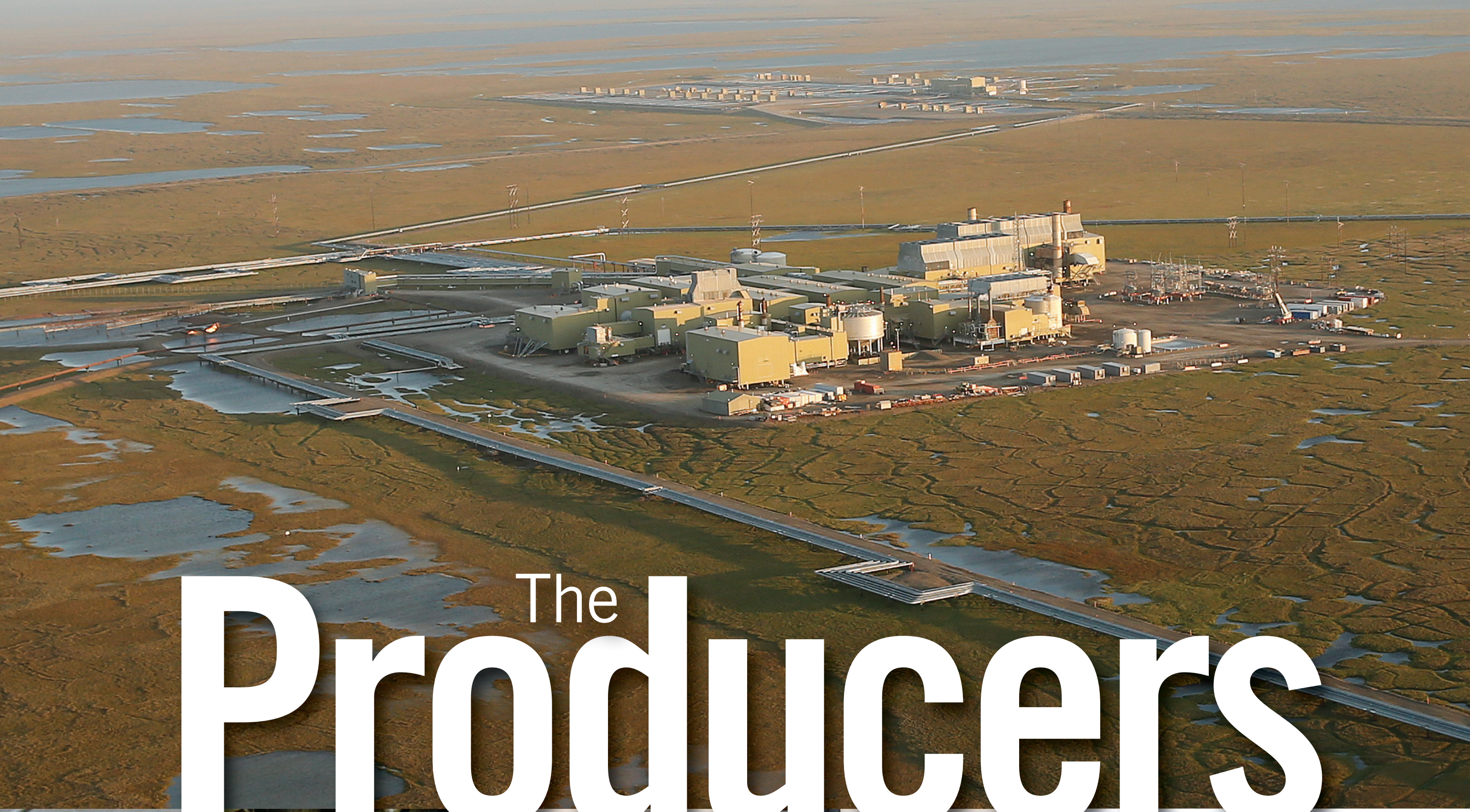

The
Producers

Oil & gas companies investing in Alaska's future

The Producers, an annual publication from Petroleum News

Bright spots amid the darkness

Even with oil prices at persistent lows, there are some signs of optimism for the Alaska oil patch in this edition of The Producers. If all goes well, Alaska could have four new producers by this time next year: BlueCrest Energy Inc. at the Cosmopolitan unit, Brooks Range Petroleum Corp. at the Southern Miluveach unit, ExxonMobil Alaska Inc. at the Point Thomson unit and Furie Operating Alaska LLC at the Kitchen Lights unit.

If all goes well, Alaska could have four new producers by this time next year: BlueCrest Energy Inc. at the Cosmopolitan unit, Brooks Range Petroleum Corp. at the Southern Miluveach unit, ExxonMobil Alaska Inc. at the Point Thomson unit and Furie Operating Alaska LLC at the Kitchen Lights unit.

Hilcorp Alaska LLC started its first year as an operator on both the North Slope and Cook Inlet after acquiring a range of properties from BP Exploration (Alaska) Inc. at the end of 2014. The first plans of development to emerge suggest that Hilcorp is taking the same steady yet aggressive approach on the North Slope that it took in Cook Inlet.

ConocoPhillips Alaska Inc. increased drilling at both the Kuparuk River unit and Colville River unit this year and saw a modest slowdown in decline. The company believes it can have a year without declines soon, which would be a first since Alpine came online. Similarly, Caelus Natural Resources Alaska Inc. sanctioned the Nuna development at its Oooguruk project after winning royalty relief from the state. And Eni US Operating Co. Inc. is evaluating several expansion opportunities at Nikaitchuq.

Aurora Gas LLC and the North Slope Borough maintained their steady operations in Cook Inlet and on the North Slope, respectively. The newcomer AIX Energy LLC was quiet but signed some short-term supply agreements, suggesting consistent operations.

The sale to Hilcorp left BP to focus almost exclusively on Prudhoe Bay. Although drilling at the largest field in North America was relatively steady over last year, the company is considering a range of projects, including viscous oil developments in the western end of the unit and projects uncovered through the North Prudhoe seismic program. Unfortunately, some of those projects are cost-sensitive and a little uncertain.

The producer who had the hardest time this year was Miller Energy Resources Ltd., who filed for bankruptcy protection as this edition was going to print. The company had spent months trying to stabilize its financial situation and sell off certain properties.

—Eric Lidji

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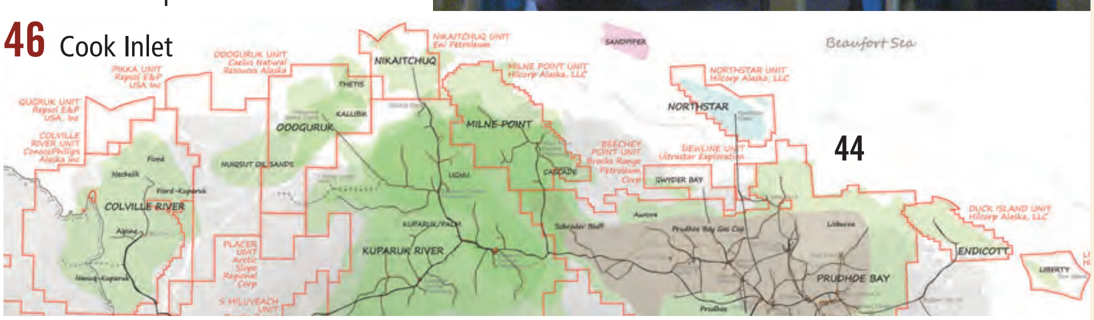

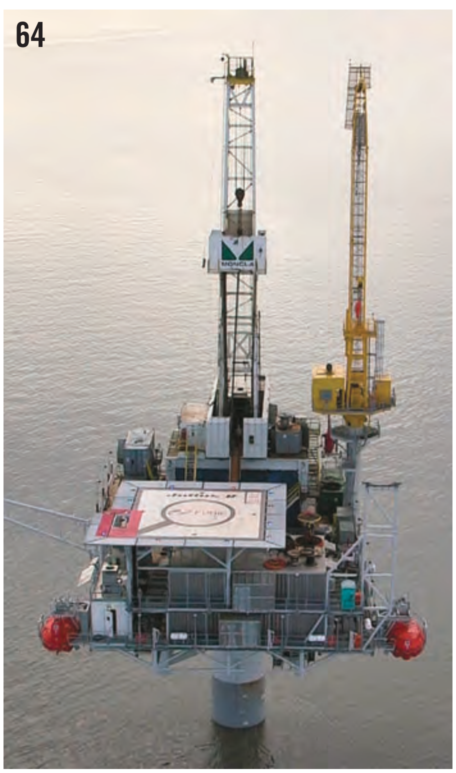

The Producers

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Weathering the storm together

By CORRI FEIGE

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

A year ago, when oil prices started to slip, who knew the price per barrel would plunge more than 50 percent? Given the current low price environment, tough financial times for the state and industry, and continued low projected prices for next year, it is prudent to concentrate on sound business principles like cost control, capturing value through efficiencies, and strategic planning for the future when prices recover.

CORRI FEIGE

We will weather this storm together, focusing on the many positive activities and accomplishments recent investments have precipitated and letting that inform us about how to do our work better in this price stressed climate. The Division of Oil and Gas remains committed to doing the very best job possible to support our industry through this time of low prices and fiscal uncertainty. We will continue to improve our business processes and guidance documentation while actively engaging our lessees to ensure we understand their challenges. Together, we will chart the best course for the industry and the state during this turbulent economic storm.

While the times are challenging, new activities and developments will put new gas and oil online in the near term and return very exciting rewards from past investments. Here's a look at what's going on, keeping Alaska's oil and gas industry moving forward.

New investment and production

•Industry continues to invest — $7 billion in North Slope investment in calendar year 2014, a $1 billion increase over CY2013.

•Areawide Lease sales for fiscal year 2015 yielded approximately $60.5 million showing strong interest in the North Slope and Cook Inlet.

•Point Thomson is moving forward with modules installed. The Point Thomson oil pipeline ties into the Badami pipeline, which connects to TAPS.

•New interest announced in Smith Bay with Caelus Energy acquiring 75 percent interest in the Tulimaniq leases and planning to drill in 2016.

•Caelus Energy sanctioned the Nuna project after royalty modification was approved in early 2015 and construction is underway.

•Furie received Cook Inlet discovery royalty relief on the KLU No. 3 and continues to move forward to production with the installation of the first new platform in Cook Inlet in 14 years.

•BlueCrest Energy formed the Cosmopolitan Unit near Anchor Point and construction is underway to support new oil production in early 2016

•State, through AIDEA, continues investment in the Southern Miluveach Unit Mustang project.

•Repsol's new Pikka unit was approved on North Slope, with encouraging exploration results indicating significant development potential.

New infrastructure

•Conoco completed the bridge over the Colville River to access CD-5, and the first oil production will occur in October.

New exploration

•Accumulate Energy is drilling their Icewine No. 1 exploration well on the North Slope to investigate shale oil potential.

•Hundreds of miles of both 2D and 3D seismic data submitted to the state through tax credit incentive programs have been received, along with exploration well data.

In 2015, the division has worked on improving processes and providing oil and gas research and information to assist producers and consumers alike. The division's Resource Evaluation Section completed and published the "Updated Engineering Evaluation of Remaining Cook Inlet Gas Reserves." In May of this year permit and bond application packets were standardized, streamlined and made available online. The Miscellaneous Land Use Permits will follow before the end of this calendar year.

When the state and industry work together, great things happen. The Division of Oil and Gas is committed to continuous improvement in serving our customers, and creating efficiencies while staying focused on a positive, bright future for Alaska's oil and gas industry. ●


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AIX Energy LLC

By ERIC LIDJI
For Petroleum News

AIX Energy LLC came to Alaska in a financial capacity. But through a series of events culminating in a bankruptcy auction, the company became a new Cook Inlet operator.

On April 30, 2014, the Texas-based company acquired the debt of Buccaneer Energy Ltd., an Australian independent which had been exploring for oil and natural gas in Cook Inlet. AIX Energy officially registered as a corporation in Alaska on May 9, 2014, according to the state Division of Corporations, Business and Professional Licensing.

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

By that point, Buccaneer had relinquished or sold many of its undeveloped properties, and had also sold its interest in an onshore rig and an offshore jack-up rig used for exploration. The sale gave AIX Energy control of the producing Kenai Loop gas field.

The Kenai Loop field

Buccaneer Energy Ltd. acquired the Kenai Loop prospect through its initial acquisition of Cook Inlet properties from the independent Stellar Oil & Gas LLC in early 2010.

The prospect brought together a collection of non-contiguous state of Alaska, Cook Inlet Region Inc. and Alaska Mental Health Land Trust leases northeast of the Cannery Loop unit, which Buccaneer later supplemented to make a roughly 9,400-acre prospect.

Over the course of its nearly five-year tenure as operator of Kenai Loop, Buccaneer drilled four wells, brought the field online in January 2012 and increased production.

Through July 2015, the Kenai Loop field had produced slightly more than 10 billion cubic feet of natural gas, according to the Alaska Oil and Gas Conservation Commission.

Using the Glacier No. 1 drilling rig, Buccaneer drilled the Kenai Loop No. 1 well in April 2011 to a total vertical depth of 10,680 feet and tested the well at 10 million cubic feet per day in June 2011. An analysis of two prospective sands by the consulting firm Ralph E. Davis Associates Inc. estimated that the prospect contained some 31.5 billion cubic feet of natural gas and some 3.9 million barrels of oil equivalent in proven reserves.

In September 2011, Buccaneer used Glacier No. 1 to drill the Kenai Loop No. 3 well to a total vertical depth of 11,000 feet to test the prospective zones identified in the first well but the well was a dry hole and Buccaneer considered permitting it for Class II disposal.

After bringing the field into production in early 2012, Buccaneer commissioned a 3-D seismic survey over a 25-square-mile region around Kenai Loop. After incorporating the results into its geologic model, Buccaneer drilled the Kenai Loop No. 4 well to some 13,000 feet in September 2012. A test in January 2013 flowed at 3 million cubic feet per day, and Buccaneer brought the well online in February 2013 at 2 million cubic feet per day. By March, the Kenai Loop field was producing some 10 million cubic feet per day.

Unit application in late 2012

Toward the end of 2012, Buccaneer applied to form a Kenai Loop unit over seven leases covering some 7,500 acres. The Alaska Department of Natural Resources denied the request because it felt Buccaneer was using the unit process as a way to preserve leases rather than to maximize development. The company had argued that a unit would help simplify operations given the multiple leaseholders in the crowded region. At the time, all activity was occurring on a single lease, which likely contributed to the differing views.

In June 2013, Buccaneer renamed the three Kenai Loop wells to better reflect their position on the drilling pad: Kenai Loop No. 1 became Kenai Loop No. 1-1, Kenai Loop No. 3 became Kenai Loop No. 1-2 and Kenai Loop No. 4 became Kenai Loop No. 1-3.

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

While Buccaneer had originally hoped to bring Kenai Loop No. 1-4 into production by the end of the year, the well quickly became the center of regulatory and legal disputes.

Specifically, CIRI accused Buccaneer of using the well to drain natural gas from neighboring leases. The dispute drew the attention of the state of Alaska and the Alaska Mental Health Trust land office, which also own neighboring leases. The dispute became even more complicated when Buccaneer filed for bankruptcy protection in late May 2014. The action suspended the regulatory and legal cases, and those cases, in turn, cast a shadow of uncertainty over the process of auctioning off Buccaneer's assets in Alaska.

Dispute resolved in early 2015

In early 2015, after AIX acquired the assets, the parties managed to resolve the dispute and AIX Energy was able to proceed as operator without worrying about the liability.

Since then, AIX Energy has been quiet about its plans for the field. The only public announcements have come through regulatory and legal channels. In late 2014, AIX Energy secured a short-term supply agreement with Chugach Electric Association. In August 2015, AIX Energy settled a legal dispute with Cook Inlet Energy LLC over a supply contract inherited from Buccaneer. AIX Energy had claimed the fellow Cook Inlet independent had "breached the contract by failing to timely pay" for gas shipments.

In a May 2015 Cook Inlet lease sale, AIX Energy acquired two tracts near Kenai Loop. ●

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Aurora Gas LLC

By ERIC LIDJI
For Petroleum News

Aurora Gas LLC has been operating in Cook Inlet longer than any other independent, and no company smaller than Aurora operates more production in the Cook Inlet region.

The utility Aurora Power Resources Inc. created Aurora Gas in 2000 as an exploration and production arm. The local independent operates five producing natural gas fields on the west side of Cook Inlet — Nicolai Creek, Lone Creek, Moquawkie, Albert Kaloa and Three Mile Creek — as well as several exploration prospects throughout the region.

Today, the Kaiser-Francis Oil Co. affiliate Aurora-KF LLC owns a 95 percent interest in Aurora Gas. Aurora Power Resources owns 4 percent and Orion Resources Inc. owns 1 percent, according to the Division of Corporations, Business, and Professional Licensing.


ED JONES

As the smallest independent company operating in the region, Aurora has regularly faced opportunities and challenges uncommon to many of the larger players in Cook Inlet.

Over the past 15 years, the company has revived production at many smaller natural gas fields that had either been ignored or abandoned by larger players in the region. In many ways, Aurora created an operating model that was repeated by many other companies as small independent explorers rushed into the Cook Inlet region at the end of the 2000s.

Over the past 15 years, the company has revived production at many smaller natural gas fields that had either been ignored or abandoned by larger players in the region.

As a small player, Aurora has regularly faced regulatory and economic challenges.

The company shut-in its Nicolai Creek unit in 2005 while it sought a commercial arrangement to use the Cook Inlet Gas Gathering System and suspended drilling operations across all its Cook Inlet properties in parts of 2006 and 2007 while it settled a contract dispute with Enstar Natural Gas Co. that rippled all the way to Fairbanks.

The Nicolai Creek unit

Texaco Inc. discovered a natural gas pool at the Nicolai Creek field in 1966 with the Nicolai Creek State No. 1A well and another in 1967 with Nicolai Creek Unit No. 3.

Although the wells initially produced more than 1 million cubic feet per day, according to state files, production declined quickly in later years and the field was shut-in in 1977.

Aurora acquired the Nicolai Creek unit in 2000 through a trade with Marathon Oil Co., giving up a working interest at Kenai and Cannery Loop in return for operatorship. The company restarted production in late 2001, after cleaning out a well killed by drilling mud. In subsequent years, Aurora also restarted the Nicolai Creek No. 1B and No. 2 wells and drilled Nicolai Creek No. 8, which is now known as Nicolai Creek No. 9.

After having to suspend production for parts of 2005, 2006 and 2007 because of commercial disputes involving marketing its product, Aurora brought the Nicolai Creek No. 11 well online in late 2009 and drilled the Nicolai Creek No. 10 well in 2011.

The results of those wells prompted Aurora to drill the Nicolai Creek No. 13 and No. 14 wells in August and July 2013, respectively. Based on the previous wells, the company had expected those two wells to yield an average production bump of 3 million cubic feet per day, according to Aurora Gas President Ed Jones, but "neither of the development wells resulted in commercially viable

continued on next page

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NICOLAI CREEK *continued from page 13*

accumulations of hydrocarbons and were plugged and abandoned," according to a plan of development for the year ending in October 2014.

In its 2015 plan of development, Aurora proposed drilling a Nicolai Creek No. 12 well to gather more information about deeper sands encountered in the No. 10 well but Alaska Oil and Gas Conservation Commission records through September show no permit for the well. The company has also been considering a storage program at Nicolai Creek.

Through July 2015, the unit had produced some 8.8 billion cubic feet of natural gas.

In its 2015 plan of development, Aurora proposed drilling a Nicolai Creek No. 12 well to gather more information about deeper sands encountered in the No. 10 well but Alaska Oil and Gas Conservation Commission records through September show no permit for the well.

The Lone Creek and Moquawkie units

Cook Inlet Region Inc. administers the Lone Creek and Moquawkie units, which are adjacent on the west side of Cook Inlet, in an inland area south of the Beluga River unit.

Socony Mobil Oil Company Inc. discovered the Moquawkie field in 1965 while looking for oil and completed the Moquawkie No. 1 discovery well as a gas producer about 1967. Production declined precipitously after two years and more gradually over eight years until the field was shut-in in 1978, according to the Division of Oil and Gas.

Various other companies pursued the field over the following two decades, when Anadarko Petroleum Corp. and ARCO Alaska Inc. began exploring in the vicinity.

Aurora acquired the field from Anadarko as part of its initial acquisition of Cook Inlet properties in 2000. The company recompleted the Moquawkie well in 2003 and brought the field online around July 2004 at 5 million cubic feet per day. The company subsequently returned the Moquawkie No. 2 well to production. In 2005, Aurora offset the discovery well with Moquawkie No. 3, which came online that summer at nearly 4 million cubic feet per day. In 2006, Aurora recompleted the discovery well.

Aurora drilled the Moquawkie No. 4 well in 2008. The well encountered a shallow gas pocket but the blowout was controlled within 24 hours. Plans for a Moquawkie No. 5 well were deferred until natural gas prices increased and ultimately cancelled altogether.

Through July 2015, the Moquawkie unit had produced more than 5 billion cubic feet.

Anadarko and ARCO Alaska discovered the Lone Creek field in the late 1990s with the Lone Creek No. 1 discovery well and the Lone Creek No. 2 delineation well.

Through July 2015, the Moquawkie unit had produced more than 5 billion cubic feet.

Aurora brought the field online in summer 2003, producing 5 million cubic feet per day from the original discovery well, and drilled the Lone Creek No. 3 offset well in 2005. The following year, Aurora recompleted the original Lone Creek No. 1. After its contract dispute, the company returned to the field in 2009 to drill the Lone Creek No. 4 well.

Gas production from Lone Creek rose and fell year by year, gradually trending downward over the first decade of operations. Aurora briefly took the field offline around 2013 and returned it to production a year later, according to the Division of Oil and Gas.

Through July 2015, the Lone Creek unit had produced more than 10.8 billion cubic feet.

The Albert Kaloa field

Pan American Petroleum Co. discovered the Albert Kaloa gas field on the west side of Cook Inlet in 1967 while searching for oil and brought the Albert Kaloa No. 1 discovery well online in 1970. The company suspended operations after sand and mud plugged the well. When Aurora acquired the prospect, the company inherited the Al-

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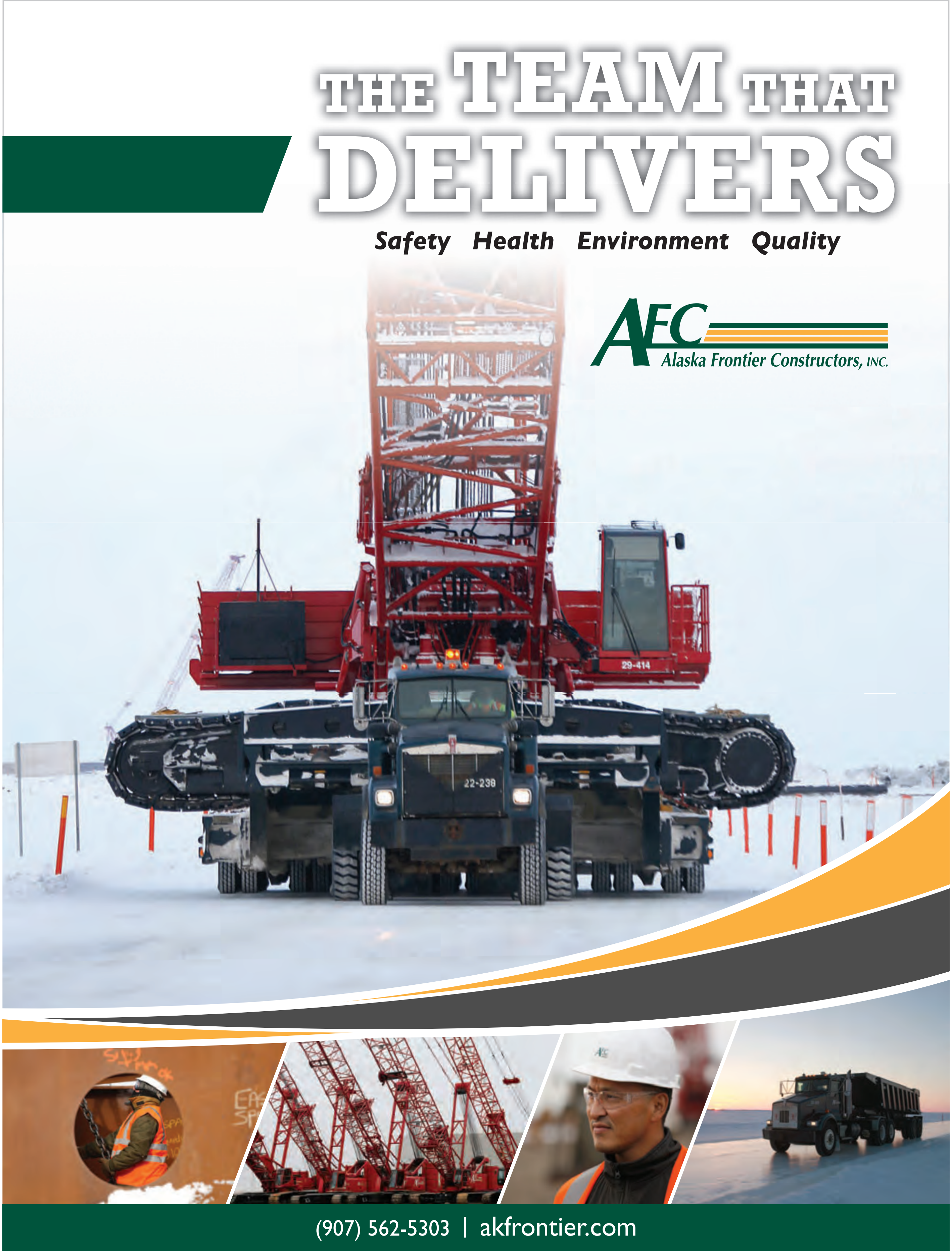
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ALBERT KALOA *continued from page 14*

bert Kaloa No. 1 well and the Simpco Kaloa No. 1 well drilled in 1978 and suspended later that year.

With those two plugged and abandoned wells unable to be salvaged, Aurora drilled the Kaloa No. 2 well in 2004. The well duplicated the target of the original Kaloa No. 1 well but utilized improved sand controlling technology to avoid the original problems. The well "perforated and tested four separate intervals at a combined flow rate of approximately 10 million cubic feet per

Through July 2015, Albert Kaloa had produced more than 3.6 billion cubic feet.

day," according to the company. Aurora returned the field to production toward the end of summer and began planning two more wells. Unfortunately, the Kaloa No. 4 well in 2005 and the Kaloa No. 3 well in 2009 were both dry holes. "The geology is starting to get to us," President Scott Pfoff told Petroleum News in 2009, after the second dry hole. "But we're not ready to throw in the towel yet."

Albert Kaloa is between the Nicolai Creek and Moquawkie units.

Through July 2015, Albert Kaloa had produced more than 3.6 billion cubic feet.

The Three Mile Creek unit

The state formed the Three Mile Creek unit in 2004 over some 9,200 acres of state of Alaska, Alaska Mental Health Trust and Cook Inlet Region Inc. leases. The unit agreement required Aurora and partner Forest Oil to drill two wells and shoot seismic.

The region had previously hosted some exploration activity. Superior Oil Co. drilled the 13,773-foot Three-Mile Creek State No. 1 well in the summer of 1967 and Phillips Petroleum drilled the 6,063-foot North Tyonek State No. 1 nearby the summer of 1973.

Despite those previous wells, Aurora President Scott Pfoff told Petroleum News at the time that its well was "going to be much closer to what I would call a wildcat well than a simple developmental reentry." In late 2004, Aurora drilled the Three Mile Creek No. 1 well and brought the field online in August 2005. The company drilled the Three Mile Creek No. 2 well in November 2005 and deferred plans for a third Three Mile Creek well. As part of a major recompletion campaign across its properties, Aurora performed an acid stimulation of the Three Mile Creek No. 2 in 2006. The company recompleted Three Mile Creek No. 2 in 2008 to perforate additional zones and hydraulically fractured the well in 2010 to improve production from the thin layers of productive sands.

Through July 2015, Three Mile Creek had produced more than 2.5 billion cubic feet.

When Forest Oil sold its Alaska assets in 2007, Pacific Energy Resources Ltd. took over the minority interest at Three Mile Creek. Pacific Energy sold the interest to Miller Energy Resources-subsidiary Cook Inlet Energy in late 2009, in a bankruptcy auction.

Through July 2015, Three Mile Creek had produced more than 2.5 billion cubic feet. ●

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BlueCrest Energy Inc.

By ERIC LIDJI
For Petroleum News

BlueCrest Energy Inc. arrived in Alaska as a partner at the Cosmopolitan prospect.

To acquire the offshore Cook Inlet prospect from Pioneer Natural Resources Alaska Inc., Buccaneer Energy Ltd. brought on BlueCrest as a majority non-operating partner. The Fort Worth-based independent took a 75 percent working interest in the field off Anchor Point and helped fund the 7,599-foot Cosmopolitan No. 1 delineation well in May 2013.

J. BENJAMIN JOHNSON

When Buccaneer began selling properties to improve its finances, BlueCrest acquired the remaining 25 percent interest in the leases and became operator of the program. The company held 22,535.69 acres in onshore and offshore leases, as of mid-August 2015.

Although based in Texas, BlueCrest boasts Alaska credentials. President and CEO J. Benjamin Johnson was raised in Kenai and worked in Cook Inlet and on the North Slope in his youth. Later, with ARCO Alaska, he created the first Kuparuk full-field development model and coordinated the first waterflood surveillance plans for Prudhoe Bay. BlueCrest currently has a regional office in Houston and another in Anchorage.

The Cosmopolitan unit

BlueCrest Energy Inc. is in the early stages of developing the Cosmopolitan unit.

The Texas-based independent has spent $144 million at the offshore Cook Inlet prospect since acquiring a stake in the oil and natural gas field in 2012 and plans to spend another $80 million through the remainder of 2015 and an additional $120 million in 2016. The company has said it expects to spend some $619 million on the project through 2019.

The development program is phased. BlueCrest is initially focusing on bringing oil production online by early 2016 using extended reach wells drilled from an existing onshore pad. Working with the liquefied natural gas company WesPac Midstream LLC, BlueCrest expects to begin gas development in 2016 with production starting as soon as 2018. The deal calls for WesPac to fund 100 percent of the development program in return for receiving 100 percent of the natural gas production, although BlueCrest would operate the program and would gradually increase its stake in the project to 80 percent.

Earlier this year, the Alaska Department of Natural Resources approved the formation of a Cosmopolitan unit over portions of five leases covering some 14,423 acres. BlueCrest had asked that the unit include all seven of its leases, covering some 22,535 acres. The approved unit includes ADL 384403, ADL 391902, ADL 391903, ADL 391904 and ADL 18790 and excludes ADL 391899, ADL 391900 and a portion of ADL 391903. The state partially denied the request because BlueCrest had not committed to developing or delineating those additional areas included in

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its proposed Cosmopolitan unit area.

Similarly, the state expressed concern about the initial plan of development for the unit.

The plan calls for BlueCrest to drill one offshore vertical well to test oil and natural gas zones in the southern part of the Cosmopolitan structure at ADL 384403. The well would be plugged at the oil zones and suspended at the gas zones until facilities come online. The plan also calls for BlueCrest to drill two onshore oil production wells with dual laterals into ADL 18790 from the existing Hansen pad, with production expected early next year. The company is planning an onshore disposal well in late 2015 or early 2016.

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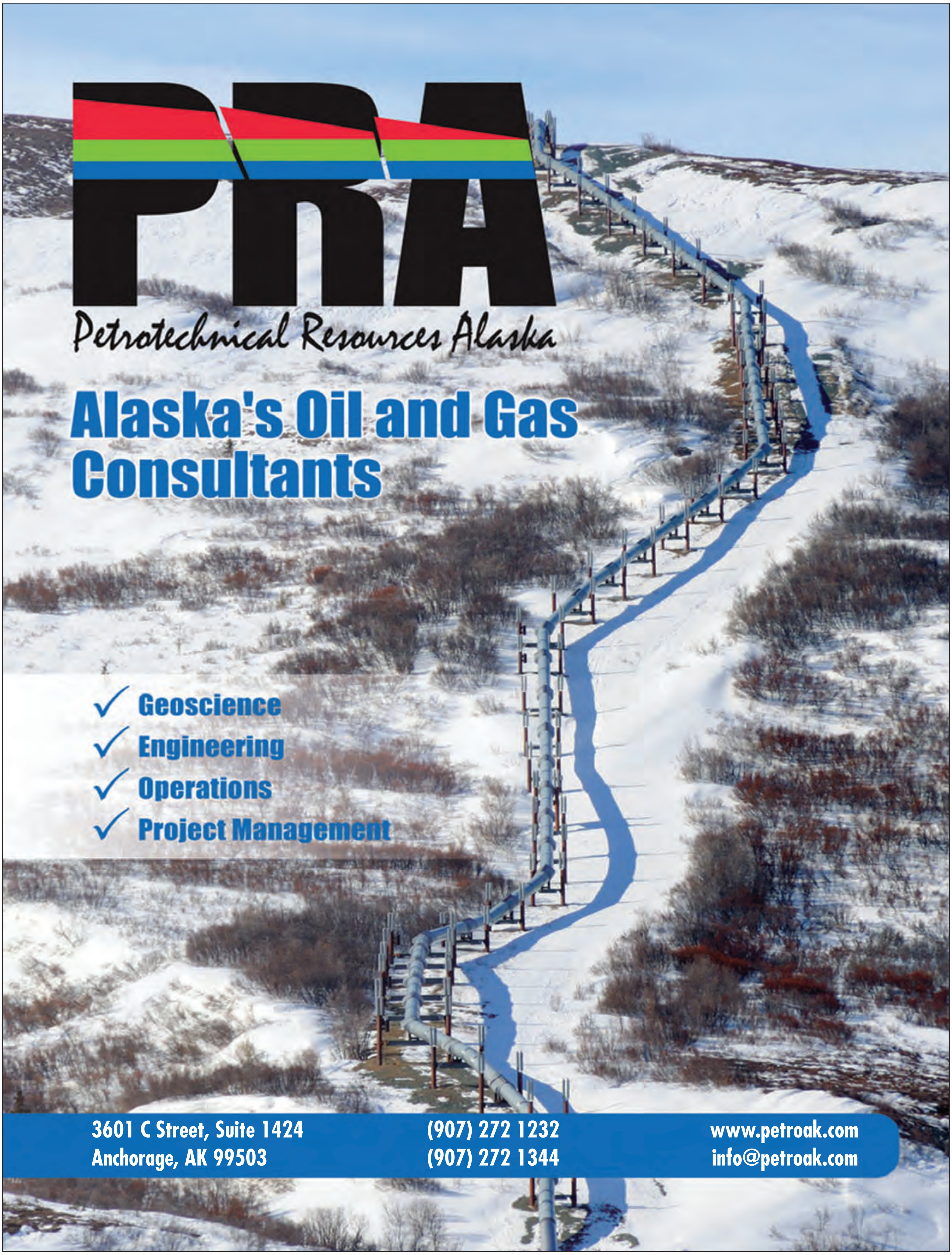
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BP Exploration (Alaska) Inc.

By ERIC LIDJI
For Petroleum News


JANET WEISS

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BP opened its Alaska office in 1959, the same year Alaska officially became a state. A decade later, the company drilled a confirmation well for the Prudhoe Bay discovery, which launched five decades of development. The company hopes it can continue for another five decades.

The delineation campaign of 1969 mapped a massive oil field stretching 45 miles from east to west along the North Slope coastline and 18 miles from north to south. Geologists initially identified four primary reservoirs — the Kuparuk River formation, the Prudhoe Bay group, the Lisburne limestone and the Kekiktuk Conglomerate — but later found heavier oil reserves in shallower reservoirs, such as West Sak, Schrader Bluff and Ugnu.

A series of drilling and infrastructure construction projects prepared Prudhoe Bay for development. All those efforts would have been for naught without the construction of the trans-Alaska oil pipeline, which connected the Prudhoe Bay field to market in 1977.

BP Exploration (Alaska) Inc. spent much of the next decade managing its portion of North America's largest oil field, where production peaked at 1,627,036 barrels per day in January 1987. But the company was also pursuing other North Slope opportunities. BP brought the onshore Lisburne field online in 1982, the onshore Milne Point unit online in 1985, the offshore Duck Island unit online in 1986, the onshore Point McIntyre field online in 1993 and the onshore Badami unit in the eastern North Slope online in 1998.

In December 1998, BP merged with Amoco to create one of the largest oil companies in the world. The following year, BP-Amoco acquired ARCO. To satisfy the U.S. Federal Trade Commission, BP agreed to sell ARCO's assets in Alaska to Phillips Petroleum Inc.

Following the merger and subsequent divestment, BP underwent a period of expansion across its existing properties on the North Slope. Between 1997 and 2004, the company brought into production the five satellites in the Greater Prudhoe Bay Area — Aurora, Borealis, Midnight Sun, Orion and Polaris — as well as the Niakuk satellite. In 2001, the company brought the offshore Northstar unit into production. In those years, the company also advanced plans for developing heavy oil prospects among its properties and began working on a strategy for the technically challenging Liberty field in the Beaufort Sea.

A period of contraction began in 2003, when BP dropped its exploration program in Alaska to focus on increasing production from existing fields. The exploration program had included investments in the Pete's Wicked and Placer discoveries, which other smaller operators have since pursued. In 2008, BP partnered with Savant Alaska LLC and ASRC Exploration LLC to bring the troubled Badami unit back into sustained production and eventually sold the field and its associated infrastructure to the two small independents. In 2014, BP sold Duck Island, Northstar and a 50 percent stake in Milne Point and Liberty to independent Hilcorp Alaska LLC in an attempt to focus its attention on Prudhoe Bay and major North Slope natural gas sales. The sale involved a major reduction in workforce, although some former BP employees later joined Hilcorp.

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Saluting Alaska's Producers

COSMOPOLITAN *continued from page 17*

Given that both ADL 384403 and ADL 18790 already have certified wells, which will protect a lease from expiration, even without unitization, the state said it "has concerns about the lack of discussion in the Initial POD regarding delineation of the rest of the reservoir that underlies the other leases." Therefore, the department only approved the initial plan of development through the end of 2015 and has required BlueCrest to submit its second plan of development by early October. "DNR expects that the second plan of development will provide specific and detailed activities and long-range plans to execute the testing, delineation, and development of the entire reservoir," Alaska Division of Oil and Gas Director Corri Feige wrote in her June 26, 2015, decision.

In October, Enstar Natural Gas Co. applied to build a spur line to Cosmopolitan.

Many former operators

Like many undeveloped fields in Cook Inlet, Cosmopolitan was discovered decades ago.

The first exploration program in the area off the coast of Anchor Point began in the late 1960s. Pennzoil discovered Cosmopolitan with the 12,112-foot Starichkof State No. 1 well in 1967. A pair of drill-stem tests produced a small amount of oil at two intervals approximately midway to total depth. The deeper Hemlock formation was wet. The Starichkof State Unit No. 1 well, drilled down-dip of the first, found good-quality sands in the upper Tyonek and Starichkof but Pennzoil saw no potential for gas production.

ARCO Alaska began a second exploration effort at Cosmopolitan in the 1990s. With the wave of mergers and acquisitions at the end of the decade, the prospect changed owners over a period of a few years without really changing hands. In 2001, after acquiring the Alaska assets of ARCO, Phillips Inc. formed the first Cosmopolitan unit. The unit covered seven state leases and two federal leases. Using an onshore pad, Phillips drilled the Hansen No. 1 well directionally to an offshore target. The well confirmed the presence of oil in the Starichkof sands and found productive sands in the Hemlock.

Following a merger, ConocoPhillips Alaska Inc. assumed control of the unit. In 2003, the company drilled Hansen No. 1A. The sidetrack of the earlier Phillips well provided a deviated penetration into the Starichkof and a lateral penetration into the Hemlock. A flow test produced some 1,000 barrels of oil per day and 14,851 barrels cumulatively.

BlueCrest is initially focusing on bringing oil production online by early 2016 using extended reach wells drilled from an existing onshore pad.

ConocoPhillips eventually brought Pioneer Natural Resources Alaska Inc. into the project as a minority partner. The two companies were also partnering at the time on some wildcat exploration ventures on the North Slope and in the National Petroleum Reserve-Alaska. In 2005, ConocoPhillips and Pioneer commissioned a 3-D seismic survey covering 40 square miles of the region. They kept quiet about the results, but according to a recent BlueCrest filing the program "provided a clear view of the perimeter flanks of an anticlinal structure, but the crestal view of the structure was obscured by a gas cloud, rendering a conclusive description of the reservoir structure unobtainable at the time."

After the joint seismic program, Pioneer Natural Resources acquired the remaining working interest at Cosmopolitan and became operator of the exploration program.

In 2007, Pioneer plugged the original Starichkof and Hemlock completions on the Hansen No. 1A sidetrack and drilled Hansen No. 1A-L1, another sidetrack off the original Hansen well. The "long-reach undulating lateral well" ran through the upper portion of the Starichkof 8 sub-interval of the sands and tested a 300 bpd.

After a hiatus caused by the collapse of the financial system in 2008, Pioneer returned to the prospect in 2010 to fracture stimulate the interval from Hansen No. 1A-L1. An extended flow-test produced 250 bpd and more than 33,000 barrels, cumulatively, which the company trucked to the Tesoro refinery under a pilot program.

While Cosmopolitan is considered to be an oil field, state officials have long believed that the region also contains a substantial amount of gas. For that reason, Cosmopolitan was often discussed in conjunction with other nearby undeveloped gas fields that could be used as an anchor to spur development in the southern Kenai Peninsula and bring gas to the city of Homer and the other smaller communities across the region. Ultimately, the North Fork unit came online first, followed by the smaller Nikolaevsk unit to the north.

Toward the end of its tenure in Alaska, Pioneer proposed an oil development program for Cosmopolitan but decided in early 2011 that "subsequent flow test results and engineering studies indicated that the resource potential was not as large as originally estimated." As such, Pioneer terminated the Cosmopolitan unit and relinquished all its leases except the two that were held by wells, which it sold to Buccaneer and BlueCrest.

The state offered three of the relinquished leases under special terms. Apache Corp. acquired the leases and proposed seismic and exploration drilling. Regulatory delays over its basin-wide seismic program prompted Apache to delay its exploration plans, and the company ultimately sold the three leases to Buccaneer and BlueCrest in August 2013.

After drilling the Cosmopolitan No. 1 well, Buccaneer said it had encountered oil at intervals much shallower than the oil discoveries at previous wells but postponed "more extensive flow test" because of the "very limited oil storage capacity" on its rig. A pair of Tyonek sands tested at 7.3 million and 7.2 million cubic feet per day, Buccaneer said. ●

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BP EXPLORATION *continued from page 19*

The Prudhoe Bay unit: Initial Participating Areas

After ARCO and Humble Oil drilled the Prudhoe Bay discovery well in 1968, the initial delineation campaign at Prudhoe Bay mapped the largest oil field in North America.

In an attempt to wrangle the massive discovery, the initial development program split the field in half. BP Exploration (Alaska) Inc. took the Western Operating Area, or WOA, and ARCO Alaska took the Eastern Operating Area, or EOA. The split gave each company a more manageable workload and divided operations between the oil reservoir and an offset gas cap. Eventually, the owners decided to unitize the field to optimize recovery, divide costs more equitably and avoid building unnecessary infrastructure. The two regions are currently managed together as the initial participating areas, or IPA.

In early 2014, before her company announced the sale to Hilcorp, BP Alaska President Janet Weiss detailed a $1.25 billion capital program for Alaska. The program amounted to a 25 percent increase in total spending and a 40 percent increase in spending aimed at increasing production through drilling, workovers and major projects. "We're drilling more wells and doing significantly more well work jobs in 2013 than 2012, and plan significantly more in 2014 than 2013," Weiss said in a February 2014 speech to the Anchorage Chamber of Commerce. "We are focusing on light oil development to ensure we have a healthy business to build the more material opportunities upon." The near-term capital program also included funds to bring two rigs to Prudhoe Bay — one by 2015 and one by 2016, which Weiss said would add between 30 and 40 wells each year at the unit.

The current plan of development for the IPA suggests the increase is largely focused on the satellite fields. The drilling activity planned for the IPA in 2015 was similar to 2013 and 2014. But the plan of development shows the oldest commercial operation on the North Slope to be continually declining and yet surprisingly robust for its fifth decade.

The initial participating areas produced 203,700 barrels per day of crude oil and condensate, 6,931 million cubic feet per day of natural gas and 39,900 bpd of natural gas liquids in 2014, according to BP. Those figures are all down from 2013, when BP produced 218,000 bpd of crude oil and condensate, 7,145 million cubic feet of natural gas and 45,000 bpd of natural gas liquids from the IPA.

The company expects IPA liquids production to fall again this year. The current forecast predicts crude oil and condensate production between 157,000 and 200,000 bpd and natural gas liquids production between 31,000 and 39,000 bpd.

The company drilled 54 penetrations in the IPA in 2014 — eight grassroots wells and 46 sidetracks. The sidetracks included 16 rotary and 30 coiled tube rig penetrations. The company also performed 1,650 well workover jobs, including 416 "rate adding jobs."

Drilling figures were down from 2013, when BP drilled 57 penetrations in the IPA and performed approximately 1,900 well workover jobs, including 300 "rate adding jobs."

Current plans

This year, BP expects a "similar" level of drilling activity with a "slightly different mix" of wells — between 13 and 20 penetrations using a rotary rig and between 35 and 40 penetrations using a coiled tubing rig. The workover program is also expected to be "similar" to last year, with 20 to 30 wells. A map of "drilling candidates" includes one new well, eight rotary sidetracks, 14 coiled tubing sidetracks and eight rigged workovers.


COURTESY BP EXPLORATION (ALASKA)

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PRUDHOE BAY UNIT *continued from page 23*

The capital projects under evaluation this year largely serve to optimize operations.

One project would upgrade the seawater systems used to process and inject water into the gas cap and other areas of the field to maintain pressure and increase production rates.

Another project would replace the gas-powered compressors at all three Prudhoe Bay flow stations with electric-powered compressors better suited for the current production profile of the field. BP sanctioned the project in 2012 and replaced the compressor at Flow Station 1 in 2014. The company never completed the other two projects and now intends to re-bid the construction contracts this year for replacement in 2016 and 2017.

The drilling activity planned for the IPA in 2015 was similar to 2013 and 2014.

Perhaps the biggest development on the horizon for the IPA — albeit so far on the horizon it may never come to pass — is the possibility of major natural gas sales. The company currently uses a small amount of Prudhoe Bay gas for operations and re-injects the majority to maintain field pressure. In July 2015, BP formally asked the Alaska Oil and Gas Conservation Commission to increase the amount of gas the company is allowed to withdraw from the field and allow the company to inject carbon dioxide instead. The current restrictions date to 1977, when the company was preparing for initial oil sales.

The company believes an increased offtake allowance is a crucial prerequisite for conducting major natural gas sales from the North Slope. The current AK LNG project calls for moving approximately 3.5 billion cubic feet per day with 75 percent coming from Prudhoe Bay. Under that program, BP would need to withdraw approximately 3.3 bcf per day from the field to meet its commitments to the pipeline project and satisfy its operational needs. The current limit is 2.7 bcf per day.

The Prudhoe Bay Unit: Western Satellites

In addition to the main Prudhoe Bay field, the unit area includes five satellites clustered mostly along its western edge: Aurora, Borealis, Midnight Sun, Orion and Polaris.

The Aurora field

Mobil Oil Corp. discovered the Aurora oil pool in the northwest corner of the Prudhoe Bay field in 1969, although BP brought the field online from S pad in November 2000.

As of July 2015, the Aurora field had 33 wells — 18 oil producers and 15 water-alternating-gas injectors, according to the most recent annual report. At the start of 2014, the field had 17 producers, 10 water injectors and six water-alternating-gas injectors.

Of the estimated 200 million barrels of oil in place at Aurora, BP had produced some 39.46 million barrels through June 2015, according to the company. The field averaged 4,305 barrels of oil per day in the year ending June 30, 2015, down from an average of 4,655 bpd in the previous year and down from a peak of 14,000 bpd in August 2006.

During the recently completed year, BP drilled three new production wells at the Aurora field. The S-42A sidetrack will replace the S-108 producer, which BP plugged and abandoned after finding collapsed tubing and casing during a workover. The S-44A sidetrack is north of the existing S-101 injector, which was also repaired this year. BP expects to bring those two wells into production by the end of the year. The S-135 well was brought online in October 2014 at an initial rate of 884 barrels of oil per day.

The company said it is using geologic models to evaluate additional wells for future drilling during the coming year, including a potential producer to accompany the existing S-107 injector and a potential injector to accompany the existing S-105 producer.

Also during the year, BP repaired the suspended S-104 injector, converted the S-128 water-alternating-gas injector to miscible injectant and conducted a hydraulic fracturing operation on S-129, which yielded a post-frack production rate of 2,486 barrels per day.

The Borealis field

Mobil Oil discovered the Borealis oil pool along the western edge of the Prudhoe Bay field in 1969. BP brought the field online in 2001 from the Prudhoe Bay L pad, and expanded development to include the V pad in April 2002 and the Z pad in March 2004.

As of July 2015, the Borealis field had 57 wells — 25 from L pad (the same as last year), 22 from V pad (the same as last year) and 10 from Z pad (one more than last year), according to the most recent plan of development. Of the estimated 350 million barrels of oil in place at Borealis, BP had produced 77.8 million through June 2015, according to the company. Borealis produced 8,768 bpd during the year ending June 30, 2015, down from 9,932 bpd the year before and a peak of 38,150 bpd in May 2003.

During the previous year, BP repaired two wells at V pad and equipment associated with one well at Z pad and began preliminary maintenance on a well with communication issues. The company is planning to begin miscible injection at a well on Z pad.

The company also finished reprocessing the S3 3-D seismic survey earlier this year.

This year, the company is evaluating potential infill opportunities at Z pad.

The Orion field

Mobil Oil discovered the Orion oil pool in the northwest corner of the Prudhoe Bay unit in 1968. BP confirmed the accumulation in 1998 and brought the field online in 2002.

BP originally developed Orion from its V pad and expanded development in mid-2004 to include L pad. As of July 2015, Orion had 49 wells — 25 from V pad (the same as last year), 23 from L pad (the same as last year) and one new injector drilled from Z pad. Of those 49 wells, 12 are active multi-lateral producers and 34 are active injectors.

Of the 3.2 billion barrels of oil in place at Orion, BP had produced 32.1 million through June 2015. Orion produced 4,693 bpd in the year ending June 30, 2015, down from 5,483 bpd the previous year and down from a peak of 14,460 bpd in June 2007.

While BP did not drill at Orion this past year and has no plans to drill this coming year, the field is part of a larger regional endeavor to economically develop viscous oil. Orion produces from the same viscous Schrader Bluff formation present at the Milne Point unit to the north and portions of the ConocoPhillips-operated Kuparuk River unit to the west.

Many projects underway at Orion are related to the viscosity of its oil. For example, BP is currently studying ways to improve Gathering Center 2 to better accommodate viscous oil. The facility was designed for light oil and improvements in 2012 and 2013 to improve solids handling have "not yielded the desired level of improvements," according to the company. Similarly, BP conducted geomechanical studies and enhanced dynamic models this year to better understand "subsurface uncertainties" related to viscous oil.

Those efforts are expected to continue this year, as is an ongoing program to reduce the rate of downtime for viscous wells, which has hit 50 percent in some sections of the field in recent years. For years, the company has been considering a multi-stage trial to better understand the project but has deferred the project "due to the current business climate."

Another deferred project at Orion is the proposed I pad.

While BP had originally expected to bring the pad online by 2006, the company has since deferred the project twice: first until 2010 and currently until as late as 2020. The program presents considerable technical challenges but has also been at the center of political debates over the past decade. The two deferrals followed changes to the state oil production tax by the Murkowski and Palin administrations and was a prominent point of discussions during legislative hearings over then Gov. Sean Parnell's tax code changes.

In its previous plan of development, BP told state officials that the original location for I pad had "proved to be unfeasible" because it was "constrained" by a Milne Point road to the west, a large lake to the east and a subterranean ice lens to the north. While that problem had a solution, the company also said the future of I pad "depends upon finding ways to more efficiently execute the project and reduce project uncertainty and risks."

This year, BP said the future of I pad "will be informed by the results of sand control technology in the Schrader Bluff formation. If a trial of sand control technology is successful, the learnings will be considered in Orion development planning."

An I pad could access 69 million to 144 million barrels of recoverable oil at Orion and 2.7 million to 3.9 million barrels of recoverable oil at Borealis, according to the state.

The Polaris field

BP discovered the Polaris oil pool in the western end of the Prudhoe Bay field in 1969, while delineating the field, and brought the field online in 1999 from W pad and S pad.

As of July 2015, Polaris had 28 wells — 21 from W pad and seven from S pad, the same number as last year. Of the estimated 1 billion barrels of oil in place at Polaris, BP had produced 18.7 million barrels through the end of June 2015. The field produced 3,890 barrels per day in the year ending June 30, down from 4,080 bpd the previous year and a peak near 7,000 bpd.

While BP drilled no Polaris wells last year and is planning none for this year, the company is dealing with many of the same issues occupying its attention at

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WESTERN SATELLITES *continued from page 25*

Orion.

And just as sand control technology is holding up the proposed I pad development at Orion, it is also holding up a proposed expansion of the S pad and M pad at Polaris.

The Midnight Sun field

BP discovered the Midnight Sun field at the center of the northern edge of the Prudhoe Bay unit in 1997 and brought the field online from the E pad in October 1998.

Through July 2015, BP had drilled six wells at E pad. The most recent was an injector drilled this year and was the first new well since 2001. Of an estimated 100 million barrels of oil in place at Midnight Sun, BP had produced some 20.4 million barrels through June 2013. Production is now 964 bpd, down from 1,106 last year.

After drilling the extended-reach P1-122i miscible injectant well at the Midnight Sun field earlier this year, BP said it has no plans for drilling activity during the coming year.

The Prudhoe Bay unit: Greater Point McIntyre Area

BP Exploration (Alaska) Inc. appears to be postponing any major development decisions in the Greater Point McIntyre Area until the results of a recent seismic survey can be processed, according to plans of development submitted to the state in late June 2015.

The Greater Point McIntyre Area incorporates six fields on the east side of Prudhoe Bay — Point McIntyre, Lisburne, Niakuk, North Prudhoe Bay, Raven and West Beach. The region produces little oil compared to the Prudhoe Bay unit as a whole, in part because the region is aging and in part because development drilling has been minimal in recent years. The future of the region depends largely on the results and effectiveness of the large and multi-year North Prudhoe 3-D seismic program completed earlier this year.

According to BP, it should take one or two years to process the results of the survey, which means any resulting development drilling is likely many years away. Until then, aging fields will continue to decline and suspended fields will remain out of production.

Through July 2015, the GPMA had produced more than 726 million barrels.

The Lisburne field

ARCO Alaska discovered the Lisburne field in the northeast corner of the Prudhoe Bay region in 1969 and brought it online in 1982. In the year ending March 31, 2015, Lisburne produced 1.7 million barrels of liquids at an average rate of 4,800 bpd — down from 2.4 million barrels at a rate of 6,400 bpd the previous year.

The main Lisburne Production Center at the aging field is currently gas constrained, which, because of the high gas-to-oil ratio of many wells at the field, impacts oil production. One strategy BP uses to manage this problem is suspending certain wells for days or even weeks after several days of production, which the company has said will often result in lower gas-to-oil ratios when wells are eventually returned to production.

Earlier this year, BP began drilling the L3-03 well at Lisburne and plans to drill two more development wells — L3-10 and L1-23 — through the remainder of the year. The results of those wells will determine the drilling program for the end of this year and next year.

In the early 1990s, the Prudhoe Bay working interest owners expanded the Lisburne Production Center to accommodate fluids from nearby Point McIntyre and Niakuk.

Through July 2015, Lisburne had produced more than 166 million barrels.

The Point McIntyre field

ARCO and Exxon discovered Point McIntyre in the coastal section of Prudhoe Bay in 1988 with the Point McIntyre No. 3 well. The field came online in 1993 and peaked at 172,995 bpd in December 1996. In the year ending March 31, 2015, Point McIntyre produced 5.94 million barrels of liquid hydrocarbons at a rate of 16,370 bpd — down from 6.79 million barrels at a rate of 18,520 bpd the previous year. “Long-term oil production is expected to continue to naturally decline from current rates due to increasing water cuts and gas-oil ratios,” BP wrote in its development plan.

Through July 2015, Point McIntyre had produced more than 457 million barrels.

The Niakuk field

Sohio discovered the Niakuk oil pool in 1985 and it came online in April 2004. Niakuk production fell dramatically last year. In the year ending March 31, 2015, the field produced 372,000 barrels of liquids at an average rate of 1,020 bpd — down from 844,000 barrels at an average rate of 2,300 bpd the previous year.

Through July 2015, Niakuk had produced more than 94.2 million barrels.

Raven, West Beach, North Prudhoe

The three other fields in the Greater Point McIntyre Area are significantly smaller.

In the year ending March 31, 2015, Raven produced 60,000 barrels of crude oil, condensate and natural gas liquids at an average

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A BP Prudhoe Bay facility worker

POINT MCINTYRE *continued from page 26*

rate of 170 bpd — down from 110,000 barrels at an average rate of 3,100 bpd during the previous year. Given that the lone producing well at the Raven field "still produces effectively," according to BP, the company has no plans to sidetrack it during the upcoming year.

Through July 2015, Raven had produced nearly 3.1 million barrels.

ARCO discovered West Beach and North Prudhoe Bay in the 1970s.

The lone producing well at North Prudhoe was suspended in February 2000 because of safety concerns related to a technical problem. An attempt to return the well to production in 2005 failed. A recently completed evaluation of the well yielded no immediate plans to return it to production, according to BP, but the company believes the results of the seismic campaign could present other development options at the field.

Through July 2015, North Prudhoe Bay had produced nearly 2 million barrels.

West Beach production was suspended in 2001 because declining reservoir pressure and increasing gas-to-oil ratio challenged the economics of the field. Since then, BP has undertaken numerous studies of the field to determine whether it might one day produce again. The future of the field now depends largely on the results of the seismic survey.

Through July 2015, West Beach had produced nearly 3.4 million barrels. ●

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Brooks Range Petroleum Corp.

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

Working on behalf of varying joint ventures, Brooks Range Petroleum pursued exploration opportunities across the North Slope, including the Beechey Point unit, Tofkat unit, Putu unit, Kachemach unit and a related cluster of prospects nestled between the Badami and Point Thomson units known under various names over the years.

BART ARMFIELD

Ultimately, Brooks Range Petroleum made a large discovery southwest of the Kuparuk River unit. The prospect was initially called North Tarn and later became known as Mustang. The discovery was eventually incorporated into the Southern Miluveach unit.

To help finance development, AVCG and its partner Ramshorn Investments Inc. sold a 90 percent stake in their Alaska holdings and 100 percent interest in Brooks Range Petroleum for $450 million to a three-company consortium in mid-2014. By using the Alaska Industrial Development and Export Authority as a financier for two major infrastructure projects, the consortium handed over some working interest in the unit to two public-private joint ventures. Today, Brooks Range Petroleum operates the Southern Miluveach unit on a behalf of seven working interest owners: Caracol Petroleum LLC (36.28 percent), TP North Slope Development LLC (22.46 percent), Mustang Operations Center 1 LLC (20 percent), MEP Alaska LLC (10.37 percent), Ramshorn Investment Inc. (6.08 percent), AVCG LLC (3.82 percent) and Mustang Road LLC (1 percent).

Caracol Petroleum is a wholly owned subsidiary of JK E&P Group Pte. Ltd., which is a wholly owned subsidiary of the Singapore-based tech firm JK Tech Holdings Ltd. TP North Slope Development is a subsidiary of Thyssen Petroleum LLC, a privately owned oil and gas exploration company based in the British Virgin Islands, with offices in Monaco and Houston and operations in the U.S. Gulf Coast. MEP Alaska is subsidiary of Magnum Energy Partners LLC, an exploration company based out of New York City.

Mustang Operations Center 1 is a joint venture between AIDEA (96 percent) and CES Oil Services Pte. Ltd (4 percent). Mustang Road is a joint venture between Caracol (55.3 percent), TP North Slope Development (34.2 percent) and MEP Alaska (10.5 percent).

The Southern Miluveach unit

A joint venture operated by Brooks Range Petroleum Corp. began exploring the area now known as the Southern Miluveach unit in 2010, after farming-in the North Tarn prospect covering six Eni Petroleum leases along the western edge of the Kuparuk River unit.

During the 2011 and 2012 exploration seasons, Brooks Range Petroleum drilled the North Tarn No. 1 exploration well, the North Tarn No. 1-A sidetrack and the Mustang No. 1 delineation well to test the Brookian formation and deeper Kuparuk formation.

Prior to the program, the company had estimated that the Brookian might contain some 35 million barrels of oil and that the Kuparuk might contain an additional 6 million barrels of oil. But the program pointed to a discovery in the range of 40 million barrels of recoverable oil from the Kuparuk — far bigger than expected. An independent audit by the global consulting firm DeGolyer and MacNaughton estimated that the so-called Mustang prospect contained proved gross reserves of 24.7 million barrels of recoverable oil. The firm also estimated that the field contained 43.6 million barrels of proved and probable reserves and 51 million barrels of proved, probable and possible reserves.

To help finance development, Brooks Range Petroleum partnered with the Alaska Industrial Development and Export Authority or two projects: a $25 million preliminary infrastructure program and a $225 million processing facility for the standalone field.

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

The financing helped Brooks Range Petroleum secure investment from private sector partners that acquired the company from AVCG and its partner Ramshorn Investments Inc. The new joint venture launched a development program — drilling and construction.

Delays

Although Brooks Range Petroleum initially expected to bring the Southern Miluveach unit into production by early 2016, a series of technical problems encountered earlier this year delayed development. Now, project startup is unlikely before the end of next year.

"Due to a myriad of mechanical and reservoir problems encountered while drilling during the period of the 2nd POD, none of the wells intended as producers were completed in the Kuparuk reservoir," operator Brooks Range Petroleum Corp. told state officials in a proposed third plan of development for the unit, filed Sept. 1. After receiving the proposed plan, the state asked the company to provide additional information and had yet to approve or deny the revised development plan by the time The Producers went to print.

The problems largely involved subsurface conditions encountered during the drilling process earlier this year. The solution requires Brooks Range Petroleum to modify the drilling rig it had been using for the program or potentially find an alternative

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BROOKS RANGE PETROLEUM *continued from page 29*

drilling rig.

Earlier this year, the company used Nabors rig 16E to drill the 9,140-foot SMU M-02 well, which was supposed to be the first of three planned development wells. The company cancelled a planned flow test "due to unfavorable petrophysical characteristics in the main pay zone" and completed the well for injection, as originally planned.

Next, the company used the rig to drill the SMU M-03 well to an intermediate depth of 7,231-feet, but "poor hole conditions in the intermediate section of the well" preventing the company from continuing the well to its total target depth. Instead, the company plugged the well back to its surface casing until it could develop a plan for re-entry.

A subsequent "root cause analysis" of the three drilling projects determined that the company needed to significantly modify its rig by installing Managed Pressure Drilling equipment before it could resume drilling.

Finally, the company returned to SMU M-01, which was a pilot hole drilled to an intermediate casing depth in 2012. The company planned to re-enter the well to add a horizontal lateral. During the first stage of drilling the lateral, "significant fluid loses were encountered," which forced the company to plug the well at its intermediate casing.

After this third set-back, the company suspended operations for the season. A subsequent "root cause analysis" of the three drilling projects determined that the company needed to significantly modify its rig by installing Managed Pressure Drilling equipment before it could resume drilling. The equipment would "lower the risk of controlling overpressure in the reservoir while at the same time prevent massive lost circulation incidents." As of early September, the company was considering bids from providers of the equipment.

Participating Area

The complications have delayed the project.

While Brooks Range Petroleum had previously projected first oil during the first quarter of 2016, the company is now forecasting startup to begin in the fourth quarter of the year.

As such, the company told state officials it would be premature to apply for a participating area, as required by the terms of the existing plan of development, until after the company successfully completes the planned drilling and completion activity. The company has asked the state to extend a March 31, 2016, deadline for applying to form the participating area. Without an extension, the unit would automatically expire.

The timeline for building and installing facilities is largely on track.

The company has built gravel roads and a gravel drilling pad, installed more than half of the piles for pipeline support and installed associated pipeline platforms, and ordered long lead materials and equipment for module fabrication and construction. Toward the end of this year, the company expects to receive oil and gas train modules and a gas conditioning module, all of which have been under construction since early this year.

2016 plans

Brooks Range Petroleum is proposing a two-well program for the coming year.

If the state approves the plan of development, the company said it would start the coming drilling season by re-entering the unsuccessful SMU M-01A sidetrack to drill and test a new lateral, to be called SMU M-01B. Then, "as economic conditions warrant," the company would re-enter, finish drilling and possibly flow test the SMU M-03 well.

Once those wells were finished, the company would "evaluate continuing with the development drilling program" with an eye toward the revised timeline for start-up.

The current scope of development calls for as many as 38 development wells with 11 production wells, 23 injection wells and two optional grind and inject disposal wells.

While the state asked the company to elaborate on the difficulties encountered earlier this year and the plans for avoiding those problems in the future, the answers are proprietary.

The company told state officials that it spent $145 million during the current plan of development from December 2014 through November 2015 — $85 million on surface facilities and $60 million of drilling activities. Through an Alaska Industrial Development and Export Authority investment, the state contributed approximately $54 million to that total spending figure, with the remainder coming from the working interest owners. "This investment demonstrates Brooks Range's commitment to moving the Mustang Field to development and the State's vested interest through AIDEA in seeing this project come online to production," the company told the state in a recent filing. ●

Contact Eric Lidji at ericlidji@mac.com

Caelus Natural Resources Alaska Inc.

By ERIC LIDJI
For Petroleum News

NAME OF COMPANY: Caelus Energy Alaska LLC
COMPANY HEADQUARTERS: Dallas, Texas
TOP EXECUTIVE: James C. Musselman, president and CEO
TELEPHONE: 214-368-6050 • **WEBSITE:** www.caelusenergy.com

Caelus Energy LLC acquired the Alaska assets of Pioneer Natural Resources Alaska Inc. in 2014 and became the operator of the offshore Oooguruk unit on the North Slope.

Through the acquisition, the Dallas-based independent acquired existing production and infrastructure at Oooguruk and retained a majority of the employees of its predecessor company. Next, Caelus announced a major financial partnership that will allow the company to fund operations. Going forward, operations should become more technical and logistical as Caelus advances construction of a satellite called the Nuna development.


JAMES MUSSELMAN

Like many small players in the global oil industry, Caelus Energy is a relatively new company created by executives who have had experience in other parts of the world.

In the 1990s, Caelus Energy President and CEO Jim Musselman and various colleagues acquired a struggling independent called Triton Energy. They oversaw discoveries in Colombia, Southeast Asia and offshore West Africa. Triton brought the West Africa discovery online within 18 months and later sold the company to Amerada Hess.

Next, Musselman and his investors founded the independent Kosmos Energy, which made a discovery offshore Ghana that justified an initial public offering in 2011.

Instead of staying with the newly public company, Musselman created Caelus Energy, which searched for opportunities and found one in Alaska. "If you're not nervous and a little bit worried or a bit scared of doing business in hostile places, you're done," he told Petroleum News in October 2013, when Pioneer announced plans to sell its Alaska subsidiary to Caelus for $550 million. In March 2014, the parties lowered the sale price to some $300 million, which cleared the path for the two sides to close in April 2014.

Early on, Caelus described big plans for Alaska. The company hoped to raise more than $1 billion for future development work and saw the potential to spend as much as $1.5 billion in Alaska over a five-to-six-year-period. In April 2014, as part of its work to close on the purchase of Pioneer Natural Resources Alaska, Caelus formed a strategic partnership with the international investment company Apollo Global Management. The partnership provided near-term funds and an avenue for borrowing money in the future.

The Oooguruk unit

ARCO Alaska Inc. discovered the Oooguruk field in 1992, and independent Armstrong Oil & Gas Inc. delineated the "Northwest Kuparuk" prospect in the early 2000s.

As has generally been its strategy in Alaska, Armstrong brought on a larger partner — in this case the Texas-based independent Pioneer Natural Resources Inc. Pioneer eventually acquired a 70 percent working interest in the leases and became unit operator, with the Italian major Eni Petroleum holding the 30 percent minority interest in the leases.

In 2008, after just five years of work, Pioneer became the first independent producer on the North Slope when it brought Oooguruk online from a six-acre artificial gravel island.

The company initially developed two pools: the Kuparuk and the larger and deeper Nuiqsut. The company later began developing the Torok, which is above the Kuparuk.

After a delineation campaign encountered a large reservoir in the southern end of the unit, and improved completion techniques increased production from existing wells, Pioneer sold the Oooguruk unit to Caelus in late 2013 to focus on Lower 48 properties.

Through early 2015, the Oooguruk unit included 40 wells — 25 into the Nuiqsut, five into the Kuparuk, four into the Torok, five outside participating areas and one disposal.

The entire Oooguruk unit produced 21.5 million barrels of oil through July 2015.

The Nuiqsut pool

In early 2015, Caelus drilled and hydraulically fractured three horizontal wells into the Oooguruk-Nuiqsut pool — ODSN-43, ODSN-42B and the ODSN-03i injector.

The wells largely stepped beyond previous development efforts. The company drilled ODSN-43 in the second expansion area, in the southwest of the unit. ODSN-42B was sidetracked

continued on next page

CAELUS *continued from page 31*

from the existing ODSK-42A well into "an untested area of the eastern Kalubik fault block." ODSK-42 and the ODSK42A sidetrack had both passed through the Oooguruk-Nuiqsut formation to reach targets in the Oooguruk-Kuparuk formation.

The ODSN-03i began as a production well but was converted to "support high rate producers in the Ivik fault block." Similarly, Caelus converted the previously drilled ODSN-48i to an injection well, after 15 months of production, to support ODSN-43.

The company also drilled the ODSN-22 well earlier this year, although fracture stimulation work is scheduled for early 2016. And the company recently worked over the ODSN-01 well to repair a casing string damaged during workover activities last year.

During the current cycle, from September 2015 to August 2016, Caelus proposes to complete ODSN-22 and drill three injectors — ODSN-11i, ODSN-06i and ODSN-21i.

ODSN-11i would target the northern-most area of the Colville Delta fault block. ODSN-06i would target the southern row of the Ivik fault block. ODSN-21i would be near ODSN-22 and ODSN-48 in the expansion area, in the southwest corner of the unit. The ODSN-21i injector is scheduled for hydraulic fracture stimulation in early 2017.

Also within the past year, Caelus stimulated the ODSN-19i injection well, which was meant to help the well match higher production rates from recently stimulated producers.

In addition to those wells, Caelus expects to drill and complete one sidetrack this year, although plans depend of scheduling and rig availability. The likely candidates for a sidetrack are ODSN-18, ODSN-29 and ODSN-37, which are spread throughout the unit.

The company is also planning to work over ODSN-28 to repair casing and install an electric submersible pump and between three to five undetermined workover projects.

The Oooguruk-Nuiqsut pool produced some 12.5 million barrels of oil through July 2015.

The Kuparuk and Torok pools

Caelus is planning no activities for the Oooguruk-Kuparuk pool this year.

The company said production "remained strong" from ODSK-14 and ODSK-41, which are supported by the ODSK-38i and ODSK-35Ai injection wells for water flooding.

But the company shut-in the ODSK-33 production well "due to high water-cut and significant hydraulic backout effects" to other wells from the Oooguruk drill site.

The company said it has completed a surveillance program of the water samples returned through Oooguruk-Kuparuk production wells and is beginning to evaluate the results.

The Oooguruk-Kuparuk pool produced some 8.3 million barrels of oil through July 2015.

Caelus also hasn't planned any activities for the Oooguruk-Torok pool this year.

The company said development of the formation "progressed as planned." The ODST-39 well continues to produce, but the company shut-in the ODST-45A sidetrack in May 2014 after an electric submersible pump and a packer vent valve failed. The company is planning to work over the well. Similarly, the ODST-

47 well remains shut-in until the company can repair a mechanical failure created during completion activities in 2013.

The horizontal ODST-46i injection well was shut-in for much of the current development cycle "due to close-approach drilling concerns and limited water supply," Caelus wrote.

The Oooguruk-Torok pool produced some 796,000 barrels of oil through July 2015.

The Nuna Development

Every Oooguruk unit well drilled into the Oooguruk-Kuparuk pool and the deeper Oooguruk-Nuiqsut pool has also passed through a reservoir in the Torok formation.

In 2010, Pioneer decided to explicitly target the Torok formation. Later that year, after studying drilling results, the company proposed the Nuna development project to target resources in the Torok formation that were too far to reach from the existing Oooguruk island. An exploration well and a subsequent appraisal well in the southern end of the unit yielded a discovery estimated in the range of 75 million to 100 million barrels of oil.

Before it sold its Alaska assets, Pioneer launched a range of initiatives to prepare for Nuna, including several expansions of the unit boundaries and an infrastructure program.

Caelus had initially expressed great enthusiasm for the Nuna project when it acquired the Oooguruk unit. But after studying the project in greater depth, the company determined it would need some form of royalty relief to make the $1.4 billion project economic. The state agreed to reduce the royalty rate on five leases to 5 percent until Caelus recovers its costs. In March 2015, Caelus announced that it had "fully sanctioned" the Nuna project.

In the first quarter, the company installed the Nuna Drill Site 1 pad and an associated access road two miles west of Kuparuk River unit Drill Site 3S, according to a recent plan of development. The company also continued engineering work for its onshore production facilities and ordered long lead items. This past winter, the company commissioned a 3-D seismic survey over some 70 square miles of the area. The company has also begun permitting Nuna Drill Site 2, which is being considered for a later date.

In the current development cycle,

In the first quarter, the company installed the Nuna Drill Site 1 pad and an associated access road two miles west of Kuparuk River unit Drill Site 3S, according to a recent plan of development.

which runs from August 2015 to August 2016, Caelus expects to complete facility design and integration between the new drill site and the existing Oooguruk drill site and Kuparuk River unit facilities. The company also expects to start building modules in early 2016, install flowlines in early 2017 and install production facilities between late 2016 and the scheduled launch of operations in 2017.

The work is part of what Caelus is calling the first phase of the Nuna project, which would access resources too far to reach from the drilling facilities at the existing Oooguruk gravel island. Nuna would drill extended reach wells from a new onshore pad. ●

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ConocoPhillips Alaska Inc.

By ERIC LIDJI
For Petroleum News

ConocoPhillips Alaska Inc. was created through the 2002 merger of Phillips Petroleum Co. and Conoco Inc., which each had considerable prior experience in Alaska.

Phillips Petroleum started its Alaska operations in 1951, through the Katalla-Yakataga contract. The contract was established to develop private leases in the Icy Bay region. In 1959, Phillips bid more than $1 million for leases in the Wide Bay region, in the first state sale. As a nod to its Phillips 66 brand, the company tacked 66 cent onto every bid.


JOE MARUSHACK

Over the following decades, Phillips participated in important early exploration ventures in the Cook Inlet region and early wells before the historic 1969 North Slope lease sale and was one of the key players in building the pioneering liquefied natural gas terminal in Kenai. During that time, Phillips undertook some interesting and risky exploration ventures, including the Tyonek Deep prospect in Cook Inlet and the first large exploration program in the National Petroleum Reserve-Alaska in recent decades.

As part of a state brokered plan to prevent a North Slope monopoly, Phillips acquired ARCO Alaska Inc. in 2002, when BP Amoco acquired the ARCO Alaska parent company Atlantic Richfield Co. The acquisition expanded Phillips' legacy in Alaska and its holdings in the state, giving the company a working interest in the Prudhoe Bay field, additional NPR-A prospects and control over the Kuparuk River and Colville River units.

Conoco Inc. had a much less illustrative career in Alaska at the time of the merger but touted some important distinctions, including work on the viscous oil at Milne Point unit and the complex Badami unit. The company sold its Alaska holdings to BP in 1994.

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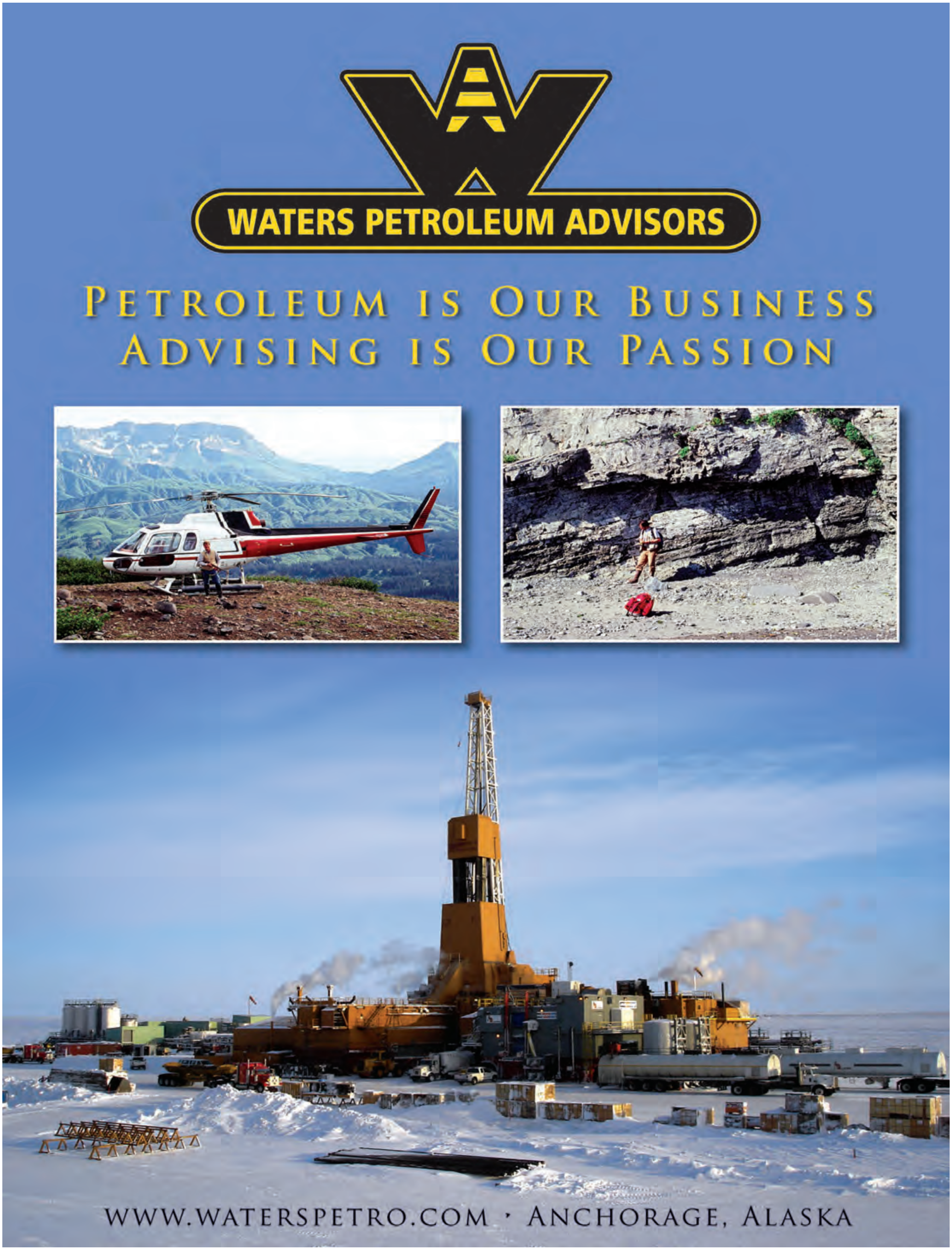
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COURTESY CONOCOPHILLIPS ALASKA

Through July 2015, the entire Kuparuk River unit had produced nearly 2.6 billion barrels of oil and the Kuparuk River field was responsible for nearly 2.4 billion barrels of oil.

We Know the Slope… and Beyond
For more than 60 years, Colville has been providing essential supplies and services across the North Slope with aviation support, fuel supply and delivery, camp services, and solid waste management. Brooks Range Supply covers industrial and general store supplies, and Brooks Camp provides a comfortable, modern place to rest when you need a home away from home.
With decades of experience, we know the slope… and beyond, when it comes to keeping your operations running smoothly north of the Arctic Circle.
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Brooks Camp

CONOCOPHILLIPS *continued from page 34*

Since the merger, Alaska has remained a major component of the global ConocoPhillips portfolio. It is the only basin for which the company reports separate financial figures.

Over the past 13 years, ConocoPhillips has generally been pushing westward across the North Slope by developing satellites at the Kuparuk River and Colville River units, exploring the NPR-A and acquiring leases and conducting studies in the Chukchi Sea, while also contributing to the Prudhoe Bay unit as a non-operating minority partner.

In the Cook Inlet region, ConocoPhillips operates some of the oldest fields and facilities in the basin: the Beluga River unit, the North Cook Inlet unit and the associated Kenai LNG terminal. After a burst of activity in the mid-2000s, the company began scaling back its investment and, in August 2015, placed its Cook Inlet assets on the market.

ConocoPhillips produced 174,000 barrels of oil equivalent per day in Alaska in the second quarter of 2015, according to quarterly figures provided by the company.

The Kuparuk River unit

The Kuparuk River unit includes the main Kuparuk oil field and four satellites. Sinclair Oil and Gas discovered the primary Kuparuk River oil pool in 1969, and ARCO Alaska sanctioned development a decade later, by which time the trans-Alaska oil pipeline was already delivering oil production from the neighboring Prudhoe Bay unit to market.

Economics caused the delay. But crimped domestic supplies and the subsequent rise in prices at the end of the decade persuaded top management to sanction Kuparuk. The program called for bringing 20 square miles of the Kuparuk field online by 1982 and working with nearby leaseholders on a longer-term plan to develop 200 square miles.

The Kuparuk River field came online in late 1981 and production peaked at 339,386 barrels per day in December 1992, according to the Alaska Oil and Gas Conservation Commission. Originally, engineers had expected peak production of 250,000 bpd.

After ARCO left the state, Phillips Alaska Inc. became the operator of the Kuparuk River unit. ConocoPhillips took over in 2002, after Conoco Inc. and Phillips Alaska merged.

In the 23 years since the unit hit peak production, those operators have been pursuing various programs to expand development and improve production through technology.

Through July 2015, the entire Kuparuk River unit had produced nearly 2.6 billion barrels of oil and the Kuparuk River field was responsible for nearly 2.4 billion barrels of oil.

Recent expansion

In July 2015, ConocoPhillips asked the state to expand the unit to include a lease along the southern boundary of the North Slope unit and to include 18 additional leases already within the unit either in the Kuparuk participating area or the West Sak participating area.

The unit expansion would bring lease ADL 392364 into the unit boundaries, expanding the total unit size by 2,560 acres. The participating area expansions would add portions of 11 tracts (including ADL

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CONOCOPHILLIPS *continued from page 38*

392364) covering some 11,900 acres to the Kuparuk participating area and eight tracts covering some 6,100 acres to West Sak participating area. All the relevant tracts and leases are currently held by production from the unit.

The expansion would allow ConocoPhillips to more easily use existing facilities to develop recent discoveries, according to the company. "The reserves discovered thus far in the Expansion Area are not large enough to support the costs of full processing facilities. Even if stand-alone development were economic, there would be economic waste due to the existence of duplicate facilities and services," the company wrote.

The state approved the unit expansion in September. With more than 2,000 bpd currently being sent to the Kuparuk facilities from the lease, the state said the requested expansion was justified. ConocoPhillips drilled the horizontal 2G-17L1 lateral in 2013 using coil tubing drilling on ADL 392364, just south of the unit boundaries. The well targeted the historically under-performing Kuparuk C sand and initially produced more than 2,900 bpd before settling to a sustained rate of 700 to 800 bpd. Given the success of the well, the company drilled the offsetting 2F-22 horizontal well at the western edge of the lease in late 2014 and initially produced more than 2,000 bpd before settling to some 1,100 bpd, also from the Kuparuk C.

The company drilled the 2E-01 and 2F-21 horizontal wells earlier this year into the lowermost Kuparuk A sand. The former came online at nearly 1,000 bpd and is now producing some 300 bpd. The latter is an offsetting injection well that is currently being "pre-produced" at a rate of some 100 to 200 bpd.

Aging field

As the oldest field in the Kuparuk River unit, the main Kuparuk field is also the most mature. At the end of 2014, ConocoPhillips was developing the field with 835 active wells at 44 drill sites, according to a June 2015 plan of development. At the end of 2013, the field had 817 active wells at 44 drill sites. The Kuparuk participating area produced 83,200 gross bpd in 2014, down from 85,700 gross bpd in 2013.

ConocoPhillips drilled 26 wells in the Kuparuk participating area last year — eight rotary wells and 18 coiled tubing sidetracks with a total of 40 laterals. The drilling program added some 3,500 gross barrels of peak incremental oil production per day, according to the company. The sidetracks were scattered throughout the field. The new wells included four at Drill Site 2E, two at Drill Site 2K and one each at Drill Site 2F and Drill Site 2M.

Those figures continue a recent trend of increased drilling and declining incremental production from the main Kuparuk field. By comparison, the company drilled 15 wells with 41 laterals at the Kuparuk field in 2013, adding some 4,520 gross barrels of peak incremental oil production per day, and drilled 14 wells with 53 laterals at the Kuparuk field in 2012, bringing some 5,050 gross bpd of incremental production online.

This year, ConocoPhillips expects to drill 23 wells at the Kuparuk field — seven new rotary wells and 16 coiled tubing sidetracks. That would be a decline from 2014.

The new wells are mostly associated with Drill Site 2S. The company is currently developing the new drill site in the southwest corner of the unit with plans to bring production on by the end of the year. The sidetracks are scattered throughout the unit. The company announced in the second quarter of 2015 that drilling had begun at the pad.

The proposed expansion of the Kuparuk participating area would include two blocks — one associated with Drill Site 2S and Drill Site 2M and the expansion lease in the south.

The expansion associated with Drill Site 2S would incorporate portions of ADL 25590, ADL 25603, ADL 355608, ADL 380053 and ADL 380051 in the participating area. The Drill Site 2M expansion would add portions of ADL 390503, ADL 25565 and ADL 25590. The southern expansion would add ADL 39264, ADL 25668 and ADL 25605.

The unit expansion at ADL 392364 would incorporate a lease in the vicinity of Drill Site 2E, Drill Site 2F and Drill Site 2G, where ConocoPhillips has been focusing a noticeable portion of its development drilling budget at Kuparuk in 2014 and for this coming year.

Altogether, ConocoPhillips said it has drilled five wells into the expansion acreage in recent years. Those include wells 2E-01, 2F-21, 2F-22, 2G-17 and 2M-36. All five of those wells encounter hydrocarbons in paying quantities, according to the company.

ConocoPhillips also added 3,360 gross bpd through a rigged workover program and another 10,600 gross bpd through a rigless workover program in 2014. Those figures are up from 2013, when the company added 2,601 gross bpd through a rigged workover program and 10,300 gross bpd through a rigless workover program.

Miscible injection

Aside from increased drilling, the two biggest developments at the Kuparuk field in 2014 were changes to the miscible injection program and an expansion of seismic activities.

The main Kuparuk field had waterflooding activities at 24 drill sites (up from 18 in 2013), immiscible water-alternating-gas at 17 drill sites (up from two in 2013) and no miscible water-alternating-gas (down from 24 in 2013). Currently, miscible injection is unavailable for technical reasons. ConocoPhillips said it intends to continue miscible injection programs at four dill sites — 1B, 1C, 1D and 1E — using indigenous supplies.

In July 2014, ConocoPhillips stopped importing natural gas liquids used for the operations from the Prudhoe Bay unit and planned to convert the Oliktok Pipeline to instead import fuel gas from Prudhoe. ConocoPhillips expects to complete the necessary modifications at Central Processing Facility No. 1 and No. 2 by the end of this year and complete similar work at Central Processing Facility No. 3 by the end of 2017.

Seismic

Another major effort last year was seismic acquisition.

Over the past decade, ConocoPhillips has been relying heavily on seismic information to identify potential targets for additional development within the existing Kuparuk field.

The company completed 4-D processing over a 60-square-mile area of the field and licensed a 47-square-mile speculative 3-D survey in the north end of the unit.

The company also undertook four seismic reprocessing efforts last year.

The WBA/Kalubik Depth Migration project will "better image" the western side of the Kuparuk field. The company expects to complete the project in the third quarter. The KRU-KWS 4-D project is reprocessing overlapping portions of the KRU 3-D program from 1990 and the KWS 3-D program from 2005. The KWS Structural Reprocessing project is considering a different aspect of the data. Preliminary interpretation is underway on both projects. The KRU 3-D Depth Migration project is improving imagining along the periphery of the field and should be completed late this year.

The Kuparuk River unit satellites

Unlike the Prudhoe Bay unit, the majority of the activity at the Kuparuk River unit is at the main field and the oldest satellites, while the newest satellites are relatively stable.

In its plans of development for the unit, ConocoPhillips details activities at the Kuparuk participating area and four satellites: West Sak, Tarn, Tabasco and Meltwater.

Through July 2015, those four defined satellite fields as well as undefined oil pools in the Ugnu and Torok formations had produced more than 229.2 million barrels of oil.

West Sak

ARCO discovered the shallow West Sak oil pool in 1971, appraised the feasibility of producing viscous oil from the field with a 15-well pilot project between June 1983 and December 1986 and brought the field into production from Drill Site 1D in late 1997.

The pool covers much of the eastern half of the Kuparuk River unit, stretching into the Milne Point unit and the northwest

continued on next page

KUPARUK RIVER UNIT SATELLITES *continued from page 41*

corner of the Prudhoe Bay unit at the north and fanning out at the south to extend beyond the southern border of the Kuparuk River unit, making it an important regional asset for various operators and working interest owners.

ConocoPhillips has devoted far more resources to West Sak than to the other Kuparuk satellites. After several years of conventional drilling, the company began a multilateral program at West Sak starting in 2000. Those wells became increasingly complex over the following decade, with tri-lateral wells and undulating wells designed to target more of the formation. ConocoPhillips also expanded pad infrastructure at West Sak. Altogether, the heavy-oil development program was estimated to have cost some $500 million.

ConocoPhillips has devoted far more resources to West Sak than to the other Kuparuk satellites.

The satellite is currently slated for even more investment.

At the end of 2014, West Sak had 92 active wells at six drill sites — down from 96 active wells at six drill sites at the end of 2013 and 102 active wells at the end of 2012. West Sak shares its drill sites — 1B, 1C, 1D, 1E, 1J and 3K — with the main Kuparuk field.

Even with the decline in active wells, production increased. The satellite produced some 16,241 barrels per day in 2014, up from 15,772 bpd in 2013, up from 14,185 bpd in 2012.

In its current plan of development, ConocoPhillips wrote: "the pace of future West Sak development has slowed while the performance of recent developments in evaluated," using language the company had previously used in its 2014 plan of development.

The biggest development planned for West Sak is North East West Sak. The NEWS project is a $450 million program to expand existing Drill Site 1H. The project was approved earlier this year and is expected to come online by early 2017 and produce some 8,000 gross bpd at its peak. According to the newest plan of development, ConocoPhillips intends to conduct preliminary work this year and drill four horizontal multilateral production wells and 15 vertical injection wells starting in 2016.

The company is also considering NEWS programs at Drill Sites 1N, 3K and 3R, although all three projects are in the early stages and have yet to be publically defined in depth.

This year, the company is planning drilling campaigns at Drill Sites 1D and 1C.

The Drill Site 1D program calls for four wells. 1D-143 would be a single-lateral into the B sand. 1D-145 would be a quad-lateral into the D Sand, A4 Sand, A3 Sand and A2 Sand. Those two wells are designed to replace the existing 1D-140 well. 1D-146 would be a single-lateral into the D Sand east of the existing 1C-135 and 1D-141A wells. 1D-142 would be an injector supporting 1C-135, 1D-141A and the new 1D-146 wells.

The company already expanded the existing gravel pad to accommodate the wells and expects the drilling will require an expansion of the Sak Core Area participating area.

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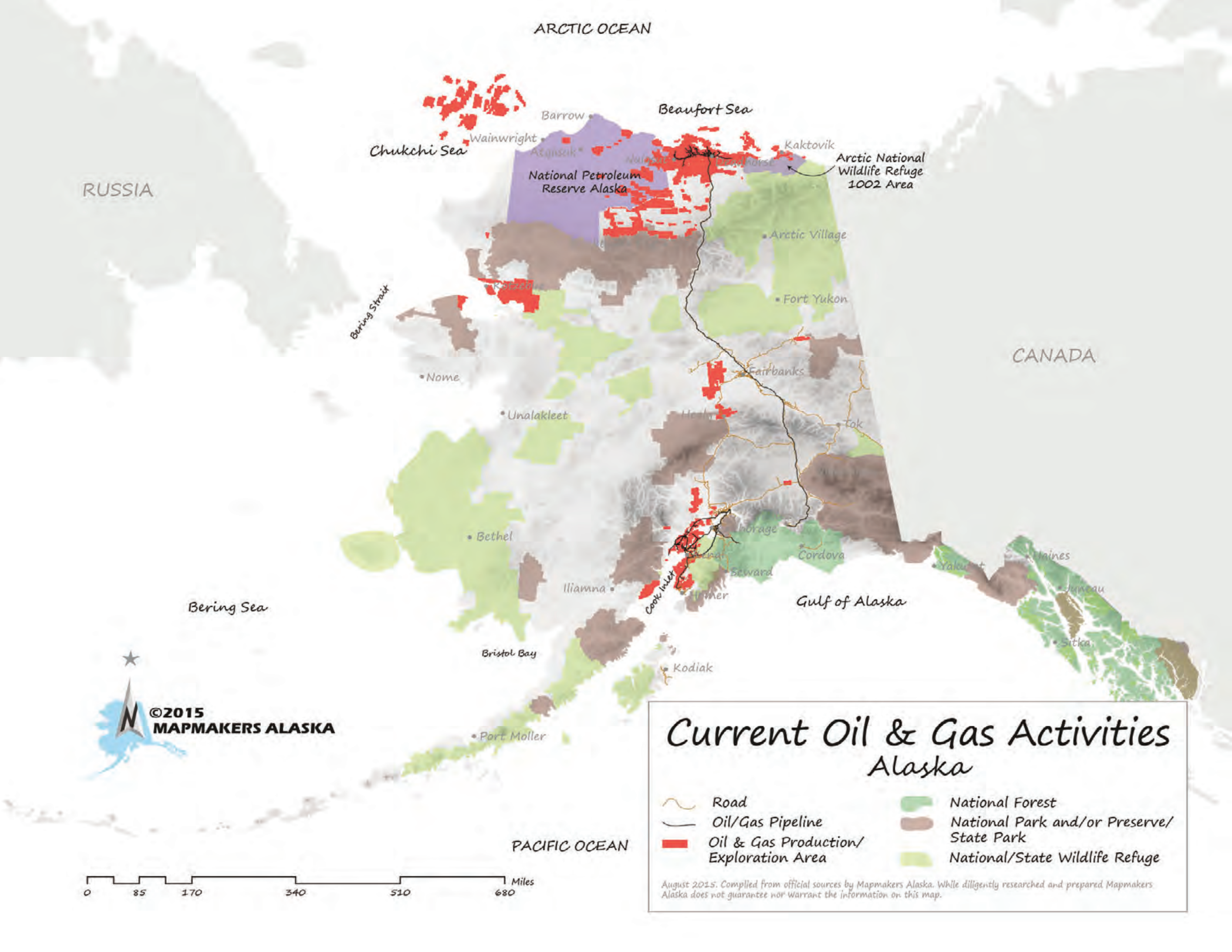

Current Oil & Gas Activities
Alaska
Road
Oil/Gas Pipeline
Oil & Gas Production/ Exploration Area
National Forest
National Park and/or Preserve/ State Park
National/State Wildlife Refuge
August 2015. Compiled from official sources by Mapmakers Alaska. While diligently researched and prepared Mapmakers Alaska does not guarantee nor warrant the information on this map.
ARCTIC OCEAN
Beaufort Sea
Chukchi Sea
RUSSIA
CANADA
Barrow
Wainwright
Kaktovik
National Petroleum Reserve Alaska
Arctic National Wildlife Refuge 1002 Area
Arctic Village
Fort Yukon
Bering Strait
Nome
Fairbanks
Unalakleet
Tok
Bethel
Cordova
Seward
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Sitka
Iliamna
Cook Inlet
Gulf of Alaska
Bering Sea
Bristol Bay
Kodiak
Port Moller
PACIFIC OCEAN
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0
85
170
340
510
680
Miles

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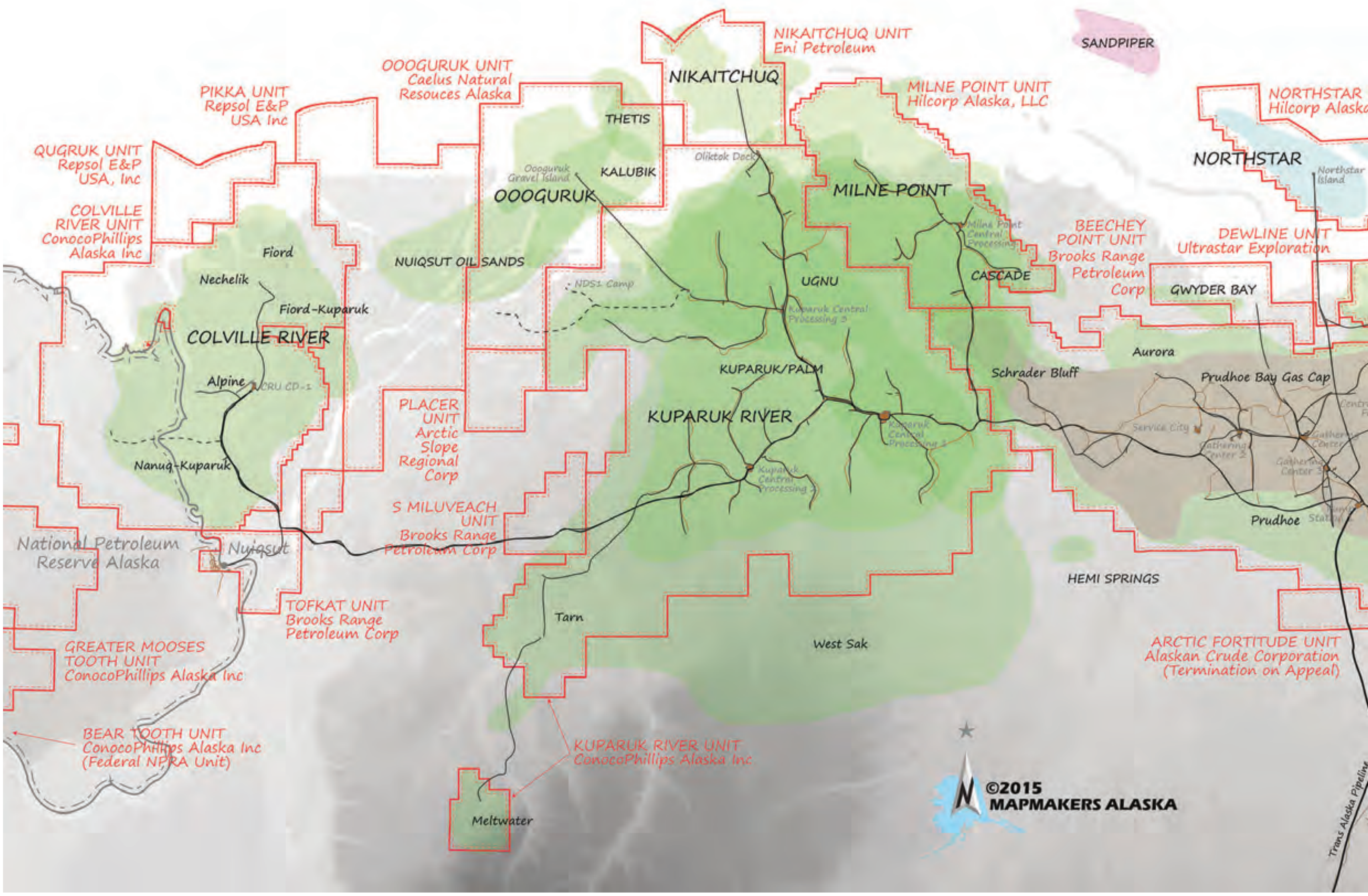

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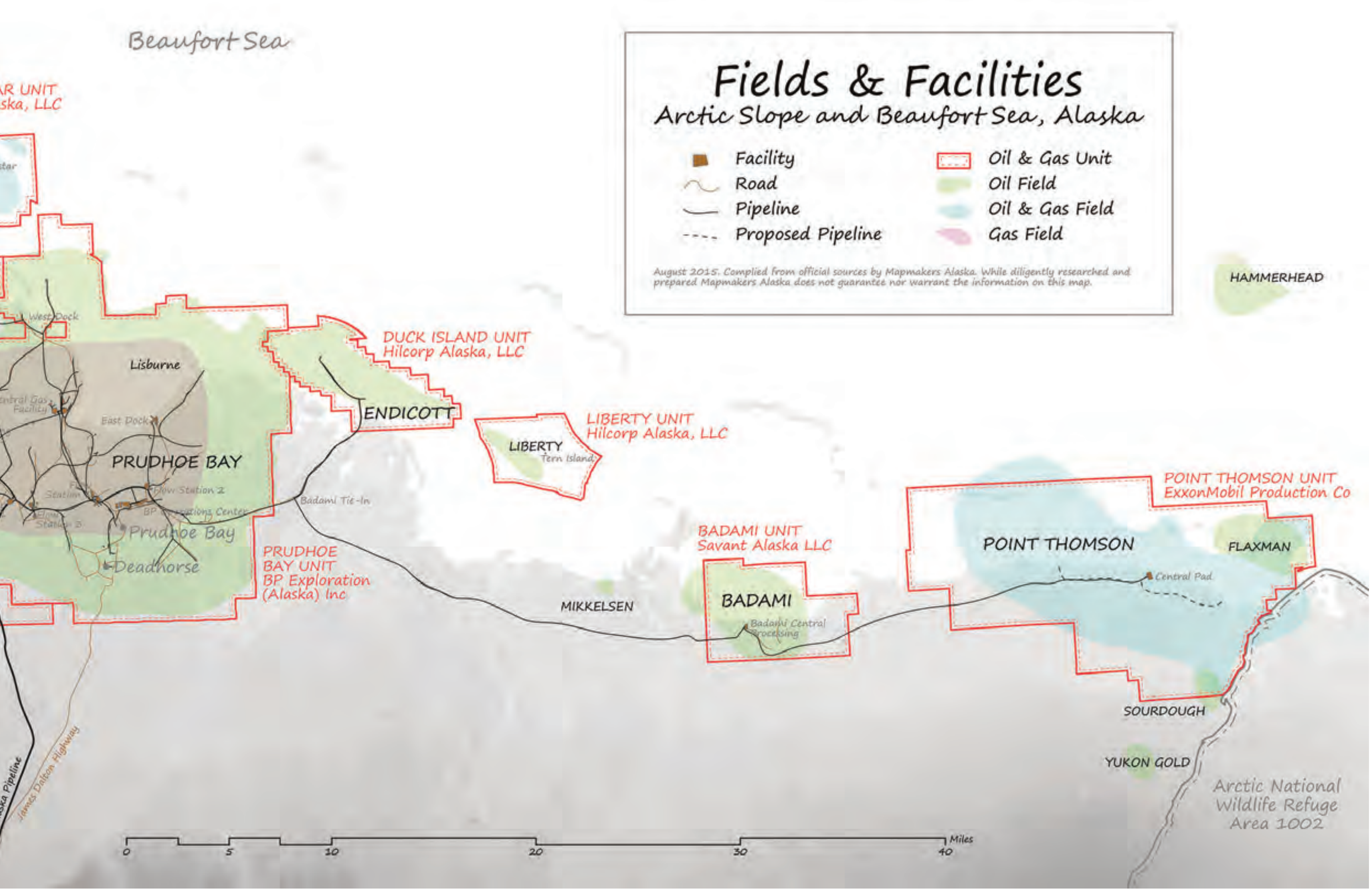
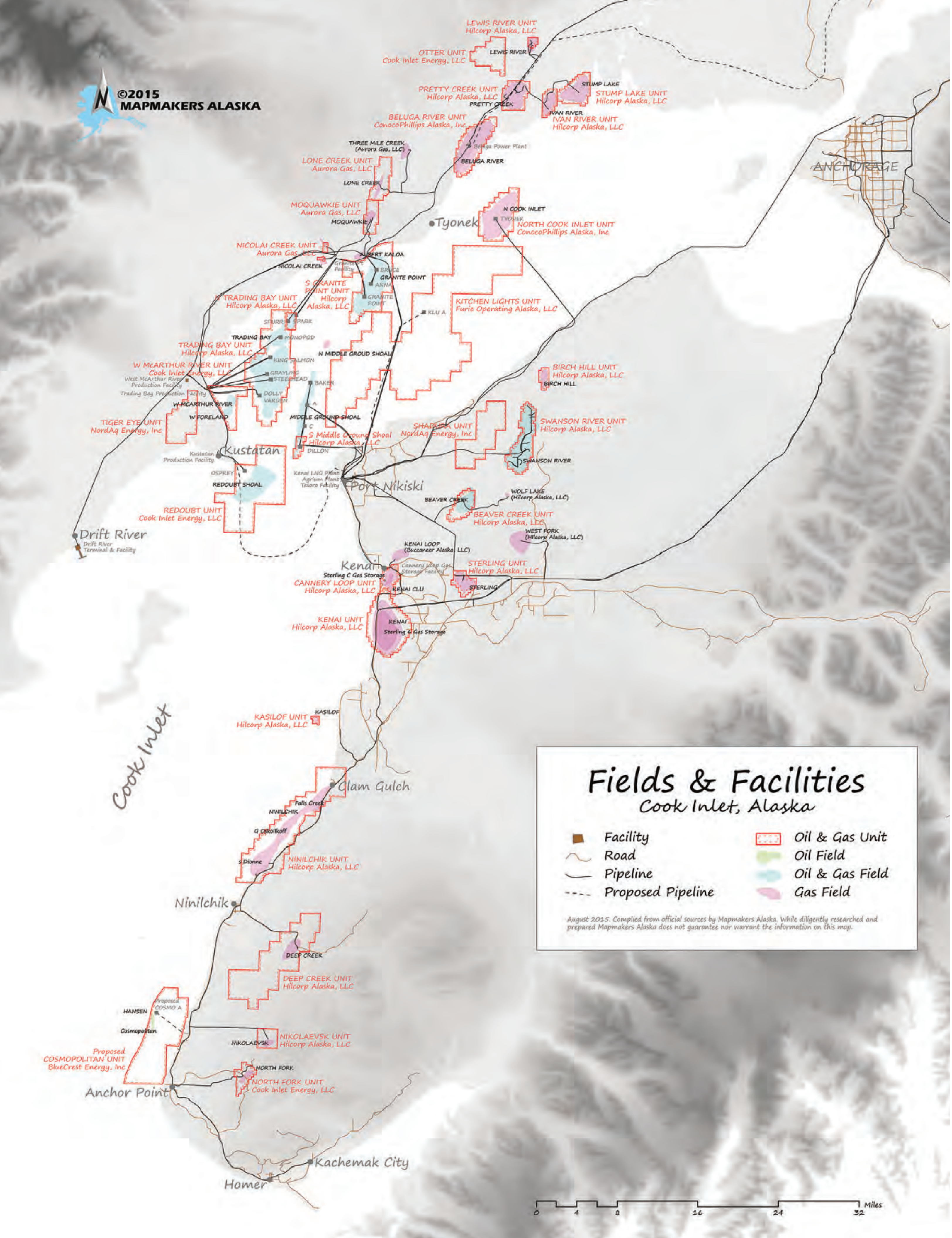


Beaufort Sea
Fields & Facilities
Arctic Slope and Beaufort Sea, Alaska
Facility
Road
Pipeline
Proposed Pipeline
Oil & Gas Unit
Oil Field
Oil & Gas Field
Gas Field
August 2015. Complied from official sources by Mapmakers Alaska. While diligently researched and prepared Mapmakers Alaska does not guarantee nor warrant the information on this map.
HAMMERHEAD
West Dock
Lisburne
East Dock
PRUDHOE BAY
Flow Station 2
BP Operations Center
Prudhoe Bay
Deadhorse
PRUDHOE BAY UNIT BP Exploration (Alaska) Inc
DUCK ISLAND UNIT Hilcorp Alaska, LLC
ENDICOTT
LIBERTY UNIT Hilcorp Alaska, LLC
LIBERTY
Tern Island
Badami Tie-In
BADAMI UNIT Savant Alaska LLC
BADAMI
Badami Central Processing
MIKKELSEN
POINT THOMSON UNIT ExxonMobil Production Co
POINT THOMSON
FLAXMAN
Central Pad
SOURDOUGH
YUKON GOLD
Arctic National Wildlife Refuge Area 1002
James Dalton Highway
0
5
10
20
30
40
Miles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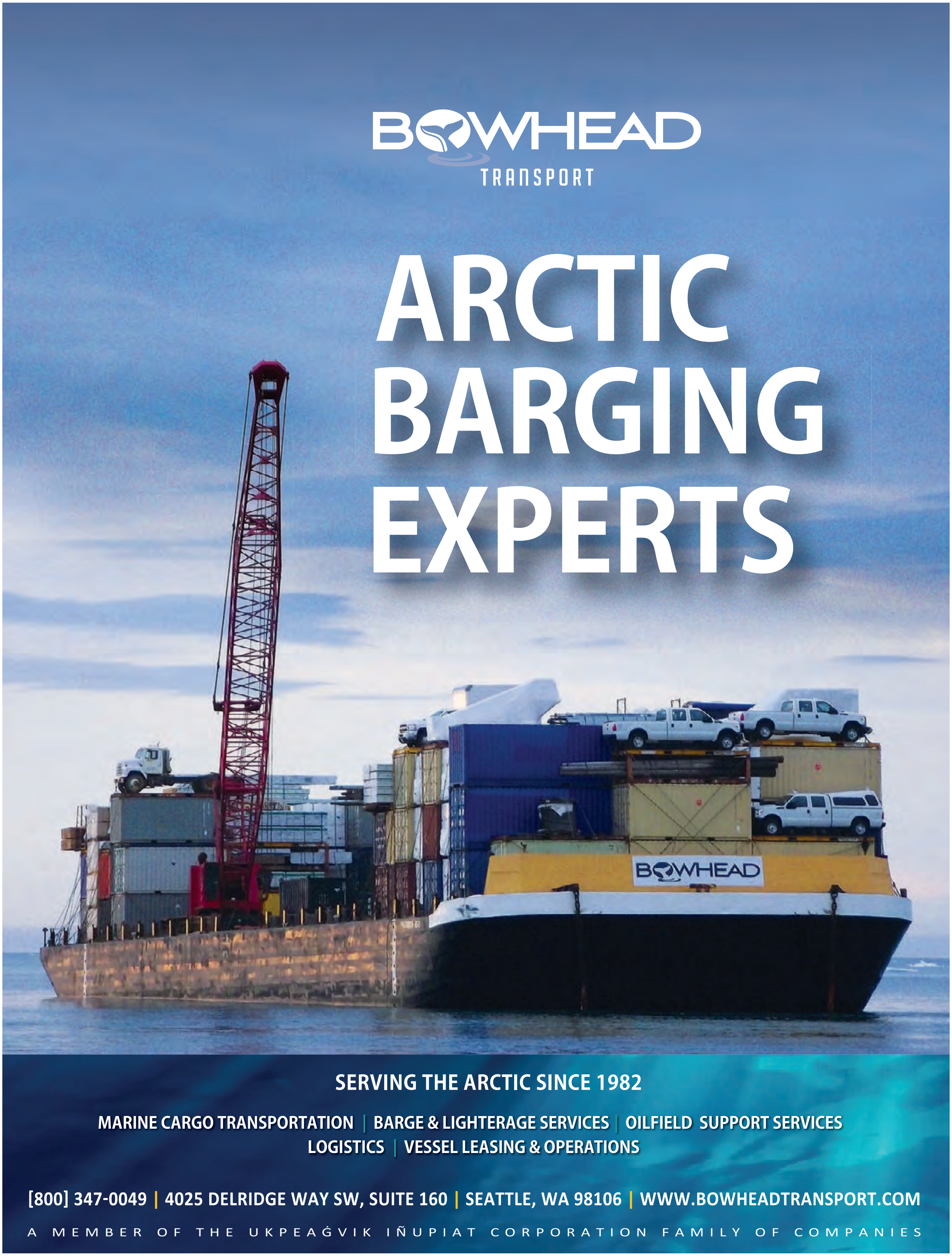
MAPMAKERS ALASKA
Fields & Facilities
Cook Inlet, Alaska
Facility
Road
Pipeline
Proposed Pipeline
Oil & Gas Unit
Oil Field
Oil & Gas Field
Gas Field
August 2015. Complied from official sources by Mapmakers Alaska. While diligently researched and prepared Mapmakers Alaska does not guarantee nor warrant the information on this map.
Miles
0
4
8
16
24
32
Cook Inlet
LEWIS RIVER UNIT
Hilcorp Alaska, LLC
LEWIS RIVER
OTTER UNIT
Cook Inlet Energy, LLC
PRETTY CREEK UNIT
Hilcorp Alaska, LLC
PRETTY CREEK
STUMP LAKE
STUMP LAKE UNIT
Hilcorp Alaska, LLC
IVAN RIVER
IVAN RIVER UNIT
Hilcorp Alaska, LLC
BELUGA RIVER UNIT
ConocoPhillips Alaska, Inc
THREE MILE CREEK
(Aurora Gas, LLC)
Beluga Power Plant
BELUGA RIVER
LONE CREEK UNIT
Aurora Gas, LLC
LONE CREEK
ANCHORAGE
MOQUAWKIE UNIT
Aurora Gas, LLC
MOQUAWKIE
Tyonek
N COOK INLET
TYONEK
NORTH COOK INLET UNIT
ConocoPhillips Alaska, Inc
NICOLAI CREEK UNIT
Aurora Gas, LLC
ALBERT KALOA
NICOLAI CREEK
BRUCE
GRANITE POINT
ANNA
S GRANITE POINT UNIT
Hilcorp Alaska, LLC
N TRADING BAY UNIT
Hilcorp Alaska, LLC
KITCHEN LIGHTS UNIT
Furie Operating Alaska, LLC
KLU A
SPURR
SPARK
TRADING BAY
MONOPOD
TRADING BAY UNIT
Hilcorp Alaska, LLC
KING SALMON
N MIDDLE GROUD SHOAL
W McARTHUR RIVER UNIT
Cook Inlet Energy, LLC
West McArthur River Production Facility
Trading Bay Production Facility
GRAYLING
STEELHEAD
BAKER
DOLLY VARDEN
W McARTHUR RIVER
BIRCH HILL UNIT
Hilcorp Alaska, LLC
BIRCH HILL
TIGER EYE UNIT
NordAq Energy, Inc
W FORELAND
MIDDLE GROUND SHOAL
SHARPIA UNIT
NordAq Energy, Inc
SWANSON RIVER UNIT
Hilcorp Alaska, LLC
S Middle Ground Shoal
Hilcorp Alaska, LLC
DILLON
Kustatan
Kustatan Production Facility
OSPREY
REDOUBT SHOAL
Kenai LNG Plant
Agrium Plant
Tesoro Facility
Port Nikiski
SWANSON RIVER
BEAVER CREEK
WOLF LAKE
(Hilcorp Alaska, LLC)
REDOUBT UNIT
Cook Inlet Energy, LLC
BEAVER CREEK UNIT
Hilcorp Alaska, LLC
WEST FORK
(Hilcorp Alaska, LLC)
Drift River
Drift River Terminal & Facility
KENAI LOOP
(Buccaneer Alaska, LLC)
Kenai
Cannery Loop Gas Storage Facility
STERLING UNIT
Hilcorp Alaska, LLC
Sterling C Gas Storage
CANNERY LOOP UNIT
Hilcorp Alaska, LLC
KENAI CLU
STERLING
KENAI UNIT
Hilcorp Alaska, LLC
KENAI
Sterling 6 Gas Storage
KASILOF UNIT
Hilcorp Alaska, LLC
KASILOF
Clam Gulch
Falls Creek
NINILCHIK
G Oskolkoff
NINILCHIK UNIT
Hilcorp Alaska, LLC
S Dionne
Ninilchik
DEEP CREEK
DEEP CREEK UNIT
Hilcorp Alaska, LLC
HANSEN
Proposed COSMO A
Cosmopolitan
Proposed COSMOPOLITAN UNIT
BlueCrest Energy, Inc
NIKOLAEVSK UNIT
Hilcorp Alaska, LLC
NIKOLAEVSK
NORTH FORK
NORTH FORK UNIT
Cook Inlet Energy, LLC
Anchor Point
Kachemak City
Homer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COURTESY CONOCOPHILLIPS ALASKA

After years of regulatory delays, ConocoPhillips recently completed construction of CD5, the newest drilling pad at the Colville River unit and is currently drilling development wells.

KUPARUK RIVER *continued from page 42*

Given the success of two recent wells at Drill Site 1C, ConocoPhillips plans to drill four more this year — two producers and two injectors — and is considering three others.

As part of its recently requested expansion, ConocoPhillips has asked the state to add eight Kuparuk River unit tracts covering some 6,100 acres to the West Sak participating area. The proposed expansion would add portions of ADL 47449, ADL 25638, ADL 25637, ADL 25636, ADL 25639, ADL 28242, ADL 25649 and ADL 28243, near Drill Site 1H. The company has drilled two recent wells in the proposed expansion area: 1C-150 and 1C-151. Both wells encountered commercial hydrocarbons, according to the company.

Through July 2015, West Sak had produced nearly 77.3 million barrels of oil.

Tarn

ARCO discovered the Tarn oil pool in the southwest corner of the Kuparuk River unit in 1991, confirmed the accumulation in 1997 and brought it into production in June 1998.

At the end of 2014, the Tarn participating area had 69 active wells at two drill sites, 2N and 2L — up from 61 active wells through 2013 and 63 active wells through 2012. Tarn produced 7,700 bpd in 2014, up from 5,600 bpd in 2013 and up from 7,100 bpd in 2012.

The drilling campaigns in 2014 and 2015 have been delineating the Bermuda sands at Tarn, according to ConocoPhillips. The company said it has been encouraged so far by results of drilling into the Purple interval and is evaluating the Cairn and Esker intervals.

After deferring four wells in 2013, ConocoPhillips drilled nine development wells at Tarn in 2014. The success of the first six wells prompted the decision to drill three more wells.

- Well 2N-323A is a rotary sidetrack slant producer brought online in May 2014. The well was producing 360 bpd by the end of 2014.
- Well 2L-322A is a new horizontal producer brought online in August 2014. The well was producing 380 bpd by the end of 2014.

•Well 2N-322 is a new horizontal producer brought online in October 2014. The well was producing 650 bpd by the end of 2014.

•Well 2L-318 is a new horizontal injector brought online in November 2014. The well was injecting 4,250 barrels of water per day by the end of 2014.

•Well 2L-314 is a new slant producer brought online in November 2014. The well was producing 274 bpd by the end of 2014.

•Well 2N-303A is a rotary sidetrack slant producer brought online in November 2014. The well was producing 740 bpd by the end of 2014.

•Well 2N-337C is a rotary sidetrack slant injector brought online in December 2014 and is currently awaiting hook-up.

•Well 2N-350A and Well 2N-319A are rotary sidetrack slant producers put into production in January and February 2015, respectively.

This year, the company is planning a five-well program and may drill more, depending on results. They would be: the horizontal multi-stage producer 2N-336, the slanted injector 2N-312 and the horizontal multistage producers 2L-308, AL-328 and 2L-316.

Through July 2015, Tarn had produced more than 114.2 million barrels of oil.

Tabasco

ARCO discovered the Tabasco oil pool 1986 through regular development drilling at the 2T pad at the western edge of the unit and brought the field into production in May 1998.

At the end of 2014, Tabasco had the same well profile as the year before — 12 wells at Drill Site 2T — nine producers and three injectors — of which only seven were active.

Tabasco produced some 1,549 gross bpd in 2014, down from some 1,711 gross bpd in 2013 and up from 1,076 bpd in 2012, according to ConocoPhillips.

Although Drill Site 2T has several empty slots for both production and injection wells from the initial phase of development, ConocoPhillips is currently focusing on enhanced oil recovery and isn't planning any exploration or development drilling this coming year.

Through July 2015, Tabasco had produced nearly 18.9 million barrels of oil.

Meltwater

ARCO discovered the Meltwater oil pool in 2000 and Phillips brought the field online in November 2001 from Drill Site 2P, some 10 miles southwest of the unit boundaries.

At the end of 2014, Meltwater had 17 active wells at Drill Site 2P, up from 15 active wells in both 2013 and 2012, according to ConocoPhillips. Meltwater produced some 1,439 gross bpd in 2014, down from 1,971 bpd in 2013 and 2,719 bpd in 2012.

Although recent activities at the field have been limited to maintenance and repairs, the company wrote that it is analyzing development opportunities, including coiled tubing sidetracks and producer-to-injector well conversions, "in the light of new seismic data, recent surveillance findings, absence of injection water supply and business climate," language identical to an assessment the company made in its last development plan.

Earlier this year, ConocoPhillips asked the AOGCC for permission to use coiled tubing drilling to sidetrack existing Meltwater wells, which the company believes will improve production rates. The request emerged from a problem experienced early in the life of the field: drilling fluids injected into the reservoir appeared in other wells. ConocoPhillips limited reservoir pressure, which solved the problem but also hampered production.

Through July 2015, Meltwater had produced more than 18.7 million barrels of oil.

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KUPARUK RIVER UNIT SATELLITES *continued from page 49*

The Colville River unit

The ConocoPhillips-predecessor Phillips Petroleum and its partner Anadarko Petroleum brought the Alpine field of the Colville River unit into production in 2000 and finished drilling all the wells planned for the initial development of the field by November 2005.

The initial Alpine development occurred from the CD-1 and CD-2 pads.

Since late 2005, ConocoPhillips has been pursuing "peripheral opportunities" at Alpine, often in conjunction with its efforts to develop the satellite fields. For example, the company began developing the Alpine A and Alpine C sands from the CD-4 pad in 2006.

In 2014, ConocoPhillips drilled only one Alpine well: CD4-93, which the company completed into the Alpine A sands in November 2014. The remainder of the development efforts planned for the Colville River unit over the next few years will be at satellites.

ConocoPhillips currently uses miscible-water-alternating-gas flooding as the primary enhanced oil recovery technique at Alpine. The company fracture stimulated three Alpine wells in 2014, which resulted in "an appreciable production rate increase," according to the company. As a result, it plans to use the technique on two Alpine wells this year.

Under current Alaska Oil and Gas Conservation Commission definitions, the Alpine oil pool combines the Alpine participating area and the Nanuq Kuparuk participating area.

By the start of 2015, ConocoPhillips had drilled 130 wells into the Alpine, which produced 33,800 barrels per day in 2014 and 389 million total barrels through 2014.

The company brought the Nanuq Kuparuk participating area into production in November 2006. The participating area "continues to exceed expectations," according to the company. By the start of 2015, the company had drilled nine wells into the Nanuq Kuparuk, which produced 500 bpd in 2014 and 25.5 million total barrels through 2014.

Through July 2015, the two fields had produced more than 421.2 million barrels.

ConocoPhillips drilled the CD4-96 well in 2013. The well originally targeted the Alpine reservoir but problems during drilling forced the company to complete it as a Kuparuk well instead. In 2014, the company sidetracked the well into the original Alpine target.

CD-5

The biggest development effort this year is at CD-5.

After years of regulatory delays, ConocoPhillips recently completed construction of the newest drilling pad at the Colville River unit and is currently drilling development wells.

The company plans to drill six production wells (CD5-03, CD5-04, CD5-05, CD5-09, CD5-10 and CD5-11) and seven injection wells (CD5-01, CD5-02, CD5-06, CD5-07, CD5-08, CD5-12 and CD5-13) into the Alpine A sands from the new pad between mid-2015 and early 2016, according to its most recent plan of development. The CD-5 program also includes two Nanuq-Kuparuk wells: the CD5-314 horizontal producer and the CD5-315 horizontal injector. The company is considering a third well, CD5-SUN3, but said the decision will depend on the results of the first two wells and rig availability.

Using information gleaned from the previous Alpine A sands work, the CD-5 program includes a horizontal pattern MWAG flood in the Alpine A sand for enhanced recovery.

The Colville River unit satellites

From the beginning, the ConocoPhillips-predecessor Phillips Petroleum and its partner Anadarko Petroleum designed the Colville River unit to have "sequential development."

The idea was to use the large Alpine oil field as an anchor to support development of smaller satellite fields in the vicinity. To date, the partners have developed three satellites — Fiord, Nanuq, Qannik — and are nearing completion on a fourth, Alpine West. As a result of the program, the Colville River unit will also support proposed developments at the eastern edge of the National Petroleum Reserve-Alaska. While Alpine West is managed through the plan of development for the main Alpine field, the other three are managed through separate plans of development associated with the main Alpine field.

Fiord

ConocoPhillips brought Fiord online from the CD-3 pad in August 2006. The Fiord pool includes the Fiord Nechelik participating area and the Fiord Kuparuk participating area.

At the start of 2015, ConocoPhillips had drilled 23 wells into the Fiord Nechelik participating area. The company completed the CD3-316B sidetrack in April 2014 and was planning a single development well into the pool in 2015. The Fiord Nechelik produced 12,100 barrels per day in 2014 and 46.1 million total barrels through 2014.

Through July 2015, Fiord had produced 61.2 million barrels of oil.

At the start of 2015, the company had five active wells in the Fiord Kuparuk participating area and had no plans to drill additional wells in 2015. The Fiord Kuparuk participating area produced 1,400 bpd in 2014 and 12.6 million total barrels through 2014.

The company is planning to fracture stimulate one Fiord well in 2015.

Nanuq

ConocoPhillips brought Nanuq online from the CD-4 pad in December 2006. At of the start of 2015, the company had drilled nine wells into the Nanuq participating area, which produced 1,600 bpd in 2014 and 2.6 million total barrels through 2014.

Through July 2015, Nanuq had produced more than 2.9 million barrels of oil.

The company drilled the CD4-289 development well in late 2014 and brought the well into production in early 2015. The well will be converted into an injector this year.

Qannik

ConocoPhillips brought Qannik online from an expanded CD-2 pad in 2008. At of the start of 2015, the company had drilled nine wells into the Qannik, which produced 1,700 bpd in

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COLVILLE RIVER UNIT SATELLITES *continued from page 51*

2014 and 4.8 million total barrels through 2014. The company drilled no wells at Qannik in 2014, planned none for 2015 and sees no near-term opportunities.

Through July 2015, Qannik had produced 5.2 million barrels of oil.

The Beluga River unit

Richfield Oil Corp., Shell and Standard Oil Company of California discovered the Beluga River gas field on the west side of Cook Inlet in 1962, while drilling for deeper oil.

Production from the field began in 1968 to service the new Chugach Electric Association power plant built nearby. Enstar Natural Gas Co. built a pipeline to Anchorage in 1984.

Through its predecessors ARCO and Phillips, ConocoPhillips became operator of the field in 1986 and currently owns a 33 percent working interest ownership in the field, alongside independent producer Hilcorp Alaska LLC and utility Anchorage Municipal Light & Power. Earlier this year, ConocoPhillips announced plans to sell its Cook Inlet properties but had yet to announce a buyer when The Producers went to print.

ConocoPhillips conducted an expensive development campaign at the field between 2008 and 2012. The program included drilling six wells and upgrading compression in an attempt to improve deliverability. The company appears to be done drilling new wells for the time being and is focusing on smaller maintenance activities to improve performance.

As it enters its 47th year of operation, the legacy Cook Inlet natural gas field is "fully delineated," according to a recent plan of development from operator ConocoPhillips Alaska Inc. The Sterling reservoir has declined to 25 percent of its original pressure, down from 30 percent a year ago. As would be expected, deliverability has also declined.

Even with those downward trends, though, annual production increased last year. Beluga River produced 25.1 billion cubic feet in 2014, up from 22.4 bcf in 2013, which suggests that some of the maintenance activities at the field are yielding results.

"Field efforts continue to mitigate well declines, find production enhancing opportunities and improve operational safety and reliability in this mature asset," the company wrote.

Through 2014, Beluga River had 14 producing wells (one less than in 2013), 10 shut-in wells (one more than in 2013) and two disposal wells, according to ConocoPhillips.

Through July 2015, the unit had produced more than 1.3 trillion cubic feet of natural gas.

Maintenance program

In 2015, ConocoPhillips has planned maintenance work on at least eight wells.

Its proposed program includes: installation of artificial lift on 212-35T and 232-26 and, if the work proves to be successful, the evaluation of similar activities on 224-34 and 214-26; installation of a velocity string on 232-23; a fill cleanout on 212-25, milling a plug on 244-23; and swabbing and flow testing 211-03, which could lead to additional work.

Many of these projects were either planned for 2014 or grew out of work begun in 2014.

ConocoPhillips had originally intended to conduct rigged workovers on three wells last year. The company completed its program on 244-23 in May 2014 and 242-04 in September 2014 but suspended work on 224-13 "due to operational issues." The well is currently a candidate for a sidetrack, which ConocoPhillips would drill in 2016.

The artificial lift installations on 212-35T and 232-26 were originally planned for last year but delayed. The project calls for installing an electric submersible pump on 212-35T and a hydraulic submersible pump on 232-26 sometime early this year. The similar installation being considered for 224-34 follows a recent mechanical integrity test.

The flow testing on 211-03 is a continuation of work conducted in May 2014. The current project includes performing a

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BELUGA RIVER UNIT *continued from page 53*

mechanical integrity test, adding perforations and conducting a swab and flow test with an eye toward adding a flow line back to C pad.

ConocoPhillips evaluated clean-out jobs on 212-25 and 212-35. The 212-35 project was scrapped for now. The 212-25 job remains under evaluation. The company also planned to install a velocity string on 232-23 last year but postponed the project to this summer.

Other projects completed last year include:

•An unsuccessful fishing operation on 211-26 in July 2014.

•A successful clean out of 212-24T in August 2014.

•Re-cylindering of seven wellhead compressors, completed in October 2014.

•Studying a proposal to install a water trunk line at the field. The company ultimately decided to keep studying the project and make a decision no earlier than 2016.

•Studying a proposal to add water storage to an existing DW-2 disposal well. The company ultimately decided that the project was "not necessary at this time."

•Upgrading water storage capacity at C pad in June 2014.

•Studying but ultimately not commissioning a similar project at E pad.

ConocoPhillips completed turnarounds on five facilities in 2014 — BRWD-1 in April, C pad facilities in April and early May, M pad in May and B pad in May and early June — and other maintenance, repairs and inspections at infrastructure throughout the field.

The North Cook Inlet unit

Pan American Petroleum Corp. discovered the North Cook Inlet Tertiary System Gas Pool in 1962. The offshore field is developed from the Tyonek platform, which connects back to the east side of Cook Inlet and eventually feeds into the Kenai LNG facility.

Today, ConocoPhillips owns the unit outright. North Cook Inlet unit production began in 1969. Through July 2015, the unit had produced nearly 1.9 trillion cubic feet of gas.

As with Beluga River, ConocoPhillips conducted a large development program at North Cook Inlet between 2008 and 2013. The company drilled three wells in 2008 and 2009 and undertook some maintenance and upgrades in 2012 that continued into 2013.

This year, ConocoPhillips performed work on four wells: adding nitrogen lift to A-09 in March, changing out a gas-lift valve at A-14 and B-01A in April and making adjustments to A-13 in August to meet requirements of the U.S. Environmental Protection Agency.

The company also performed a range of maintenance and upgrades on field infrastructure, including installing temporary living quarters, upgrading turbine compressors and performing a summer platform turnaround in August.

In 2016, ConocoPhillips plans to continue an ongoing evaluation of potential rigged workovers or drilling opportunities, with an eye toward a 2017 workover program.

Although ConocoPhillips was marketing the unit (as well as the Beluga River unit) to potential buyers as The Producers went to print, the company intended to retain 100 percent working interest in its Kenai liquefied natural gas export terminal in Nikiski.

Over the past five years, the fortunes of the pioneering operation have swung wildly.

While the facility was the largest in the world when operations began in 1969, larger facilities and facilities closer to East Asian markets gradually overshadowed it. In early 2011, ConocoPhillips and its then-partner Marathon Oil (ConocoPhillips later bought out Marathon to become the sole owner of the facility) announced plans to mothball the facility for lack of sufficient contracts. But they ended up keeping the facility open through 2012 and into 2013 to accommodate an unexpected increase in Asian demand.

ConocoPhillips decided against seeking an extension of its federal export license in early 2013 but said it would consider restarting the facility once local energy needs had been satisfied and also said it would consider alternative uses for the facility, including imports, if necessary. When Hilcorp Alaska LLC contracted with utilities to meet local demand through 2018, the state asked ConocoPhillips to apply for a new export license.

ConocoPhillips acquiesced, and in early 2014 the U.S. Department of Energy issued a license for the company to export as much as 40 billion cubic feet over two years.

The company told the federal regulator it planned to make as many as six shipments to Pacific Rim customers between May and October 2015. The company also made two deliveries to Fairbanks distribution utility Fairbanks Natural Gas LLC in the first half of the year, according to the federal filing. In addition to shipments, ConocoPhillips undertook a limited maintenance campaign to clean, re-coat and re-seal its storage tanks.

Although ConocoPhillips continues to supply the facility using the North Cook Inlet unit, the export terminal has also begun accepting volumes from other suppliers in the region. ●

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Eni US Operating Co. Inc.

By ERIC LIDJI
For Petroleum News

The Italian major Eni Petroleum first invested in Alaska through its subsidiary Agip Petroleum, which acquired leases in the 1960s and operated on the Kenai Peninsula through "outsourcing agreements" signed with American operators in the late 1970s.

In 2005, Eni acquired a minority interest in several North Slope prospects from Armstrong Alaska, and in 2007 the company acquired the outstanding interest in those prospects from Kerr-McGee Corp. The assets included three offshore prospects in the state waters of the Beaufort Sea, north and northwest of the Kuparuk River unit: Nikaitchuq, Tuvaaq and a stake in Oooguruk. It also included the onshore Maggiore and Rock Flour prospects in the central North Slope south of Prudhoe Bay and Kuparuk.

Eni relinquished the Rock Flour and Maggiore prospects in 2010, after drilling wells at both prospects in early 2007. In 2011, the company farmed out six leases in the North Tarn prospect, southwest of the Kuparuk River unit, to a joint venture operated by Brooks Range Petroleum Corp. A new joint venture is currently developing that prospect.

The start up of the Oooguruk unit in mid-2008 made Eni a producer, albeit in a non-operating capacity. The experience gave the company insight into the Alaska Arctic.

Over the course of 2007, Eni more than doubled the size of the Nikaitchuq unit by incorporating leases from the neighboring Tuvaaq unit to the west as well as a bundle of un-unitized leases to the south. The company also secured royalty modification on 12 of the 18 leases at the expanded unit, creating a structure where it would pay lower royalties to the state if the price of oil dropped below an inflation-adjusted threshold.

In January 2008, Eni sanctioned a $1.45 billion program to bring Nikaitchuq into production by late 2009. Weather delays, combined with the short Arctic sealift season, ultimately pushed the program back one year. The unit came online in February 2011.

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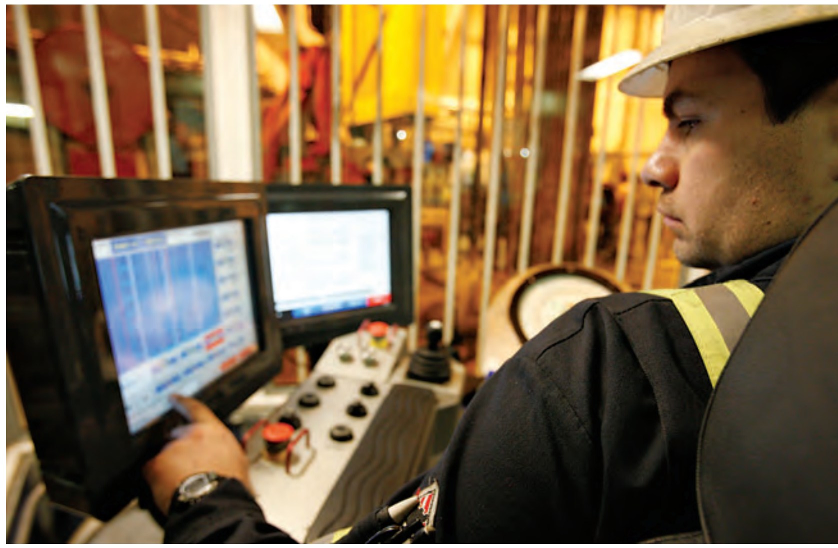

ENI PETROLEUM *continued from page 56*

The development program called for an onshore pad at Oliktok Point and an offshore pad at Spy Island. The initial drilling program from the Oliktok Point pad finished in August 2012 and continuous drilling from the Spy Island drill site began in November 2012.

The Nikaitchuq unit

Eni US Operating Co. Inc. might complete its initial development program at the Nikaitchuq unit by the end of next year, according to its current plan of development.

The American subsidiary of the Italian major had previously projected that the work would be completed by the end of this year, but a program of lateral sidetracks to increase oil production is expected to continue well into 2016, the company said.

This year, Eni intends to drill five wells — three producers (SP31-W7, SP04-SE5 and SP01-SE7) and two injectors (SI34-W6 and SI107-SE4) — and seven dual lateral producers (SP31-W7 L1, SP04-SE5 L1, SP33-W3 L1, SP30-W1 L1, SP01-SE7 L1, SP16-FN3 L1 and SP23-N3 L1) into the OA reservoir from the Spy Island drill site. The wells include penetrations associated with an expansion into the northwest of the unit.

The dual laterals are part of a strategy for optimizing oil production by designing wells that undulate through a target formation counter to the undulation of existing laterals.

The company currently plans to drill five dual lateral producers from its Spy Island drill site in 2016: SP23-N3 L1 (which is also listed as one of the proposed well locations intended for this year), SP10-FN5 L1, SP27-N1 L1, SP18-N5 L1 and SP05-FN7 L1.

Eni initially planned a two-phased program for Nikaitchuq, starting with drilling from the onshore Oliktok Point Pad and continuing from the offshore Spy Island drill site.

The company completed its initial Oliktok Point Pad program in August 2012 and began continuous drilling from the Spy Island drill site in November 2012 with Doyon Rig 15.

In 2013 and 2014, the company conducted a sidetrack program to add second laterals to certain producers drilled from the Oliktok Point Pad. The program included workovers to replace electric submersible pumps as well as an N sands pilot well. The program finished in May 2014. The company also worked over two wells at Spy Island in 2014.

Through the end of this year, Eni expects it will have drilled 55 wells at the unit — 28 producers, 22 injectors, three water source wells and two disposal wells. Of the 55 wells, 23 will have been drilled from the Oliktok Point Pad and 32 from the Spy Island drill site.

The unit was producing 25,393 barrels per day at the end of 2014. Through July 2015, the unit had produced 23.2 million barrels of oil from the Schrader Bluff formation.

Expansions

The future of the unit depends on various expansions — some which have been under evaluation for years and one that was recently proposed publicly for the first time.

The newest proposal is being called the "East Extension Project" and could add three or four wells to the development program in 2016, according to the company. The company provided no further details about the proposed project in its plan of development.

Last year, Eni listed three proposed expansion opportunities for the unit: extending the current development of the Schrader Bluff OA sands into the "western area" of the unit, developing the Schrader Bluff N sands and developing a Sag River oil reservoir.

Those three proposals are developing at different rates.

Eni recently sanctioned its "western area development," which will extend drilling into the northwest corner of the unit. The area was considered technically unfeasible until recent years, when it became merely "challenging," according to the company.

The program includes two producers (SP21-NW1, SP31-W7), two injectors (SI34-W6, SI26) and two dual laterals (SP21-NW1 L1, SP31-W7 L1) drilled from the Spy Island drill site. Eni completed the producer SP21-NW1 and the lateral SP21-NW1 L1 in November 2014, the producer SP31-W7 and the lateral SP31-W7 L1 in February 2015, and the SI34-W6 injector in March 2015, according to the Alaska Oil and Gas Conservation Commission. The remaining injector, SI-26 has yet to be permitted.

The company said it will "continue evaluating opportunities" from Spy Island and plans to drill two producers (SP28-NW3 and SP03-FN9) and one injector (SI06-FN9) in 2015.

N sands, Sag River

Eni sanctioned Nikaitchuq based entirely on the potential of the Schrader Bluff OA sands but early on the company saw an opportunity to develop the shallower N sands.

In recent years, the company launched an appraisal program after preliminary studies suggested between 40 million and 100 million barrels of "contingent resources" in the N sands. Previous plans of development for the unit mentioned "sedimentological, petrophysical and reservoir studies," the extension of the several OA sands development wells to test the N sands and a pilot well drilled in 2013 to test completion strategies.

Having completed reservoir modeling and original oil in place calculations for the N sands in 2014, the company is launching a "technical economic analysis" this year to craft a develop scenario. The process could produce a conceptual proposal by 2016.

The proposed Sag River development is missing from the current plan of development.

In its previous plan of development, submitted July 2014, the company said it intended to submit a proposal for a Sag River development to upper management within 18 months.

The oil in the Sag River formation is deeper and generally lighter than the oil in the Schrader Bluff formation, where development currently occurs. The Sag River is "plagued with poor quality reservoir rock" and development would be "marginal at best unless there are significant advances in stimulation or enhanced oil recovery technology," state officials wrote in a previous decision to modify the royalty structure at Nikaitchuq.

In the current plan of development, Eni said it would "continue to review its geological, petrophysical, and drilling information to help improve our understanding of the Nikaitchuq unit reservoir(s)" and would "continue assessing exploitation opportunities when available in the acreage immediately outside current develop areas, outside the Unit and at various horizons," which leaves room for a future Sag River development. ●

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ExxonMobil Alaska Inc.

By ERIC LIDJI
For Petroleum News

ExxonMobil Alaska Inc. is sometimes described as a silent partner in Alaska.

Even though the company was not operating any producing assets in the state when 2015 began, and hasn't for years, the company has been around a long time. It opened its first Alaska field office in 1921 and drilled its first Alaska well in 1926. Since then, it has drilled exploration and development wells on the North Slope and in Cook Inlet, and has explored almost every frontier basin in the state: the Gulf of Alaska, the Arctic Ocean, the Bering Sea, Bristol Bay, the Copper River basin and the Brooks Range foothills.

Exxon helped discover the Kuparuk River unit, the Point Thomson unit, the Duck Island unit and several smaller prospects across the North Slope still awaiting development. In Cook Inlet, Exxon played a role in discovering Ninilchik, Granite Point and Moquawkie.


CORY QUARLES

ExxonMobil was created through a 1999 merger. Since the merger, the company in Alaska has primarily focused on the North Slope, although it became a Cook Inlet operator after its parent acquired the independent XTO Energy Inc. in 2010. The acquisition made Exxon the ultimate owner of the XTO-operated Middle Ground Shoal field, although XTO recently sold the offshore Cook Inlet field to Hilcorp Alaska LLC.

Along the way, Exxon was also at the center of the largest oil-related disaster in Alaska with the 1989 grounding of the Exxon Valdez tanker and one of the largest political controversies with the ongoing disputes over how to develop the Point Thomson field.

Today, Exxon is primarily concerned with two Alaska ventures. The first is its effort to bring the Point Thomson unit into production. The other is the Alaska LNG project.

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The Point Thomson unit

As the Producers went to print, ExxonMobil Alaska Production Inc. was in the final stages of bringing condensate production online from the Point Thomson unit.

Over the past few years, the local subsidiary of the global energy giant has been drilling development wells and building production facilities at the eastern North Slope natural gas and condensate field. And over the past few months, the company has been filing some of the final permits required to bring the long-awaited field into operation.

In late August, the Alaska Oil and Gas Conservation Commission approved a request from Exxon to inject natural gas into the field reservoir, which is a crucial technical requirement for the "Initial Production System" Exxon has planned for Point Thomson.

Also, Exxon applied for AOGCC pool rules at the field and applied to the Regulatory Commission of Alaska for permission to connect the Point Thomson production facilities to the Point Thomson Export Pipeline System, which would carry supplies to market.

As part of those filings, Exxon said it expects the system to be operational by December 2015, although the regulatory process might push the actual startup into January 2016.

Either way, the event will mark a milestone in the history of the North Slope. Point Thomson is one of the oldest and largest undeveloped fields in northern Alaska and has been a point of contention between the company and state officials for decades. Given the importance of the field for any future major natural gas sales from the North Slope, the start of condensate production from Point Thomson marks an "end of the beginning" rather than a "beginning of the end." If plans for a large-diameter natural gas pipeline come to fruition, Exxon and state officials will have to decide when and how to phase out gas-cycling for condensate production and phase-in gas production to feed the pipeline.

50 years in the making

The original leases at Point Thomson were issued around 1965. Exxon discovered oil in the area in 1975 and natural gas in 1977 and formed the Point Thomson unit later that same year. Although Exxon and other companies had drilled 17 wells by 1983, a series of technical, economic, legal and regulatory challenges delayed development for decades.

Those delays eventually tried the patience of state officials, setting off a complex legal and regulatory battle. The debate largely concerned two competing development strategies for the field: Was it economically and technically wiser to prioritize condensate production or gas production? The two strategies involved two very different timelines.

Believing Point Thomson was ready to be developed, the Alaska Department of Natural Resources put the unit into default in 2005 and terminated the unit in late 2006. Exxon and its partners appealed the decision, and an Alaska Superior Court judge sided with the companies and sent the matter back to the state in December 2007. The state ultimately rejected a new plan of development for the unit in April 2008 and the producers appealed the decision to Superior Court, which sided with the companies. The Alaska Supreme Court granted a petition from the state for review, halting the Superior Court litigation.

The debate was as much a public relations battle as a legal or a regulatory one, as shown by an odd fact: while the two sides were arguing in court, the state gave Exxon permission to drill the first two wells at the unit in several decades: PTU-15 and PTU-16.

Through a court-ordered settlement reached in early 2012, the

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POINT THOMSON UNIT *continued from page 60*

state and Exxon created a timetable for bringing Point Thomson online by early 2016 and subsequently expanding development. The Initial Production System is the first part of that timetable and aims to produce some 10,000 barrels per day of liquid condensate while cycling some 200 million cubic feet per day of residual gas into the field. Originally, the system was envisioned as having two injection wells and one production well. In May 2015, the company said it might initiate production from the two existing wells, using PTU-15 as a producer and PTU-16 as an injector. Once the PTU-17 well is completed, it would become a producer and the entire operation would revert to the original specifications.

The AOGCC approved a drilling permit for PTU-17 on Aug. 4, which may or may not provide enough time to complete the well and establish the system by project startup.

While the settlement allowed Point Thomson operations to continue, some challenges remained. In 2012, prior to being elected governor, Bill Walker sued to prevent the settlement from proceeding, calling it "a giveaway of historic proportions" and claiming that state officials had exceeded their authority and had violated state regulations.

In early 2015, after taking office, Walker agreed to drop the suit but filed legislation designed to regulate future settlements related to oil and gas activity in the state.

What comes next?

Once the field is operational, the next issue to address is expansion.

The current expansion plans present three alternatives: sanctioning major gas sales by June 2016, expanding liquids production to at least 30,000 barrels per day by 2019 or integrating Point Thomson and Prudhoe Bay operations to mutually improve recovery.

If the Initial Production System is successful at producing condensate from the high-pressure Point Thomson reservoir, focus will likely shift to the role of the field in major gas sales. The field is generally considered to hold 25 percent of the known natural gas reserves on the North Slope and is likely to be crucial for making a pipeline economic.

Exxon helped discover the Kuparuk River unit, the Point Thomson unit, the Duck Island unit and several smaller prospects across the North Slope still awaiting development.

In its pool rules application, Exxon said it would prefer to transition from the Initial Production System directly into exporting natural gas, rather than expanding condensate production. Under its proposed scenario, Exxon would produce some 820 million cubic feet per day from Point Thomson with peak production of 920 million cubic feet per day during winter. The company is asking regulators to approve an annual average rate of 1,100 million cubic feet per day to allow for operational and engineering flexibility.

Even under that scenario, Point Thomson would continue to produce small amounts of condensate, although much less than if condensate production was given priority.

Exxon is skeptical about the economic viability of expanding condensate production. In its pool rules applications the company wrote: "Major impediments were the limited amount of condensate that could be recovered, the high cost of the facilities and wells, and the significant risks associated with a gas cycling development." While acknowledging that the Initial Production System would provide useful information about the reservoir, "no scenarios have been identified in which this information would materially improve the current outlook for the viability of expanded gas recycling," the company said.

As far as the prospect of integrating Prudhoe Bay and Point Thomson, Exxon believes that strategy depends largely on progress of the larger AK LNG project. While using Point Thomson gas for Prudhoe Bay field operations could accelerate Point Thomson gas sales by two years, the acceleration is unlikely to justify the cost of implementation.

Under the current proposal for the AK LNG project, 75 percent of the natural gas supplies for the pipeline would come from Prudhoe Bay with the remaining volumes coming from "other sources," of which Point Thomson is one likely candidate.

Generally, the state would prefer expanded condensate production because condensate is currently a more valuable commodity than natural gas and because natural gas is stranded without a pipeline. At an AOGCC hearing earlier this year, Commissioner Cathy Foerster noted that the success of the Initial Production System would determine future development plans. "So it's critically important to this agency that you've done your best job of trying to ensure that you've given cycling every chance to succeed," she said.

While a major gas sale is the most important development hinging on Point Thomson, the field will also likely become important to oil development on acreage farther to the east, which is why Exxon built the Point Thomson Export Pipeline to carry as much as 70,000 barrels per day, far larger than current needs. The RCA certified the pipeline in November 2012 and approved its connection to the neighboring Badami unit in August 2013. Exxon installed the 22-mile along the Beaufort Sea coastline during 2014. The final administrative requirement is connecting the pipeline to the Point Thomson facilities. ●

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Furie Operating Alaska LLC

By ERIC LIDJI
For Petroleum News

The Houston-based independent Escopeta Oil & Gas Co. spent more than a decade acquiring a lease position in upper Cook Inlet, securing a jack-up rig and bringing the rig to Alaska to conduct an exploration program at what is now the Kitchen Lights unit.

BRUCE WEBB

The Kitchen Lights unit was created through a 2009 settlement between the state and various independent operators in the region. The 83,394-acre unit combined 40,733 acres from the Escopeta-operated Kitchen unit, 15,930 acres from the Renaissance Alaska LLC-operated Northern Lights prospect and 26,721 acres from the Corsair prospect that had previously been owned by the bankrupt Pacific Energy Resources Ltd. The idea behind combining the three prospects was to prevent a legal battle over missed work commitments while simultaneously prompting exploration and development activities.

A corporate shuffle in 2011 divided Kitchen Lights. Through its subsidiary Furie Operating Alaska LLC, the German company Deutsche Oil & Gas became the new unit operator. Cornucopia Oil and Gas Co. became the primary working interest owner. Later, Energy Capital Partners Mezzanine Opportunities Fund became a primary financier.

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The subsequent exploration campaign was successful but left the companies with some bruises, particularly a $15 million fine from the federal government for violating the Jones Act, which regulates marine traffic. The company continues to challenge the fine.

The Kitchen Lights unit

Kitchen Lights is the largest unit in the Cook Inlet basin. The current plan of exploration divides the unit into four exploration blocks: North, Corsair, Central and Southwest. The development project underway only targets the Corsair block. The remaining three exploration blocks are slated for future work.

To date, Furie has drilled five wells and a sidetrack throughout the Kitchen Lights unit, although the current development program is based only around a portion of that drilling.

Using the Spartan 151 jack-up rig, Furie drilled the Kitchen Lights Unit No. 1 well in the Corsair block in 2011 and 2012. Work occurred over two years because the rig arrived in Cook Inlet during the summer, too late to complete activities before the end of the drilling season. Also, Furie suspended operations earlier than it had intended because the state had asked the company to slow the pace of its work to ensure operational safety.

By the time Furie stored the rig for the season, the company had drilled KLU No. 1 to a depth of some 8,805 feet, about halfway to the target depth of 16,500 feet. The following year, the company finished drilling, reaching a total depth of 15,298 feet before starting work on the Kitchen Lights Unit No. 2 well, also in the Corsair block. The company reached a total depth of some 9,000 feet and drilled the Kitchen Lights Unit No. 2A sidetrack to test several gas-bearing zones in the Beluga. In 2013, Furie drilled the Kitchen Lights Unit No. 3 well, also in the Corsair block, to a total depth of 10,391 feet.

Those three wells formed the basis for the current development program.

Toward the end of the drilling season in 2013, after completing KLU No. 3, Furie began the Kitchen Lights Unit No. 4 well in the northern block. In 2014, Furie completed KLU No. 4 and drilled the 11,800-foot Kitchen Lights Unit No. 5 well in the central block.

Resource estimates

Even though KLU No. 1 was only halfway to total depth when the first drilling season ended, Furie announced a major discovery:

COURTESY FURIE OPERATING ALASKA LLC

By August 2015, Furie had finished installing the Julius R platform, shown here, laying the pipeline and constructing the onshore production facilities.

approximately 46.7 billion cubic feet of natural gas in place, which, extrapolated over a larger area, suggested some 3.5 trillion cubic feet of gas present at the unit. If correct, those figures would rank among the largest natural gas discoveries in the history of the Cook Inlet basin. However, some state officials and industry watchers expressed skepticism at the time, saying that the announcement pushed the upper limits of what geologists expected the basin to contain.

In the years since, Furie has elaborated upon the initial figures. Speaking to lawmakers in March 2012, then President Damon Kade estimated probable gas reserves of 750 billion cubic feet and peak production of 30 million cubic feet per day from Kitchen Lights. The lower figure was based on a smaller geographic drainage area, Kade later told Petroleum News.

In early 2013, parent company Deutsche Oil & Gas released an assessment of "roughly one ninth of its production area in Kitchen Lights unit." It estimated a mid-case scenario of 72.1 million barrels of oil and 543.8 billion cubic feet of gas "classified as 'probable' and 'prospective' exploitable reserves." Under generally accepted definitions, "probable" indicates 50 percent likelihood and "prospective" indicates 10 percent likelihood.

As might be assumed given their proximity, KLU No. 2 and KLU No. 3 were intended to delineate the initial KLU No. 1 discovery, as well as to find additional resources.

In a formal statement of discovery filed with the Alaska Department of Natural Resources in July 2013, Furie said that the KLU No. 3 well had encountered multiple productive gas pools in the Sterling and Beluga formations at depths ranging from 3,618 feet to 6,228 feet. The company also said that it had conducted modular dynamic testing of 28 gas pools and had flow tested six pools. In the most recent plan of development for the unit, from November 2014, Furie said that the KLU No. 3 well had produced 15.83 million cubic feet during a four-point test, which confirmed a commercial discovery. The gas samples taken during the test were 99 percent methane, according to the company.

In a Sept. 16 decision, Division of Oil and Gas Director Corri Feige certified KLU No. 3 as the official discovery well for four previously undiscovered natural gas pools in the Sterling and Beluga formations. Under the ruling, Furie and its working interest owners will pay a 5 percent royalty rate for all natural gas produced at lease ADL 389197 from those four previously undiscovered pools, rather than the traditional 12.5 percent royalty rate. The decision begins retroactive to June 30, 2013, and runs through June 29, 2023.

Julius R platform

Furie sanctioned its initial development at Kitchen Lights based on the results of KLU No. 3, and the company is using the well as the basis for its current development.

The first phase will install KLU the Julius R platform and a subsea pipeline connecting to new onshore gas production facilities. In July 2014, the private equity firm Energy Capital Partners Mezzanine Opportunities Fund committed $160 million to the development.

The Julius R platform is a monopod platform with three primary decks — a production deck 62 feet above sea level, a main deck 82 feet above sea level and a helideck 100 feet above sea level. Once operations begin, the company will cantilever its jack-up rig over the fixed platform and drill wells through an 18-foot-diameter caisson, into the seafloor.

While Furie had initially intended to install the platform by the end of 2014, a delay in receiving the components and concerns about encountering bad weather as the open water season neared an end convinced the company to delay installation until this year.

By August 2015, Furie had finished installing the platform, lay-

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Hilcorp Alaska LLC

By ERIC LIDJI
For Petroleum News

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Hilcorp Alaska LLC became a top player in Alaska through three big purchases.

The privately held Houston-based independent acquired the Cook Inlet assets of Chevron subsidiary Union Oil Company of California in July 2011 and the Cook Inlet assets of Marathon Oil Co. in April 2012. Those two deals made Hilcorp the operator of some 20 oil and natural gas fields across the Cook Inlet basin: on the west side — the Lewis River, Pretty Creek, Stump Lake and Ivan River units; offshore — the Granite Point field, South Granite Point unit, Trading Bay unit, North Trading Bay unit, McArthur River field, North Middle Ground Shoal field, South Middle Ground Shoal unit; in the southern Kenai Peninsula — the Kasilof, Ninilchik, Deep Creek and Nikolaevsk units; in the northern Kenai Peninsula — the Birch Hill, Swanson River, Beaver Creek, Sterling, Cannery Loop and Kenai units, as well as the small Wolf Lake and West Fork fields. The deals also gave Hilcorp a minority interest in the ConocoPhillips-operated Beluga River unit and the XTO-operated Middle Ground Shoal field, which Hilcorp acquired from its majority partner this year.


DAVE WILKINS

The investment Hilcorp has made at those fields to date — some $300 million a year, compared to some $70 million a year by previous operators, according to the company — has altered the marketplace, taking a region that had been on the verge of importing liquefied natural gas to meet local demand to one that is, at least for the next few years, self-sufficient. The story is the same for oil. Since arriving in Alaska, Hilcorp has more than doubled oil production, to some 13,000 barrels per day up from some 6,000 bpd.

By owning so many fields at once, Hilcorp has also been able to consolidate in ways that were difficult when the region was divided among various players. Those consolidations include joining smaller fields into single units and combining four regional pipelines into a single integrated system, now called the Kenai Beluga Pipeline. The company has also been working to enter the Fairbanks market by attempting to acquire a liquefied natural gas terminal at Point MacKenzie and, as The Producers went to print, was in the running to partner with the Alaska Industrial Development and Export Authority on a plan to bring LNG to the Interior, which currently uses fuel oil as its primary heating supply.

This dominance has brought mixed feelings in Cook Inlet. While many are relieved to finally have an enthusiastic player in the region after decades of declining investment, some smaller independents worry about being crowded out of the local marketplace.

In late 2014, Hilcorp closed on its third major acquisition in Alaska, buying BP Exploration (Alaska) Inc.'s interest in a selection of North Slope properties. Through the deal Hilcorp became operator and owner of the Northstar unit, majority owner and operator of the Endicott field — the Duck Island unit, operator and 50 percent working interest owner of the Milne Point unit alongside BP and a 50 percent working interest owner of the BP-operated Liberty field, in federal waters of the Beaufort Sea. Hilcorp has since become the operator at Liberty.

Even though its North Slope operations are only a few months old, Hilcorp already claims to have flattened production at fields that had previously reported a 15 percent decline rate. And the company has filed a new plan for the stalled Liberty development.

Hilcorp spent $374 million in Alaska in 2014, of which 90 percent went toward Cook Inlet activities. The company has budgeted $340 million for 2015, which, given the level of activity Hilcorp has underway, reflects a concerted effort to cut operating costs.

Over its first four years in Alaska, Hilcorp claims to have made its Cook Inlet operating costs competitive with its Lower 48 operating costs. Now, the company is working to pull off the same feat on the North Slope, which is a harsher and more remote environment.

Founded in 1989 on a principle of "acquire and exploit," Hilcorp doubled between 2006 and 2010 and its arrival in Cook Inlet was a step toward doubling again by this year.

The Ivan River, Stump Lake, Lewis River and Pretty Creek units

Since arriving in Alaska in 2011, Hilcorp has devoted far fewer resources to its assets at the northern end of the west side of Cook Inlet than it has to other regions in its portfolio.

The company operates four units in a small area along the coastline and inland south of the mouth of the Susitna River: Ivan

River, Stump Lake, Lewis River and Pretty Creek.

Hilcorp might begin investing more in the region, soon. This year, Hilcorp will continue a "comprehensive field study" at Ivan River and conclude similar studies of Lewis River and Pretty Creek. Whether those studies will lead to development remains to be seen.

The Ivan River unit

The Ivan River unit hosts both production and storage.

Ivan River operations include the Sterling-Beluga participating area and the Tyonek participating area. In the Sterling-Beluga, Hilcorp produced 566 million cubic feet in 2014 at an average rate of 1.55 million cubic feet per day. In the Tyonek, Hilcorp produced 441 million cubic feet at an average rate of 1.2 million cubic feet per day.

Hilcorp didn't drill at the unit in 2014 but added perforations to the IRU 44-01 and IRU 41-01 wells in May and June 2014, respectively. Both had "little effect" on production.

This year, Hilcorp is considering a grassroots well or a sidetrack to further develop the Sterling and Beluga reservoirs and a workover of the Sterling-Beluga at and IRU 41-01.

Through July 2015, the unit had produced more than 85.3 billion cubic feet.

Ivan River also includes a legacy storage facility on ADL 391556. The state agreed to suspend the storage operations in 2012, after Hilcorp identified damage at the IRU 44-36 injection well. Hilcorp said it "recognizes the importance of gas storage facilities in Cook Inlet" and is continuing to evaluate options for either converting or reactivating the well.

The Stump Lake unit

Stump Lake gas production was suspended in 1978, shortly after the unit was formed, and restarted in 1990. After a brief increase, production fell drastically until 2000, when the operations were once again suspended. Chevron returned Stump Lake to production in 2009 by sidetracking the original discovery well. Hilcorp added perforations to the SLU 41-33RD well but suspended production again in 2012 because of a build-up of solids.

In its recent plan of development, Hilcorp said there are currently few opportunities to revive existing wells and no justification for drilling additional wells, which is why the company has asked to keep operations suspended for another year, through May 2016.

Through July 2015, the unit had produced more than 6.6 billion cubic feet.

The Lewis River unit

Other than basic operations to maintain existing production, Hilcorp conducted no activities at Lewis River in 2014 and planned no activities for 2015. The unit produced some 428 million cubic feet throughout 2014, all from the LCU C-01RD well. Daily production declined slightly in 2015 from some 1.17 million cubic feet per day in 2014.

Through July 2015, the unit had produced more than 15 billion cubic feet.

The Pretty Creek unit

The Pretty Creek unit hosts both gas production and storage. Other than basic operations, Hilcorp conducted no activities at Pretty Creek in 2014 and planned none for 2015.

The unit produced 21 million cubic feet in 2014, all from PCU No. 2. Hilcorp injected 228 million cubic feet into PCU No. 4 in 2014, withdrawing 163 million during the year.

Through July 2015, the unit had produced more than 9.5 billion cubic feet.

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KITCHEN LIGHTS *continued from page 65*

ing the pipeline and constructing the onshore production facilities. The company had also secured an important administrative distinction when the Regulatory Commission of Alaska approved a connection of between the facility and the nearby Kenai Beluga Pipeline.

As The Producers was going to press, Furie was completing final activities, including connecting the subsea pipeline to the platform and pressure testing the pipeline, installing a workover rig on the platform and tying the KLU No. 3 well to the pipeline. The company expected production to begin in November 2015, in time to meet the commitments of the first supply contracts, which start in January 2016. In September 2015, Furie announced another supply contract, this one with Homer Electric Association Inc. The contract begins April 2016 and runs through the end of 2018, with options to extend the term through the end of 2020. The agreement calls for Homer Electric to buy between 4 billion and 6.2 billion cubic feet of natural gas annually starting March 31.

What comes next?

With the initial development nearing completion, Furie is giving thought to the future.

As described in public documents, the second phase of development involves "continued operations and maintenance of these facilities" through "initial and intermittent production well drilling" with temporary rigs. Previously, the company had suggested it might develop the current reservoir with "up to six wells," including KLU No. 3. The company has also said it might install additional platforms, depending on its needs.

In a March 2015 plan of exploration, Furie told the state it would complete KLU No. 3 as a development well and would drill two more development wells into the Corsair block by the end of the current drilling season but would postpone completion activities on those wells until 2016. As of late August 2015, the company had yet to receive Alaska Oil and Gas Conservation Commission permits for new wells at Kitchen Lights.

Furie also told the state that it would continue its exploration program. If the company aims to fulfill its initial commitments, the Kitchen Lights Unit No. 6 well would be in the southwest block, which is the only exploration block at the unit yet to be explored. The company also said it might sanction a second development instead of exploring. While the company has yet to announce the results from KLU No. 4, KLU No. 5 was a dry hole. ●

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HILCORP *continued from page 67*

The Granite Point unit

When Hilcorp acquired its initial Cook Inlet portfolio, the neighboring Granite Point field and South Granite Point unit were independent administrative entities. In early 2015, the Alaska Department of Natural Resources agreed to expand the South Granite Point unit to include the Granite Point field. The larger entity is now called the Granite Point unit.

Mobil Oil Corp. discovered the offshore Granite Point oil field in 1965 with the Granite Point No. 1 well, drilled into the Tyonek and Hemlock formations. The following year, the company installed three platforms — from south to north Granite Point, Anna and Bruce. Sustained production began in 1967 and waterflood operations began in 1971.

All three platforms primarily produce from the Middle Kenai "C" sands of the Tyonek formation, with the Hemlock formation currently producing from one well on the Granite Point platform. According to the state, some 112 wells have been drilled in the field.

Through July 2015, the unit had produced 151 million barrels of oil and more than 135 billion cubic feet of gas, according to the Alaska Oil and Gas Conservation Commission.

Since acquiring the fields, Hilcorp has been working over wells using the three offshore platforms: Anna and Bruce at Granite Point and Granite Point at South Granite Point.

The company completed projects at all three platforms in 2014.

At Anna, Hilcorp used Rig 428 to complete the AN-17A uphole sidetrack of a well it had drilled in November 2013. The platform started the year at some 1,221 barrels of oil equivalent per day and ended the year at some 1,195 boepd.

At Bruce, Hilcorp used the Moncla rig 301 to fracture stimulate BR-86-08 and return the well to production. The well had been shut-in since 2010 due to parted tubing. The platform started the year at some 414 boepd and ended the year at some 476 boepd. At Granite Point, the company used the Moncla rig 301 to work over GP-54 and return it to project. The well had been shut-in since 2005, due to parted tubing. The platform started the year at some 1,361 boepd and ended the year at some 1,518 boepd.

This year, Hilcorp planned a much busier workover regime at its expanded unit.

At Anna, the company plans to work over four wells using Moncla 301. The plan calls for recompleting AN-17A to produce from the Tyonek C sands, adding Tyonek C perforations to AN-24RD and AN-11RD and replacing a jet pump cavity in AN-51.

At Bruce, the company plans to use Moncla rig 404 to replace the completion of BR-20RD-42 and work on a lower jet pump in the bottom-hole assembly of BR-42-42.

At Granite Point, the company plans to use Moncla 301 to replace a failed electric submersible pump in GP-54, add a Tyonek C perforation in GP-11-13RD that would comingle with an existing perforation into the Hemlock sands, add a Tyonek C perforation in GP-51 and install an ESP and install an ESP completion in GP-42-23D.

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GRANITE POINT UNIT *continued from page 68*

The Trading Bay, North Trading Bay and McArthur River fields

At the southern end of the west side of Cook Inlet, Hilcorp operates three offshore fields: the Trading Bay unit and the nearby McArthur River field and the North Trading Bay unit. Hilcorp currently manages Trading Bay and McArthur River through a single plan of development and appears to desire even greater unity among the three offshore fields.

The Trading Bay unit and McArthur River field are home to the Grayling, Dolly Varden and King Salmon platforms — all named for types of fish common to Alaska waters. In 2014, Hilcorp commissioned the built-for-purpose HAK No. 1 rig for these platforms.

Union Oil Company of California discovered the three oil-bearing reservoirs at Trading Bay in 1965 and brought them online in 1967. The company discovered the Grayling gas sands at the unit in 1968. Today, the unit continues to produce both oil and natural gas.

At Trading Bay, Hilcorp started 2014 producing 342 barrels of oil equivalent per day and finished the year at 192 boepd. The reduction appears to have been largely the result of declining natural gas production because the unit was producing 156 barrels of oil per day at the start of the year 149 bopd by the end.

The Trading Bay unit includes the Undefined Oil Pool, the Tyonek Oil Pool and the Hemlock Oil Pool. Last year, Hilcorp drilled only one new well at the unit, the A-31 production well into the Hemlock. The company worked over seven wells in 2014.

The current plan of development calls for an eight well workover program this year.

Through July 2015, the unit had produced more than 105.7 million barrels of oil and 83 billion cubic feet of gas, according to the Alaska Oil and Gas Conservation Commission.

At the McArthur River field, Hilcorp started 2014 producing 4,372 boepd and finished the year at 5,500 boepd. In the Grayling Gas Sands, the company started the year producing 5,842 boepd and finished the year at 4,556 boepd.

In 2014, the company drilled one well at the McArthur River field, the Steelhead M-34 producer into the Hemlock. The company also performed 19 workover projects. This year, the company plans to drill one well and work over seven existing wells.

Through July 2015, the McArthur River field had produced more than 638.6 million barrels of oil and more than 1.3 trillion cubic feet of gas.

The North Trading Bay unit has the Spark and Spurr platforms. Chevron discovered the accumulation in the Hemlock and "G" formation participating area in 1965 with the Trading Bay No. 1A well and brought the unit online in 1968. The platforms have been light-housed since in 1992, aside from an attempt at gas production from Spark in 2007.

Since acquiring the assets, Hilcorp has been conducting reservoir engineering and geological studies to identify future opportunities. The work is scheduled through 2017.

Marathon had been moving toward decommissioning and removing the platforms, and had been submitting abandonment plans to state officials since 2009. But Hilcorp has said it believes "additional evaluation and analysis may yield development and production opportunities which Hilcorp finds preferable to abandonment and believes there is value in maintaining the platforms to support future exploration and development."

Among the potential opportunities is the possibility of using the Spurr platform to further develop the Kokanee fault block located outside the North Trading Bay unit boundaries.

In October 2014, Hilcorp drilled the A-31 exploration well from its Monopod platform at the neighboring Trading Bay field. The well encountered "productive hydrocarbons in the Hemlock and Tyonek E zone formations but did not find hydrocarbons in the Tyonek C or D zones," according to the company, which said it "is now working to reevaluate potential in the Kokanee fault block that would be used to justify platform reactivation."

The Middle Ground Shoal fields

In the center of the Cook Inlet, Hilcorp operates three neighboring and related offshore fields: North Middle Ground Shoal and its Baker platform, South Middle Ground Shoal and its Dillon platform and Middle Ground Shoal and its "A" and "C" platforms.

Through July 2015, the fields had produced more than 202 million barrels of oil and 94.6 billion cubic feet of gas, according to the Alaska Oil and Gas Conservation Commission.

Middle Ground Shoal

Shell Oil discovered Middle Ground Shoal in 1963 with MGS State No. 1, the first offshore oil completion in Alaska, according to the American Association of Petroleum Geologists. By the time XTO-predecessor Cross Timbers Oil Co. purchased the field from Shell in 1998, Middle Ground Shoal was producing 3,600 barrels per day and falling. By 2006, XTO had drilled 12 penetrations throughout the field, which doubled oil reserves to 24 million barrels and brought production to the range of 3,000 to 4,500 bpd.

That pace slowed as XTO turned its attention to more profitable assets. Despite ongoing maintenance, and various proposals over the years for additional development opportunities including sidetracks and wells into other formations, XTO hasn't drilled at the field since 2005, according to Alaska Oil and Gas Conservation Commission records.

Still, Middle Ground Shoal remains important to the regional economy. The field accounts for approximately one-eighth of total Cook Inlet oil production, which made XTO among the largest taxpayers in the Kenai Peninsula Borough for many years.

Even so, Middle Ground Shoal was mostly irrelevant to Exxon when, in late 2009, it purchased XTO in an all-stock deal worth $31 billion. Instead, Exxon wanted XTO's sizable North American natural gas holdings as an entree to the unconventional boom then underway. XTO sold Middle Ground Shoal to Hilcorp Alaska LLC in early 2015.

North Middle Ground Shoal

The state approved a plan in 2012 for abandoning the lighthoused Baker platform, but Hilcorp amended the plan later in the year. The company had decided to reactivate the platform for gas exploration. A workover program in 2013 returned the existing BA-14 well to production. Now, the well provides fuel gas to the Middle Ground Shoal field.

Although Hilcorp neither drilled nor worked over any wells at North Middle Ground Shoal in 2014, and is planning neither for 2015, the company completed a reservoir study last year to determine the future of oil production at the field. The company is in the early stages of planning a seven-well workover program that would finish by the end of 2016.

South Middle Ground Shoal

Previous operator Unocal decommissioned the Dillon platform at the South Middle Ground Shoal unit in 2003. Hilcorp has been undertaking a multiyear study to evaluate the possibility of reactivating the platform in mid-2018, pushed back from a prior deadline of mid-2016. The delay would allow Hilcorp to complete its activities at North Middle Ground Shoal. The study includes remapping relevant horizons, compiling well histories, building reservoir simulation models and potentially shooting a 3-D seismic survey. Hilcorp performed no drilling or well work in 2014 and planned none for 2015.

Swanson River unit

Richfield Oil Corp. discovered the Swanson River oil field in April 1957. When oil production began from the Hemlock formation the following year, it helped bolster the case for statehood by giving Alaska a realistic platform on which to build its economy.

Oil production peaked at 38,323 barrels per day in November 1967 but the field was only producing some 300 bpd by the time Hilcorp took over as operator.

The U.S. Bureau of Land Management manages the unit.

Swanson River became a model for how Hilcorp approached its Cook Inlet portfolio: a drilling campaign combined with a thorough effort to sidetrack or repair existing wells.

By the end of 2012, Swanson River production hit 2,200 bpd. The field produced an average of 2,165 bpd in July, down 11.6 percent from a June average of 2,449 bpd.

Through July 2015, Swanson River had produced 232.6 million barrels of oil and 2.9 trillion cubic feet of gas, according to the Alaska Oil and Gas Conservation Commission.

At an informal meeting of the Alaska House Resources Committee in February 2013, Hilcorp Energy President Greg Lalicker outlined plans to drill seven more wells and perform 15 workovers, with production expected to jump another 2,000 to 3,000 bpd.

Between January 2012 and September 2013, Hilcorp permitted at least 10 wells at the unit and drilled at least eight, completing the latest in September 2013, according to the AOGCC. By late

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2013, Swanson River oil production had risen to some 2,500 bpd.

A survey Hilcorp provided to federal officials for the 2013 and 2014 drilling season, and updated since, proposed activities at 10 idle wells in 2015 and 14 idle wells in 2016.

Through late September, Hilcorp had completed two new oil wells at the unit this year: the Soldotna Creek Unit 41B-04 and the Soldotna Creek unit 21C-04 (from late 2014).

Work to date at Swanson River has focused on increasing oil production. But BLM has recently posted two notices of staking by Hilcorp for proposed gas production wells at the unit — SRU 41B-33 and SRU 212B-15. Staking notices show where a company is interesting in drilling. Hilcorp must get additional permits before it can drill the wells.

The company received Alaska Oil and Gas Conservation Commission permits for two proposed natural gas wells in 2015: Swanson River Unit No. 213-15 and No. 213B-15.

The Beaver Creek unit

Marathon discovered natural gas producing intervals in the Beluga, Sterling and Tyonek formations at the Beaver Creek field in 1967 and an oil pool in 1972. Gas production peaked in 1986 at 17.7 billion cubic feet per year and oil production peaked in 1973 at 416,000 barrels per year. The U.S. Bureau of Land Management manages the unit.

In its 2014 plan for development, Hilcorp said it planned to drill eight wells or sidetracks and perform six well workovers at the unit within the next few years. In its current plan of development, ending March 2016, the company said it drilled seven penetrations — three wells and four sidetracks — in 2014 and conducted maintenance on eight wells.

The wells were drilled at the end of the year and came online in December: BCU 23 into the Beluga, BCU 24 into the Beluga and Tyonek and BCU 25 into the Sterling B4 interval.

The sidetracks were drilled earlier in the year. The BCU 1B sidetrack into the Beluga came online in April 2014. The BCU 14A sidetrack into the Beluga and Sterling came online in May 2014. The BCU 7A sidetrack into the Beluga came online in August 2014. The BCU 12A sidetrack into the Beluga and Sterling came online in September 2014.

To accommodate this renewed focus, the Alaska Oil and Gas Conservation Commission approved a vertical expansion of the official Beluga pool dimensions in 2014 to include all potentially gas-bearing sands in the pool and an easing of restrictions on well spacing, which Hilcorp said would allow development of isolated areas within the reservoir that are currently being bypassed.

This year, Hilcorp planned no drilling activity at Beaver Creek but described a six-well workover program in its development plan. The program includes work on BCU 25, BCU 12A, BCU 10 and BCU 24 to improve gas production and work on BCU 2 and BCU 3RD to improve well disposal capabilities. The company is also planning a major campaign to upgrade facilities at the unit, similar to a program conducted last year.

Through July 2015, the Beaver Creek unit had produced nearly 6.3 million barrels of oil and nearly 225 billion cubic feet of gas, according to the AOGCC.

The Sterling unit

Union Oil Company of California discovered the first reservoir at the Sterling unit in 1961 with the Sterling Unit No. 32-09 well and brought the unit into production in 1962 from the "A" Zone participating area. The company discovered three more reservoirs in 1998 and 1999: the Upper Beluga, Lower Beluga and Tyonek participating areas.

Over the decades, production has been slow and sporadic. At times, individual intervals, entire reservoirs and even the unit as a whole has been shut-in for stretches. The unit produced approximately 139 million cubic feet of natural gas in 2014 before the SU 41-15RD and SU 32-09 wells went offline and stopped production from the entire unit, according to Hilcorp. In October 2014, the company asked the U.S. Bureau of Land Management for permission to suspend production from the unit for the time being.

At a January 2015 technical meeting with the federal agency, Hilcorp detailed aspects of "a field study to determine the extent and feasibility of extending field life." While the company has yet to plan any wells, it might conduct a workover campaign to restore production. In March, the company began permitting a workover of the existing and currently shut-in SU 41-15 RD well to add perforations into the Lower Beluga formation.

This year, the company intends to "evaluate and execute" workover projects as they arise and said it would conduct repairs and upgrades including potential pad and production facility expansions, upgrades to piping and electrical systems and increased compression.

Through July 2015, the unit had produced nearly 14.5 billion cubic feet.

The Kenai unit

The Kenai unit was the first major natural gas discovery in the Cook Inlet basin.

Union Oil Company of California and Ohio Oil Co. discovered the Kenai natural gas field in 1959, a few years after a major oil discovery at the Swanson River field to the northeast. Those companies eventually became Chevron and Marathon, respectively.

They brought the field online in 1961 with a pipeline into Anchorage and later delivered surplus volumes to the Swanson River unit for enhanced oil recovery, to the Kenai liquefied natural gas terminal for export and to the Agrium fertilizer plant in Nikiski. Gas production peaked in the mid-1980s and declined through the late 1990s, when renewed investments led to a bump. Production has been falling somewhat steadily since 2003.

Through September, Hilcorp had drilled two new wells at the unit in 2015: the Kenai Beluga Unit 31-18 and the Kenai Beluga Unit 22-06Y. In 2014, the company drilled as many as five wells at the unit: Kenai Beluga Unit 42-06Y, Kenai Beluga Unit 11-08Z, Kenai Beluga Unit 23-05, Kenai Beluga Unit 43-07Y and Kenai Deep Unit 10.

Through July 2015, the unit had produced more than 2.4 trillion cubic feet.

The Kenai unit is a self-contained petroleum system and one nearly depleted pool is currently being used for gas storage operations. In 2014, Hilcorp produced 1.65 billion cubic feet of natural gas at an average daily rate of 4.5 million cubic feet per day from the storage operation. The company injected 6.33 billion cubic feet

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KENAI UNIT *continued from page 73*

of gas at an average rate of 17.3 million cubic feet per day through its storage operations. The company drilled no wells, performed no well work and conducted no major facility improvements at the storage operation in 2014 and planned none of those activities for 2015, according to the most recent plan of development for the storage operation, submitted earlier this year.

The Cannery Loop field

Union Oil Company of California discovered four reservoirs at the Cannery Loop field in 1978 and 1979 with the Cannery Loop Unit No. 1 well. Although originally a federal unit, the U.S. Bureau of Land Management gave the unit to state oversight in 2010.

Initially a producing natural gas field, Cannery Loop currently plays a more important regional function as the site of the Cook Inlet Natural Gas Storage Alaska Inc. facility, also called CINGSA. The storage operation uses the depleted Sterling C reservoir, although recently discovered native gas has created the possibility of future production.

Hilcorp still operates Cannery Loop production from three other reservoirs: the Beluga Gas pool, the Upper Tyonek Gas pool and the Tyonek D Gas pool. After taking over operatorship in February 2013, Hilcorp amended an existing plan of development to accommodate an exploration well into the Hemlock and West Foreland formations.

Hilcorp did not drill or work over any wells at the Beluga Gas pool in 2014 but intends to drill the CLU No. 14 well into the pool this year. The pool started 2014 at 1,473 barrels of oil equivalent per day and ended the year at 1,024 boepd.

Hilcorp did not drill any wells at the Upper Tyonek Gas Pool in 2014 but completed the CLU No. 13 well in early 2015. Hilcorp also performed some maintenance activity on CLU 01RD, which "seemed to increase production slightly," according to the company.

Hilcorp did not drill or work over any wells at the Tyonek D pool in 2014 but plans to drill the CLU 15 well into the pool this year. CLU 13 would also target those sands.

In 2014, Hilcorp installed a small compressor at the CLU No. 3 pad and intends to use the equipment at CLU No. 11 in the future. The company is considering a compression installation at the CLU No. 1 pad this year. The company also conducted an unsuccessful repair job on CLU No. 7 and intends to return to the well this year to fix the problem.

Through July 2015, the unit had produced 192.9 billion cubic feet.

The Birch Hill, West Fork and Wolf Lake fields

Through its two Cook Inlet acquisitions, Hilcorp assumed responsibility for several once-producing oil or natural gas fields that are currently shut-in for various reasons.

The company operates three such fields in the northern Kenai Peninsula.

Birch Hill

ARCO Alaska Inc. discovered the Birch Hill field in the northern end of the Kenai Peninsula in 1965 and produced some 65 million cubic feet that year before suspending production. Although the field has since been shut-in and Hilcorp conducted no activities in 2014, the company told federal officials it plans to revive production in the near future.

Throughout 2012 and 2013, the company conducted and revised planning and engineering design for a road, gathering line and facilities and cleared vegetation from the right of way. In late April 2014, representatives from Hilcorp, the U.S. Bureau of Land Management and the U.S. Fish and Wildlife Service visited the Birch Hill pad, which can currently only be accessed by foot along the proposed road corridor.

Following all those activities, Hilcorp is currently planning to build a snow road, move a workover rig and testing equipment to the pad, remove the plug and test the well this coming winter, if market and weather conditions accommodate. If the test proves the field is non-commercial, the company would re-plug and abandon the well. If the test is successful, Hilcorp would build surface facilities and install a natural gas gathering line.

West Fork and Wolf Lake

The West Fork field dates to exploration from 1960, but has produced sporadically through the years. Through July 2015, the field had produced nearly 6 billion cubic feet.

The nearby Wolf Lake field dates to exploration from the late 1990s, but was always one of the smaller fields in Cook Inlet and stopped producing around 2005 after declining steeply. Through July 2015, the field had produced more than 822 million cubic feet.

The Kasilof unit

Union Oil Co. drilled three dry holes at the Kasilof field in the late 1960s and other companies including Mesa Petroleum and Standard Oil Company of California later discovered gas at the field. Marathon Oil Co. brought the Kasilof unit into production in November 2006, using a 17,000-foot extended reach dual-lateral well drilled from an onshore pad. After initial drilling proved the producing area to be smaller than expected, Marathon requested a major contraction at the unit, to 329 acres down from 13,289 acres.

Of the three wells in the Kasilof participating area — Kasilof No. 1, Kasilof South No. 1 and KAS-1 — only the seasonally produced KAS-1 has ever been reliably productive.

Hilcorp did not drill any wells or perform any major well work at Kasilof in 2014. The unit started the year at some 2 million cubic feet per day but Hilcorp suspended operations in April 2014 and moved some of the production equipment to other fields.

"The existing intermittent producing well will remain shut in until a smaller and more economic production facility can be installed," the company said in its current plan of development, filed with state officials in early March 2015. Hilcorp has asked for permission to keep operations suspended through at least May 2016. "At this point in the field's development, no new drilling programs are justified, and current opportunities to enhance production from existing well bores are limited," the company wrote in its plan.

In 2014, Hilcorp told the state that it might use the Kasilof facilities to assist another asset, probably the nearby Ninilchik unit, where Hilcorp has been rapidly expanding exploration and development activities. "Existing facilities may be downsized to accommodate the reduced production capacity of the (Kasilof participating area) while benefitting the production of Hilcorp's other assets that are currently not producing," the company wrote.

But no such language appeared in the 2015 plan of development.

Through July 2015, Kasilof had produced 4.3 billion cubic feet.

The Ninilchik unit

Although Ninilchik is a producing unit, many of Hilcorp's current projects are exploratory in nature. Since acquiring the unit, Hilcorp has built several drilling pads to target potential oil and natural gas accumulations outside of existing participating areas.

As such, sections of the unit are regularly moving from exploration into development.

The Ninilchik unit follows the coastline in the area south of Kasilof in the southern Kenai Peninsula. Chevron discovered a gas field in the Tyonek formation in the area in June 1961. Marathon discovered two other nearby fields in 2001 and 2002 and subsequently pursued a development program. The state formed the Ninilchik unit in 2001 and expanded it to include the former Falls Creek unit in 2003. Also in 2003, the state formed three participating areas: Falls Creek, Grassim Oskolkoff and Susan Dionne, which was expanded in 2007. Hilcorp recently has completed an eighth drilling pad and was working on a ninth as The Producers went to press.

Although Hilcorp appears to be shifting its focus at Ninilchik toward development activities, the company proposed three wells in its plan of development for 2015.

The first is the 12,000-foot Blossom No. 1 exploration well to target the Beluga and Tyonek formations from the Blossom pad. The second is the 12,000-foot GO No. 8 exploration well targeting the Beluga and Tyonek north of the Grassim Oskolkoff pad. The third is the 9,000-foot Kalotsa No. 1 development well at the new Kalotsa pad.

The AOGCC issued drilling permits for Blossom No. 1 in late March 2015 and GO No. 8 in June 2015 and had yet to issue a drilling permit for Kalotsa No. 1 by late September.

This year, Hilcorp has been working on the Blossom and the Kalotsa pads — the eighth and ninth at the unit. Blossom will connect to the existing Grassim Oskolkoff pad to the south. Kalotsa, in the southern end of the unit, between the existing Susan Dionne and Paxton pads, will support a two-well program into the Tyonek and Beluga formations.

The 2015 program also includes maintenance work on nine existing wells. Those activities include plans to return shut-in wells to produce, improve performance from old wells by adding perforations and conducting maintenance work on some newer wells.

Through July 2015, Ninilchik had produced 171.6 billion cubic feet.

The Deep Creek unit

Following up on a 1958 exploration program by Standard Oil Company of California, Union Oil Company of California brought the Deep Creek unit online in 2004 at 3 million to 4 million cubic feet per day and drilled some 13 wells between 2003 and 2009.

Despite this initial enthusiasm, investment soon flagged at the onshore unit in the southern Kenai Peninsula. In an eighth plan of development, from December 2010, Unocal offered no plans for further exploration but said it wanted to farm out exploration acreage in the south of the unit. Believing that the unit contained ad-

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DEEP CREEK UNIT *continued from page 75*

ditional accumulations, Alaska Division of Oil and Gas Director Bill Barron required the next plan of development for the unit to include plans for exploring acreage outside the Happy Valley participating area. By the time Hilcorp acquired the unit, the state and Cook Inlet Region Inc., also a subsurface owner in Deep Creek, were on the verge of contracting the unit. Instead, they extended the eighth plan of development to give Hilcorp more time to determine its plans for the unit. The extension gave the company until February 2013, or six months after closing, whichever came first, to file a ninth plan of development with exploration plans.

To start, Hilcorp drilled three development wells at the unit: The 2,005-foot Happy Valley B-14 tested the Sterling formation shallower than the existing participating area; the 3,069-foot Happy Valley B-15 tested the Upper Beluga formation, also shallower than the existing participating area; and the 4,857-foot Happy Valley B-16 well targeted the Beluga formation, although "rig limitations" prevented it from reaching its target depth. In early 2013, Hilcorp acquired some 50 square miles of 3-D seismic over the unit.

The program discovered commercial quantities of gas in the Sterling and Beluga formations, shallower than the producing Beluga/Tyonek pool. Speaking in June 2013, Senior Vice President John Barnes said the field was "making more now than it was shortly after Unocal discovered and developed it" and estimated that the resource at Happy Valley is "probably three to four times larger than the current participating area."

With the successful program, Hilcorp said it would expand its exploration activities for two years and asked the state to defer contraction of the unit through the end of 2015.

The 2014 plan called for completing the B-16 well, potentially using a sidetrack, and drilling two exploration wells from a newly constructed C pad. The 6,000-foot Happy Valley C-17 well and the 5,000-foot Happy Valley C-18 well would both target the Sterling and Beluga formations outside the Happy Valley participating area. If successful, the exploration program would likely justify a new participating area, Hilcorp has said.

Ultimately, Hilcorp drilled none of those wells in 2014. However, the company processed preliminary data from the seismic survey between March and October 2013 and conducted "pre stack depth mitigation" processing in 2014. As of March 2015, "interpretation of the 3-D data is in progress and will be used to establish the Deep Creek unit's exploratory and development drilling program throughout 2016," according to the most recent plan of development. The plan also proposes drilling a Middle Happy Valley No. 1 well, which would require the construction of a new drilling pad at the unit. The company began permitting the Middle Happy Valley pad toward the end of this summer.

In July 2014, Hilcorp proposed construction of a Happy Valley C pad and an accompanying four-well appraisal program to prove up and possibly develop a shallow natural gas accumulation. If successful, Hilcorp said it would initially develop the pad using existing facilities at B pad and potential construct new facilities at the C pad. The company began permitting some of those projects in mid-2014 and the first half of 2015.

Through July 2015, Deep Creek had produced 29.2 billion cubic feet.

The Nikolaevsk unit

Union Oil Company of California discovered gas from a well at the Red pad at the Nikolaevsk unit in 2004 but never developed the field because of its distance from the end of the regional natural gas transmission grid at Happy Valley, to the north.

In early 2009, in a bid to extend the unit terms, Unocal proposed two wells at Nikolaevsk, one at the existing Red prospect and another at the associated Blue prospect. The state approved the plan, which extended the unit terms by two years, through March 2011.

Ultimately, Unocal relinquished the Blue prospect rather than drill and was unable to farm-out the Red prospect, blaming market conditions and infrastructure limitations.

In early 2011, as development of the nearby North Fork unit cut the distance to market, Unocal reached an agreement with the Department of Natural Resources to study a pipeline to North Fork rather than its earlier plan to connect to the grid at Happy Valley.

Instead, production went the opposite direction.

In September 2012, Hilcorp and the Enstar affiliate Alaska Pipeline Co. announced an $8.4 million pipeline running 10 miles from the field to the Anchor Point Pipeline, an extension of the Kenai Kachemak Pipeline that connects to the North Fork Pipeline.

Hilcorp brought the Red No. 1 well online in December 2012 at 5 million cubic feet per day.

Since then, operations have proven tricky.

Red No. 1 was producing 2.5 million cubic feet per day at the start of 2013. Hilcorp suspended production from April to October 2013 because of seasonal demand restrictions. By the end of the year, production had fallen to 796,000 cubic feet per day.

Even though Hilcorp installed a compressor at the field in the first quarter of 2014 to increase production from the Red No. 1 well, production rates declined significantly over the course of the year — from 1.1 million cubic feet per day at the start of the year to 300,000 cubic feet per day at the end of the year. Then the company shut in the field between November 2014 and February 2015 “due to the lack of a market for the gas.”

Hilcorp performed no drilling or major well work activity at the unit last year and has planned no drilling or major well work activity for this year, according to the company.

Through July 2015, Nikolaevsk had produced 690 million cubic feet of gas.

The Milne Point unit

Standard Oil Company of California discovered four Milne Point horizons in the area northwest of the Prudhoe Bay unit in 1969. The unit primarily produces from the Kuparuk oil pool, as well as from the heavier Sag River and Schrader Bluff pools.

An even heavier Ugnu pool has been under evaluation for many years.

Conoco Inc. delineated the field in 1980 and brought it online in November 1985 but suspended operations from January 1987 until April 1989 because of low oil prices.

By the time BP acquired the unit, in 1994, oil production had fallen to 17,000 barrels per day from a peak of 20,000 bpd several years earlier, according to the Alaska Oil and Gas Conservation Commission. BP built the F pad in the northern end of the unit and the K pad in the southeastern corner of the unit, which pushed production to 52,900 bpd by July 1998. But oil production has since fallen back below 20,000 bpd, according to BP.

Through July 2015, Milne Point had produced nearly 326 million barrels of oil.

In its first year as operator, Hilcorp began a major revitalization of Milne Point. In the first three months after formally taking over the unit in December 2014, Hilcorp brought five wells back into operation but nevertheless saw a slight decline in total unit production, which the company blamed on a large backlog of workovers to complete.

In the first half of 2015, the state agreed to extend an existing plan of development submitted previously BP to shift the annual cycle so that it begins in the spring. The current plan of development now runs from January 2015 through the end of July 2016.

With the extension, Hilcorp also proposed some additional activities.

The current plan now calls for drilling as many as six wells across the three main reservoirs and conducting maintenance on as many as 39 existing wells at the unit. The proposed workover program includes wells at B, C, D, E, F, J, K, L and S pads. While some of those efforts were carried over from BP, Hilcorp also announced plans to build a fairly sizable new facility designed to improve the environmental impact of operations.

As of Jan. 31, the Milne Point unit was producing 19,400 barrels of oil per day from the Kuparuk, Schrader Bluff and Sag River formations. The unit had 327 wells, of which only 187 — 108 producers and 79 injectors — were active, according to Hilcorp.

The Schrader Bluff formation

Conoco spent $130 million building four pads and drilling 22 wells at Schrader Bluff and brought the formation online in March 1991 at 3,700 bpd. But oil production had fallen to 2,850 bpd by the time BP took over the unit in early 1994, according to the AOGCC.

After several years of drilling activities without a significant boost in production, BP announced a plan in 1997 to develop Schrader Bluff with seven new or expanded pads, 75 miles of new pipeline and some 300 wells. By 2001, BP decided the program was uneconomic. Instead, BP expanded conventional drilling at E pad, H pad and J pad, lifting production to 12,000 bpd by April 2002, and built S pad in the south of the unit.

While BP had previously proposed a four-well program into the Schrader Bluff in 2013, the company postponed those wells until 2016 “to allow additional planning time due to concerns over reservoir pressure in existing injector wells near the planned targets and complications in defining the completion design,” accord to the plan of development.

So far, Hilcorp appears to be focusing its energies on the Schrader Bluff formation.

Between mid-July and early September, the Alaska Oil and Gas Conservation Commission issued permits for six wells at Milne Point — three development and three service, all targeting the Schrader Bluff formation. The producers would be the Milne Pt Unit SB L-46, Milne Pt Unit SB L-47 and Milne Pt Unit SB J-27. The injectors would be the Milne Pt Unit SB L-48, Milne Pt Unit SB L-49 and Milne Pt Unit SB L-50. The company has contracted the Nordic 3 rig for grassroots wells and rigged workovers.

Through July 2015, the Schrader Bluff had produced nearly 74 million barrels.

The Kuparuk formation

The proposed drilling campaign would be the first at Milne

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Point since early 2014, when BP drilled at least 17 wells into the Kuparuk formation, according to AOGCC records.

That program, in turn, was the first development program at Milne Point in five years.

In the Kuparuk formation, Hilcorp is mostly continuing waterflood and enhanced oil recovery techniques over the short run. But the company said it is currently evaluating a 2012 seismic survey conducted over the region to "determine if economic accumulations of oil exist near the margins of the existing development patterns," which could led to infill drilling. The company expects to complete some of this evaluation this year.

Through July 2015, the Kuparuk had produced more than 249 million barrels.

The Sag River formation

Conoco tested the Sag River formation at Milne Point as early as 1980, and BP brought the field into production in 1995. Despite occasional spikes through the years, average annual production has generally been less than 700 bpd. Sag River is the deepest producing interval at Milne Point, with lighter oil than either Schrader Bluff or Ugnu.

But high gas-to-oil ratios and poor pump performance have challenged production.

Prior to the Hilcorp sale, BP had planned a 15-well program at Sag River in 2015 and 2016, according to BP Alaska President Janet Weiss. If successful, BP could potentially drill as many as 200 wells, accessing some 200 million barrels of resources with full development. Now, Hilcorp said it is continuing to study options. The company plugged the K-33 well into the Sag River back to the Kuparuk because of low Sag River production. The current set-up allows the company to switch between the formations.

Through July 2015, the Sag River had produced nearly 2.8 million barrels.

The Ugnu formation

The 20 billion barrel Ugnu formation overlying portions of the Prudhoe Bay, Kuparuk River and Milne Point unit is the most technically challenging field at Milne Point.

Starting in 2007, BP launched a pilot program at S pad to test various techniques for producing heavier oil. The first, called CHOPS, or cold heavy oil production with sand, produces oil-saturated sand and heats the mixture at the surface to separate the oil from the sand. BP also began evaluating an alternate method involving horizontal wells.

Following the launch of a $100 million testing facility, BP brought a horizontal heavy oil test well into operation in April 2011. This initial well surpassed expectations, as did the first CHOPS well completed in late 2012. But BP believes it still must demonstrate the long-term viability of the program and better manage the costs of heavy oil production before Ugnu can become a regular component of the North Slope production picture.

Prior to the sale, BP drilled four test wells, two nearly vertical and two horizontal. The initial production tests produced as much as 500 bpd, BP Exploration (Alaska) technology manager Frank Paskvan told the state Senate Resources Committee in April 2014. But a rotating metal rod used drive the underground pump rotor wore holes in the well casing, Paskvan said. "So we're doing studies now on artificial lift and hope that will improve the run life, because these workovers and tubing replacements were very expensive and made it difficult to continue the operations of the pilot," he said.

While Hilcorp now has access to the results of those wells, the company is taking it slow at Ugnu for the moment. The current plan of development calls for working over the S-39 well this year and launching a larger Ugnu drilling campaign sometime in 2016.

Grind and Inject

The amended plan of development also called for constructing a Grind and Inject Facility at the Milne Point unit to create a waste discharge system with fewer surface impacts.

The project includes a facility at Milne Point Unit B Pad, installing surface piping to connect the facility to an injection well and other associated infrastructure requirements.

Hilcorp began permitting the facility this past summer. In filings with the state, the company described a facility capable of processing some 40,000 cubic yards per year.

The company said it was also evaluating a plan to reactive a similar facility at the Northstar unit. Previous operator BP built the facility in 1998 and closed it in 2010.

The Duck Island unit

Sohio Alaska Petroleum Co. discovered the offshore Endicott oil pool in 1978.

After building two compact gravel islands connected to shore by a causeway — the first offshore islands for oil production in the Arctic — BP Exploration (Alaska) Inc. brought Endicott online in July 1986. The field was later incorporated into the Duck Island unit.

Oil production peaked at some 118,000 barrels per day in the early 1990s.

Today, the Duck Island unit includes the Endicott, Eider and Sag River North participating areas at the northern end of the unit and production from the Minke tract at ADL 34633. Through July 2015, the unit had produced more than 480.6 million barrels of oil from those areas, according to the Alaska Oil and Gas Conservation Commission.

Endicott history

The bulk of production comes from Endicott.

BP launched a five-year renewal campaign at the field in 2008. The heart of the program was infrastructure upgrades from wellheads to processing facilities, Endicott Field Manager TJ Barnes told Petroleum News in early 2009. Those efforts, in part, were meant to prepare the facility for an expected influx of oil from the proposed Liberty field.

(For a time, BP planned to use the Endicott facilities to develop the offshore Liberty field through state-of-the-art ultra-extended reaching wells. Those plans have since changed.)

The plan was to use LoSal enhanced oil recovery program first, followed by enhanced oil recovery using carbon dioxide once North Slope gas sales began. "We've rebuilt our reservoir models and have developed a comprehensive depletion plan for Endicott," Alaska Consolidated Team Resource Manager John Denis told Petroleum News in early 2009. "We're into the fourth year of a program to stabilize and improve the reliability of our facilities and wellstock, we have brought (the safety and integrity Operations Management System) to Endicott, and we have a robust program underway to renew our facilities. With the development of new

COURTESY HILCORP ALASKA LLC

Hilcorp expects Northstar oil production to be "maintained or increased" this year through a combination of maintenance activities and restructuring of existing wells.

technologies like LoSal and production from the new Liberty field, we're looking ahead to a very bright future for Endicott."

After trademarking the technology in 2005, BP tested its proprietary LoSal technique at the Endicott field between June 2008 and early 2010. The test suggested the possibility to recover as much as 20 percent of the oil remaining in an aging reservoir such as Endicott.

When the five-year renewal campaign ended and plans for developing the Liberty field stalled under technical pressures, Endicott lost its immediacy for BP. The company worked over three wells in 2013 and performed no drilling or maintenance work in 2014.

Using miscible water alternating gas flood injections, Hilcorp realized what it called "modest" production increases in its first months as operator of Duck Island. The unit produced 208,170 barrels of oil in October 2014, before Hilcorp assumed operations, according to figures from the company. This January, the unit produced 258,350 barrels, down from a high of 274,647 barrels in December 2014. The company said it "intends this same progress to continue" through the current reporting period of May 2016.

Endicott plans

In its first year as operator, Hilcorp approached Endicott from two angles.

First, the company launched a monitoring campaign to track the movement of injection fluids through the reservoir. The results of this monitoring will determine whether the company can expand its enhanced oil recovery process "to new patterns in the upper subzones" or whether an alternative enhanced oil recovery process would be viable.

Similarly, Hilcorp is also performing engineering studies to determine whether it should inject water into the gas cap at Endicott. Those studies will likely continue into 2016.

Second, the company planned to once again work over existing wells at the field for the first time since 2013. The company said it is also considering conversions, sidetracks and other maintenance activities at Endicott this year, although these activities have yet to be sanctioned and depend on economics and on the results of studies currently underway.

Hilcorp planned no workovers, sidetracks or notable maintenance at Eider, Sag Delta North or the Minke tract this year but said it would look for opportunities at all three.

The Northstar unit

Shell Western E&P Inc. discovered Northstar in 1984. The state and federal governments jointly formed the Northstar unit in 1990 and expanded it in 2001. BP Exploration (Alaska) built a five-acre gravel island and a subsea pipeline and brought the offshore oil field into production in November 2001. The Northstar participating area at the unit was contracted in 2005 and 2011 and expanded in 2014.

The federal government approved the Fido participating area in 2002 and the state and federal governments jointly approved the Hooligan participating area in early 2015.

Prior to selling the unit, BP was injecting gas into the Ivishak formation to improve reservoir pressure for enhanced oil recovery and was considering a plan to convert one or more production wells at the unit into injection wells to aid with that ongoing effort.

Hilcorp expects Northstar oil production to be "maintained or increased" this year through a combination of maintenance activities and restructuring of existing wells.

The company said it would achieve this goal "through well intervention projects, infrastructure and facility repairs, and other optimization opportunities as they arise, including the evaluation of shut-in wells for potential return to service or utility." Since taking over the unit, Hilcorp has returned the NS-33A and NS-22 wells to production.

The unit produced 11,100 barrels per day during the first quarter, according to Hilcorp.

Through July 2015, the unit had produced more than 164.8 million barrels of oil.

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NORTHSTAR UNIT *continued from page 79*

Northstar plans

This year, Hilcorp plans to recomplete the NS-18 Ivishak producer to target the Kuparuk sands, recomplete the NS-24 Ivishak producer to test the Sag reservoir and fix a surface casing leak at the NS-22 well. The company also plans to convert the NS-28 well to a gas injector targeting the Ivishak, which the company said would optimize the horsepower of existing compressors by reducing injection pressure into the field. The company will soon to start a reservoir simulation model to optimize injections.

Optimizing the injection strategy for the unit gained importance toward the end of last year when Hilcorp discontinued natural gas imports from Prudhoe Bay and began relying on gas produced at Northstar, using some 12 million cubic feet per day in 2015. BP had been investigating the possibility of converting the field to self-sufficiency for gas.

Although Hilcorp has presented no definitive plans, the company suggested it would pursue exploration that could potentially lead to new developments in the unit. That work would depend on "equipment availability, plant capacity, and commercial viability."

In 2014, BP and its minority partner Murphy Exploration (Alaska) Inc. asked state and federal regulators to expand the Northstar unit to include some 454.62 acres from two state of Alaska leases — ADL 312798 and ADL 312808 along the southern border. The addition was meant to incorporate a proposed Hooligan participating area into the unit.

BP had requested the participating area in late June 2012 and provided additional information to regulators in February and April 2013. The U.S. Bureau of Safety and Environmental Enforcement approved the participating area in February 2014. The Alaska Department of Natural Resource approved the participating area in early 2015.

When state and federal regulators approved the Northstar unit in January 1990 and the Northstar participating area in October 2001, the unit agreement included a provision requiring any acreage outside the participating area to contract after 10 years. By forming the Fido participating area around federal lease OCS-Y-0181, BP was able to reduce the extent of the contraction in the northeast of the unit. But regulators later contracted portions of ADL 312798, ADL 312808 and ADL 312809 along the southern border.

Around November 2010, BP plugged the NS-08 well above the Ivishak to produce from the shallower Kuparuk formation on a tract basis. Using that well and information from other Ivishak wells at the unit, all of which have passed through the Kuparuk, BP mapped out the Hooligan field. The proposed Hooligan participating area would cover the Kuparuk formation at Northstar. Except for the expansion acreage, the reservoir exists entirely within the existing aerial boundaries of the Northstar unit and participating area.

With approval of the Hooligan participating area, BP had said it would continue to test the Kuparuk formation at Northstar through its current development plan, into 2015. In its most recent plan of development, Hilcorp said it would continue Kuparuk sands production. ●

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Miller Energy Resources Ltd.

By ERIC LIDJI
For Petroleum News

Miller Energy Resources Ltd. is the parent company of Cook Inlet Energy LLC and Savant Alaska LLC and operates production in Cook Inlet and on the North Slope.

The company expanded its Alaska operations quickly over the past two years and was vulnerable when global oil prices declined over the second half of 2014. Now, the Tennessee-based independent is looking for a plan to get its balance sheet in order, and is considering a range of options including selling various assets in its Alaska portfolio.

In early October 2015, as the Producers was going to print, Miller filed for reorganization with the U.S. Bankruptcy Court in Alaska.

SCOTT BORUFF

The principals of Cook Inlet Energy LLC formed the company in 2009 to acquire Cook Inlet assets in the bankruptcy proceedings of Pacific Energy Resources Ltd. The company initially worked to revive existing properties including the West McArthur River unit, the West Foreland gas field, the offshore Redoubt unit and its Osprey platform, the Kustatan production facility and its minority stake in the onshore Three Mile Creek gas field.

A five-well workover campaign at West McArthur River in 2010 brought more than 1,100 barrel per day into production, according to the company. That summer, the company also returned the shut-in KF No. 1 well at the Kustatan field into production at some 70,000 cubic feet per day. By mid-2011, the company had returned the Osprey platform to commercial operation, bringing some 600 barrels of oil equivalent per day in initial production from two existing wells at the Redoubt unit. The company has continued to devote resources to increasing production at those fields in the years since.

In late 2013, Cook Inlet Energy acquired Armstrong Cook Inlet LLC for nearly $65 million and assumed control of the North Fork unit and associated infrastructure. In February 2014, the company acquired the Glacier No. 1 rig — now Rig 37 — for some $7 million. As oil prices fell, the purchase of a producing gas field seemed fortuitous.

In May 2014, Miller Energy announced that it would purchase Savant Alaska LLC for some $9 million. While the company originally expected to close the deal in August, the actual closing came in late 2014, after oil prices had fallen drastically from summer highs. The deal gave Miller majority ownership and operatorship of the Badami unit on the eastern North Slope.

Given the low oil prices and higher than average Alaska gas prices, Miller made a strategic shift to focus on natural gas and low-risk oil development in the short term. In late July 2015, the company said it had identified eight workover projects costing approximately $1.8 million that should increase production by 1.7 million cubic feet of gas and 220 barrels of oil per day and yield a return on investment in less than a year.

In August 2015, the U.S. Securities and Exchange Commission charged Miller Energy Resources Inc. and three people associated with the company with overvaluing its Alaska properties. Toward the end of the month, the company and the federal agency reached a tentative $5 million settlement to resolve the dispute over the next three years.

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The West McArthur River unit

Stewart Petroleum Co. discovered the West McArthur River field with the W. McArthur River No. 1 well in 1991 and brought the unit on the west side of Cook Inlet into production in September 1994.

Several companies operated the west side Cook Inlet unit over the following decade and a half. Forcenergy Inc. acquired the leases in 1997. Forest Oil Corp. became the operator in late 2000 after acquiring Forcenergy. In 2007, Forest sold the unit to Pacific Energy Resources Ltd., which sold the unit to Cook Inlet Energy in a 2009 bankruptcy auction.

Cook Inlet Energy spent some $7 million in 2010 working over five West McArthur River unit wells: WMRU-5 in March, WMRU-6 in April, WMRU-1A in May, WMRU-7A in June and the shut-in WMRU-2A toward the end of the year. The work brought more than 1,100 barrels of oil equivalent per day online, according to the company, and made WMRU-2A available for a future waterflood pilot program to enhance oil recovery.

The company drilled two wells at the unit in 2014. The 15,535-foot WMRU-8 had a primary target in the Hemlock and a secondary target in the pre-tertiary Jurassic oil zone, which some geologists consider to be the source rock for Hemlock and West Foreland oil reservoirs across the Cook Inlet region. The 14,470-foot WMRU-2B sidetrack came online in June 2014 at an initial rate of 630 barrels of oil equivalent per day.

At the West McArthur River unit, Cook Inlet Energy has “determined that sidetracking holds the best opportunity to restore and increase production,” according to a January 2015 plan of development. Specifically, the company told state officials it would sidetrack the shut-in WMRU No. 1A and No. 7A sidetracks and was evaluating the producing WMRU No. 8 well as a sidetrack candidate.

Future plans for West McArthur River focus on two exploration prospects, which Cook Inlet Energy calls Sword and Sabre. The company is still evaluating both projects, according to the plan of development. Information from the Sword No. 1 exploration well will inform the plan for a Sword No. 2 appraisal well, which the company has tentatively slated for April 2017. Cook

continued on next page

MILLER ENERGY *continued from page 81*

Inlet Energy is "still evaluating" plans for Sabre, although, as an extended reach exploration well, the prospect conflicts with the current strategy of "developing lower risk targets," according to the company. The company expects to delay work until after it finishes developing proven prospects and may seek out a partner.

Through July 2015, the West McArthur River unit had produced more than 14 million barrels of oil, according to the Alaska Oil and Gas Conservation Commission.

The Redoubt unit

Pan American Petroleum Corp. discovered the Redoubt Shoal oil field in 1968 with the Redoubt Shoal Unit No. 2 well. Forcenergy and Union Oil Company of California initially partnered on a plan in the late 1990s to bring the offshore field into production but the effort was delayed after Unocal backed away from the project. Forcenergy merged with Forest Oil in 2000 and the expanded company installed the Osprey platform in 2001 and brought it into operation in 2002.

The platform had been the newest in Cook Inlet until Furie Operating Alaska LLC installed the Julius R platform at its offshore Kitchen Lights unit earlier this year.

The Redoubt unit includes the Osprey platform and the Kustatan production facilities.

The unit and the platform were offline when Cook Inlet Energy acquired the prospect in 2009. The company brought the facilities back into production in mid-2011 by replacing electric submersible pumps in the RU-1 and RU-7 wells. The company later shut-in RU-1 because of an equipment problem, but the RU-7 well continued to produce regularly.

Using its newly purchased Rig 35, Cook Inlet Energy worked over RU-1 in August 2012, removing some 31,000 pounds of junk from the wellbore to bring the well back online at an initial production rate of 482 bpd. In late 2012 and early 2013, the company worked over RU-3 and RU-4A, a pair of natural gas wells needed for operational fuel. RU-3 faced some complications, but RU-4A tested at a peak rate of 1.7 million cubic feet per day, which allowed Cook Inlet Energy to suspend some $500,000 in monthly third-party fuel deliveries. By early summer, the company was selling excess gas into the market.

In June 2013, Cook Inlet Energy more than doubled its total Alaska crude production by bringing the RU-2A sidetrack online at an initial rate of 1,281 barrels per day. In August, the company brought the RU-1A sidetrack online at an initial production rate of 700 barrels per day. The company also sidetracked the RU-5 well toward the end of 2013.

Since then, Cook Inlet Energy has performed additional work on RU-7, adding perforations in the producing interval and conducting repairs to the platform and rig.

With the maintenance work underway, the company also began step-out drilling at the unit with RU-9, which the company said was "intended to capture oil reserves from a large four-way structure located approximately 2.5 miles southwest of the Osprey platform." In September, after completing the well, Miller said that a well test confirmed the presence of oil: "While flow rates have varied preliminary results are encouraging."

Through July 2015, the unit had produced nearly 3.5 million barrels of oil.

Scaled back plans

While earlier projections for Redoubt had envisioned a busy year, the decline in oil prices forced Cook Inlet Energy to scale back its ambitions. As with the West McArthur River unit, the company planned to drill as many as four sidetracks at the Redoubt unit to improve production from various fault blocks, according to the most recent plan of development.

The plan prioritized a sidetrack of RU No. 7A. The company would complete the sidetrack with hydraulic fracturing, which executives believe would double or triple recovery rates, according to recent company statements. Given the uncertainty of oil prices and the attractiveness of gas developments in the portfolio, the company has said it would wait until summer before deciding whether to sanction the sidetrack this year.

The sidetrack will likely be the only well at Redoubt this year, according to the company, and the results will determine whether and how the company proceeds in the near term.

The proposed plan of development calls for drilling as many as two other sidetracks starting in April 2017. The RU No. 3A and RU No. 3B sidetracks would target the Central fault block to produce oil in the Hemlock participating area. The company had originally planned to sidetrack the existing RU No. 3 well or RU No. 4A sidetrack (both of which have been depleted) last year but delayed those plans in favor of sidetracking RU No. 7.

The plan also proposes an RU No. 7B sidetrack for the near term. The Alaska Oil and Gas Conservation Commission issued a drilling permit for RU No. 7B in March 2015.

Cook Inlet Energy has identified two other oil-bearing fault blocks at the unit, although plans for delineating those Northern and Southern blocks are vague and dependent on economics, according to the company, which hopes to start drilling by April 2017.

Work on the Southern block depends on the results of the RU No. 9 well. The company plans to conduct rigged maintenance to change out a pump on the well in the near term.

The company recently described the November 2014 well as a disappointment, saying that it only produced about 100 barrels of oil per day before an electrical failure.

The North Fork unit

Standard Oil of California drilled the North Fork 41-35 discovery well in 1965 while looking for oil but relatively cheap natural gas prices made development uneconomic.

Renewed interest in the onshore field in the southern Kenai Peninsula began in the late 1990s but each new company that acquired the field failed to bring it into development.

In 2007, the Denver independent Armstrong Oil and Gas Inc. acquired the prospect from Gas-Pro LLC and brought on four partners, all small independents. The joint venture re-entered the original well, drilled new wells and brought the unit into production in 2011.

Through its subsidiary Cook Inlet Energy, Miller Energy Resources Ltd. acquired the North Fork unit in late 2013. The decline in global oil prices in late 2014 made the existing gas production at the North Fork unit particularly valuable to the company.

With North Fork, Miller acquired six wells and 15,465 acres, the transmission subsidiary Anchor Point Energy LLC and the existing supply contract with Enstar Natural Gas Co.

After completing the acquisition in February 2014, Cook Inlet Energy became operator of the onshore unit in the southern Kenai

Peninsula and filed an updated development plan.

Through July 2015, North Fork had production 11 billion cubic feet of natural gas.

Up for sale?

When Cook Inlet Energy acquired North Fork, the company proposed a drilling program for fiscal year 2015 that included working over the existing NFU 14-25 and NFU 32-35 wells, sidetracking the existing NFU 23-25 well and drilling the new NFU-07 and NFU 32-35 wells to increase gas production. Looking down the road, a proposed fiscal year 2016 program called for drilling three new gas wells: NFU-08, NFU-09 and NFU-10.

But the company was also thinking long term, and said that it saw an opportunity to drill as many as 24 wells at the unit. The drilling would attempt to expand gas production as well as start oil production, which had stymied previous operators, including Armstrong.

In a 50th plan of development for the field, submitted to the state in late December 2014, Cook Inlet Energy said it had spent the year analyzing existing seismic and well data and planning an appropriate drilling program. The company said it intended to drill three wells — NFU No. 24-26, NFU No. 42-35 and NFU No. 31-3 — from the existing North Fork pad using the recently purchased Glacier Rig 1, which is now known as Rig 37.

By March 2015, the company had completed the NFU No. 24-26 and NFU No. 42-35 on time and on budget and was preparing to drill three workovers planned for the unit. As of late July 2015, the NFU No. 24-26 was producing some 1.8 million cubic feet per day and NFU No. 42-35 was producing some 300,000 cubic feet per day, according to Miller.

"After conducting a detailed field study, we continue to believe North Fork holds significant recoverable gas and that we can drill additional North Fork wells even more cost and time efficiently, as well as more productively," Miller Energy CEO Carl Giesler said in a quarterly teleconference with analysts and investors at the end of July 2015.

The company also said it had identified seven projects at North Fork that would increase production by an estimated 1.5 million cubic feet per day and could start oil production.

For the current plan of development, which runs through March 2016, Miller said it intended to continue the delineation program while also analyzing results with an eye toward a potential drilling program outside the North Fork Gas Pool No. 1 participating area. Lower risk gas targets at North Fork are a major focus for Miller in 2015, given the attractiveness of gas compared to oil in the current commodity price environment.

Whether Cook Inlet Energy will have the opportunity to pursue those projects is unclear, both because of financial and regulatory uncertainty and because Miller recently listed the North Fork unit and the associated Anchor Point pipeline as potential sales options.

The Badami unit

Conoco Inc. discovered the Badami oil pool in 1990 and BP Exploration (Alaska) Inc. brought the eastern North Slope oil field into production in August 1998.

From nearly the beginning, the complex geology of the region hampered operations.

Oil production peaked a month after startup at some 7,450 barrels per day. By January 1999, it had fallen to some 3,300 bpd. BP suspended production until May 1999 to upgrade facilities. By July, the field was producing nearly 5,300 bpd. Production had fallen to some 3,000 bpd by the end of the year and 1,300 bpd by July 2003, when BP suspended operations for more than two years, until September 2005. Production was averaging 1,785 bpd by October, 1,437 bpd by December 2005 and some 876 bpd by August 2007, when BP suspended operations to allow reservoir pressure to recharge.

In mid-2008, BP took a different approach. The company gave Savant Alaska and ASRC Exploration LLC a stake in Badami in return for returning the unit to operation. With Savant taking the lead, the companies succeeded in returning the unit to sustained production, albeit at low levels. The two companies acquired the field outright in early 2012 and acquired the Badami Pipeline system through a joint venture in early 2014.

Miller Energy Resources Ltd. acquired Savant Alaska in May 2014 and closed on the purchase in December 2014, becoming operator and majority owner of the unit. As the deal was moving toward closing, global oil prices fell by more than half, which severely challenged the economics of an already complex operating environment. Savant, and then Miller, decided to defer much of the development plan outlined for 2014 and early 2015.

Through July 2015, Badami had produced some 7.2 million barrels of oil.

Future uncertain

The current plan of development at Badami calls for completing those projects, although the realities of the global oil market have created uncertainty for the unit going forward.

In its 11th plan of development, from Nov. 16, 2014, through July 15, 2015, Savant had planned to evaluate hydraulic fracture stimulations on the Bl-18A and Bl-38 wells and to use those results to design stimulations for wells to be drilled in the first half of this year.

Ultimately, the company postponed the completion activities for Bl-18A and Bl-38 because it was unable to secure the necessary equipment and barge it to the Badami unit in time to complete the activities. The company also postponed the wells planned for earlier this year because of a similar problem with securing equipment, a desire to conduct a geological review as part of the change in ownership and current oil prices.

The 12th plan of development, through July 15, 2016, calls for completing hydraulic fracturing operations on the two wells and, if prices permit, drilling the two new wells.

Over the course of 2015, Miller regularly mentioned Badami as one of the Alaska assets it would be willing to sell in order to improve its financial position as a company.

The East Mikkelsen prospect

Another outstanding factor that could complicate those plans is the fate of five leases currently under appeal. The leases are between Badami and the Point Thomson unit.

In late 2012, Savant and the Alaska Venture Capital Group LLC asked the state to add seven leases, covering some 10,121 acres, to the Badami unit. The addition would have incorporated the East Mikkelsen prospect into the unit. Instead, in March 2013, the Alaska Department of Natural Resources agreed to include only two of the seven leases.

The ruling also approved an exploration plan that required Savant to drill a directional well through the entire Canning Forma-

continued on next page

The North Slope Borough

By ERIC LIDJI
For Petroleum News

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CHARLOTTE BROWER

The city of Barrow generates power using energy from three nearby natural gas fields: South Barrow, East Barrow and Walakpa. While residents once cut wood and hauled coal, or used expensive diesel fuel like most of rural Alaska, the northernmost city in the United States has enjoyed a localized form of energy independence for several decades.

The U.S. Navy and the U.S. Geological Survey discovered all three fields as part of federal exploration of the National Petroleum Reserve-Alaska after World War II.

Today, the city of Barrow expects the fields to last for decades to come, thanks to two trends. The first is geologic. Although somewhat unconfirmed, the East Barrow field appears to be regenerating through the production of methane hydrates. The second trend is developmental. To ensure that future deliverability would meet forecasted demand, the city of Barrow launched a rejuvenation campaign in recent years. A pair of voter-approved bond sales allowed the city to launch a $92 million program in 2011. The city commissioned the Savik 1 and 2 wells at East Barrow and the Walakpa 11, 12, and 13 wells at Walakpa — the first horizontal drilling campaign ever conducted at the fields.

By improving deliverability, Barrow has been able to use natural gas for its energy needs even during cold snaps or maintenance activities, instead of relying on diesel fuel.

The South Barrow, East Barrow and Walakpa fields

The U.S. Navy discovered the South Barrow field with the 2,505-foot South Barrow No. 2 well in 1948, during its initial wave of NPR-A exploration. Production began the following year. But development drilling continued for decades, with 13 new wells drilled and one existing well deepened through 1987, according to the Alaska Oil and Gas Conservation Commission. Production peaked at some 3.5 million cubic feet per day in November 1981.

Through July 2015, South Barrow had produced some 23.7 billion cubic feet, according to the AOGCC. Originally, the field was expected to produce some 32 billion cubic feet. The field is now used primarily to meet demand during peak winter months.

The U.S. Geological Survey discovered the East Barrow field with the South Barrow No. 12 well in 1974, during the second wave of NPR-A exploration. Production began in December 1981, but drilling continued through 1990, with eight wells altogether. East Barrow production peaked at some 2.75 million cubic feet per day in early 1984 and the field had produced nearly 9 billion cubic feet through July 2015, according to the AOGCC. That figure greatly surpasses an early estimate of 6.2 billion cubic feet in place.

The city of Barrow attributes the productivity of East Barrow beyond original field estimates to methane hydrates, which are thought to exist at the field. Methane hydrates are molecules of natural gas trapped inside cages of ice. The gas can be released through pressure changes. Drops in pressure occur naturally during the aging process of a field.

Walakpa

The South Barrow and East Barrow reservoirs are in a stratigraphic setting similar to the Alpine oil field some 135 miles to the east. The third field supplying the city of Barrow, Walakpa, is in the Pebble Shale unit, a major North Slope petroleum source rock.

Today, Walakpa produces the majority of the gas delivered to Barrow.

Working under a Navy contract, Husky Oil discovered Walakpa 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.

Through July 2015, Walakpa had produced nearly 27.6 billion cubic feet of gas. ●

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BADAMI UNIT *continued from page 83*

tion and into the underlying Hue Shale to evaluate the potential of the hydrocarbon-bearing Killian interval encountered in the earlier East Mikkelsen Bay No. 1 well. If successful, Savant would have needed to complete the well, perform an extended test and present the results of the test to the state by June 30, 2014.

Savant appealed the ruling in April 2013, saying it needed all seven leases to effectively explore the prospect. To address the pending drilling deadline, Savant also requested a stay of its plan of exploration in August 2013. Even though the company and state officials have met in the years since filing the appeal, the matter remains unresolved.

In the current plan of development, Miller said it would review all potential targets outside the participating area, "including, but not limited to, the Killian Sands on the east side of the unit" and "intends to continue exploration to fully explore the unit area as economic conditions warrant, and once the unit expansion appeal issue is resolved."

Without definite plans for the acreage, though, and with the appeal unresolved, the Badami unit "remains subject to a finding of default," according to the state. ●

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Petroleum news

page 5 Q&A: Meyer is ready to resume AKLNG work in special session

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This week's Mining News

Intriguing drill results hint at greater gold-copper potential at Tetlin project near Tok. Read more in Mining News, page 11.

RCA to investigate ML&P fund use; continuation from a 2013 rate case

An announcement in September 2013 by Anchorage electricity utility Municipal Light & Power that the utility wanted to raise the rates it charges its customers by more than 31 percent triggered a Regulatory Commission of Alaska investigation that did not end until July of this year. The ramifications from that investigation continue.

During the rate case investigation, Providence Health & Services, the company that operates Providence Hospital, a major user of ML&P's power supply services, had argued that the commission should allow ML&P to use a fund called the Deferred Regulatory Liability from Gas Sales fund, or DRLGS, to offset some of the cost of the utility's power. The commission declined to allow use of the DRLGS in this way

see **RCA PROBE** *page 18*

ConocoPhillips: Kuparuk DS 2S is in production ahead of schedule

ConocoPhillips said Oct. 12 that Kuparuk River unit Drill Site 2S, the first new drill site at the field in more than 12 years, is on production — under budget and ahead of schedule.

When the project was approved for funding in October 2014 production was expected to start this December.

JOE MARUSHACK

"Drill Site 2S is one of the key projects that we announced after passage of tax reform," ConocoPhillips Alaska President Joe Marushack said in a statement. "The $475 million project created about 250 jobs during construction with

see **DS 2S IN PRODUCTION** *page 18*

EXPLORATION & PRODUCTION

Armstrong takes over

Repsol backs away from North Slope program to focus on Talisman acquisition

By ERIC LIDJI
For Petroleum News

Just when it seemed as though Repsol E&P USA Inc. might be nearing the finishing line of its multi-year exploration campaign in the Colville River Delta, the company has announced a major shuffle with a minority partner and cancelled upcoming drilling plans.

In a deal worth more than $800 million, a subsidiary of the Spanish major is transferring significant working interest in its North Slope holdings to Armstrong Oil & Gas Inc.

If fully executed, the deal would make Armstrong the operator and majority owner of a proposed development program in the Colville River Delta and more than 750,000 acres of jointly held exploration acreage extending across much of the central North Slope.

According to Armstrong, even with the deferment, permitting will continue on a three-pad development with estimated production on the order of 120,000 barrels per day.

Armstrong had held a 45 percent interest in the exploration acreage and a 30 percent interest in the development acreage. Following the restructuring, Armstrong now holds a 75 percent interest and operatorship in the exploration acreage and a 45 percent interest in the development acreage with an option to acquire another 6 percent and operatorship.

The announcement came the same day the Alaska

see **ARMSTRONG DEAL** *page 22*

EXPLORATION & PRODUCTION

Umiat by 2022?

With scaled-down development plan, Linc finds optimism at Umiat oil field

By ERIC LIDJI
For Petroleum News

Even with low oil prices hampering an already complex project, Linc Energy Ltd. believes it can bring the Umiat oil field into production by the end of 2022.

In an annual report released Oct. 1, the Australian independent said it had "a detailed development plan in place" for the field in the National Petroleum Reserve-Alaska. So far, "the team have progressed engineering studies, compliance with regulation and environmental studies, while also clearly defining export options and development plans." The company plans to spend the coming year "implementing a low capital cost program specifically designed to advance our environmental impact study and plan of development, and progress the project towards full development approval."

An overview included in the report revised two previous development plans offered by the company. Under a brief description, Linc said it would build five drilling pads with approximately 35 development wells targeting the Upper and Lower Grandstand formations in an 80-acre drainage pattern. Well spacing would be 900 feet. The development program would use horizontal wells with

see **UMIAT OPTIMISM** *page 24*

PIPELINES & DOWNSTREAM

Pipeline in the balance

Canadian federal appeal court judges reserve decision on Northern Gateway plan

By GARY PARK
For Petroleum News

The fate of the most contentious regulatory process in the history of Canadian energy pipelines is now in the hands of three judges on the Federal Court of Appeal who have reserved a verdict on whether to uphold or scuttle Enbridge's C$7 billion Northern Gateway plan.

Despite federal government approval in June 2014 of the plan to export 525,000 barrels per day of oil sands bitumen and import 193,000 bpd of condensate, the 710-mile twin pipeline system connecting the Alberta oil sands and a tanker terminal at Kitimat on the northern British Columbia coast continues to be bogged down before regulators and courts.

The company estimates the project would boost Canada's gross domestic product by $300 billion over 30 years, as well as provide employment opportunities and sizable tax and royalty revenue.

Challenges filed

But that has failed to sway First Nations, environmentalists and labor unions, who filed 18 challenges before the six-day federal court hearing, which ended with a sharp rebuke to the opponents

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