at which point operators began to suspend production sporadically.

The field was shut-in with increasing regularly through the 2000s, often being used only to increase supplies in winter.

South Barrow experienced dramatic production swings in recent years: 56.1 million cubic feet in 2020, 99.3 mmcf in 2021, down to 37.5 mmcf in 2022, up to 61.4 mmcf in 2023, down to 49.7 mmcf in 2024. AOGCC reports suggest the field has been offline since June 2024.

Cumulative production at South Barrow is more than 24.2 billion cubic feet, according to the AOGCC. Early forecasts had estimated 32 billion cubic feet in lifetime production.

East Barrow

The U.S Geologic Survey discovered the East Barrow field in 1974. Drilling continued through 1990, with eight wells total, followed by the 2011 rejuvenation campaign.

The East Barrow field has also reported some dramatic production swings in recent years: 139.1 mmcf in 2020, down to 47 mmcf in 2021, up to 99.3 mmcf in 2022, and down to 83.1 mmcf in 2023. The field was taken offline in mid-2023, according to the AOGCC, but came back online in December 2024 and produced 73.3 mmcf through June 2025.

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

Walakpa

Working under a U.S. Navy contract, Husky Oil discovered the Walakpa field in the 1980s. The field was included in the 2011 rejuvenation campaign.

Walakpa is the most extensive and productive of the three Barrow gas fields, producing from 11 wells.

The Walakpa field produced some 1.45 billion cubic feet of natural gas in 2024, up from 1.34 bcf in 2023, 1.388 bcf in 2022 and 1.413 bcf in 2021, according to the AOGCC.

Cumulative production through June 30, 2025, was more than 41.4 billion cubic feet.

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

Contact Eric Lidji at ericlidji@mac.com

Santos says first oil draws closer

As of Aug. 27, 2025, Pikka Phase I development was 91% complete, on 22nd well

By KAY CASHMAN
Petroleum News Publisher


BRUCE DINGEMAN

On Aug. 27 mid-morning Alaska-time, Santos Ltd. hosted a live webcast providing an overview of its half-year 2025 results. Led by Santos Managing Director and CEO Kevin Gallagher, the webcast revealed the latest news about the company's Pikka Phase 1 development on Alaska's North Slope.

Gallagher said the project is "progressing well" and that Santos has brought first oil guidance forward from mid-2026 to first quarter 2026, with the ramp-up to plateau of 80,000 barrels per day expected in the second quarter 2026.

"This is another outstanding example of Santos' self-execution project delivery model in action," Gallagher said. "The pipeline was completed a year ahead of schedule and the challenging logistics of river-lifting key processing modules from Canada and barging the seawater treatment plant from Indonesia have been executed flawlessly. Our drilling and completions team have just finished the 21st well, the first combination well with a 10,000-foot-long horizontal section that replaces two wells with one single well."

Combination wells together with "deployment of other innovative drilling technologies and techniques are delivering real cost savings and faster job completion times," he said.

Santos

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"This represents a significant value upside opportunity for future developments in Alaska. We're now drilling the 22nd well, which will be the longest well in the field with an expected total depth of 27,000 feet," Gallagher said.

Six wells have been "flowed back" in 2025, including three producers, bringing average expected flow rates per well to 7,000 barrels per day at start-up.

KEVIN GALLAGHER

AOGA presentation

At an Aug. 27, 2025, presentation to AOGA in Anchorage, Pete Laliberte, Santos vice president business development, said all major equipment is now onsite at its Pikka Phase I project.

"This is our core development area, so when we sanctioned Pikka Phase I, we sanctioned it in this core development area with our partner Repsol."

Laliberte said his colleague Mark Ireland likes to say, 'in this core area we have three Pikkas.'

"I think that we've got the one Pikka development that we're doing right now, but we also have a unit called Horseshoe and a unit called Quokka," Laliberte said.

"In Quokka we're drilling another appraisal well this winter" and in the Quokka and Horseshoe units "we see …the potential for two more Pikkas."

In other words, Santos has much more to come on the Slope.

Pikka Phase 1 is going to be developed on some 17,000 acres of land, 1% of the total Santos leasehold on the North Slope, Laliberte said, adding, "So we have a huge amount of running room and this is exactly what our subsurface team is looking at."

"We've also got a major discovery in Lagniappe in the eastern North Slope and that's with our partners, APA Corporation and Armstrong," he said. "And then finally we've got a big NPR (National Petroleum Reserve-Alaska) position -- probably a little bit longer term."

Ahead of curve

Santos is ahead of the curve at Pikka. It has announced that first oil will be in first quarter of 2026 rather than midyear as originally anticipated.

"We've been drilling since June of 2023, so after starting in June 2023 we're on the 22nd well -- now this is going to be the longest -- about 27,000 feet," he said. "So really an incredible achievement."

End of 2025?

In March 2025, Santos Executive Vice President and President Alaska Bruce Dingeman said the company was in a good position to accelerate first oil to the end of 2025. This, he said at the time, will be "dependent on logistics and weather allowing for the mobilization of key production models by barge up the Hay River."

All the modules made it to Alaska in August 2025, so it remains to be seen whether end of 2025 or first quarter 2026 will be the ultimate first oil date.

XRG acquisition canceled

The non-binding, indicative proposal announced on June 16, 2025, by a consortium led by XRG P.J.S.C., a subsidiary of Abu Dhabi National Oil Company and including Abu Dhabi Development Holding Company and Carlyle (the XRG Consortium), to acquire 100% of the issued shares of Santos Ltd. via a cash scheme has been withdrawn by the consortium.

Pikka Phase 1 is going to be developed on some 17,000 acres of land, 1% of the total Santos leasehold on the North Slope.

On Sept. 15, 2025, the Santos Board advised the XRG Consortium that Santos expected to enter into a binding SIA (scheme implementation agreement) at the agreed offer price of US$5.63 if a binding proposal was received from the XRG Consortium on acceptable terms on or prior to Sept. 19, 2025.

In response the XRG Consortium notified the Santos Board of its decision to withdraw its proposal and not proceed with the transaction.

The XRG Consortium said it had not found anything in due diligence that would lead it to withdraw its indicative proposal.

The consortium confirmed that it maintains a positive view of the Santos business and has respect for the management team.

The Santos Board had expressed its concern to the XRG Consortium about delays in agreeing to the SIA. The consortium would not agree to acceptable terms that protected the value of the potential transaction for Santos shareholders, Santos said.

Further, under the SIA the XRG Consortium would not agree to an appropriate allocation of risk between it and Santos shareholders. This included the obligation of the consortium to secure regulatory approvals and the provision of a reasonable commitment to the development and supply of domestic gas. ●

Contact Kay Cashman at publisher@petroleumnews.com

Badami oil production continues to climb

Glacier/Savant's Eastern North Slope unit output up, East Pad construction on track to begin summer 2026

By KAY CASHMAN
Petroleum News Publisher

DAVID PASCAL

Savant Alaska, a Glacier Oil and Gas company, is planning to drill an exploration well from the Badami Main Pad during the 2025-2026 ice road season into a new Killian reservoir sand.

This well is expected to prove-up the extensive Killian play beyond the participating area, or PA, at Badami.

Savant has continued to vet-out recently identified drill targets in the Badami and Killian sands that can be drilled from both the Badami Main Pad and the proposed Badami East Pad.

On May 15, 2025, Savant's 22nd plan of development, or POD, was approved by the Alaska Department of Natural Resources' Division of Oil and Gas. The 22nd POD covers the period from July 16, 2025, through July 15, 2026.

The Badami Unit, or BU, was formed on March 13, 1995, with BP Exploration (Alaska), Inc. (BPX) as the original operator.

Glacier Oil & Gas Corp.

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The BU is located approximately 25 miles west of the Point Thomson Unit and 30 miles east of Deadhorse on the Beaufort Sea Coast. Savant succeeded BPX as operator of the BU in 2012.

As of March 31, 2025, the BU has cumulatively produced 11.283 million barrels of oil. Average daily oil production from the BU between April 1, 2024, and March 31, 2025, was 1,954 barrels of oil per day. This was a 127% increase from 859 bpd compared to the prior 12-month period, mainly driven by bringing online the new B1-33A well.

21st POD work

For its 21st Badami Unit POD, Savant committed to the following:

- Continuing the exploration and development activities for the new Badami and Killian sand prospects;
- Drilling two Badami sand wells from the Badami Main Pad;
- Evaluating additional well workover on the B1-01 Class 1 injection well to expand injection zones;
- Exploring options to convert existing Badami wells to Class I or II injection wells;
- Evaluating targets for a third Killian exploration well;
- Evaluating Killian sand prospects for acreage outside the PA and unit boundary;
- Continuing the evaluation of newly acquired acreage;
- Evaluating B1-14 and B1-21 wells for gas injection/storage and retrieval;
- Continuing well and facility maintenance and optimization;
- Upgrading the control system for the two Badami turbines; and
- Exploring options for restarting the shut-in Grind & Inject, or G&I, facility.

Although Savant initially committed to drilling two Badami Sand wells from the Badami Main Pad, Savant deferred the plan and redirected capital toward the Killian Kennicott B1-33 exploration well. The Kennicott B1-33 well encountered the Badami Sand targets, prompting the need for further evaluation to assess the prospectivity of these targets.

A workover on the B1-01 injection well was also considered economically viable to expand injection zones and support future G&I operations for a multi- well drilling campaign. However, Savant determined that converting the well for single-well use at Kennicott would not be cost-effective and thus postponed the conversion.

Additionally, injection rate testing on the B1-14 and B1-21 wells was not conducted, as operations were focused on the Kennicott program.

Savant successfully completed all other proposed commitments for the 21st POD period.

Badami Unit Production

Date	Produced Oil (bbls)	Produced Gas (MCF)	Produced Water (Bbls)
Jan-23	15580	10886	1029
Feb-23	14106	10305	434
Mar-23	15653	13585	426
Apr-23	15150	8675	384
May-23	17974	10003	610
Jun-23	31215	17107	718
Jul-23	30483	17536	433
Aug-23	29275	18359	297
Sep-23	27091	16460	301
Oct-23	29106	18452	456
Nov-23	27528	15971	402
Dec-23	27899	16661	1134
2023 Total	**281060**	**174000**	**6624**
Jan-24	26865	16202	249
Feb-24	24959	15532	207
Mar-24	26167	16930	145
Apr-24	22551	10854	228
May-24	26753	12392	281
Jun-24	25190	11819	146
Jul-24	25862	15665	224
Aug-24	25346	17517	57
Sep-24	77011	38404	37
Oct-24	118085	54603	28
Nov-24	97696	41027	27
Dec-24	84558	50635	97
2024 Total	**581043**	**301580**	**1726**
Jan-25	72600	48193	86

continued on next page

SAVANT ALASKA *continued from page 51*

22nd POD commitments

For the 22nd POD Savant committed to the following operations:

- Drilling two Badami sand wells from the Badami Main Pad;
- Conducting injection rate testing on B1-14 and B1-21 wells for gas injection, storage and retrieval;
- Conducting Pressure-Temperature, or PT, surveys on B 1-33 and B 1-07 to determine fluid level, reservoir pressure, and reservoir mobility;
- Continuing the exploration and development activities for the new Badami and Killian sand prospects;
- Drilling at least one Killian development well, of the Steller Prospect, from the Badami Main Pad;
- Continuing to refine, characterize, and de-risk the prospects related to the Killian sands outside of the PA;
- Conducting a well workover on the B1-01 Class 1 injection well to expand injection zones;
- Conducting geochemical analysis of Hue Shale oil samples collected from the Bl-33 pilot hole and from produced Killian oil;
- Continuing the evaluation of newly acquired acreage;
- Continuing well and facility maintenance and optimization;
- Advancing plans to construct the proposed Badami East Pad, pending success of its Steller drilling program, with anticipated construction beginning in the summer of 2026;
- Conducting a full overhaul of the Vapor Recovery Unit, or VRU, and its injection gas compressors IGA and IGB;
- Performing an engine core upgrade and control systems enhancements for Solar Turbine B; and
- Reviving on-site gravel mine in preparation for anticipated East Pad construction, road maintenance, and drilling operations support. Additionally, staging ice road construction equipment on the Badami storage pad in preparation for 2025-2026 winter season ice road construction.

Findings and decision

In its findings and decision, the division noted that the public has an interest in "diligent exploration and development" of the State's resources.

The plans set forth in the 22nd POD protect this public interest, division director Derek Nottingham said in his decision, "by maintaining production, drilling two Badami sand wells and at least one Killian development well from the Badami Main Pad, conducting gas injection testing on select wells, performing pressure-temperature surveys, conducting a workover on the B1-01 injection well to expand injection zones, continuing exploration and development efforts for both Badami and Killian sand prospects, continuing well and facility maintenance, conducting facility upgrades such as a full overhaul of the Vapor Recovery Unit and turbine enhancements and advancing plans to construct the Badami East Pad in summer 2026.

The approval is only for a general plan of development. Specific field operations require separate approval under the Badami Unit plan of operations.

The 23rd POD is due on April 16, 2026, 90 days before the 22nd POD expires. ●

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Saluting Alaska's Producers

A new pipeline being pressure-tested before being placed into service on the North Slope.

PHOTO BY JUDY PATRICK

A

B-F

G-M

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Q-Z

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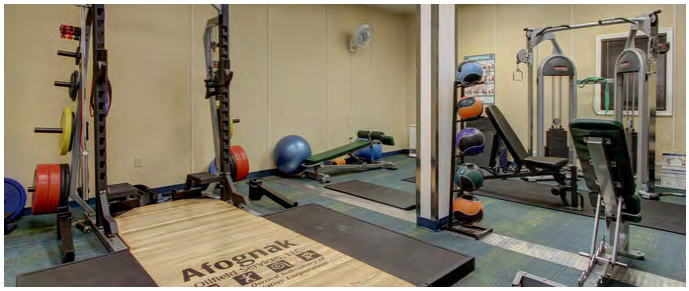

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