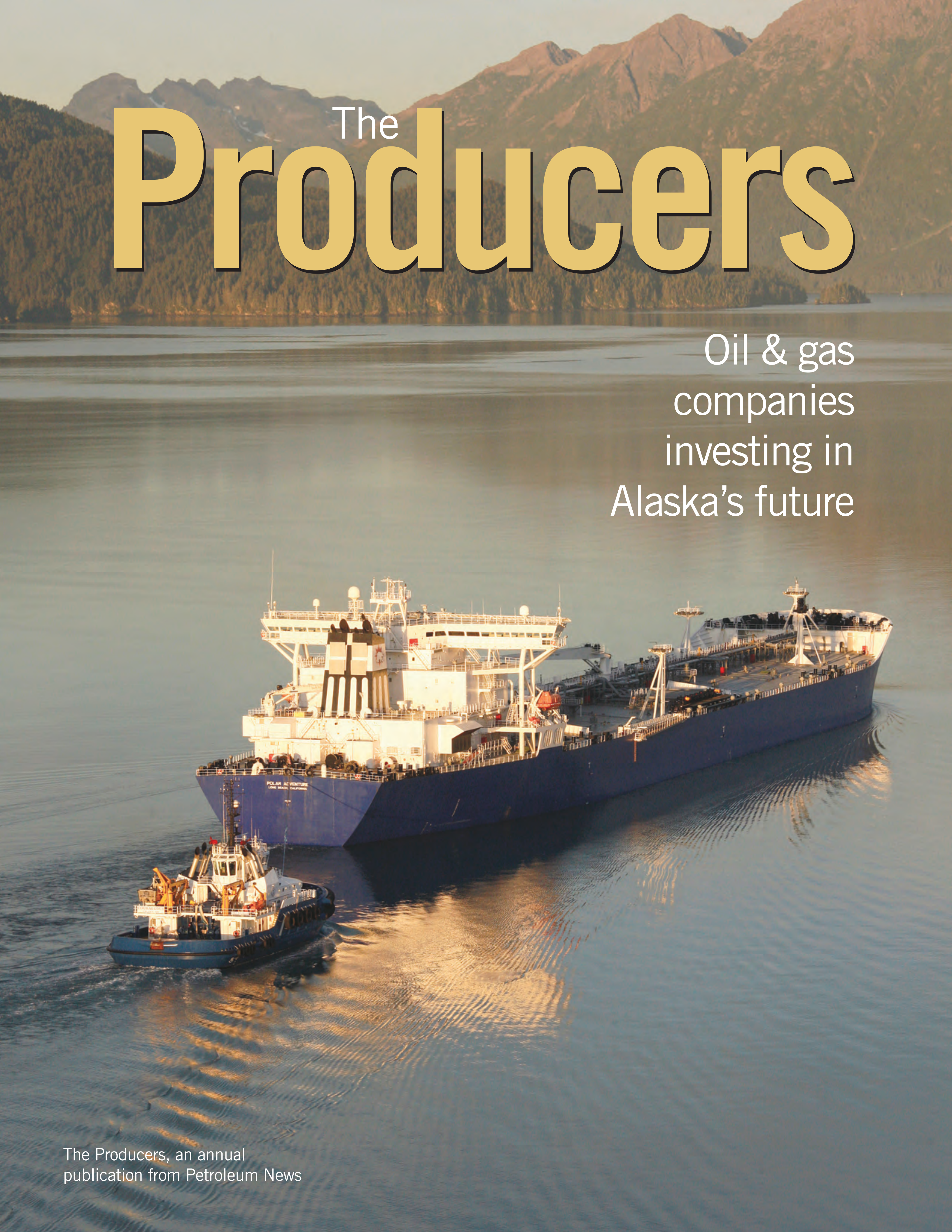

The Producers

Oil & gas companies investing in Alaska's future

The Producers, an annual publication from Petroleum News


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Alaska development seems to be recovering

Most operators have resumed drilling activities; some in exciting ways

Oil prices are recovering, and the big question is whether development is recovering as well. This issue of The Producers suggests that operators are slowly gaining confidence.

BP is maintaining and occasionally increasing oil production at the Prudhoe Bay unit while reducing drilling. ConocoPhillips is doing something similar in older areas of the Kuparuk River unit while confidently expanding its development activities at the Colville River unit and the Greater Mooses Tooth unit (and inching into the Bear Tooth unit).

Eni ended its drilling suspension at the Nikaitchuq unit with an ambitious exploration well to the north, while Caelus maintained its drilling suspension at the Oooguruk unit.

ExxonMobil is working to overcome the technical challenges hampering production at the Point Thomson unit, while Brooks Range Petroleum is working to overcome the longstanding hurdles that have delayed production at the Southern Miluveach unit.

Hilcorp is increasing its investment on the North Slope, particularly with a new pad at the Milne Point unit and momentum building for its Liberty project with BP. In Cook Inlet, the company appears to have entered a less aggressive phase of its reinvestment.

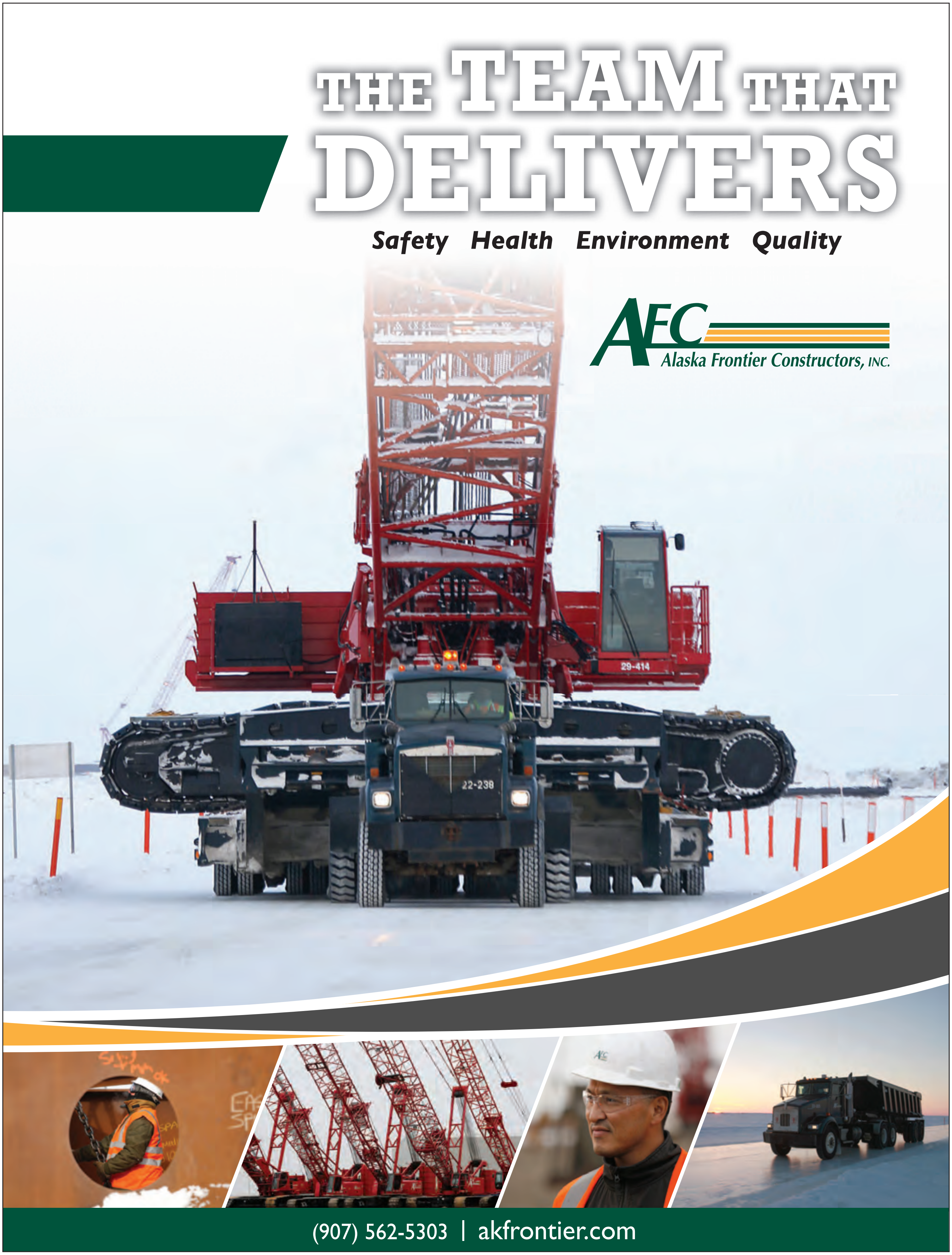
The only other operator with assets both on the North Slope and in Cook Inlet, Glacier, found success with a well at the Badami unit and continues to take a measured approach in the Cook Inlet region at West McArthur River, Redoubt and North Fork.

Amaroq tackled several maintenance projects at the Nicolai Creek unit. AIX Energy continues to find ways to defer similar expensive investments at the Kenai Loop field.

With three wells online and a fourth coming, Furie is approaching a turning point at the Kitchen Lights unit and will have to decide how to proceed. BlueCrest found success at the Cosmopolitan unit with a new well design that it intends to replicate in the future.

And as always, the North Slope Borough chugged along as the most consistent operator in Alaska, continuing to produce from its three gas fields for the benefit of its citizens.

—ERIC LIDJI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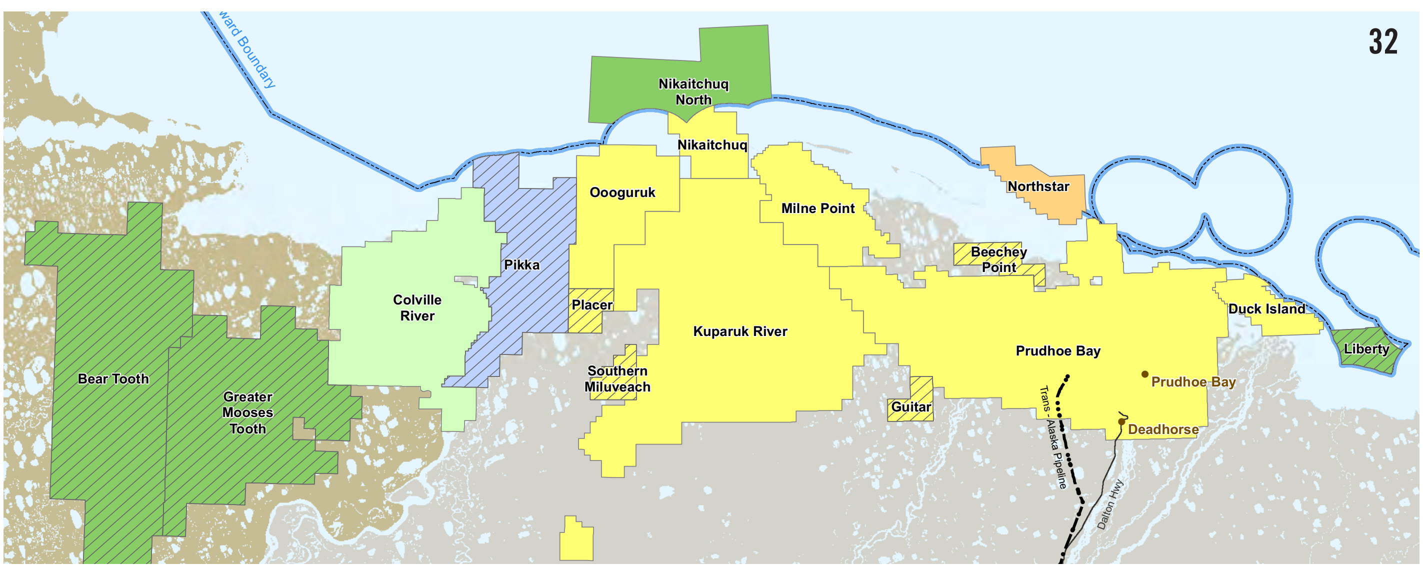

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*On the cover:
A tug escorts a tanker from the terminal towards the Valdez Narrows in September 2018..*

Photo by Judy Patrick, courtesy of Alyeska Pipeline Service Company

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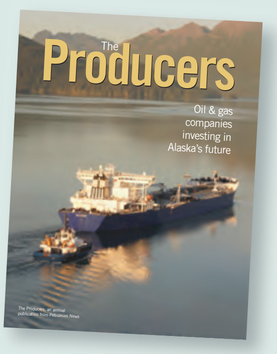

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Message from the director

By CHANTAL WALSH

Director, Alaska Division of Oil and Gas

CHANTAL WALSH

There are ample reasons to be excited about the recent news coming from Alaska's North Slope. Among the positive reports are predictions of increased oil production, increased investment and increased jobs. If these predictions come to fruition, Alaskans will reap the benefits from the increased oil revenues. Announcements are coming in regularly now, so I'll like to take a moment to talk about how the Division of Oil and Gas has been promoting North Slope activity and success.

For years, we observed oil production into the trans-Alaska Pipeline falling each year by approximately 5 percent. But three years ago, a remarkable trend occurred: production was flattening out and even increasing slightly. In FY15 production averaged 501,000 barrels a day for the year. By FY17, production had hit 524,000 barrels. We haven't finalized our FY18 numbers yet, but we are expecting more positive production news.

Leveraging this momentum, on Nov. 13 the state of Alaska will hold its annual North Slope, Beaufort Sea, and North Slope Foothills lease sales. Especially exciting this year is the introduction of a new concept for Alaska oil and gas leasing, a concept we designate as SALSA, or Special Alaska Lease Sale Areas. SALSA blocks are multiple-lease blocks being offered together, each with publicly available seismic data and an abundance of other data, including logs, well tests, etc. We believe these SALSA blocks, along with the information available for them, will provide explorers and investors with valuable tools to inform their participation in the special lease sale. Find out more by searching for "SALSA" on the Division of Oil and Gas website.

Data key

As our SALSA concept acknowledges, data is a key element for successful exploration and development. Talented geologists, geophysicists, and technical staff in our Resource Evaluation team have labored for more than a year to compile the data needed to accelerate the private sector's oil and gas evaluations. And we didn't limit the data to just that from within the Division of Oil and Gas. We scoured the databases of the Alaska Oil and Gas Conservation Commission, the Division of Geological and Geophysical Surveys, and DNR's Geologic Materials Center.

Speaking of data, we continue releasing valuable seismic data sets from across the North Slope — a win-win for the state and industry. This seismic data makes it possible for companies to acquire data inexpensively about areas of interest, increasing the chance they may develop resources. But, at a time when the state is facing

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Investment on the horizon at Kenai Loop

New gas sales agreement allows for increases and decreases in year three

By ERIC LIDJI
For Petroleum News

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AIX Energy LLC is beginning a new phase at its Kenai Loop field.

Over the summer, the Texas-based independent completed the terms of the gas sales agreement it inherited from predecessor Buccaneer Energy Ltd. and started a new three-year gas sales agreement negotiated with regional distributor Enstar Natural Gas Co.

The new gas sales agreement reflects the reality of the Kenai Loop field today and the uncertainty going forward. It accounts for increasing production in the first two years and allows the company to either increase production further in year three or to decrease it.

The company is currently considering three related projects that will determine future production rates at the onshore Cook Inlet field northeast of the city of Kenai. One project would install compression at the field to improve reservoir pressure. A second would connect a dormant well to the system. A third would work over existing wells.

In the years since AIX Energy acquired the Kenai Loop field from Buccaneer in late 2014, the company has met its commercial obligations without significant investments beyond those required for daily operations. The cautiousness of this strategy differs starkly from the approach of Buccaneer, which leveraged the equity at Kenai Loop into an ambitious portfolio of Cook Inlet properties and ultimately declared bankruptcy.

In its nearly four years as operator, AIX Energy has generally invested only when required. For example, the biggest infrastructure project over the past year was the decommissioning of a second, unused drilling pad in June 2017. The decommissioning allowed the company to end a surface lease with the Alaska Mental Health Trust.

More investment will become inevitable as Kenai Loop ages. Average production at the field peaked above 11 million cubic feet per day between October 2015 and January 2016, according to figures provided by the company. The field produced 2.827 billion cubic feet in the year ending March 31, 2018, down from 3.159 bcf in the year ending March 31, 2017 and down from 3.657 bcf in the year ending March 31, 2016.

According to terms provided by AIX Energy and Enstar, the new agreement requires AIX Energy to provide a firm supply of 1.370 bcf between July 1, 2018, and March 31, 2019. The volume would increase to 1.464 bcf between April 1, 2019, and March 31, 2020.

Between April 1, 2020, and March 31, 2021, the volume would either decrease to 1.095 bcf or increase to 1.825 bcf (a range of 3-5 million cubic feet per day). AIX Energy has until Sept. 1, 2019, to inform Enstar about the ultimate volume it intends to deliver.

Compression

The plan to add compression is the most expensive one currently on the docket.

In its fourth plan of development, submitted to the state in May 2018, AIX Energy claimed it could meet production obligations through the fall before it would need to install compression. "Extended flowing and shut-in data was used to update nodal analysis and systems models, resulting in a high level of confidence that under current market conditions compression could be deferred until the fall of 2018," AIX wrote.

AIX Energy publicly raised the inevitability of adding a compression system at Kenai Loop in its first plan of development, submitted to state authorities in May 2015. At the time, the company estimated that the field would need compression within 12 to 18 months, depending on the demand for near-term and non-firm gas sales. The company repeated the 12-to-18-month estimate in its second plan of development from early 2016.

In its third plan, from early 2017, AIX Energy pushed its esti-

continued on page 11

AIX ENERGY *continued from page 10*

mated date for installing compression to this summer and said it would use flowing and shut-in data to assist with planning. The result of that modeling allowed the company to defer the project to fall.

Interconnection and recompletion

Associated with the compression project is a proposal to connect the shut-in KL 1-4 production well into the existing system to increase both deliverability and redundancy.

Buccaneer drilled four wells during its initial development campaign at Kenai Loop. The field is currently producing from KL 1-1 and KL 1-3. The KL 1-2 is temporarily suspended, and AIX Energy has expressed an interest in converting the well to disposal.

Connecting the KL 1-4 well into the system would improve operations by increasing deliverability from the field and creating a backup for the existing wells. The project could potentially increase overall recovery at Kenai Loop, according to the company. In the coming year, AIX Energy plans to perform a cost-benefit analysis of the interconnection project and a related project to recomplete the KL 1-1 and KL 1-3 wells. ●

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WALSH *continued from page 8*

large deficits, we also see revenue from the sale of these data sets. Credit is due to the Legislature for establishing what has turned out to be a successful and revenue positive program for the state. We look forward to continuing to release seismic data, and generating interest, for some years into the future.

The Division of Oil and Gas is also working diligently to participate in and cooperate on federal permitting processes to move projects forward. A fair amount of work and staff time is going into the Arctic National Wildlife Refuge Environmental Impact Statement. As we all know, opening ANWR has long been a goal of Alaskan governors, policy makers and the public alike for decades. We strongly believe oil and gas exploration in ANWR can be done safely and responsibly, as we do elsewhere in Alaska. We look forward to the leasing program.

Field information

Division of Oil and Gas staff are also logging field time and coordinating efforts with other state agencies to gather valuable field information. In June and July, our staff, along with staff from DNR's Division of Geologic and Geophysical Survey, carried out field programs focusing on the Nanushuk formation and other Brookian depositional systems. Our DNR geologists also joined USGS geologists working in and near the ANWR Coastal Plain to better document and interpret the source rocks, reservoir units, trapping mechanisms, and oil occurrence of the eastern North Slope.

The Geologic Materials Center, home to massive amounts of the state's geological and geochemical data and samples, continues to expand its services, hosting core workshops and tours, increasing public access to core samples and data, and generating new revenue for the state through the collection of fees. Samples stored at this facility have been used to help discover hundreds of millions of barrels of oil in the North Slope region.

New developments

We are excited about near-term production from new developments like Greater Mooses Tooth-1. GMT-1 is an important project. It marks the first significant production coming from federally owned land in the National Petroleum Reserve-Alaska. A billion-dollar project, it is forecast to add nearly 30,000 barrels a day of production at its peak. Critically important to the state is where the revenue from oil and gas activities in NPR-A will flow. The state will realize positive benefits from production taxes and corporate income taxes, while the state's share of royalty revenues will flow to directly-affected Native communities as impact mitigation revenues.

Hilcorp's Moose Pad, on state land, is another exciting development set to come online at the end of 2018 and it will bring direct royalties and taxes to the state. Hilcorp has been working hard to expand its portfolio and position on the North Slope and may soon log Moose Pad production as another success. This development is expected to produce between 16,000 and 18,000 barrels a day at peak production.

The benefits of all these new projects extend beyond just the direct jobs and revenue. Each barrel of new oil from state or federal lands produced into the Trans-Alaska Pipeline System contributes toward reducing the tariff on all barrels that flow through TAPS. This reduces operating cost on existing production, while also improving the economics for projects across the entire North Slope.

There is good reason for excitement when it comes to activity on the North Slope. We at the Division of Oil and Gas look forward to reviewing applications, partnering with producers and explorers, and assisting companies with getting to production to the best of our abilities. North to the future, to new opportunity, and to oil and gas development in Alaska. ●

Amaroq sets course at Nicolai Creek

Five-well workover program yields production increase but investment needed to preserve field

By ERIC LIDJI
For Petroleum News

Amaroq Resources LLC alleviated confusion in three ways over the past year.

The first was its name. The company started the year as Aurora Exploration LLC. But it was not affiliated with the former Aurora Gas LLC, despite a shared history in the Cook Inlet region, and it adopted the name Amaroq in April to avoid inevitable misattributions.

The second involved regulation. The purchase of the Nicolai Creek unit was delayed in late 2017 by a dispute over bonding. The Alaska Oil and Gas Conservation Commission initially required several million dollars worth of bonds to guarantee the plugging and abandonment of six Nicolai Creek gas wells. The company said that the amount would render the field uneconomic. The commission later reduced the requirement to $200,000.

The third was its direction. Amaroq completed its purchase of the Nicolai Creek unit from Aurora Gas in January 2018 and set in motion a development program at the west side Cook Inlet natural gas field. Instead of pursuing a development well proposed during the months of transition between the companies, Amaroq focused on maintenance and workover activities designed to improve operations and production at existing wells.

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Workovers

The development program started with a compressor repair that Amaroq credited with doubling production at Nicolai Creek and continued with a major sand clearance effort.

A series of workover operations at several wells over the summer months yielded mixed results — increasing production in some cases and necessitating shut-ins at others, according to a 45th plan of development submitted by Amaroq in late September 2018.

The company did not drill at the Nicolai Creek unit during the current development year and had no plans to do so in the remaining months of the cycle, which runs through the end of December. But the company conducted workover operations on at

Without additional investment, either through development drilling or gas storage, the Nicolai Creek unit will likely become uneconomic in 2022, according to Amaroq.

least five existing wells at the onshore Cook Inlet, mostly to check for and clean out sand fill.

The company ran slickline at Nicolai Creek No. 2 in August 2018 to evaluate the potential for future production or storage. The company identified mechanical issues, and the well is currently shut in until the company can gather additional information.

The Nicolai Creek No. 3 well will remain shut-in until the company can obtain 1.25-inch coiled tubing, which is unavailable in the Cook Inlet region at the present time.

A slickline operation on the Nicolai Creek No. 9 well in the third quarter of 2018 addressed fill identified in an August 2016 operation. The recent operation resulted in an approximately 50 percent increase in production. The well produced 38.4 million cubic feet through the first eight months of 2018, according to production figures in the plan.

As of September, Amaroq was evaluating the economics of conducting a rig workover of the Nicolai Creek No. 10 well sometime in 2019 to replace damaged tubing and to implement sand control. The company attempted to workover the well in the third quarter of this year but discovered parted tubing in the well, which required rig work.

Prior to the attempted clean out, Nicolai Creek No. 10 had been producing from the Carya 2-1 sand. The previous operator had comingled the Carya 2-1 with the Carya 2-3 in May 2015, but fill discovered in December 2015 and August 2016 closed the Carya 2-3.

The Nicolai Creek No. 10 well produced 25.6 million cubic feet through the first eight months of 2018, according to figures provided by Amaroq in the development plan.

A coiled tubing workover of the Nicolai Creek No. 11 well in the third quarter of this year increased production by approximately 85 percent, according to Amaroq. A previous slickline check from December 2015 had discovered sand blocking the completion in the Lower Tyonek formation and attempts to clean out the sand failed. As a result, the well had been producing only from the Beluga formation. The well produced 27.7 million cubic feet through the first eight months of the year, according to figures in the plan.

The company reported no activity on the Nicolai Creek No. 1B well, which produced 10.2 million cubic feet through the first eight months of the year, according to the plan.

Development

Amaroq proposed a similar work plan for the coming year.

The biggest projects on the agenda were the rig workover of the Nicolai Creek No. 10 well and any economically and logistically feasible workover projects at other wells.

In its plan, the company also acknowledged the potential of the Nicolai Creek No. 12 well. Aurora Gas proposed the well in its 44th plan of development, submitted last year.

"Additional evaluation of geologic and seismic data will be necessary to determine the economics of this well," Amaroq President G. Scott Pfoff wrote in the newest plan.

The proposed well would target deeper sands to the north of the unit, in an area beyond the reach of the existing Nicolai Creek No. 3 well. The 5,650-foot well would target the Beluga and Upper Tyonek sands found in the Nicolai Creek No. 3 and No. 10 wells.

In addition to development activities aimed at increasing production, Amaroq was also considering an earlier plan to convert the Nicolai Creek No. 2 and Nicolai Creek No. 9 wells into a gas storage operation capable of holding between 2.5 billion and 3 billion cubic feet. The plan could potentially include a new horizontal well. "While there has been renewed interest in this project, studies have not yet commenced. Commencement of feasibility studies, leasing, permitting, and implementation are all possible during this 45th Plan period but are not planned at this time," Pfoff wrote in the development plan.

Without additional investment, either through development drilling or gas storage, the Nicolai Creek unit will likely become uneconomic in 2022, according to Amaroq.

Exploration

Amaroq also said it remains interested in a plan to explore for deeper oil and natural gas deposits beneath the Nicolai Creek unit but is not planning to pursue the project in 2019.

Aurora Gas had sold those rights to Apache Alaska Corp., which acquired 3-D seismic over the acreage in early 2012. Apache withdrew from Alaska exploration activities without advancing the project. "Nonetheless, Amaroq Resources is interested in acquiring and/or accessing this new seismic with plans to interpret and evaluate; and along with other geologic data, determine possible exploration, development, and extension drilling targets at all depths," Pfoff wrote, while noting that the work was unlikely in 2019.

The company has also been searching for funds to pay for exploration programs at its Chedatna Lakes and North Alexander prospects, on the west side of the Cook Inlet. ●

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BlueCrest finds success with new well

Innovative 'fishbone' pattern allowed company to target multiple intervals simultaneously at Cosmopolitan

By ERIC LIDJI
For Petroleum News

J. BENJAMIN JOHNSON

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BlueCrest Alaska Operating LLC planned to drill one well at its Cosmopolitan unit in 2018, and it did. But the well was more ambitious than that description would suggest.

The local subsidiary of the Texas-based independent completed the H-12 well at the offshore Cook Inlet unit and began adding eight laterals starting in late July 2018.

Using a self-described "fish bone" pattern that the company believes is the first of its kind in Alaska, and perhaps beyond, the H-12 well has a "spine" well running along the Hemlock formation with seven "ribs" drilled every 800 feet up through the Hemlock and Starichkof horizons. These ribs drain to the spine well, which then flows back to shore.

BlueCrest received Alaska Oil and Gas Conservation Commission permits in mid-September 2018 to re-drill the existing H-16 well using the fish bone pattern with eight laterals, suggesting that the approach may become standard at the Cosmopolitan unit.

The fifth plan of development for Cosmopolitan was due in early October 2018 but had yet to appear on the Division of Oil and Gas website as The Producers went to print.

BlueCrest hinted at these ambitions in its fourth plan of development for Cosmopolitan, which covered its activities for 2018. The company said it would use the results of the H-16 and the H-14 well, both completed in 2017, to determine its "path forward."

The company had begun drilling the H-16 well in late November 2016 and completed work on the well in March 2017. The 22,810-foot well reached a target in the Hemlock formation at 7,089 feet and was producing 330 barrels per day by September 2017.

BlueCrest then began drilling the H-14 Lower Lateral in late March 2017 and finished the 23,415-foot well into the Hemlock formation in mid-May 2017. But technical problems involving the liner complicated the well, forcing the company to start three separate sidetrack attempts before finally completing the well at 22,300 feet on Sept. 25, 2017.

At the time BlueCrest submitted its fourth plan of development, in late September 2017, it said it had an AOGCC permit to drill the H-12 well. But the company noted that the drilling permit "will need some revisions as we have changed our completion package."

The company also said that it planned to apply in late 2017 or early 2018 for permits to drill the H-16 Upper Lateral and H16 Exploratory Lateral. The company described the H-16 Upper Lateral as targeting the Starichkof Zone, which was the location of the initial discovery within the Cosmopolitan field by Pennzoil in 1967. (Phillips confirmed the discovery and also discovered Hemlock oil with the Hansen No. 1 well in 2001.) The company said it wanted to test the Starichkof Zone with one of its next wells at the unit.

BlueCrest also received permission from the state Division of Oil and Gas to form a participating area at the Cosmopolitan unit covering both the Starichkof and Hemlock.

Past and future plans

BlueCrest brought the Cosmopolitan unit into production in early 2016 from an existing well drilled at the unit by former operator (and former partner) Buccaneer Energy Ltd.

Using its custom-built BlueCrest Rig No. 1, BlueCrest launched its own development program in November 2016. The powerful rig was designed to drill directional wells and laterals to offshore targets from an onshore drilling pad near the city of Anchor Point, keeping the company from having to build an offshore platform or contract a jack-up rig.

The wells at Cosmopolitan are ambitious and complex. They generally extend three miles out from the onshore drilling pad, 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 original development plan involved drilling five wells starting in early 2017: the H-16 well, the H-14 well and H-14L lateral, and the H-12 well and H-12L lateral. The company intended the five-well program to be the first stage in a full development program that would potentially require 20 wells over a seven-year timeline. The facilities at the Cosmopolitan unit are capable of handling as much as 10,000 barrels per day.

The 38-acre onshore parcel for the Cosmopolitan development project is much larger than the existing pad and facility require and could easily accommodate expansion.

The company briefly suspended drilling operations in early 2017, after the state withheld between $75 million and $100 million in tax credits owed for previous work. The state policy decision forced the privately owned company to raise significant additional funds.

Cosmopolitan is in the early stages of development. The company said it has identified enough potential targets to justify seven years of expansion drilling. A known natural gas deposit overlying the oil reservoirs would likely require a separate development campaign, although those plans have been put on hold while the company focuses on oil.

Productive volumes remain low but are rapidly growing. The unit produced 865 barrels per day in July 2018, up from 801 bpd in June 2018 and 275 bpd in July 2017, according to figures from AOGCC. ●

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BP increasing production without drilling

Company makes the case for redefining the measurements for activity at aging fields like Prudhoe Bay

By ERIC LIDJI
For Petroleum News

BP Exploration (Alaska) Inc. is making a strong case against using drilling as the key metric for measuring development activity, at least when it comes to aging oil fields.

The local subsidiary of the international company reported notable production increases at many of its fields at the Prudhoe Bay unit over the past year and strong gains in efficiency at other fields, while also reporting a notable decline in drilling activity.

The company has been working over existing wells and refining its approach to enhanced oil recovery at the oldest and largest oil field on the North Slope. Describing its current strategy in a recent plan of development for the Initial Participating Areas at Prudhoe Bay, the company wrote, "While drilling was the key driver for production during the development phase of the IPA, now that the field is in production phase, large scale drilling programs (i.e., more than 50 new penetrations per year) have largely been replaced by operations efficiency increases, hundreds of wellwork jobs each year to maintain and enhance existing wellstock (including accessing rich gas for increased liquids production), and reservoir management techniques as the key drivers."


JUDY PATRICK
JANET WEISS

BP files three plans of development each year for the Prudhoe Bay unit — one for the Initial Participating Areas early in the year, one for the Greater Point McIntyre Area in the middle of the year and one for the Western Satellites toward the end of the year.

Initial Participating Areas

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

BP expects development drilling to continue to play a role at the IPA, depending on economic conditions and the ability to identify worthwhile targets. But the company is crediting most of its production activity at the IPA on its ongoing wellwork program.

The IPA produced 186,800 barrels of crude oil and condensate per day in 2017 and delivered 68.19 million barrels to the trans-Alaska oil pipeline last year. Those rates were down from 197,900 bpd and 72.43 million cumulative barrels during 2016.

The IPA also produced 42,000 barrels of natural gas liquids per day in 2017 and delivered 15.3 million barrels to the trans-Alaska oil pipeline. Those rates were down from 38,000 bpd and 13.9 million cumulative barrels during 2016.

While acknowledging the effect of natural declines at the aging field, the company attributed the production decline, in part, to a turnaround at Gathering Center No. 1. (The primary goal of the turnaround was to replace corroded steel piping use for wet gas.)

According to the company, operational efficiency increased two percentage points

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BP *continued from page 16*

to 85 percent in 2017, which helped partially offset some of the declines in production.

BP expects IPA crude and condensate production of 150,000 to 187,000 bpd in 2018 with associated NGL production between 30,000 and 46,000 bpd.

The development program planned at the Initial Participating Areas for this current year involved a notable reduction in drilling with a slight increase in well work activity.

BP planned to drill 14 wells this year — five rotary and nine coiled — down from 27 wells in 2017 — five rotary and 22 coiled. Rigged workover activity was expected to increase to three wells from one, largely with the goal of returning shut-in wells to active service.

The company expected to perform approximately 400 rate-adding well work jobs this year and approximately 700 non-rate-adding jobs "as well as an active, fieldwide reservoir surveillance program driving these activities," according to BP. By comparison, the company performed 1,000 well work jobs last year, of which 386 added production.

A focus area for BP in 2017 was recovering condensate from the Sag River gas cap. The project involved plugging "uncompetitive" Ivishak production wells and adding perforations higher in the wellbore to target the gas cap of the Sag River formation.

The company undertook this process at 29 wells located at pads in the Gathering Center No. 1, Gathering Center No. 3, Flow Station No. 1 and Flow Station No. 3 regions. The work yielded 7,000 bpd at "competitive" gas-to-oil ratios by the end of the year. The entire program yielded 12,000 bpd from 650 million cubic feet. The company expects to undertake the process at 10 existing Ivishak wells this year.

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Greater Point McIntyre

For several years, BP has said that the future of the development work in the Greater Point McIntyre Area would depend on the results of the North Prudhoe seismic survey.

The company wrapped up the survey in April 2015 and completed final merged Pre-Stack Depth Migration processing in September 2016 but only finished interpreting the data in January 2018. Although the company said that the survey has already improved its understanding of flank opportunities and noted that it is currently evaluating coil sidetrack operations, the plans for the coming year does not reflect the survey results.

Even so, BP reported noteworthy production increases at most of the fields in the area.

The Point McIntyre field produced 14,800 bpd (and 5.4 million barrels total) of crude oil, condensate and natural gas liquids during the year ending March 31, 2018, up from 12,400 bpd (and 4.5 million barrels total) during the previous year.

Although the company did not drill any new wells at Point McIntyre, it maintained "active wellwork and scale inhibition programs." The work included a recompletion of P1-09 to access the Ivishak formation, welding on P1-18, a rigged workover on P1-04 to repair a leak and fracture operations on the low producing P1-20 and P1-23 wells.

The recently completed year was the first full year since BP returned the STP 36-inch pipeline to service in October 2016, allowing production to go to Gathering Center No. 1, rather than the Lisburne Production Center. The line had been out since November 2011.

For the coming year, BP is planning a project to expand miscible injectant at the PM-1 pad, similar to a project undertaken at the PM-2 pad during a previous development year.

The Lisburne field produced 13,800 bpd (and 5.1 million barrels total) of crude oil, condensate and natural gas liquids during the year ending March 31, 2018, up from 10,700 bpd (and 3.9 million barrels total) during the previous year.

BP drilled one well — the onshore L3-25 well into the Wahoo interval — and began drilling a second — the coastal NK-26A well into the Alapah interval — at Lisburne during the reporting period. The company performed 30 rate-adding workovers on 25 wells.

The company plans to drill three wells during the year ending Sept. 30, 2019 — L3-22A, L5-03 and L5-25A — and additional unidentified locations, pending well results.

Lisburne produced 83 billion cubic feet of natural gas during the reporting year, of which 54.5 billion was injected into the Lisburne Gas Cap to improve reservoir pressure. A related Lisburne Gas Cap Water Injection pilot project became permanent in early 2017.

BP EXPLORATION (ALASKA)

The high gas-to-oil ratio at Lisburne requires BP to cycle wells through periods of production for periods of days or weeks, rather than allowing for continuous production.

The four remaining fields in the region account for minimal production.

The Niakuk field produced 1,200 bpd (and 436,000 barrels total) of crude oil, condensate and natural gas liquids during the year ending March 31, 2018, down from 1,300 bpd (and 478,000

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barrels total) during the previous development year.

The company performed work on the NK-27 well and conducted a test on the NK-43 well to determine the appropriate allocation split between the Sag River and Kuparuk.

The company conducted an evaluation of potential infill and peripheral drilling opportunities during the year ending March 31, 2018, using some of the seismic data.

The Raven field produced 1,050 bpd (and 390,000 barrels total) of crude oil, condensate and natural gas liquids during the year ending March 31, 2018, up slightly from 940 bpd (and 340,000 barrels total) during the previous reporting year.

BP began drilling the horizontal NK-14B well into the Sag River formation in March 2017. The well was developed on a tract basis to gather information for future work.

But the well casing leaked after three months, requiring the company to shut in the well from September 2017 to March 2018. The well has since been returned to production.

The company also drilled the NK-15Ai injector well in February 2018 and plans to convert the NK-65Ai injector to a producer once NK-15Ai begins operations.

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.

Western Satellites

BP reported increased production at four of the five fields in the Western Satellites region, after reporting declines during the previous year. In its most recent plan of development, the company reported increased oil production at the Borealis, Midnight Sun, Orion and Polaris fields at the west end of the Prudhoe Bay unit. The company reported a slight decline at the Aurora field that essentially constituted flat production.

BP files three plans of development each year for the Prudhoe Bay unit — one for the Initial Participating Areas early in the year, one for the Greater Point McIntyre Area in the middle of the year and one for the Western Satellites toward the end of the year.

BP made no firm drilling commitments at the Aurora field for the coming year but said it expected to continue its existing workover regimen. The company is evaluating potential infill drilling targets identified from its geological models, including recent well results.

The company performed 55 workover jobs on existing producers and injectors at the satellite. The projects included tree change out, gas lift optimization, hot oil treatments, safety valve work and vertical support member work. Fourteen of the 55 jobs added production. The remainder either sustained production or addressed maintenance issues.

In its plan, the company listed several projects: It sidetracked the S-200A well in mid-2017 and brought the well into production before the end of that year. It performed hydraulic fracturing on the S-129 well in May 2018 and the S-113B well in June 2018.

As part of a tertiary recovery process underway at the field over the past 15 years, the company also injected miscible injectant into five water-alternating-gas injectors.

The Aurora field came online in November 2000 after several months of initial development drilling. As of the end of June 2018, Aurora had 33 active wells from S pad (18 producers and 15 injectors) with oil processed at Gathering Center No. 2.

Aurora field produced 4,609 bpd in the year ending June 30, 2018, down from 4,696 bpd the previous year. Cumulative production reached 45.1 million barrels.

Borealis and Midnight Sun

BP made no firm drilling commitments at the Borealis field for the coming year but said it expected to workover wells and cycle high gas-to-oil ratio wells "as needed."

"The Borealis owners will continue to evaluate the optimal number of development wells and their locations throughout the life of the reservoir," the company wrote. "The dynamic model for the Borealis field will be used to evaluate potential drilling targets."

The company performed 37 workover operations at Borealis in the year ending June 30, 2018, for purposes similar to those at the Aurora field. Nine of those operations added production, while the remainder sustained production or addressed maintenance issues.

BP drilled the V-137 grass roots well in the fourth quarter of 2017 but ultimately suspended drilling operations "due to structure coming in deep." The company drilled the L-118L1 lateral in the first quarter of 2018 and brought the well online in the third quarter. The company also plugged and abandoned the V-119 well during the year.

As part of its tertiary recovery program begun at the Borealis field in June 2004, the company also injected miscible injectant into seven water-alternating-gas injectors.

The Borealis field came online in November 2001, following several months of initial drilling. As of the end of June 2018, Borealis had 49 active wells: 22 wells at L pad (13 producers and nine injectors), 19 wells at V pad (11 producers and eight injectors) and eight wells at Z pad (four producers and four injectors) and was processed at GC-2.

Borealis produced 7,914 bpd during the year ending June 30, 2018, up considerably from 6,040 bpd the previous year. Cumulatively, the field had produced 86 million barrels through the end of June 2018, according to figures from BP.

BP is not planning new wells at the Midnight Sun field for the coming year, although it plans to convert the E-100 injector to an Ivishak producer and could begin sidetracking maturing wells at the field as the benefits of water-alternating-gas injection are realized.

Midnight Sun was initially developed in 1997. As of the end of June 2018, the field had six active wells: the E-101 and E-102 producers, the E-100, E-103 and E-104 water injectors and the P1-122 water-alternating-gas well. The most recent was drilled in early 2015. Oil production is comingled at E pad and processed at Gathering Center No. 1.

Midnight Sun produced 1,158 bpd in the year ending June 30, 2018, up from 983 bpd the previous year. Cumulatively, the field had produced 21.6 million barrels through the end of June 2018, according to figures provided by the company.

Orion and Polaris

BP made no firm drilling commitments for the Orion field for the coming year but said it would continue its workover program and would evaluate sidetrack options at L pad.

The company performed 75 workover jobs at Orion in the year ending June 30, 2018, for purposes similar to those at other satellites. Eleven of those jobs added production, while the remainder either sustained existing production or addressed maintenance issues.

The company changed out waterflood regulating valves on 13 injection wells. The company also started drilling the L-205A sidetrack in the fourth quarter of 2017 and brought the well into production in the second quarter of this year. The well is the first vertical frack packed producer in the Orion participating area, according to the company.

BP is planning several near-term projects at Orion, some of which have been on the agenda for years. Several of these projects address sand production at the Orion field.

The company is studying possible improvements to sand-handling technology installed at GC-2 in 2012 and 2013. The technology was intended to address sand-laden viscous oil from Orion but, so far, has failed to yield the level of improvement desired by BP.

Additionally, BP is looking for ways to address the significant downtime affecting viscous wells in the northwest portion of the

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Orion participating area. Those wells have been down nearly half the time in recent years due to sand production, matrix bypass events and downhole equipment failures. The company is studying alternate well designs.

In the recently completed development year, BP tested some alternate well designs on the L-200 and L-203 producers, which have often been hampered by sand production.

One of the longest-desired and longest-delayed projects at Orion is the proposed I pad, which the company claims is dependent "upon the results of sand control technology deployed in the Schrader Bluff Formation and the business environment." Work on the recent L-205A project provided some information in that regard, according to BP.

The Orion field came online in April 2002, following several months of initial development drilling dating back to December 2001. As of the end of June 2018, the field had 33 active wells: 12 wells at L pad (four producers and eight injectors) and 21 wells at V pad (five producers and 16 injectors). Orion oil production is processed at GC-2.

Orion produced 3,900 bpd in the year ending June 30, 2018, up from 3,469 bpd the previous year. Cumulatively, the field had produced 35.1 million barrels through the end of June 2018, according to figures provided by the company.

BP made no firm drilling commitments for the Polaris field for the coming year but said it would continue its workover program with an eye toward mitigating declines.

The company did not drill or complete any new wells at Polaris during the year ending June 30, 2018 but performed 27 workover jobs on existing producers and injectors to minimize declines in oil production. Twelve of those jobs added production, while the remainder either sustained existing production rates or addressed maintenance issues.

Many of the projects occurring at Polaris and planned for the immediate future, particularly those involving viscous oil and sand control, overlap with those at Orion.

BP is studying ways to use existing well designs as M pad and S pad to access areas at Polaris with good oil mobility. The company began evaluating two new waterflood enhanced oil recovery patterns at S pad during the reporting year ending June 2018.

"If proven to be viable, development of additional areas at S pad with good oil mobility would be limited to the number of donor wellbores and surface slots available that are able to reach the target without anti-collision issues. The modeling and completions studies work at S pad will transfer to other areas in both the Orion (participating area) and Polaris (participating area)," the company wrote in its plan. A wider viscous oil development at M pad and S pad is contingent on sand control in the Schrader Bluff.

The Polaris field came online in November 1999, after two years of development drilling.

As of the end of June 2018, the field had 24 active wells: four wells at S pad (one producer and three injectors) and 20 wells at W pad (seven producers and 13 injectors).

Polaris oil production is processed at GC-2.

Polaris produced 4,158 bpd in the year ending June 30, 2018, up from 3,891 bpd the previous year. Cumulatively, the field had produced 23.2 million barrels through the end of June 2018, according to figures provided by the company. ●

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BRPC inching closer to development

Latest plans commit to start-up in 2019 using temporary production facility and existing wells

By ERIC LIDJI
For Petroleum News

BART ARMFIELD

Brooks Range Petroleum Corp. has been working for nearly seven years to bring the Southern Miluveach unit into development in the face of various setbacks, and this past year once again brought a mixture of advancement, delays and creative maneuvering.

The local operating arm of a multiparty joint venture started 2018 with a plan in place to cross the finish line into development within a year, only to revise its deadline in two directions: delaying the installation of permanent facilities while simultaneously advancing a plan to bring the unit online early next year through temporary facilities.

In its sixth plan of development, submitted in early October 2018, the company said it expects to finish installing its temporary production facility at the onshore North Slope field by the second quarter of 2019, allowing oil production to begin from existing wells while the company continues its efforts to install permanent infrastructure at the site.

The Mustang field is the first development at Southern Miluveach, which sits in the increasingly crowded fairway between the Kuparuk River unit and the Colville River unit. BRPC discovered the field in 2012 but a series of technical, economic and logistical complications led to years of delays, requiring alternative approaches to development.

To avoid losing the unit and its leases to expiration, BRPC successfully applied for certification of an existing well and proposed a plan to start production in the short term by connecting a 6,000-barrel-per-day Early Production Facility to the Alpine Pipeline.

The temporary system would produce from three existing

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Brooks Range Petroleum

BRPC *continued from page 23*

Its longer-term plans for the unit include installation of a 15,000-barrel-per-day central processing facility, completion of drill site facilities, construction of two pipelines and implementation of a 21-well development program with 10 producers and 11 injectors.

wells: North Tarn No. 1A, Mustang No. 1 and SMU M-02. Some work is required on two of those wells before they can begin producing. BRPC said it needs to drill either a lateral extension or a sidetrack at Mustang No. 1, and it needs to perforate and stimulate SMU M-02 before start-up.

During the initial field commissioning, BRPC expects to pre-produce from the SMU M-02 well in order to better understand the Kuparuk A sands. The company mentioned plans to flare any excess gas during this period — a proposal the state recently rejected.

BRPC also plans to drill as many as four new wells at the Southern Miluveach unit during the coming year, as part of its initial development campaign for the Mustang field.

Its longer-term plans for the unit include installation of a 15,000-barrel-per-day central processing facility, completion of drill site facilities, construction of two pipelines and implementation of a 21-well development program with 10 producers and 11 injectors.

The Division of Oil and Gas had yet to approve the plan as The Producers went to print.

Brooks Range Petroleum operates the Southern Miluveach unit on behalf of working interest owners CaraCol Petroleum LLC, TP North Slope Development LLC, Nabors Drilling Technologies USA Inc., AVCG, LLC, Mustang Road LLC and MOC1 LLC.

EPF

In its fifth plan of development for the unit, submitted shortly before the previous issue of The Producers went to print, BRPC said it expected to bring Mustang into production in early 2019. The target was well beyond a December 2017 deadline that the state Division of Oil and Gas had imposed under the terms of an extension granted in early 2016.

To resolve the gap, Brooks Range Petroleum re-entered the North Tarn No. 1A sidetrack for fracture stimulation and testing, with the goal of having the state certify the well as capable of producing in paying quantities, which would protect the unit from termination.

In late December 2017, the state certified the North Tarn No. 1A well and approved an associated plan of development for bringing the unit into production by early 2019.

A few months later, in late March 2018, Brooks Range Petroleum filed an amendment to the plan, proposing an Early Production Facility to bring the unit into production by late 2018 or early 2019 while the company worked toward installing its permanent facilities.

The company described the EPF as "a modular design, fit for purpose, that is design ready and can be transported to the site and begin operations in a timely manner."

The EPF would be able to handle 6,000 barrels of oil per day with a gas-to-oil ratio of 1,000 and capacity for 1,500 barrels of produced water per day. Oil produced at Mustang and processed at the EPF would be trucked to a predetermined point of sale. The amendment also revised the timeline for larger, more permanent aspects of the project.

A few weeks after the state approved the temporary production plan in early May, the company proposed an amendment to its plan of development with a new timetable.

The state approved the revised schedule and called it "acceptable" as a plan, but it also noted, "Whether this schedule and BRPC's action will be sufficient for the Division to conclude that "operations are being conducted" remains an open question. If BRPC is not conducting operations, (the Southern Miluveach unit) will automatically expire."

In the same ruling, the state denied a request by Brooks Range Petroleum to flare natural gas associated with SMU M-02 operations for three to six months, or longer, while the company worked to complete a crucial tie-in with the Alpine pipeline. The proposal would have flared any gas not used for power generation, which the company later acknowledged would have been more than two-thirds of all gas produced in that time.

The state also expressed skepticism about the transportation plan, saying that temporarily trucking oil to the Alpine Pipeline may not qualify as a "reasonable cost of transportation" under the terms of the Southern Miluveach unit leases. The state said it would evaluate those costs as part of its eventual audit of the company's royalty filings.

The state rejected a concurrent request by BRPC over the past year to expand the Southern Miluveach unit, saying the idea had not yet been justified by exploration work. ●

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Caelus activity on North Slope remains suspended

Recent upturn in oil prices has not convinced the company to resume drilling activity at Oooguruk

By **ERIC LIDJI**
For Petroleum News

JAMES MUSSELMAN

Caelus Natural Resources Alaska LLC responded to the most recent downturn in oil prices more drastically than any other producer operating on the North Slope.

In May 2016, the local subsidiary of the Texas-based independent suspended drilling operations at its Oooguruk unit and deferred work on its related Nuna development.

The company also slowed work on its major oil discovery in the Smith Bay region, although its decision on that front was also partly a response to state fiscal policy.

In making the decision to halt drilling at its flagship Oooguruk project, Caelus said it would resume drilling "when oil prices recover and investor confidence resumes."

Even though oil prices have been climbing steadily for the past year, the company is remaining cautious about drilling, choosing instead to focus on workover operations.

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In its 12th plan of development, covering the year ending Aug. 31, 2019, the company proposed no new wells or sidetracks. The company announced plans for three workover projects "pending approval by management," down from eight this past year. In its 11th plan of development, the company had mentioned six potential well locations it hoped to drill when economics improved. Those wells were not mentioned in the current plan.

The company also pushed back the estimated launch of its

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Nuna development by at least a year, although work continues, and the project seems to remain a company priority.

The company also recently sold 350,000 acres of exploration leases in the eastern North Slope to Eni US Operating Co., its long-time minority partner at the Oooguruk unit.

Workover program

Aside from general repairs, the workover program at Oooguruk involves adding electric submersible pumps to wells or replacing failed electric submersible pumps with gas lift.

As described in the plan, the workover program for the coming year involves replacing failed electric submersible pumps with gas lift at the ODSN-02, ODSN-04 and ODST-39 and repairing casing at the ODST-39 well that was damaged during workover activities this past year. The company said the workover program could be expanded or contracted.

Caelus is also planning a complete shutdown for approximately a week in the summer of 2019 to inspect "the (Oooguruk Tie-In Pad) production separator, turbine generator packages, gas compressors, multiphase meters and other critical equipment." The work will occur during a six-week window driven by planned maintenance at the Kuparuk River unit Central Processing Facility-3, which is downstream of the Oooguruk unit.

Oooguruk-Kuparuk

The Oooguruk unit includes three pools: the Kuparuk, Nuiqsut and Torok.

Caelus expanded the Oooguruk-Kuparuk participating area this year to include six wells: active producers ODSK-14, ODSN-29 Kuparuk and ODSK-41, active injectors ODSK-35Ai and ODSK-38i, and the producer ODSK-33, which is inactive due to water cut.

Oil production continued as expected from the horizontal ODSK-14 and ODSK-41 wells.

The company completed a workover on the ODSN-29 Kuparuk well in September 2017 and brought the well online in October 2017. The well has been consistently producing 1,500 barrels per day with cumulative production of 263,000 barrels through April 2018.

Pressures in the ODSN-29 Kuparuk well align with those at ODSK-38i in the main Kalubik fault block but not with those at ODSK-13 in the western Ivik fault block. And production rates at ODSK-13 remained level after ODSN-29 Kuparuk came online, further reinforcing the evidence that the newer well is targeting a different block.

The company temporarily shut-in Nuiqsut production from ODSN-29 while producing from the Kuparuk but plans to ask the Alaska Oil and Gas Conservation Commission for permission to either co-mingle or alternate production from both pools at the well.

According to the company, oil production and water-to-oil rates at the Oooguruk-Kuparuk participating area have remained stable (and sometimes even exceeded expectations) because the participating area is a "mature dual porosity system."

Oooguruk-Nuiqsut

Caelus also expanded the Oooguruk-Nuiqsut participating area to include all existing development wells. The area now has 28 active wells — 18 producers and 10 injectors.

The central ONPA Kalubik fault block is producing from the ODSN-01A, ODSN-24, ODSN-25, ODSN-31, ODSN-36, ODSN-37 and ODSN-42B wells with water and gas injection from the ODSN-19i, ODSN-26i, ODSN-32i and ODSN-34i wells. The company cycled ODSN-01A production this year "to manage voidage replacement."

The ONPA Colville Delta fault block is producing from the ODSN-10, ODSN-16, ODSN-17 and ODSN-18 wells with water and gas injection from the ODSN-23i and ODSN-15i wells. The ODSN-10 well from 2016 "successfully defined the potential of the area and also demonstrated very high production potential," according to Caelus.

The northern ONPA Ivik fault block is producing from the ODSN-02, ODSN-04, ODSN-06, ODSN-28 and ODSN-29 wells. The ODSN-29 well is currently offline in the Nuiqsut pool to accommodate initial production from the Kuparuk. The ODSN-07i was converted to injection in January 2017 to provide support for the ODSN-03i well. The company has been restricting Ivik production "when feasible" to minimize increasing gas-to-oil ratios "until injection response is fully established" following ongoing reservoir surveillance.

The company is planning remediation of a "thief interval" in the ODSN-03i well in August 2018. Following water breakthrough at two offset producing wells, the company plugged the lateral at ODSN-03i and eventually identified the thief interval in 2017.

The southwestern ONPA is producing from the ODSN-22 and ODSN-43 wells with water and gas injection from the ODSN-48i well. Production is being alternated between the two production wells "to manage voidage" and producing gas-to-oil ratios.

Oooguruk-Torok

The Oooguruk-Torok participating area produces from the ODST-45A well with support from the ODST-46i injection well.

Both wells were returned to operation in 2017 after maintenance activities, but related producers ODST-39 and ODST-47 remain offline.

The Torok formation is an important component of the proposed Nuna development, and Caelus said it plans to apply for a Nuna-Torok participating area sometime this year.

In a plan of exploration accompanying the development plan, Caelus announced a range of efforts for the coming year to bring the Nuna project online no sooner than 2019.

The company had already sanctioned the Nuna project by the time it suspended drilling operations at Oooguruk but delayed Nuna plans as well. The current plan involves three basic parts: maintaining existing assets, improving modeling and advancing the project.

The company said it plans to perform preventative maintenance on assets acquired before the suspension and will eventually continue procurement alongside construction.

The modeling work covers two areas. The first involves improving the geologic and geophysical analysis of the project through well data and also through information about the nearby Pikka unit that would be obtained through the CGG Tabasco seismic survey.

The second involves updating the cost and timeline for facility installation "in light of oil price and tax structure environment." The company said it planned to "complete the facility design and integration" of the Nuna development with the Oooguruk Tie-in Pad and the Kuparuk River unit this year "in anticipation of start-up in 2019 or later."

The proposed start-up date in the new plan is a delay from a proposed start-up date of "2018 or later" in the current plan, which was a delay from a previous date of late 2017.

The work described in the proposed plan of exploration is similar to the work undertaken in the current plan, albeit somewhat more robust in planning and modeling activities.

The state had approved royalty relief for the Nuna project but cancelled the opportunity after Caelus failed to meet development timelines. State officials said that the company would be allowed to reapply, and company officials have said Caelus plans to reapply. ●

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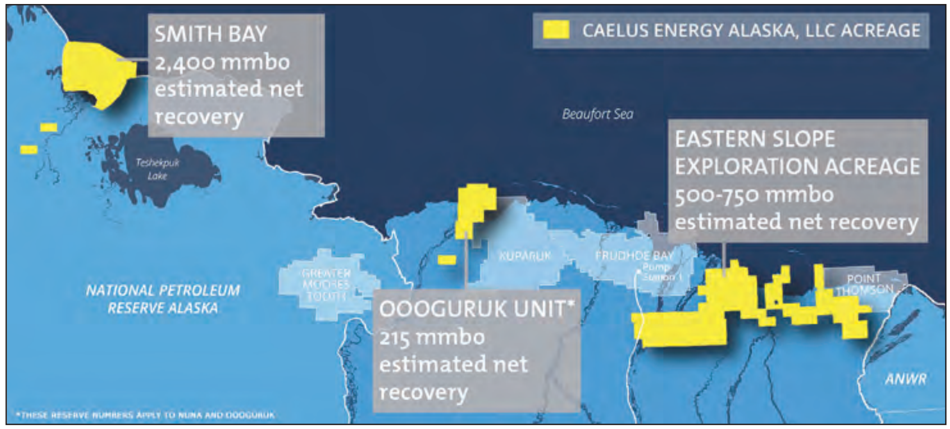

Conoco advances westward, mostly alone

Company bought out Anadarko and BP over the past year; making waves at four units

By ERIC LIDJI
For Petroleum News

JOE MARUSHACK

The past year brought a quiet consolidation to one corner of the North Slope, leaving ConocoPhillips Alaska Inc. increasingly solo in its decades-long advance to the west.

The local subsidiary of the Houston-based independent announced in February 2018 that it would be buying out its minority partner Anadarko Petroleum Corp. at the Colville River, Greater Mooses Tooth and Bear Tooth units. In July 2018, ConocoPhillips announced it would acquire a 39.2 percent interest in the Kuparuk River unit from its minority partner BP Exploration (Alaska) Inc. in return for assets in the United Kingdom.

Anadarko and BP are retreating from the western end of the central North Slope as ConocoPhillips is advancing at its four operated units: increasing oil production at the Kuparuk River unit through strategic workover activities, increasing oil production at the Colville River unit through its CD-5 development, working toward first oil at the Greater Mooses Tooth unit and evaluating a potential exploration program at the Bear Tooth unit.

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The Kuparuk field

The Kuparuk River unit is shifting into an era of increased efficiency, where ConocoPhillips is producing more oil despite a

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reduction of development activity.

"We have really advanced drilling technology to the point where it's making a significant difference in terms of what we can develop and how much we can develop," ConocoPhillips Alaska Vice President of External Affairs and Transportation Scott Jepsen told a joint meeting of Alaska state lawmakers in September 2018.

The second-most productive unit in Alaska produced 109,100 barrels per day in 2017, up from an average of 103,000 bpd in 2016, according to the most recent plan of development for the unit. The main Kuparuk oil field produced 84,100 bp0d in 2017, up from 78,100 bpd in 2016. The remaining production came from the four Kuparuk satellites, although only West Sak reported an increase in production.

ConocoPhillips attributed 7,500 bpd of incremental oil production to a 16-well (and 42-lateral) coiled tubing drilling program implemented at the main Kuparuk field last year, down from a 20-well (and 55-lateral) coiled tubing program from 2016 that had been credited with only 3,500 bpd of incremental production. The company also drilled four rotary wells in 2017 at the Kuparuk participating area (and another six as part of its West Sak development), compared with eight rotary wells at Kuparuk in 2016.

For the current development year, ConocoPhillips expects a slight increase in drilling activity at the main Kuparuk field — 17 coiled tubing sidetracks and five rotary wells.

An associated workover program in 2017 at the Kuparuk field yielded no increase. The company attributed 2,000 bpd to a rigged workover program and another 8,000 bpd to non-rig well work at the Kuparuk field, compared with 1,600 bpd for rigged work and 10,700 bpd from non-rig work in 2016.

The recent activity at the main Kuparuk field reflects the results of the Kuparuk West Sak 3-D seismic program from 2005 and the Western Kuparuk 3-D seismic program from 2011. But the company has also been engaging in a broader infrastructure-led exploration strategy, where exploration targets close to existing production are given higher priority.

Among those projects is one targeting the Cretaceous Brookian Moraine interval from Drill Site 3S. The company has been monitoring the reservoir for years from a pair of wells — 3S-613 and 3S-620 — and intends a drill a follow-up pair in 2019. Another exploration project involves 17,920 acres near Drill Site 2S, added in December 2017.

Through the end of 2017, the Kuparuk field had produced 2.44 billion cumulative barrels of oil and was being developed from 866 active wells — 471 producers and 395 injectors.

Kuparuk satellites

The other production bump at the Kuparuk River unit came from the West Sak satellite.

West Sak produced 13,818 bpd from 119 active wells — 60 producers and 59 injectors — in 2017, up from 13,701 bpd from 112 active wells in 2016.

The increase in wells came largely but not entirely from the Drill Site 1H program that came online last year. ConocoPhillips drilled two producers — the 3R-101 and 1H-102 multilaterals — and four injectors — 3R-102, 1H-111, 1H-114 and 1H-118. (Figures from the Alaska Oil and Gas Conservation Commission indicate an additional injection well.)

Through the end of 2017, West Sak had produced 88.6 million cumulative barrels of oil.

The company expects to continue Drill Site 1H development this year. The total 2017-18 program calls for four horizontal multilateral producers and 15 vertical injectors.

A subsequent phase planned for 2019 will target viscous oil at Drill Site 3R. Additional viscous oil opportunities at West Sak exist at Drill Site 1C, Drill Site 1D, Drill Site 3K and Drill Site 3N. Opportunities also remain at Drill Site 1H and Eastern NEWS. The company is currently projecting a 2023 startup date for the Eastern NEWS project.

The expansion of West Sak projects reflects the progressed of technology for producing viscous oil on the North Slope. Efforts to develop the prospects began decades ago.

The other three Kuparuk satellites all experienced production declines last year.

The Meltwater satellite southwest of the main field produced 947 bpd in 2017, down from 1,326 bpd in 2016. The satellite was being developed from 15 active wells in 2017 — nine producers and six injectors — down one injector from 2016.

The decline in oil production came, in some measure, from increased natural gas production. A three-week shut-in of the satellite in June 2017 measured back pressure to determine how much oil was being backed out of a common production line due to natural gas production and placed the total at approximately 900 bpd.

While gas flooding remains an efficient tool for enhanced recovery at Meltwater, the increasing gas-to-oil ratio is threatening the economics of some wells, according to ConocoPhillips. The company plans to convert to waterflood in late 2018 or early 2019.

Through the end of 2017, Meltwater had produced 19.7 million cumulative barrels of oil.

The Tabasco satellite produced 1,380 bpd in 2017, down from 1,430 bpd in 2016 from a similar profile of active wells — four producers and two injectors. Through the end of 2017, Tabasco had produced 20.1 million cumulative barrels of oil.

The Tarn satellite produced 7,800 bpd in 2017, down from 8,400 bpd in 2016, despite an identical active well profile — 39 producers and 24 injectors. Through the end of 2017, Tarn had produced 121.6 million cumulative barrels of oil.

Colville River unit

ConocoPhillips is expanding operations at the Colville River unit almost 20 years after the company brought the Alpine field online near the beginning of the 21st century.

The first two years of development at the CD-5 pad revealed new opportunities, leading to a physical expansion of the pad. The company first expanded the CD-5 pad in 2017, adding 12 well slots. The company is working on permitting and engineering for a second expansion, called CD5X2, which would add 10 more well slots starting in 2019.

A separate project at the CD-2 pad this year, called CD2X, would expand the drilling pad by some 5.8 acres to accommodate 32 additional wells at the Fiord West development.

The company expects the existing facilities to be able to handle the change in production profile but will be analyzing its facilities to ensure their ability to handle future growth.

The Colville River unit produced 62,901 bpd in 2017, up from 58,830 bpd in 2016, according to figures from the company and the state. The production figures could be even higher for the coming development year, with nine development wells, multiple sidetracks and potential a new exploration well currently on the agenda.

If sanctioned, the CD4-95 Narwhal exploration well would target the Brookian Nanushuk sand within the Narwhal trend using an existing slot and infrastructure at the CD-4 pad.

Alpine

Colville River unit development activities in recent years have focused heavily on the Alpine field from the CD-5 pad, which came online in late 2015 after years of delays. But ConocoPhillips develops the unit from six participating areas — Alpine, Nanuq

If sanctioned, the CD4-95 Narwhal exploration well would target the Brookian Nanushuk sand within the Narwhal trend using an existing slot and infrastructure at the CD-4 pad.

Kuparuk, Fiord Kuparuk, Fiord Nechelik, Nanuq and Qannik — accessed from five drilling pads.

The Alpine oil pool includes the Alpine participating area and the Nanuq Kuparuk participating area, which have historically been the center of development at the unit.

ConocoPhillips drilled seven wells and sidetracks at the Alpine participating area in 2017: the CD5-18, CD5-20, CD5-22, CD5-39A and CD2-47A producers and the CD5-17 and CD5-19 injectors. The company could drill as many as six rotary wells at the Alpine participating area during the current development year, which runs through March 2019.

ConocoPhillips completed the 30,218-foot CD5-25 well and its 20,973-foot CD5-25 lateral in March 2018. The directional multilateral injector targeted the Alpine A and C sand and is a companion to the CD5-23 injector from January 2018. Those two injector wells would support a trio of proposed production wells — CD5-11A, CD5-11B and CD5-11C, as named by ConocoPhillips. The CD5-24 producer would aim for a target west of CD5-19. The sixth well would be the CD4-5D targeting the C sand west of CD4-26.

ConocoPhillips is also considering several coiled tubing drilling sidetracks, including a northward expansion of the CD4-208A pattern, a re-drilling of the CD4-210A well, a lateral drilled

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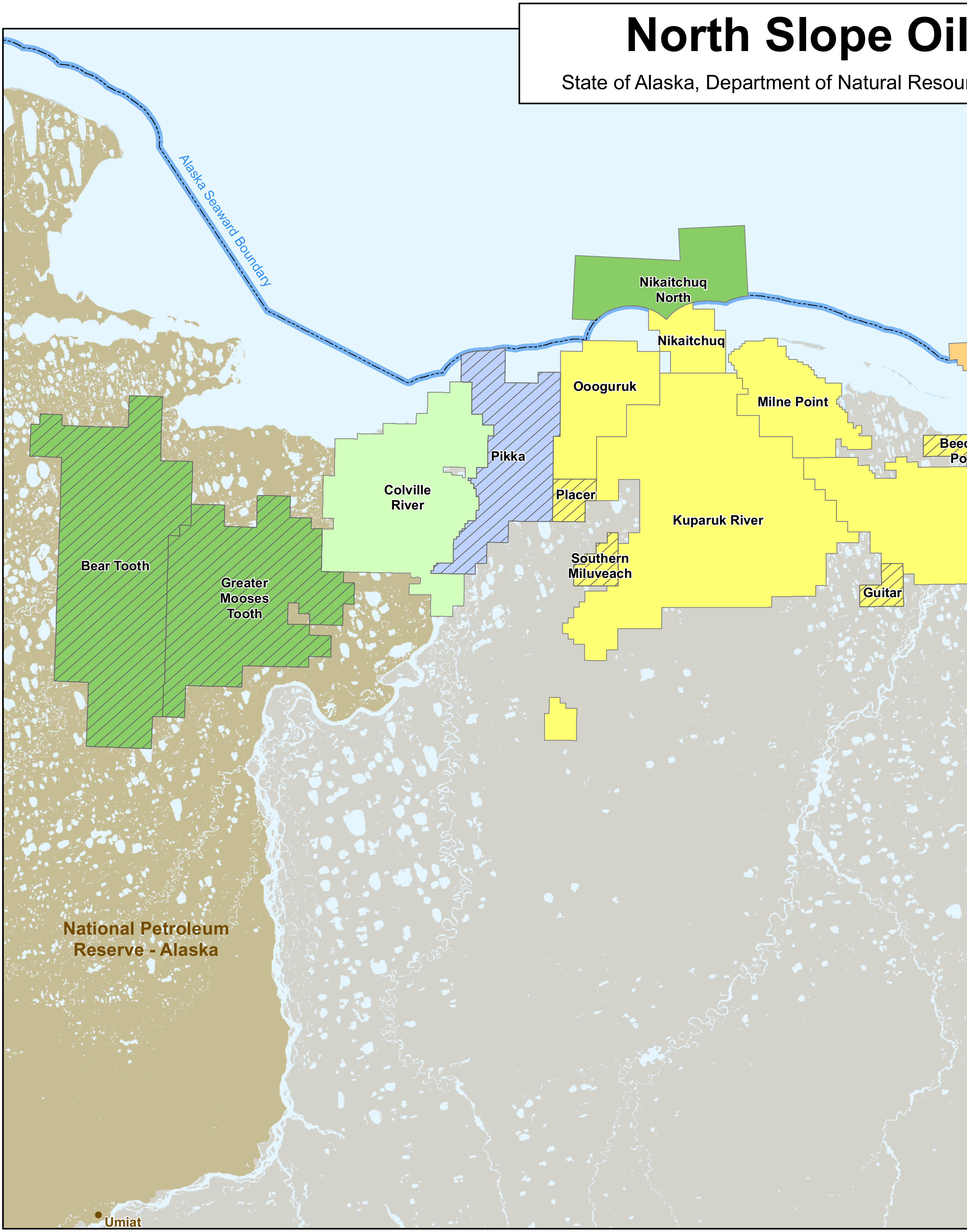
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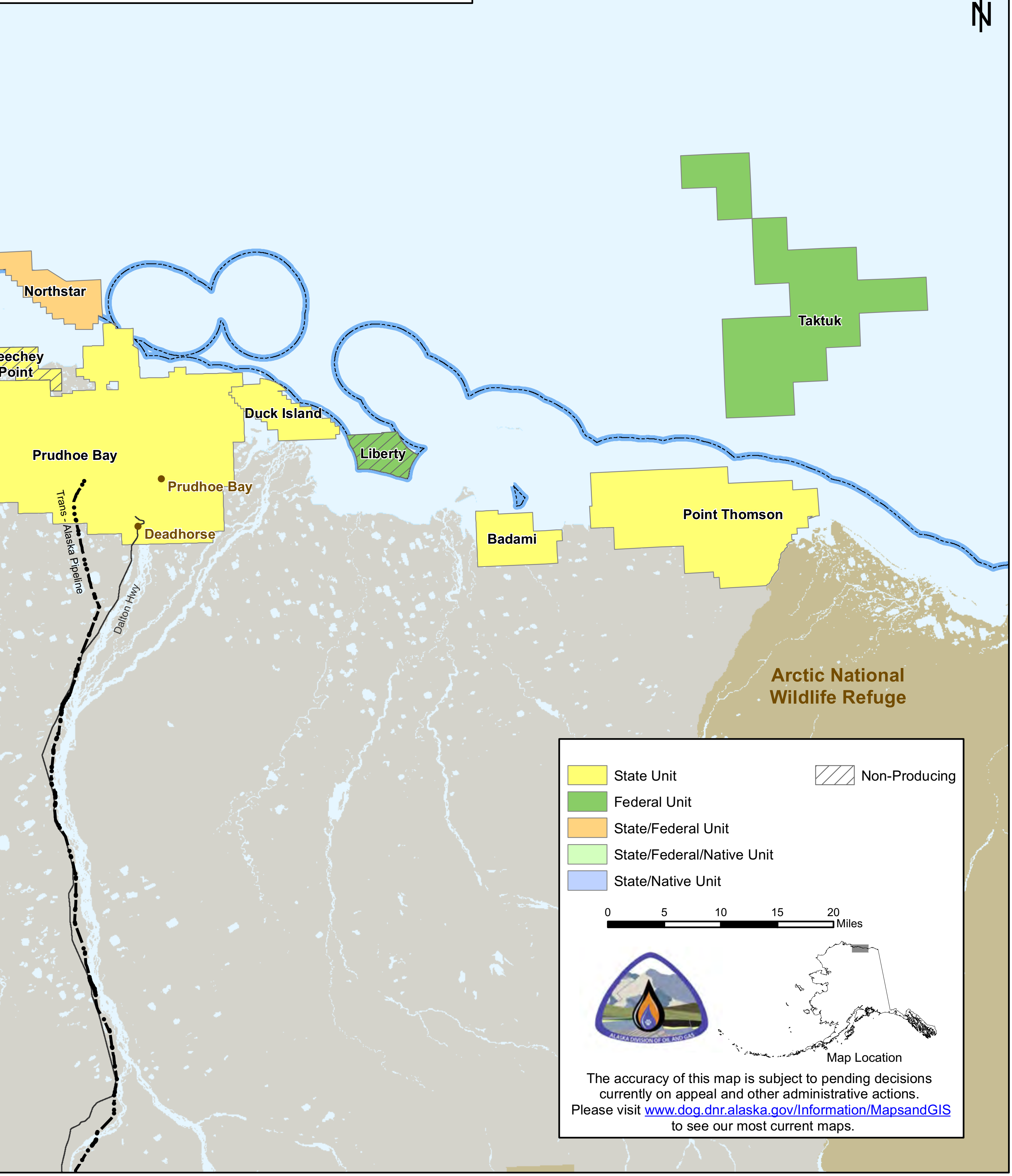
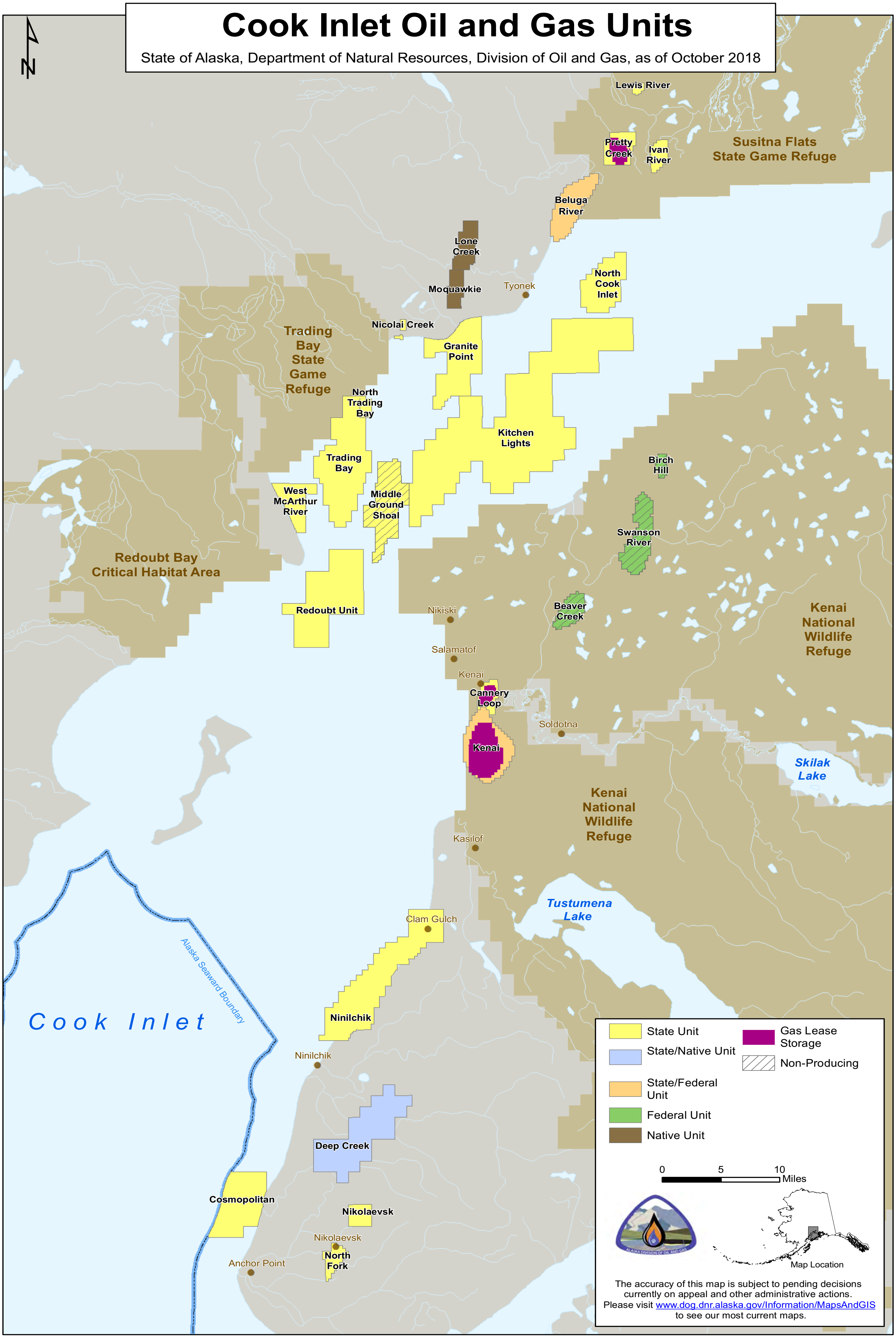


Cook Inlet Oil and Gas Units

State of Alaska, Department of Natural Resources, Division of Oil and Gas, as of October 2018



CONOCOPHILLIPS *continued from page 31*

into the space between the CD5-23 and CD5-25 injectors, among a range of other opportunities into the Alpine participating area from the CD2 and CD5 pads.

The company drilled two wells at the Nanuq Kuparuk participating area in 2017: the CD5-314X producer and the CD5-316 injector. The CD5-314X well suggested the presence of a new target to the west but accessing it would require a bigger drilling rig.

As of March 2018, the Alpine participating area was being developed from 150 wells — 78 producers, 70 injectors and two disposal wells — up five from the previous year. The increased represents new drilling at the new CD-5 pad. The participating area produced 41,100 bpd of oil in 2017, up from 37,100 bpd the previous year.

As of March 2018, the Nanuq Kuparuk participating area was being developed from 13 wells — six producers and seven injectors — up two from the previous year. Nanuq Kuparuk produced 10,600 bpd in 2017, up from 9,600 bpd in 2016.

Cumulatively through 2017, the Alpine participating area had produced 429 million barrels and the Nanuq Kuparuk participating area had produced 33.7 million barrels.

Satellites

The remaining pools are considered satellites of the main Alpine development.

The Fiord satellite at CD-3 includes the Fiord Kuparuk and Fiord Nechelik participating areas. ConocoPhillips re-drilled a completed Fiord Nechelik producer and conducted a fracture stimulation operation on one well in 2017, but the company is not planning any drilling or stimulation at the Fiord participating areas in the current development year.

As of March 2018, the Fiord Kuparuk participating area was being produced from five wells — two producers and three injectors. The participating area produced 1,100 bpd in 2017, equal to the average production date from 2016.

ConocoPhillips is planning at extended reach drilling program at the unit starting in 2020 and may drill a slant pilot hole production well from the CD-2 pad targeting the Fiord West Kuparuk reservoirs to assist with planning efforts for the extended reach program.

As of March 2018, the Fiord Kuparuk participating area was being produced from five wells — two producers and three injectors. The participating area produced 1,100 bpd in 2017, equal to the average production date from 2016. The Fiord Nechelik participating area was being produced from 23 wells — 13 producers and 10 injectors. The participating area produced 7,100 bpd in 2017, down from 7,800 bpd in 2016.

Through the end of 2017, the Fiord Kuparuk participating area had produced 13.8 million barrels and the Fiord Nechelik participating area had produced 55.4 million barrels.

The Nanuq satellite at CD-4 includes the Nanuq participating area.

ConocoPhillips plans to drill one rotary well and one coiled tubing drilling sidetrack at the Nanuq participating area this development year but has not yet defined either project.

As of March 2018, the company was developing the Nanuq participating area from nine wells — five producers and four injectors, equal to 2017. The participating area produced 1,500 bpd in 2017, equal to the production rate from 2016. The Nanuq participating area had produced 4.3 million cumulative barrels through the end of 2017.

The Qannik satellite at CD-2 includes the Qannik participating area.

ConocoPhillips plans to drill one rotary well at Qannik during the current development year and may drill other undefined rotary wells or coiled tubing sidetracks as appropriate.

As of March 2018, the company was developing Qannik from nine wells — six producers and three injectors. The participating area produced 1,500 bpd in 2017, equal to the 2016 rate. The participating area had produced 6.5 million barrels through 2017.

Greater Mooses Tooth

ConocoPhillips is replicating its step-out approach at the Colville River unit at its Greater Mooses Tooth unit in the National Petroleum Reserve-Alaska, with one crucial difference. The company is moving toward building a standalone production facility.

The company is pursuing three projects at the unit: GMT-1, GMT-2 and Willow (which sits on the boundary between Greater Mooses Tooth and Bear Tooth and impacts both).

ConocoPhillips plans to bring the GMT-1 development at the eastern end of the unit into production by the end of the year. The nearly $1 billion project includes a drilling pad, a 7.7-mile road and associated infrastructure and pipelines, and an initial drilling program of nine development wells with the physical capacity to handle as many as 33 wells total.

Earlier this year, the U.S. Department of Interior released a final supplementary environmental impact statement for the GMT-2 project at the center of the Greater Mooses Tooth unit. The $1.5 billion project includes a 36-well program with the capacity to handle as many as 48 wells. Construction could begin this winter, with first oil as soon as late 2021, according to ConocoPhillips, which has not yet sanctioned the project.

The two GMT developments would use existing processing infrastructure, with GMT-2 linked to GMT-1 and GMT-1 linked to CD-5 and the existing Alpine Central Facilities.

As currently envisioned, the proposed Willow development at the western end of the unit would have standalone processing facilities, a mark of its potential size and importance.

ConocoPhillips was initially uncertain about its development strategy for Willow but decided on standalone facilities in mid-2018, after increasing its resource estimate.

The company now believes that the prospect could produce between 400 million and 750 million recoverable barrels of oil equivalent, up from an earlier estimate of 300 million.

The company expects to make a sanctioning decision about the $2 billion to $3 billion project in 2021, which could potentially lead to first oil in the 2024 to 2025 timeframe.

By late summer 2018, the U.S. Bureau of Land Management was seeking public comments on the scope of a potential Environmental Impact Statement for Willow.

Bear Tooth

While the Kuparuk River unit, Colville River unit and Greater Mooses Tooth unit account for the majority of ConocoPhillips' activity, the company is beginning to consider its options for the Bear Tooth unit just north of Greater Mooses Tooth.

While the Kuparuk River unit, Colville River unit and Greater Mooses Tooth unit account for the majority of ConocoPhillips' activity, the company is beginning to consider its options for the Bear Tooth unit just north of Greater Mooses Tooth.

The company plans to drill as many as three exploration wells at the Bear Tooth unit during the upcoming winter exploration season, according to a continuing development obligation plan submitted to the U. S. Bureau of Land Management earlier this year.

Although no names or locations for the wells were provided in the plan, ConocoPhillips said that two of the three wells would be located within proposed expansion acreage at Bear Tooth, which BLM had yet to approve in February.

ConocoPhillips is also planning to re-enter and test the Tinmiaq No. 6 well, which helped form the basis of the major Willow oil discovery at the Greater Mooses Tooth unit.

The connection between the re-entry and the new wells appears to be a sense that the Willow structure extends to the north of Greater Mooses Tooth, into the Bear Tooth unit.

In 2017, the company integrated its previous Cassin 3-D seismic program into its evaluation of the Willow prospect. "Additional newly reprocessed data was interpreted along with the existing Cassin 3D seismic data and this data was used to evaluate both Cassin and the northern extension of the Willow structure," the company explained. ●

Contact Eric Lidji at ericlidji@mac.com

Eni looking north at Nikaitchuq

Resumption of drilling activities at the unit is focusing on exploration prospect in federal waters; workovers at existing wells

By ERIC LIDJI
For Petroleum News

ROBERT PROVINCE

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In the years just prior to the downturn in oil prices in late 2014, Eni US Operating Co. Inc. tried to expand oil production at its Nikaitchuq unit through small expansions.

The local subsidiary of the Italian-based major undertook a range of projects: adding multilaterals to existing wells, evaluating the potential of the N sand beneath the OA sand development, and drilling farther west and farther east than the original pattern of wells.

A suspension of drilling activities in May 2015, in response to the downturn, halted those initiatives. And now, with prices recovering, Eni is looking in a new direction: north.

Earlier this year, the company launched the Nikaitchuq North exploration project by drilling the NN-01 well. The well was the first exploration activity at Nikaitchuq since the original delineation of the North Slope field more than a decade ago. The ultra-extended reach well used the existing Spy Island Drillsite at Nikaitchuq to access a target in the Harrison Bay Block 6423 Unit in federal waters north of the unit boundaries.

Eni expects the program to guide its development decisions going forward. Depending on the results of the exploration program, the company could resume development drilling at Nikaitchuq as soon as this fall. In a plan of development from July 2018, the company announced plans to drill as many as three new wells and to add laterals to as many as eight existing single lateral wells at its Spy Island Drillsite as soon as October 2018, as well as plans to continue workover activity on its existing Oliktok Point Pad wells.

The new development drilling depends on the ongoing exploration program in part for a practical reason: Eni would be using the same rig — Doyon 15 — for both drilling efforts.

The relationship between the two programs may also involve drilling targets. In its plan, Eni said that the development program could begin as early as late 2018 "pending the results and scope of exploration work." From the beginning, the purpose of the exploration program was to add reserves to Nikaitchuq and to increase oil production.

In an announcement laying out its strategy for 2018-21, Eni CEO Claudio Descalzi said his company was "doing well" in Alaska and was planning "increased investment."

The Nikaitchuq North project may have revived Eni's appetite for North Slope exploration, which had faltered after a pair of disappointing onshore wells drilled a decade ago. In late August 2018, the company announced that it had acquired some 350,000 acres on the eastern North Slope from Caelus Natural Resources Alaska LLC for an undisclosed price. The company is a partner on the Caelus-operated Ooguruk unit, which neighbors the Nikaitchuq unit in nearshore state waters north of the Kuparuk River unit.

Upcoming plans

From the beginning, Eni has been developing Nikaitchuq from the onshore Oliktok Point Pad and the offshore Spy Island Drillsite. The suspension came after the completion of the initial Oliktok Point program and before the completion of the Spy Island program.

The plan for the current year, running through September 2019, calls for drilling three new wells at Spy Island and converting eight existing Spy Island wells into multilaterals.

According to a schedule in the plan, the new Spy Island wells are SP03-FN9, SP06 and SI02-SE6, planned for October 2018 through late February 2019. (In a different part of the plan, Eni listed SP03-FN9, SI02-SE5 and SI06-FN8.) The eight new laterals are SP33-W3, SP30-W1L1, SP16-FN3L1, SP27-N1L1, SP23-N3L1, SP10-FN5L1, SP18-N5L1 and SP05-FN7L1, planned for late February 2019 through mid-September 2019.

Under the current naming conventions used at Spy Island, wells beginning with "SP" represent productions wells while wells beginning with "SI" represent injection wells.

Eni is using Doyon 15 for its Spy Island program. The company contracted the rig in preparation for its Nikaitchuq North exploration program earlier this year. The program involved drilling an ultra-extended reach well from the Spy Island Drillsite into federal waters north of the Nikaitchuq unit, and the rig required considerable modification.

The timetable of the proposed development activities depends on the timing and results of the NN-01 exploration well being drilled into the Harrison Bay Block 6423 Unit.

Eni had initially planned to spud the well by Dec. 10, 2017, complete the well in mid-February 2018 and conduct flow testing between mid-February and mid-March 2018.

The actual spud date was pushed to Dec. 23, with drilling activities beginning in February 2018 and expected to continue into mid-July and flow testing occurring in late July or August. The delays forced the company to defer plans to drill a sidetrack in order to comply with summer drilling restrictions in the waters off the North Slope. The company still plans to drill an NN-02 appraisal well during the upcoming winter exploration season.

The company is not planning to resume development drilling from the Oliktok Point Pad but does plan to continue its ongoing workover activities from the pad in early 2019.

The company is also planning to conduct workover activities on Spy Island wells.

Prior suspension

Eni suspended development drilling at Nikaitchuq in May 2015 in response to the global downturn in oil prices. The suspension occurred as the company was completing some of its initial development plans and was beginning to consider opportunities for expansion.

The company completed its initial drilling plans for the Oliktok Point Pad in October 2012 and conducted a sidetrack campaign on select wells in 2013 and 2014. The additional work also included an appraisal in mid-2014 to evaluate an N sand target. All the previous wells drilled from the Oliktok Point Pad had targeted an OA sand reservoir.

After the end of the sidetrack program in May 2014, all development activity at the Oliktok Point Pad shifted from drilling to workover operations. The company eventually released its Nabors 245 rig in late 2017 and contracted the Nordic Calista 4 rig.

A continuous drilling program at Spy Island began in November 2012. The program was expanded in early 2013 with the first multilateral at Nikaitchuq and expanded again in late 2013 with a campaign to add a second lateral to all new Spy Island production wells.

The company conducted the West Extension Project at Spy Island between the third quarter of 2014 and early 2015 and launched the East Extension Project in 2015, before suspending all drilling activities at the unit and putting the Doyon 15 rig in cold stack.

The Nikaitchuq unit produced 20,797 bpd in 2017, down from a peak of some 27,000 bpd in late 2015, according to Eni. The unit came online in February 2011, and cumulative production passed 45 million barrels in April 2018. ●

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Exxon advancing two Point Thomson fronts

Company is working to reach immediate 10,000 barrel per day target while also negotiating with the state over expansion

By ERIC LIDJI
For Petroleum News

DARLENE GATES

Rare among the development plans filed with Alaska oil and gas officials, the plan of development for the Point Thomson unit includes two components. One component covers an existing development at the unit. The other covers a future expansion project.

The two components acknowledge the unusual state of Point Thomson: the development activity underway does not represent the full potential of the eastern North Slope unit.

The existing development is producing a small amount of condensate and cycling the resulting natural gas back into the reservoir. The future expansion would dramatically increase the amount of condensate production and ship gas to the Prudhoe Bay unit.

Complications underlie both of those efforts.

The existing development, or Initial Production System, was supposed to produce 10,000 barrels of condensate per day and recycle 200 million cubic feet of natural gas per day.

Since operator ExxonMobil Alaska Production Inc. brought the unit online in April 2016, average production has consistently fallen short of that target, often by a large amount.

Through the first half of 2018, for example, the unit was online for an average of 22 days per month, and condensate production ranged from 5,200 barrels to 9,100 barrels per day.

As of early August 2018, the unit was shut down for an undisclosed amount of time to conduct unspecified maintenance work. "The advanced equipment at the facility requires rigorous inspection and maintenance protocols to ensure safe operation," Hans Neidig, public and government affairs manager for Exxon in Alaska, told Petroleum News.

The chief complication facing the Initial Production System is the high-pressure sands of the eastern North Slope — 10,000 pounds per square inch, according to ExxonMobil.

The company claims that the field pressure at Point Thomson is higher than any other field in its global portfolio and perhaps any producing field in the world. The situation required Exxon to commission special "industry first" compressors at Point Thomson.

The 10,000-barrel-per-day figure was included a plan of development covering Point Thomson unit activities from 2012 through 2017. Even though state Division of Oil and Gas Director Chantal Walsh noted that ExxonMobil failed to meet the production target and two other work commitments included in the plan — to propose debottlenecking activities and to address plans for a future East Pad — she ultimately approved a new plan of development addressing Initial Production System activities running through 2019.

The new plan focused on continuing Initial Production System operations and did not include plans for any additional wells or any advancement of the East Pad and only included a vague commitment to consider debottlenecking activities, according to Walsh.

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In a long rebuttal from October 2017, the company maintained that its activities at the Initial Production System between 2012 and 2017 met the terms of the original plan.

Walsh ultimately decided that the benefits of the existing production at Point Thomson outweighed her concerns about ongoing production shortfalls and other shortcomings, and therefore she approved the newest plan of development through the end of 2019.

Expansion plans

The bigger challenge at Point Thomson is and always has been its future.

In her August 2017 ruling approving the Initial Production System plan of development, Walsh rejected the associated plan of development for the Point Thomson expansion.

Walsh was opposed to conditional clauses in the plan that would have allowed ExxonMobil to back out of the expansion project if its partners decided not to proceed.

In an October 2017 document released after a meeting with state officials, ExxonMobil provided "explanatory detail and clarification" about its plans for the expansion project.

The proposed project would expand condensate production to more than 50,000 barrels per day and to ship 920 million cubic feet of natural gas per day to the Prudhoe Bay unit.

The proposal also included plans to drill two production wells and one disposal well from the Central Pad and to convert the PTU-15 and PTU-16 injection wells to production.

According to the state, Exxon effectively eliminated the conditional clauses from its plans by noting that it "does not condition all planning work on agreement on terms for delivery of gas to Prudhoe Bay, and engineering and permitting work is ongoing."

In her ruling approving the plan, Walsh wrote, "If the PTU Working Interest Owners do not fund the planning work or enter a commercial agreement with the Prudhoe Bay Unit working interest owners, those events will not in any way absolve Exxon from fulfilling its obligation to complete the planning work promised in the Revised Planning POD."

The expansion was one of the conditions of a 2012 settlement between Exxon and the state over the nature of the development activities completed up to that point at the unit.

The condition required Exxon to either increase the Initial Production System to 30,000 barrels of condensate per day or to ship natural gas to the Prudhoe Bay unit for injection.

The expansion clause was triggered when Exxon and its partners failed to sanction a major gas sale by June 2016. The settlement required Exxon to submit a plan by the end of 2019 for expanding the Point Thomson development. But in a letter from September 2018, the state stayed the deadline so long as the Alaska LNG Project is progressing.

Eastern North Slope

For decades, the conversation about Point Thomson has focused largely, and at times exclusively, on its importance to any future North Slope natural gas pipeline project.

In the years since the Point Thomson unit came online, an additional topic has become increasingly popular: the importance of the unit to other prospects in the vicinity.

By constructing pipeline infrastructure at the Point Thomson unit, Exxon changed the economics of adjacent and nearby lands and waters across the eastern North Slope.

The independent 88 Energy recently commissioned the 251-square-mile Yukon Gold 3-D seismic survey over its Yukon Gold prospect south of Point Thomson. The company acquired the property in late 2017 through a lease sale, attracted in part by the results of the Yukon Gold well drilled by BP Exploration (Alaska) Inc. in 1993 and 1994. The state has estimated that the prospect contains some 120 million barrels of recoverable oil.

The Point Thomson facilities would also be crucial to any future development activities at Area 1002 of the Arctic National Wildlife Refuge. Exploration activities in the area have been advancing in recent months after decades since the most recent drilling work.

The crucial infrastructure in both cases is the Point Thomson Export Pipeline connecting the Point Thomson unit to the Badami unit and onward to the trans-Alaska oil pipeline.

In August 2018, PTE Pipeline LLC proposed a rate of $20.84 per barrel for the 22-mile liquids pipeline, up from a rate of $12.09 per barrel that went into effect in April 2017.

The shipping rate is based on actual and estimated throughput on the 70,000-bpd pipeline. ●

Furie closing in on four wells

Company expects to finish out 2018 with four wells at Kitchen Lights, meeting terms of Enstar deal

By ERIC LIDJI
For Petroleum News


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By the end of this year, Furie Operating Alaska LLC expects to have four production wells in operation at its offshore Kitchen Lights unit in the waters of Cook Inlet.

The local company started the year producing natural gas from the KLU No. 2 and KLU No. 3 wells at its Julius R. platform. The company completed the KLU A-1 well in late July 2018. And as this issue of The Producers was going to print in early October, the company was in the process of drilling KLU A-4 using the Spartan 151 jack-up rig.

Having four production wells in operation before the end of the summer drilling season would satisfy the terms of a gas supply agreement with Enstar Natural Gas Co. Inc.

The KLU A-1 well tested the Sterling formation and found it "very productive," Chief Operating Officer Scott Pinsonnault told Petroleum News in late September 2018.

At the time, the company was conducting tests at the well to better understand the relationship between the pressures found at various zones within the reservoir. The information will be important for guiding the ongoing production strategy at the unit.

The current plan involves depleting the Sterling formation before developing the Beluga formation below it. The Beluga typically contains more water than the Sterling, which would increase the production costs for natural gas, when the time comes to produce.

To conduct the tests on the KLU A-1 well while simultaneously drilling KLU A-4 from the same platform, the rig crew has been using wireline equipment rather than a rig.

As of late September, the KLU A-4 well had penetrated the Beluga formation and was drilling down towards the Tyonek, where the company planned to add an "exploration tail."

"We're excited about that," Pinsonnault said. "We have good reason to believe that it's prospective. There's a direct hydrocarbon indicator, a bright spot, on the seismic." If successful, the company said it would to complete the well in the Tyonek. If not, it would complete it in the Beluga.

Previous plans

In addition to satisfying the terms of the Enstar contract, the work would satisfy the terms of the fifth plan of development with the state, covering the year ending Jan. 4, 2019.

That plan proposed completing the KLU A-1 well and either drilling and testing a second development well into the Sterling formation, deepening the existing KLU No. 4 well or drilling the KLU No. 6 exploration well to test for oil in the deep Jurassic formation.

The state Division of Oil and Gas had placed the Kitchen Lights unit in default in late December 2017 for failure to meet work commitments, a charge the company disputed.

The debate stemmed in part from tax credits. After the state withheld credits promised for previous work, Furie suspended its program planned for the 2017 open water season. By that point, Furie had started but not completed the KLU A-1 well the previous summer.

A sixth plan of development was due with state officials in early October but had yet to be released on the Division of Oil and Gas website as The Producers was going to print. One outstanding issue was how the company will balance development and exploration work.

"It will definitely be focused on more development activity in the existing field, because we've got production targets to

continued on page 44

The Spartan 151 jack-up rig cantilevered over the Julius R. platform for development drilling in the Kitchen Lights gas field in the Cook Inlet.

COURTESY FURIE OPERATING ALASKA

FURIE *continued from page 43*

maintain under our offtake agreement," Pinsonnault noted, adding that any exploration ventures being considered were "a work in progress."

Some of those development decisions may depend on the coming winter. The company wants to see how the unit performs with four wells, rather than two, during the months of peak demand. "Our goal is to meet our obligations under our contracts," Pinsonnault explained. "If we have excess gas leftover, we can sell it at spot, or put it into storage."

Future plans

The expansive opportunities at the Kitchen Lights unit emerge from its origins.

The 83,394-acre Kitchen Lights unit includes three previously independent prospects that were administratively divided into four exploration blocks: Corsair, North, Central and Southwest. All development activities to date have occurred within the Corsair block.

Furie is a small, privately held independent company, and its strategic decisions at Kitchen Lights have always seemed to depend on the results of its immediate activities.

Early plans of exploration for Kitchen Lights required Furie to drill at least one well in each block. Furie drilled KLU No. 1, KLU No. 2 and KLU No. 2-A, and KLU No. 3 in the Corsair block between 2011 and 2013. Through the end of the 2013 open-water season and the beginning of the 2014 open-water season, the company drilled KLU No. 4 in the North block. At the end 2014, the company drilled KLU No. 5 in the Central block.

A sixth plan of development was due with state officials in early October but had yet to be released on the Division of Oil and Gas website as The Producers was going to print.

At that point, the balance of activities at Kitchen Light shifted toward development from the KLU No. 3 well, leaving the Southwest exploration block undrilled, as of yet.

A plan of exploration in early 2016 proposed a nine-well exploration program over five years. The locations of those proposed wells covered most of the unit. The well depths proposed in the plan ranged from 7,230 feet to some 24,000 feet, which covered many of the noteworthy formations and intervals at the unit — both known and prospective.

A new plan submitted the following year tempered that proposal. The plan laid out two alternatives for the unit: deepening an existing well or drilling a new exploration well.

Later, the demands of various gas supply agreements, including the Enstar deal, shifted activities toward development that could generate the promised production volumes.

An interruptible gas supply agreement with Chugach Electric Associations includes a clause for firm supplies starting in April 2023. The demands of that contract, combined with the results of the current slate of wells, could determine whether exploration or development is the most prudent path forward at Kitchen Lights over the next few years. ●

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Glacier advancing four units; bullish on Badami

Success at Starfish project renewed hope in the frustrating but promising eastern North Slope unit

By ERIC LIDJI
For Petroleum News

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The biggest project planned for the West McArthur River unit in the coming year is exploration activity at the long-delayed Sabre prospect in an offshore corner of the unit.

Glacier Oil & Gas Corp. spent the past year performing small tasks at its four units and planning two large exploration ventures that might guide work in the years to come.

The company was created through the bankruptcy case of the former Miller Energy Resources Ltd. and now operates four units. Through its subsidiary Cook Inlet Energy LLC, Glacier operates the West McArthur River unit and the Redoubt unit on the west side of Cook Inlet and the North Fork unit in the southern Kenai Peninsula. Through its subsidiary Savant Alaska LLC, it operates the Badami unit on the eastern North Slope.

Unlike its predecessor Miller Energy, which had acquired multiple prospects throughout Alaska and eventually became overextend when commodity prices dropped, Glacier has been taking a gradual approach by focusing on maintenance activities to improve operations at existing wells and reserving its larger resources for targeted projects. Those projects include exploration drilling but also include large infrastructure investments.

West McArthur River

The biggest project planned for the West McArthur River unit in the coming year is exploration activity at the long-delayed Sabre prospect in an offshore corner of the unit.

The current plan calls for using the Spartan 151 jack-up rig to drill the offshore well.

In its 27th plan of development from late January 2018, Glacier said it was "seeking partners in the Sabre prospect to reduce the risk factors" associated with the well.

According to the plan, Sabre is the only specific project on the docket at the West McArthur River unit for the coming development year, which runs through April 2019.

The Alaska Department of Environmental Conservation issued a key permit for the project in mid-May 2018. The pollutant discharge elimination system individual permit allows the company to discharge certain waste fluids from the Spartan 151 into upper Cook Inlet during its operations at the Sabre prospect. The permit expires June 15, 2023.

Glacier subsidiary Cook Inlet Energy first discussed plans for a Sabre exploration well as early as late 2013 but delayed the project due to the logistics and the approximately $25 million cost of drilling an extended reach well from onshore facilities to the offshore prospect. The arrival of a jack-up rig in Cook Inlet after decades of failed attempts improved the economics of the well by allowed for vertical drilling from an offshore site.

Over the past development year, Glacier undertook one of the largest infrastructure projects in the history of the unit by shifting processing to the Kustatan Production Facility, which is newer and larger than the West McArthur River Production Facility.

Redoubt

Glacier is taking a gradual approach at the Redoubt unit. Although the company has a long-term goal of delineating and developing the Central, Southern and Northern fault blocks within the unit, its immediate plans mostly involve sidetracks and workovers.

The company undertook a similar range of projects in its 17th development year, running through the end of April 2018. The company drilled the Redoubt Unit No. 3A sidetrack as a waterflood injection well. The company also replaced electric submersible pumps in the Redoubt Unit No. 1A and Redoubt Unit No. 5B wells, although a related project to hydraulically fracture those two sidetracks was cancelled following pump failures.

Glacier also applied to contract the Redoubt unit and to create a new South Step Out participating area at the unit. The state had yet to rule on either application by mid-2018.

In the coming 18th development year, running through April 2019, Glacier plans to continue that approach. The company expects to use the results of current and planned waterflood activity to determine whether to convert additional wells to waterflood. The company plans to drill and stimulate the Redoubt Unit No. 4A sidetrack for waterflood.

The company is also planning to replace a failed electric submersible pump at the Redoubt Unit No. 9 well and might stimulate the well through hydraulic fracturing.

North Fork

As it prepares targeted exploration and delineation programs

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GLACIER *continued from page 45*

at its other properties, Glacier is trying to maximize production from existing wells at the North Fork unit.

The company emerged from the bankruptcy process with an immediate plan to undertake "small ball" projects at North Fork. The term described low-risk efforts to improve production and operations from existing wells, rather than ambitious expansion programs.

One of the projects undertaken during the 52nd plan of development ending in March 2018 was setting down-hole plugs to control water intrusion. The success of the work allowed the company to postpone plans to convert an existing well to Class II disposal, although the project could theoretically become necessary at some point in the future.

The company also perforated additional zones at the North Fork Unit No. 14-25 and North Fork Unit No. 41-35 wells in order to increase production. The company also completed "an optimization project to improve gas well process flow" and replaced well houses on the North Fork Unit No. 24-26 and North Fork Unit No. 42-35 wells.

In its 53rd plan of development running through March 2019, Glacier said it would continue this approach for the coming year, focusing on existing wells over new drilling.

Glacier also hinted at future plans, saying it intended to "fully delineate and develop all fault blocks" within the unit as market and technical conditions allowed. The two wells currently under consideration are North Fork Unit No. 42-35A and either North Fork Unit No. 22-26 or North Fork Unit No. 14-26. The company also said it was evaluating a plan to build an additional drilling pad at the unit to accommodate future drilling and a plan to drill outside of the current North Fork Gas Pool No. 1 participating area boundaries.

JUDY PATRICK

Through its subsidiary Savant Alaska LLC, Glacier Oil and Gas Corp. began drilling the B1-07 Badami exploration well with Nabors Rig 27E in early 2018 and has since announced the discovery of the Starfish prospect.

Badami

The results of the Starfish program will likely guide development plans at the Badami unit for several years, according to a

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GLACIER *continued from page 46*

development plan for the eastern North Slope unit.

The B1-07 well discovered oil and came online in mid-May 2018. Production topped 2,500 barrels per day in early testing, CEO Carl Giesler told Petroleum News in June.

The well resulted in a considerable increase in Badami unit production. The unit produced 698 barrels per day in April 2018 and climbed to 1,329 barrels per day in May, according to figures from the Alaska Oil and Gas Conservation Commission. The Starfish well averaged 1,567 barrels per day in June and 1,214 barrels per day in July.

The mid-May start-up beat targets by several months. In public comments and in a 15th plan of development for Badami, filed with the state Division of Oil and Gas on April 18, Glacier said that it expected to bring the B1-07 well into pilot production by mid-July.

Through its subsidiary Savant Alaska LLC, the company began drilling the well earlier this year outside the existing Badami Sands participating area using Nabors rig 27E.

In its plan, Glacier it would drill as many as two additional wells at Badami during the winter of 2018-2019, if warranted by B1-07 well results and by economic conditions.

Glacier also said that it intends to apply for a new participating area covering Starfish oil production, if the well is successful. And the company noted that a new drilling pad "will likely be necessary" to fully explore and delineate outside existing participating areas.

Describing the Starfish project to the Alaska Support Industry Alliance in September 2017, Giesler said, "If this well works close to what we think it will, it should open five to seven more prospects similar to it." In its 2017 plan of development, Glacier described Starfish as one of "several new target 'pods' of interest" identified through a recent review of the Badami and Killian sands. The prospect is "southwest of the current development area within the Badami Sands" participating area in the middle of the unit.

The Alaska Oil and Gas Conservation Commission issued a permit on Jan. 12 for Savant to drill the Badami B1-07 well on ADL 367011. Although the company is describing the project as exploratory, the commission categorized the project as a development well.

Badami is uniquely positioned to accommodate new development. The 38,500-barrel-per-day processing facilities at the unit currently handle approximately 1,000 bpd, a reminder of the ambitions of the original operator, BP Exploration (Alaska) Inc.

The Starfish project is the first new drilling at Badami since Savant completed the Badami Unit Red Wolf No. 2 well in April 2012, according to AOGCC well reports. In the intervening years, Savant devoted its resources to workover projects and was stalled by a bankruptcy proceeding involving its former owner Miller Energy Resources Inc.

Through those proceedings, Glacier assumed control of Savant in early 2016. The company initially took a cautious approach to its new properties by focusing on low-risk development projects but began announcing potential exploration work last summer. ●

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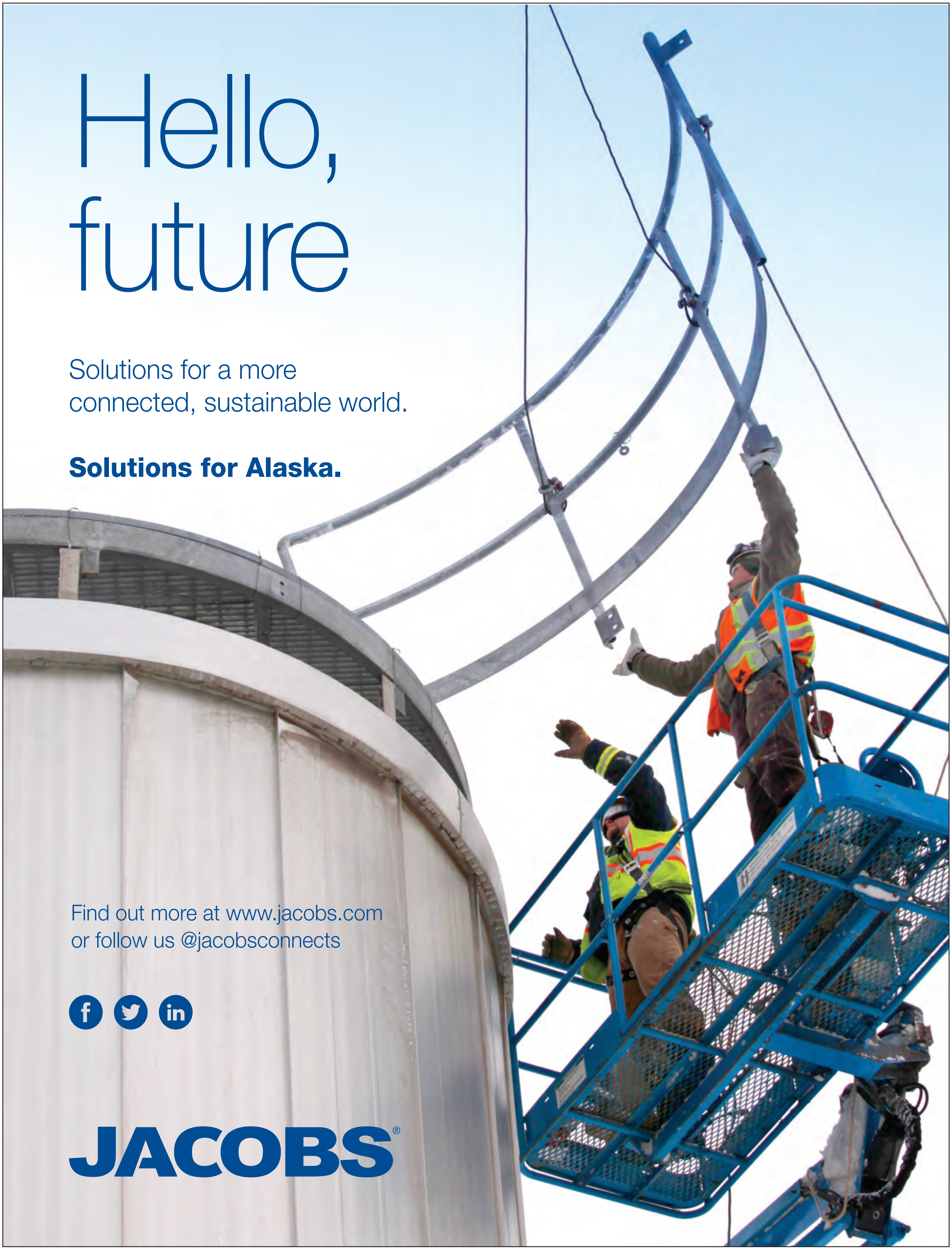
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Hilcorp staggering its efforts on the North Slope

Company planning large program at Milne Point, lesser programs at Duck Island and Northstar; Liberty gets big boosts

By ERIC LIDJI
For Petroleum News

Hilcorp Alaska LLC is entering the final months of an extension of its plans of development for its three active North Slope units. The administrative quirk is intended to shift the annual reporting schedule for those units to a different quarter of the calendar.

As a result, the company reported its planned activities shortly before the start of the development year in early 2017 and again in a series of amendments this past summer.

The plans and their amendments show that the company is advancing its development activities at different rates at its four North Slope properties. The Milne Point unit is receiving the largest investment and will host the greatest amount of drilling, followed by the Endicott field at the Duck Island unit and then the Northstar unit. The Liberty project remains in pre-development but is gaining momentum again after several years of delays.

Hilcorp acquired a major stake in the North Slope in late 2014, though an acquisition from BP Exploration (Alaska) Inc. and has since expanded its interest in those holdings.


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Hilcorp Energy Company

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Alaska's Northstar Island at night. Built of gravel and located in the Beaufort Sea six miles off the Alaska coastline, Northstar has been in operation since 2001.

COURTESY HILCORP ALASKA

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Milne Point

Hilcorp fell short of its targets for the Milne Point unit during the 2017 development year but surpassed the pace of development activity it had reported in recent years at the unit.

In its 36th plan of development for the Milne Point unit, running through the year ending July 31, 2018, Hilcorp told the state it would drill as many as 18 wells. The proposed program included 10 wells at F pad, five wells at L pad, two wells at E pad and one well at C pad. The 18-well program was designed to target several intervals throughout the Schrader Bluff formation, as well as targeted intervals in the Sag River and Kuparuk formations.

In addition to Moose pad construction, Hilcorp commissioned the custom-built Innovation rig, touted as the lightest modular rig on the North Slope. The rig can drill closely spaced wells, allowing it to also operate at Endicott and at the Northstar unit.

The program also included workover activities at as many as 16 wells.

According to information from the Alaska Oil and Gas Conservation Commission, Hilcorp drilled 12 development wells at Milne Point in the year ending July 31, 2018.

The program started with the C-45 producer drilled into the Kuparuk formation in October 2017. The company drilled the L-51 producer, L-52 injector and L53 producer between late October 2017 and mid-January 2018 and the L-54 producer, L-56 producer and L57 producer in June and July 2018. The company drilled the F-106 injector, F-107 producer, F-108 injector, F-109 producer and F-110 injector between mid-February 2018 and mid-May 2018. The L pad and F pad wells were drilled into the Schrader Bluff formation. As of mid-September 2018, the company had not permitted the two proposed E pad wells.

As part of its 36th plan of development, Hilcorp asked the state to extend the plan of development through Jan. 12, 2019. The extension would allow the company to shift its reporting schedule to later in the year. The state agreed but required the company to file an amendment that reported on its development activities for the latter half of 2018.

In the subsequent amendment, Hilcorp proposed work at as many as 22 wells — a combination of drilling and workovers — at Milne Point by January 2019 using the Doyon 14, Innovations and ASR1 rigs. The amendment proposed work at six L pad wells, four E pad wells, three Moose pad wells and as many as eight undefined workover projects.

The L pad wells include two Kuparuk producers, one Sag River producer and converting two producers to injectors. The E pad wells include two Schrader Bluff producers, one Schrader Bluff injector and converting one producer to a new water well. The Moose pad wells include one Schrader Bluff producer, one disposal well and one water well.

The amendment also provided updates about several facility projects.

By the January deadline, Hilcorp expects to install and commission the Titan 130 turbine and associated infrastructure at the L pad. The company applied in late 2017 to expand the pad to accommodate the added infrastructure and as many as five new development wells. The expansion added 2.29 acres of gravel to three sections of the existing pad.

The company expects to complete facility upgrades at J pad and A pad by the January deadline. The work involves installing polymer injection facilities at the two pads. The company is also planning electrical upgrades at E pad during the remainder of 2018.

Aside from the ongoing drilling activities at existing pads, the biggest development at Milne Point is the ongoing work on the Moose pad. The 44-well pad would be the first new pad at the unit since 2002. It would target oil in the Kuparuk and Schrader Bluff formations at the western end of the unit and could eventually accommodate 50-70 wells.

In addition to Moose pad construction, Hilcorp commissioned the custom-built Innovation rig, touted as the lightest modular rig on the North Slope. The rig can drill closely spaced wells, allowing it to also operate at Endicott and at the Northstar unit.

In previous announcements, Hilcorp said it planned to begin drilling activities at Moose pad in 2018 with first oil expected by the end of the year. As of mid-September, the company had yet to receive AOGCC drilling permits. The most recent permitting activity at Moose pad involved a pipeline tie-in pad and access road requested in May 2018. In the amendment, Hilcorp said it expected to commission the new pad by January 2019.

Duck Island

This past year was the first where Hilcorp conducted drilling activities at the Endicott field of the Duck Island unit as part of its ongoing development work at the unit.

Hilcorp Alaska delivered the newly built module rig, name the Innovation, to the North Slope fall of 2016.

COURTESY HILCORP ALASKA

The company initially announced plans to drill at least one and as many as seven sidetracks, according to a plan of development for the year ending July 31, 2018.

According to AOGCC records, the company drilled the SDI 3-23A sidetrack in October 2017. The well was the first at the Duck Island unit since BP Exploration (Alaska) Inc. drilled the Duck Island Unit SDI 4-04A/T30 production well in 2009.

Hilcorp also drilled the MPI 2-66A sidetrack in September 2018, during the current development year. The company also permitted the SDI 4-26A sidetrack in late July 2018 but had not yet completed the well by mid-September, according to the AOGCC.

Hilcorp expanded its ownership of the Duck Island unit in June and July 2018 by acquiring the outstanding interest of ExxonMobil in the unit and its main pipeline.

Hilcorp requested that the current Duck Island unit plan of development continue through Feb. 12, 2019, to allow the company to shift its reporting schedule to later in the year. The state approved the request but required the company to prepare an amendment covering its activities for the latter half of the year. In its amendment, the company said that it was not planning any activities outside of the scope of the original plan of development.

Northstar

Hilcorp has been focusing on workover activities, rather than drilling, at the Northstar unit. But the company reduced its activities somewhat in the current development year.

In the 13th development year, ending July 31, 2017, the company performed six workover projects at four wells in three participating areas: Northstar, Fido and Hooligan.

The company also completed several major facility projects.

The 14th plan of development, through July 31, 2018, included no drilling activities and a workover project to recomplete the NS-15 well, in addition to several fa-

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cility projects.

Hilcorp requested that the Northstar unit plan of development continue through Feb. 12, 2019, to allow the company to shift its reporting schedule. The state approved the request but required the company to provide an amendment covering its later activities.

The amendment to its plan of development, submitted in August 2018 and accounting for the extension period, included projects at the NS-08, NS-13 and NS-18 wells. The projects involve acidizing Kuparuk C formations at NS-08 and NS-18 to remove wellbore damage and acidizing an existing injection well, recompleting the NS-13 Ivishak well to a Kuparuk well, and converting an existing Kuparuk production well into an injector.

Liberty

Hilcorp is operating the Liberty project on behalf of partner BP. The long-delayed and oft-revised project is targeting a resource in the federal waters of the Beaufort Sea.

The project received two big boosts over the past year.

The first came when the Trump administration cancelled an Obama administration order that had withdrawn the Chukchi Sea and portions of the Beaufort Sea from drilling.

The second came in early September 2018, when the U. S. Bureau of Ocean Energy Management issued its final environmental impact statement for the project, accepting a plan by Hilcorp to develop Liberty from a gravel island some five miles offshore.

Hilcorp is looking to begin construction on the 9.3-acre island in late 2019. A 16-well development program would begin sometime after, with first oil as early as 2022.

The company expects the field to come online between 10,000 and 15,000 barrels per day, peaking at 60,000 to 70,000 bpd within two years. The company also expects the field to produce as much as 120 million cubic feet of natural gas per day.

The plan for the gravel island mimics an earlier development plan by BP from the late 1990s. BP later revised the project in favor of an ultra-extended reach drilling plan. ●

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Hilcorp dominates Cook Inlet production

Company operates nearly 20 fields spread across all four segments of the basin

By ERIC LIDJI
For Petroleum News


DAVE WILKINS

Hilcorp Alaska LLC remains the dominant producer in the Cook Inlet basin. The local subsidiary of the Texas-based independent operates about 19 fields and units — a number that seems to fluctuate each year due to acquisitions, consolidations and terminations.

On the west side of Cook Inlet, Hilcorp operates the Ivan River, Lewis River, Pretty Creek and Beluga River units. Offshore, the company operates the North Cook Inlet unit, the Granite Point unit, the Middle Ground Shoal unit, the Trading Bay unit and the North Trading Bay unit and associated McArthur River field. In the southern Kenai Peninsula, the company operates the Ninilchik, Deep Creek and Nikolaevsk units. In the northern Kenai Peninsula, the company operates the Birch Hill unit, the Swanson River unit, the Beaver Creek unit, the Sterling unit, the Kenai unit and the Cannery Loop unit.

Offshore

Hilcorp operates five offshore units in Cook Inlet: North Cook Inlet, Granite Point, Trading Bay, North Trading Bay and Middle Ground Shoal. Those units are the result of significant consolidation. A decade ago, several were divided into two or three units.

Hilcorp is in the early stages of redeveloping the North Cook Inlet unit.

The company acquired the unit from ConocoPhillips Alaska Inc. in late 2016 and quickly asked the state for permission to extend an existing plan of development to June 2018.

A plan of development filed in April 2018 represents the first full plan from Hilcorp since it took over the unit and takes a measured approach to activities at North Cook Inlet.

Hilcorp is not planning any exploration or delineation activities at North Cook Inlet in the coming development year, which runs through May 2019. Instead, the company will launch a "comprehensive field study" to evaluate the remaining potential of the Beluga and Sterling sands and to determine the need for future wells, sidetracks and perforations.

The company intends to study the potential of developing deep oil prospects at North Cook Inlet. Previous operators and farm-in partners over the years have considered a similar venture at the field, but Hilcorp is going one step further by installing a subsea oil pipeline as part of its efforts to extend natural gas transmission across Cook Inlet.

The proposed program for the upcoming year includes work on the Tyonek platform that accesses offshore targets at North Cook Inlet. The program also includes a structural assessment in advance of planned upgrades to the rig and other infrastructure, preparation for upgraded living quarters, natural gas pipeline and oil pipeline work in advance of the Cook Inlet Pipeline Cross Inlet Extension Project and other transmission infrastructure.

Even without development work, Hilcorp expects production to be "maintained and enhanced" through the coming development year. The unit produced approximately 16.2 million cubic

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feet per day in 2017, up from 13.8 million cubic feet per day in 2016.

The production increase came despite the lack of drilling or workover activities at the unit last year. Hilcorp shot perforations into abandoned intervals at the A-03, A-09 and A-12 wells in the fall of 2017. Hilcorp subsequently opened the productive Sterling A and Stray sands at the A-09 well and identify the previously unproduced Sterling X sand.

The success of the perforation program convinced Hilcorp to cancel plans to add compression capacity at the associated Tyonek platform to increase production volumes.

To the southwest, Hilcorp is not planning any exploration or delineation at the Granite Point unit over the coming development year running through May 2019 but plans to use the results of its 2017 drilling program to identify future drilling opportunities at the unit.

The company expects Granite Point production to be "maintained or enhanced" over the coming year. The unit produces from three platforms: Granite Point, Anna and Bruce.

The Granite Point platform produced 311.1 million cubic feet of gas and 492,500 barrels of oil in 2017. The Anna platform produced 240 million cubic feet of gas and 276,400 barrels of oil in 2017. The Bruce platform produced 201.6 million cubic feet of gas and 110,100 barrels of oil in 2017. Adding those platform-level figures together, the Granite Point unit produced 752.7 million cubic feet of gas and 879,000 barrels of oil in 2017.

The unit produced 2,408 barrels of oil per day in 2017, down from 2,530 bpd in 2016.

Hilcorp drilled two sidetracks in 2017. The company completed the GP-11-24RD well to the C5 sand and completed the GP-24-13RD2 well to the C7 sand. A plan to sidetrack the MUCI-02 well to the C7 sand was set aside as more information became available.

The Granite Point unit was created in 2015 from the former South Granite Point unit and Granite Point field. The unit is associated with the Granite Point Production Facility.

Farther to the southwest, Hilcorp is planning a two-well and one-sidetrack program at the Trading Bay unit and associated McArthur River field in the year ending May 2019.

At McArthur River, the company plans to drill the M-22 well targeting the Grayling gas sands and the M-35 well and M-25L1 lateral targeting the upper West Foreland sand.

At the Trading Bay unit, the company plans to sidetrack the A-04RD well into the North Trading Bay unit, targeting the Hemlock and Tyonek G-zone sands. If successful, the sidetrack would be used to return the former North Trading Bay unit to production. The unit had previously produced from the now lighthoused Spark and Spurr platforms.

Going into the previous year at the McArthur River field, Hilcorp announced plans to drill as many as three new wells from the Steelhead platform targeting the upper West Foreland oil pool — M-35, M-36 and M-37 — four sidetracks from the King Salmon platform — K-06RD2, K-24RD3, K-03RD2 and K-26RD2 wells — and no workovers.

Instead, the company drilled no new wells, three of the four sidetracks and 15 unplanned workover operations spread across all four platforms at the field. The operations included completing wells, preparing for sidetracks, repairing pumps and adding perforations.

COURTESY HILCORP ALASKA

The company explained that the three sidetracks successfully targeted the upper West Foreland oil pool, which made the three proposed grassroots wells unnecessary. The company cancelled the K-26RD2 sidetrack based on the productivity of the existing well.

The field produced 1.703 million barrels of oil and 7.2 billion cubic feet of natural gas in 2017, down from 1.797 million barrels of oil and 8.5 billion cubic feet of gas in 2016.

Going into the previous year at the Trading Bay field, Hilcorp announced plans to sidetrack the A-04RD well at the Monopod platform. The work was postponed to the current year to allow for additional evaluation of existing seismic to define the target.

The company instead installed deep-set electric submersible pumps in the A-13 and A-18 wells at Monopod. The company credited the work with improving production rates.

Due east, Hilcorp operates four drilling platforms at the Middle Ground Shoal unit: the active Platform A and Platform C and the currently dormant Baker and Dillon platforms.

Although the company is not planning any drilling activities at any of the four platforms during the current development year, running through May 2019, the company is evaluating the economics of a plan to reactivate the drilling rigs on Platform A and Platform C. If approved, the company could begin drilling in the 2019 development year.

The company had originally planned to drill rotary sidetracks at the C-23-26RD, C-33/26RD and C-34-26RD wells at Platform C during the 2017 development year.

But the work was contingent on the results of an In-Line Inspection program on associated pipelines. The inspection program was required under the terms of a consent agreement with the U.S. Pipeline and Hazardous Materials Safety Administration following a disruption to fuel gas supply pipelines at the Middle Ground Shoal unit. The inspection led to several repair projects on two pipelines associated with the unit.

The three sidetracks were postponed because Platform C was shut-in during the year.

The Division of Oil and Gas approved the development plans for Platform A and Platform C but rejected the development plans for the Baker and Dillon platforms, citing the "lack of work" planned and the "lack of production" currently.

The unit produced 308,649 barrels of oil and 83.1 million cubic feet of gas in 2017, down considerably from 680,900 barrels of oil and 158 million cubic feet of gas in 2016.

West side

The three units Hilcorp operates at the north end of the west side of Cook Inlet are likely the most economically marginal in its portfolio and have received the least investment.

The future of the sub-region depends largely on the results of a "comprehensive field study" launched during the development year that ended May 31, 2018. The study remains ongoing, and the company has said that its preliminary results are confidential.

The company intends to study the potential of developing deep oil prospects at North Cook Inlet.

While the study could lead to renewed investment in the region, it could also presumably lead to lower investment. The state terminated the Stump Lake unit in late 2017 after Hilcorp determined that it was not feasible to return the suspended field to production.

The three smaller units in the region — Ivan River, Lewis River and Pretty Creek — have been in a holding pattern for years. Hilcorp did not drill any wells or sidetracks and did not conduct any workover operations at the three units during the 2017 development year, and it is not planning any development work at the units for the 2018 development year.

Ivan River unit production declined to 651,000 cubic feet per day in 2017 from 750,000 cubic feet per day in 2016, according to Hilcorp. The unit was formed in 1967, came online in 1990 and had cumulative production of 86.1 billion cubic feet through the end of 2017. The unit produced almost exclusively from the Tyonek participating area in 2017, with no production reported from the Sterling-Beluga Gas participating area. The IRU 14-31 and IRU 13-31 wells at the unit are currently used as regional disposal wells.

Lewis River unit production increased to 137 million cubic feet per day in 2017 from 128 million cubic feet per day in 2016, perhaps as a result of a new sand separator which was added upstream of the compressor on Lewis River 0lRD well during the year. The unit was brought into production in 1984 and had cumulative production of 15.4 billion cubic feet through the end of 2017. The unit produced exclusively from the Lewis River Gas Pool No. 2, with no production reported from the Lewis River Gas Pool No. 1 participating area.

Pretty Creek unit production was "intermittent and variable" in 2017 but only averaged about 28,000 cubic feet per day, according to the Division of Oil and Gas. The unit came online in

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1986 and had cumulative production of 9.51 billion cubic feet through the end of 2017. The Pretty Creek unit produced exclusively from the Beluga participating area.

A storage operation injected 32 million cubic feet and withdrew 172 million cubic feet.

Just south of that cluster of units is the federally managed Beluga River unit, which remains an important link for regional electricity markets. Hilcorp operates the unit on behalf of partners Municipal Light & Power and Chugach Electric Association.

Hilcorp is not planning any drilling at the Beluga River unit during the current development year but is planning several undefined workover projects for later this summer. In its previous plan, the company made no firm drilling commitments and ultimately did not drill, focusing instead on overhauling seven compressors at the unit.

The unit produced 14.9 billion cubic feet in 2017, down from 17.4 billion in 2016.

Southern Kenai Peninsula

Hilcorp operates three units in the southern half of the Kenai Peninsula: the coastal Ninilchik unit, the onshore Deep Creek unit and the onshore Nikolaevsk unit.

Hilcorp expects a reduction in its drilling activities at the Ninilchik unit, although a change in market conditions during the year could lead to a dramatic uptick in work.

The company plans to drill the Pearl No. 2A delineation well from a new drilling pad on private land outside of the unit. The well is scheduled for late in the development year, which runs through the May 2019. The well was deferred from the previous year.

According to Hilcorp, the results of Pearl No. 2A will likely require changes to the configuration of both the Ninilchik unit and the associated participating areas.

A field study of the Grassim Oskolkoff participating area in early 2018 identified six potential locations and a re-evaluation of the Blossom No. 1 exploratory well. The results suggested that the Blossom No. 1 well might have missed its target due to geologic faulting. Unless market conditions change, the company does not expect to drill the six Grassim Oskolkoff wells or sidetrack Blossom No. 1 during the current development year.

The company is planning a workover operation to return the GO No. 6 well to production and is considering workover projects on the Paxton No. 8, SD No. 6 and GO No. 7 wells.

The drilling program conducted in the recently completed year included an active program at the Kalotsa prospect and a series of stratigraphic wells at the Pearl prospect.

Hilcorp completed construction work on the Kalotsa drilling pad in 2017. The company brought the Kalotsa No. 1 and Kalotsa No. 2 wells into production in February and March 2017, respectively. Both wells have been producing from the Tyonek formation.

The company completed the Kalotsa No. 3 and Kalotsa No. 4 wells in August and September 2017 and said it had identified "significant potential" in the Beluga and Tyonek formations in both wells. But in response to what it considers to be a lack in near-term market demand, the company plans to "systematically identify unbooked/unproven sands in the lower Tyonek until demand warrants production from the larger sands."

The Kalotsa program "allowed for reallocation and additions" of the Susan Dionne-Paxton participating area. The process began

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last year and carried into this year.

The company deferred the GO No. 9 well in favor of other projects and also deferred workover operations at several wells but completed a workover on the GO No. 8 well.

The Ninilchik unit produces from three participating areas and one tract operation.

The Falls Creek participating area produced between 2.5 million and 2.8 million cubic feet per day in 2017. The Grassim Oskolkoff participating area produced between 1.6 million and 3.65 million cubic feet per day in 2017. The Susan Dionne-Paxton participating area produced between 15.4 million and 18.7 million cubic feet per day in 2017. A tract operation from eight active wells in the Beluga and Tyonek pools produced 8 million and 8.9 million cubic feet per day in 2017. Combined, those production figures yield a range between 27.5 million and 34.05 million cubic feet per day in 2017.

Hilcorp also completed seven stratigraphic test wells in the Ninilchik unit area — Pearl No. 1A, Pearl No. 2, Pearl No. 3, Pearl No. 4, Pearl No. 5, Pearl No. 6 and Pearl No. 7 — between July and August 2017. The company used the test wells to design the Pearl No. 2A well and to begin the process of configuring the unit and the participating area.

In the current development year at the Deep Creek unit, running through July 2019, Hilcorp plans to complete all or some of the work left unfinished this past year.

The program was unfinished due to technical complications, according to the company.

The purpose of the program is to set forth new exploration targets, most likely in the Sterling and Beluga formations, in advance of the 2018 and 2019 drilling season.

The company had intended to complete four of six planned stratigraphic test wells in the vicinity of the unit by June 2017 but only completed two — DC SW 3 and DC SW 4. The company blamed the shortcoming on "unexpected high water flow rates from the Sterling Formation at shallow depths" from the two wells and on "unusually muddy conditions."

Although the results of the two wells are confidential, Hilcorp told state officials that the limited program "significantly helped our exploration and development efforts."

The scope of the upcoming program convinced state oil and gas officials to once again defer until May 31, 2019, a long-proposed contraction of the Deep Creek unit.

The company is currently considering a plan to access the two remaining well locations later this year, during the brief window immediately after freeze-up but before the first major snow. The company drilled the two previous wells in mid-October 2017.

The company also said it was progressing plans to drill at Middle Happy Valley and C Pad within the Happy Valley participating area but could not commit to the project "operational and economic risk associated with such exploratory efforts is reduced."

The Deep Creek unit produced 5.94 million cubic feet per day from the Tyonek and Beluga formations in the Happy Valley participating area in 2017, down from 6.25 million cubic feet per day in 2016. The unit was formed in 2001, brought online in 2004 and had produced approximately 34.6 billion cubic feet cumulatively through 2017.

After years where Nikolaevsk unit operations were in a holding pattern, Hilcorp reported a significant increase in production last year as the result of fracture stimulation activities.

The company credits the stimulation of the Red No. 1 well in March 2017 with increasing natural gas production to 600,000 cubic feet per day in 2017, up from 154,000 cubic feet per day in 2016. The results were short lived. The well produced 232,000 cubic feet per day before the operation and 2.3 million cubic feet per day immediately following the operation. But production had fallen to 850,000 cubic feet per day by June 2017 and eventually to "pre-stimulation levels," reaching 540,000 cubic feet day by March 2018.

Prior to conducting the operation, Hilcorp had estimated that the fracture stimulation would add between 1 million to 3 million cubic feet per day from the Tyonek formation.

Hilcorp generally produces at the Nikolaevsk unit intermittently during winter months and during periods of low market demand, which might explain the bump in early 2018.

In a plan of development submitted to the state in May 2018, Hilcorp did not propose any drilling or workover projects at the Nikolaevsk unit during the coming development year.

Northern Kenai Peninsula

In addition to Beluga River on the west side, Hilcorp operates four federally managed in the northern Kenai Peninsula: Swanson River, Beaver Creek, Kenai and Birch Hill.

The company is expecting a light year of development work at those units.

The company plans to drill between one and three new wells or sidetracks at the Swanson River unit during the current development year, which runs through March 2019.

The company listed one potential well, SCU 33-33RD, in its newest development plan and described the other two wells as "possible." The company is also planning workover activities at two existing wells: SCU 322C-04 and SCU 44-04. (The Swanson River unit and Soldotna Creek unit were once separate administrative entities but have been managed together since 1963. Some well names still reflect those earlier designations.)

In addition to its drilling plans, Hilcorp is continuing a field study of the Hemlock formation at the Swanson River unit to identify remaining reserves, particularly in the Upper Hemlock. "The inventory of sidetrack candidates will be vital for economically reaching these smaller/less economic targets," the company explained in its plan.

In its previous development year, running through March 2018, Hilcorp had initially planned to drill one well, SRU 241-33, and potentially four additional wells or sidetracks, and it had also planned to conduct workover activities at an existing well, SCU 44-33.

The company brought the SRU 241-33 well into production in September 2017 and reported cumulative production of 16.6 million cubic feet by March 2018. The company described the four additional wells or sidetracks as "not possible" during the year. The company ultimately cancelled its proposed workover activities at SCU 44-33, choosing instead to recomplete the existing SRU 32C-15, SCU 22B-04 and SCU 12B-09 wells.

In the Cook Inlet basin, Hilcorp also operates the Birch Hill unit at the northern end of the Kenai Peninsula, but the U.S. Bureau of Land Management has yet to approve the plan for 2018.

The Swanson River unit produced 6.69 billion cubic feet of natural gas and 691,200 barrels of oil in 2017, entering the year at 4 million cubic feet and 1,850 barrels per day and finishing the year at 4 million cubic feet and 1,750 barrels of oil per day. The decline fell short of company goals to maintain or increase production through development.

To the southwest, Hilcorp is not planning any new wells at the Beaver Creek unit during the current development year but did propose a new sidetrack, BCU-05RD2. The company is also not planning any workover activities at the unit during the current year.

The company received an AOGCC permit for BCU-05RD2 on July 11, 2018. As of late September, AOGCC had not listed the well on its weekly "complete wells" list.

In its previous development plan, Hilcorp proposed no new drilling projects. The company initially proposed a workover project targeting Sterling B3 gas production at the BCU 25 well but later redirected the capital toward other projects in its portfolio.

The Beaver Creek unit produced 57,800 barrels of oil and 4.72 billion cubic feet of natural gas in 2017, according to figures provided by the company in the plan.

Farther to the southwest, Hilcorp is not planning any drilling or workover activities at the Kenai unit. In its plan for the previous development year, Hilcorp proposed as many as eight new wells at Kenai — four wells in the Deep Tyonek participating area, two wells targeting the Beluga/Tyonek gas pool, and as many as two additional unidentified wells or sidetracks. The company also proposed as many as 10 coil tubing workover projects, as many as 10 e-line recompletions and as many as five rig workover projects at the unit.

Hilcorp ultimately drilled three new wells during the year.

The company drilled the KBU 32-06 well into the D-4B interval of the Tyonek formation in April 2017. The well was producing 460,000 cubic feet per day in March 2018. The company drilled the KU 14-05 well into the D-6B interval of the Tyonek formation in May 2017. The well was producing 190,000 cubic feet per day in March 2018. The company drilled the KU 11-07X well into the D-3B interval of the Tyonek formation in August 2017. The well was producing 3.9 million cubic feet per day in March 2018.

Given the "exceptional results" of these three development wells and also "current gas market constraints," Hilcorp deferred the three remaining wells in its proposed drilling program for 2017 as well as the 25 proposed workover operations to "future years."

In the Cook Inlet basin, Hilcorp also operates the Birch Hill unit at the northern end of the Kenai Peninsula, but the U.S. Bureau of Land Management has yet to approve the plan for 2018. The previous development plan included a proposal to test an existing well at the unit in the hopes of returning it to production over a three-to-six-month period. ●

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Barrow gas field remains steady

South Barrow, East Barrow and Walakpa all produced in 2018 for the first time in years

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For Petroleum News

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The Barrow gas fields are unique in Alaska hydrocarbon development.

The three natural gas fields in the vicinity of Utqiagvik, formerly Barrow, are the only oil or natural gas properties in the state operated by a public entity for public consumption.

The fields — South Barrow, East Barrow and Walakpa — are also the only place on the North Slope where natural gas is being used for a purpose other than field operations.

Federal contractors discovered the three fields on separate expeditions throughout the region between the late 1940s and the 1980s. The North Slope Borough has operated the fields for decades. The fields have generally required minimal development, aside from a $92 million rejuvenation program launched in 2011 to combat declining production.

With that effort, the city commissioned the Savik 1 and 2 wells at the East Barrow field and the Walakpa 11, 12, and 13 wells at the Walakpa field. By improving deliverability, the city of 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 National Petroleum Reserve-Alaska exploration.

Production began the following year. Drilling continued for decades, with 13 new wells drilled and one existing well deepened by 1987, according to the Alaska Oil and Gas Conservation Commission. Production peaked at some 3.5 million cubic feet per day in November 1981. The field is now used primarily to meet peak demand during the winter.

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, and today produces only a few months each year at most.

The South Barrow Test Well No. 6 flowed for a total of 61 days from May through August 2018, according to the Alaska Oil and Gas Conservation Commission, producing some 28 million cubic feet or slightly more than 459,000 cubic feet per day. The production was the first reported from the South Barrow field since November 2015.

According to the AOGCC, cumulative production at the South Barrow field is nearly 24 billion cubic feet. Geologists had originally expected the field to produce some 32 bcf.

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. East Barrow production peaked at some 2.75 million cubic feet per day in 1984.

According to the AOGCC, cumulative production at East Barrow was 9.2 billion cubic feet through the end of 2016, 9.3 billion cubic feet through the end of 2017 and 9.4 billion cubic feet through the first six months of 2018. The current cumulative total is well above the originally estimated 6.2 billion cubic feet in place for the East Barrow field. Utqiagvik attributes the productivity to methane hydrates — natural gas molecules trapped inside cages of ice and released through pressure changes at the aging field.

Walakpa

Working under a Navy contract, Husky Oil discovered the Walakpa field with the 3,666-foot Walakpa No. 1 well in the 1980s. Production began in the early 1990s. The field has peaked above 5 million cubic feet per day numerous times, including in early 2013.

Today, Walakpa accounts for most of the gas delivered to Utqiagvik. According to the AOGCC, cumulative production was some 31.6 billion cubic feet through the end of 2015, 31.7 billion cubic feet through the end of 2016, 31.9 billion cubic feet through the end of 2017 and more than 32 billion cubic feet through the end of June 2018.

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

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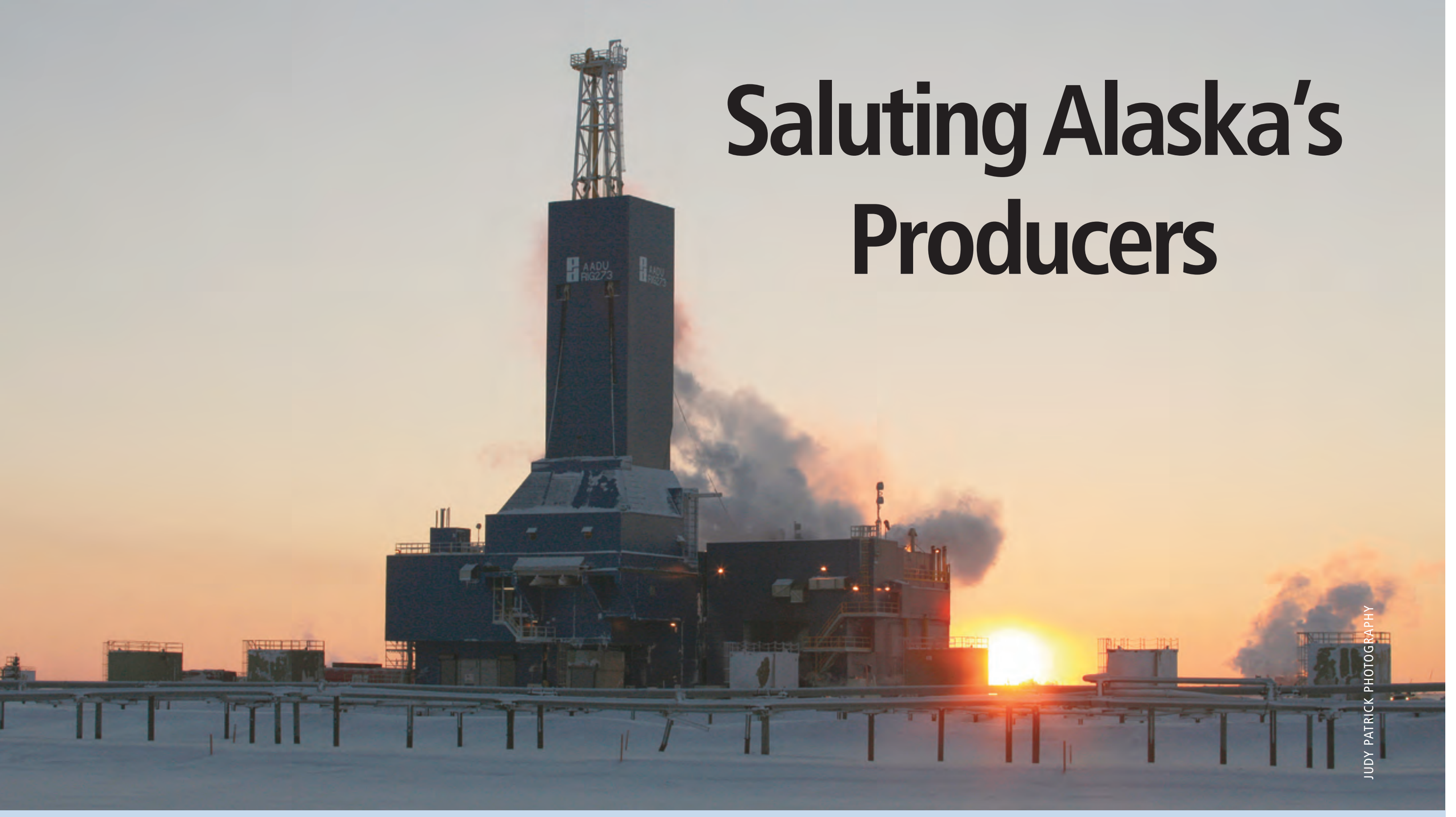

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