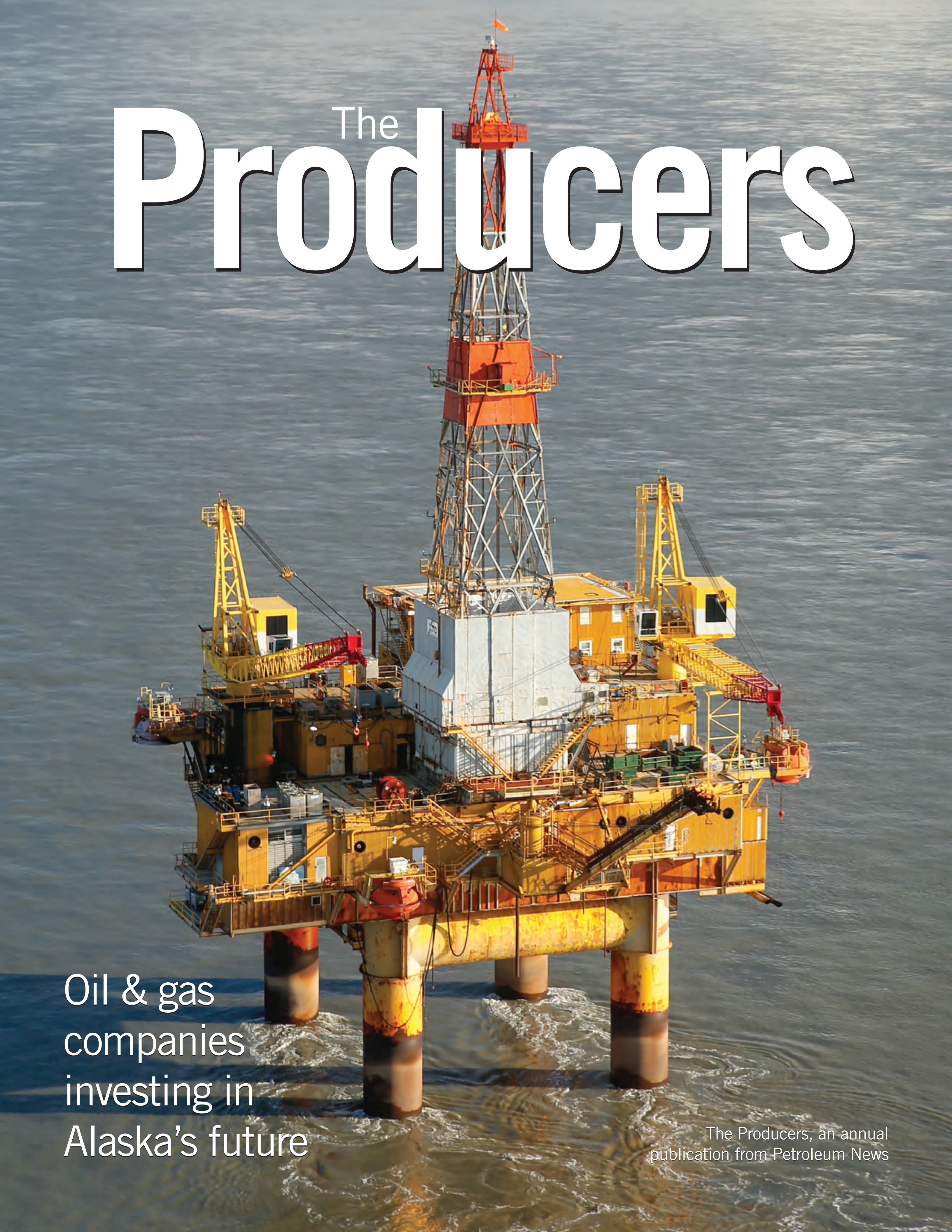
The Producers



Oil & gas companies investing in Alaska's future

The Producers, an annual publication from Petroleum News

WELCOME

One word: uncertainty

Alaska oil patch weathers one of the strangest years in its history.

By ERIC LIDJI
For Petroleum News

The shutdown arrived with summer on its heels. Always resourceful, many companies used the time to conduct maintenance work that would have required shutdowns anyway.

Uncertainty was the key word in the Alaska oil patch in 2020. The business of producing hydrocarbons has always favored those who can stomach an unhealthy amount of uncertainty. But even so, this year made it hard to look ahead.

The emergence of the coronavirus pandemic prompted economic shutdowns around the world, leading to a cliff-like drop in global demand followed by an oil price crash that quickly turned bizarre. Alaska North Slope crude oil traded at a negative price in late April 2020, something few in the oil patch had ever witnessed. The drop in demand led to a drop in production and proration of trans-Alaska oil pipeline throughput.

All told: any plan of development submitted before April was soon irrelevant, or at least contingent. The development forecasts in this edition of The Producers aim to be as complete and accurate as possible, given the impossibility of forecasts at the moment.

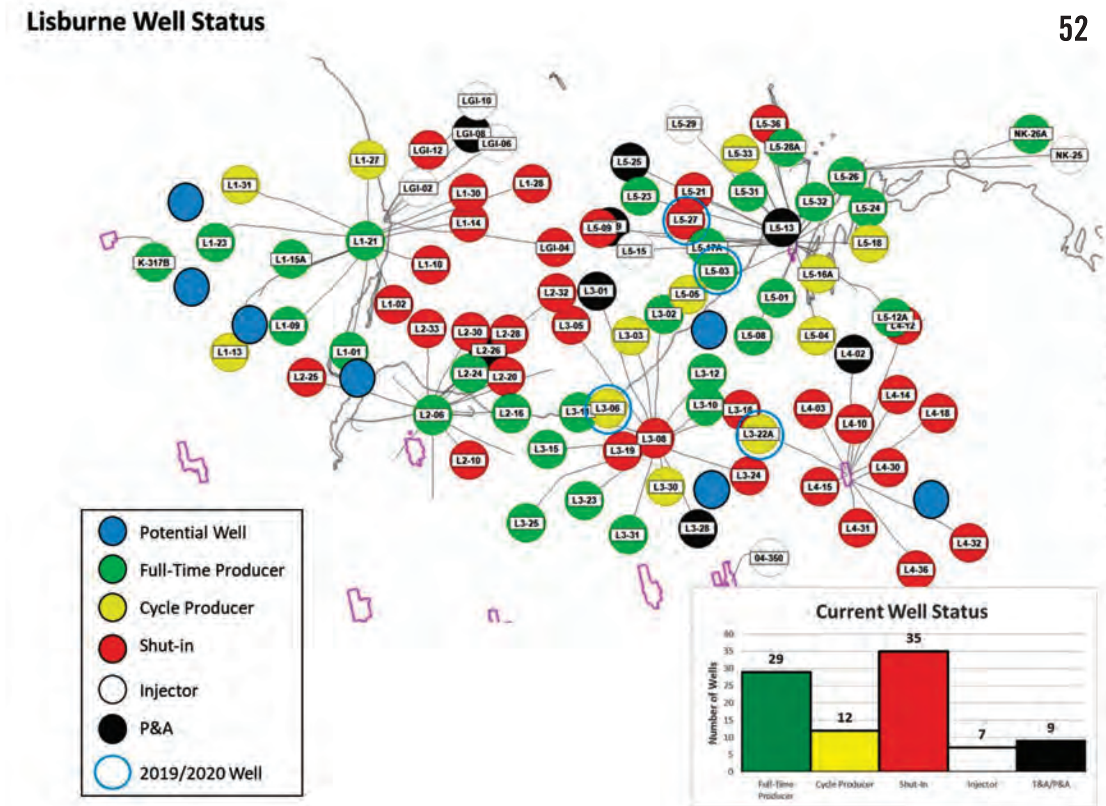
Though felt by all companies, the uncertainty of 2020 impacted different companies in different ways. Size was of course a major factor. Some companies are better prepared to weather long stretches of uncertainty than others. But, interestingly, commodity and basin also seemed to matter. The North Slope fared differently than Cook Inlet, and locally distributed natural gas fared differently than liquids bound for markets outside the state.

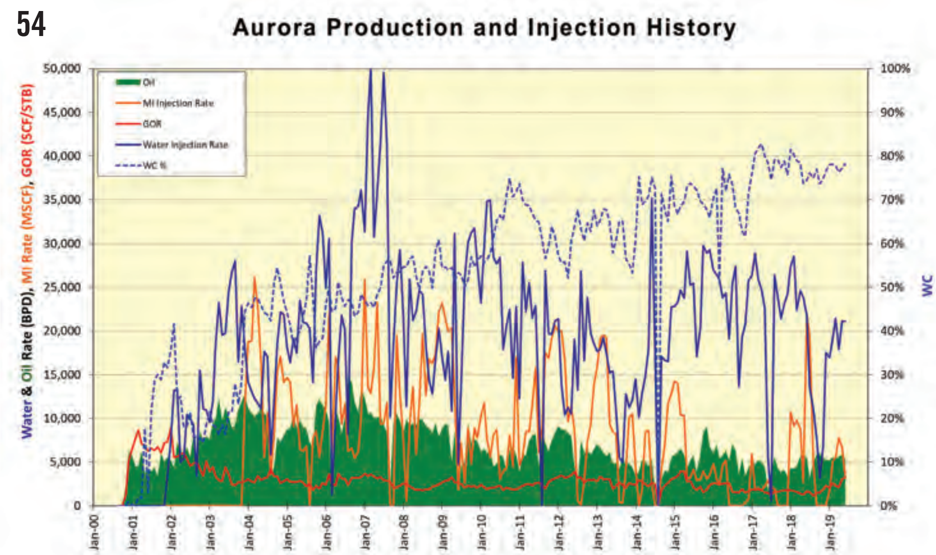
The shutdown arrived with summer on its heels. Always resourceful, many companies used the time to conduct maintenance work that would have required shutdowns anyway.

One shining bit of certainty did emerge from the storm of 2020. After years of rumors and months of behind the scenes work, Hilcorp Alaska LLC, under the Hilcorp North Slope name, became the newest operator of the Prudhoe Bay unit, assuming the title long held by BP Exploration (Alaska) LLC.

The move is historic and promises to be hugely consequential. But of course, even in the best of times, it is hard to predict what might happen in the Alaska oil and gas business. ●

CONTENTS





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MARTI REEVE
SPECIAL PUBLICATIONS DIRECTOR

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PUBLISHER & FOUNDER

KRISTEN NELSON
EDITOR-IN-CHIEF

ERIC LIDJI
CONTRIBUTING WRITER

STEVEN MERRITT
PRODUCTION DIRECTOR

MARY MACK
CHIEF FINANCIAL OFFICER

SUSAN CRANE
ADVERTISING DIRECTOR

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HEATHER YATES
BOOKKEEPER

JUDY PATRICK
CONTRACT PHOTOGRAPHER

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MAILING ADDRESS:
PO Box 231647, Anchorage, AK 99523-1647
Phone: (907) 522-9469
Fax: (907) 522-9583
Email: circulation@PetroleumNews.com
Web page: www.PetroleumNews.com

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On the cover:
Platform "C," originally installed by Shell in 1967, today is operated by Hilcorp. The platform is located in the Middle Ground Shoal Field of Cook Inlet.

Photo by Judy Patrick, courtesy of Hilcorp

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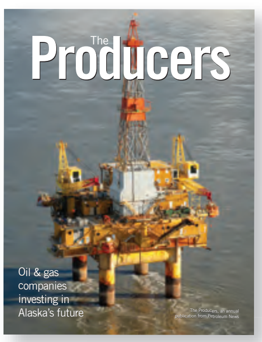

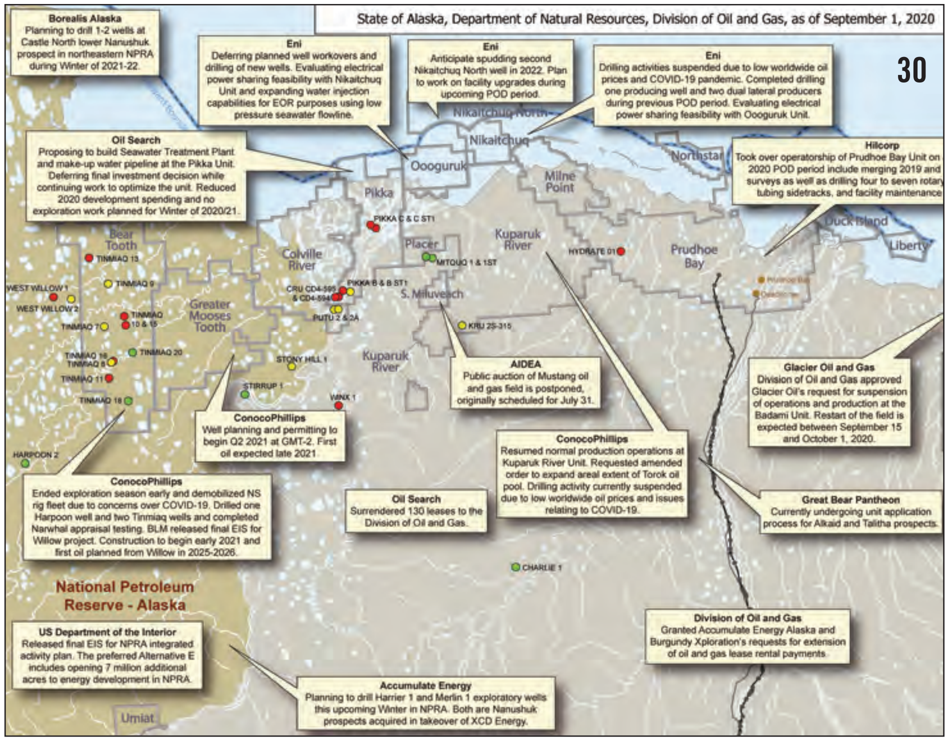

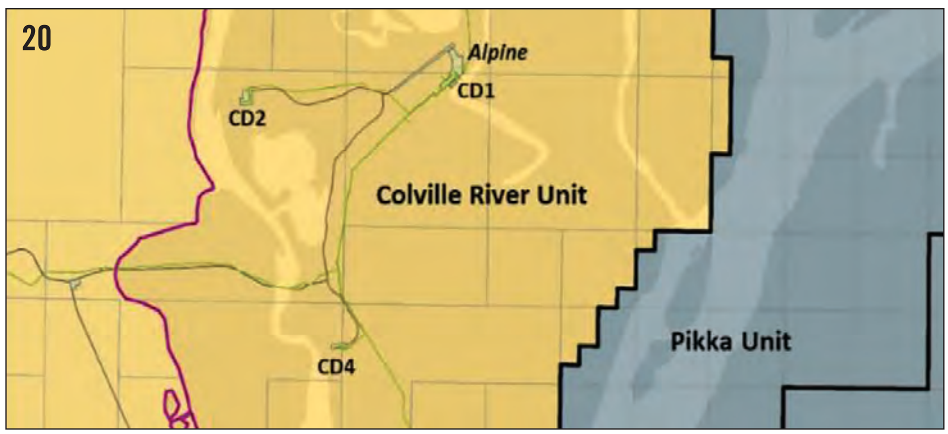

Alaska's oil and gas industry is meeting the challenge

By CORRI A. FEIGE

Commissioner, Alaska Department of Natural Resources


CORRI FEIGE

If there's one thing folks in the oil and gas business can be sure of … it's that there's actually very little you can ever be sure of!

Alaska's petroleum industry operates in a complex, interdependent system often buffeted by powerful and shifting economic and technological winds. Success goes to those who can improvise and adapt to overcome the challenges of this ever-changing environment.

In the past year, the industry and the public agencies that regulate and serve it have faced unprecedented challenges from the global COVID-19 pandemic. As commissioner of the Alaska Department of Natural Resources, I am proud of my team for successfully meeting the challenge of implementing Gov. Mike Dunleavy's priorities to keep our state open for business, protecting the people, infrastructure and systems that produce oil and gas in the best interest of the Alaska people.

DNR has been vigilant in protecting the professionals in leasing, permitting and compliance, royalty accounting, and other functions that ensure the industry operates safely and efficiently.

To reduce the risk of contagion, nearly 70% of the Division of Oil and Gas workforce is now working remotely, and all employees have embraced protocols for social distancing and hygiene.

We have conducted oil and gas lease sales virtually, made supporting information more easily available online, and made other adjustments to reduce potentially hazardous face-to-face contacts wherever possible. At the same time, every DNR office remains open to serve the public at traditional office locations.

Adjust lease rental payment schedules

COVID-19 impacts have not only burdened operations for both government and industry, they have also reduced global demand for oil, resulting in a price collapse that has only recently stabilized, albeit at lower prices. In response, DNR has assisted our explorers and producers by adjusting lease rental

continued on page 10


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FEIGE *continued from page 8*

payment schedules, continuing to process applications for new units, conducting new lease sales, and maintaining predictable, stable regulatory policies.

While dealing with COVID, DNR has also been working to facilitate the durability of Alaska's oil patch to anchor not only legacy producers, but also the independent operators representing the next generation of players in Alaska's oil industry. The best example of this is BP's sale of its Alaska assets to Hilcorp.

For nearly a year, the professionals at the Division of Oil and Gas have done outstanding work in analyzing the upstream and midstream portions of the transaction, serving the public's interest well.

Their strict due diligence ensures every aspect of this critical transaction meets the highest standards of accuracy, completeness, and operational and financial capability. Their robust and meticulous analyses are essential parts of the record on which the Regulatory Commission of Alaska will base its final decision on the midstream asset sale.

Lobby feds on major actions

DNR has also continued to push for completion of major federal actions that are critical to the short- and long-term health of the oil industry and the state as a whole. These include the release of the record of decision on the Integrated Activity Plan for the National Petroleum Reserve-Alaska, the first of two scheduled lease sales in the 1002 Area of the Arctic National Wildlife Refuge, and the much-needed modernization of federal environmental permitting process, some 40 years after enactment of the National Environmental Protection Act.

We have conducted oil and gas lease sales virtually, made supporting information more easily available online, and made other adjustments to reduce potentially hazardous face-to-face contacts wherever possible. At the same time, every DNR office remains open.

Given the importance of federal actions to Alaska's oil industry, we are pleased to see efforts to modernize federal environmental permitting through a more coordinated federal process.

The proposed process is very similar to the coordinated approach to project permitting that has been available to Alaska's project applicants through DNR's Office of Project Management and Permitting for many years. A coordinated permitting process creates value by helping large resources projects navigate the complexities of multi-agency permitting.

The work being done at both the state and federal level will pave the way for expanded production and delivery of oil through the Trans-Alaska Pipeline System within the next 10 years. That new production will mean increased revenue to the state in the form of both royalties and taxes, and will extend the operational life of the infrastructure that is the literal backbone of the state's economy and prosperity.

Making sure we can bring Alaska's vast oil resources to market — both the already-identified reserves and those yet to be discovered — protects both our infrastructure and Alaska families by ensuring we have a strong job base and skilled workforce to support those operations. It is a fulfilment of our constitutional obligation to develop the state's natural resources for the benefit of Alaskans.

Support major projects

The petroleum industry will always be important to Alaska.

We can also strengthen and diversify our economy by supporting large new infrastructure projects. One of the most exciting is the Alberta-to-Alaska, or "A2A" rail project, and I was encouraged at President Trump's announcement that he will issue the Presidential Permit critical to its success. This project would help reduce Alaska's historic geographical isolation from larger global markets, opening up new opportunities for Alaska's products and resources to "go global."

I commend the men and women of Alaska's oil and gas industry for their strength of conviction and dedication to purpose in keeping Alaska's oil flowing during the difficult months of the global pandemic. Smaller workforces, longer hitches, and ever-evolving roles and responsibilities take their toll, but Alaska's oil and gas professionals maintained a stellar environmental and safety record throughout these very trying times.

The successful response to a global pandemic and all the problems that have come with it demonstrates the skill of our people, the value of our resources and their impact on our economy, and the positive future of our state. ●


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AIX Energy making the most of Kenai Loop assets

Small independent focuses on gas supply agreements and infrastructure upgrades

By ERIC LIDJI
For Petroleum News

Under the operatorship of AIX Energy LLC over the past six years, the Kenai Loop field has become a disciplined and predictable operation without much talk of future drilling.

"It is AIX's objective to maximize field recovery and net present value by aligning production capacity with commercial opportunities," the company told state regulators in its sixth plan of development, filed earlier this year and running through May 6, 2021.

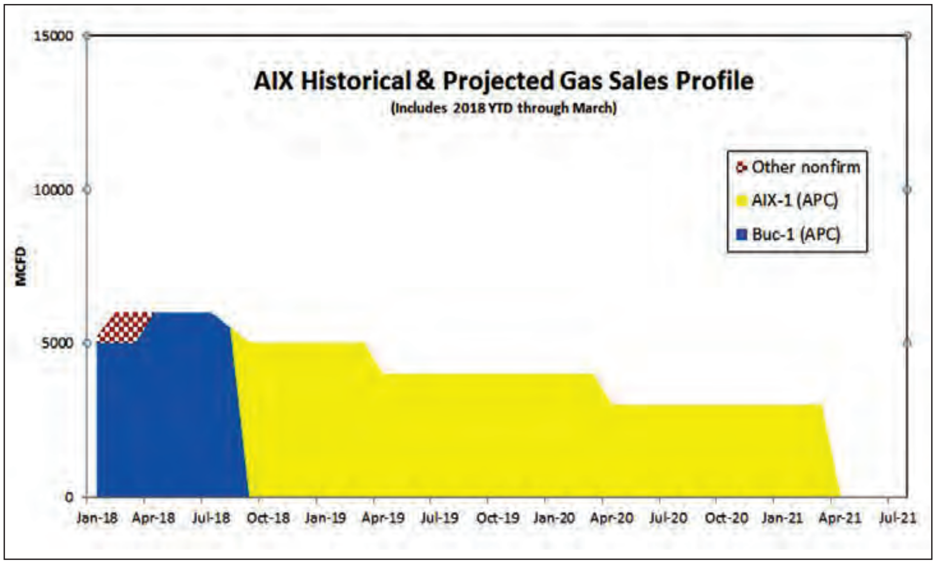
The Texas-based AIX Energy acquired the small Cook Inlet natural gas field in 2014, as part of the bankruptcy proceedings of the Australian independent Buccaneer Energy.

The styles of the two companies have been starkly opposed. Buccaneer Energy was ambitious and outspoken, undertaking many projects simultaneously and promoting its efforts internationally. AIX Energy has been disciplined and quiet. The company is still working with the wells it inherited from Buccaneer and rarely issues press releases.

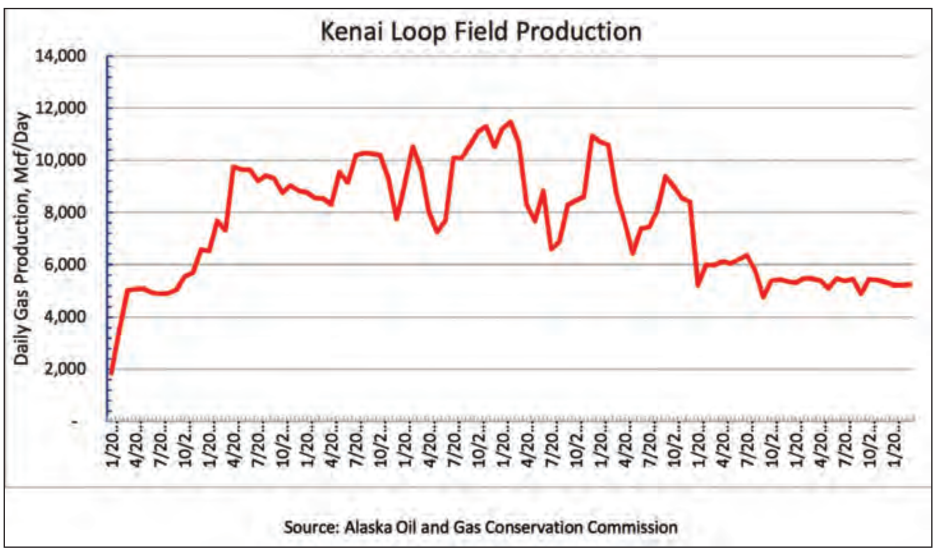
The two biggest development projects that AIX Energy has undertaken to date at Kenai Loop have involved maintenance. The company decommissioned an unused drilling pad in June 2017, and it installed a natural gas compressor system in the winter of 2018.

The result of this approach has been relatively stable production rates since late 2018, after years of notable seasonal production swings. In the year ending June 1, 2020, the field produced nearly 1.9 billion cubic feet or nearly 5.2 million cubic feet per day, according to the Alaska Oil and Gas Conservation Commission. That was down slightly from nearly 2 billion cubic feet or more than 5.4 million cubic feet in the year prior.

Through June 1, 2020, Kenai Loop has produced more than 23 billion cubic feet of natural gas and 2,962 barrels of condensate from the field, according to the AOGCC.



AIX ENERGY INC.



AIX ENERGY INC.

Gas supply agreements

In addition to physical field assets, AIX Energy acquired an existing gas sales agreement with Enstar Natural Gas Co. The inherited agreement ran through into fourth quarter 2018 and was replaced by a new agreement between AIX Energy and Enstar Natural Gas.

The current gas sales agreement between AIX Energy and Enstar Natural Gas runs through March 2021. It allows for gradually decreasing volumes of firm supplies each year. AIX Energy was required to supply 1.37 billion cubic feet between July 1, 2018, and March 31, 2019, and 1.464 billion cubic feet between April 1, 2019, and March 31, 2020. The current and final year of the contract allows AIX Energy to supply between 1.095 billion cubic feet and 1.825 billion cubic feet between April 1, 2020, and March 31, 2021.

In addition to the firm contract, AIX Energy has "multiple contracts which are likely to lead to additional non firm sales in 2020," according to its most recent plan of development. Describing its marketing goals for the upcoming year, the company said it would "continue to pursue value added, near term gas sales opportunities (to align with existing and future production capacity), while maintaining pricing discipline."

Compression soon?

Before filing for bankruptcy, Buccaneer Energy drilled four wells at Kenai Loop.

Today, the field is producing from the Kenai Loop No. 1-1 discovery well and the Kenai Loop No. 1-3 well. The Kenai Loop No. 1-2 well was a dry hole and is temporarily suspended, although AIX Energy may convert it into a disposal well in the future.

The Kenai Loop No. 1-4 well produced from the same reservoir as the discovery well and was never tied into the production system. The well is used to monitor reservoir pressure.

AIX Energy began compression at the KL 1-3 well in early 2019 and expects to begin compression at the KL 1-1 well "when required." Although the company has no drilling plans on the horizon, it is evaluating a plan to connect KL 1-4 to the system "to provide increased deliverability, to provide redundancy to meet firm gas sales obligations and to possibly increase ultimate recovery." The company is also evaluating a plan to recomplete some of the production wells at the field to provide additional deliverability.

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The Kenai Loop field includes State of Alaska, Alaska Mental Health Trust Office and Cook Inlet Region Inc. leases. AIX Energy met with CIRI representatives earlier this year to discuss exploration opportunities, but the parties have not announced any plans. ●

Contact Eric Lidji at ericlidji@mac.com

AIX Energy LLC

COMPANY HEADQUARTERS:
2441 High Timbers Dr. 120,
The Woodlands, TX 77380

EXECUTIVE INVOLVED IN ALASKA:
Ronald C. Nutt, chief operating officer

EXECUTIVE INVOLVED IN ALASKA:
Randy A. Bates, member manager

TELEPHONE:
832-813-0900

Challenges and opportunities for Amaroq

Nicolai Creek making gradual comeback, but big threats remain

By ERIC LIDJI
For Petroleum News

Amaroq Resources, LLC

COMPANY HEADQUARTERS: Sugar Land, Texas
TOP EXECUTIVE: G. Scott Pfoff, president & CEO
ALASKA OFFICE: 406 West Fireweed Ln., Anchorage, AK 99503
TOP ALASKA EXECUTIVE: Lyle Savage, field operations manager
TELEPHONE: 907-240-8809

The future of the Nicolai Creek unit will be decided by the outcome of two pending threats and one possible opportunity, according to operator Amaroq Resources LLC.

The company acquired the unit in early 2018, as part of the bankruptcy proceedings of former operator Aurora Gas LLC. (Amaroq Resources was previously known as Aurora Exploration LLC but was unrelated to Aurora Gas, despite shared names and histories.)

As a result of renewed investment through maintenance and upgrade activities, Nicolai Creek production doubled during the first year under the guidance of Amaroq. But the aging gas field is perpetually in need of investment to remain economically viable.


SCOTT PFOFF

In its 2020 plan of development for the unit, Amaroq estimated that Nicolai Creek would become uneconomic in late 2020 or early 2021 without new investment. Amaroq appears to have forestalled that prediction but remains concerned about future work.

The company removed that forecast from its 2021 plan — a response to its investments.

The unit produced 92.881 million cubic feet of natural gas in the year ending Aug. 31, 2020, with 69% coming from the Nicolai Creek Unit No. 9 well and another 20% coming from the Nicolai Creek Unit No. 11 well, according to Amaroq.

Water conversion

Without a better method for disposing produced water, the unit will soon become uneconomic, according to Amaroq. The company approached the problem by converting the depleted Nicolai Creek Unit No. 1B production well into a water disposal well.

Nicolai Creek Unit No. 1B was drilled in 2002 as a sidetrack of Nicolai Creek State No. 1A, which itself was a sidetrack of the original Nicolai Creek State No. 1 well. The well had cumulatively produced some 581.5 million cubic feet by September 2019.

The company began the conversion process by testing the injection potential of the well, followed by permitting activity to oversee disposal work. The Alaska Oil and Gas Conservation Commission issued a disposal injection order in late January 2020.

Amaroq converted the well during the spring and early summer. It deemed the well ready for injections by mid-June. The company was installing surface injection facilities as of late September 2020, when it submitted its 2021 plan of development to the state.

Under its proposal, Amaroq would inject non-hazardous Class II waste from other Nicolai Creek wells into two zones in the Tyonek between 2,307 and 2,370 feet measured depth. The company would not accept similar wastes from other operators in the area.

The company acquired surface injection facilities used at the Aspen No. 1 well and relocated the infrastructure to the Nicolai Creek well pad. The facilities are designed to handle approximately 200 barrels per day with maximum volumes of some 364 bpd.

The injections would void an estimated 34.2 million cubic feet of remaining recoverable reserves in the Carya 2-1.2 sand. But the company would still be able to access zones deeper in the well in the future because of the geology and well design at the unit.

In hearings for the disposal well, Amaroq estimated 1.8 billion cubic feet of proved reserves at the unit, of which some 1 billion was allocated to the Nicolai Creek Unit No. 10 well. That well is expected to produce between 100 and 200 barrels of water per day. The lack of a disposal option would threaten these proved reserves, according to Amaroq.

Given the relationship between the two wells, Amaroq suspended operations at NCU No. 10 until the water disposal issue was resolved. According to AOGCC production records, the suspension began in mid-2018 and remained in effect throughout this past summer.

Amaroq said a gravel pack or rig workover might lead to increased production.

The company attempted a coiled tubing cleanout in mid-2018, leading some of the water production complications now being addressed through the NCU 1B disposal project.

NCU No. 2 and No. 3

Amaroq shut-in the Nicolai Creek Unit No. 2 and Nicolai Creek Unit No. 3 wells as a result of mechanical issues. Both wells would require workovers to resume production.

The company restored the Nicolai Creek Unit No. 2 well to production in June 2020, following three years of inactivity. "The well is produced from time to time, pressure permitting," the company wrote. According to AOGCC records, the well produced 1.867 million cubic feet over 20 production days in June; then 599,000 cubic feet over 11 production days in July; and 561,000 cubic feet over eight production days in August.

The Nicolai Creek Unit No. 3 well is shut-in pending a coiled tubing cleanout using 1.25-inch coiled tubing, which the company said is unavailable in Cook Inlet at the moment.

The Nicolai Creek Unit No. 9 and Nicolai Creek Unit No. 11 well have both been producing consistently following coiled tubing operations in mid-2018 and mid-2019.

Bonding

The second threat is regulatory.

In its most recent plan, Amaroq said that an AOGCC proposal to increase bonding requirements would harm the unit. "If the operator is required to post a $2.4 million bond with AOGCC pursuant to the newly established requirements, the field immediately becomes uneconomic and is likely destined for cessation of operations," Amaroq wrote.

Earlier regulations to insure the cost of plugging and abandoning wells required operators to post a $100,000 bond for single wells. The cost doubled to $200,000 to cover an entire portfolio of wells in the state. The proposed increase would create a graduated scale starting at $400,000 for one well and increasing to $30 million for more than 1,000 wells.

The $2.4 million figure cited by Amaroq would cover the six producing wells at the unit.

The proposal was especially troubling to smaller operators. The AOGCC received reconsideration requests from six companies, including Amaroq. The AOGGC has only approved one of those requests, reducing a proposed $1.6 million bond requirement at the AIX Energy Inc.-operated Kenai Loop field to an earlier $200,000 bond requirement.

The AOGCC made the adjustment because the company had a $950,000 deposit with the Alaska Mental Health Trust land office, in addition to its existing $200,000 bond.

Future investments

The big opportunity is geologic.

"Nicolai Creek Unit has tremendous upside potential for conventional oil and gas, unconventional gas, and storage development," Amaroq wrote in its 2021 plan. "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."

In particular, the company noted the potential of deep oil and natural gas prospects at the Nicolai Creek unit. But it made no plans to explore those prospects at any point in the near future. Apache Alaska Corp. previously acquired rights to those prospects and even acquired 3D seismic information over the acreage in early 2012, before leaving the state.

In a plan of development before the bankruptcy proceedings, Aurora Gas proposed a Nicolai Creek Unit No. 12 well targeting deeper sands in the Beluga and Upper Tyonek, north of current production. ●

Contact Eric Lidji at ericlidji@mac.com

BlueCrest eyes gas as oil declines

Cosmopolitan has increasingly complex oil wells and an advancing gas project

By ERIC LIDJI
For Petroleum News

Blue Crest Energy Inc.

COMPANY HEADQUARTERS: 1320 South University Dr., Ste. 825, Fort Worth TX, 76107
ALASKA REGIONAL ENTITY: BlueCrest Alaska Operating LLC
DIRECTOR INVOLVED IN ALASKA: J. Benjamin Johnson
TOP ALASKA EXECUTIVE: John M. Martinek, president
ALASKA OFFICE: 3301 C St., Ste. 202, Anchorage, AK 99503
TELEPHONE: 907-754-9550
EMAIL: john.martinek@bluecrestenergy.com
COMPANY WEBSITE: www.bluecrestenergy.com

The recent uncertainties in economic markets — and in world oil markets in particular — have favored gas over oil at the Cosmopolitan unit for BlueCrest Alaska Operating LLC.

The company had been planning a series of remarkably complex oil wells at its offshore Cook Inlet unit, located off the coast of Anchor Point, in the southern Kenai Peninsula.

"With the development of the COVID Pandemic in early 2020 and the collapse in the oil markets, BlueCrest put its drilling plans on hold," the company wrote in its 2021 plan of development, submitted to the state in late September 2020. "This pause in drilling has allowed BlueCrest to advance the evaluation of developing the offshore gas reserves."


J. BENJAMIN JOHNSON


JOHN M. MARTINECK

For several years, BlueCrest has been developing Cosmopolitan using increasingly complex well designs intended to improve production while saving both time and money.

Before the coronavirus, the local subsidiary of the Dallas-based independent had been working through the permitting process on a proposed well with 24 distinct laterals.

The proposed well would have combined three of its previously tested eight-lateral "fishbone" wells into a single well. In the "trident" well, BlueCrest would drill one main wellbore from the surface that would then split into three subsurface "fishbone" wells.

The project is as much a regulatory challenge as a technical one. BlueCrest needs to obtain 24 separate drilling permits from the Alaska Oil and Gas Conservation Commission, not to mention a field-wide development plan intended to obviate the need for requesting a series of spacing exemptions for each of the individual lateral wells.

The AOGCC approved spacing exemptions for the H-13XX well and its seven laterals in late February 2019 and issued drilling permits in early March 2019. But in late July 2019, Principal Drilling Engineer Tom McKay wrote to the agency, cancelling the drilling permit for the H-13 well "since we have no current plans to drill this well at this time."

In June 2020, the AOGCC approved updated pool rules for the Cosmopolitan unit allowing BlueCrest to proceed with the 800-foot spacing of the fishbone design, provided that the company does not drill any wells within 500 feet of existing lease boundaries.

In its 2020 plan of development, BlueCrest proposed drilling at least one and possible two of these trident wells in 2020. But by late September 2020, the company had yet to receive all its necessary permits for the first well, let alone a second. In its 2021 plan, the company said that it had delayed the trident project in response to economic conditions.

Instead, BlueCrest said it would "conduct some well work" on the Hansen 1AL1 well over the coming year "to extend its life." The company also said it would "perform Hot Oil treatments" on the H4, H12, H14 and H16A wells, "to maintain production rates."

All additional drilling plans are "dependent upon the current market conditions."

The case for fishbones

Despite its prior administrative challenges, BlueCrest believes that the complex trident design is worth it, especially given the inherent complexities of the Cosmopolitan field — an offshore accumulation accessed from an onshore pad using directional drilling.

"The fishbone wells achieve significantly more reservoir contact and penetration than conventional wells, but we haven't calculated the incremental ultimate recovery; it is substantial," CEO and President J. Benjamin Johnson told Petroleum News in 2019.

"Each fishbone well contacts the same amount of reservoir rock as seven-nine individual horizontal wells, and each trident well should recover the same ultimate reserves as three fishbone wells since the reservoir contact is the same," Johnson said, adding, "so, each trident well provides the same amount of reservoir contact as 21-27 individual wells."

And because each lateral builds off existing surface work, the design saves time — as much as five months for each well, shaving two years for an entire trident, Johnson said.

Trending toward complexity

The development of the Cosmopolitan unit has grown in complexity year by year.

BlueCrest brought Cosmopolitan into production in early 2016 from a well drilled by former operator (and former partner) Buccaneer Energy Ltd. Using its custom-built BlueCrest Rig No. 1, BlueCrest launched a solo development effort in November 2016.

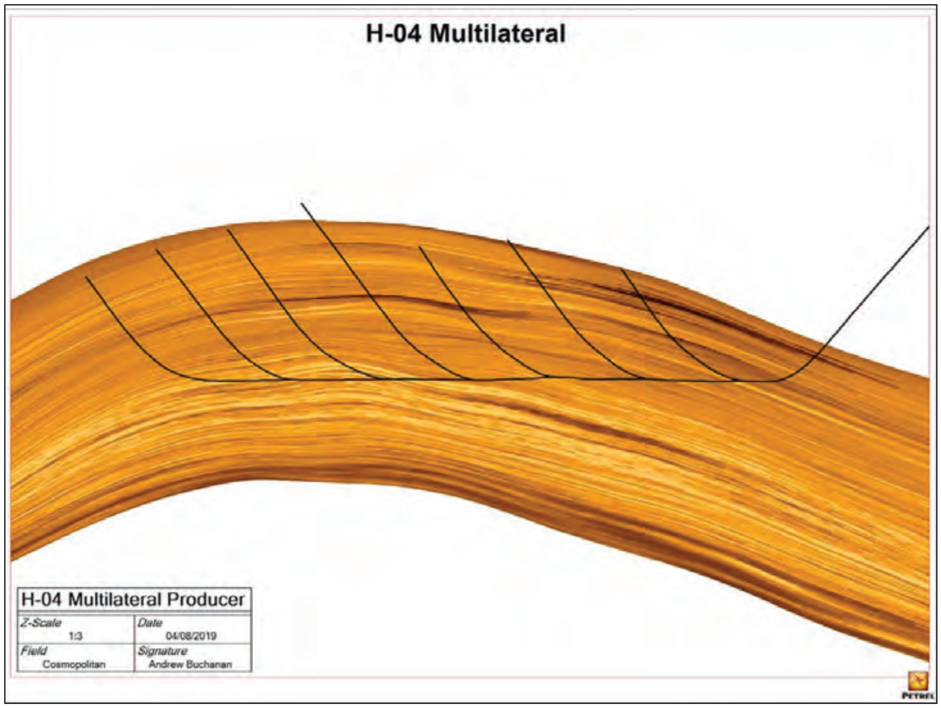
The program began with the H-16 well and H-14 well. Even those initial wells were complex by normal Cook Inlet standards. BlueCrest Rig No. 1 accommodated wells extending three miles out and then a mile-and-a-half down to the reservoir and an additional mile-and-a-half horizontally through the sands, according to the company. The H-16 well, for example, was a 22,810-foot well targeting the Hemlock at 7,089 feet.

The company suspended the rest of its five-well program proposed in early 2017, in response to the state withholding between $75 million and $100 million exploration tax credits.

In the interim, the company re-evaluated its approach.

The following summer, in late July 2018, BlueCrest completed the H-12 well in a “fishbone” design: a “spine” well running through the Hemlock with seven lateral “ribs” drilled every 800 feet up through the Hemlock and Starichkof horizons. These ribs drained to the spine well, which then flows back to shore, where oil is trucked to market.

The company repeated the design later in the year by re-drilling the H-16 well. The H-16A well also used the eight-well fishbone design mimicking an 800-foot spacing array.



BLUECREST ALASKA OPERATING LLC

According to the company, the fishbone wells are particularly well suited for the rock formation at the unit. The consolidated nature of the geology allows wellbores to remain open after drilling, making hydraulic fracturing less effective than the multilateral approach. The wells “have been very effective in maximizing the production from a given area.” The H-16A well came online in December 2018 and accounted for 29% of oil production

continued on next page

BLUECREST *continued from page 17*

and 10% of gas production at the field as of October 2019.

Pleased with those results, BlueCrest drilled the H-4 well into the southern end of the reservoir in early 2019. The well also had the one-well/seven-lateral fishbone pattern.

The company brought the H-4 well online in March 2019. The well accounted for 26% of oil production and 7% of gas production at the field as of October 2019.

Crunching the numbers reveals the cumulative benefits of this approach. BlueCrest has drilled only three wells at the unit, but it's producing from 20 supplemental laterals. And, seen another way, the company has only used five of the 20 slots at its drilling pad.

The program has yielded large increases in oil production. Cosmopolitan produced 1,356.7 barrels of oil per day on average in the year ending July 2019, up from 526.8 barrels per day the year prior. The unit produced 9.64 million cubic feet per day of gas during that year, down considerably from 2.7 billion cubic feet per day the year prior.

In its previous plan of development, submitted late September 2019, BlueCrest proposed a "trident" well design as a way to further improve efficiency at the unit.

What about gas?

While oil remains the immediate focus at the Cosmopolitan unit BlueCrest has been intrigued by the potential of a distinct natural gas field over the oil accumulation.

The company discovered the gas field in 2013, with its initial offshore exploration drilling in the area. The field would require an offshore platform or a jack-up rig.

"We have a large gas resource, proven; it's been tested, but it's expensive to develop," Johnson said. "We're just waiting to see what the market looks like."

The natural gas deposit consists of coalbed methane that has migrated into the Tyonek formation, which lies above all the oil zones in the unit, according to Johnson.

As a result of the delays brought about by the coronavirus and the resulting economic upheavals, BlueCrest also addressed a different natural gas issue by commissioning a mechanical refrigeration unit, MRU, at the unit.

The MRU allows BlueCrest to meet Alaska pipeline quality standards by reducing the dew point of produced natural gas produced in its existing oil stream. The unit removes propane, butane and other liquids not desired for Alaska distribution. The unit can process as much as 35 million cubic feet per day.

"We're not sure exactly what its origin is, but (the natural gas is) intermixed within the oil zones, and so, one way or another it has absorbed natural gas liquids," Johnson told Petroleum News in late September 2020. "Some of our oil wells initially will produce a lot of gas," he added. "We have one well that — we were never able to open it up because we didn't have a MRU that could handle its gas rate — it probably would have made 17 million a day."

The MRU was designed to handle all gas-related needs from existing oil production and could perhaps also handle any additional needs from the proposed offshore development, which is a much drier gas. ●

Contact Eric Lidji at ericlidji@mac.com

Despite pandemic setbacks, ConocoPhillips advances

The decades-long westward march continues for Alaska's reliable producer

By ERIC LIDJI
For Petroleum News


RYAN LANCE

ConocoPhillips Alaska Inc. has generally been a predictable operator.

Over the past generation, the local subsidiary of the large Houston-based independent has been gradually and diligently advancing westward across the central North Slope.

The company operates the Kuparuk River unit, the Colville River unit and the Greater Mooses Tooth unit. Each of these has built upon existing infrastructure to carry North Slope development farther west. (The plans for the undeveloped Bear Tooth and Willow projects continue the trend.)

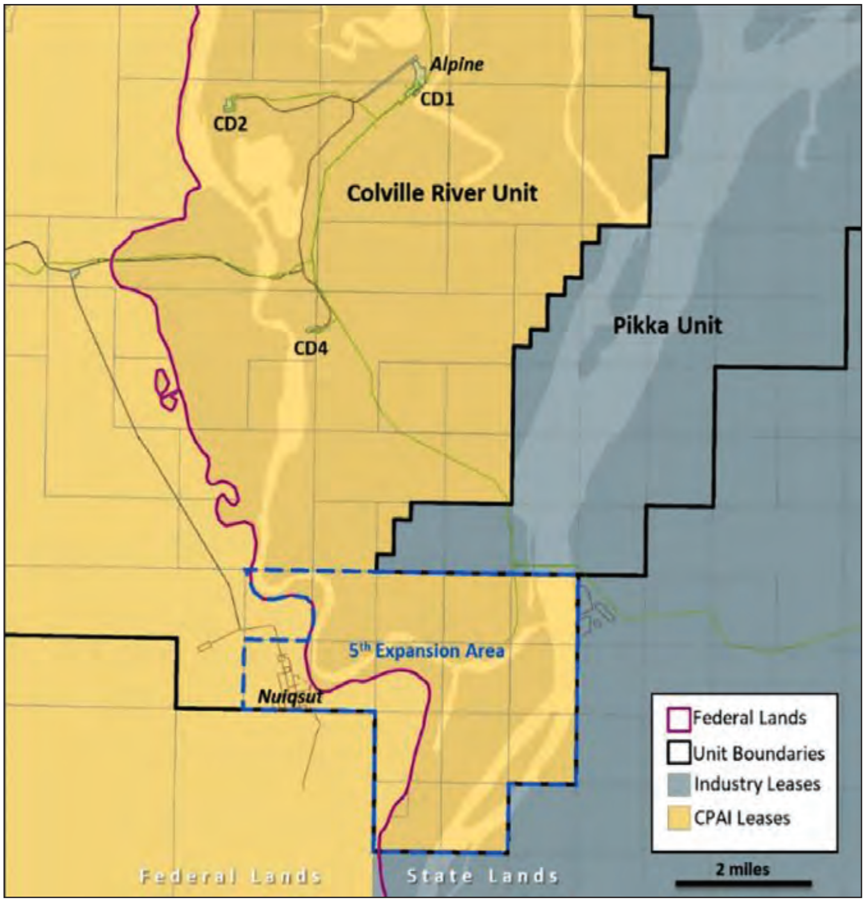
And while long lead times for Alaska projects generally protect the state from the full impact of short-term crises, the uncertainties around the coronavirus pandemic made it hard to predict what work ConocoPhillips would undertake at those three units this year.

The company submitted its Colville River unit plan of development in March, just as the pandemic was upending American life. By the time the company submitted its Kuparuk River unit plan of

continued on next page

ConocoPhillips

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



CONOCOPHILLIPS ALASKA INC.

CONOCO *continued from page 19*

development in early May, it had added pandemic-related disclaimers.

In between those two releases, the company made two major operational decisions.

In early April 2020, it demobilized its North Slope rig fleet. The move was a way to reduce onsite personnel in response to the fast spread of COVID-19 in North America.

And toward the end of the month, the company announced that it would be curtailing North Slope oil production by 100,000 barrels per day for the month of June, in response to low prices as economic shutdowns lead to a decline in the global demand for oil.


JOE MARUSHACK

The company returned to normal operations in July 2020.

When it reported quarterly earnings figures in late July 2020, it said actual curtailments had been about 40,000 barrels per day from the Kuparuk River and Colville River units.

But the disruptions of this year (and perhaps next year, as well) will likely mean little to the ongoing trends at its North Slope properties.

continued on page 22

CONOCO *continued from page 20*

ConocoPhillips is working to extract additional production from the aging Kuparuk River unit, expand production on two fronts at the Colville River unit and study initial production results at Greater Mooses Tooth. A small but significant sign of optimism: in its Kuparuk River plan, the company mentioned infrastructure upgrades intended to support 25 additional years of operations.

The Kuparuk River unit

With the Kuparuk River unit already deep into its mature phase, oil production mostly depends on the extensiveness of development drilling, the diligence of well maintenance and workover activities, and the sophistication of enhanced oil recovery efforts. Even so, ConocoPhillips has continued to find new opportunities by stepping out at the western edge of the unit and by developing viscous oil resources at the eastern edge of the unit.

The second-most productive unit in Alaska produced an average of 102,690 barrels per day in 2019, down 7% from an average of 110,500 bpd in 2018, according to the most recent plan of development for the unit, covering 2019. ConocoPhillips reported declining production at the main Kuparuk oil field and at three of its four satellite fields (Meltwater, Tarn and West Sak). Production increased at the Tabasco satellite field.

Unusually, the company provided few firm drilling or workover commitments for the current development year in the plan of development it submitted to state officials on May 1. The omission is a nod to the uncertainties caused by the COVID-19 pandemic.

KRU: Kuparuk field

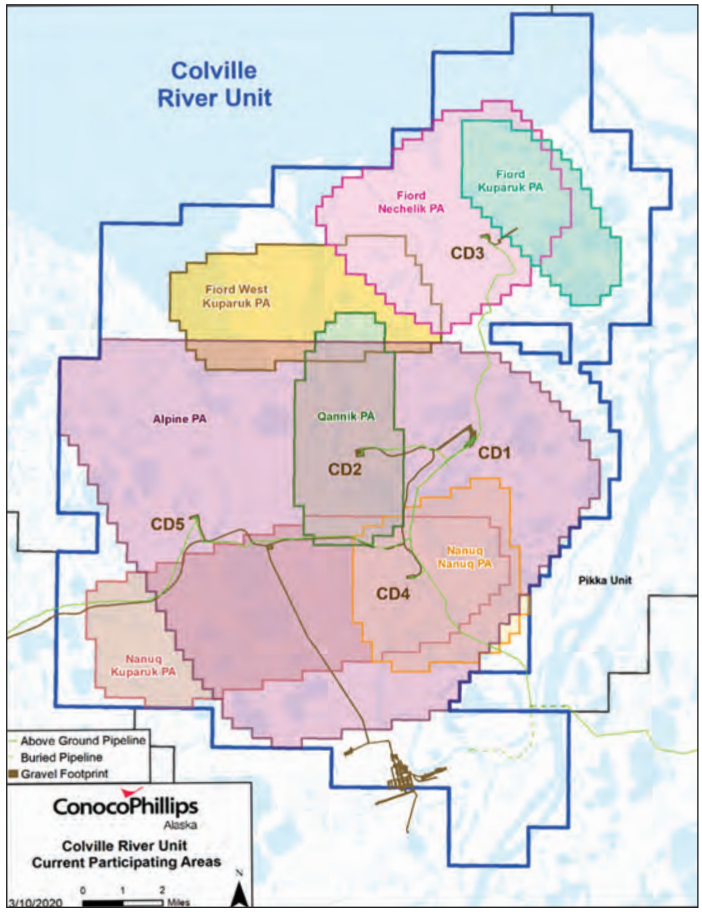
ConocoPhillips is developing the main Kuparuk oil field from 878 active wells — 506 producers and 372 injectors — at 46 drill sites (of which 14 also produce from satellites).

Oil and natural production are declining. The field produced 73,000 barrels of oil per day in 2019, down 7.5% from 79,000 bpd in 2018. It also produced 143 million cubic feet of natural gas per day in 2019, down 22% from 184 million cfpd in 2018.

Those declines came as drilling and enhanced oil recovery activities increased.

A 22-well coiled tubing drilling program in 2019 accounted for some 2,100 bpd of peak gross incremental oil production. By comparison, a 12-well coiled tubing drilling program in 2018 accounted for some 3,300 bpd of peak gross incremental oil production.

The program was spread across the field, but it included a five-well cluster at Drill Sites 1R and 1G targeting the West Sak field. The wells were also geologically diverse, with six targeting the A Sand, 10 targeting the C Sand and one targeting both the A and C sands.



CONOCOPHILLIPS ALASKA INC.

The company also completed five rotary wells in 2019 — three producers and two injectors — but did not provide production estimates. The rotary program included three wells from Drill Site 2M and two wells from Drill Site 3G. Non-rig well work added some 8,000 bpd in 2019, compared to 11,500 bpd attributed to similar projects in 2018.

According to Alaska Oil and Gas Conservation Commission records, ConocoPhillips drilled 14 wells and laterals at the Kuparuk River unit through July 2020 — all before submitting its plan. The current development plan covers the year ending July 31, 2021.

ConocoPhillips began importing natural gas liquids from the neighboring Prudhoe Bay unit in September 2018 to blend with natural gas to create miscible injection.

The outside NGL supplies allowed the company to increase its enhanced oil recovery program at the Kuparuk field at Drill Sites 1B, 1C, 1D, 1E and 2C and to initiate EOR at other sites connected with Central Processing Facility 2. The company switched to field-wide miscible injection in October 2019, which allowed it to conduct EOR activities at drill sites connected with Central Processing Facility 1 and Central Processing Facility 3.

The Kuparuk field received an average of 83 million cfpd of miscible injection in 2019, accounting for some 7,700 bpd. By comparison, the company logged some 9,400 bpd of increased production from an average of 64 million cfpd of miscible injection in 2018.

"Alternative EOR opportunities for Kuparuk are being explored, with laboratory investigation and field testing of promising methods to recover additional resources that are currently considered residual oil," the company wrote in its plan of development.

The biggest area of growth at the Kuparuk River unit is the Nuna Moraine interval, in the northwest corner of the unit. ConocoPhillips has been testing wells in the area for years, but it gained additional assets following the acquisition of the nearby Nuna prospect.

The company conducted a two-well pilot project in late 2018 with the 3S-611 and 3S-612 producer-injector pair and expects to drill two follow-up wells at some point in the future.

In August 2020, ConocoPhillips asked the state Division of Oil and Gas to expand the Kuparuk River Torok oil pool to include the leases in the recent Nuna acquisition.

KRU: West Sak

ConocoPhillips is developing the West Sak satellite from 117 active wells — 55 producers and 62 injectors — at 10 drill sites: 1B, 1C, 1D, 1E, 1G, 1H, 1J, 1R, 3K and 3R.

Oil and natural production are declining at West Sak. The field produced 21,700 bpd in 2019, down slightly from 22,700 bpd in 2018. The field also produced 12.7 million cfpd of natural gas per day in 2019, down some 14% from 14.8 million cfpd in 2018.

The company completed a five-well coiled tubing drilling development program at West Sak in 2019. The program included two producers and one injector at Drill Site 1R and one producer and one injector at Drill Site 1G — all single laterals targeting the B Sand.

For the coming development year ending July 31, 2021, the company is planning a five-well program at Drill Site 3R. The program includes the 3R-105 dual lateral and the 3R-107 dual lateral. The program would eventually expand the drill site to include as many as nine new wells, requiring the formation of a new North West Sak participating area.

In its latest plan, ConocoPhillips had plans to extend viscosity reducing water alternative gas, or VRWAG, injections at certain 1H North East West Sak wells in mid-2020.

KRU: Meltwater

ConocoPhillips is developing the Meltwater satellite from 17 active wells — 10 producers and seven injectors — at Drill Site 2P, which also produces from the main Kuparuk field.

Oil and natural production are declining at Meltwater. The field produced 450 bpd in 2019, down 35.7% from 700 bpd in 2018. The field also produced 7 million cfpd of natural gas per day in 2019, down nearly

In its most recent plan of development, the company said it would drill as many as 21 development wells across the Colville River unit in 2020 and into the first quarter of 2021, although the company asked the state not to release the locations of those wells.

34% from 10.6 million cfpd in 2018.

To address rising gas-to-oil ratios attributed to injection practices, ConocoPhillips switched the field to water flooding in mid-2019. Without the change, several wells would have become uneconomic, according to the company. The water-only injections followed six months of miscible injections and almost a decade of gas only injections.

"It is expected that it will be at least years before the producers start to observe the benefit of water injection," the company wrote in its current plan of development.

KRU: Tabasco

ConocoPhillips is developing the Tabasco satellite from eight active wells — five producers and three injectors — at Drill Site 2T, which also targets the Kuparuk field.

Oil production increased at Tabasco. The field produced 1,390 bpd in 2019, up 13.6% from 1,200 bpd in 2018. Natural gas production declined. The field produced 170,000 cfpd per day in 2019, down more than 43% from 300,000 cfpd in 2018.

The increase is likely the result of several maintenance projects completed in 2019.

ConocoPhillips converted the 2T-209 producer to injection about seven years after the well was suspended. The company returned the 2T-203 and 2T-218 producers to production in early 2019 following repairs to their electric submersible pump motors.

KRU: Tarn

ConocoPhillips is developing the Tarn satellite from 56 active wells — 39 producers and 17 injectors — at Drill Sites 2L and 2N, which also both target the Kuparuk field.

Oil and natural production are both declining at Tarn. The field produced 6,150 bpd in 2019, down slightly from 6,900 bpd in 2018. The field also produced 6.1 million cfpd of natural gas per day in 2019, down more than 50% from 13.2 million cfpd in 2018.

The Colville River unit

ConocoPhillips is planning a considerable increase in development drilling at the Colville River unit this year, as well as ongoing work toward two expansion opportunities.

The company currently develops the unit from four pads targeting seven participating areas. But forecasts have always envisioned additional pads, to accommodate expansion.

In its most recent plan of development, the company said it would drill as many as 21 development wells across the Colville River unit in 2020 and into the first quarter of 2021, although the company asked the state not to release the locations of those wells.

According to AOGCC records, the company had completed nine wells and laterals through the first six months of 2020 (as well as a well-and-lateral pair completed in the final weeks of 2019). The wells were completed largely in the first quarter of the year, before complications from the coronavirus emerged. The completed wells were located at the CD4 and CD5 pads. Several other permitted wells have not yet been completed.

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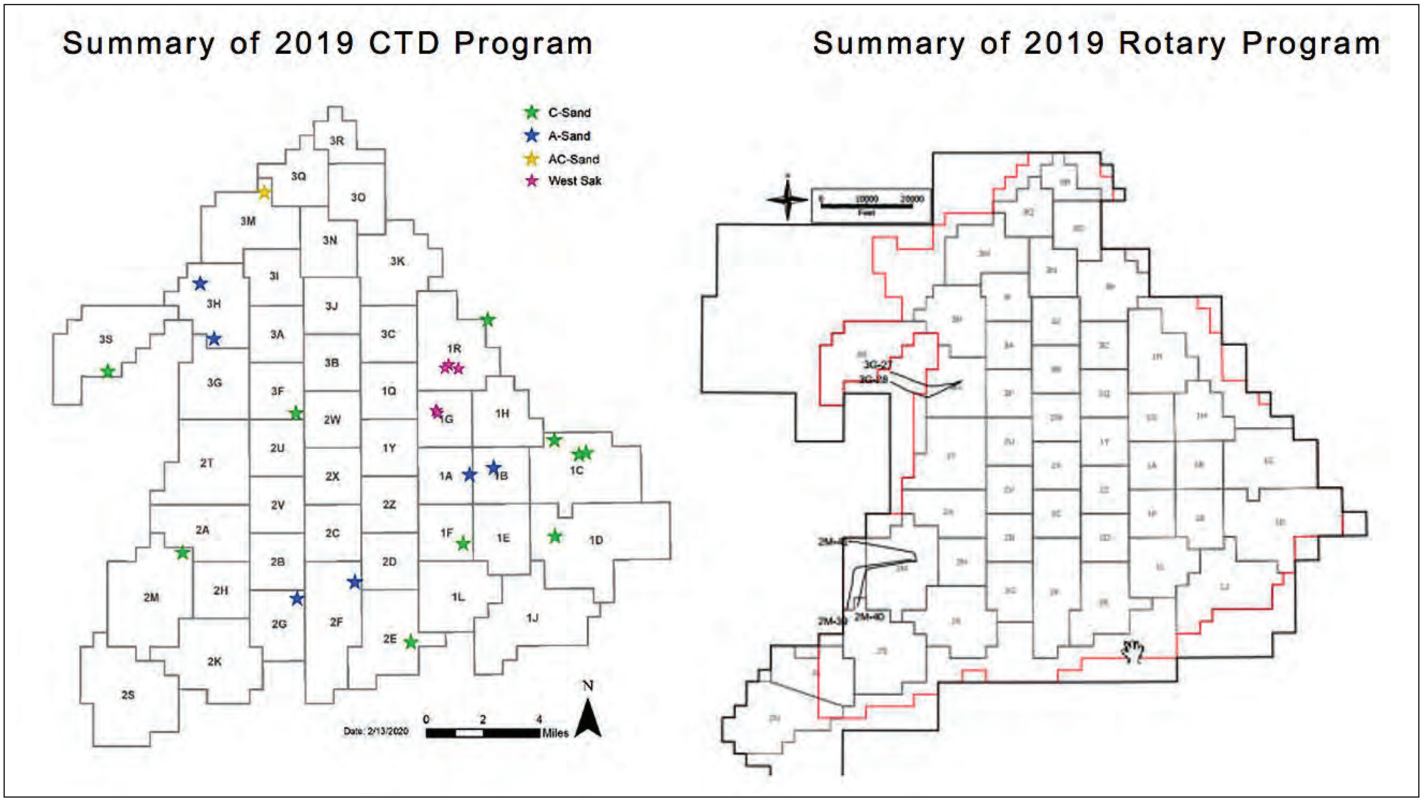

CONOCOPHILLIPS ALASKA INC.

CONOCO *continued from page 23*

The company drilled five wells at the unit in 2019. The program included three multilaterals and a horizontal well at CD5 targeting Alpine and a slant well at CD2 targeting Fiord West. The company postponed three planned CD5 wells over rig scheduling delays and cancelled a fourth by combining it with an existing well. The company also postponed two planned CD4 wells "due to rig optimization decisions."

ConocoPhillips is progressing two important expansion projects at the unit.

Work on the CD2X expansion project last year added 21 well slots and converted six existing well slots at the CD2 pad, giving the company 27 well slots for extended reach drilling activities. The project would support the new Fiord West Kuparuk satellite.

The company received an AOGCC drilling permit for the CD2-310 well in mid-August 2020, the first drilling permit issued for the company at the unit since early May 2020.

The second project targets the Narwhal prospect in the south of the unit. Following many regulatory disputes, the state approved the expansion in August 2017, subject to certain conditions. The expansion incorporated the formerly named Putu prospect into the unit.

To meet the initial conditions required by the state, ConocoPhillips drilled the Putu No. 2 and Putu No. 2A wells and made a $3 million bonus bid replacement. The company also drilled four appraisal wells — CD4-595PH1, CD4-595, CD4-594PH1 and CD4-594 — beyond its work commitments "to better understand the reservoir and to test the technical feasibility of extended reach drilling at shallow depth," according to the company.

The next round of commitments requires ConocoPhillips to either pay $4 million to the state and submit a plan detailing efforts to either bring the leases into sustained production or it must voluntarily contract the leases. The company chose the former.

While the company had initially intended to access the area from its existing CD4 pad using extended reach wells, the CD4-594 and CD4-595 wells "stretched the limits" of serviceable extended reach drilling at shallow depths, according to ConocoPhillips.

To reach Narwhal, the company is now designing a CD8 gravel pad connected by road to the CD4 pad. CD8 would support between 20 and 40 new development wells, depending on modeling. The company expects CD8 production no sooner than 2025.

A CD4-597 injector well in late 2020 or early 2021 would complete the intended pattern of pilot project drilling, allowing the company to better design well spacing and facility design for the pad. Other drilling might be conducted for other engineering purposes.

CRU: Alpine

The Alpine pool is the largest producing field at the Colville River unit.

ConocoPhillips completed initial development drilling at the field in November 2005 from the CD1 and CD2 pads and switched to peripheral opportunities. The startup of the CD5 pad in late 2015 provided additional opportunities to produce from the pool.

The Alpine pool includes two participating areas: Alpine and Nanuq Kuparuk. The Alpine participating area is currently being developed from 156 wells — 82 producers, 72 injectors, and two disposal wells in the Ivishak. The Nanuq Kuparuk participating area is currently being developed from 13 wells — six producers and seven injectors.

In the coming year, the company is planning an undefined coiled tubing drilling program at the Alpine field using laterals to target areas between existing producers. The company is also planning a rotary program at Alpine including three producers and six injectors.

Within the Nanuq Kuparuk sand, the company is planning to use an extended reach drilling rig in early 2021 to access opportunities to the west of the CD5-316 well.

Oil production is declining at the pool. The Alpine participating area produced 34,900 barrels of oil per day in 2019, down from

37,100 bpd in 2018. The Nanuq Kuparuk participating area produced 10,000 bpd in 2019, down from 12,600 bpd in 2018. The combined pool has produced 504.4 million barrels of oil cumulative since start up.

CRU: Fiord

ConocoPhillips is not planning any new development wells at the Fiord pool in the coming cycle, although it is considering as many as five sidetracks at the Fiord Nechelik participating area and one workover project in the Fiord Kuparuk participating area.

The company drilled the CD2-162 slant well in early 2019 targeting the Fiord West Kuparuk reservoir, near planned extended reach well locations. The pilot well was designed to provide information to support future extended reach drilling activity but was suspended before reaching its target after its bottom hole assembly became stuck.

The company is now planning as many as four additional slant pilot wells over the coming development cycle. The wells would also support future development activities.

The Fiord pool is currently developed from 23 wells at Fiord Nechelik — 13 producers and 10 injectors — and six wells at Fiord Kuparuk — three producers and three injectors.

The Fiord Nechelik participating area produced 4,800 bpd in 2019, down from 5,500 bpd in 2018. The Fiord Kuparuk participating area produced 400 bpd in 2019, equal to 2018. The Fiord pool has produced 73.3 million barrels of oil cumulatively since start up.

CRU: Nanuq and Qannik

ConocoPhillips is planning no new development wells at the Nanuq pool, but it expects to finish two coiled tubing drilling sidetracks from CD4 in the coming development year.

The company is currently developing the Nanuq pool from 10 wells — six producers and four injectors — at the Nanuq participating area. The Nanuq pool produced 1,400 bpd in 2019, down from 1,200 bpd in 2018. Cumulative oil production is 5.2 million barrels.

The company completed the CD4-499 horizontal production well into the Qannik pool in late 2019 and early 2020. The well targeted an opportunity to the east of the existing CD2 development. The company may drill an offset injector in the coming development year.

The company is developing the Qannik pool from nine wells — six producers and three injectors — at the Qannik participating area. The Qannik pool produced 1,700 bpd in 2019, down from 1,600 bpd in 2018. Cumulative oil production is 7.7 million barrels.

The Greater Mooses Tooth unit

The Greater Mooses Tooth unit is practically an extension of the Colville River unit, although administrated independently and overseen by a different land manager.

ConocoPhillips first announced the possibility of a development in the area in the early days of the Alpine project. But the GMT project was dependent on the CD5 pad, which crossed the Nigliq Channel of the Colville River, opening western leases to development.

The 11.8-acre GMT-1 drilling pad is the first commercial development in the National Petroleum Reserve-Alaska, overseen by the U.S. Bureau of Land Management. The pad is also the hub for future ConocoPhillips development projects in the region, including the GMT-2 pad and the Willow prospect at the unit, and the Bear Tooth unit to the north.

ConocoPhillips brought the 33-well pad online in mid-2018 with sustained oil production beginning in October 2018. The unit produced approximately 10,646 barrels per day in its first year. But production volumes began falling in late 2019. Over the year ending June 1, 2020, the most recent available information, production was down to 6,532 bpd.

ConocoPhillips is currently developing the unit from three production wells — GMTU MT6-03, GMTU MT6-05 and GMTU MT6-06. The wells have been producing unequally, although parity appears to be underway. Of the 95,452 barrels of oil produced at the unit in June 2020, 74% came from GMTU MT6-05, 22.6% came from GMTU MT6-03 and 3.2% came from GMTU MT6-06. By comparison, in July 2019, the wells accounted for 86.7%, 12.2% and 1.1%, respectively.

ConocoPhillips expected better results for its initial drilling campaign but said no remediation is planned at the moment. The company is using the result of the project to inform its ongoing work at the GMT-2 pad. GMT-2 is targeting a different reservoir.

Last year, ConocoPhillips finished processing an 810-square mile seismic program covering much of the unit. The results will guide future exploration and development.

The GMT-2 pad is currently under construction, with pipeline installation planned for earlier this year. The company expects major administrative work with the Alaska Oil and Gas Conservation Commission this fall, with start-up planned for late 2021.

At the Bear Tooth unit to the north of Greater Mooses Tooth, ConocoPhillips is planning a four-well exploration program this year but no development work as of yet. At the nearby Willow project, the BLM recently released a final EIS for the proposed project. ●

Contact Eric Lidji at ericlidji@mac.com

Eni operating neighboring nearshore units

Italian company overseeing the Oooguruk unit and the Nikaitchuq unit

By ERIC LIDJI
For Petroleum News

The fates of the Nikaitchuq and Oooguruk units have long been intertwined.

Both prospects were discovered during related exploration efforts at the turn of the 21st century. In the years since, operators of both units have faced similar challenges, arising from the complications of working on nearshore prospects in the Arctic Ocean. The solutions brought to bear at one unit have often informed decision making at the other.

But the units are now more intertwined than at any point in their producing lives. After being a minority partner at Oooguruk for its entire existence as a producing field, Eni US Operating Co. Inc. is wrapping up its first year as the operator of the neighboring units.

ROBERT PROVINCE

Eni US

COMPANY HEADQUARTERS: Eni US Operating Co. Inc, Houston, Texas
ALASKA OFFICE: 3800 Centerpoint Dr., Ste. 300, Anchorage, Alaska 99503
TOP ALASKA EXECUTIVE: Robert A. Province, Manager – land, public relations & Alaska representative
PHONE: 907-865-3300
PARENT COMPANY WEBSITE: www.eni.it

Oooguruk

In its first year as operator of Oooguruk, the American subsidiary of the Italian major Eni Petroleum was hampered by a series of external factors, mostly arising from the impact of the coronavirus pandemic on the Alaska oil industry, and the North Slope in particular.

The proration of the trans-Alaska oil pipeline and the curtailment of the gas handling capacity at the Kuparuk River unit created secondary problems at Oooguruk. The unit produced 8,700 barrels of oil per day in March 2020 and just 6,300 bpd in May 2020.

Prompted by those infrastructure challenges and by the broader economic conditions of falling oil prices and declining demand, Eni deferred its original plans to conduct several workover projects in 2020 in advance of resuming the drilling of new wells at the unit in 2021. The company instead performed 15 maintenance and repair projects on 10 wells.

The company also undertook a range of other maintenance activities, including a gas debottlenecking project responsible for “several hundred” barrels per day of production.

Even with economic conditions now improving, Eni is hesitant to resume activities. The company is not planning drilling or workover projects for the coming development year, running through September 2021, although it is planning two well maintenance projects.

Further down the road, the company is evaluating two appraisal wells — ERD-N01 and ERD-N02 — on leases outside existing participating areas. The program would test the productivity and quality of oil on three leases beyond the reach of existing drilling but within the technical limitations of drilling technology from its offshore drilling pad.

Some of the challenges at Oooguruk this year are an extreme version of an ongoing challenge at the unit. The lack of independent infrastructure at the unit has forced previous operators to rely on infrastructure operated by neighboring ConocoPhillips.

ARCO Alaska Inc. discovered Oooguruk in 1992, and independent Armstrong Oil & Gas Inc. delineated the “Northwest Kuparuk” prospect in the early 2000s. Through a series of deals, Texas-based Pioneer Natural Resources Alaska LLC acquired a 70% interest and became operator of the unit, with Eni acquiring the remaining 30% interest.

After just five years of work, Pioneer brought the nearshore Oooguruk unit into production in June 2008, becoming the first independent producer on the North Slope.

In late 2013, after optimizing completion techniques at the unit and expanding the resource with a large discovery to the south called the Nuna prospect, Pioneer sold the Oooguruk unit to the independent company Caelus Natural Resources Alaska LLC.

Caelus was a smaller company with a history of short-term projects. The company announced major plans and even sanctioned the Nuna project. But when prices dropped in 2016, the company suspended regular operations and deferred development work. The company eventually sold its stake in Oooguruk to its partner Eni Petroleum in mid-2019.

Pioneer made a strategic decision to use facilities at the Kuparuk River unit rather than bear the expense of building independent facilities at Oooguruk. It occasionally struggled with the lack of control created by that decision, as did Caelus in its years as operator.

Eni recently launched a study to gauge the feasibility of installing partial gas processing facilities at the Oooguruk Tie-in Pad to avoid those Kuparuk River unit constraints. The company also launched a study looking at the possibility of connecting the power generation systems at Oooguruk and Nikaitchuq, to improve efficiency at both units.

Oooguruk produces from three horizons: the Oooguruk-Kuparuk participating area, the Oooguruk-Nuiqsut participating area, and the Oooguruk-Torok participating area.

The unit produced 3,023,150 barrels of oil (approximately 8,282 barrels per day) in 2019 and 1,476,908 barrels (approximately 8,114 barrels per day) in the first half of 2020.

Nikaitchuq

Eni completed some of its work plan at Nikaitchuq early in the development year.

Before suspending operations, the company drilled the SP03-NE2 producer and the dual-lateral producers SP03-NE2 L1 and SP10-FN1 L1 from the Spy Island drilling site.

The original three-well program planned for the unit included a different slate of wells: the SP03-FN6 producer and the SI02-SE6 and SI06-FN8 water injection wells.

The SP03-NE2 project began with the SP03-NE2 PH pilot hole to the northwest to evaluate the prospect. Positive results led to an expansion of drilling plans for the area.

The workover campaign included projects at the SP12-SE3 producer, SP04-SE5 producer and SD37-DSP01 disposal well at the Spy Island drill site and the OP05-06 producer, OP17-02 producer and OP22-WW03 water well at the Oliktok Point drilling pad.

The company subsequently cold-stacked Doyon Rig 15 and Nordic Calista Rig 4 but is evaluation electrical submersible pump replacements projects in early 2021.

As with some other companies, the suspension of drilling

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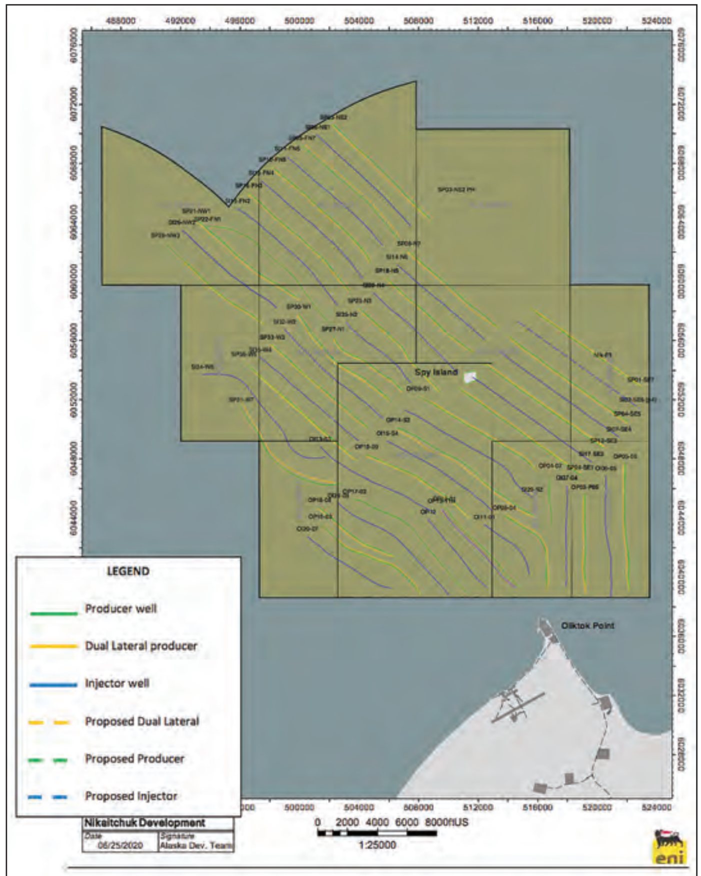
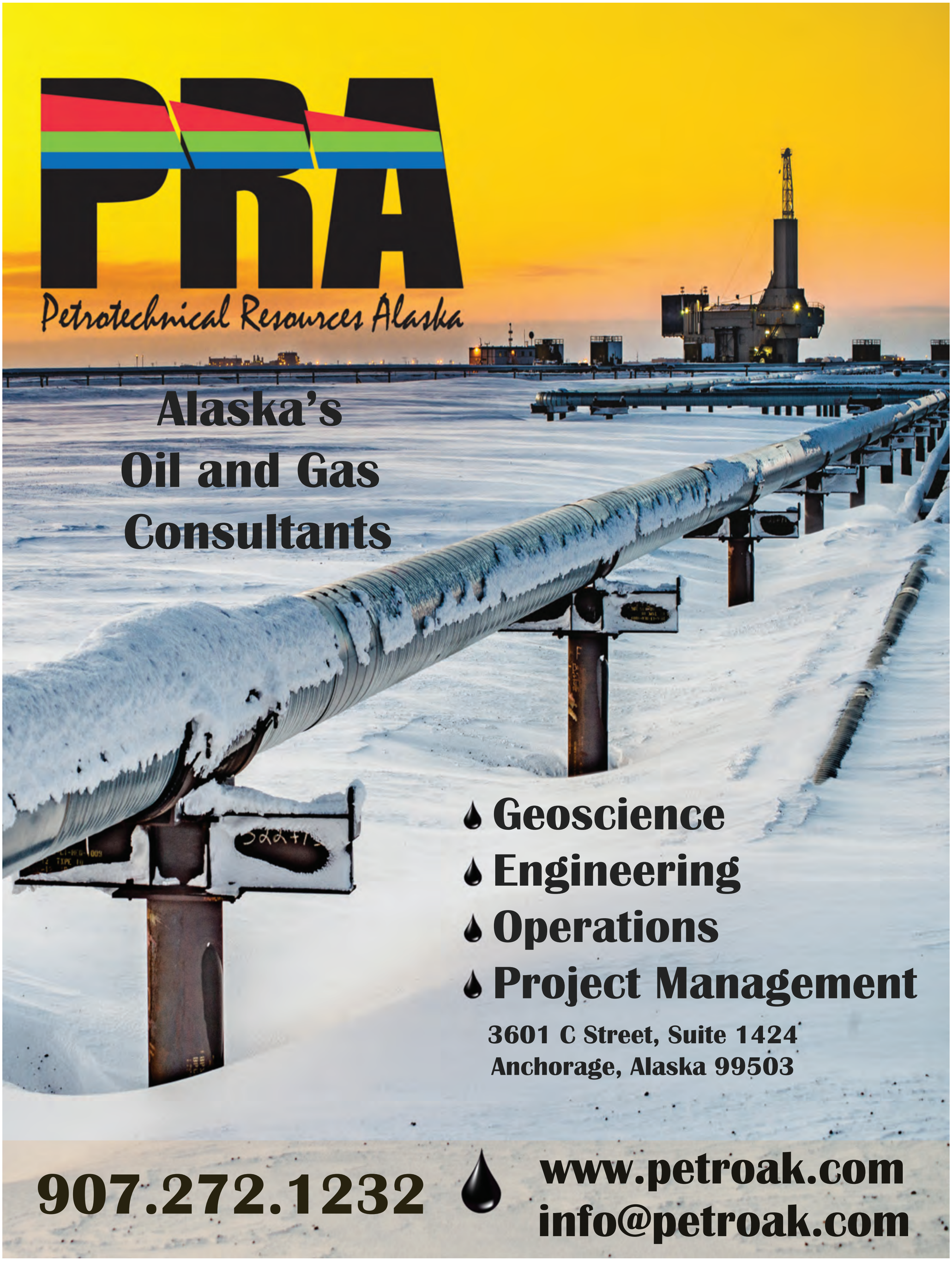


Figure 1. Proposed Nikaitchuq Unit development activity through July 2020

ENI US OPERATING CO. INC.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Geoscience
Engineering
Operations
Project Management
3601 C Street, Suite 1424
Anchorage, Alaska 99503
907.272.1232
www.petroak.com
info@petroak.com

Exxon following two paths at Point Thomson

The longtime Alaska player is pursuing AGDC project and new Qilak project

By ERIC LIDJI
For Petroleum News

ExxonMobil Corp.

COMPANY HEADQUARTERS: Irving, Texas
ALASKA OFFICE: 3301 C St., Ste. 400, Anchorage, AK 99503
PHONE: 907-561-5331
TOP ALASKA EXECUTIVE: Darlene Gates, President, ExxonMobil Alaska
COMPANY WEBSITE: www.exxonmobil.com

The current Point Thomson Initial Production System produces natural gas entrained with condensate from the PTU-17 well. The natural gas is removed from the stream and injected back into the field using the PTU-15 and PTU-16 wells.

For the past 43 years, the Point Thomson unit has been widely viewed as one of the saviors of the North Slope basin: a major field with resources that could help the State of Alaska shift from an oil-based economy to an industrial economy based on natural gas.

But to date, the story of the unit has been one of future promise.

Its first 35 years were consumed by inactivity and then by regulatory and legal debates between the State of Alaska and operator ExxonMobil Alaska Production Inc. Then came four years of construction, eventually leading to sustained production in early 2016.


DARLENE GATES

Even with that milestone, Point Thomson is far from its full potential — an opinion held by ExxonMobil, the State of Alaska, nearby leaseholders, and the oil patch generally.

The Point Thomson unit is currently producing between 9,000 and 9,500 barrels per day of condensate. That is a shortcoming by two important measurements. First, it is below the 10,000 barrel per day minimum required by a settlement agreement with the state.

Second, condensate is not the ultimate goal of the unit. Point Thomson contains 8 trillion cubic feet of natural gas — a quarter of the known, recoverable resources on the North Slope. Those resources are currently constrained by the lack of a viable route to market.

The current Point Thomson Initial Production System produces natural gas entrained with condensate from the PTU-17 well. The natural gas is removed from the stream and injected back into the field using the PTU-15 and PTU-16 wells. The condensate is shipped through the Point Thomson Export Pipeline to the trans-Alaska oil pipeline. The system is designed to cycle as much as 200 million cubic feet of natural gas per day.

The unit produced 5,200 barrels per day during the 18 months ending July 31, 2019 — an average taken from various high and low swings. The unit hit a peak of 10,700 barrels per day in December 2018, exceeding the minimum rate required by the settlement.

During the same period, the unit produced 95.9 million cubic feet of natural gas per day, cycling 93 million back into the field. (The remaining 2.9 million cubic feet was used as field gas to support operations at the unit.) As with condensate production, average daily natural gas production peaked in December 2018, with 199.4 million cubic feet per day.

At issue are the extreme pressures found at the field. According to Exxon, the gas injection equipment has struggled in recent years, leading the company to work with its manufacturer on improvements. The first of those new components was installed in July 2019. The company said that it expected the remaining components to arrive this year.

Next steps

The 2012 settlement proposed three possible paths for Point Thomson after the start-up of the Initial Production System. ExxonMobil could either sanction a major gas sale by 2016, expand liquids production to 30,000 barrels per day by 2019, or integrate Point Thomson into the Prudhoe Bay unit by shipping gas supplies to improve oil recovery.

To date, none of those have occurred.

ExxonMobil insists that a major gas sale is the best of all possible options. Its most recent plan of development touts various efforts toward that goal in recent years. Even so, those efforts have not been enough to justify the sanctioning of the multibillion-dollar project.

A 2017 settlement allowed ExxonMobil to expand condensate production or to integrate the unit with Prudhoe Bay. ExxonMobil preferred the latter option but was delayed by the need for reaching a commercial agreement with the owners of the Prudhoe Bay unit.

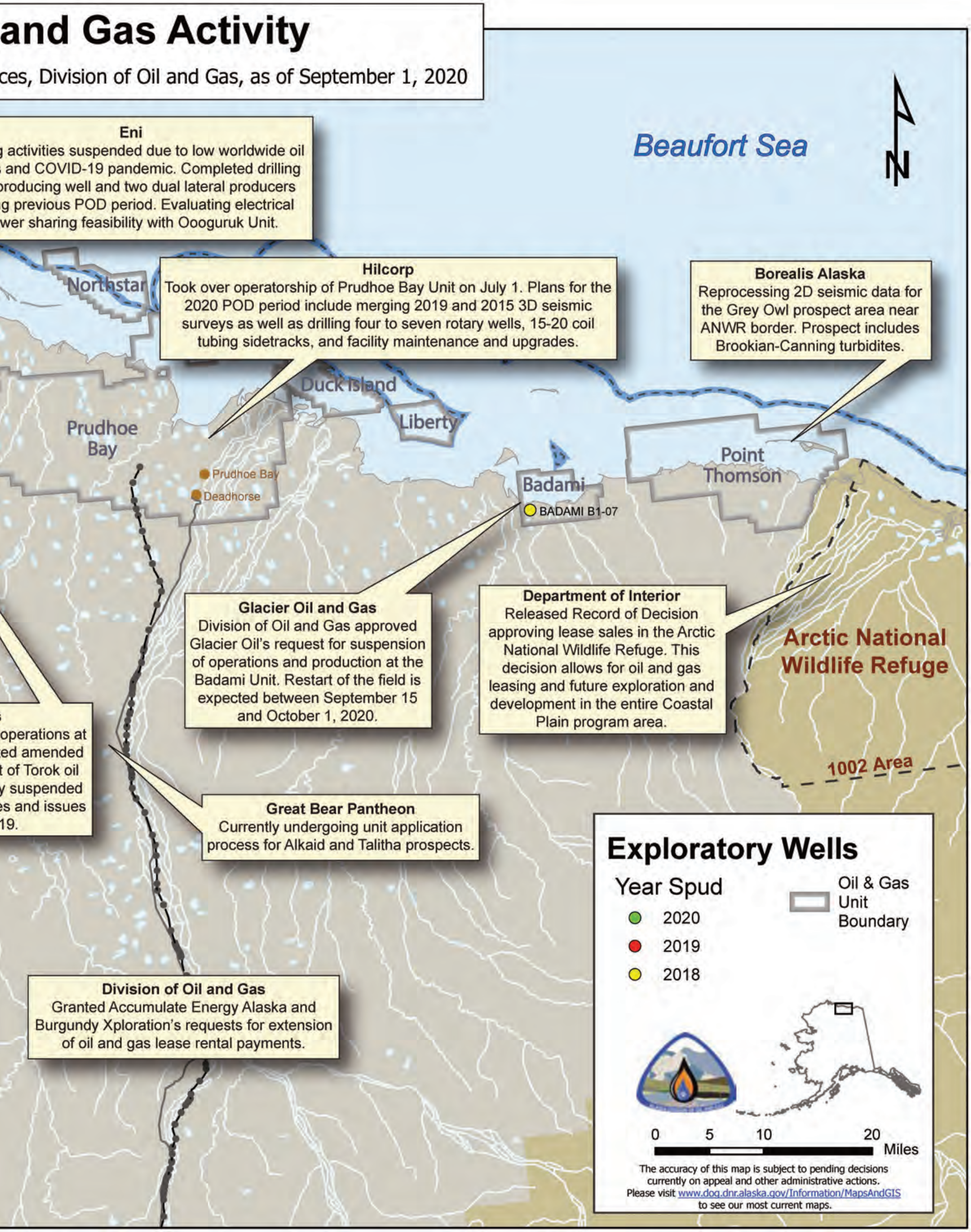
In a September 2018 agreement, Alaska Department of Natural Resources Commissioner Andy Mack deferred the 2019 deadline for expanding liquids production while ExxonMobil was advancing the Alaska LNG project to bring gas to market. Whenever the project reaches a final investment decision or the state determines that the project has stalled, the Point Thomson owners will have 30 months to advance or will lose acreage.

ExxonMobil is involved in two possible projects to bring North Slope gas to market. The first is the Alaska LNG project being overseen by the Alaska Gasline Development Corp.

Under its previous plan of development, covering 2018 and 2019, ExxonMobil worked with the public corporation on financial

continued on page 33

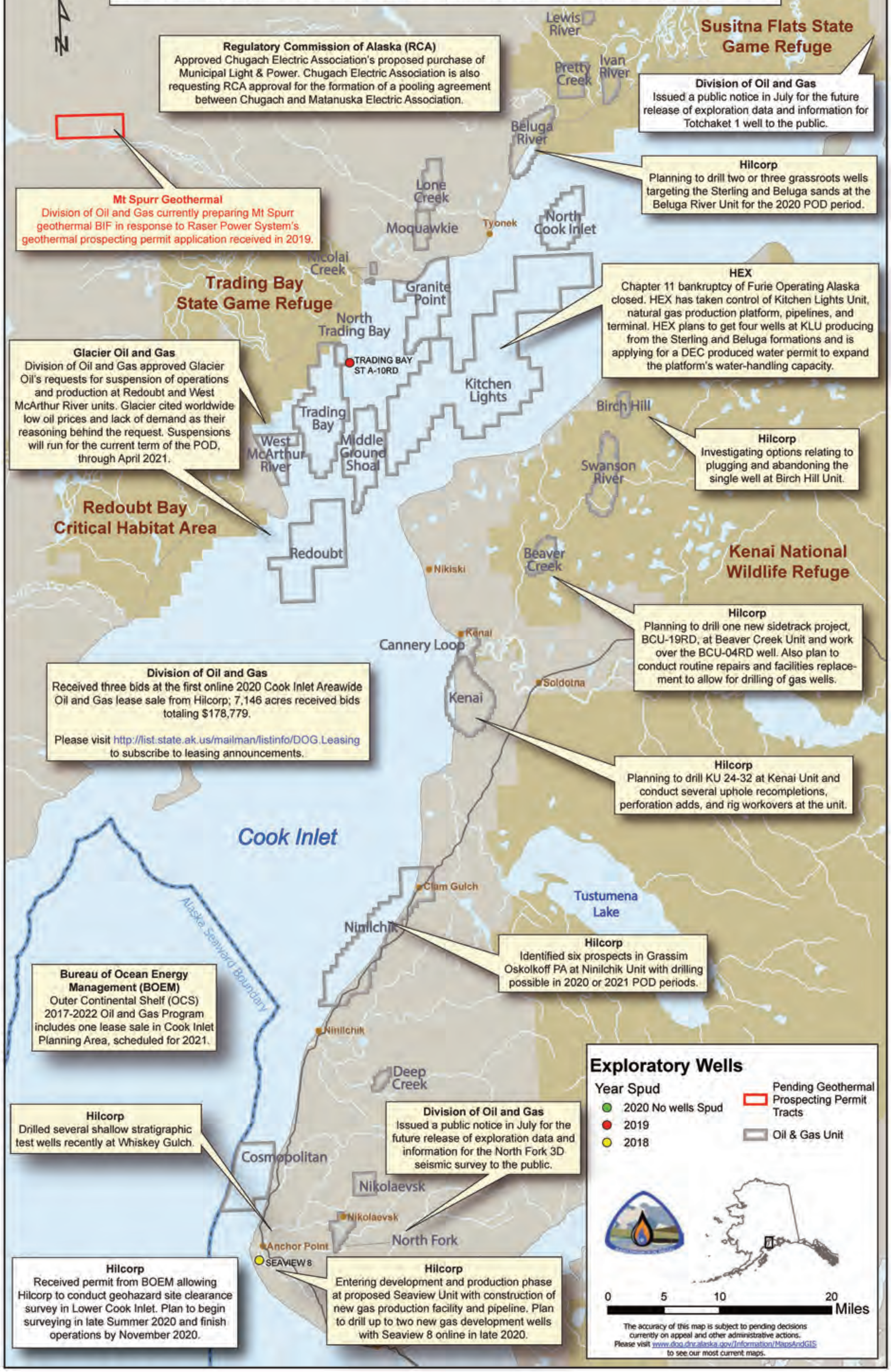

North Slope Oil a
State of Alaska, Department of Natural Resource
Borealis Alaska
Planning to drill 1-2 wells at Castle North lower Nanushuk prospect in northeastern NPRA during Winter of 2021-22.
Eni
Deferring planned well workovers and drilling of new wells. Evaluating electrical power sharing feasibility with Nikaitchuq Unit and expanding water injection capabilities for EOR purposes using low pressure seawater flowline.
Eni
Anticipate spudding second Nikaitchuq North well in 2022. Plan to work on facility upgrades during upcoming POD period.
Drilling a
prices a
one pro
during
powe
Oil Search
Proposing to build Seawater Treatment Plant and make-up water pipeline at the Pikka Unit. Deferring final investment decision while continuing work to optimize the unit. Reduced 2020 development spending and no exploration work planned for Winter of 2020/21.
Nikaitchuq North
Nikaitchuq
Oooguruk
Pikka
Milne Point
Kuparuk River
Placer
Bear Tooth
Colville River
Greater Mooses Tooth
S. Miluveach
Kuparuk River
PIKKA C & C ST1
HYDRATE 01
MITQUQ 1 & 1ST
TINMIAQ 13
TINMIAQ 9
WEST WILLOW 1
WEST WILLOW 2
PIKKA B & B ST1
CRU CD4-595 & CD4-594
PUTU 2 & 2A
TINMIAQ 10 & 15
TINMIAQ 7
KRU 2S-315
TINMIAQ 20
TINMIAQ 16
TINMIAQ 8
STONY HILL 1
TINMIAQ 11
STIRRUP 1
TINMIAQ 18
WINX 1
AIDEA
Public auction of Mustang oil and gas field is postponed, originally scheduled for July 31.
ConocoPhillips
Well planning and permitting to begin Q2 2021 at GMT-2. First oil expected late 2021.
HARPOON 2
ConocoPhillips
Resumed normal production op
Kuparuk River Unit. Requested
order to expand areal extent o
pool. Drilling activity currently s
due to low worldwide oil prices
relating to COVID-19
ConocoPhillips
Ended exploration season early and demobilized NS rig fleet due to concerns over COVID-19. Drilled one Harpoon well and two Tinmiaq wells and completed Narwhal appraisal testing. BLM released final EIS for Willow project. Construction to begin early 2021 and first oil planned from Willow in 2025-2026.
Oil Search
Surrendered 130 leases to the Division of Oil and Gas.
CHARLIE 1
National Petroleum Reserve - Alaska
US Department of the Interior
Released final EIS for NPRA integrated activity plan. The preferred Alternative E includes opening 7 million additional acres to energy development in NPRA.
Accumulate Energy
Planning to drill Harrier 1 and Merlin 1 exploratory wells this upcoming Winter in NPRA. Both are Nanushuk prospects acquired in takeover of XCD Energy.
Umiat



and Gas Activity
ces, Division of Oil and Gas, as of September 1, 2020
Eni
g activities suspended due to low worldwide oil
s and COVID-19 pandemic. Completed drilling
producing well and two dual lateral producers
g previous POD period. Evaluating electrical
wer sharing feasibility with Oooguruk Unit.
Beaufort Sea
N
Hilcorp
Took over operatorship of Prudhoe Bay Unit on July 1. Plans for the 2020 POD period include merging 2019 and 2015 3D seismic surveys as well as drilling four to seven rotary wells, 15-20 coil tubing sidetracks, and facility maintenance and upgrades.
Borealis Alaska
Reprocessing 2D seismic data for the Grey Owl prospect area near ANWR border. Prospect includes Brookian-Canning turbidites.
Northstar
Duck Island
Liberty
Prudhoe Bay
Prudhoe Bay
Deadhorse
Point Thomson
Badami
BADAMI B1-07
Glacier Oil and Gas
Division of Oil and Gas approved Glacier Oil's request for suspension of operations and production at the Badami Unit. Restart of the field is expected between September 15 and October 1, 2020.
Department of Interior
Released Record of Decision approving lease sales in the Arctic National Wildlife Refuge. This decision allows for oil and gas leasing and future exploration and development in the entire Coastal Plain program area.
Arctic National Wildlife Refuge
1002 Area
s
operations at
ed amended
t of Torok oil
y suspended
es and issues
19.
Great Bear Pantheon
Currently undergoing unit application process for Alkaid and Talitha prospects.
Exploratory Wells
Year Spud
2020
2019
2018
Oil & Gas Unit Boundary
Division of Oil and Gas
Granted Accumulate Energy Alaska and Burgundy Xploration's requests for extension of oil and gas lease rental payments.
0 5 10 20
Miles
The accuracy of this map is subject to pending decisions currently on appeal and other administrative actions.
Please visit www.dog.dnr.alaska.gov/Information/MapsAndGIS to see our most current maps.

Cook Inlet Oil and Gas Activity

State of Alaska, Department of Natural Resources, Division of Oil and Gas, as of September 1, 2020



ENI *continued from page 27*

activities allowed Eni to complete some maintenance activities that would have required a temporary shutdown.

Even so, the company is planning a summer 2021 turnaround at Nikaitchuq to coincide with a planned turnaround at the Kuparuk River Unit Central Processing Facility 2.

But the shutdown of regional infrastructure impacted Nikaitchuq production.

The unit produced 19,400 barrels per day between September 2019 and May 2020 but only 17,100 barrels per day during the month when throughput on the trans-Alaska oil pipeline was prorated. Production returned to 20,000 barrels per day in early June.

Eni also added six well slots to one of its drilling pads to accommodate the proposed NN02 exploratory well and as many as four additional Nikaitchuq wells. The company delayed the project after partner Shell declined to participate in the project. Eni subsequently received permission from federal authorities to suspend operations for two years, until April 2022.

In its plan for the current development year, running through September 2021, the company proposed no new drilling and said it would perform workovers as needed.

"Eni reports the global COVID-19 pandemic and subsequent global oil demand and price impact has temporarily curtailed planned drilling activity in the 2020 (Plan of Development)," Eni wrote. "Actual activities may change as conditions improve."

Nikaitchuq produced 6,772,787 barrels of oil (approximately 18,555 bpd) in 2019, compared to 3,489,408 barrels (approximately 19,172 bpd) in the first half of 2020.

Eni acquired the Nikaitchuq leases through purchases in 2005 and 2007, sanctioned a $1.45 billion development program in January 2008, and brought the unit into production in early 2011. The company completed its initial onshore Oliktok Point pad drilling program in 2012 and shifted to continuous drilling at the offshore Spy Island drill site. ●

Contact Eric Lidji at ericlidji@mac.com

EXXONMOBIL *continued from page 29*

and technical matters related to the project.

Alaska LNG received a final environmental impact statement from the Federation Energy Regulatory Commission in March 2020, a milestone years in the works. The Alaska Gasline Development Corp. later received a final order from federal regulators.

The Alaska Gasline Development Corp. is now looking for a private sponsor who could take over the $38.7 billion project to build a large diameter pipeline through the state to a new liquefaction facility in Nikiski. The goal is to step back sometime later this year.

ExxonMobil is also pursuing a second possibility for marketing Point Thomson supplies.

In October 2019, the company signed an agreement with Qilak LNG Inc. to supply at least 560 million cubic feet per day of natural gas to a newly proposed LNG project.

The gas supplies from Point Thomson would be used for Phase 1 of the Qilak LNG 1 Project, a proposed $5 billion nearshore liquefied natural gas facility that the Alaska subsidiary of Lloyds Energy of Dubai wants to build near Flaxman Island. Qilak LNG is looking to ship between 4 million and 6 million tons of LNG per year to customers in the Indo-Pacific region as soon as 2025 or 2026, using a fleet of icebreaking LNG tankers.

The full vision for the project would require additional producers. "The agreement at the moment is exclusively with Exxon; once we're able to talk to Hilcorp, once they take over the BP interests, then we hope to have enough gas to increase that to at least 6 million tons," Qilak President and COO David Clarke told Petroleum News at the time.

Hilcorp later closed on its acquisition of the remaining BP Exploration (Alaska) Inc. holdings on the North Slope, assuming 32% interest in the Point Thomson unit.

Qilak is now conducting an extensive feasibility study including preliminary permitting work this year with the goal of reaching a final investment decision sometime in 2021.

The Qilak project is smaller and cheaper than the state-backed Alaska LNG project. The advantage, according to Qilak, is cost. According to its figures, the Alaska LNG Project would cost some $2,150 per ton of LNG while the Qilak project would cost about $1,250 per ton of LNG. Given that the distance to Tokyo is roughly the same for both projects, the cost of Alaska-based infrastructure is a major factor for determining LNG prices. ●

Contact Eric Lidji at ericlidji@mac.com

Finnex takes the reigns at Mustang

BRPC brought field online after seven years of work, but challenges persisted

By ERIC LIDJI
For Petroleum News

> ## Finnex LLC
>
> **ANCHORAGE OFFICE:** 301 Calista Court, Ste. 201,
> Anchorage, AK 99518
> **PHONE:** 907-865-5850
> **REGISTERED AGENT:** Harry Bockmeulen
> **EMAIL:** admin@finnexllc.com

The Anchorage-based Finnex was formed on June 23, 2020, according to filings with the Alaska Division of Corporations, Business and Professional Licensing. According to the filing, Thyssen Petroleum Alaska LLC holds 85% of the company and Galactico LLC holds the remaining 15%.

The story of the Mustang field has been one of frustration and persistence. It is the frustration and persistence specific to small independent companies on the North Slope.

Finnex LLC recently assumed control of the initial development of the South Miluveach unit, located in the fairway between the Kuparuk River unit and the Colville River unit. The company is currently working with its partners on a "recovery plan" to resume development work stalled by financial challenges.

Although the future of the project appears to belong to Finnex, the history of the project to date belongs mostly to Brooks Range Petroleum Corp.

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

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

With the start of commercial production on Oct. 30, 2019, BRPC became the first small independent oil company in Alaska history to bring a North Slope field from discovery to production. The company conducted an extended production test from its North Tarn 1A well using its temporary processing facilities and exported oil to the Alpine Pipeline System. By the time a flaring permit for the unit expired on Nov. 27, the company had produced 11,944 barrels of oil, according to its estimates. Although the production test was small and temporary, it was a sign that the basin was at least theoretically accessible to players beyond multinational majors and even beyond large and mighty independents with strong balance sheets.

But the complications that had plagued earlier years continued apace.

As the production test was proceeding, a private sector backer failed to meet its financial obligations on the project. BRPC and working interest owners began refinancing a major loan with its main financial backer Alaska Industrial Development and Export Authority. According to BRPC, AIDEA issued a notice of default on that debt in early October. And then, in early November, it exercised its rights to accelerate debt repayments. In response, BRPC suspended operations until it could secure financing it needed.

The dream of a small independent operator had lasted one month.

BRPC operated the unit on behalf of a joint venture — Caracol Petroleum LLC, TP North Slope Development LLC, Nabors Drilling Technologies USA Inc. and AVCG LLC.

Even after negotiating new financing terms in January 2020, the immediate economic conditions surrounding the project proved to be insurmountable. BRPC said that the low oil price environment in the early days of the coronavirus pandemic made it "very difficult" to find new financing "in the short term." The company put the field in cold shutdown in early April 2020 and began some demobilization activities.

And then in mid-September 2020, AIDEA authorized a sale of the field to Finnex LLC and approved a debt settlement and restructuring agreement, DRSA, between AIDEA, Finnex and the major creditors on the project.

The Anchorage-based Finnex was formed on June 23, 2020, according to filings with the Alaska Division of Corporations, Business and Professional Licensing. According to the filing, Thyssen Petroleum Alaska LLC holds 85% of the company and Galactico LLC holds the remaining 15%.

Even with this latest round of setbacks, work continues.

According to the latest plan of development, submitted in early October 2020, the DRSA will allow the companies to restart design and engineering work to complete Mustang production facilities.

"Procurement of materials and module fabrication for the support modules and pad infrastructure will begin to meet a goal of production from the wells drilled and future wells to be drilled by the 3rd quarter of 2021," the companies wrote.

Despite the recent challenges, and the lost year of the proposed schedule, the companies continue to believe that the underlying project "remains fundamentally sound and (capable) of being brought to fruition."

Help from AIDEA

Brooks Range Petroleum Corp. was formed in 2004 as the operating arm of the Kansas-based Alaska Venture Capital Group LLC, which was created explicitly to pursue large or mid-sized oil fields passed over during the first decades of North Slope development.

In the years following the 2012 discovery of Mustang, a joint venture comprising JK E&P Group Pte. Ltd., Thyssen Petroleum North Slope Development LLC and MEP Alaska LLC acquired the entity BRPC as well as a package of associated North Slope properties for $450 million from AVCG and its partner Ramshorn Investments Inc.

Singapore-based Caracol Petroleum also joined the joint venture. The company later failed to meet loan obligations to AIDEA, which ultimately prompted the foreclosure.

AIDEA has been involved in the project since its early days.

To encourage development, AIDEA provided financing for a $25 million preliminary infrastructure program and a $225 million processing facility for the standalone field.

Through the deal, AIDEA contributed a portion of the costs in return for a set rate of return and a small working interest ownership in the Southern Miluveach unit leases.

The financing helped BRPC secure investment from the private sector joint venture that acquired the company and launched a development program — construction and drilling.

In a notice of sale published in June 2020, AIDEA listed more than $76 million in principle, late fees, accrued interest and foreclosure fees on the property. The expected gross value of oil production from the Mustang field is estimated at $1.3 billion.

The sale included a gravel pad and road, pipelines and related facilities at the Mustang field, as well as the State of Alaska leases underpinning the Southern Miluveach unit.

EPF to start

In its original plan of development for the unit for 2020, Brooks Range Petroleum described plans to advance an early production facility, or EPF, at the unit.

The revenue generated from initial production would have been used to finance a 15,000-barrel-per-day central processing facility, which would accommodate Mustang production as well as third-party production from other independent operators in the area.

With the larger processing facilities in place, BRPC would have begun an initial development drilling campaign with as many as 10 producers and 11 injectors.

The next plan of development for the unit was scheduled for release in late September, but with the transfer of the project to new ownership, future plans will likely be delayed. ●

Contact Eric Lidji at ericlidji@mac.com

Glacier Oil & Gas suspends, restores, advances

The small independent shut-in its oil fields over low prices, retains gas production

By ERIC LIDJI
For Petroleum News

Few operators in Alaska better illustrate the recent uncertainties in the oil and gas industry than Glacier Oil & Gas Corp. The local independent announced development plans early in the year, then suspended operations at several fields in response to low oil prices and demand, and later reinstated some production as the economy improved.

The details of those decisions reveal the nuances of the Alaska oil and gas industry, especially the way market fluctuations are felt in different basins and commodities.

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


STEPHEN RATCLIFF

These properties make Glacier Oil & Gas is one of only two companies operating production in both of the major Alaska basins: the North Slope and Cook Inlet. The other company, Hilcorp Alaska LLC, is the dominant oil and gas producer in the state.

Glacier Oil & Gas was created in early 2016, as a result of the bankruptcy proceedings of the Tennessee-based Miller Energy Resources Inc. The company is currently led by President Stephen Ratcliff, who was promoted from vice president of drilling this year.

Badami

Glacier became the operator of the Badami unit on the eastern North Slope through its acquisition of Savant Alaska. Savant had brought renewed focused to the geologically challenging unit after decades of work by former operator BP Exploration (Alaska) Inc.

In its most recent plan of development for Badami, submitted in late March 2020 and covering the year ending July 15, 2021, Glacier proposed a continuation of work from the previous year. The plan called for evaluating the B1-07 well to gain insights for developing other Killian sands prospects at the unit and possibly drilling additional prospects outside the Badami Sands participating area "as economic conditions warrant."

The company brought the B1-07 well into production in May 2018, leading to a significant increase in Badami oil production. It was the first new drilling activity at the unit since 2012. The company expressed great optimism about the so-called Starfish prospect, saying that it could lead to exploration and development of similar prospects.

Glacier Oil & Gas Corp.

COMPANY HEADQUARTERS: 4601 Washington Ave., Ste. 220 Houston, Texas 77002
ALASKA OFFICE: 188 W Northern Lights Blvd., Ste. 510, Anchorage, Alaska 99503
PHONE: 907-868-1258
TOP ALASKA EXECUTIVE: Stephen Ratcliff, president
WEBSITE: www.glacieroil.com

In its plans, the company also said it would continue permitting the proposed Badami East pad to become the base of operations for drilling at the eastern edge of the unit.

A few months later, in late May, Glacier asked for permission to suspend operations and production at Badami through July 15, 2021. The request essentially extended the previous development plan by one year, requiring no additionally work commitments.

"The present global condition of low crude oil prices, combined with a lack of demand, obligates Glacier to act as a prudent operator and suspend operations until both demand and market price have sufficiently recovered to justify the resumption of production operations," the company wrote in its request. "This change in operating status to an (Suspension of Operations) will be undertaken with the intent to re-start operations."

The suspension placed the unit into warm-standby status with a small crew to oversee facilities including field infrastructure, the Badami Pipeline, and a small private airstrip.

The company also said it would restart production sooner than the deadline, if warranted by larger economic conditions. Those conditions arrived by the end of the summer. In mid-August, Glacier announced plans to restart full Badami operations in late September.

The company also revealed that it had decided to use the early summer suspension period to undertake "a significant turnaround operation and inspection" of equipment across the Badami unit. "The scope of this work is extensive and there are tanks and equipment that have not been inspected and serviced since installation," the company explained.

It is common for North Slope operators to temporarily suspend operations in the summer months to accommodate major maintenance and upgrade activities. In a sense, although unplanned and likely undesired, the shutdown this year provided a similar opportunity.

Although partial year-over-year comparisons can be imperfect, oil production at Badami was declining before the suspension in May 2020. The unit produced 161,115 barrels of oil in the first four months of 2020, compared to 229,122 barrels of oil during the same period in 2019, according to the Alaska Oil and Gas Conservation Commission.

WMRU and Redoubt

Recent swings in the economy also led Glacier Oil & Gas to suspend operations at its two offshore units on the west side of Cook Inlet: West McArthur River and Redoubt.

The development plans for the West McArthur River unit over the past two cycles have been slight and focused mostly on conversions and repairs, rather than drilling activities.

Glacier is looking to convert a shut-in well at the unit for use as a disposal well. The company is also planning a workover to restore production at the Sword well following a failed electric submersible pump but wants to time the project with other well activity.

And the company is continuing permitting activities on its Sabre project. The long-proposed offshore development calls for drilling an exploration well with a jack-up rig.

At the moment, only two of the 11 wells at the unit are producing — WMRU No. 2B and WMRU No. 6 — both from the Area No. 1 participating area. The unit produced approximately 183,338 barrels of oil and 34.8 million cubic feet of natural gas in 2019.

In early April, the state approved the current development plan, covering activities through April 30, 2021. But in late May, Glacier Oil & Gas applied to suspend operations from the West McArthur River unit and the associated Sword participating area through the remainder of the current development plan, citing low prices and flagging demand.

Under the plan approved by the state in early June, Glacier Oil & Gas was required to take preventative measures to protect wells and other infrastructure and was required to provide quarterly updates starting at the end of August and carrying through next April.

Glacier Oil & Gas has been busier at the Redoubt unit than at West McArthur River.

The company drilled the RU-6A sidetrack last year as a water injection well to enhance oil production at the field. The company also worked over the RU-2A well, replacing an electric submersible pump and adding perforations. The company deferred a plan to replace a failed electric submersible pump in the RU-9 well until later this year.

Redoubt produces from four of its nine wells — RU No 1A, RU No. 2A, RU No. 5B and RU No. 7B — 435,350 barrels of oil and 92.2 million cubic feet of natural gas in 2019.

In its original plan for this cycle, running through April 30, 2021, Glacier said it would work over the new RU-6A sidetrack to add perforations and also to improve injection capacity. The company said it might drill an additional well or sidetrack, if warranted.

And the company expressed interest in exploring the leases north of the Northern Fault Block at the unit, although the project would require "favorable economic conditions."

Those conditions have yet to materialize.

In late June, a month after requesting permission to suspend operations at West McArthur River, the company asked the state for permission to suspend operations at Redoubt.

Under a plan approved by the state in early July, Glacier Oil & Gas suspended operations from its Osprey platform but maintain

continued on next page

GLACIER *continued from page 37*

limited operations on its RU-D1 disposal well. The company also switched its power source to a diesel-powered generator fueled by two temporary tanks — 5,000 and 16,800 gallons — placed at the Kustatan Production Facility.

As part of the suspension, the state required regular reports. The company released its first quarterly report in early September 2020. According to the report, Glacier said it had shut-in the Redoubt wells from its Osprey platform, drained its pipelines, switched its power source, inspected its Brucker escape capsule, and was freezing facilities for winter.

Overriding royalty interest holder Dan Donkel appealed the decision to suspend the units, saying that the decision was not supported by evidence and that the state had failed to solicit public comment or to notify interest holders before allowing Glacier to proceed.

Unlike the summer turnaround at the Badami unit, Glacier Oil & Gas had yet to restart production at the West McArthur River unit or at the Redoubt unit by early September.

North Fork

The North Fork unit has fared better over the past year. As a natural gas field under medium-term contracts, it is less susceptible to short-term changes in price or demand.

In recent years, Glacier Oil & Gas has promoted "small ball" projects at the onshore unit in the southern Kenai Peninsula, north of the city of Homer. In looking for these projects, the company values relatively easy and affordable work that improves gas production.

As an example from the past year: a workover at the NFU 22-35 well in April 2019 added perforations to the well, increasing production by 1 million cubic feet per day.

The plan for the current development year, running through March 2021, called for a similar range of smaller projects but did not provide any details on those activities.

The North Fork unit produced 1.3 million cubic feet in the year ending June 2020, down from 1.4 million cubic feet in the preceding 12-month period, according to the AOGCC. ●

Contact Eric Lidji at ericlidji@mac.com

HEX getting to work at Kitchen Lights

HEX Cook Inlet is taking a pragmatic approach at its new Cook Inlet property

By ERIC LIDJI
For Petroleum News


JOHN L. HENDRIX

HEX Cook Inlet LLC became the newest operator in Alaska this summer when it closed on a deal to acquire the assets of Furie Operating Alaska LLC and related companies.

The $5 million acquisition was the culmination of the intense bankruptcy proceedings of Furie and its partners Cornucopia Oil & Gas Company LLC and Corsair Oil & Gas LLC.

The centerpiece of the purchase is the offshore Kitchen Lights unit, which is largest unit in Cook Inlet by area and which has been seen as a source of growth for the basin.

HEX Cook Inlet LLC is a joint venture between HEX LLC (80%) and Rogue Wave AK LLC (20%) founded by longtime Alaska oil industry player John Hendrix.

A native of Alaska with a long history in the region, Hendrix has stated his desire to hire locally. His company quickly switched suppliers to Udelhoven Oilfield System Services.

> **Hex Cook Inlet LLC**
>
> **COMPANY HEADQUARTERS:** 188 West Northern Lights Blvd. Ste.620, Anchorage, AK 99503
> **TOP ALASKA EXECUTIVE:** John L. Hendrix, president/CEO
> **PHONE:** 907-277-3726
> **EMAIL:** Admin@furiealaska.com

Fixing what it bought

HEX is acquiring an underperforming unit with considerable potential.

The Kitchen Lights unit includes three previously distinct

continued on next page

HEX COOK INLET *continued from page 39*

prospects that were unitized and then administratively divided into four exploration blocks: Corsair, North, Central and Southwest. All development activities to date have occurred within the Corsair block.

Furie brought the unit into production from the KLU 3 well in July 2013 and subsequently drilled three more wells — the KLU A-1 well between 2016 and 2018, the KLU A-2A well in September 2016, and the KLU A-4 well in October 2018. The development work involved construction of the new Julius R platform in Cook Inlet.

By the time HEX arrived as the new operator earlier this year, one of those wells was offline, awaiting upgrades and repairs. And the three producing wells were underperforming. The Kitchen Lights unit is currently producing around 13 million cubic feet per day, down from approximately 18 million cubic feet from a year earlier.

In one of its most immediate plans for the unit, HEX is eager to have all four existing wells produce from both the Beluga and the Sterling formations. As a first step toward that goal, the company is applying for a produced water permit from the state, which would allow it to better handle waterlogged gas production from the Sterling formation.

Improved water handling would allow the company to bring the offline well back online and would reduce the likelihood of prior technical challenges recurring at the unit.

It would also allow the company to add Sterling perforations to the three existing wells that are producing from the Beluga formation, thereby increasing overall production.

The Kitchen Lights unit includes three previously distinct prospects that were unitized and then administratively divided into four exploration blocks: Corsair, North, Central and Southwest. All development activities to date have occurred within the Corsair block.

By late summer, HEX was still awaiting the permit but had attempted repairs on the KLU A-4 well. There were two wireline fish and a tubing plug complicating operations.

"We made attempts to fish A-4 and learned a lot about it," Hendrix told Petroleum News in mid-August. "Prior to going to the next phase, we went ahead and punched the tubing to ensure production in case future fishing jobs prevented access. A-4 is currently producing about 2.0 MMCFPD. We now have several options in front of us."

History and future growth

Although HEX is currently focused on maintaining existing assets, the Kitchen Lights unit also contains significant growth potential, whenever the time comes.

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

The unit combined the Escopeta Oil & Gas Co.-operated Kitchen unit, the Renaissance Alaska LLC-operated Northern Lights prospect and the Pacific Energy Resources Ltd.-operated Corsair prospect. A corporate shuffle in 2011 put Furie in charge of the project.

Early plans of exploration for Kitchen Lights established four exploration blocks and required Furie to drill at least one well in each block. The company drilled exploration wells across the unit between 2011 and 2014 before shifting to development, leaving the North and Central blocks underexplored and the Southwest block undrilled, as of yet.

Beyond those aerial possibilities, the unit is also thought to contain deep resources. In previous plans, Furie proposed wells below 20,000 feet to look for deep Jurassic oil.

During the tenure of Furie and its predecessors, the Kitchen Lights unit was a perennial source of drama. After bringing a jack-up rig to Alaska to drill the prospect, the company was hit with a $15 million fine for violating the federal Jones Act, the largest fine ever levied for a violation of the federal law governing domestic and foreign naval vessels.

Furie publicly criticized the state and unilaterally suspended some operations in the 2017 open water season following a dispute with the state over oil and gas tax credits.

The company regularly proposed major exploration and development campaigns for the unit, although it only made minimal progress toward those commitments. The state even put the unit into default in late 2017 for Furie's failure to meet work commitments.

The company faced technical challenges in early 2019 when frozen hydrate plugs complicated natural gas shipments, leading the company to declare a force majeure event and requiring Enstar Natural Gas Co. to revise gas sales agreements for the unit. ●

Contact Eric Lidji at ericlidji@mac.com

Hilcorp nears 10 years in Cook Inlet

First decade included increases, consolidations and expansions across the basin

By ERIC LIDJI
For Petroleum News

As it nears its first decade in the Cook Inlet basin, Hilcorp Alaska LLC can claim several victories. The company has increased or maintained production at several legacy fields. It consolidated or suspended some of its smaller, dying fields. And it may soon be doing something it is not generally known for doing: expanding development into new areas.

The largest privately held oil company in America arrived in Alaska through major acquisitions of Cook Inlet properties from Union Oil Company of California and Marathon Oil Corp. in 2011 and 2012. Today, it operates some 20 fields in the basin, a figure that changes annually as the result of acquisition, development, and consolidations.


DAVE WILKINS

Those properties can be divided into four groups: 1) onshore west side properties, 2) offshore properties, 3) northern Kenai properties and 4) southern Kenai properties.

Onshore west side

Hilcorp operates four units at the northern end of the west side of the Cook Inlet basin: the Beluga River unit, the Lewis River unit, the Ivan River unit and the Pretty Creek unit.

The units in the region are actually divided into smaller clusters. Hilcorp became the operator of Lewis River, Ivan River, Pretty Creek and Stump Lake as part of its early acquisitions in the region. The company undertook areawide field studies, although the effort yielded few results. The Stump Lake unit was eventually terminated in 2017.

The subsequent acquisition of the major Beluga River unit created the possibility of integrating the three smaller fields to the north with the much larger field to the south.

The Lewis River unit includes two participating areas, Gas Pool No. 1 and Gas Pool No. 2. The unit produced exclusively

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Hilcorp Energy Co.

COMPANY HEADQUARTERS: 1111 Travis St., Houston, Texas 77002
TELEPHONE: 713-209-2400
ALASKA SUBSIDIARY: Hilcorp Alaska LLC
ALASKA SUBSIDIARY: Harvest Alaska
TOP ALASKA EXECUTIVE: Dave S. Wilkins, senior vice president
ALASKA OFFICE: 3800 Centerpoint Dr., Ste.1400, Anchorage, AK 99503
TELEPHONE: 907-777-8300
COMPANY WEBSITE: www.hilcorp.com

HILCORP *continued from page 41*

from the LRU C-01RD well in Lewis River Gas Pool No. 2 in 2019, totaling 185.6 million cubic feet — an increase of 28 percent from 2018.

The company performed one workover operation on the well in September 2019, adding perforations in the Tyonek F5 sand to address production and pressure issues in the well.

The company said it was not planning any drilling projects at the unit for the development year running through May 31, 2021, aside from unplanned maintenance.

Hilcorp did not conduct any drilling or workover projects at the Ivan River unit in the 2019 development year and did not plan any for the current year, running through May 31, 2021. The Ivan River unit produced 146.7 million cubic feet in 2019, down from 184.9 million cubic feet in 2018. The Ivan River unit also includes two disposal wells — IRU 14-31 and IRU 13-31—utilized by Hilcorp for all its west side Cook Inlet fields.

At the Pretty Creek unit, Hilcorp did not conduct any drilling or workover projects in the 2019 development year and did not plan any for the current year, running through May 31, 2021. The unit produced exclusively from the Beluga participating area, reporting 47.3 million cubic feet in 2019. The Pretty Creek unit also includes a gas storage operation from the PCU No. 4 well. The company injected 41.9 million cubic feet into the well in 2019 and withdrew 176.9 million cubic feet.

Offshore

Hilcorp operates five offshore units spread across the waters of Cook Inlet: North Cook inlet, Granite Point, Trading Bay, North Trading Bay and Middle Ground Shoal.

The company acquired North Cook Inlet from ConocoPhillips in late 2016 and launched a field study to determine the state of the unit and to guide development opportunities.

Although the company has yet to drill any wells at the unit, it began working over existing wells during its most recent development year, which ran through June 2020.

In its previous plan. Hilcorp proposed workover operations on the NCI-A-03 and NCI-A-09 wells. But after completing the NCI-A-03 project, the company determined that the NCI-A-09 project was not currently needed to access the target, according to Hilcorp.

For the coming year, running through June 2021, Hilcorp is not planning any drilling activity but expects to work over the existing NCI-A-04, NCI-A-07 and NCI-A-16 wells.

The company is continuing its field study of the Beluga and Sterling sands and advancing its plans to drill a development well sometime around 2022 to test deep oil prospects.

In the meantime, natural gas production is declining. The North Cook Inlet unit produced 5.1 billion cubic feet in 2019, down approximately 19% from the previous year.

Granite Point produces from three offshore platforms: Granite Point, Anna and Bruce.

Hilcorp proposed a two-to-three well sidetrack program at the Granite Point platform for 2019, depending on Cook Inlet ice conditions. The company completed the GP-53RD sidetrack, resulting in more than 1,100 barrels per day of oil. The company drilled the GP-55RD sidetrack but did not complete the project “due to hole instability in the coals overlying the target sands.” The company did not undertake the third sidetrack project.

The company is not proposing any drilling or workover projects at the Granite Point unit this year, although it is planning a pilot water injection test at the GP-24-13RD2 horizontal well to test injectivity in horizontal wellbores. The company is also evaluating the effectiveness of multilateral sidetracks at the Anna and Bruce platforms using coiled tubing drilling. The company has already undertaken these evaluations on wells at the Granite Point platform.

The Granite Point unit produces oil and natural gas. The unit produced 956,000 barrels of oil in 2019, down slightly from 1.027 million barrels in 2018. The unit produced 1.02 billion cubic feet of natural gas in 2019, up slightly from 1.004 billion cubic feet in 2018.

The Trading Bay unit includes two fields: Trading Bay and McArthur River.

In its 2019 development year, Hilcorp completed workover projects at the A-31 and A-03RD wells at the Trading Bay field. Both projects had been scheduled for 2018 but were delayed by a year. The company also drilled the A-10RD sidetrack to evaluate the Hemlock and Tyonek G-zone sands. The well was a dry hole and was not completed.

For the coming year, the company plans to work over the A-15RD2 well at the Trading Bay field to restore production from the Hemlock zone at the McArthur River field.

The Trading Bay field experienced declining production in 2019. The field produced 506.8 million barrels of oil in 2019, down 89,000 barrels from 2018. The field also produced 1.148 billion cubic feet of gas in 2019, down 229 million cubic feet from 2018.

In its 2019 development year, Hilcorp repaired an electric submersible pump at the G-33 well at the McArthur River field. The company is planning two workovers this year.

The McArthur River field also experienced declining production in 2019. The field produced 1.704 million barrels of oil in 2019, down 51,000 barrels from 2018. The field produced 8.347 billion cubic feet of gas in 2019, down 1.406 billon cubic feet from 2018.

The current development plan at the North Trading Bay unit is the first since the Division of Oil and Gas terminated the unit in in May 2019 and then reinstated it in March 2020.

The state agency said at the time that it had terminated the unit because there "currently are no diligent operations to restore production." But Hilcorp successfully appealed the decision, allowing it to proceed with activities intended to guide future operations.

In its earlier 2019 plan, Hilcorp announced plans to return the unit to production by sidetracking the A-10RD well. But the well did not encounter pay, setting efforts back.

The company is currently revising its plans using the results of the A-10RD project. The company expects to identify potential targets this year and undertake drilling in 2021.

Hilcorp operates four platforms at the Middle Ground Shoal unit. The unit currently produces from Platform A and Platform C. The Baker and Dillon platforms are shuttered.

Although the company originally did not propose any drilling or workover projects at the unit for the 2019 development year, the company reported five workover projects and announced plans to complete four additional projects before the end of the year.

Even with these workover projects, Hilcorp reported declining production for the year, with the exception of a notable bump in natural gas production at Platform C.

Platform A averaged 170,000 cubic feet per day of natural gas in 2019, down 72,000 cubic feet per day from 2018. The platform also averaged 839 barrels of oil per day in 2019, down 140 barrels per day from 2018. Platform C averaged 80,000 cubic feet per day of natural gas in 2019, up 18,000 cubic feet per day from 2018. The platform also averaged 420 barrels of oil per day in 2019, down 30 barrels per day from 2018.

The company is not planning any drilling or workover activities this year, aside from possible maintenance activities to repair electric submersible pumps as needed.

Northern Kenai Peninsula

The onshore fields on the east side of Cook Inlet are among

continued on next page

HILCORP *continued from page 43*

the oldest in the region.

Hilcorp operates four producing fields in the area: the Kenai unit, the Cannery Loop unit, the Swanson River unit and the Beaver Creek unit. The Birch Hill unit is not currently producing, according to the state. The Sterling unit was terminated in late 2017.

The Kenai unit is the oldest producing field in the region, responsible for launching the modern Alaska natural gas industry. The field produced 11.5 billion cubic feet in 2019.

The company drilled the KU 24-05B production well from the Kenai Unit Pad 41-07 in August 2019. The well was completed into the Tyonek D4, D3 and D2 sands.

For the current development year, running through March 2021, the company plans to maintain production by drilling the KU 24-32 well from the Kenai Unit Pad 34-31 targeting the Upper Tyonek and Beluga formations and by conducting workover projects.

At the Cannery Loop unit, Hilcorp drilled the CLU No. 14 well into the Beluga MB-8A and LB-4 sands, reporting initial production of some 4.5 million cubic feet per day. As of early 2020, the company was completing work on the CLU No. 15 well, targeting the Upper and Middle Beluga formations with a secondary target in the Sterling formation.

The results of the two wells will provide Hilcorp with information about the size and shape of the eastern flank of the Beluga and Tyonek structure at the Cannery Loop unit.

Hilcorp also reported eight workover projects at Cannery Loop during the 2019 development year. The company added perforations in the Upper Beluga UB-1 sands to the CLU No. 8 well, adding some 3.8 million cubic feet per day of incremental production. A pair of projects at the new CLU No. 14 well added no production, and neither did projects at the CLU No. 1RD CLU No. 5RD or CLU No. 13 wells.

Even with these drilling and workover projects, Cannery Loop production declined. The unit produced 1.77 billion cubic feet in 2019, averaging about 4.8 million cubic feet per day — down from 2.9 billion cubic feet in 2018, according to figures from the state.

The Birch Hill unit is currently offline, awaiting a major decision. Either Hilcorp can plug and abandon its well, or it can propose a plan for resuming oil and gas development.

The decision currently turns on access.

Hilcorp would prefer to access the site using a new gravel road from the north. The company believes this option would be shorter and less environmentally disruptive and would involve fewer land management challenges than a road coming from the south.

Construction of the so-called North Road depends on prior construction of the proposed Kenai Spur Highway extension project. The Kenai Peninsula Borough had originally expected to complete that highway extension this year, but it has since delayed the project until 2021, leading Hilcorp to request a corresponding delay for its North Road.

Even though it prefers the North Road, Hilcorp is still considering a plan to access the site by helicopter. The company is reluctant to use helicopters for the project, citing safety concerns. A proposed snow and gravel road from the Swanson River unit to the south "are now no longer viable options," due to economic and environmental reasons.

The road could also support future development at Birch Hill.

Hilcorp and minority partner CIRI Production Co. (20%) have been searching for third parties to develop the oil and gas resources at Birch Hill. A pair of meetings with an unnamed partner has not yielded firm arrangements. Hilcorp believes that the certainty provided by delaying the road project to 2021 would make it easier to find partners.

At the same time, Hilcorp has been working with civic and Native governmental authorities to permit plugging and abandoning the Birch Hill Unit No. 22-25 well.

The company plans to ask federal authority to extend the "plug or produce" deadline for BHU No. 22-25 until May 1, 2022, to better align the project with the highway work.

At the Beaver Creek unit, Hilcorp drilled a sidetrack of the BCU-04 well in the 2019 development year and conducted workover operations on the BCU-01B, BCU-09 and BCU-07A wells, but details of all four projects were redacted in its development plan.

For the coming year, running through March 2021, the company plans to drill the BCU-19RD sidetrack and workover the BCU-04RD well, plus other unnamed projects.

Natural gas production at the Beaver Creek unit declined in 2019 to 2.73 billion cubic feet, compared with 3.57 billion cubic feet in 2018, according to the AOGCC. Oil production increased to 129,888 barrels in 2019, compared with 74,998 barrels in 2018.

Southern Kenai Peninsula

Hilcorp operates three units in the southern Kenai Peninsula: Ninilchik, Deep Creek and Nikolaevsk. The company also leases several sizable clusters of un-unitized acreage in area. The company recently applied to form some of that acreage into the Seaview unit.

The southern Kenai Peninsula was an anomaly in the Cook Inlet region for decades. Its leases were underexplored, its prospects were under-developed, and its communities were unable to participate in the local natural gas supplies enjoyed by northern communities.

But increased investment by Hilcorp, as well as landmark projects by Glacier Oil & Gas and BlueCrest Energy, have revived interest in the region in a small but important way.

At all three of its properties in the region, Hilcorp has been trying to balance its desire to focus on existing assets with expanding into undeveloped corners of its lease holdings as a way to avoid various contraction deadlines that it inherited in one form or another.

The Ninilchik unit produced 37.5 million cubic feet per day in 2019, up around 30% from 2018 production rates, according to figures provided by Hilcorp.

The increases came from one drilling project and several workovers across the unit.

The Kalotsa No. 6 well into the Beluga BLG-134 sand in October 2019 added about 3.1 million cubic feet per day. Perforations in the Tyonek T-4, T-8 and T-10 sands at the Kalotsa No. 3 well in August 2019, adding 1 million cubic feet per day. Perforations in the Tyonek T- 65 sand at the Kalotsa No. 4 well in January 2020, adding some 14 million cubic feet per day.

Perforations in the Beluga BLG-53 sand at the Paxton No. 9 well in January 2020 added about 200,000 cubic feet per day. The

continued on next page

HILCORP *continued from page 45*

company also repaired the Paxton No. 2 well.

Perforations in the Beluga BLG-58/58A and 59 sands at Falls Creek No. 6 in October 2019 added about 100,000 cubic feet per day. Hilcorp also worked on Falls Creek No. 3.

The company also planned additional projects the Grassim Oskolkoff No. 8 and Susan Dionne No. 8 well during the development year but has not yet reported results.

The plan for the current development year, running through July 2021, involves drilling the Kalotsa No. 5 well and possible targets in the Grassim Oskolkoff participating area.

The company expects its workover activities to continue this coming year, including possible work on the Frances No. 1 well. Hilcorp made no firm commitments, though.

In the near term, the company is considering plans to drill the Blossom No. 1 sidetrack and the Pearl No. 2A delineation well and is evaluating its new Abalone prospect.

The Deep Creek unit produced 4.56 million cubic feet per day in 2019, according to Hilcorp. The unit produces from both the Happy Valley participating area (3.47 million cubic feet per day) and from two wells on a tract basis (1.09 million cubic feet per day).

Although the company had expected to maintain or increase production, rates fell from the year prior, in 2018, when Deep Creek produced 5.11 million cubic feet per day. But production diversified last year. The 2018 production came entirely from the Happy Valley participating area without any tract production outside of the participating area.

In mid-2019, after years of negotiations and deferrals, the Division of Oil and Gas contracted the Deep Creek unit down to

its participating area and producing leases.

The contraction was initially scheduled to occur November 2014, based on the statutory timeline requiring mandatory contraction 10 years after sustained production. The state and Cook Inlet Region Inc. agreed to extension in December 2011, when Hilcorp acquired the unit. The extension gave the new owner time to evaluate the property.

Even though Hilcorp had a record of seismic acquisition and exploration drilling in the area, the state wanted to see more immediate plans for developing those leases.

The previous development plan was limited to a few drilling and workover projects.

Bottlenecks in the Kenai Beluga Pipeline delayed the planned HVB No. 18 well this past year. The company is looking to drill the well in early 2021, although the project depends on market conditions. The results of HVB No. 18 will determine whether Hilcorp drills the proposed HVB No. 19 well or other wells targeting the Middle/Deep Tyonek sand.

In the coming development year, running through July 2021, Hilcorp expects to maintain production rates, largely through its planned workover activities. Those projects include recompleting the HVB No. 16 well to produce from the Sterling A sand, adding an Upper Tyonek perforation to the HVB No. 13 well, and returning HVA No. 1 to production.

A workover on the HVA No. 10 well in the previous development year added perforations into the T1 and T2 sands without any significant change in production rates.

The Nikolaevsk unit produced 476,000 cubic feet per day in 2019, down from about 500,000 cubic feet per day in 2018, according to figures provided by Hilcorp.

The company proposed no development activities at the unit last year and again proposed no activities for the current development year, running through July 2021. Although the plan was submitted in May 2020, the state had yet to approve or deny it by August 2020.

Nikolaevsk produces entirely from a single well, the Red Well No. 1. A stimulation campaign in early 2017 yielded a notable bump in production rates. But the effect was short-lived. The well had returned to pre-stimulate levels by early 2018. The company had hoped to add as much as 3 million cubic feet per day from the stimulation work.

Without justification for investment, Hilcorp turned its attention to other projects.

Hilcorp began exploring the Seaview prospect in 2015.

The work yielded the successful Seaview No. 8 well in 2018, which made a discovery in the Tyonek. The company is working to construct a pipeline to connect the Seaview pad to a nearby Enstar Natural Gas Co. Bailey Street Station, some two miles from the pad.

Hilcorp said it plans to drill the Seaview No. 9 well late this year or early next year.

The company is aiming to begin natural gas production by November. The current plan calls for delivering into the regional system in winter and storing supplies in summer.

As it moves toward development, Hilcorp asked the state to combine two state leases and un-leased state, borough, Native and private interests into the 2,975-acre Seaview unit. ●

Contact Eric Lidji at ericlidji@mac.com

Hilcorp launches a new era

With the acquisition of Prudhoe Bay, Hilcorp now leads Alaska development

By ERIC LIDJI
For Petroleum News

Milne Point was producing 18,400 barrels per day when Hilcorp took over the field in November 2014. By early 2020, production had reached 34,000 barrels per day with forecasts suggesting 40,000 barrels per day by year-end.

When Hilcorp Alaska LLC acquired a stake in four midsize North Slope oil fields from BP Exploration (Alaska) Inc. in 2014, it looked like an expansion of its previous work.

A large privately held independent, Hilcorp had acquired a significant percentage of the producing Cook Inlet basin through two acquisitions in 2011 and 2012 — one from Union Oil Co. of California and the other from Marathon Oil Corp. The company was known for rejuvenating aging oil fields, and it quickly pursued that strategy in Cook Inlet. Its investments yielded flat or growing production at fields that had long been in decline.

Even after those big deals, Hilcorp continued to display an eagerness for acquiring properties as they became available. It was living its mission to "acquire and exploit."

BP appeared to be going a different direction. An integrated multinational major with a long history in Alaska, the company had increasingly been narrowing its activities in Alaska, focusing on its responsibilities at the Prudhoe Bay unit. The company stopped wildcat exploration; it continued to make big investments in its North Slope properties, although to varying degrees by project.

Seen that way, the 2014 deal between Hilcorp and BP seemed like a perfect marriage. It allowed an eager newcomer to grow, and it allowed an established company to focus.

Hilcorp became the operator and 50% working interest owner of the Milne Point unit, the operator and majority working interest owner of the Duck Island and Northstar units, and a 50% working interest owner of the undeveloped offshore Liberty field.

But many in the oil patch wondered whether the company was actually auditioning for a much bigger gig.

Regardless of its intentions, its actions made a convincing case.

Within a few months of taking over the properties, Hilcorp devoted considerable resources to the Milne Point unit, just as it had done with its legacy Cook Inlet fields.

The company drilled more wells in more places. It renewed the focus on viscous oil. And it even commissioned a new drilling pad. In the six years since the sale in 2014, the two partners have invested approximately $700 million to date and drilled more than 60 wells.

The results have been dramatic. Milne Point was producing 18,400 barrels per day when Hilcorp took over the field in November 2014. By early 2020, production had reached 34,000 barrels per day with forecasts suggesting 40,000 barrels per day by year-end.

Prudhoe dreams

In view of those successes, it was natural to wonder what might be possible if Hilcorp was given the opportunity to apply its methods to other aging fields in the basin.

Milne Point may be large by Lower 48 standards, but it is relatively small by North Slope standards. The mighty Prudhoe Bay unit produces some 280,000 barrels per day. That's about seven times the rate Hilcorp is forecasting for Milne Point for the end of this year.

Ever since the announcement of the deal, the oil patch has been speculating on what strategy we might see in the next few years. Speaking to Petroleum News Publisher Kay Cashman toward the end of 2019, a retired unnamed BP Exploration (Alaska) executive pointed to the different management structures of the companies as a source of change.

Hilcorp is thought to have roughly half the levels of management between low-level employees and top executives compared to BP, which could lead to greater investment in technology and equipment. "That's what Hilcorp did at the Milne Point field when they took over from BP five years ago — they'll go after the big prize at Prudhoe, which is viscous oil. … Lower operating costs … will mean more oil for Hilcorp and the other Prudhoe partners (ExxonMobil and ConocoPhillips), but it will also mean more oil down TAPS and more revenues for the State of Alaska," the former executive explained.

As that comment suggests, the Prudhoe Bay field has always been seen as a keystone of the North Slope oil industry — and by obvious extension, the broader economy of Alaska.

Exploration work by the U.S. Geological Survey in the 1920s, and around World War II, created great interest in the North Slope basin in the early 1950s, as turmoil in several Middle East countries prompted some companies to reconsider remote American plays.

Territorial Alaska ranked high for its potential. Then the discovery of the Swanson River oil field in the Cook Inlet basin in 1957 made the economic case for Alaska statehood.

BP opened its Alaska field office in downtown Anchorage in 1959. The company spent the better part of a decade studying and exploring corners of the North Slope, without much success, before finally completing the Prudhoe Bay State No. 1 discovery well in 1968 — and discovering the largest producing conventional oil field in North America.

The discovery of the Prudhoe Bay oil field justified the construction of the trans-Alaska oil pipeline, which eventually came online in 1977. The pipeline created a path to market for the massive Kuparuk River oil field, the second largest oil field in North America.

Without the Prudhoe Bay unit, and by extension the trans-Alaska oil pipeline and the Kuparuk River unit, it is hard to imagine how any of the smaller oil fields across the North Slope could have been developed. While many of those fields would be considered elite properties if they were located in the Lower 48, their position in the wilderness of Arctic Alaska increases the cost of development, making many uneconomic on their own.

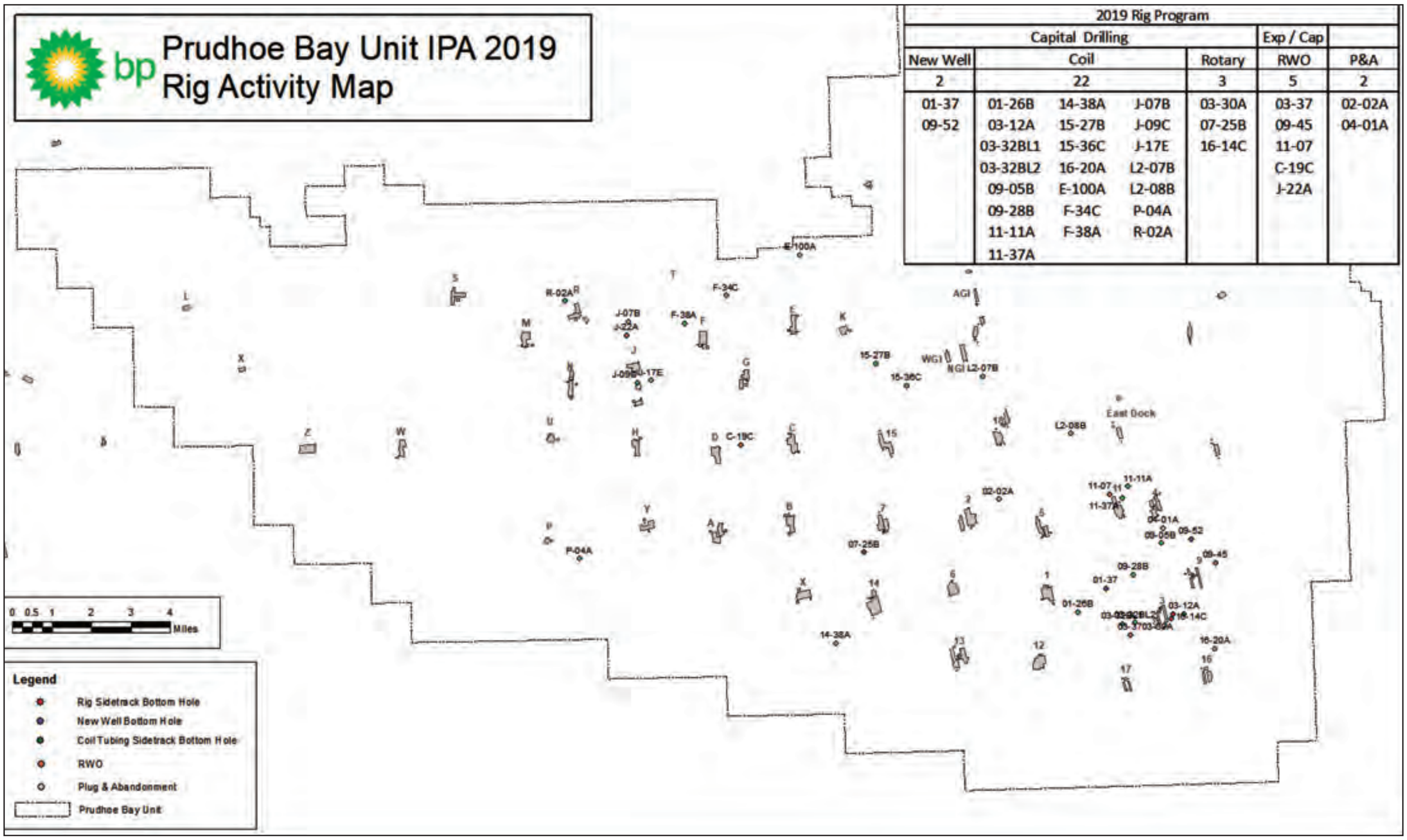
In fact, even today, more than 60 years after the discovery of the Prudhoe Bay oil field and the expansion of infrastructure in several directions, many significant North Slope oil fields remain stubbornly beyond the reach of economic development — at least as-of-yet.

The importance of the Prudhoe Bay unit can also be seen in its longevity.

No exploration work in Alaska has yet knocked Prudhoe Bay from its perch as the largest discovery. And even with decades of declining production, it continues to be the most productive field in Alaska. It has even remained one of the 10 most productive fields in the United States, despite the emergence of major unconventional plays in the Lower 48.

Those distinctions reflect not only the

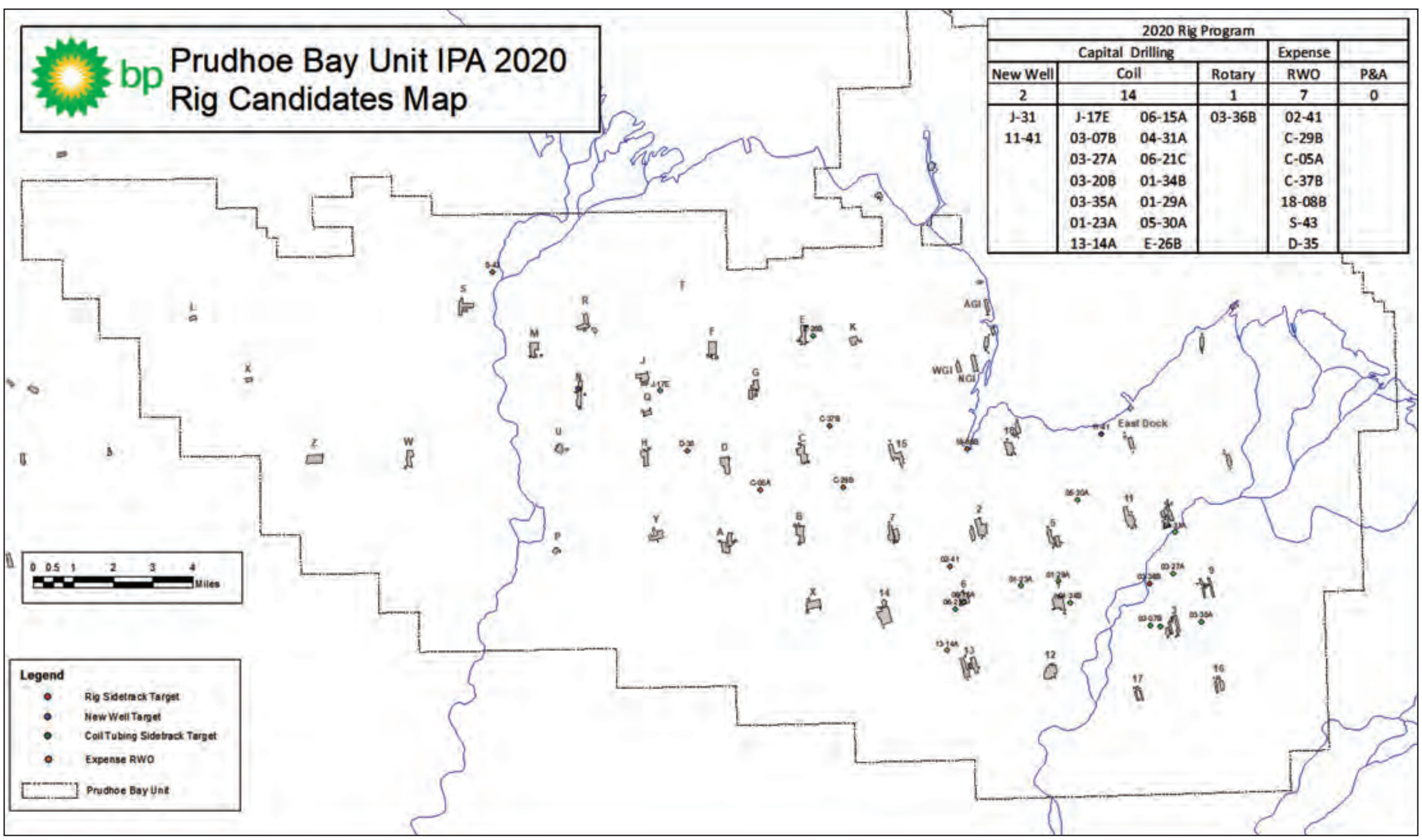
continued on page 51



2019 Rig Program

Capital Drilling					Exp / Cap	
New Well	Coil			Rotary	RWO	P&A
2	22			3	5	2
01-37	01-26B	14-38A	J-07B	03-30A	03-37	02-02A
09-52	03-12A	15-27B	J-09C	07-25B	09-45	04-01A
	03-32BL1	15-36C	J-17E	16-14C	11-07	
	03-32BL2	16-20A	L2-07B		C-19C	
	09-05B	E-100A	L2-08B		J-22A	
	09-28B	F-34C	P-04A			
	11-11A	F-38A	R-02A			
	11-37A					

BP EXPLORATION (ALASKA) INC./HILCORP ALASKA LLC



2020 Rig Program

Capital Drilling				Expense	
New Well	Coil		Rotary	RWO	P&A
2	14		1	7	0
J-31	J-17E	06-15A	03-36B	02-41	
11-41	03-07B	04-31A		C-29B	
	03-27A	06-21C		C-05A	
	03-20B	01-34B		C-37B	
	03-35A	01-29A		18-08B	
	01-23A	05-30A		S-43	
	13-14A	E-26B		D-35	

BP EXPLORATION (ALASKA) INC./HILCORP ALASKA LLC

HILCORP *continued from page 49*

tremendous size of the original resource, but also the incredible technological advances that have allowed operators to keep the field alive.

If recent history is any guide, Hilcorp will be continuing that recent spirit of persistence and resourcefulness is as it takes over as operator of the storied Prudhoe Bay field.

The deal

As the rumored sale of the Prudhoe Bay unit started to become a reality, the oil patch wondered whether BP Exploration (Alaska) Inc. might split the complex field — selling the west side assets to ConocoPhillips Alaska Inc. and selling the east side to Hilcorp.

But when BP finally announced the terms of the deal in late August 2019, Hilcorp had acquired everything. For the sum of $5.6 billion, the largest private oil and gas producer in the United States would own a major stake in the largest oil field in North America.

And although Prudhoe Bay was the obvious headline, the deal covered much more.

Hilcorp acquired the remaining interests in the Milne Point unit and the Liberty unit. The company originally acquired partial ownership and operatorship of those units in the 2014 deal.

Hilcorp also acquired a 32% non-operating interest in the ExxonMobil-operated Point Thomson unit. It also acquired an interest in exploration leases in the 1002 area of the Arctic National Wildlife Refuge, including a 50% stake in the KIC well.

Hilcorp also acquired ownership interests in several midstream assets: a 49% stake in the Trans Alaska Pipeline System and the Alyeska Pipeline Service Co., a 50% stake in the Milne Point Pipeline and a 32% stake in the Point Thomson Pipeline.

Hilcorp also acquired a 25% interest in the Prince William Sound Oil Spill Response Corp., which was created following the Exxon Valdez Oil Spill in 1989.

Even after the announcement, the question of operatorship remained unresolved.

The issue was one with a long history.

For decades following the discovery and commissioning of the field, ARCO Alaska Inc. operated the east side of the Prudhoe Bay unit, while BP operated the west side.

In the wake of the big corporate mergers of the late 1990s and early 2000s, operatorship changed. For the past two decades, BP Exploration (Alaska) has operated the entire Prudhoe Bay unit, although it only holds a 26% interest in the unit. ConocoPhillips and ExxonMobil each own a 36% interest, leaving 2% to minority owners.

The $5.6 billion announcement explicitly mentioned the 26% interest but not the operatorship, leaving many in the oil patch to wonder whether the unit would once again be split geographically or whether ConocoPhillips might even take over as operator.

But for reasons that may not come to light for a while time, if ever, the parties decided that Hilcorp would slip into the role BP was departing: 26% owner, full operator.

Added to its Cook Inlet holdings, the deal made Hilcorp a dominant player — perhaps the dominant player — in the Alaska oil industry. Few companies have ever owned so much.

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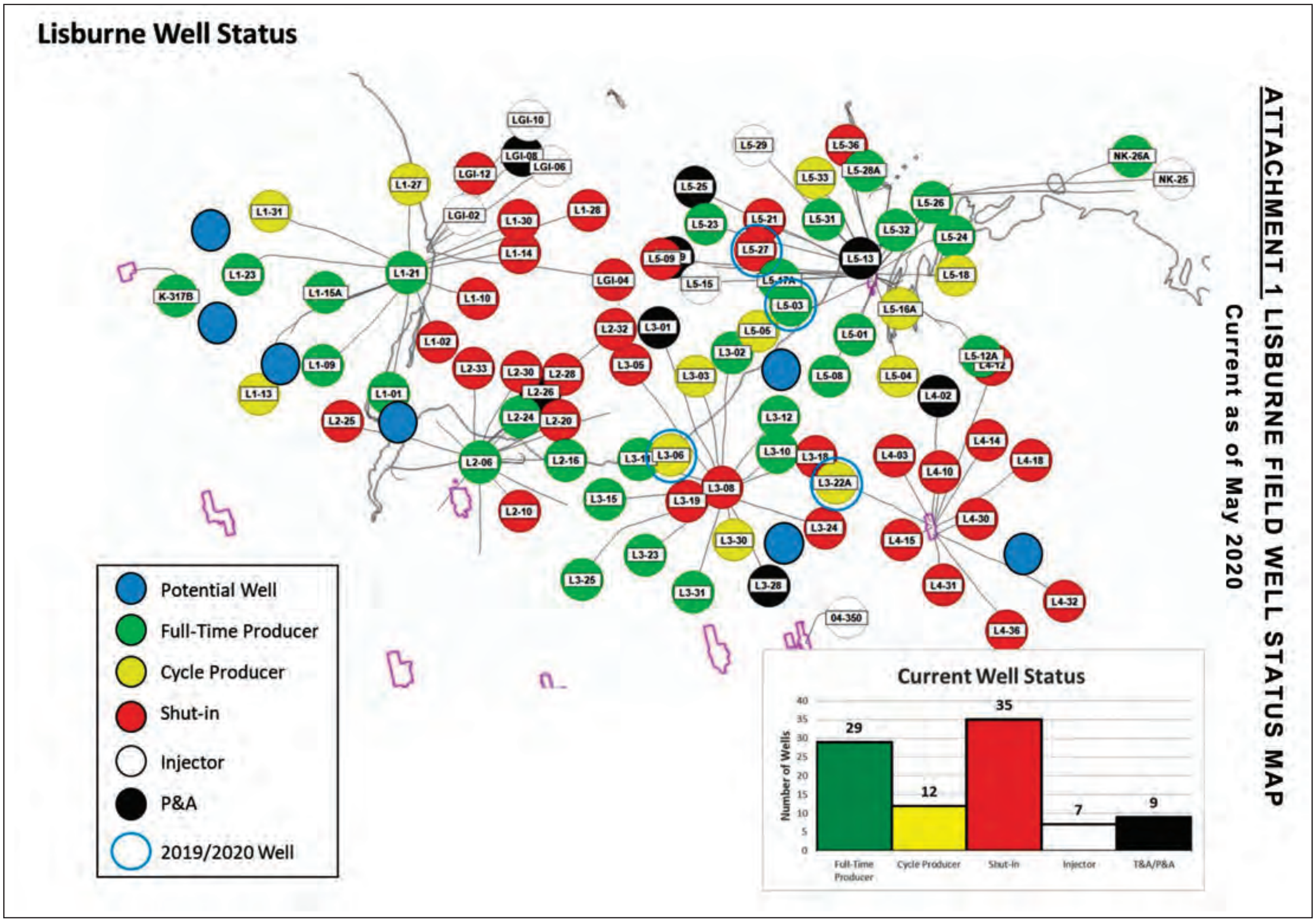

BP EXPLORATION (ALASKA) INC./HILCORP ALASKA LLC

HILCORP NORTH SLOPE *continued from page 51*

The Prudhoe Bay unit

As was the case with Milne Point, it will take a few years before Hilcorp's new strategy at the Prudhoe Bay unit is fully reflected in the commitments of its plans of development.

But if its experience in Alaska to date is any guide, the influence of Hilcorp at the largest oil field in the state will be felt quickly and will increase gradually over the coming years.

The operations of the Prudhoe Bay unit have typically been administered by three separate plans of development, each submitted at different points in the year: for the Initial Participating Areas, the Greater Point McIntyre Area and the Western Satellites.

BP Exploration (Alaska) filed the Initial Participating Areas and the Greater Point McIntyre Area plans of development before turning over operatorship of the unit to Hilcorp. Hilcorp filed an amendment to an earlier plan of development for the Western Satellites shortly after becoming operator in July.

PBU: Initial Participating Areas

The Initial Participating Areas, or IPA, is the largest of the three administrative regions at the Prudhoe Bay unit. It covers the initial oil and gas caps discovered at the unit.

The IPA is beginning its 43rd year of continuous operation and its 32nd year since peak production in the late 1980s. "With over 1400 wells, the field is well developed," BP explained in its plan of development. "Minimizing natural decline is the constant goal."

In its plan, BP presented a five-point strategy for managing the IPA: optimizing production in line with facility constraints, enhancing recovery through well work, managing pressure through injection, optimizing flooding and drilling new wells.

The IPA produced 165,030 barrels of crude oil and condensate per day in 2019, down from 174,200 bpd the previous year. The company had forecast crude oil and condensate production between 147,000 and 165,000 bpd for the current year. By comparison, the company had forecast a production range between 150,000 and 187,000 bpd for 2019.

The IPA also produced 43,600 barrels of natural gas liquids per day in 2019, equal to the year prior. The company forecast NGL production between 35,000 and 50,000 bpd for 2020, higher than the range of 30,000 to 46,000 bpd the company had predicted for 2019.

BP described its current development drilling strategy at the IPA as "focused," meaning limited and targeted toward specific opportunities or regions. For example, of the 27 wells the company drilled at the IPA in 2019, eight were associated with Flow Station 2.

The company proposed a smaller plan for this year, with 17 wells. The decline would largely come from a decrease in coil tubing drilling. The company had expected to use coiled tubing rigs for wells in other part of the unit or to conduct rig workover jobs.

The company acquired seismic data in 2019 and is now merging the results with previously acquired data sets. The results should guide drilling and other field operations.

Even though well maintenance was crucial to the BP strategy at the IPA, well work has been declining. The company performed approximately 880 jobs in 2019, of which 316 increased production rates. The year prior, the company had performed approximately 900 jobs, of which 360 increased production rates. This year, the company announced plans to perform approximately 800 jobs, of which 300 would increase production rates.

PBU: Greater Point McIntyre Area

BP submitted its IPA plan of development in late March, just as states were beginning to shut down over the COVID-19 pandemic, leading to a historic drop in oil prices.

The plan did not mention the pandemic. By the time the company submitted its Greater Point McIntyre Area plan in late June, the pandemic had become a central element.

The plan covers four producing fields: Point McIntyre, Lisburne, Raven and Niakuk. The plan also includes two suspended fields: North Prudhoe Bay and West Beach.

"As a result of the combination of COVID-19 presence in Alaska and the unprecedented drop in oil price, BPXA is re-leveling PBU activity for the remainder of 2020. Activity plans during the upcoming plan year beginning October I, 2020 through September 30, 2021 are uncertain," the company wrote, noting that it would meet regulatory obligations.

In fact, even today, more than 60 years after the discovery of the Prudhoe Bay oil field and the expansion of infrastructure in several directions, many significant North Slope oil fields remain stubbornly beyond the reach of economic development — at least as-of-yet.

The Point McIntyre field produced 13,800 bpd of crude oil, condensate and natural gas liquids during the year ending March 31, 2020, down from 16,700 bpd the year prior.

The company reported no drilling, workovers, or rate-adding activities for 2019 and announced no firm plans for the current year, although "active wellwork and scale inhibition programs" continue, according to the most recent plan of development.

The Lisburne field produced 11,800 bpd of crude oil, condensate and natural gas liquids in the year ending March 31, 2020, up slightly from 11,500 bpd the year prior.

During the development year, BP drilled three wells — L3-06, L5-03 and L5-27 — and started a fourth — L5-07. The company

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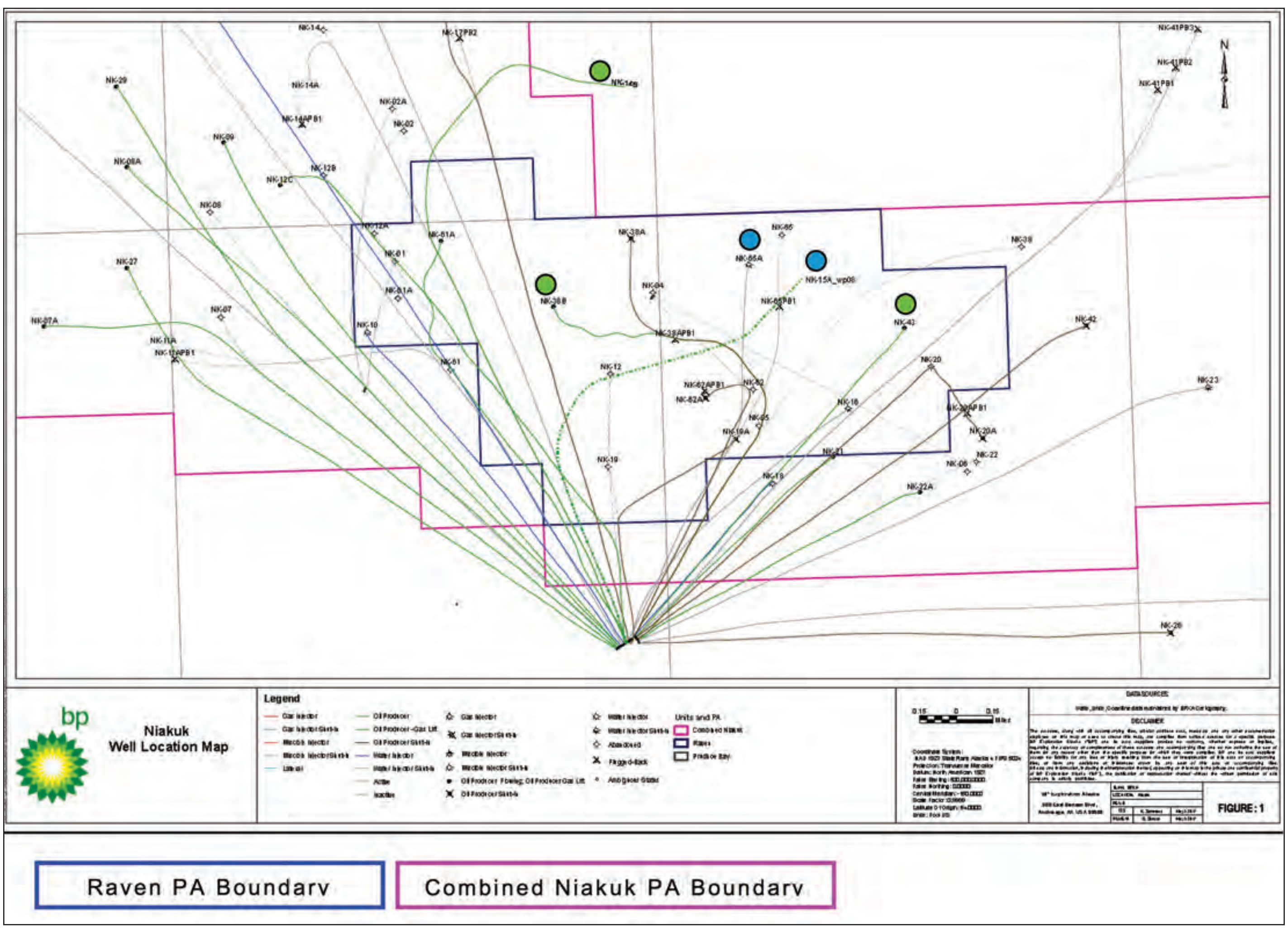

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HILCORP *continued from page 53*

also completed the L3-22A sidetrack and worked over the L1-31 well. The company performed rate adding non-rig projects on 21 wells.

In addition to L5-07, BP was considering four rotary and two coil tubing drilling well locations in the near future. "Several additional Lisburne drilling locations are being considered for possible future drilling but are contingent on the continued performance of the wells drilled during the 2015-2019 period, the results of the current planned wells, and the business environment. Additional rate-adding non-rig interventions are planned," the company noted, referring to the period following the North Prudhoe seismic survey.

The Raven field produced 1,440 bpd of crude oil, condensate and natural gas liquids during the year ending March 31, 2020, up slightly from 1,370 bpd the year prior.

The increase came in part from the NK-08B well brought online in May 2019. The well "has experienced stable production through the reporting period," according to BP.

The company announced no firm drilling or workover plans for the coming year, other than noting the importance of the North Prudhoe seismic survey for guiding future plans.

The Niakuk field produced 900 barrels per day of crude oil, condensate and natural gas liquids during the year ending March 31, 2020, down from 1,100 bpd in the year prior.

The company performed nine rate-adding jobs to six Niakuk wells during the year. The company made no firm drilling or workover commitments for the current year, but it said the North Prudhoe seismic survey was being used to study "subsurface areas of interest."

The North Prudhoe Bay field and West Beach field have been shut-in since the early 2000s. North Prudhoe Bay had produced 2.1 million barrels cumulative of crude oil and condensate before the WB-03 well was taken offline in February 2000. West Beach produced 3.37 million barrels of crude oil before it was taken offline in early 2001.

Although the company announced no plans to bring either field back into production, it noted that both fields were contained within the North Prudhoe

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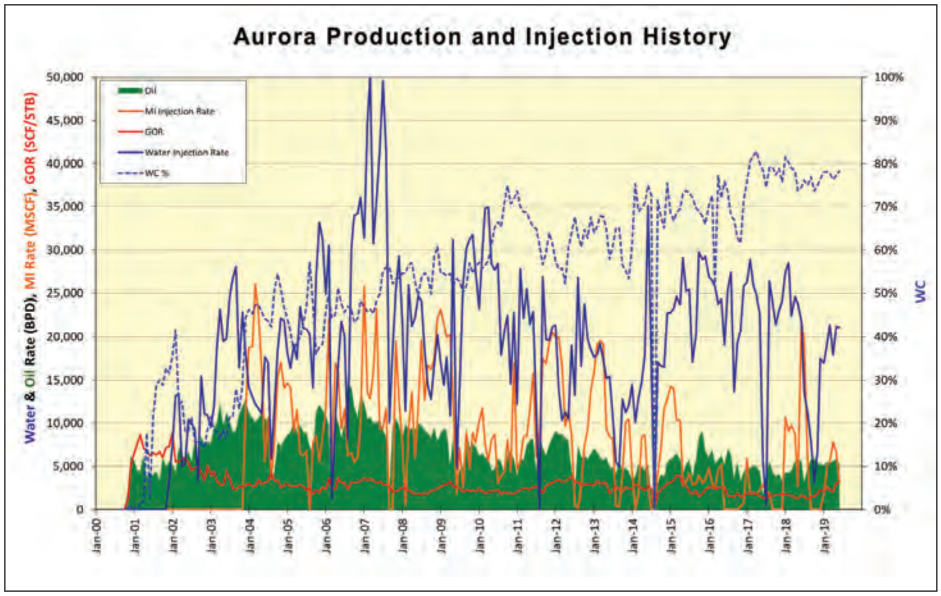

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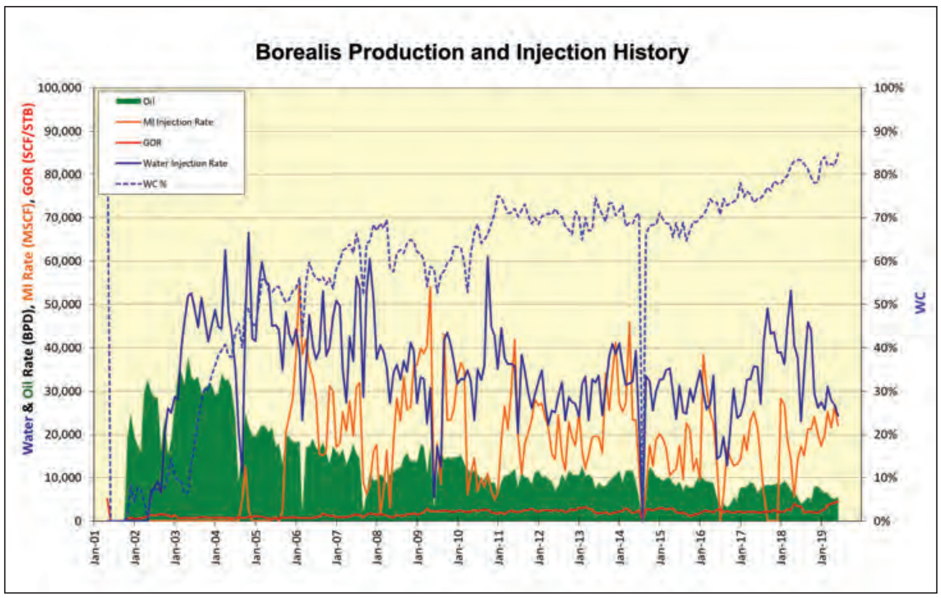

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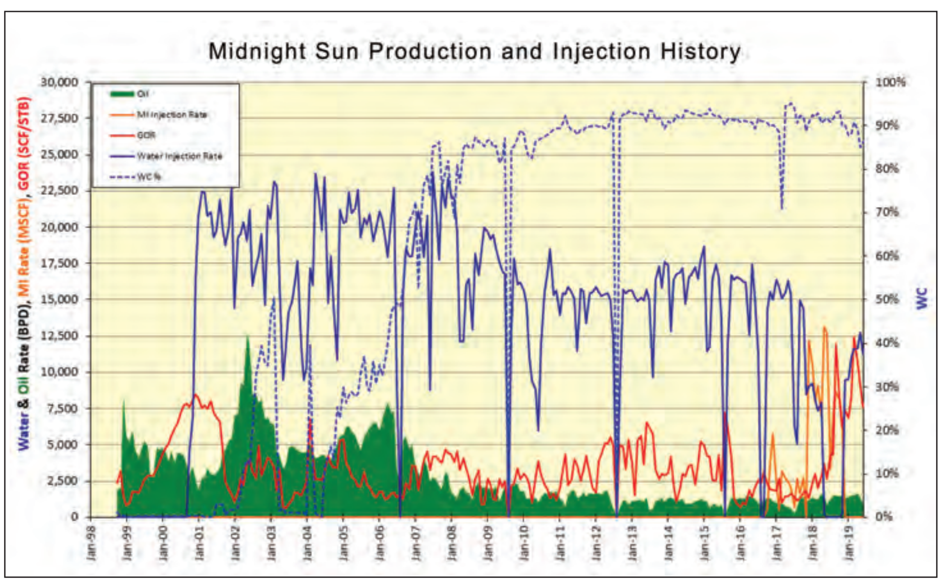

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seismic survey area.

PBU: Western Satellites

As with the other administrative regions of Prudhoe Bay, the immediate development plans for the Western Satellites were made uncertain by the change in operatorship.

BP Exploration (Alaska) submitted its 2020 development plan for the region in the latter half of 2019, after it announced plans to sell Prudhoe Bay to Hilcorp but before the deal had closed. State officials approved that development plan before the end of the year.

But in August 2020, a month after closing, Hilcorp requested a three-month extension, through March 2021. The extension would "allow for time to become familiar with PBU Western Satellites" before submitting a revised plan of development by February 1.

The Western Satellites include five participating areas: Aurora, Borealis, Midnight Sun, Orion and Polaris. The first three produce primarily from the Kuparuk River formation, while the other two produce primarily from the more viscous Schrader Bluff formation.

The Aurora, Borealis and Midnight Sun fields all produce from the Kuparuk formation.

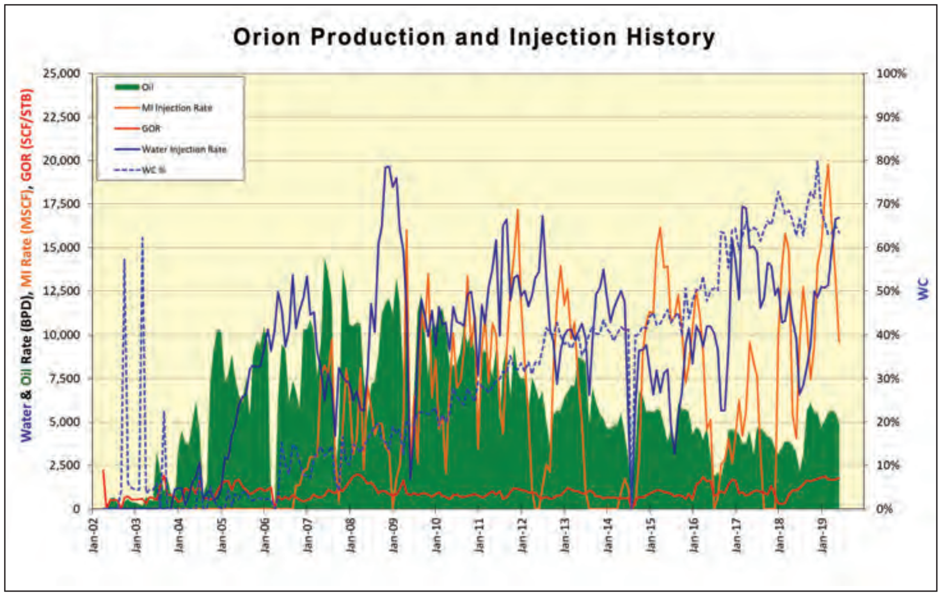
At the Aurora field in 2019, BP drilled a sidetrack of the S-105A well. The company also completed 66 workover projects, of which 20 yielded increases to field production rates.

Those projects were responsible for an uptick in production. Aurora produced 5,291 barrels of oil per day in the year ending June 30, 2019, up from 4,609 bpd the year prior.

At the Borealis field in 2019, BP completed 70 workover projects, of which 21 yielded increases to field production rates. Even so, oil production declined. Borealis produced 5,905 bpd in the year ending June 30, 2019, down from 7,914 bpd in the year prior.

At the Midnight Sun field in 2019, BP sidetracked the E-100 well into the Sambuca block, removing it from Midnight Sun production. Midnight Sun produced 1,394 barrels of oil per day in the year ending June 30, 2019, up from 1,158 bpd the year prior.

The 2020 plan included no firm development commitments for either the Aurora, Borealis or Midnight Sun fields. But the plan called for continuing well work to mitigate production declines at all three fields and potentially drilling infill wells, as appropriate.



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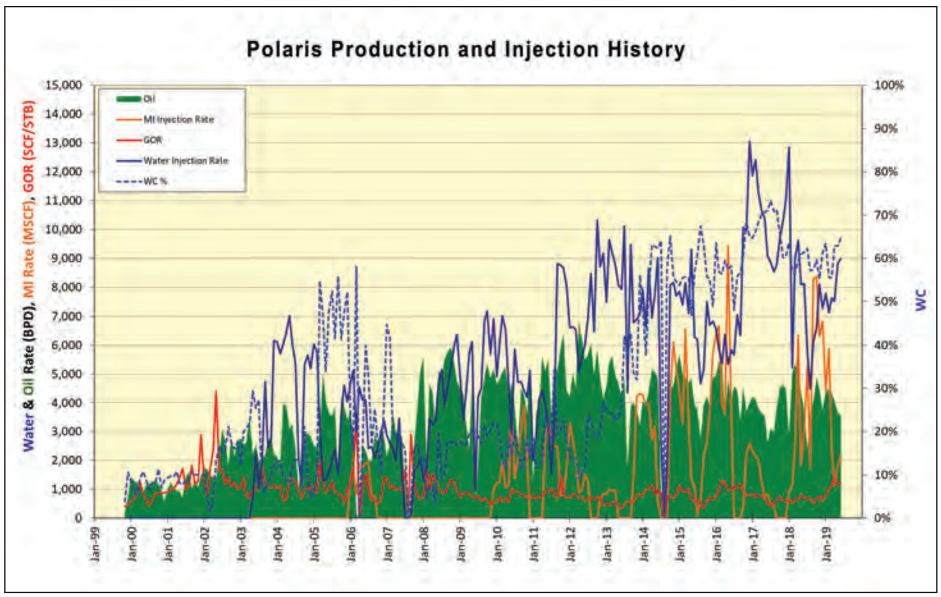

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The Orion and Polaris fields produce from the viscous Schrader Bluff formation.

At the Orion field in 2019, BP completed 65 workover projects, of which 20 yielded increases to field production rates. Overall, oil production increased. Orion produced 4,955 bpd in the year ending June 30, 2019, up from 3,900 bpd in the year prior.

At the Polaris field in 2019, BP completed 31 workover projects, of which seven yielded increases to field production rates. Even so, oil production declined. Polaris produced 3,969 bpd in the year ending June 30, 2019, down from 4,158 bpd in the year prior.

Toward the end of 2019, in response to comments from the state, BP submitted an amendment to its plan, calling for drilling three new wells by early 2020. The program included the S-202 multilateral producer and the S-201 and S-210A vertical injectors.

The program is something of a pilot initiative to test well design and completion technologies in the southern S Pad region. If viable, the work could be expanded.

For many years, BP has discussed the possibility of an I Pad project at the Orion and Polaris fields. The project currently hinges on the results of sand control technology, which could also be used in other areas of the fields, such as M Pad and S Pad.

The Milne Point unit

The most likely guide to the future of Prudhoe Bay is the nearby Milne Point unit.

In the years since it first acquired assets from BP, Hilcorp has directed most of its North Slope resources toward Milne Point, increasing activity, infrastructure and production.

The work not only included increased attention to aging wells. Hilcorp also increased grassroots drilling activities and quickly announced new pad permitting efforts. The company recently brought the new Moose Pad into production in just two years, under budget and without incident. Moose Pad is the first new pad at Milne Point since 2002.

The results are clear: Hilcorp says it is on track to double production at Milne Point. The unit was producing 18,400 barrels of oil per day when the company took over as operator in November 2014. Hilcorp expects production to reach 40,000 bpd by the end of 2020.

The unit produced some 25,541 bpd in 2019, up from approximately 20,839 bpd in 2018, according to Alaska Oil and Gas Conservation Commission figure. The unit produced 34,000 bpd in late January — the highest average production recorded since May 2008.

The production increases at the Milne Point unit are "an important milestone for the state of Alaska and Hilcorp," Hilcorp Energy Co. President Jason Rebrook said in the first quarter of this year. "By empowering our employees closest to the wellhead, driving efficiencies, and innovating, we're increasing production at Milne Point and putting more oil in TAPS. Our goal is to apply these successes at Prudhoe Bay and beyond."

Hilcorp fell slightly short of its drilling projections for the development year, completing 25 wells at the unit in 2019, down from the 29 wells it had forecasted in its previous plan.

The company completed 14 Moose pad wells targeting the Schrader Bluff formation. The program included 10 producers (M-10, M-12, M-14, M-15, M-16, M-17, M-18, M-20, M-21 and M-22), two injectors (M-11 and M-13) and two water wells (M-04 and M-06).

Hilcorp completed nine penetrations at seven wells at the E Pad, all targeting the Schrader Bluff formation in its 2019 campaign. The program included the E-37, E-41, E-42 and E-42L1 producers and the E-36, E-38, E-39, E-39L1 and E-40 injectors. The company also completed the S-201 and S-203 production wells into the Ugnu formation.

In addition to its drilling work, Hilcorp expected to reach its target of 16 workover projects in 2019. The work primarily involved changing out electric submersible pumps.

In its plan for the current year, Hilcorp proposed drilling 28 wells. The program would include 18 wells at Moose Pad and 10 wells at S Pad, targeting the Schrader Bluff, Ugnu and Kuparuk formations. The company is also proposing 20 workovers at Milne Point.

Through the first eight months of 2020, Hilcorp had completed 18 wells at the unit and received permits for another eight wells, nearly the entire planned drilling program.

As it proceeds with its initial Moose Pad development, Hilcorp is also advancing preliminary work for a proposed Raven Pad and an expansion of its existing S Pad.

The Duck Island and Northstar units

Although unable to match the successes at Milne Point, the Duck Island and Northstar units are beginning to see some maintenance activities with an eye toward optimization.

In its plan for the current year, Hilcorp proposed drilling 28 wells. The program would include 18 wells at Moose Pad and 10 wells at S Pad, targeting the Schrader Bluff, Ugnu and Kuparuk formations. The company is also proposing 20 workovers at Milne Point.

Even so, oil production is declining at both fields.

Hilcorp conducted approximately nine workover projects at the Duck Island unit in 2019 and completed several facility projects designed to improve overall field operations.

The company is projecting a decline in work this year, with no new drilling and just three workover projects. The workovers could return some suspended wells to production.

The unit experienced a slight decline in oil production last year. The main Endicott field produced approximately 6,338 bpd in 2019, down from approximately 6,487 bpd in 2018, according to the AOGCC. The field produced some 6,251 bpd in the first half of 2020.

Hilcorp conducted two workovers at the Northstar unit in 2019, converting the NS-07 Ivishak producer into a Kuparuk C producer and the NS-17 Ivishak injector to a Kuparuk C injector. The company also advanced its Northstar Propane Chiller Project to improve natural gas liquids recovery from the field. The project is continuing into this year, too.

The company is planning two workover projects this year. One would acidize one or more Kuparuk wells to improve operations. The other would repair surface casing.

The unit produced some 7,610 bpd in 2019, down from 8,211 bpd in 2018, according to the AOGCC. The unit produced some 6,418 bpd in the first half of this year.

The Liberty field

The biggest and hardest project in the Hilcorp portfolio on the North Slope is the Liberty unit, which BP failed to bring into production after decades of ambitious attempts.

Under the current strategy, Hilcorp wants to develop the offshore field from a gravel island in the federally managed Outer Continental Shelf of the Beaufort Sea. The $1 billion project could produce for 30 years, reaching a peak of 70,000 barrels per day. ●

Contact Eric Lidji at ericlidji@mac.com

Utqiagvik sees another year of small, steady success

The northernmost city in the United States continues to benefit from local gas production

By ERIC LIDJI
For Petroleum News

In the aftermath of World War II, the federal government sponsored exploration in the National Petroleum Reserve-Alaska in a bid to improve domestic energy security. But the most lasting impact of that exploration work to date has been local, not national.

Under the operatorship of the North Slope Borough, the Barrow gas fields have been providing affordable energy to the people of the city of Utqiagvik for decades.

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


HARRY K. BROWER, JR.

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

South Barrow

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

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

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

After nearly six years of inconsistent production, South Barrow has now been producing regularly since May 2018. In the year ending June 1, 2020, the field produced nearly 102 million cubic feet, or some 279 thousand cubic feet per day, according to the AOGCC.

Cumulative production at the South Barrow field is 23.96 billion cubic feet, according to the AOGCC. Early geological forecasts estimated some 32 billion cubic feet in lifetime production at the field, suggesting the potential of ongoing production for years to come.

North Slope Borough

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

By improving deliverability, the city of Utqiagvik 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.

East Barrow

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

Production began in December 1981. Drilling continued through 1990, with eight wells total. Gas production peaked in early 1983 at some 2.75 million cubic feet per day.

In the year ending June 1, 2020, East Barrow produced some 137 million cubic feet, averaging 375 thousand cubic feet per day, according to the AOGCC. That was down from some 143 million cubic feet and 391 thousand cubic feet per day in the year prior.

Cumulative production through June 1, 2020, was 9.7 billion cubic feet, well above the 6.2 billion cubic feet in place originally estimated for the East Barrow field. The city of Utqiagvik attributes the productivity to the presence of methane hydrates at the field.

Walakpa

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

Walakpa is the most productive of the Barrow gas fields. In the year ending June 1, 2020, it produced 1.3 billion cubic feet or nearly 3.6 million cubic feet per day, according to the AOGCC, up from 12.8 billion cubic feet or more than 3.5 million cubic feet per day in the year prior. Cumulative production through June 1, 2020, was 34.4 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

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