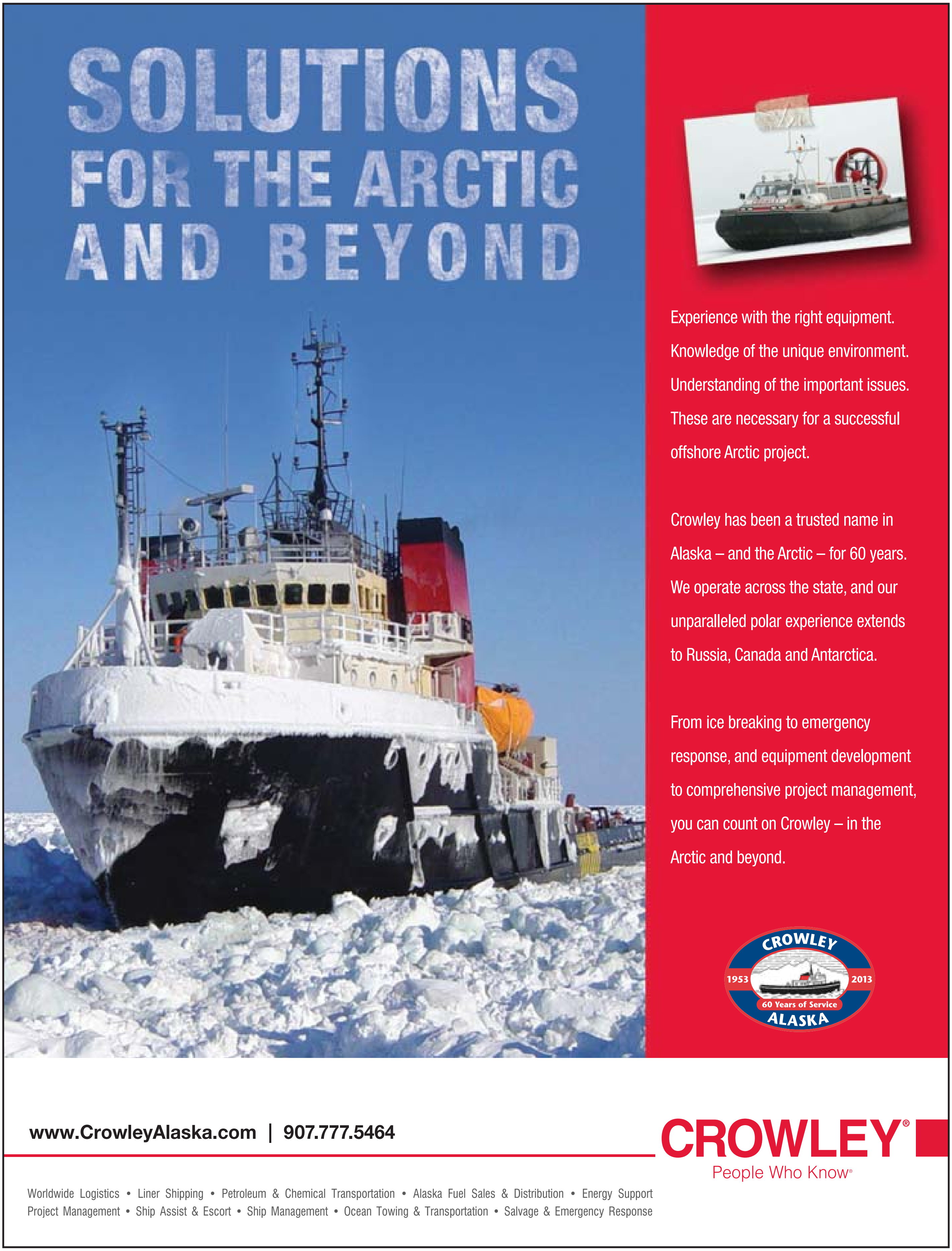
The Producers

Oil & gas companies investing in Alaska's future

The Producers, an annual publication from Petroleum News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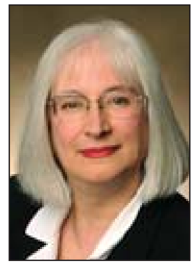
Impressive, if not exciting

By MARTI REEVE & KAY CASHMAN

Petroleum News special publications director & Petroleum News publisher and executive editor

MARTI REEVE



KAY CASHMAN

Reading about oil and gas production is not nearly as exciting as reading about oil and gas exploration, but the effort and investment that goes into production far exceeds that of exploration.

This year Petroleum News is publishing The Producers in the place of our usual annual magazine, The Explorers.

But next year, in 2014, both magazines will be published.

The articles that follow tell an impressive story of Alaska's operator-producers — with BP and ConocoPhillips the largest in northern Alaska, and Hilcorp the largest in the Southcentral part of the state, the Cook Inlet basin.

Smaller operators of production in both areas are also covered, as are two companies with fields under development.

If all goes according to plan, independent Brooks Range Petroleum will become the newest North Slope operator-producer sometime in early 2015 — see Contents for a page number for the full Brooks Range story and the others mentioned below.

ConocoPhillips is covered twice because it is a major North Slope operator-producer, as well as the operator of Cook Inlet legacy fields.

Cook Inlet Energy has been working the west side of the inlet, bringing oil properties back online and is now looking for production increases via new drilling.

Unfortunately, XTO Energy's emphasis and investment in the Cook Inlet Middle Ground Shoal field has declined since the independent became part ExxonMobil. However, its legacy field's July output was up some 12.5 percent from July 2012.

The smallest operator-producer on the North Slope, Savant, is working the region's most challenging field, Badami.

Pioneer Natural Resources, the first independent operator-producer in northern Alaska, keeps searching for, and finding, new oil at its Oooguruk field.

In less than two years Hilcorp became the dominant oil and gas producer in the Cook Inlet basin, touting some impressive production increases.

At its Point Thomson development longtime North Slope producer ExxonMobil will soon be operating its first field in Alaska.

And there are more — Armstrong, the southernmost producer-operator in Alaska; BP, operator of the giant Prudhoe Bay field; Aurora, which operates five gas fields in the Cook Inlet basin; Buccaneer, operator of a small onshore Cook Inlet field; Eni, which is looking to expand its Nikaitchuq unit; and the North Slope Borough, operating three gas fields near Barrow.

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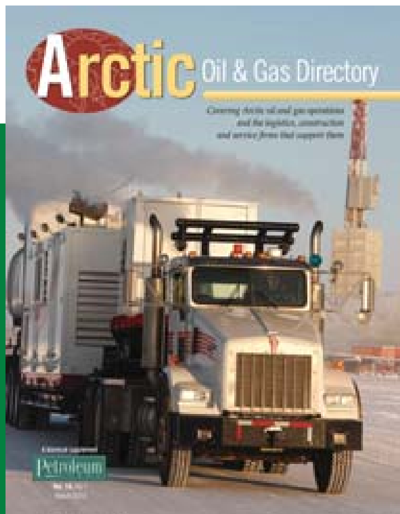

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Released Nov. 17, 2013

The Producers is a special annual supplement to Petroleum News, which is owned by Petroleum Newspapers of Alaska LLC.

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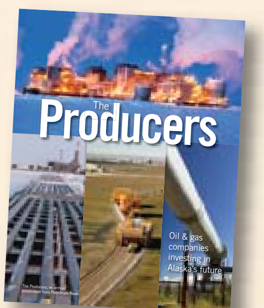
Cover photos courtesy Judy Patrick Photography

Printed by Journal Graphics, Portland, Oregon



Petroleum news

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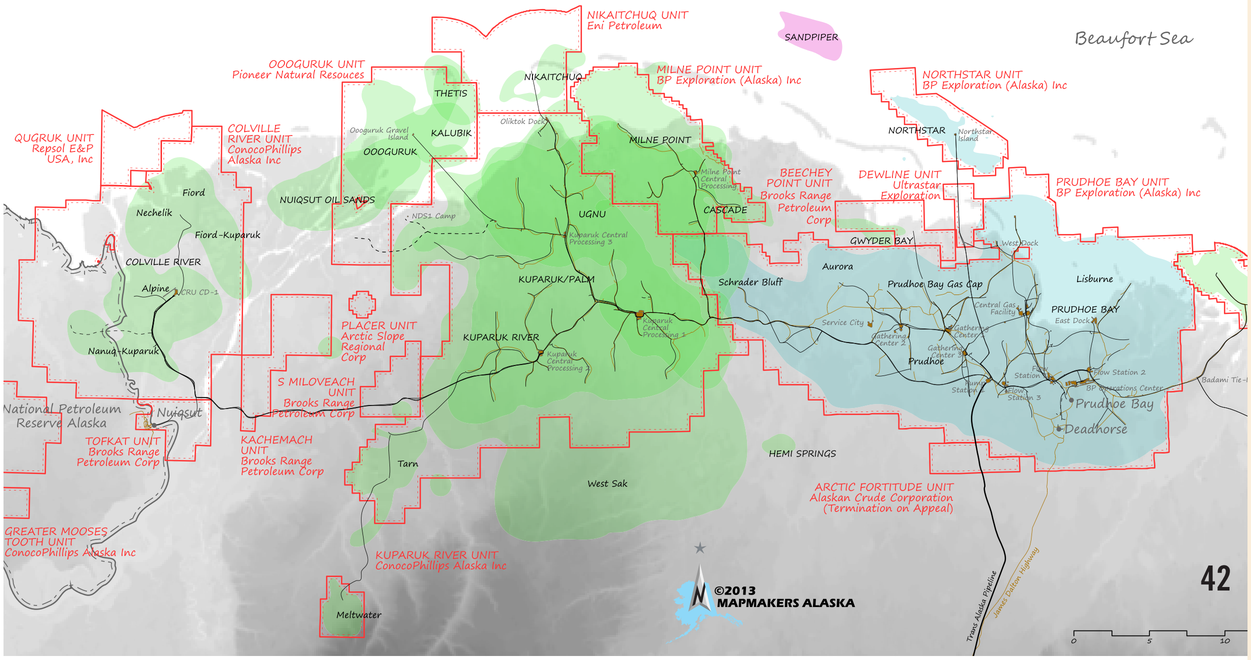


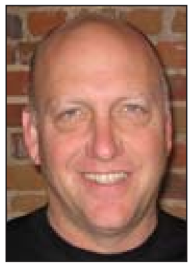
Armstrong: southernmost producer

The Denver independent and its four partners are working to increase gas production at their signature Cook Inlet development

By ERIC LIDJI
For Petroleum News

When Armstrong Oil and Gas Inc. acquired the North Fork unit in 2007, the independent was better known for facilitating development than bringing its assets into production.

In the early 2000s, the small Denver-based company brought Pioneer Natural Resources Inc., Kerr-McGee Corp. and Eni S.p.A. to Alaska. Those partnerships led to the Oooguruk and Nikaitchuq units, the newest oil fields in production on the North Slope.



BILL ARMSTRONG

In 2007, though, through its affiliate Armstrong Cook Inlet LLC, the company planned to pursue an aggressive development plan at the onshore gas field in the southern Kenai Peninsula, and ultimately succeeded by bringing the field into production in early 2011.

Now, Armstrong and its partners are working to increase production.

The North Fork field produced some 7 million cubic feet per day from five wells in July 2013, up from nearly 4 mmcf per day from four wells in July 2012, according to averages gleaned from monthly Alaska Oil and Gas Conservation Commission figures. To accommodate seasonal demand, Armstrong has typically produced more in the winter. The field produced more than 11 mmcf per day from five wells in January 2013, up from 6.5 mmcf per day from three wells in January 2012, according to the AOGCC.

From the start, Armstrong said North Fork would be first of many deals. "We are looking to get active in the Cook Inlet," President Bill Armstrong told Petroleum News in 2007. "We think it's a good time to explore for gas in the Cook Inlet. … We're looking forward to doing more deals. … Assuming we're successful, we'll be doing what was typical for us on the North Slope — a combination of wildcat and development drilling."

Known, but undeveloped

The North Fork unit was a known prospect when Armstrong arrived.

Standard Oil of California drilled the North Fork 41-35 discovery well in 1965 while looking for oil, but the low value of gas made development a hard sell (especially because it sat in the southern reaches of the Kenai Peninsula, far from Anchorage).

A variety of companies took their turn at the field starting in the late 1990s, but none brought the field into development. Armstrong acquired the prospect from Gas-Pro LLC and brought on four partners, all small independents: GMT Exploration Co., Jonah Gas Co. LLC, Nerd Gas Co. LLC and Dale Resources Alaska LLC.

The partners drilled the North Fork 34-26 well in June and July 2008 to 9,000 feet using the Aurora Well Services AWS-1 workover rig, which was modified to accommodate the depth of the well and also to make the rig quieter — a consideration for nearby residents.

The North Fork geology contains lenticular sands, or layers of sand and mud. Armstrong started drilling through the layers, looking for productive sections within the sandstones.

In September 2008, Armstrong Vice President of Land and Business Development Ed Kerr told Petroleum News he was

continued on next page

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ARMSTRONG *continued from page 9*

"cautiously optimistic" about the results. "I am 100 percent positive we have a gas well — in any other part of the world that's what I would say, but we still have to get a pipeline to it," he said. Speaking before the House Resources Committee in March 2009, Kerr said Armstrong was "very comfortable" that the prospect held between 7.5 billion and 12.5 billion cubic feet of gas reserves and said it was "realistic" the prospect could hold between 20 billion and 60 billion cubic feet.

"There is some potential that it could be substantially larger than that," Kerr said.

Under the 2009 contract, Anchor Point Energy built the 7.4-mile North Fork Pipeline from the North Fork unit and Enstar built the 21-mile South Peninsula Pipeline from the terminus of the existing Kenai Kachemak Pipeline.

New thoughts about pricing

But, Kerr added, Armstrong needed a price between $7 and $10 per thousand cubic feet to make the prospect work — a shock in the waning days of cheap Cook Inlet supplies.

In mid-2009, Enstar signed a supply agreement with Anchor Point Energy LLC, a joint venture created by the five North Fork partners. The deal required Anchor Point Energy to provide Enstar with 1.2 billion cubic feet per year up to a total of 10 bcf.

ED KERR

The price was indexed to quarterly average gas futures on the New York Mercantile Exchange, with a floor price of $6.85 per mcf and a ceiling price of $9.90 per mcf, both adjusted for inflation. Coming amid debates over how to price Cook Inlet gas, it was unclear how the Regulatory Commission of Alaska would handle the contract, but the RCA approved it less than two months later. The precedent helped make Nymex futures a standard pricing mechanism for contracts brought to the RCA in the years since.

Additional drilling

The contract required Armstrong to drill at least two more North Fork wells.

Toward the end of 2009, Armstrong hired PGS Onshore to shoot a 3-D seismic campaign over some 20 square miles around North Fork to help guide future drilling decisions.

In the summer of 2010, Armstrong took on a full plate.

First, Armstrong re-entered the original NFU No. 41-35 well to re-perforate the two sands Socal tested back in 1965. Then, Armstrong drilled the 11,700-foot NFU No. 14-25 directional well bearing eastward to a total vertical depth of 10,311 feet into the Beluga formation. Finally, the company drilled the 12,070-foot NFU No. 32-35 directional well bearing south to a total vertical depth of 11,266 feet, also into the Beluga formation.

Armstrong brought the field online in late March 2011. Since then, Armstrong has been producing from six Tyonek sandstones. The original NFU No. 41-35 well has been the most productive well at the unit and the NFU No. 14-25 has been the least productive.

Limited unit expansion approved

A year later, in March 2012, Armstrong

asked the Division of Oil and Gas to expand the unit to reincorporate the former federal acreage included in earlier iterations of the unit.

Originally, the North Fork unit was a federally administered unit containing both state and federal acreage, but previous officials contracted it in 1971 to include just the state acreage, a 640-acre gas pool. With the former federal acreage having since been transferred to the state, Armstrong wanted the unit to be expanded to its early contours.

The proposed expansion would have brought the unit to 4,801 acres over six state and three Cook Inlet Region Inc. leases. The state only agreed to add 2,903 acres around the western side of the unit. Several un-unitized Armstrong leases have since expired.

The state also agreed to expand the North Fork Gas Pool No. 1 participating area to 800 acres, from 640 acres. Armstrong had asked the state to expand it to 2,600 acres.

Following the approvals, Armstrong permitted four wells — NFU Nos. 23-25, 33-35, 42-35 and 22-35 — but only planned on drilling two.

In late 2012 and early 2013, Armstrong drilled NFU No. 22-35 and NFU No. 23-25. The 11,017-foot NFU No. 22-35 well bore south to a total vertical depth of 9,800 feet and the 10,785-foot NFU No. 23-25 well bore eastward to a total vertical depth of 9621 feet.

Those two wells fell under the 47th Plan of Development for the unit. Under the same plan, Armstrong installed a compression unit at North Fork in November 2012, began producing from a new zone at the NFU No. 34-26 well and brought gas to Nikolaevsk.

Under the 48th Plan of Development in place for 2013, Armstrong tested the NFU No. 23-25 and NFU No. 22-35 wells and continued to monitor its existing production wells.

A 49th Plan of Development is due at the end of 2013.

Elusive oil

Early on, Armstrong also expressed an interest in looking for oil at North Fork.

In mid-2010, the company filed an oil discharge prevention and contingency plan with the Alaska Department of Environmental Conservation, a necessity for any oil exploration, and announced plans to test the Hemlock formation sometime in 2011.

The NFU No. 41-35 well had tested minor amounts of oil in the Hemlock, but when Armstrong extended one of its gas wells to test the formation, it came up empty handed.

Armstrong brought the field online in late March 2011. Since then, Armstrong has been producing from six Tyonek sandstones.

Gas for Homer

For decades, the southern Kenai lagged behind the rest of the Southcentral region. Anchorage, the Mat-Su and the northern Kenai enjoyed the cost effectiveness of natural gas, but the small communities around Homer continued to burn expensive fuel oil.

A trio of known southern Kenai prospects promised resources to extend the transmission grid from its prior terminus at Happy Valley. They were North Fork, the Nikolaevsk unit to the northeast and the Cosmopolitan prospect off the coast of Anchor Point. In each case the operators wanted infrastructure to improve

continued on next page

Nabors Alaska rig 27E one of two rigs Kerr- McGee and partner Armstrong Alaska had under contract on the North Slope in the winter exploration season of 2004-05.

ARMSTRONG *continued from page 11*

the economics of their prospects but Enstar Natural Gas Co. wanted sustained gas production to justify building new pipelines.

The development of North Fork ended the logjam, but discussions continued about whether to take the gas north to the existing system or south toward Homer.

Eventually, the gas went both ways.

Under the 2009 contract, Anchor Point Energy built the 7.4-mile North Fork Pipeline from the North Fork unit and Enstar built the 21-mile South Peninsula Pipeline from the terminus of the existing Kenai Kachemak Pipeline. The pipelines met in Anchor Point.

A series of regulatory hurdles — some expected, and some the result of the small private companies worried about publically disclosing their finances — delayed the project, but the pipelines allowed Armstrong to deliver North Fork into the existing grid. Over several years of legislative wrangling and piecemeal funding, the state eventually helped pay for a trunk line into Homer, an extension to Kachemak City and a short line to Nikolaevsk.

Now, the southern Kenai Peninsula is finally getting natural gas.

Contact Eric Lidji at ericlidji@mac.com

Aurora: the indie before the boom

Aurora Gas has been operating in Cook Inlet for more than a decade, pre-dating the current rush of independents into the basin

By **ERIC LIDJI**
For Petroleum News

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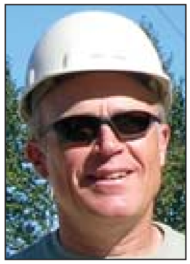
Years before small independents flocked to Alaska to explore passed over corners of Cook Inlet, Aurora Gas saw an opportunity in the basin for a company of its size.

Aurora began acquiring properties in early 2000, picking up a block of acreage from ConocoPhillips Alaska Inc. and later grabbing another block from Anadarko Petroleum Corp., always with an eye toward shallow, discovered and undeveloped gas prospects.


ED JONES

The local independent currently operates five gas fields on the west side of Cook Inlet: Nicolai Creek, Lone Creek, Moquawkie, Albert Kaloa and Three Mile Creek.

Averaging cumulative production, Aurora Gas produced 3.4 million cubic feet per day between July 2012 and July 2013, according to the Alaska Oil and Gas Conservation Commission.

The Nicolai Creek unit

Aurora Power Resources Inc. created Aurora Gas in 2000 as an exploration and production arm. That same year, Aurora also traded its working interest in the Kenai and Cannery Loop gas fields to Marathon Oil Co. in return for the Nicolai Creek unit.

"We essentially traded a modest quantity of proved developed producing reserves at Kenai and Cannery Loop for a larger quantity of proved undeveloped reserves at Nicolai Creek," Aurora Power President G. Scott Pfoff told Petroleum News in January 2000.

Between 1968 and 1977, Nicolai Creek produced fuel gas for offshore platforms. A pipeline would later allow the field to contribute to the regional grid, but in the early 1990s a former operator killed the best producing well at the field with drilling mud.

continued on next page

AURORA *continued from page 13*

After cleaning out the well — Nicolai Creek Unit No. 3 — Aurora restarted production in late 2001. In subsequent years, Aurora also restarted production from the Nicolai Creek No. 1B and No. 2 wells and drilled Nicolai Creek No. 8 (now Nicolai Creek No. 9).

Aurora shut-in the Nicolai Creek field in 2005 while it sought a commercial arrangement to use the Cook Inlet Gas Gathering System, which transports gas across Cook Inlet.

In 2006-07, Aurora suspended drilling operations across its properties while it settled a dispute with Enstar Natural Gas Co, but recompleted Nicolai Creek No. 1B and No. 9.

Renewed focus at Nicolai

In recent years, Aurora has been renewing its focus at Nicolai Creek by bringing the Nicolai Creek No. 11 online in late 2009 and drilling the Nicolai Creek No. 10 in 2011.

Pleased with the results, Aurora permitted the Nicolai Creek No. 13 and No. 14 wells in early 2013 and expects each to yield an average production bump of 3 mmcf per day, according to Aurora Gas President Ed Jones. Aurora also plans to workover Nicolai Creek No. 10, which is producing more than 3 mmcf per day, but needs sand control.

Effective Jan. 31, 2012, Aurora sold the deep rights at Nicolai Creek — defined as starting below the Middle Tyonek — to Apache Alaska Corp. and Hilcorp Alaska LLC. As part of the deal, Apache included the area is its broad seismic plans for the Cook Inlet basin.

Averaging cumulative rates, Nicolai Creek produced 2.2 mmcf per day between July 2012 and 2013 and 3.1 mmcf per day between January 2012 and 2013, according to the AOGCC. In July 2013, the field produced nearly 55 mmcf, or nearly 1.8 mmcf per day.

Cumulatively, the field had produced nearly 7.9 billion cubic feet through July 2013.

For several years, Aurora has wanted to use a section of Nicolai Creek for third-party gas storage, a business proposition that would also improve deliverability in Cook Inlet.

The project would have converted Nicolai Creek No. 2 into an injection well.

Aurora held an open season in 2009 and got AOGCC approval in 2010, but has failed to sign up any customers in the years since.

With the Cook Inlet Natural Gas Storage Alaska facility now operational, the local storage market looks different, but if the current Cook Inlet exploration boom becomes a production boom, another third-party storage facility in the region may be welcomed.

Lone Creek and Moquawkie

The Anadarko acquisition also included the Lone Creek and Moquawkie fields.

Anadarko and ARCO Alaska discovered Lone Creek in the late 1990s with the Lone Creek No. 1 and also drilled Lone Creek No. 2. Aurora brought the field online in summer 2003, producing 5 mmcf per day from the original discovery well.

In 2005, Aurora offset Lone Creek No. 1 with the Lone Creek No. 3 well, which tested at 16.4 mmcf per day. The following year, Aurora recompleted several wells, including Lone Creek No. 1, describing the venture as a moderate success. After its two-year hiatus, Aurora returned to the field in 2009, drilling the Lone Creek No. 4 well.

Averaging cumulative rates, Lone Creek produced 749 thousand cubic per day between July 2012 and 2013 and 1.2 mmcf per day between January 2012 and 2013, according to the AOGCC. With no summer production listed, the field appears to have been offline.

In recent years, Aurora has been renewing its focus at Nicolai Creek by bringing the Nicolai Creek No. 11 online in late 2009 and drilling the Nicolai Creek No. 10 in 2011.

Cumulatively, the field had produced 9.8 bcf through July 2013.

Concurrent with its efforts at Lone Creek, Aurora also developed the Moquawkie field, which is adjacent to Lone Creek along its southern border. The two prospects primarily consist of Cook Inlet Region Inc. acreage, and their management is intertwined.

Discovered in late 1960s

Mobil Oil Corp. had drilled the Moquawkie No. 1 discovery well in the late 1960s to look for oil, but completed it as a gas well. Aurora recompleted the well in 2003, testing it at a rate of 7.6 mmcf per day, and brought the field online in July 2004 at 5 mmcf per day.

The success gave Aurora optimism for its chances at bringing the other existing Moquawkie wells back into production. Those included Simpco Moquawkie No. 1 and No. 2 from 1978 and 1979, respectively, and Mobil Oil West Moquawkie No. 1 from 1970.

It was successful with Moquawkie No. 2.

In 2005, Aurora drilled Moquawkie No. 3, to offset the discovery well. It tested at 5.5 mmcf per day and came online that summer at nearly 4 mmcf per day. In 2006, Aurora recompleted the discovery well, work it handled in the same batch at Lone Creek No. 1.

Contract dispute

In 2006, the field became the center of a contract dispute with Enstar Natural Gas Co.

The dispute came when Aurora tried to exercise its contractual right to suspend deliveries at prices it called "far below what is economic." Enstar sued Aurora for breach of contract. Under a 2008 settlement, Aurora agreed to pay Enstar more than $11 million to compensate the utility for the more expensive gas it purchased during the proceedings.

The debate raised questions about the fiscal regime for Cook Inlet.

With the state calculating taxes and royalties based on the "prevailing value" of all gas under contract, a producer selling below that value ended up making less for its gas.

Having resolved the legal issue, Aurora resumed its operations, drilling the Moquawkie No. 4 in 2008. The well encountered a shallow gas pocket, forcing drilling mud out of the wellbore, but the drilling operator was able to control the blowout within 24 hours.

Aurora also planned to drill a Moquawkie No. 5 well, but its parent company deferred the well until natural gas prices improved and ultimately never sanctioned the well. The well would have been near Moquawkie No. 4 and would have tested the high pressure gas responsible for the Moquawkie No. 4 blowout, as well as some coal beds in the area.

Averaging cumulative rates, Moquawkie produced 237 mcf per day between July 2012 and 2013 and 339 mcf per day between January 2012 and 2013, according to the AOGCC. In July 2013, the field produced 5.6 mmcf, or some 180 mcf per day. Cumulatively, the field had produced 4.9 bcf through July 2013.

The Albert Kaloa field

Albert Kaloa also came from the search for oil.

Pan American Petroleum Co. discovered the field in 1967 with the Kaloa No. 1 exploration well. The results from the Beluga formation justified bringing the well online in 1970, but Pan Am suspended operations in 1971, after sand and mud plugged the well.

Aurora took a stab at the Albert Kaloa field in 2004, drilling the Kaloa No. 2. The results led Aurora to bring the field back online in October 2004. Aurora subsequently drilled the Kaloa No. 4 in 2005 and the Kaloa No. 3 in 2009, but both wells were dry holes.

Albert Kaloa is located between the Nicolai Creek and Moquawkie units.

Averaging cumulative rates, Albert Kaloa produced 141 mcf per day between July 2012 and 2013 and 158 mcf per day between January 2012 and 2013, according to the AOGCC. In July 2013, the field produced nearly 2.6 mmcf, or 83 mcf per day. Cumulatively, the field had produced nearly 3.6 bcf through July 2013.

The Three Mile Creek unit

A little ways to the north, Aurora also operates the Three Mile Creek field.

Aurora and Forest Oil proposed the Three Mile Creek unit in 2003 to cover some 9,200 acres of State of Alaska, Alaska Mental Health Trust and Cook Inlet Region Inc. leases.

Using a slate of previous drilling and a recent seismic acquisition, the partners said they had identified at least two natural gas prospects and proposed an exploration campaign.

The state approved the unit in 2004, requiring two wells and new seismic.

Aurora drilled the Three Mile Creek No. 1 well in late 2004. It was the first exploration well for the company and tested at 5 mmcf per day from two Beluga intervals. Aurora brought the field online in August 2005 and drilled the Three Mile Creek No. 2 delineation well in November 2005. Aurora deferred a third Three Mile Creek well.

In 2006, Aurora performed an acid stimulation of the Three Mile Creek No. 2 as part of its recompletion activities. In 2008, after the hiatus, Aurora recompleted Three Mile Creek No. 2 to perforate some additional zones. Aurora hydraulically fractured the well in 2010 to improve production from the thin layers of productive sands in the Beluga. The successful program led Aurora to consider using the technique at its other wells.

Forest sold its Alaska assets, including Three Mile Creek, to Pacific Energy Resources Ltd. in 2007, but Pacific Energy filed for bankruptcy protection in 2009. The Miller Energy Resources-subsidiary Cook Inlet Energy acquired the minority stake in late 2009.

Aurora Gas drilled the Three Mile Creek No. 3 well in recent years, but despite completion work in numerous intervals the well has yet to support sustained production.

The fate of the well could determine whether Aurora drills a fourth development well.

On average, Three Mile Creek produced 134 mcf per day between July 2012 and 2013 and 231 mcf per day between January 2012 and 2013, according to the AOGCC. With no production listed, the field appears to have been offline this summer.

Cumulatively, the field had produced nearly 2.4 bcf through July 2013.

Contact Eric Lidji at ericlidji@mac.com

BP: 50 years down, 50 to go?

Since opening its Alaska office in 1959, BP has been shepherding the largest oil field in North America, and a few others too

By ERIC LIDJI
For Petroleum News

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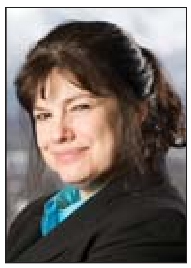
BP Exploration (Alaska) Inc. is focused on old fields. The British giant dropped its Alaska exploration program in 2003 to focus on combating production declines from its 13 North Slope fields, including the massive Prudhoe Bay field that underpins the Alaska economy. Those efforts include infill drilling, enhanced oil recovery and a long-term study of the heavy oil potential across much of its holdings.

As an operator in 2012, BP produced some 363,000 gross barrels of oil per day from four North Slope units — Prudhoe Bay, Milne Point, Duck Island and Northstar. Through subsidiaries, BP also operates the Badami pipelines, Endicott pipeline, Milne Point pipelines and Northstar pipelines, and owns the largest share of the trans-Alaska oil pipeline.



JANET WEISS

BP also operates the federal Liberty unit that remains years from startup.

Prudhoe Bay comes to life

In 1959, Alaska became a state and BP opened its local office.

A decade later, BP drilled a confirmation well for the Prudhoe Bay discovery, which launched 44 years of development work. The discovery of Prudhoe Bay is an adventure tale, but what happened next, what continues to happen daily and what BP hopes will happen for the next 50 years or more, is of greater importance to the State of Alaska.

The delineation campaign of 1969 mapped a field stretching 45 miles from east to west along the 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 pinpointed heavier oil reserves contained in shallower reservoirs, such as West Sak, Schrader Bluff and Ugnu.

The initial development program split the field in half, with BP handling the Western Operating Area, WOA, and ARCO Alaska handling the Eastern Operating Area, EOA.

The historic sealifts of 1969 and 1970 brought nearly 250,000 tons of supplies and equipment, including the first of six gathering centers to handle up to 1.8 million bpd. The sealifts continued each open water season through the 1970s, bringing additional items, including components for the "BP-Hilton" and the Central Power Station.

A gravel road built in the 1970s traversed the field. Later, the working interest owners built extensions connecting this spine road to the individual pads. The BP-operated pads in the WOA were lettered while the ARCO-operated pads in the EOA were numbered.

This naming scheme is still used today.

The initial split guaranteed adequate manpower to develop the gigantic field. It also divided operations between the oil reservoir and an offset gas cap overlying it.

Prudhoe Bay unitization

Eventually, though, the owners realized they needed to unitize the field.

"The basic reason for 'unitizing' the Prudhoe field was to optimize recovery and equitably divide costs among working interest owners and avoid duplication of facilities," George Abraham, a now-retired BP executive who worked on the Prudhoe Bay Unit Operating Agreement in the mid-1970s, told Petroleum News in 2008. "By limiting surface facilities you would also minimize possible environmental impacts."

The negotiations wrapped up as construction finished on the trans-Alaska oil pipeline, the 800-mile pipeline that carries North Slope crude oil to Valdez for tanker shipments.

The pipeline connected the Prudhoe Bay field to market on June 20, 1977.

"There was friendly competition with ARCO, operator of the eastern side of the field," former BP production operator Gene Smagge said in 2009. "We were trying to see who could get their oil into Pump Station 1 first. I think we beat them by a shave."

Prudhoe Bay production topped 1 million bpd in March 1978 and peaked at 1,627,036 bpd in January 1987 before dropping below 1 million bpd in March 1994, according to the Alaska Oil and Gas Conservation Commission. Of the 24 billion barrels of oil in place, its operators had produced some 11.5 billion barrels through July 2013, according to the AOGCC. Original estimates had pegged total recovery at 9.6 billion barrels.

The production rate was 225,000 bpd at the end of 2012, according to BP. With its associated fields, production was 266,339 bpd in July 2013 and 238,507 bpd in August 2013, according to the AOGCC and Alaska Department of Revenue, respectively.

The sharp drop was due in large part to planned summer maintenance.

Even 45 years after its discovery, Prudhoe Bay remains BP's primary focus.

The company drilled 45 wells and performed some 1,700 well work jobs at the field in 2012. As of mid-September, BP had completed some 36 wells at the field in 2013.

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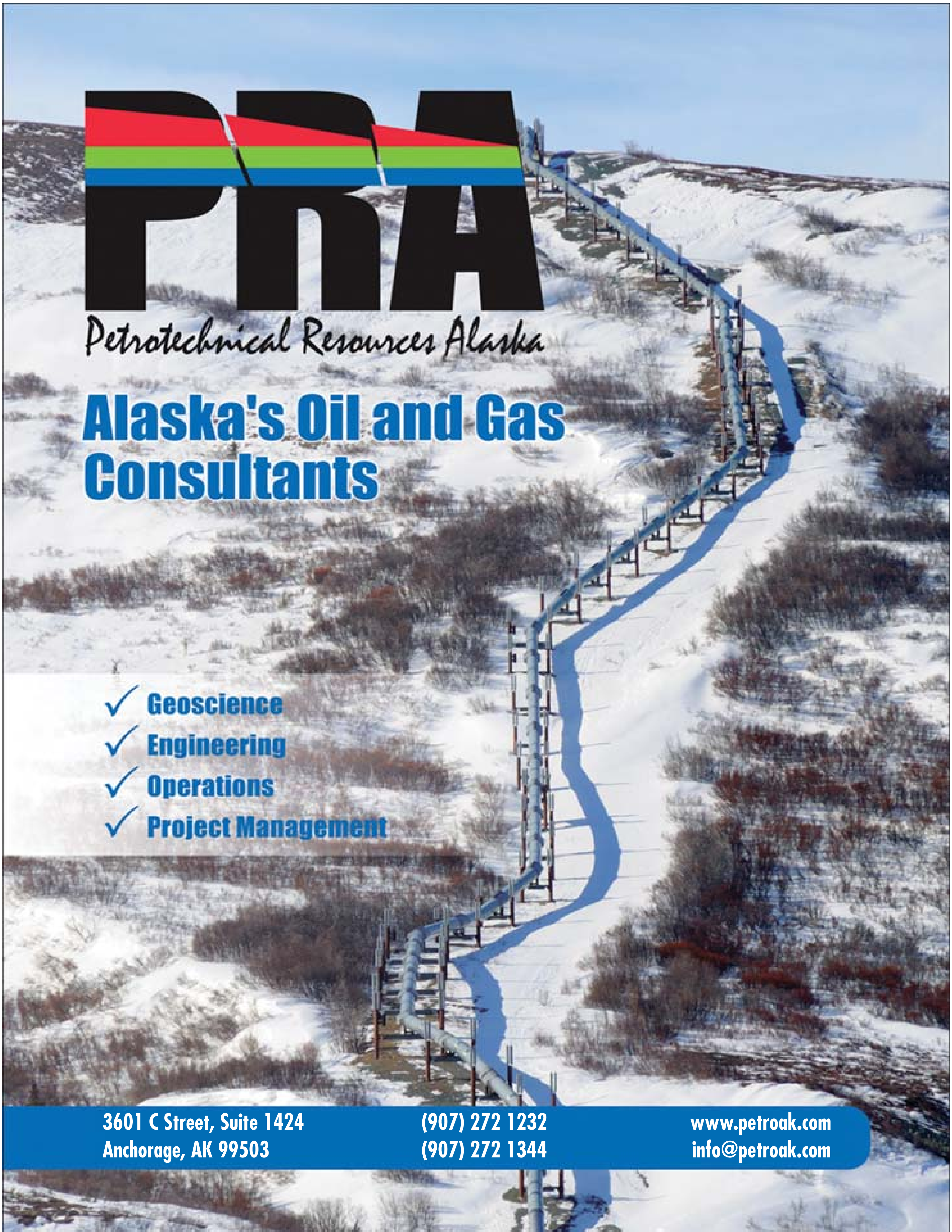
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COURTESY BP

At Prudhoe Bay, about 8 billion cubic feet of natural gas is produced daily and injected back into the ground to maintain reservoir pressure and produce more oil. Prudhoe has produced more than 12 billion barrels of oil since its startup. The gas injection has improved oil recovery and extended the life of the field beyond initial estimates.

BP *continued from page 16*

Capital to improve operations

With the increasing maturity of the Prudhoe Bay field in the 1980s, the working interest owners launched numerous capital expenditure programs to improve operations.

Those included an expansion of the flowlines connecting wells to the gathering centers, increasing the gas and produced water capacity of the field, tinkering with gas handling to improve productivity and launching enhanced oil recovery efforts such as waterflooding and a miscible injection program aided by a new Central Gas Facility.

Prudhoe Bay also hosted many technologies pioneered (or at least embraced) on the North Slope. Those include multilateral wells, coiled tubing drilling, extended reach drilling and ongoing tests into multistage hydraulic fracturing, but they also include BP field technologies such as the Bright Water polymer used to sweep oil from reservoirs and the LoSal technique that uses lower salinity water to improve oil recovery.

Perhaps the biggest changes at Prudhoe Bay yielded the least physical evidence.

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 all ARCO's Alaska assets to Phillips Petroleum.

The deal left BP as the sole operator of the Prudhoe Bay unit, a position it retains today.

To satisfy the State of Alaska, BP also signed the Charter for the Development of the Alaskan North Slope, which prevented any company from having too large a footprint, and set out terms for how the operators would accommodate each other and smaller players.

The Prudhoe Bay satellites

Prudhoe Bay is bigger than the Prudhoe Bay field.

The Greater Prudhoe Bay Area includes the Prudhoe Bay field and five satellites: Aurora, Borealis, Midnight Sun, Orion and Polaris. The nearby Greater Point McIntyre Area includes the Point McIntyre field and four satellites: West Beach, North Prudhoe Bay, Niakuk and Raven. The facilities in the region also handle the Lisburne field.

While Prudhoe Bay dwarfs those fields, they are each large by any standard except the North Slope. Without Prudhoe Bay, though, none would have justified development.

The Aurora pool

Mobil Oil Corp. discovered the Aurora oil pool in the northwest quadrant of the Prudhoe Bay field in 1969 with the Mobil-Phillips North Kuparuk State No. 26-12-12 well.

It took until November 2000 for BP to bring the field online from the S pad.

By 2013, BP was developing Aurora using 33 wells — 17 producers, 10 water injectors and six water-alternating-gas, WAG, injectors, according to the 2013 BP annual report.

Of the 200 million barrels of oil in place, BP had produced some 34 million by June 2012, according to its most recent plan of development. Aurora production peaked at 14,000 bpd in August 2006 and averaged 7,500 bpd in 2012, according to BP.

Aurora produces from the Kuparuk formation.

The primary development work at Aurora concerns a tertiary recovery program launched in 2003, where BP alternates cycles of miscible gas injection and water injection.

While BP drilled a production well at Aurora as recently as 2010 and an injection well the following year, the company had no development drilling planned at Aurora for 2013.

The Borealis and Orion pools

Also in 1969, Mobil Oil discovered the Borealis oil pool along the western edge of the Prudhoe Bay field with the W Kuparuk St 3-11-11 well into the Kuparuk formation.

BP brought the field online in May 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.

By 2013, BP was developing Borealis using 50 wells — 31 producers, nine water injectors and 10 WAG injectors, according to the 2013 BP annual report.

Of the 350 million barrels of oil in place, BP had produced some 69 million barrels of oil equivalent through 2012, according to BP. Borealis peaked at 38,150 bpd in May 2003, according to the AOGCC, and produced 10,000 bpd in 2012, according to BP figures.

Mobil Oil discovered the Orion oil pool in 1968 with the Kuparuk State No. 1 well and BP confirmed the accumulation in 1998 with the Northwest Eileen 2-01 well.

The Orion pool is in the northwest corner of the Prudhoe Bay unit. Brought online in April 2002, Orion produces from the same viscous Schrader Bluff formation present at the BP-operated Milne Point unit to the north and the ConocoPhillips-operated Kuparuk River unit to the west, and is part of joint efforts to expand production of heavier oil.

BP originally developed Orion from its V pad and expanded development to include L pad in mid-2004. As of the end of 2012, BP was developing Orion from 43 wells — 12 oil producers, 20 water injectors and 11 WAG injectors. The two pads pushed production to a peak of 14,460 bpd in June 2007. Of the 3.2 billion barrels of oil in place at Orion, BP has produced 27 million barrels of oil equivalent through 2012 at a rate of 6,000 bpd.

As with all heavier reservoirs on the North Slope, Orion (and Borealis, which it overlaps) is thought to be a crucial component for maintaining production for decades to come.

BP deployed these two Parker rigs in the North Slope rig fleet this year. According to BP, the modernized rigs increase crew safety and efficiency in the company's drilling operations.

COURTESY THOMPSON METAL FABRICATORS

Proposed I pad

The efforts at Orion and Borealis concern a proposed I pad.

BP originally expected to bring the pad online by 2006, but later deferred those plans until the 2010 timeframe and subsequently deferred them again until as late as

continued on next page

BP *continued from page 17*

2020.

While BP has also cited technical challenges through the years, those delays have largely concerned the changing fiscal systems in Alaska over the past decade. BP deferred I pad for the first time in early 2005, after then-Gov. Frank Murkowski proposed combining Prudhoe Bay and its satellites for tax purposes, which would have increased the tax rate for the smaller fields. BP deferred I pad development again in early 2008, just months after then-Gov. Sarah Palin approved ACES, the Alaska's Clear and Equitable Share production tax increase.

In early 2011, I pad emerged as a crucial point of discussion in debates over House Bill 110, Gov. Sean Parnell's revision to the production tax code. In hearings and speeches around that time, BP and ConocoPhillips executives both pointed specifically to I pad as an example of the short-term investment opportunity that lower taxes could facilitate.

An I Pad could access between 69 million and 144 million barrels of recoverable oil at Orion and between 2.7 million and 3.9 million barrels of recoverable oil at Borealis, according to state estimates. In its most recent development plans, BP proposed work to bring northwest Orion into production, but deferred northwest Borealis. Considering the size discrepancy between the fields, BP wants to develop Orion and Borealis together, but because Orion is more technically complex, it felt the need to defer both projects.

The state approved the 2013 plan for Orion, but rejected the Borealis plan. The issue of I pad is almost certain to emerge when BP submits its 2014 development plans this fall.

The Polaris field

The Polaris oil pool is another remnant of the early days of Prudhoe Bay delineation.

BP discovered the pool in the western end of the Prudhoe Bay field in 1969 with the North Kuparuk State 26-12-12 well into the shallow and viscous Schrader Bluff and Ugnu formations, and brought the field online in 1999 from W pad and S pad.

Through 2012, BP had developed the field from 26 wells — nine oil producers, 15 water injectors and two WAG injectors. Of the 1 billion barrels of oil in place at Polaris, BP had produced 13.4 million barrels through 2012, at a 2012 rate of some 5,238 bpd.

BP drilled its most recent Polaris wells in 2011.

While BP planned no Polaris drilling in 2013, the company is appraising a program to expand its S pad and M pad to better access oil reserves in the northern part of the field.

The Midnight Sun field

BP discovered the Midnight Sun field in 1997 with the Sambuca No.1 well.

Midnight Sun began producing from the Kuparuk formation in October 1998. BP is developing the field from two producers and three injectors at E pad at the center of the northern edge of the unit. The most recent of those wells was drilled in 2001.

Of the 100 million barrels of oil in place at Midnight Sun, BP had produced some 19 million barrels through 2012, but production is currently some 1,000 to 1,500 bpd.

Currently, BP is exclusively using water injection to enhance oil recovery at Midnight Sun, in part because the company has yet to build a miscible injection line to the field.

While BP has no drilling planned for Midnight Sun, the company told the state it might someday sidetrack existing wells to

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BP *continued from page 20*

improve recovery as waterflooding matures.

The Lisburne field

The Greater Prudhoe Bay Area covers the five satellites on the western side of Prudhoe Bay. On the eastern side, BP also operates the fields in the Greater Point McIntyre Area.

The largest of those is Lisburne.

ARCO Alaska discovered the field in the northeast corner of the Prudhoe Bay field in 1969 with the Prudhoe Bay State No. 1 well and production began in 1982. Through the end of 2012, BP had developed the field through 46 wells — 39 oil producers, three gas injectors and four water injectors. Of the 2.4 billion barrels of oil in place, BP had produced some 178 million barrels of oil equivalent through 2012, according to its annual report. Production peaked at 47,600 bpd in mid-1987 and in 2012 was around 6,000 bpd.

The Lisburne reservoir is beneath the Prudhoe Bay reservoir in a tight formation of limestone and dolomite. The geology continues to present challenges for BP. The Lisburne wells have a high gas-to-oil ratio, which BP combats by cycling wells through several days of production followed by several days or weeks of suspending production.

The Point McIntyre and Niakuk fields

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

ARCO and Exxon discovered Point McIntyre in the coastal section of Prudhoe Bay in 1988 with the Point McIntyre No. 3 well into the Kuparuk River and Kalubik formations.

The field came online in 1993 and peaked at 172,995 bpd in December 1996.

Of the 880 million barrels of oil in place, BP had produced some 454 million barrels of oil equivalent through 2012, at a 2012 rate of some 18,000 bpd, according to BP. The two gravel drill sites accommodate 64 wells — 47 oil producers, one gas injector, 12 water injectors and four WAG injectors, according to the company.

After drilling a well and a sidetrack at Point McIntyre in 2012 and early 2013, BP is now evaluating additional sidetracks, potentially in the north and southeast, two areas the state added to the Prudhoe Bay unit and the Point McIntyre participating area in June 2009.

Sohio discovered the Niakuk oil pool in 1985 with the Niakuk No. 5 well into the Kuparuk formation. The field came online in April 2004 and production peaked at 37,172 bpd in September 1996, but has since dropped off considerably. The two pads at Niakuk currently accommodate some 19 wells — 13 oil producers and six water injectors.

Of the 400 million barrels of oil in place at Niakuk, BP had produced some 94 million barrels of oil equivalent through 2012, at a 2012 rate of some 2,800 bpd.

The nearby Raven field produced some 470 bpd in 2012, almost entirely from one producer supported by a water injector. BP said it has no immediate plans for Raven.

ARCO discovered the remaining Greater Point McIntyre fields — West Beach and North Prudhoe Bay — in the 1970s, but both fields are currently shut-in for low production.

The Milne Point unit

To the northwest of Prudhoe Bay, the Milne Point unit primarily produces from the Kuparuk oil pool, but also from the heavier Sag River, Schrader Bluff and Ugnu pools.

The history of the Milne Point unit can be divided into three periods: the slow decade following its discovery, the active decade after BP became the operator and the present.

Standard Oil Company of California discovered the four Milne Point horizons in 1969 with the Kavearak Pt. No. 32-25 well, according to the AOGCC, but Conoco Inc. delineated and developed the field in 1980 and brought it online in November 1985.

With the low oil prices of the late 1980s, Conoco suspended production from January 1987 until April 1989. The field peaked at 20,000 bpd in the early 1990s, but had declined to 17,000 bpd by the time BP took over the unit in early 1994, according to the AOGCC.

BP quickly built the F pad in the northern end of the unit and the K pad in the southeastern end of the unit, which pushed production to 52,900 bpd by July 1998.

To better understand the offshore and nearshore potential of the Kuparuk reservoir, BP commissioned a seismic program in late 2012 covering some 90 square miles.

Heavier oil tantalizing

While BP acquired Milne Point for the lighter oil Kuparuk reserves, the three prodigious heavier oil reserves have since proved tantalizing.

Conoco spent $130 million building four pads and drilling 22 wells at Schrader Bluff in the early 1990s, bringing the field online in March 1991 at 3,700 bpd, but production from the shallow formation was down to 2,850 bpd by the time BP took over the unit in early 1994, according to the AOGCC. After several years of drilling without greatly improving production, BP announced a plan in 1997 to develop the Schrader Bluff pool with seven new or expanded pads, 75 miles of new pipeline and some 300 wells.

By 2001, BP said its ambitious program had "proved to be uneconomic." Instead, the company expanded conventional drilling at E pad, H pad and J pad, which lifted production to 12,000 bpd by April 2002, and built S pad in the south of the unit.

The biggest challenges at Schrader Bluff are the viscous oil and sandy formation, but BP found that horizontal drilling, jet pumps and waterfloods were useful in both regards.

This work helped Schrader Bluff production peak at 23,922 bpd in October 2003.

For 2013, BP planned to drill four Schrader Bluff infill wells originally planned for 2012 — one producer and three injectors — and four Kuparuk coil sidetrack wells, but AOGCC records through mid-September showed no wells completed at Milne Point.

Sag, Ugnu challenging

Conoco tested the Sag River starting in 1980, but BP brought the field into production in 1995. The Sag River is the deepest of the producing intervals at Milne Point, and therefore the oil is lighter than at Schrader Bluff and Ugnu, but the high gas-to-oil ratios and poor pump performance have challenged production. Despite some occasional spikes through the years, average annual production has remained less than 700 bpd.

The Ugnu pool — a 20 billion barrel reservoir overlying portions of the Prudhoe Bay, Kuparuk River and Milne Point fields — is an even tougher nut to crack than the Schrader Bluff, but underpins long-term hopes for the heavy oil potential of the region.

Starting in 2007, BP launched a pilot program at S pad to test various techniques for producing this heavy 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 needs to demonstrate the long-term viability of the program and to better manage the costs of heavy oil production before Ugnu can become a regular component of the North Slope production picture.

To date, BP has drilled four test wells, two nearly vertical and two horizontal.

Of the 8.9 billion barrels of oil in place at the Milne Point unit, BP had produced 308 million barrels of oil equivalent through 2012, at a 2012 rate of 17,000 bpd.

The Duck Island unit

The other fields in the BP portfolio are all offshore.

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BP *continued from page 25*

The earliest developed among those is the Duck Island unit, better known by the name of its largest field: Endicott. The unit also includes the Eider and Sag River North participating areas.

Sohio Alaska Petroleum Co. discovered the Endicott oil pool in 1978 with the Sag Delta No. 4 well and tested it the following year with a well into the Kekiktuk formation.

After building two compact gravel islands connected to shore by a causeway — the first offshore oil producing islands in the Arctic — BP brought Endicott online in July 1986.

Endicott peaked at some 104,000 bpd between November 1987 and October 1993, but the field had declined to 30,450 bpd by February 2001, according to the AOGCC.

In 1998, while developing the northwest corner of Endicott, BP discovered the Eider oil pool in the Ivishak formation. While production hit 6,244 bpd by February 1999, it soon dropped precipitously. BP suspended production from October 1999 to May 2000, and again in June 2007. Except for a six-day test in December 2009, it has remained offline.

The current development work at Endicott involves enhanced oil recovery using miscible water-alternating-gas injections. BP may bring its Bright Water technology to the field, according to the most recent development plan. BP also suggested it might work over wells or drill sidetracks this year, but had not permitted any wells as of mid-September.

Of the 1 billion barrels of oil in place at Endicott, BP had produced 487 million barrels of oil equivalent through 2012 at a 2012 rate of only 9,000 bpd. The field is developed with 80 wells — 55 oil producers, four gas injectors and 21 water injectors.

Of the 14 million barrels of oil in place at Sag River North, BP had produced 9 million barrels of oil equivalent through 2012 at a 2012 rate of 1,000 bpd.

The Northstar unit

After breaking an Arctic offshore barrier with Endicott, BP pushed farther with Northstar, the first Arctic field to be developed from an island connected to the shore only by pipeline.

Instead of the causeway used to connect Endicott to land, BP installed a buried subsea pipeline at Northstar, a technique later replicated at the Oooguruk and Nikaitchuq units.

Shell Western E&P Inc. discovered Northstar in 1984 with the BF-47 No. 1 well and BP constructed its five-acre gravel island in the winter of 1999 and 2000. After coming online in November 2001, production quickly rose, peaking at some 69,000 bpd by 2004.

The Northstar unit primarily produces from the Ivishak and the Shublik formations, but in recent years BP also began developing two smaller reservoirs called Fido and Kuparuk. BP is currently seeking participating areas for both reservoirs. With the unit split between state and federal leases, participating areas have caused problems in the past, such as a recent dispute between the state and minority partner Murphy Oil Corp.

Of the 310 million barrels of oil in place at Northstar, BP had produced 156 million barrels of oil equivalent through 2012 at a 2012 rate of 8,000 bpd. The field is developed with 23 wells — 15 oil producers, six gas injectors and two water injectors.

Liberty

Endicott and Northstar set the stage for another offshore venture: the Liberty field.

After drilling Liberty No. 1 on a federal lease situated six miles offshore in the Beaufort Sea, BP announced a 100 million barrel oil discovery in 1997. Seeing Northstar as a model, BP initially planned to develop Liberty from a standalone gravel island connected to shore by a subsea pipeline, but the company ultimately decided to drill ultra-extended reach wells — some as long as eight miles — from the existing Endicott facilities.

To accommodate this boundary-pushing proposal, BP commissioned a massive drilling rig from Parker Drilling Co. The rig components arrived in Alaska in 2009, but BP suspended the project in November 2010 while it conducted an engineering review and ultimately BP cancelled the project — at least "in its current form" — in early 2012.

Having already spent more than $1 billion on Liberty, BP is still actively considering alternative ways to develop the field, including its original idea of a gravel island. The company must submit a new development plan to federal regulators by the end of 2014.

Contact Eric Lidji at ericlidji@mac.com

BPRC is getting ready to ride

The independent and its partners are nearing first oil at Mustang after nearly a decade and a half of North Slope exploration

By ERIC LIDJI
For Petroleum News

If all goes according to plan, Brooks Range Petroleum Corp. will become the newest operator-producer in Alaska sometime in early 2015 — after some 15 years in the state.

If successful at its Mustang project, the local operating arm of the Kansas-based independent Alaska Venture Capital Group LLC will also be the smallest company in the history of the North Slope to bring a field from exploration to discovery to production.

JOHN J. "BO" DARRAH, JR.

The wave of independents

When long-time oilmen John Jay "Bo" Darrah Jr. and Barton Armfield formed AVCG in 1999, they were part of a wave of independents interested in sizeable oil fields passed over by the majors during the first three decades of North Slope development. Although the company acquired several exploration properties, it struggled in its early years to find partners and to negotiate access agreements with the facility operators.

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TOP ALASKA EXECUTIVE: John J. "Bo" Darrah, Jr.
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Brooks Range Petroleum

Eager to play a bigger role in the oil and gas sector, AIDEA is interested in helping to fund a 15,000-barrel per day production facilities for Mustang — a major upfront cost component.

AVCG formed Brooks Range Petroleum Corp. in 2004 and established a multi-party joint venture over the course of 2006. Today, BRPC is partnering with Nabors Industries-subsidiary Ramshorn Investments Inc. at the Mustang field.

Although the joint venture spent years drilling at numerous other prospects across the North Slope, its first production will come from one of its most recent acquisitions.

In early 2010, a larger iteration of the joint venture farmed-in the North Tarn prospect, a group of six Eni Petroleum leases along the western edge of the Kuparuk River unit.

BRPC later began calling the prospect Mustang. The state approved the formation of the Southern Miluveach unit around five leases covering some 8,960 acres at the prospect — a protracted version of the 60,864-acre unit it had first requested.

North Tarn drilled in 2011

As the lone North Slope explorer of the season, BRPC drilled the North Tarn No.1 well and started drilling a sidetrack in early 2011 using Nabors rig 9ES.

The 6,223-foot well tested the Brookian (the producing formation at the nearby Tarn satellite) and deeper Kuparuk (the main producing formation at the Kuparuk River unit).

Beforehand, BRPC estimated that the Brookian reservoir could contain some 35 million barrels of oil and that the Kuparuk reservoir could contain an additional 6 million barrels of oil. Given the notoriously compartmentalized geology of the Brookian, the company was eyeing the Kuparuk, believing the smaller reservoir could be economic.

The well and sidetrack encountered oil, but "well control challenges" prevented a complete test. BRPC returned in early 2012 to complete the sidetrack, and drill the Mustang No. 1 delineation well. The work proved up a discovery in the range of 40 million barrels of recoverable oil from the Kuparuk — bigger than expected.

Independent audit

An independent audit proved up the internal estimates.

According to the global consulting firm DeGolyer and MacNaughton, the Mustang prospect contains proved, or P1, gross reserves of 24.7 million barrels of recoverable oil. The firm also estimated the field contained 43.6 million barrels of proved and probable, or P2, reserves and 51 million barrels of proved, probable and possible, or P3, reserves.

"These estimates confirm commerciality and a favorable rate-of-return to proceed with development," AVCG lead member Ken Thompson told Petroleum News Aug. 3.

The oil shows in the Brookian sands were of "lower permeability than anticipated," according to BRPC, but the company is evaluating several ideas for developing the formation, including fracture stimulating long horizontal wells or recompleting depleted Kuparuk producing wells into the Brookian using horizontals.

Additionally, the company wants to explore a potential Kuparuk formation extension to the northwest called Appaloosa that could add reserves and field life.

Aid from AIDEA

Developing the project is requiring BRPC to be strategic and using Tudor, Pickering, Holt & Co., a Houston-based integrated energy investment and advisory firm, it began considering two strategies.

The first was to find a private equity firm willing to fund development until Mustang production could fund continuing operations, after which the company would consider going public as a way to generate capital for future exploration work.

The second was to find a partner who would fund the work in return for a majority stake in the prospect, but would be willing to let BRPC operate the development.

BRPC ultimately found a local way to fund its operations.

In late 2012, the Alaska Industrial Development and Export Authority agreed to loan the company $20 million to help build a winter ice road, a gravel mine, a 19.3-acre gravel production pad, a 0.7-mile access road from the mine to the pad and a 4.4-mile open access road from the pad to the existing road system at the nearby Kuparuk River unit.

The loan covered 80 percent of the $25 million cost of the project, with BRPC on the hook for the remainder, but the parties expected tax credits from ACES, Alaska's Clear and Equitable Share 2007 production tax, to cover some 46 percent of the cost, or $11.5 million.

Mustang Road LLC

Rather than fund the operations directly, AIDEA and BRPC created a joint venture company, Mustang Road LLC. The deal involved an 8 percent rate of return over 15 years and made Mustang Road LLC a 1 percent working interest owner in the Southern Miluveach unit.

As the lone North Slope explorer of the season, BRPC drilled the North Tarn No.1 well and started drilling a sidetrack in early 2011 using Nabors rig 9ES.

Asked why the company sought public financing for the project, Armfield, BRPC's chief operating officer, said the interest rates AIDEA offered were "very competitive" compared to the financing available from the Lower 48.

Mustang Road completed the infrastructure in early 2013, but the partnership continued.

Eager to play a bigger role in the oil and gas sector, AIDEA is interested in helping to fund a 15,000-barrel per day production facilities for Mustang — a major upfront cost component. Under a February 2013 proposal, AIDEA would put down $45 million of the estimated $190 million cost of the project, earning a 10 percent rate of return over 10 years and a small working interest in the unit. Singapore-based Ezion Holdings Ltd. would contribute between $95 million and $125 million to the project and an as-yet-undetermined third party would contribute the remaining $20 million to $50 million.

With the state having recently expanded the authority of the public corporation, AIDEA can now pursue this project — if it finds the economics of it to be acceptable.

Contact Eric Lidji at ericlidji@mac.com

Buccaneer growing Kenai Loop

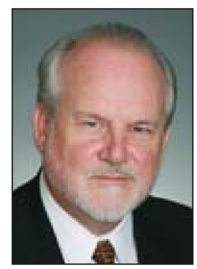
Small onshore Cook Inlet field is providing revenue while the Australian independent pursues bigger exploration targets

By ERIC LIDJI
For Petroleum News

While Buccaneer Energy Ltd. is aiming for much bigger targets in Cook Inlet, it has been earning revenue for nearly two years from a small onshore gas field near Kenai.

The Australian independent brought the Kenai Loop field into production in early 2012 and the field was producing some 10 million cubic feet per day as of September 2013.

Drilling Kenai Loop



JAMES WATT

The relatively young independent arrived in Alaska in early 2010 by acquiring the Cook Inlet assets (and some of the executives) of independent Stellar Oil & Gas LLC.

The acreage included a non-contiguous block of 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. Before drilling, Buccaneer estimated the field contained "multiple stacked pay zone possibilities between 5,000 and 10,000 feet" and reserves between 35 billion and 78 billion cubic feet.

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. In June, the well flowed at a rate of 10 million cubic feet per day. The company said well logs indicated 510 feet of gross pay in the Beluga and Upper Tyonek, an estimate the company quickly upgraded to 645 feet.

An analysis from the consulting firm Ralph E. Davis Associates Inc. — looking at two sands, at 9,700 feet and 10,000 feet — estimated that the prospect contained 31.5 bcf of natural gas and 3.9 million barrels of oil equivalent in proven reserves.

In September 2011, Buccaneer used the 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. The well was a dry hole, which Buccaneer is now permitting for Class II disposal.

Online in January 2012

Despite the setback, Buccaneer brought Kenai Loop online in January 2012. After initial ramp up, the well started producing at some 5 million cubic feet per day, but the company said it was

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"confident that the well can be produced reliably at higher rates." Buccaneer increased the rate to 6 mmcf per day in October and 6.5 mmcf per day in December.

Through the remainder of winter, the company permitted a 3-D seismic shoot covering some 25 square miles around Kenai Loop to improve its understanding of the prospect.

In June 2012, a Buccaneer subsidiary signed a three-year lease on Glacier No. 1 with an option to purchase, giving the company a rig for all its near-term onshore operations.

After incorporating the seismic results into its geologic model of the region, Buccaneer drilled the Kenai Loop No. 4 well to some 13,000 feet in September 2012. A test in January 2013 flowed at 3 mmcf per day. Buccaneer brought the well online in February at 2 mmcf per day. By March, the entire field was producing some 10 mmcf per day.

Unit request denied

In December 2012, Buccaneer applied to form a 7,500-acre unit over seven leases, but the Department of Natural Resources denied the request, saying its "primary propose" appeared to be "lease extension and not the efficient development of the unit area."

In June 2013, Buccaneer renamed its Kenai Loop wells "to reflect their pad number."

Under the new scheme, 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.

In August 2013, Buccaneer started drilling the Kenai Loop No. 1-4, a 10,700-foot well targeting what "appears to be fault separated from the current producing zones in the Kenai Loop No. 1-1 and Kenai Loop No. 1-3 wells," according to the company.

As of early September, Buccaneer was near total depth at the well. Buccaneer is aiming to bring the well online at 3 mmcf to 5 mmcf per day by the end of the year.

With the two existing wells draining only about 340 acres of the field, Buccaneer is likely to drill additional wells, according to a recent analysis from Canaccord Genuity.

Contracts and markets

The Kenai Loop field shows the challenges and opportunities for a small producer.

After testing Kenai Loop No. 1, Buccaneer secured a contract with Enstar Natural Gas Co. in August 2011 to provide firm commitments for the Cook Inlet Natural Gas Storage Alaska facility on the Kenai Peninsula, then under construction and now in operation.

Under the contract, Buccaneer must deliver 5 mmcf per day to the facility, up to 12 mmcf per day by 2018. The contract allows Buccaneer to sell as much as 15 mmcf per day and 31.5 billion cubic feet by 2018 should Kenai Loop production increase. The contract is tied to the New York Mercantile Exchange gas futures with a ceiling of $10 per thousand cubic feet and a seasonally adjusted floor between $5.75 and $6.85 per mcf, with the floor and ceiling regularly adjusted for inflation.

Because Buccaneer expected the field to come online four months before the storage facility, Buccaneer also signed a short-term contract with ConocoPhillips in late 2011.

The unique contract gave Buccaneer the option to sell up to 2.5 bcf to the ConocoPhillips-operated liquefied natural gas terminal on the Kenai Peninsula. The contract came after ConocoPhillips mothballed the plant, but delayed the closing to accommodate four summer shipments and delayed it again for a shipment in October.

Volumes to daily winter auction

In addition to the ConocoPhillips contract, Buccaneer was able to sell uncommitted volumes into the daily winter auction, the Enstar spot market for peak demand days. In early 2013, the market

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BUCCANEER ENERGY *continued from page 31*

price hit $22 per thousand cubic feet, according to Buccaneer.

When Buccaneer increased Kenai Loop No. 1 production in October 2012, it signed a two-month contract to sell 1 mmcf per day to an unnamed party for $7.50 per thousand cubic feet, net tariffs. Buccaneer signed a month-long contract in December to sell 500 thousand cubic feet to an unnamed party for $15 per thousand cubic feet, net tariffs.

Once those contracts expired, Buccaneer sold the additional volumes to Enstar, as it also did when Kenai Loop No. 4 brought total field production up to 8.5 mmcf per day.

To accommodate the anticipated production from Kenai Loop No. 4, Buccaneer and Enstar started negotiating a multiyear contract but also signed a short-term summer contract. Under the agreement, Buccaneer committed to provide between 4.37 mmcf and 5 mmcf per day from March 20 to Sept. 30, 2013, at $6.80 per mcf.

In July 2013, Enstar and Buccaneer signed the longer-term contract.

Under the deal, Buccaneer will provide 2.663 bcf at a "continuous rate" through June 30, 2016. The price starts at $6.80 per mcf and increases 4 percent annually.

Even though Buccaneer is currently selling all or mostly all of its Cook Inlet production, this history of cobbling together small, short-term contracts clearly concerns Buccaneer.

The company recently complained to the Regulatory Commission of Alaska about a proposed contract between Enstar and Hilcorp Alaska LLC, which, according to Buccaneer, would shut small producers out of the local utility market through early 2018.

On numerous occasions over the past few years, Buccaneer has suggested that it wants the option of being able to export any additional gas supplies as liquefied natural gas, but also wants policymakers to expand markets for Cook Inlet gas outside of Southcentral.

Financing stabilizing

The Kenai Loop field is the only revenue-generating asset in the Buccaneer portfolio of Cook Inlet properties, but the field is not yet producing enough to fund expansion work.

To pay for drilling, both at Kenai Loop and at other prospects, the publicly traded Buccaneer has used loans and stock placements, but in December 2011 the company also took the unusual step of using state tax credits to back a $50 million credit facility.

In early 2012, though, several Buccaneer contractors complained to the Kenai city council about unpaid bills for work performed at Kenai Loop. Buccaneer addressed the issue by taking out $50 million in additional loans and lines of credit in May 2012.

The bulk of the financing also covers other projects in the Buccaneer portfolio.

Concerned about the company becoming unfocused, a pair of shareholders called for a vote to replace the board of directors. The vote yielded a split, but the three challenging board members added to the board subsequently resigned without a public explanation.

Subsequently, Buccaneer farmed-out many prospects, which, along with the credit facilities, helped stabilize its wallet. The farm out covers eight wells at four exploration prospects, but Buccaneer retained its 100 percent working interest in Kenai Loop.

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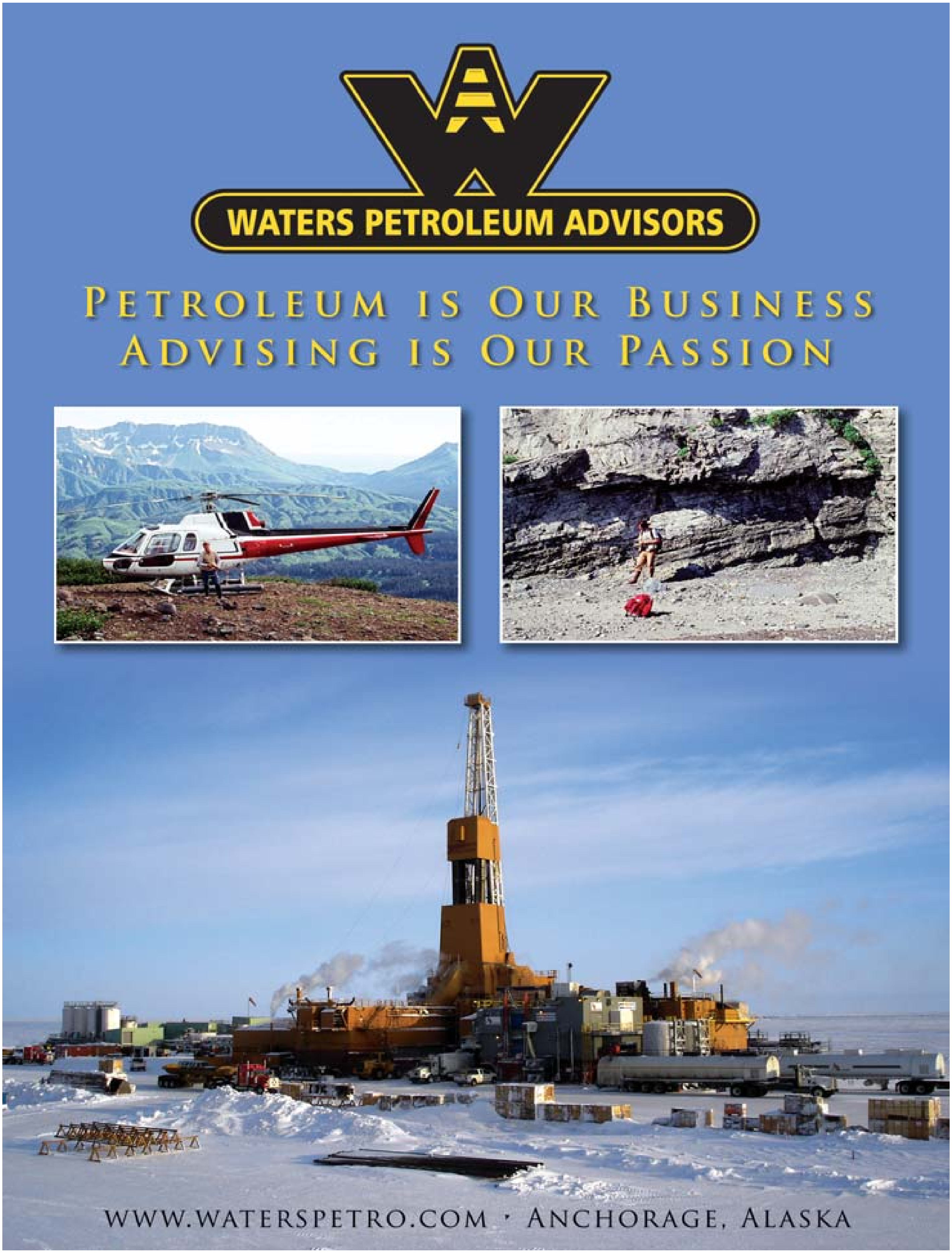
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Alpine satellite CD2 is connected to the main Alpine pad by a combination gravel road/airstrip.

Conoco: Going west since 1980

From the Kuparuk River unit, to the Colville River unit, to the Greater Mooses Tooth unit, ConocoPhillips is focused on expansion

By ERIC LIDJI
For Petroleum News

ConocoPhillips is the company most responsible for the westward expansion of oil development across the North Slope and it continues to set its sights even farther west.

TROND-ERIK JOHANSEN

The company currently operates production from the Kuparuk River and Colville River units on state and Native land, and is eyeing development from the Greater Mooses Tooth and Bear Tooth units on federal land within the National Petroleum Reserve-Alaska.

Through various subsidiaries, ConocoPhillips also operates the Alpine, Kuparuk and Oliktok pipelines, as well as owning some 28 percent of the trans-Alaska oil pipeline.

Combined, ConocoPhillips was operating an average of 171,809 gross barrels of oil per day in July 2013, according to the Alaska Oil and Gas Conservation Commission.

The Kuparuk River unit

Sinclair Oil and Gas discovered the Kuparuk River oil pool in 1969 with the Ugnu No. 1 well, but it took another decade before ARCO Alaska sanctioned development.

The delay gave the industry time to build the trans-Alaska oil pipeline and to bring the Prudhoe Bay unit into production to the east, but for ARCO it had more to do with economics. Even a year earlier, the Kuparuk development team had been unable to persuade top management to sanction the "marginally economical" field, but rising oil prices and the demand for domestic energy supplies changed the picture by 1979.

At the time, ARCO and Sohio were suing the state over its corporate income tax, but ARCO Chairman Robert O. Anderson said the lawsuit primarily concerned the impact on wildcat exploration. "The Kuparuk represents a fairly well-known quantity, with limited risk, which differs from the high-risk investments cited in the lawsuit," Anderson said.

The development program called for bringing 20 square miles of the field online by 1982, but also working with nearby leaseholders on a longer-term plan for 200 square miles.

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CONOCOPHILLIPS *continued from page 35*

ARCO started work on Central Processing Facility 1 in 1979 and after three sealifts the company brought the Kuparuk River field online in late 1981. At the same time, ARCO was working with the other interest owners on the agreements needed to unitize the field.

The Kuparuk River field produced 32.4 million barrels in 1982 and 39.9 million barrels in 1983, when ARCO started building Central Processing Facility 2 and the Seawater Treatment Plant, and the additional facilities accommodated additional production. The field produced 46.1 million barrels in 1984, 79.7 million barrels in 1985 and 95 million barrels in 1986, when ARCO began construction on Central Processing Facility 3.

Those early years saw two secondary recovery projects, a CPF-1 waterflood launched in 1983 and a small-scale enhanced oil recovery project in 1988. ARCO also began infill drilling in 1988. In December 1992, total Kuparuk River unit production peaked at 339,386 barrels per day, according to the Alaska Oil and Gas Conservation Commission.

Originally, engineers had expected production to peak at 250,000 bpd.

After the peak

In the two decades since, activities at Kuparuk River have been dedicated to expanding the field through infill drilling, satellite development and enhanced oil recovery. The success of these efforts can be expressed in a single fact: In 1999, cumulative Kuparuk production passed 1.6 billion barrels, which was the initial expected recovery estimate for the field.

Through mergers and acquisitions between 1999 and 2002, ConocoPhillips became the operator of the Kuparuk River unit. Today, ConocoPhillips owns a 55.3 percent interest in the unit, with BP Exploration (Alaska) Inc. owning 39.2 percent, Chevron U.S.A Inc. owning 4.9 percent and ExxonMobil Alaska Production Inc. owning 0.6 percent.

By the end of 2012, ConocoPhillips was developing the main Kuparuk field from 44 drill sites — including seven shared with satellites — and 821 active wells, according to a June 2013 report. To enhance recovery, ConocoPhillips was using waterflood at 14 sites, immiscible water-alternating-gas, WAG, at five sites and miscible WAG at 25 sites.

A major program at Kuparuk in recent years has used coiled tubing drilling to access smaller accumulations missed by conventional drilling equipment. A 14-well program in 2012 completed 53 laterals, which brought 5,050 bpd of incremental production online.

ConocoPhillips identified up to 17 coiled-tubing drilling candidates for 2013, including a cluster of sidetracks in the southern reaches of the field at drill sites 2F, 2G, 2H and 2K.

The Kuparuk participating area produced 87,900 bpd in 2012.

The current program includes delineating peripheral areas of the field and using tertiary recovery techniques at select locations. It also involves managing the changing profile of the aging field. Gas and water handling limits have constrained oil production in recent years. The gas handling constraint will be alleviated as the Greater Kuparuk Area naturally becomes gas short — ConocoPhillips even plans to import fuel gas from Prudhoe Bay starting in 2014 to reserve native gas for injection — but ConocoPhillips is working on numerous upgrade projects to alleviate its water handling constraints.

ConocoPhillips described its future exploration and appraisal plans at Kuparuk as being an "infrastructure-led exploration strategy" based on a 2011 3-D seismic acquisition.

The West Sak satellite

Of the 2.5 billion barrels of oil produced from the unit through July 2013, the main field is responsible for some 2.3 billion and the five satellites account for the remainder.

In 1997 and 1998, ARCO began production from three satellites — West Sak, Tarn and Tabasco — and in 2000 it announced the discovery of a fourth satellite, Meltwater.

In 2012, the Kuparuk satellites produced some 25,200 bpd.

ARCO discovered the shallow West Sak oil pool in 1971 with the West Sak River State No. 1 well and proved the feasibility of producing the viscous oil through a 15-well pilot project across 45 acres of the field between June 1983 and December 1986, but it took another decade before regular production began from the 1D drill site in December 1997.

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

ARCO followed the initial phase of conventional drilling with multilateral wells starting in 1999 and 2000, but launched a major heavy oil development at West Sak in 2004. The $500 million program called for an expansion of the existing 1E pad and the construction of a 1J pad to better access the huge viscous and heavy oil contained in the reservoir.

ARCO originally developed West Sak from the pre-existing 1B pad at Kuparuk and the new 1C and 1D pads, but added the 1E pad in 2004 and the 1J pad in 2006 and later began using 3K pad to access the field. Through 2012, the field was being developed from 102 active wells — 49 producers and 53 injectors — on those six pads.

Through the end of 2012, the West Sak oil pool had produced 62 million cumulative barrels of oil, including a rate of 14,185 bpd in 2012, according to ConocoPhillips.

Heavy oil

This success, though, masks the difficulty in producing the heavier oil at West Sak.

Efforts to date have included multilateral, horizontal and "undulating" wells, sand filtering, various waterflooding and gas injection techniques and different well spacing. However, as ConocoPhillips recently told the state, "the pace of future West Sak development has slowed while performance of recent developments is evaluated."

The most recent pilot project — Viscosity Reducing Water Alternating Gas — wrapped up in May 2013, and ConocoPhillips wants to expand it to other areas of the field.

Among those is Eastern NEWS, or North East West Sak, where ConocoPhillips would drill five horizontal multilateral producers and 13 vertical injectors on an existing pad.

The Tarn satellite

ARCO discovered the Tarn oil pool with the Bermuda No. 1 well in 1991.

The Tarn oil pool is in the southwest corner of the Kuparuk River unit and consists of five intervals of late Cretaceous-aged marine sandstone in the Seabee formation. From deepest to shallowest, the intervals are called Iceberg, Arete, Cairn, Bermuda and C30.

ARCO brought Tarn online in June 1998.

ConocoPhillips is currently developing the satellite from the 2N and 2L pads. Through 2012, 63 wells have been drilled from the pads — 43 producers and 20 injectors.

"Recent studies have indicated that there may be additional infill and peripheral development opportunities," ConocoPhillips wrote in its most recent Tarn update. "Plans for 2013 and 2014 include three grassroots rotary wells and one rotary sidetrack."

The 2L wells would target the eastern and northern flank of the accumulation with fracture stimulation and focused injection on the western flank. The 2N wells would realign a waterflood pattern and target an area north and east of current production.

2S pad under consideration

ConocoPhillips is currently considering a 2S pad in the region and evaluating a 2008 discovery in the younger Cairn interval as well as an older Esker interval.

Through the end of 2012, the Tarn oil pool had produced 107 million cumulative barrels of oil, including a rate of 7,100 bpd in 2012, according to ConocoPhillips.

In early 2012, ConocoPhillips used Doyon rig 141 to drill the Shark Tooth No. 1 well from an ice pad four miles from the 2K pad, which is northeast of 2N and 2L.

Shark Tooth No. 1 appraised a discovery ARCO made with the KRU 21-10-08 well in the late 1980s. It was "critical for any future development of this part of the Kuparuk reservoir," as ConocoPhillips told regulators, because it would "provide additional reservoir information in this area and narrow uncertainty

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CONOCOPHILLIPS *continued from page 37*

around reservoir description parameters including oil-water contact, sand quality and thickness, and oil viscosity."

The well "discovered hydrocarbons in the Kuparuk sands, in accordance with expectations, and confirmed mapped volumes," ConocoPhillips said in late 2012.

ConocoPhillips is now permitting a 24-well S pad, an access road and a gravel mine, as well as associated pipelines and power lines at Shark Tooth with an eye toward a 2015 start date, but must sanction the project before it can move forward. ConocoPhillips originally considered developing the prospect from its existing 2L, 2M or 2K pads, but decided those plans would have taxed the abilities of existing drilling technology.

The Tabasco and Meltwater satellites

ARCO discovered the Tabasco oil pool with the Kuparuk River unit 2T-02 well in 1986, as part of its regular development drilling from the 2T pad at the western edge of the unit.

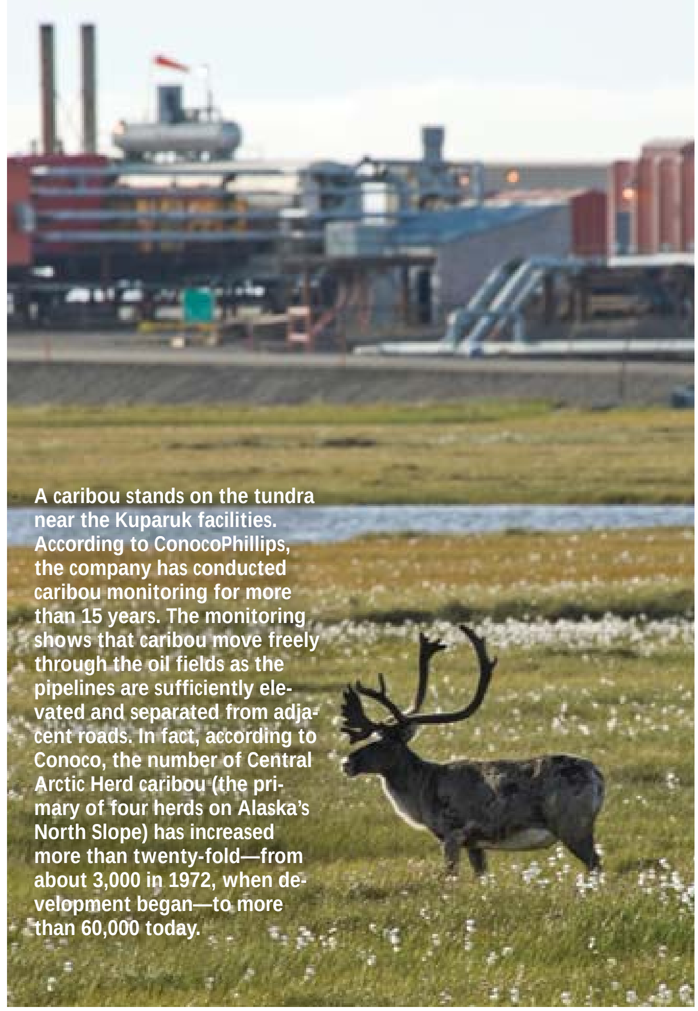
The shallow, viscous satellite in the middle Cretaceous Nanushuk Group Tabasco sand at approximately 3,000 feet subsea came online in May 1998 from the existing 2T pad.

Through the end of 2012, eight of the 12 wells at the field were online. While ConocoPhillips currently has no plans to delineate the field, the existing infrastructure can accommodate eight additional wells with only a minimal gravel expansion.

Through the end of 2012, the Tabasco oil pool had produced 17,345,000 cumulative barrels of oil, including a rate of 1,076 bpd in 2012, according to ConocoPhillips.

ARCO discovered the Meltwater oil pool in 2000 with the Meltwater North No. 1 exploration well drilled into the middle Cretaceous Seabee formation Bermuda/Cairn Sands, the stratigraphic equivalent of Tarn. Philips Petroleum brought Meltwater online in November 2001 from the 2P pad, which accesses two leases some 10 miles southwest of the unit boundaries. A two-phase, 19-well drilling program wrapped up in 2004, but only 15 wells were active by the end of 2012 — nine producers and six injectors.

Originally, ConocoPhillips alternated water and gas injections to enhance recovery at the field, but in 2009 it took a water injection line out of service over concerns about corrosion. Now,



A caribou stands on the tundra near the Kuparuk facilities. According to ConocoPhillips, the company has conducted caribou monitoring for more than 15 years. The monitoring shows that caribou move freely through the oil fields as the pipelines are sufficiently elevated and separated from adjacent roads. In fact, according to Conoco, the number of Central Arctic Herd caribou (the primary of four herds on Alaska's North Slope) has increased more than twenty-fold—from about 3,000 in 1972, when development began—to more than 60,000 today.

ConocoPhillips only uses miscible gas injection for enhanced recovery.

After well monitoring suggested these injections might be migrating underground, the AOGCC prohibited ConocoPhillips from drilling new wells or converting existing wells to MI until it resolved the issue. While ConocoPhillips had no immediate drilling plans for the satellite anyway, the company launched a two-year study of the overburden in the area to better identify the problem.

The AOGCC said the migration was not a threat to drinking water.

The current work at Meltwater primarily involves field maintenance, such as pigging the produced oil line and monitoring bottom-hole pressures at the four shut-in wells.

Through the end of 2012, the Meltwater oil pool had produced 17,015,000 cumulative barrels of oil, including a rate of 2,719 bpd in 2012, according to ConocoPhillips.

The Palm satellite

Kuparuk development has expanded in other ways, too.

Phillips Petroleum discovered the Palm accumulation in 2001 with the Palm No. 1 well, at the far western edge of the Kuparuk River unit. The accumulation is in a Kuparuk C4 interval now known to be in communication with the main Kuparuk reservoir.

To develop the reservoir, ConocoPhillips built the 3S pad, which came online in November 2003. In early 2013, ConocoPhillips conducted a perforation and hydraulic fracture pilot test at the existing DS 3S-19 well to evaluate the Cretaceous Brookian Moraine interval, but is still analyzing the results. "Any development would, of course, require adequate appraisal and study to prove commerciality," ConocoPhillips said.

The Colville River unit

While Kuparuk was the western frontier for North Slope oil development for nearly two decades, the title now belongs to the Colville River unit — although not perhaps for long.

The main Alpine field and its three satellites — Fiord, Nanuq and Qannik — produced an average of 60,742 bpd in July 2013, according to the AOGCC. A fourth satellite is under construction. The unit is the gateway to National Petroleum Reserve-Alaska production.

ARCO Alaska discovered the Alpine oil pool in 1994 with the Bergschrund No. 1 exploration well and decided the field was commercial in 1996. Along with partners Anadarko Petroleum Corp. and Union Texas Petroleum Alaska Corp., ARCO proposed a $700 million to $800 million program to build infrastructure and drill 100 to 150 wells.

Through mergers and acquisitions, ConocoPhillips now operates the unit and owns a 78 percent working interest in the leases, and Anadarko owns the remaining 22 percent.

The partners originally estimated that the field contained 365 million barrels of recoverable oil, but they increased the reserve estimate to 429 million barrels in 1997.

Cumulatively, the entire Colville River unit had produced nearly 453 million barrels of oil through July 2013.

Existing facilities

Early on, Anadarko said Alpine offered “repeatability” and “running room,” or the ability to develop a string of smaller discoveries using its existing facilities, equipment and know-how. While the Alpine satellites are large by Lower 48 standards, they are considered too small to be economic on their own. By timing the startup of the four satellites sanctioned to date, ConocoPhillips has been able to use its existing facilities.

The Alpine field surpassed expectations. While initial projections had pegged production at 80,000 bpd, Alpine produced 98,895 bpd in 2004 and peaked at 130,685 bpd in November 2005. As production increased and the profile began changing, ConocoPhillips expanded the capacity of its Alpine facilities in 2004 and again in 2005 to accommodate 35,000 additional barrels of crude oil and 100,000 barrels of produced water each day.

Alpine production comes from Jurassic-aged sandstone not producing anywhere else on the North Slope, and, at 40 degrees API, is lighter than at Prudhoe Bay or Kuparuk.

Horizontal drilling

The Colville River unit is also unique for being developed using horizontal wells, which has resulted in a much smaller footprint than at older fields. Before CD-5, ConocoPhillips was developing the 25,000-acre reservoir from just 97 acres of surface infrastructure, according to the AOGCC.

For 2013 and early 2014, ConocoPhillips planned to drill five new production wells and seven new injection wells in peripheral southwest and east areas of Alpine, which could lead to future drilling, but planned no Nanuq-Kuparuk drilling in 2013 in spite of (or perhaps because of) current production exceeding expectations. As of mid-September, ConocoPhillips had completed the CD1-47 producer and the CD1-49 service well.

After finding success with a four-well hydraulic fracturing program in 2012, ConocoPhillips planned to use the technique on as many as 15 wells this year.

By the start of 2013, ConocoPhillips had drilled 131 wells including 65 producers at Alpine and nine wells including four producers at Nanuq-Kuparuk. In 2012, Alpine produced 45,300 bpd and Nanuq-Kuparuk produced 2,400 bpd.

Cumulatively, those produced some 396 million barrels through July 2013, the AOGCC reports.

Fiord at CD-3, Nanuq at CD-4

As production grew, ConocoPhillips began thinking about satellites.

ConocoPhillips initially developed Alpine from two pads, CD-1 and CD-2, but in a 2003 environmental impact statement the company proposed five Alpine satellites called Fiord, Nanuq, Lookout, Spark and Alpine West, and hinted at 10 additional oil accumulations within 30 miles of Alpine that could possibly become future satellites.

In 2004, with the facility expansion just beginning, ConocoPhillips sanctioned the first two Alpine satellites: Fiord from CD-3 to the north and Nanuq from CD-4 to the south.

(Today, ConocoPhillips uses CD-4 to develop Alpine, as well as Nanuq.)

The Nechelik No. 1 well encountered the Fiord oil pool as early as 1982, but ARCO Alaska’s Fiord No. 1 well from 1992 is considered to be the discovery well for the satellite. Fiord No. 2 confirmed the discovery in 1994, and several wells and sidetracks between 1999 and 2001 delineated it. Fiord now produces from two zones, the Nechelik sand of the Jurassic Kingak formation and the Cretaceous-aged Kuparuk C sand.

By the start of 2013, ConocoPhillips had completed 11 production wells and 10 injection wells into the Fiord-Nechelik zone. The company planned to drill one well in 2013, two wells in 2014 and one well in 2015. ConocoPhillips had three active production wells and three active injection wells in the Fiord-Kuparuk zone as of 2012 with plans for 2013 to drill two new production wells and to convert an existing production well to an injector.

According to September 2013 AOGCC filings, ConocoPhillips completed the CD3-127 producer, and permitted the CD3-320 and CD3-316B producers this year at Fiord.

Up to 32 wells at Fiord

The existing development plan at Fiord calls for as many as 32 active wells.

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Conoco managing old CI assets

While ConocoPhillips expands its North Slope operations, the company continues to maintain legacy assets in the Cook Inlet basin

By ERIC LIDJI
For Petroleum News

ConocoPhillips is the only company to operate production in both major basins in Alaska.

While the bulk of ConocoPhillips' production comes from the North Slope, the company maintains three major operations in Cook Inlet: the onshore Beluga River unit, the offshore North Cook Inlet unit and the liquefied natural gas export terminal in Nikiski.

The Beluga River unit

Standard Oil Co. of California — working with Shell and Richfield Oil Corp. — discovered the Beluga River gas pool in December 1962 with the Beluga River Unit No. 1 while looking for oil in deeper formations on the west side of the Cook Inlet basin.

The company brought the field online in 1968, after Chugach Electric Association built the Beluga River Power Plant nearby. With a major pipeline in 1984, Enstar Natural Gas Co. connected the field to residential and commercial heating markets in Anchorage.

Today, ConocoPhillips, Hilcorp and Municipal Light & Power each own a one-third interest in the field, which produces some 80 million to 90 million cubic feet per day.

Cumulatively, the Beluga River unit had produced some 1.3 trillion cubic feet of gas through July 2013, according to the Alaska Oil and Gas Conservation Commission.

As of early 2013, the Beluga River unit hosted 27 wells — 15 in production, two operating disposal wells, one plugged and abandoned, and nine shut-in.

With 45 years of hard work under its belt, the Beluga River unit remains a mainstay for the Southcentral region, but its performance is in decline. The Sterling formation is at 30 percent of its original pressure, according to ConocoPhillips, leading to a decrease in deliverability. Water production from the field has risen rapidly over the past decade. Those two facts are driving much of the current development activities.

ConocoPhillips spent more than $80 million drilling four wells at the Beluga River unit between 2008 and 2010 and spent another $60 million in 2011 dispersing compressor stations to improve the pressure and increase the quality of the machines at the field.

Between mid-2012 and mid-2013, ConocoPhillips drilled the BRU 244-23, recompleted the 212-24T to stimulate shallower Beluga sands, planned six well turnarounds and began evaluating several projects to improve well performance.

The current plan of development runs through June 17, 2014, and calls for no new drilling, but ConocoPhillips is proposing to install velocity strings and artificial lift to improve the production from ex-

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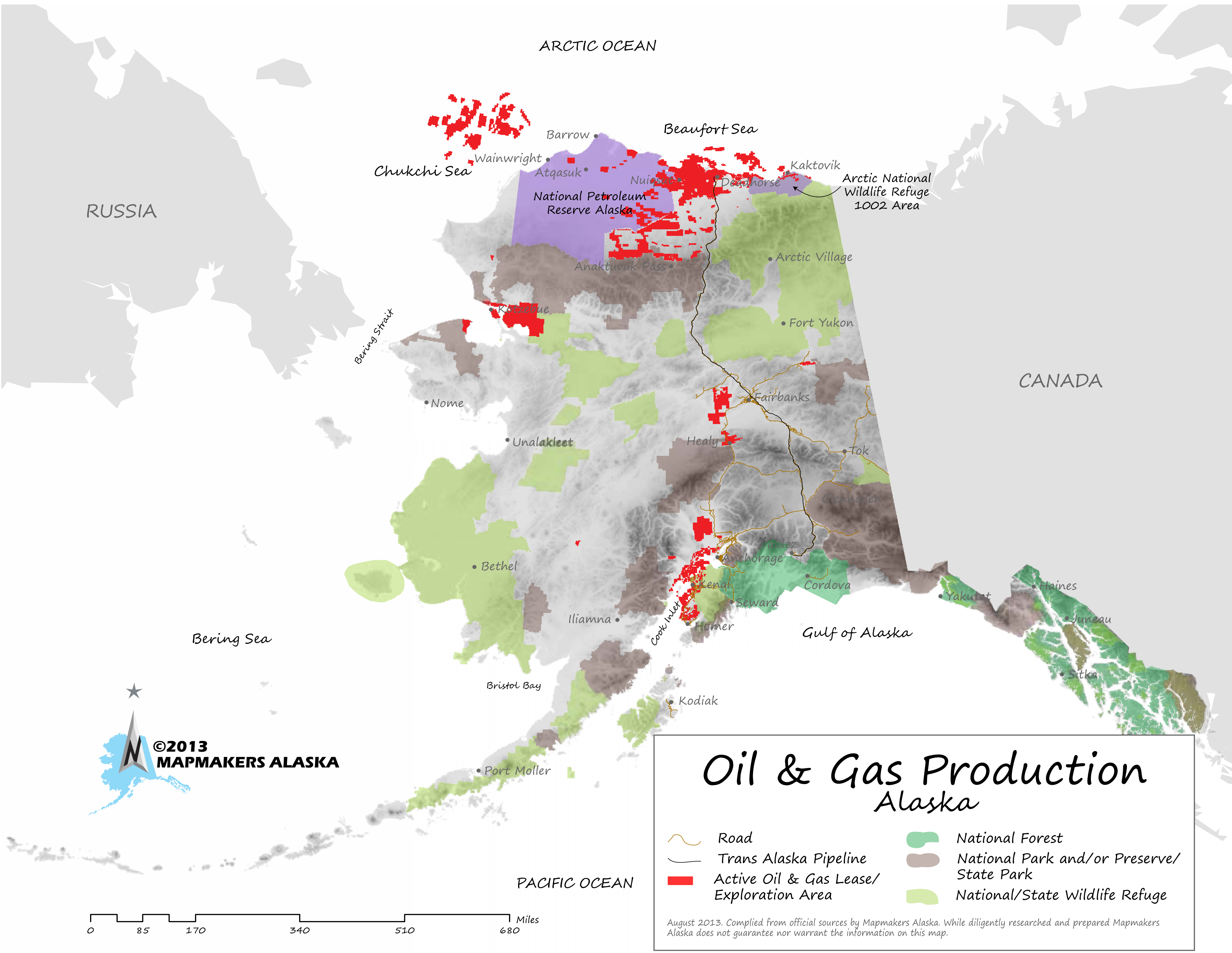

Oil & Gas Production
Alaska

- Road
- Trans Alaska Pipeline
- Active Oil & Gas Lease/ Exploration Area
- National Forest
- National Park and/or Preserve/ State Park
- National/State Wildlife Refuge

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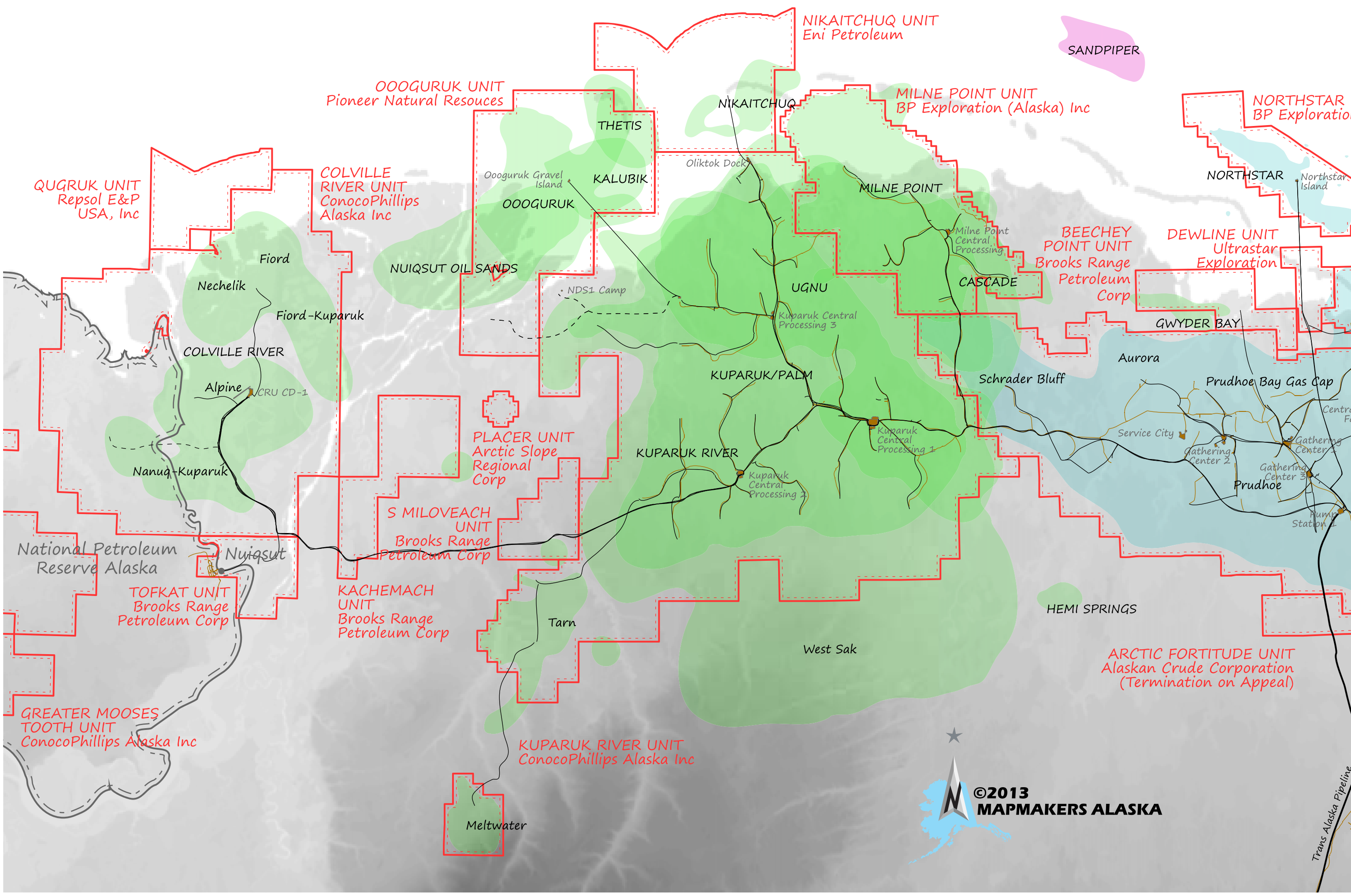


LEGACY ASSETS *continued from page 40*

isting wells, as well as to upgrade the cylinders on several wellhead compressors, among numerous other projects aimed at similar outcomes. The company also continues to analyze ways to bring shut-in wells back into production.

The North Cook Inlet unit

Pan American Petroleum Corp. discovered the North Cook Inlet Tertiary System Gas Pool in 1962 in the waters off Tyonek with the Cook Inlet St 17589 No. 1.

ConocoPhillips developed the field using the Tyonek platform, which ties back to the east side of Cook Inlet and eventually feeds into the Kenai LNG facility. North Cook Inlet came online in 1969, the same year the pioneering facility exported its first shipment.

In late 2012 and 2013, ConocoPhillips conducted a limited program at the unit. The biggest item was installing gas lift at four wells, three of which were shut-in and one of which has since been brought back into production. The two wells that remain shut-in both produced water after the gas lift and ConocoPhillips is considering alternatives.

ConocoPhillips also replaced both cranes at the platform.

In 2008 and 2009, ConocoPhillips spent $75 million drilling three wells at the unit, but later called those wells disappointing. ConocoPhillips did not drill this year, but told regulators it "plans to perform a rig work-over program that may or may not include drilling in 2014 or 2015" and "plans to evaluate future drilling opportunities after 2015."

Other work being considered for the next two years includes upgrading compressors, performing concentric coiled tubing well work delayed by the crane replacement, installing or improving artificial lift at four more wells and potentially conducting two rig workovers and sidetracking a well, in addition to ongoing maintenance and repairs.

Cumulatively, North Cook Inlet had produced some 1.8 tcf through July 2013.

The Kenai LNG facility

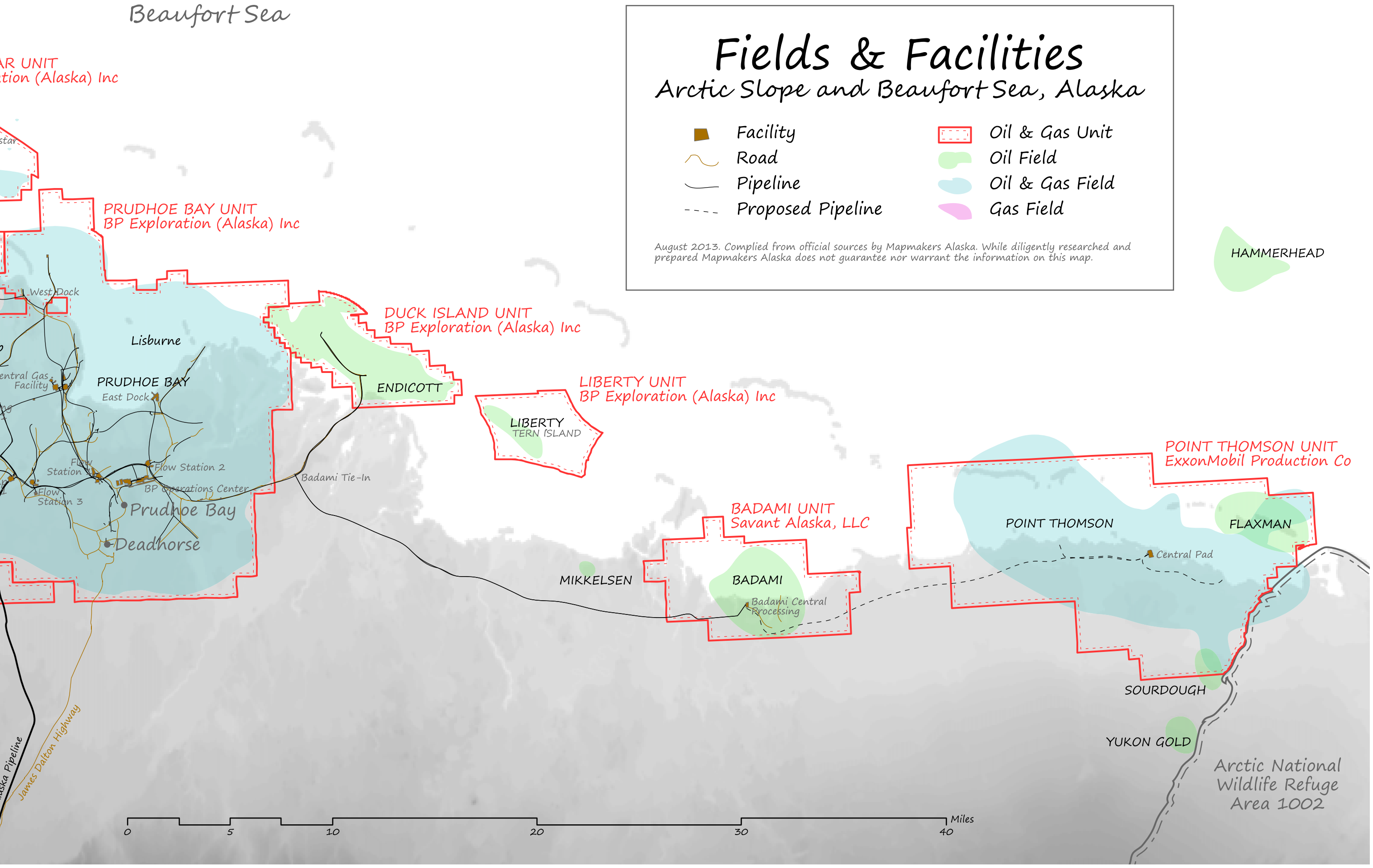
While North Cook Inlet has spent much of its life feeding the Kenai LNG plant, the relationship the between field and facility has been strained in recent years. ConocoPhillips and partner Marathon Oil announced plans in early 2011 to mothball the facility because they could not secure contracts in the Asian markets, but subsequently kept the facility operational through 2012 to accommodate unexpected increases in Asian demand.

Those shipments came to an end when the most recent export license expired in March 2013. With tightening supplies in the Cook Inlet basin, ConocoPhillips — now the lone operator — saw no need to apply for another extension.

In September 2013, though, the Alaska Department of Natural Resources asked ConocoPhillips to apply for a three-year extension. With local demand met through 2018, the state believes the facility is a needed market for Cook Inlet producers.

ConocoPhillips is currently considering the request, the company said. The North Cook Inlet unit also includes a Tyonek Deep oil prospect, which ConocoPhillips considers "uneconomic as a stand-alone development at this time," but recently farmed out to Buccaneer Energy Ltd.

Contact Eric Lidji at ericlidji@mac.com


Fields & Facilities
Arctic Slope and Beaufort Sea, Alaska
Facility
Road
Pipeline
Proposed Pipeline
Oil & Gas Unit
Oil Field
Oil & Gas Field
Gas Field
August 2013. Complied from official sources by Mapmakers Alaska. While diligently researched and prepared Mapmakers Alaska does not guarantee nor warrant the information on this map.
Beaufort Sea
PRUDHOE BAY UNIT
BP Exploration (Alaska) Inc
West Dock
Lisburne
PRUDHOE BAY
East Dock
Flow Station 2
BP Operations Center
Flow Station 3
Prudhoe Bay
Deadhorse
DUCK ISLAND UNIT
BP Exploration (Alaska) Inc
ENDICOTT
LIBERTY UNIT
BP Exploration (Alaska) Inc
LIBERTY
TERN ISLAND
Badami Tie-In
MIKKELSEN
BADAMI UNIT
Savant Alaska, LLC
BADAMI
Badami Central Processing
POINT THOMSON UNIT
ExxonMobil Production Co
POINT THOMSON
Central Pad
FLAXMAN
HAMMERHEAD
SOURDOUGH
YUKON GOLD
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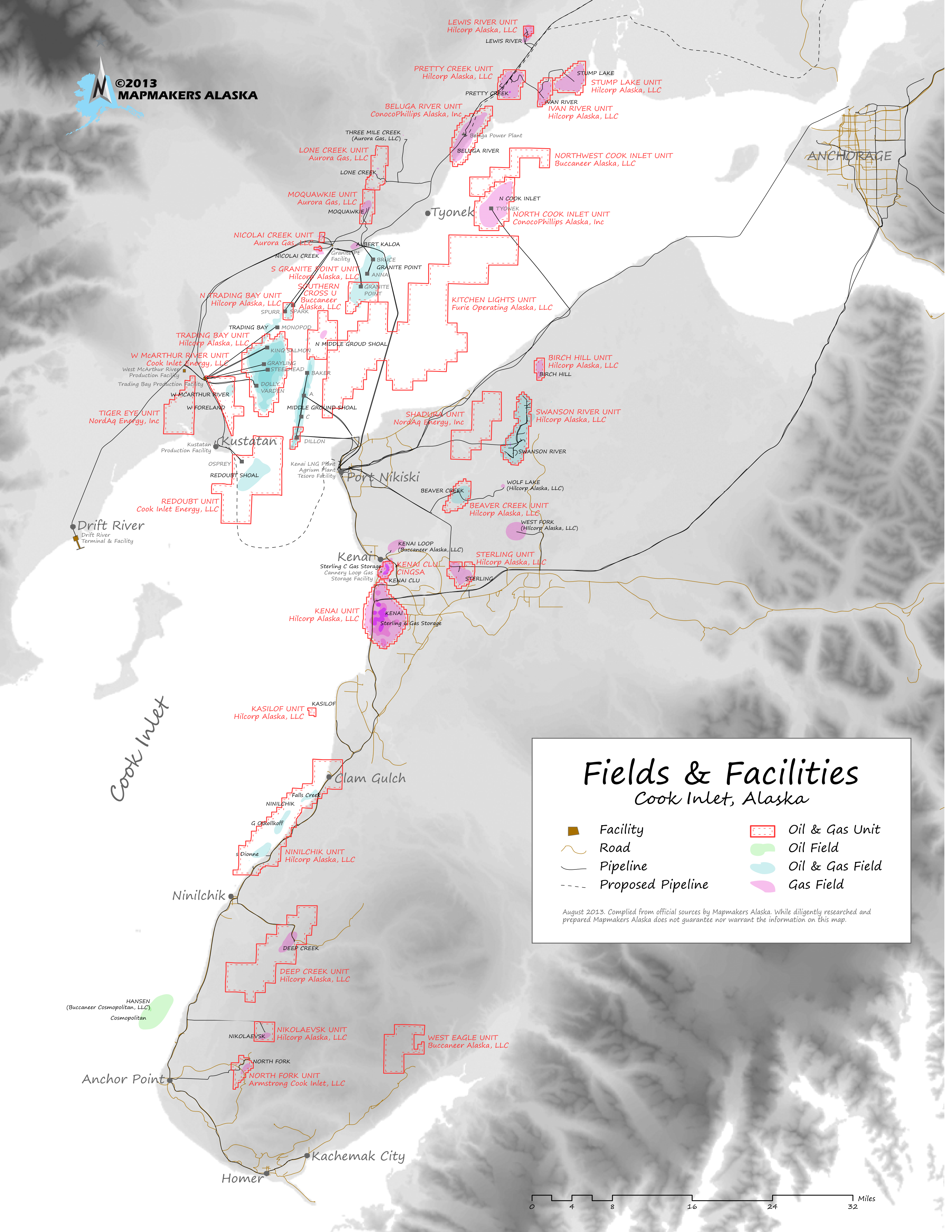

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MAPMAKERS ALASKA
Fields & Facilities
Cook Inlet, Alaska
Facility
Road
Pipeline
Proposed Pipeline
Oil & Gas Unit
Oil Field
Oil & Gas Field
Gas Field
August 2013. Complied from official sources by Mapmakers Alaska. While diligently researched and prepared Mapmakers Alaska does not guarantee nor warrant the information on this map.
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8
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Miles
LEWIS RIVER UNIT
Hilcorp Alaska, LLC
LEWIS RIVER
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
Beluga Power Plant
BELUGA RIVER
THREE MILE CREEK
(Aurora Gas, LLC)
LONE CREEK UNIT
Aurora Gas, LLC
LONE CREEK
NORTHWEST COOK INLET UNIT
Buccaneer Alaska, LLC
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
NICOLAI CREEK
Granite Pt Facility
ALBERT KALOA
BRUCE
GRANITE POINT
ANNA
S GRANITE POINT UNIT
Hilcorp Alaska, LLC
SOUTHERN CROSS U
Buccaneer Alaska, LLC
GRANITE POINT
N TRADING BAY UNIT
Hilcorp Alaska, LLC
SPURR
SPARK
KITCHEN LIGHTS UNIT
Furie Operating Alaska, LLC
TRADING BAY
MONOPOD
TRADING BAY UNIT
Hilcorp Alaska, LLC
N MIDDLE GROUD SHOAL
KING SALMON
W MCARTHUR RIVER UNIT
Cook Inlet Energy, LLC
West McArthur River Production Facility
GRAYLING
STEELHEAD
BAKER
Trading Bay Production Facility
DOLLY VARDEN
BIRCH HILL UNIT
Hilcorp Alaska, LLC
BIRCH HILL
W MCARTHUR RIVER
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MIDDLE GROUND SHOAL
TIGER EYE UNIT
NordAq Energy, Inc
C
SHADURA UNIT
NordAq Energy, Inc
SWANSON RIVER UNIT
Hilcorp Alaska, LLC
Kustatan
Kustatan Production Facility
DILLON
SWANSON RIVER
OSPREY
REDOUBT SHOAL
Kenai LNG Plant
Agrium Plant
Tesoro Facility
Port Nikiski
WOLF LAKE
(Hilcorp Alaska, LLC)
BEAVER CREEK
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
Sterling C Gas Storage
Cannery Loop Gas Storage Facility
KENAI CLU
CINGSA
KENAI CLU
STERLING UNIT
Hilcorp Alaska, LLC
STERLING
KENAI UNIT
Hilcorp Alaska, LLC
KENAI
Sterling 6 Gas Storage
Cook Inlet
KASILOF UNIT
Hilcorp Alaska, LLC
KASILOF
Clam Gulch
Falls Creek
NINILCHIK
G Oskollkoff
s Dionne
NINILCHIK UNIT
Hilcorp Alaska, LLC
Ninilchik
DEEP CREEK
DEEP CREEK UNIT
Hilcorp Alaska, LLC
HANSEN
(Buccaneer Cosmopolitan, LLC)
Cosmopolitan
NIKOLAEVSK
NIKOLAEVSK UNIT
Hilcorp Alaska, LLC
WEST EAGLE UNIT
Buccaneer Alaska, LLC
NORTH FORK
NORTH FORK UNIT
Armstrong Cook Inlet, LLC
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Learn more about Nabors' new drilling technologies at Nabors.com.
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Safer, Smarter - Incident Free

CONOCOPHILLIPS *continued from page 39*

Fiord peaked at 32,906 bpd in early 2010. Cumulatively, Fiord produced some 51 million barrels through July 2013. In 2012, its two participating areas produced some 20,100 bpd.

ARCO Alaska discovered the Nanuq oil pool with the Nanuq No. 1 well in 1996 and the Nanuq No. 2 well in 2000. The satellite originally produced from Kuparuk C sands equivalent to those at Fiord, in addition to the shallower and younger Nanuq sands, but AOGGC incorporated the Nanuq-Kuparuk reservoir into the Alpine oil pool in 2009.

Through the end of 2012, ConocoPhillips had three active production wells and two active injections wells at Nanuq and planned to drill seven additional wells in 2013. As of mid-September, ConocoPhillips had permitted four wells — the CD4-96, CD4-290 and CD4-292 producers and CD4-291 service well at Nanuq — and completed CD4-292.

Cumulatively, Nanuq had produced some 1.7 million barrels through July 2013, according to the AOGCC. In 2012, the field produced some 1,000 bpd on average.

Fiord and Nanuq came online in August and December 2006, respectively.

The timing worked well. Alpine production averaged 123,000 bpd in fiscal year 2006, according to the Alaska Department of Revenue. In fiscal year 2007, with Fiord and Nanuq both in production, combined Colville River unit production averaged 124,000 bpd — 103,000 bpd from Alpine, 11,000 bpd from Fiord and 10,000 bpd from Nanuq.

Qannik at CD-2

Although the Nanuq No. 1 well encountered the Qannik oil pool as early as 1996, ARCO believed the reservoir was too tight and too thin to be productive. ConocoPhillips demonstrated the quality of the pool through an appraisal program in 2005 and 2006.

The Qannik satellite was not one of the original five satellites ConocoPhillips listed in its 2003 filings, but the pool is in the center of the Colville River unit and is shallower than Alpine, which allowed ConocoPhillips to develop it by expanding the existing CD-2 pad.

The field came online in July 2008.

Through the end of 2012, ConocoPhillips had six active production wells and three active injections wells at Qannik, but drilled no wells in 2012 and planned to drill none in 2013.

Qannik peaked at 2,937 bpd in early 2010. Cumulatively, Qannik had produced nearly 4 million barrels through July 2013. In 2012, the field produced some 1,800 bpd.

Alpine West at CD-5

With success at the three satellites, ConocoPhillips planned to expand into the NPR-A.

The original 2003 filings listed three NPR-A satellites: a CD-5 pad at the Alpine West prospect, a CD-6 pad at the Lookout prospect and a CD-7 pad at the Spark prospect.

The CD-6 and CD-7 pads would be on federal leases, but the CD-5 pad would be on an Arctic Slope Regional Corp./Kuukpik Corp. lease across the Nigliq Channel of the Colville River from the existing Alpine facilities. While ConocoPhillips had drilled an Alpine West exploration well directionally from the CD-2 pad in 2001, the company proposed accessing Alpine West using a bridge connecting back to the CD-2 pad.

ConocoPhillips originally thought that the Alpine West prospect could not, on its own, justify the construction of a bridge across the Nigliq Channel and so it planned to develop CD-6 first starting in 2007 and return in 2009 to develop CD-5 and CD-7 concurrently.

After further evaluation, though, the company changed its view. In 2005, ConocoPhillips began permitting a CD-5 development and described CD-6 as "economically marginal."

The bridge proposal, though, created years of delays.

Route negotiations

First, ConocoPhillips and local Native groups spent years negotiating the route of the bridge. After they reached an agreement in early 2009, ConocoPhillips revised its CD-5 proposal to

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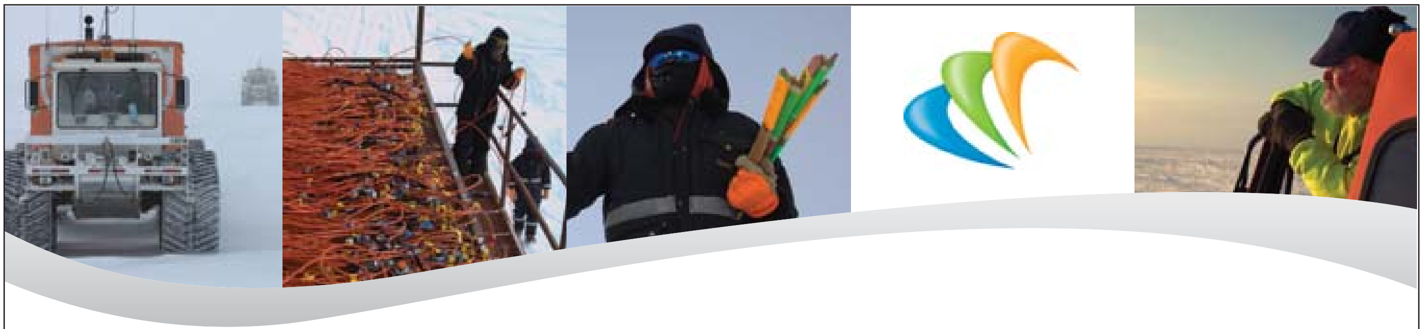


CONOCOPHILLIPS *continued from page 46*

accommodate additional drilling. The company said the intervening years of Alpine development had improved its understanding of the Alpine West satellite.

The U.S. Army Corps of Engineers rejected the bridge idea entirely in early 2010, though, telling ConocoPhillips to instead drill directionally underneath the channel. An appeal process led to an "agreement in principle" between ConocoPhillips and federal regulators in late 2011, which allowed the company to move forward on the bridge.

ConocoPhillips sanctioned the CD-5 project in late 2012. With partner approval, it intends to start construction next year in advance of first oil in late 2015 or early 2016, but now the development is facing two court challenges from environmental groups.

In June 2013 court filings related to those cases, ConocoPhillips Alaska Vice President of North Slope Operations and Development Nicholas G. Olds said that the Colville River unit partners have already spent "in excess of $100 million" on acquisition, exploration and development related to CD-5, and expect the satellite to produce some 15,800 bpd.

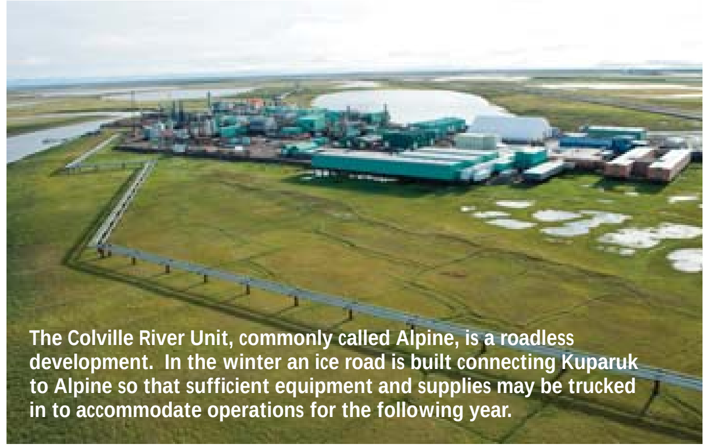
Economic perspective

To put the larger economics into perspective, ConocoPhillips Alaska President Trond-Erik Johansen compared the CD-1 and CD-5 projects in a speech at the annual Meet Alaska conference in January 2013. When Phillips brought CD-1 online in 2000, it spent $1 billion in return for 80,000 barrels per day, Johansen said. Now ConocoPhillips plans to spend $1 billion on CD-5 in return for what he estimated would be some 18,000 bpd.

Coming as lawmakers debated revisions to the fiscal regime, Johansen credited this disparity to taxes. "The tax system was much more favorable than it is today, and you got five times the production for the investment you spent. So let's get real," he said.

The speech failed to mention a range of other factors.

While Alaska oil sold for $20 to $30 per barrel in 2000, the state expects the price to stay above $100 per barrel in the coming years. Of course, oil prices are also higher in cheaper basins. A decade of inflation and rising construction costs has challenged economics, though. Then again, Alaska now offers numerous tax credits not available back in 2000.



The Colville River Unit, commonly called Alpine, is a roadless development. In the winter an ice road is built connecting Kuparuk to Alpine so that sufficient equipment and supplies may be trucked in to accommodate operations for the following year.

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All of which suggests how difficult it is to compare the economics of any two projects (and even more so without the benefit of complex and proprietary modeling software.)

As with the rest of the unit, ConocoPhillips plans to develop CD-5 using horizontal wells — six production wells and seven injection wells alternating water and miscible injectant.

Greater Mooses Tooth

As it moves toward first oil at CD-5, ConocoPhillips is also in the early permitting stages for CD-6, although the company has since re-named and refocused the satellite project.

After the U.S. Bureau of Land Management formed the Greater Mooses Tooth unit in 2008, ConocoPhillips changed the names of the CD-6 and CD-7 pads to GMT-1 and GMT-2, respectively, to better distinguish between its state and federal developments.

In July 2013, ConocoPhillips submitted a GMT-1 proposal calling for an 11.8-acre gravel pad with the capacity for 33 wells. A 7.8-mile gravel access road would connect the GMT-1 pad to the CD-5 pad. The road would also accommodate pipelines, power lines and other associated infrastructure. ConocoPhillips expects first oil by late 2017.

The GMT-1 proposal is "very similar" to the original Alpine CD-6 pad the BLM approved in its 2004 decision, according to the agency, but does include some "notable changes."

The changes mostly stem from a new location proposed for the drill site, which would reduce the length of roads and pipelines and therefore the amount of gravel required for construction. The original CD-6 pad would have been on lease AA-81819, but the proposed GMT-1 pad would be on lease AA-81798, which is slightly closer to Alpine.

The GMT-1 project also proposes a longer Ublutuoch River bridge, requires 3.3 additional miles of ancillary pipeline from the CD-1 pad to a pipeline tie-in north of the CD-4 pad, and would accommodate larger pipelines in the future than the CD-6 plan.

To consider those changes, the BLM is supplementing its 2004 Alpine Satellite Development Plan environmental impact statement. The supplemental EIS will also consider environmental studies conducted since 2004, such as the regional climate change assessment for the NPR-A, the recent Integrated Activity Plan for the NPR-A and the listing of the polar bear as a threatened species under the endangered species act.

The supplemental EIS will also consider future drilling, such as a GMT-2 pad.

In September, ConocoPhillips staked four wells in leases AA-81784 and AA-81803, which cover the Rendezvous prospect in the center of the Greater Mooses Tooth unit.

The original CD-7 pad would have been on lease AA-81802, slightly closer to Alpine.

Technology

At both the Kuparuk River and Colville River units, ConocoPhillips is using a combination of technologies to improve the economics of smaller pockets of oil.

With time-lapse 3-D seismic (also known as "4-D" seismic), ConocoPhillips can "illuminate pockets of oil that are in separate fault blocks or for whatever reason are not producing into an existing well bore," Executive Vice President of Technology and Projects Alan Hirshberg said in February 2013, during the annual update for analysts.

Coiled-tubing drilling can "twist and turn through the rock" to reach these pockets.

The coiled tubing is a continuous length of flexible, small-diameter steel tubing instead of the lengths of rigid steel drill-pipe used in conventional drilling. A tool at the end of the drilling equipment can turn more than 60 degrees over a 100-foot stretch of well, which "allows us to go right to these pockets that we found with the 4-D," Hirshberg said.

This process allows ConocoPhillips to use existing wellbores to target pockets of oil that would be too small to justify drilling a separate vertical well. When seismic information uncovered eight different zones near a single wellbore at Kuparuk, the company used coil-tubing equipment to drill the first "octolateral" on the North Slope. "That's a very cost effective way to get at those zones that weren't producing before," Hirshberg said.

Coiled-tubing drilling has been used on the North Slope for more than a decade, but it has become particularly useful at the compartmentalized reservoir rocks of Kuparuk. With a growing portfolio of coiled-tubing drilling candidates, ConocoPhillips commissioned the Nabors CDR2-AC rig in 2009 and has been drilling sidetracks continually ever since.

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Cook Inlet Energy brought the Osprey platform back into production in 2011 and is using a custom rig to sidetrack existing wells.

COURTESY COOK INLET ENERGY

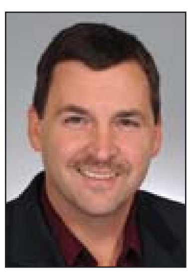
Cook Inlet Energy works west side

A slate of work since 2009 has been bringing west side Cook Inlet oil properties back online, now looking for production increases

By ERIC LIDJI
For Petroleum News

Cook Inlet Energy is attempting a resurrection. The small independent was created in 2009 to bid for the Cook Inlet properties that came on the market when Pacific Energy Resources Ltd. filed for bankruptcy protection.

With a $2.25 million bid, the local subsidiary of Tennessee-based independent Miller Petroleum picked up several Pacific Energy production assets on the west side of Cook Inlet. Those include the West McArthur River unit and oil field, the West Foreland gas field and the Redoubt unit with its associated Osprey platform and Kustatan facility, as well as a stake in the Three Mile Creek unit and a portfolio of exploration prospects.



DAVID HALL

The acquisition required considerable work. "Our initial strategy will be to restore base production at the West McArthur River field by repairing a couple of our champion wells," CEO David Hall said in December 2009, "but our long-term strategy is to significantly raise oil and gas production at the properties through new drilling."

As of summer 2013, Cook Inlet Energy said it had invested some $41.5 million on the offshore Redoubt unit, and $13.3 million on the West McArthur River unit.

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ALASKA OFFICE: 601 W. Fifth Ave., Ste. 310, Anchorage, AK 99501
TOP ALASKA EXECUTIVE: David Hall
PHONE: 907-344-6745
PARENT COMPANY WEBSITE: www.millerenergyresources.com

West McArthur River

Cook Inlet Energy spent some $7 million in 2010 working over five West McArthur River unit wells, bringing more than 1,100 barrels of oil equivalent per day online.

The work happened quickly.

Cook Inlet Energy completed the WMRU-5 workover in March 2010 at 578 barrels of oil equivalent per day, the WMRU-6 workover in April 2010 at 584 boe per day and the WMRU-1A in May at 33 boe per day. In June, Cook Inlet Energy completed work on the WMRU-7A well.

Toward the end of the year, Cook Inlet Energy completed its workover of the WMRU-2A well, which had been shut-in since 2001 because of a high water cut. WMRU-2A tested at 37 boe per day, but Cook Inlet Energy planned to use the well for a waterflood pilot program to enhance oil recovery, and also as a backup for its existing injection well.

continued on page 52

COURTESY COOK INLET ENERGY

COOK INLET ENERGY *continued from page 50*

The WMRU-2A workover involved a coil tubing unit, rather than a traditional rig.

In July 2010, Cook Inlet Energy brought the KF-1 well online at the Kustatan field at 70 thousand cubic feet per day, which it used for fuel operations. The well had been shut-in for a year.

As of summer 2013, West McArthur River was producing some 630 barrels per day from two wells, a 10 percent decline curve from the original 2010 levels, according to the company.

While those efforts significantly increased West McArthur River production — albeit to a level considered small by Alaska standards — Cook Inlet Energy aspires to drill as many as five new wells at the unit, which it said could yield a 2,000 bpd bump in production.

The work requires considerable investment, though. In an August 2013 presentation, Cook Inlet Energy estimated a net well cost of $9 million for West McArthur River.

In early 2013, Cook Inlet Energy began permitting a pad expansion at West McArthur River, looking to add 3.1 acres to accommodate expanded oil and gas operations.

The Redoubt unit

After West McArthur River, Cook Inlet Energy turned its attention to Redoubt.

Forcenergy Inc. installed the Osprey platform over the Redoubt Shoal field in 2000, but it was only producing 20 bpd by the time Pacific Energy shut-in the field in July 2009.

Using a hydraulic snubbing unit, Cook Inlet Energy brought the platform back online in summer 2011 by replacing electric submersible pumps in the RU-1 and RU-7 wells, which allowed the wells to flow at 350 boe per day and 250 boe per day respectively.

By the following summer, Cook Inlet Energy had to shut-in the RU-1 well because of an equipment problem, but the RU-7 well continued to produce some 230 boe per day.

In development plans, the company said it would drill four sidetracks off existing damaged wells, which it expected to produce some 2,000 bpd. The original wells needed to be sidetracked because improper design had allowed the casing to collapse. The company also saw the possibility to drill 13 new wells from the platform, with proper investment.

New rig for Redoubt

Using a line of credit from New York-based Guggenheim Corporate Funding LLC, Cook Inlet Energy paid $19.5 million for Rig 35, a 2,000-horsepower National 1320 model built in Houston and assembled in Alaska by Voorhees Equipment and Consulting Inc.

The rig went to work on RU-1 in August 2012 and after removing 31,000 pounds of junk from the wellbore, brought the well back online at an initial production rate of 482 bpd.

In late 2012 and early 2013, Cook Inlet Energy worked over the RU-3 and RU-4A wells, a pair of natural gas wells the company needed to provide cheap fuel for its operations.

The RU-3 well 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 $500,000 in monthly third-party fuel deliveries and by early summer start selling its excess gas into the market.

In June, Cook Inlet Energy more than doubled its total Alaska crude output by bringing the RU-2A sidetrack online at an initial production rate of 1,281 bpd. In August, the company brought the RU-1A sidetrack online at an initial production rate of 700 bpd.

As The Producers went to print, Cook Inlet Energy was sidetracking the RU-5 well, but oil equivalent production from the five reworked oil and natural gas wells was some 2,567 boepd, as of August 2013.

In September 2013, Miller Petroleum terminated its contract with Voorhees over claims of outstanding invoices. The companies are settling the dispute through arbitration.

In September, Miller said it was on track to produce 4,000 barrels of oil equivalent per day companywide by the end of the calendar year, the majority coming from Alaska.

Trans-Foreland Pipeline

On top of its upstream work, Cook Inlet Energy is pushing a major midstream project.

The $53 million subsea Trans-Foreland Pipeline would carry oil from the Kustatan production facility to the existing Tesoro oil refinery in Kenai. The 29-mile pipeline would eliminate the short tanker voyage currently used to move oil across the Inlet.

The 8-inch pipeline would have 90,000-bpd capacity. Installation could begin as early as next summer and wrap up by fall, with some 130 jobs created during construction.

Cook Inlet Energy sees the pipeline as a way to reduce delays and transportation costs.

The Cook Inlet Regional Citizens Advisory Council endorsed the pipeline because it would reduce tanker traffic and sidestep concerns associated with the Redoubt volcano.

Tesoro recently agreed to contribute $1.4 million to the design phase of the project.

Early in its Alaska tenure, Cook Inlet Energy got into a spat with the Cook Inlet Pipe Line system over a 259 percent increase in the tariffs to move oil through the pipeline to the Drift River terminal, but the sides reached a settlement tariff rate in late 2010.

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Eni looking to expand Nikaitchuq

With its initial development of the OA sands wrapping up, the Italian major is now evaluating development of the N sands

By ERIC LIDJI
For Petroleum News

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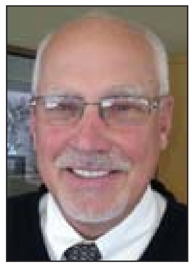
Eni Petroleum is expanding its operations at its Nikaitchuq unit.

After more than three years of sustained production, the Italian major is evaluating a previously undeveloped oil-bearing interval at the North Slope field in the state waters of Harrison Bay, and also looking at using multilateral completion techniques for its wells.

When Eni sanctioned Nikaitchuq in early 2008, it made the case for development based on the oil contained in the OA sands of the Schrader Bluff formation. But the company always suggested it might someday pursue the shallower N sands of the same formation, as well as a minor oil accumulation encountered in the deeper Sag River formation. Now, as Eni nears the end of its initial slate of OA development wells, it is testing the N sands.



STEVE MASSEY

Eni said it intends to drill three development wells at Nikaitchuq in the latter half of 2013, one of which will primarily test oil production from the N sands reservoir.

It would be the first well Eni has drilled exclusively to evaluate the N sands.

Pilot well in 2015

The goal is to use the results of the test well and an ongoing reservoir modeling study "to plan a pilot well of this reservoir" in 2015. If the pilot proves the N sands to be economic, Eni envisions an "initial development phase" with four to nine "pre-development" wells.

Because the N sands are shallower than the OA sands, all previous drilling at Nikaitchuq has penetrated the interval, but Eni has also been testing the extent of the N sands by extending four existing horizontal OA sands wells into the northwest corner of the unit.

Additionally, Eni said it is considering a second offshore drilling island at the unit, which would allow it to better target potential resources in the farther northwestern reaches.

Cumulatively, Eni produced more than 7.4 million barrels of oil at Nikaitchuq through July 2013. The field produced 12,062 bpd in July, down from 12,117 bpd in June.

An eight-year cycle

Eni first arrived in Alaska in the late 1960s through its affiliate company Agip Petroleum, but the company traces its most recent push in the state to the mid-2000s. In 2005, Eni bought a minority interest in several North Slope prospects from Armstrong Alaska and in 2007 it bought the outstanding interest in those prospects from Kerr-McGee Corp.

Those assets included Nikaitchuq, Tuvaaq and a stake in Oooguruk, three offshore prospects in the state waters of the Beaufort Sea, north and northwest of the Kuparuk River unit. It also included several onshore prospects, including the Maggiore and Rock Flour prospects in the central North Slope south of Prudhoe Bay and Kuparuk River.

Working with Armstrong Alaska Inc., Kerr-McGee Corp. drilled the Nikaitchuq No. 1 discovery well in 2004, and delineated the field in 2004 and 2005 with the Nikaitchuq No. 2, No. 3 and No. 4, Kigun No. 1 and Tuvaaq No. 1 exploration wells. Eni Petroleum gradually acquired 100 percent working interest in the field between 2005 and 2007, and drilled the Oliktok Point No. I-1 and No. I-2 delineation wells in 2006 and 2007.

Developing Nikaitchuq

Eni quickly worked to make its offshore prospects viable.

In 2007 and 2008, the Alaska Department of Natural Resources agreed to expand Nikaitchuq to include Tuvaaq, and granted royalty modification for much of the unit.

The modification allows Eni to pay the state a 5 percent royalty rate when the delivered price of Alaska North Slope crude oil drops below $42.64 per barrel, a threshold adjusted annually for inflation. The modification is available to Eni for the first 25 years of sustained production at Nikaitchuq, which would be early 2036, barring any shutdowns.

In February 2008, less than a month after getting the royalty relief, Eni sanctioned a $1.45 billion development program at Nikaitchuq. The plan envisioned 73 production and injection wells split between an onshore pad at Oliktok Point and an offshore artificial island in the shallow waters near Spy Island. The plan also included a 3.8-mile subsea pipeline and a 40,000-barrel-per-day production facility at Oliktok Point — the first such facility in northern Alaska to be operated by a company other than BP or ConocoPhillips.

Production in 2011

At the time, Eni expected to bring Nikaitchuq online by late 2009, but weather delays and the short Arctic sealift season delayed the program. Production began from Oliktok Point on Jan. 31, 2011, just four days shy of three years after Eni sanctioned development.

After the summer construction season, Eni completed the Spy Island drill site in August 2011, spud its first well from the island in October and began production in November.

The Nikaitchuq field produces from the same oil-bearing sands

continued on next page

ENI PETROLEUM *continued from page 53*

of the Late Cretaceous-aged Schrader Bluff formation found at Prudhoe Bay, Kuparuk River and Milne Point.

The Nikaitchuq Schrader Bluff Oil Pool contains two sands: the OA and the N. Testing has also encountered minor oil accumulations in the Triassic-era Sag River sandstones.

Eni believes the OA sands hold between 800 million and 930 million barrels of oil in place and expects to produce as much as 220 million using primary recovery and waterflood injection — a 30-year field life peaking at some 28,000 barrels of oil per day.

Testing multilaterals

Those figures could rise, though, if Eni finds success with multilaterals.

In February 2013, Eni tested an “alternative completion methodology” at Nikaitchuq by drilling a multilateral well from its offshore island, its first such well in Alaska.

Eni drilled the SP22-FN1 directional well to 22,923 feet measured depth and 3,408 feet vertical depth with four laterals ranging from 1,600 to 2,000 feet each. The results of the first well prompted the company to later drill OP08-OL41, a second multilateral well from its onshore pad. Unlike the first multilateral, Eni drilled the laterals of this second well after casing and cementing the main wellbore to improve the integrity of the well.

Should Eni ultimately sanction an N sand development, these multilaterals could allow it to develop both intervals simultaneously, or at least reduce its overall drilling footprint.

For now, though, Eni clearly sees multilaterals as an important next step for the field.

Eni plans to cold stack Nabors Rig 245 until March 2014, when it would launch a workover campaign to convert eight existing Oliktok Point wells to multilaterals by drilling sidetracks between 6,000 and 10,000 feet in length. Eni is also considering a plan to drill all future Spy Island drill site wells as multilaterals starting in January 2014.

For its 2015 program, Eni is considering a workover campaign to convert eight existing Spy Island drill site wells to multilaterals with specifications similar to those planned for the Oliktok Point pad. This would be in addition to the proposed N sands development.

Both campaigns are contingent on corporate approval, the company said.

Spy Island drilling

Eni released one rig from its program in October 2012 after completing its initial slate of OA sands wells planned for the Oliktok Point pad, but with the three-well program planned for summer 2013 — which includes the N sands test well — the company now plans to conduct “intermittent” drilling from the onshore pad using Nabors Rig 245.

Since November 2012, Eni has been conducting “continuous” drilling from the Spy Island drill site using Doyon Rig 15. The program includes four production and five injection wells, which include the N sands extensions, and is scheduled to run through November. Eni expects to complete its initial slate of offshore wells in November 2014.

In addition to its development drilling, Eni has also been conducting or plans to soon conduct workovers from both drilling pads this year — three rigless and four rigged.

While Eni expects this activity to increase production this year to as much as 14,000 barrels per day up from 10,000 bpd, the company expressed “significant uncertainty concerning the production potential from the wells to be drilled in the coming year.”

Is Sag River next?

In addition to its N sands appraisals planned for the coming year, Eni is also in the early stages of evaluating a potential development of the Sag River formation at Nikaitchuq.

The program would require Eni to build a second artificial island to better reach prospects in the northwest corner of the unit. Eni said it intends to submit a proposal for such a development to its “upper management” within the next 12 to 18 months. The proposal or something similar could be necessary for Eni to keep all its acreage at the Nikaitchuq.

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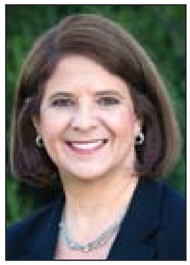
Exxon at work at Point Thomson

After years of delays, technicalities and lawsuits, the oil giant is starting out small at the eastern North Slope field

By ERIC LIDJI
For Petroleum News

The only field ExxonMobil operates on the North Slope is one of the most challenging in Alaska.

Since the global giant discovered Point Thomson in the eastern North Slope in the mid-1970s, the field has presented technical, economic, legal and regulatory challenges.



KAREN HAGEDORN

Those challenges eased enough in 2013 for Exxon to begin the first significant construction at the largest proven undeveloped oil and gas field in the state, and perhaps the country. The work is aimed at bringing the field into production by May 2016.

The work completed this year focused on infrastructure development.

Exxon and its contractors built gravel roads, an airstrip and a pier, installed a permanent work camp at an expanded pad and turned on the lights of their new telecommunications and power systems. The crews also installed more than 2,200 vertical support members, which will hold the 22-mile insulated Point Thomson Pipeline being built this winter.

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This work, though, is only the beginning of the beginning.

2012 settlement

Through a settlement reached in early 2012, the State of Alaska and the working interest owners agreed to a schedule for starting and expanding Point Thomson production.

The first step is called the Initial Production System, in which Exxon would produce some 10,000 barrels per day of liquid condensate from two existing wells and cycle some 200 million

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EXXONMOBIL *continued from page 56*

cubic feet per day of residual natural gas production back into the field.

Only then does the settlement address full field development, which would include a major gas sale, expanded liquids production, or both (depending on the markets).

Under a plan of operations filed soon after the settlement, Exxon proposed drilling a disposal well and up to five producers or injectors — a total which includes the two wells completed in recent years — from west, central and east pads. The three gravel pads would allow Exxon to reach all sections of the reservoir with extended-reach drilling.

The two recent wells are on the central pad. Exxon proposed drilling one well each on the west and east pad, and would site the fifth well based on the results of the previous four.

The Point Thomson unit currently covers 93,291 acres over 38 leases along the Beaufort Sea coastline some 60 miles east of Prudhoe Bay. The long list of working interest owners includes operator-ExxonMobil, BP and ConocoPhillips. In early 2013, Exxon and the state-owned Russian oil giant Rosneft announced a partnership including “potential participation by Rosneft (or its affiliate) in the Point Thomson project in Alaska.”

Technical and economic challenges

The state issued the Point Thomson leases in 1965.

The Alaska State A-1 well in 1975 found oil and gas in the lower Tertiary Flaxman sand, and the Point Thomson Unit No. 1 well in 1977 found oil and gas in the Lower Cretaceous Thomson sand. The state approved the formation of the Point Thomson unit in 1977, as Prudhoe Bay oil began flowing down the 800-mile trans-Alaska oil pipeline.

A delineation effort over the following seven years discovered two additional reservoirs.

Today, Point Thomson is understood to be a high-pressure retrograde gas-condensate reservoir with a viscous oil rim in the Thomson sands, and a smaller oil pool in the shallower Brookian sands. The challenge is how to maximize production of all resources.

The 8 trillion cubic feet of gas at Point Thomson constitute some 25 percent of the known reserves on the North Slope, making the field crucial for the success of a gas pipeline.

Even without the gas resources, though, the hundreds of millions of barrels of liquids at Point Thomson would constitute a major discovery almost anywhere in the world.

Issue of what’s produced first

By producing the gas first, an operator could recover some of the condensate, but the resulting drop in reservoir pressure would liquefy the remaining condensate underground, which would challenge future production. Cycling the gas would maintain reservoir pressure, but would challenge the economics of the project by requiring more complex technology and by delaying gas sales until after the liquids had been suitably depleted.

By cycling gas for 20 years, Point Thomson could yield 620 million to 850 million barrels of oil and condensate, followed by 4.8 trillion to 5.9 trillion cubic feet of gas, according to a June 2008 state-commissioned study by PetroTel Inc. By comparison, the firm estimated, producing the gas first would yield between 210 million to 305 million barrels of liquids and between 6 trillion and 7 trillion cubic feet of gas.

The difference in liquids production represented another Alpine, the report concluded.

At the time, Exxon challenged those figures.

The company said the report made optimistic assumptions about recovery rates in a thin, discontinuous rim of viscous oil. It also questioned the feasibility of gas cycling, which would only maintain reservoir pressure if production and injection wells “communicated,” and would make any gas unavailable to a pipeline for 20 years.

What’s the prize?

The complex technical debate boiled down to a simple question: What’s the prize?

The state argued for the benefits of the liquids resources, which could move to market immediately through the trans-Alaska oil pipeline. The companies argued for the benefits of the gas resources, which required construction of a multibillion-dollar gas pipeline.

In the 2012 settlement, the parties agreed to a gas cycling program. The program starts with limited condensate production, but gives the lessees three alternatives for the future.

Under Alternative A, the producers would sanction a “major” gas sale by June 2016.

With “major” being defined as more than 500 million cubic feet per day, the decision is really about whether the producers are willing to commit to building a gas pipeline.

Under Alternative B, the producers would commit to expanding liquids production to 30,000 bpd or more by 2019. The decision depends largely on whether the Initial Production System proves the feasibility of gas cycling at Point Thomson, but increasing production would also require drilling more wells and expanding processing capacity.

Under Alternative C, the producers would integrate Point Thomson and Prudhoe Bay to increase recovery at both fields. The scheme involves injecting Point Thomson gas into Prudhoe Bay to enhance oil recovery at the aging field, expanding Point Thomson liquids production and dedicating significantly gas volumes for in-state use no later than 2019.

The settlement also requires development of the Brookian oil reservoir by 2018.

Legal challenges

A settlement was required because the technical challenges spawned a legal challenge.

Exxon drilled numerous wells at Point Thomson over the decade following its discovery, but in the early 1980s the company decided it had sufficiently delineated the field, and said any future drilling should promote gas development, which depended on a pipeline.

The Alaska Department of Natural Resources approved development plans without drilling commitments into the 1990s, but grew increasingly impatient with the lack of progress.

The gas cycling option changed the outlook by removing the necessity of a gas pipeline.

Exxon outlined a plan in 2002 to use gas cycling to produce up to 75,000 bpd of liquids, but decided the idea was uneconomic and submitted a development plan in 2005 that called for gas production first. The department rejected the plan, placed the unit in default in 2005 and subsequently terminated the unit in 2008.

Those moves set off a major court battle.

While the case unfolded, though, the state gave Exxon permission to start drilling at Point Thomson, work the company proposed to prove its commitment to bringing the field online by 2014. By late October 2010, Exxon had competed both wells — PTU-15 and PTU-16.

The Alaska Superior Court ultimately reversed the termination of the unit, but as the case went to the Alaska Supreme Court the state and the lessees ramped up settlement talks.

To mollify the state, the April 2012 settlement contains consequences.

If Exxon misses certain early work deadlines, the unit would contract in 2015.

If Exxon fails to bring the Initial Production System online or sanction a major gas sale by 2019, the unit would terminate and all the leases — including those hosting wells capable of producing in commercial quantities — would return to the state. If Exxon fails to expand production beyond the Initial Production System, the unit would contract.

And Exxon would lose its Brookian acreage unless it sanctions development by 2018.

In all these instances, Exxon waived its right to appeal any termination or contraction.

The other challenges

Even with a settlement, though, Point Thomson is far from settled.

By April 2011, the U.S. Army Corps of Engineers was running a year behind schedule on its environmental impact statement for the gas cycling project. The series of delays came from additional studies, and later from revisions Exxon made to the project description.

The delays made it difficult, if not impossible, for Exxon to meet its 2014 deadline for bringing the field online, which is why the settlement gave the company until May 2016.

The Corps released the final EIS in August 2012, and issued a crucial wetlands permit in October 2012, but Exxon acknowledged in late 2012 that it would be a "challenge" to meet the deadline. "We are on schedule, but it is very tight," Jeff Ray of the Exxon transportation subsidiary PTE Pipeline LLC told the Regulatory Commission of Alaska, which subsequently gave Exxon approval to build the Point Thomson Export Pipeline.

Another challenge came in early 2013, when Exxon encountered high levels of hydrogen sulfide in the PTU-15 and PTU-16 wells. The discovery required Exxon to initiate mitigation measures to keep the acidic gas from damaging well materials, but the company insisted the issue "does not impact the overall schedule" of the development.

The eastern North Slope

Where there are challenges, there are usually opportunities, too.

The 70,000-bpd Point Thomson Export Pipeline is much bigger than Exxon requires for the Initial Production System or its expansion. The big capacity is meant to accommodate the "string of pearls." The "string" is the pipeline, and the "pearls" are several known oil fields between the BP-operated Endicott field and the Arctic National Wildlife Refuge.

The first of those pearls is Badami, which BP brought online in 1998 and Savant Alaska is currently operating. The associated 35,000-bpd Badami Pipeline is the first string.

The Point Thomson field and its 22-mile pipeline are the second pearl and second string.

The other pearls on the string include the Red Dog, Telemark, Kuvlum-Lonestar, Stinson and Yukon Gold prospects. The final and most difficult pearl to string would be ANWR.

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Hilcorp: biggest little newcomer

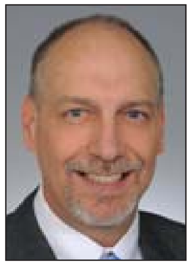
In less than two years Hilcorp became the dominant oil and gas producer in the Cook Inlet basin, and has big plans for the future

By ERIC LIDJI
For Petroleum News

When 2011 began, Hilcorp Energy Co. was unknown to most Alaskans.

By the end of 2012, Hilcorp was the dominant producer in the Cook Inlet basin.

Its quick accession occurred in two deals. In July 2011, the privately held independent Hilcorp purchased the Cook Inlet assets of Chevron affiliate Union Oil Company of California. In April 2012, Hilcorp acquired the Cook Inlet assets of Marathon Oil Corp.


JOHN BARNES

Through exploration work dating back in the 1950s, Chevron/Unocal and Marathon helped make many of the biggest discoveries in the basin, but over the past decade the companies had showed increasingly little interest in investing in further exploration.

Founded in 1989 on a principle of "acquire and exploit," Hilcorp doubled between 2006 and 2010 and its arrival in Cook Inlet is a step toward doubling again by 2015.

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Hilcorp Energy Company

Now the Houston-based company is in the early stages of a campaign to rejuvenate some 20 oil and gas fields across Cook Inlet. A recent slate of short-term gas supply agreements with the major utilities in the region suggests the company is finding success.

On the west side, Hilcorp operates the Lewis River unit, Pretty Creek unit, Stump Lake unit and Ivan River unit. Offshore, Hilcorp operates the Granite Point field, South Granite Point unit, Trading Bay unit, North Trading Bay unit, North Middle Ground Shoal field, South Middle Ground Shoal unit, Kasilof unit and Ninilchik unit. In the northern Kenai, Hilcorp operates the Birch

Hill unit, Swanson River unit, Beaver Creek unit, Sterling unit, Cannery Loop unit and Kenai unit, as well as the Wolf Lake and West Fork fields. In the southern Kenai, Hilcorp operates the Deep Creek unit and the Nikolaevsk unit.

Hilcorp also acquired associated platforms, oil and natural gas pipelines and storage facilities, as well as minority interests in two non-operated fields, the ConocoPhillips-operated Beluga River unit and the XTO-operated Middle Ground Shoal oil field.

In 2012, Hilcorp spent some $230 million in Cook Inlet, with 38 percent going to refurbishing old Chevron assets, such as reactivating the Drift River terminal. The company planned to spend $300 million this year on the Chevron and Marathon assets.

The Ivan River unit

Between 1966 and 1979, Unocal, Chevron and Cities Service Oil Co. discovered the four onshore fields Hilcorp operates on the west side of Cook Inlet between Tyonek and the mouth of the Susitna River: Ivan River, Lewis River, Stump Lake and Pretty Creek.

Unocal discovered Ivan River in 1966 with the Ivan River Unit No. 44-01 well, but production only began in 1990, when Enstar Natural Gas Co. built a pipeline to the field. The unit also includes a suspended gas storage operation on ADL 391556.

There are currently five active wells at Ivan River — three producers and two water disposal wells — all drilled by either Unocal or Chevron between 1966 and 2009.

Under a development plan running through June 16, 2014, Hilcorp said it wants to increase existing production while expanding development of the Tyonek, Beluga and Sterling reservoirs, which could include a new well or a sidetrack into the Beluga.

Subsurface mapping

"Work is continuing on subsurface mapping throughout the unit and we believe there may be significant reserves remaining at Ivan River," the company wrote in the plan.

The remaining work outlined in the development plan includes maintenance such as upgrading water disposal pumps and installing a radio tower to improve communication.

In 2012, Hilcorp added perforations to the IRU 41-01 discovery well, which had the highest cumulative production but lowest current production rate of the three producers.

Hilcorp is also evaluating the storage operation it inherited at the field. The Department of Natural Resources allowed Hilcorp to temporarily suspend operations in 2012 because of problems the company identified at the lease. Now, Hilcorp is considering whether to convert the IRU 44-36 disposal well into a gas storage operation into the 71-3 sand interval. The conversion would require the installation of new compression facilities.

Also in 2012 and 2013, Chevron led an effort to clean up an old reserve pit at Ivan River.

Averaging cumulative rates, Ivan River produced 2.6 million cubic feet per day between July 2012 and 2013 and nearly 3 mmcf per day between January 2012 and 2013, according to the Alaska Oil and Gas Conservation Commission. In July 2013, the field produced nearly 70 mmcf, or some 2.2 mmcf per day. Cumulatively, Ivan River had produced nearly 84 billion cubic feet through July 2013.

Lewis River, Stump Lake, Pretty Creek

As with Ivan River, the primary work outlined for Lewis River this year is subsurface mapping, installing a radio tower and potentially upgrading compression facilities.

The current plan runs through June 30, 2014.

Cities Service discovered the field in September 1975 with the Lewis River No. 1 well.

There are currently four active wells at Lewis River — three producers and a disposal well — all drilled by Cities Service, Unocal or Chevron between 1975 and 2001.

Averaging cumulative rates, the Lewis River field produced 1.39 mmcf per day between July 2012 and 2013 and 1.37 mmcf per day between January 2012 and 2013, according to the AOGCC. In July 2013, the field produced 40 mmcf, or 1.3 mmcf per day. The unit produced nearly 1.5 mmcf per day in 2012, according to information from Hilcorp.

Cumulatively, Lewis River had produced nearly 14.1 bcf through July 2013.

Restoring production

At Stump Lake, Hilcorp is working to restore production. After adding perforations to the SLU 41-33RD well, solids build up forced Hilcorp to take the line producing well offline.

Chevron USA Inc. discovered the field with SLU No. 41-33 in May 1978. After an eight-year shutdown, Chevron sidetracked the discovery well in 2009, restarting production.

In addition to the well work, Hilcorp is conducting subsurface mapping that will form the basis for a multiyear development plan. The current plan runs through June 30, 2014.

The SLU No. 41-33 well produced 335 thousand cubic feet per day in 2012, according to Hilcorp. Cumulatively, the field had produced 6.7 bcf through July 2013.

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HILCORP *continued from page 61*

Pretty Creek is also under evaluation for future development opportunities.

Unocal discovered the field in February 1979 with the Pretty Creek Unit No. 2 well.

After installing a temporary sand separator at the unit in 2011 and 2012, Hilcorp is considering a permanent sand separator, as well as a two-phase separator and an additional water tank to allow production from the well to proceed more effectively.

The current unit plan of development runs through June 30, 2014.

The unit includes a gas storage operation from the Pretty Creek Unit No. 4 well.

The Pretty Creek Unit No. 2 well produced only 36 mcf per day in 2012, but the Pretty Creek Unit No. 4 storage well produced slightly more than 3 mmcf per day, according to Hilcorp. Cumulatively, Pretty Creek had produced some 9.5 bcf through July 2013.

Granite Point and South Granite Point

Offshore, from north to south, Hilcorp operates the Granite Point field and South Granite Point unit, the Trading Bay and North Trading Bay units, North Middle Ground Shoal field and South Middle Ground Shoal unit, the Kasilof unit and the Ninilchik unit.

The Granite Point field consists of three un-unitized leases held by production. The state formed the South Granite Point unit over three adjacent leases to the south in 1998.

Since taking over the neighboring Granite Point fields in January 2012, Hilcorp has been working over numerous existing wells from the three offshore platforms at the two fields.

The work from all three platforms includes downhole repairs, re-completions or additional perforations to improve production from the Tyonek formation and the deeper Hemlock oil formation, as well as physical maintenance of the actual platforms.

The Granite Point field contains two platforms: Anna and Bruce.

At Anna, Hilcorp worked on 11 wells and sidetracks in 2012.

The repairs and additional perforations Hilcorp performed on six of those yielded a combined production increase of some 125 barrels of oil equivalent per day, but the work on the remaining five were "unsuccessful." In one case, on the shut-in AN 9 well, Hilcorp postponed its proposed work because the "risk of mechanical failure" was "too high."

For 2013, Hilcorp planned to use Rig 428 to repair AN 39RD (one of the unsuccessful 2012 ventures) and AN 32RD2, and to convert the injector AN 38 into a producer. It also plans to convert the AN 17 Tyonek injector into a producer from the deeper Hemlock.

The AOGCC issued a permit for a Granite Point St. 18742-17A well on April 25, 2013.

Moncla rig

At Bruce, Hilcorp worked on six wells and sidetracks in 2012, yielding some 36 to 81 barrels of incremental oil equivalent production per day from three wells. Although one of those wells, BR 3-86, saw production growth between 15 and 40 barrels of oil equivalent per day after the work, Hilcorp described the results as "lower than suspected," which it said was "probably due to operational problems that occurred during stimulation." The work on BR 3-86 involved an acid stimulation test using 20,000 gallons of hydrofluoric and hydrochloric acid to remove damage from the wellbore.

By May 2013, Hilcorp was touting a 36 percent increase across all fields, including a 412 percent increase at Swanson River and a 157 percent increase at Trading Bay.

Of the remaining three wells, the repairs on two were unsuccessful, and Hilcorp is now listing those wells as candidates for future workovers. A workover on the third was also unsuccessful, and the well is shut-in while Hilcorp evaluates potential repair options.

For 2013, Hilcorp planned to use its newly commissioned Moncla rig in the second half of the year to perform repairs and recompletions on seven Bruce wells. Hilcorp also planned to conduct a chemical tracer test on one well from the platform to gauge the effectiveness of nitrogen injections for enhanced oil recovery operations at the field.

‘Derricks down’

The South Granite Point unit hosts the Granite Point platform.

Almost immediately upon arriving in Alaska, Hilcorp launched a “derricks down” project at Granite Point, replacing the existing derrick on the platform with a “modern drilling rig,” as Hilcorp’s senior vice president for Alaska John Barnes described it in May 2012.

From Granite Point, Hilcorp conducted work on five wells and sidetracks in 2012.

The work on three of those wells yielded some 36 barrels of oil equivalent per day of incremental growth. A coiled tubing workover on a fourth, GP 50, initially yielded 60 barrels of oil equivalent, but the well subsequently stopped producing, Hilcorp said. The fifth well also returned to production after a workover, but producing primarily water.

For 2013, Hilcorp planned to use its Moncla rig to perform four workovers from the Granite Point platform, including additional Tyonek perforations or stimulations at three wells. Hilcorp also plans to improve Hemlock oil production from two existing wells.

Cumulatively, Granite Point had produced some 149 million barrels of oil through July 2013, including nearly 1.3 million barrels since Hilcorp took over in January 2012.

Granite Point averaged 2,290 bpd in July 2013, according to the AOGCC.

Trading Bay and North Trading Bay

To the south of Granite Point are the Trading Bay and North Trading Bay units.

The neighboring units — and an un-unitized field between them — host seven platforms and Hilcorp is conducting a similar mix of rig and well maintenance at the units.

The Trading Bay unit hosts four platforms — Steelhead, Dolly Varden, King Salmon and Grayling — that produce from four McArthur River field intervals discovered in 1965.

The work at Trading Bay included a “derricks down” program, such as the one at Granite Point, to modernize the drilling equipment at the unit needed for workovers.

With the rig now on-hand, Hilcorp is working through a list of

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HILCORP *continued from page 63*

wells it wants to repair and said it may seek out a dedicated rig if it finds enough candidates for new wells and sidetracks. Prior to the arrival of the rig, Hilcorp launched a major repair program.

Restoring waterflood

At the McArthur River Hemlock oil pool, Hilcorp is working to restore a waterflood program (and thereby increase production) by repairing injectors, installing electric submersible pumps at producers and converting some "redundant" producers to injectors.

At the McArthur River Middle Kenai G-Zone oil pool, Hilcorp is working to improve its waterflood operations by creating "dedicated" completions into the interval. Currently, the Middle Kenai G-Zone completions are comingled with the Hemlock of West Foreland pools. "It will take several years to downspace the G-Zone waterflood and achieve a fully functional waterflood," Hilcorp said in its most recent development plan.

At the McArthur River West Foreland oil pool, Hilcorp believes that repairing existing wells will improve the management of all three pools. The company proposed no work for a deeper pool in the Jurassic formation during the period, but repaired and recompleted a gas well from the Grayling platform to provide fuel gas for its operations.

After drilling the M-29A well in 2012, Hilcorp completed M-31A in January 2013 and M-31B in February 2013, both from the Steelhead platform, according to the AOGCC.

The McArthur River field averaged 4,311 bpd in July 2013 with cumulative oil production of some 635 million barrels through July 2013, according to the AOGCC.

Expansion requested

In mid-2013, Hilcorp asked the Department of Natural Resources to include two leases at the Trading Bay field into the Trading Bay unit to accommodate a "newly discovered natural gas deposit" from the Monopod platform on ADL 18731. The expanded unit would prevent "duplicative infrastructure and operation systems," according to Hilcorp.

The current development plan runs through Aug. 25, 2014.

The North Trading Bay unit currently operates under a prior Marathon Oil plan of development through the end of 2013. The Spark and Spurr platforms at the unit have been in lighthouse mode since in 1992, aside from an attempt at gas production from Spark in 2007. There has been talk in recent years of removing the platforms, but Marathon said, "abandonment operations have been deferred to provide the purchaser, Hilcorp Alaska, sufficient time to evaluate any future utility for the well bores."

The Middle Ground Shoal fields

Due east of Trading Bay are the Middle Ground Shoal fields.

Hilcorp operates the North Middle Ground Shoal field and the South Middle Ground Shoal unit and holds a minority interest in the XTO-operated Middle Ground Shoal field.

North Middle Ground Shoal hosts the Baker platform. The state approved a plan for abandoning the lighthoused platform in early 2012, but later in the year Hilcorp amended the plan. It had decided to reactivate the platform to accommodate gas exploration.

In late 2012, Hilcorp perforated the T-40 gas sands at the BA-27 well to test for commercial production, but said the zone appears to be wet. At the BA-18 well, Hilcorp isolated the T-31 gas zone and recompleted two shallower zones, T-24 and T-25. In early 2013, Hilcorp perforated the shallower zones, but found they were unable to produce.

Hilcorp expects the reactivation work to continue through early 2014. Hilcorp restarted gas production in mid-2013 and is studying potential oil production from the platform.

The current development plan for the field runs through May 31, 2014.

The South Middle Ground Shoal unit and its Dillon platform are currently shut-in.

Kasilof and Ninilchik

The Kasilof and Ninilchik units are in lower Cook Inlet, produced from the shore.

Union Oil Co. drilled three dry holes at Kasilof in the late 1960s, but other companies, including Mesa Petroleum and Standard Oil Company of California, subsequently found gas at the field. Marathon ultimately brought the Kasilof field online in November 2006, using a 17,000-foot extended reach dual-lateral well drilled from an onshore pad.

After initial drilling results 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.

The Kasilof unit continues to operate under a prior Marathon plan of development through the end of 2013. The plan called for drilling projects during the period.

Cumulatively, the field has produced some 4.2 bcf through July 2013.

Ninilchik hugs shore

The Ninilchik unit hugs the coastline south of Kasilof.

Chevron discovered a Tyonek gas field at the unit in June 1961 with the Falls Creek Unit No. 1 well, and Marathon later discovered two other fields in 2001 and 2002.

While Marathon originally planned a year of regular production from its existing wells at the unit, Hilcorp subsequently amended the development plan to include up to six new wells, including at least one to test the deep oil potential at the traditional gas field.

The heart of the program is three exploration wells — the

12,000-foot SD-8 targeting deep oil, the 2,400-foot PAX-5 targeting the upper Beluga and the 5,500-foot NS-4 targeting the Sterling. It also includes four potential locations — a 12,000-foot SD-9 to appraise the SD-8 well, a 4,000-foot PAX-6 targeting the lower Beluga, a 12,000-foot GO-8 targeting deeper oil and the 12,000-foot FC-5 target the same deeper oil intervals.

The AOGCC issued a permit for the SD-8 well on April 25, 2013.

The results of this exploration work could lead to an expansion of the Falls Creek, Grassim Oskolkoff and Susan Dionne-Paxton participating areas, according to Hilcorp.

Comprehensive unit review

The proposed program also included well work on the SD-1, SD-2, SD-5, SD-6, SD-7, PAX-1, PAX-3 and FC-1 wells to increase gas production from the Tyonek and Beluga.

This work, if successful, would likely require expanded facilities, Hilcorp said.

Even with the workload, or more likely because of it, Hilcorp said it would take at least two years to complete a comprehensive review of the oil and gas potential for the unit.

In September 2013, the AOGCC issued a permit for Hilcorp to drill the Frances No. 1 exploration on private land either inside the unit or just outside its eastern boundaries.

Averaging cumulative rates, Ninilchik produced 26.6 mmcf per day between July 2012 and 2013 and nearly 31.2 mmcf per day between January 2012 and 2013, according to the AOGCC. In July 2013, the field produced nearly 518 mmcf, or 16.7 mmcf per day.

Cumulatively, Ninilchik had produced nearly 146 bcf through July 2013.

Swanson River

The Swanson River unit is the biggest success to date for Hilcorp in Alaska.

When Richfield Oil Corp. drilled the Swanson River No. 1 well in April 1957, the company made the first significant oil discovery and justified Alaska's bid for statehood.

Swanson River oil production began from the Hemlock formation the following year and peaked at 38,323 bpd in November 1967, but had fallen below 1,000 bpd by 2004.

By the time Hilcorp arrived, it was producing some 300 bpd, Hilcorp's Barnes told Commonwealth North in December 2012.

In addition to drilling plans, Hilcorp started by using a pulling unit for well remediation, and bringing in a workover rig for well work. "There are a lot of wells out there that need to be fixed," Barnes said. "We've scratched the surface and have a long way to go." The initial work involved sidetracking three existing and repairing eight damaged 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.

Cumulatively, Swanson River had produced some 231 million barrels through July 2013.

Another year of projects

Speaking at an informal meeting of the Alaska House Resources Committee in February 2013, Hilcorp Energy President Greg Lalicker outlined another year of projects.

"This year we're going to drill seven more wells and we have about 15 workover, recompletion projects," Lalicker said. "It's

The Saxon 169 rig on site at the Swanson River field, one of two land rigs Hilcorp brought to Alaska to launch a drilling program late this summer.

COURTESY HILCORP

not inconceivable that you'll see the rate climb another 2,000 to 3,000 barrels per day, by the time we're all said and done."

Between January 2012 and mid-September 2013, Hilcorp permitted 10 wells at Swanson River and drilled seven, the latest completed in late May 2013, according to the AOGCC.

In early 2013, Hilcorp acquired the Swanson River Oil Pipeline from the Kenai Pipe Line Co., which gave the producer more control over its destiny at the historic oil field.

In mid-2013, though, Hilcorp paid a civil penalty of $115,500 after failing to notify the AOGCC about changes to drilling permits and for failing to test blowout prevention equipment after it was used to control a well. The incident was one of more than a dozen enforcement actions initiated against the company, according to the AOGCC. "The aggressiveness with which Hilcorp is moving forward with operations appears to be contributing to regulatory compliance issues," the AOGCC said in an April 2013 order.

In a statement at the time, Hilcorp said that its "investment in Alaska's resources has certainly brought an increased level of activity to Cook Inlet, but we believe we're on the right path forward and remain committed to operating safely and responsibly."

Birch Hill, Beaver, Sterling

The nearby federal units have yet to see the investment directed at Swanson River.

Just north of the Swanson River unit is the Birch Hill unit.

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HILCORP *continued from page 65*

ARCO Alaska Inc. discovered the field in 1965 with the Birch Hill Unit No. 22-25 well, but production has been limited to a short run of some 65 mmcf in that initial year.

South of Swanson River are the Beaver Creek unit and the Wolf Lake and West Fork fields.

Marathon Oil Co. discovered three gas producing intervals at Beaver Creek in 1967 with the Beaver Creek No. 1 well and an oil pool in 1972 with the Beaver Creek No. 4.

Beaver Creek gas production peaked in 1986 at 17.7 bcf per year and Beaver Creek oil production peaked in 1973 at 416,000 barrels per year. In July 2013, Beaver Creek produced 5.3 mmcf per day on average and 154 bpd on average. Cumulatively, Beaver Creek had produced some 212 bcf and 6.2 million barrels of oil through July 2013.

The West Fork and Wolf Lake fields are currently offline.

The West Fork field dates to exploration from 1960, but has produced sporadically through the years. As of July 2013, cumulative production was some 5.7 bcf.

The Wolf Lake field dates to exploration from the late 1990s, but was always one of the smaller fields in the basin. As of July 2013, cumulative production was some 822 mmcf.

The Sterling unit dates to Unocal exploration from the early 1960s, but production has been small-scale and sporadic over the decades, with intervals or even entire fields shut-in at times. The unit produced some 801 mcf per day in July 2013, predominately from the Upper Beluga formation. Cumulatively production through July 2013 is some 14 bcf.

The Kenai gas field

The Kenai unit is due east of Sterling.

Without an amendment from Hilcorp such as the one it supplied for Ninilchik, the unit is operating under a prior Marathon plan of develop running through Feb. 7, 2014.

While Marathon drilled no new wells at the unit in 2012 and planned no new wells for 2013, it performed and planned "numerous non-rig remedial activities" for both years.

Union Oil Company of California discovered the Kenai gas field on Oct. 11, 1959, in a 50-50 partnership with Ohio Oil Co. Those companies eventually became Chevron and Marathon, making Hilcorp now the sole owner of the large gas discovery in Cook Inlet.

Unocal discovered the field with the onshore KU 14-6 well. While the company had been looking for oil, the well initially tested at 12 mmcf per day from two zones in the Sterling formation. The discovery launched the Southcentral natural gas market.

In launching the local gas market, the Kenai gas field also defined two oddities — long-term contracts and cheap prices — that have began to disintegrate in the past decade.

Kenai production peaked in 1982 at 116 bcf per year, but dropped 30 percent in 1984 and 42 percent in 1989 before reaching a low of 10 bcf per year in 1998 and 1999.

2000 course reversal

But Marathon reversed course at Kenai. In 2000 its newly commissioned Glacier No. 1 truck-mounted drilling rig made it quicker to move from one drill site to the next and its Excape completion technology in 2001 allowed the company to stimulate several production zones at the same time using perforating guns placed outside the well casing.

Those efforts lifted production to as high as 28.5 bcf in 2003, according to the state, but in 2012 the field produced some 11.4 bcf from three formations, according to Marathon.

Cumulatively, the Kenai gas field had produced 2.4 trillion cubic feet through July 2013.

The Kenai gas field produced some 16.2 million cubic feet per day in July 2013, according to the AOGCC.

The associated Cannery Loop unit produced an average of 4.7 mmcf per day from the Beluga in July 2013, with cumulative production of 186 bcf through July 2013.

The field dates to exploration from 1959, and the depleted reservoirs at the old field are now home to the Enstar-affiliated Cook Inlet Natural Gas Storage Inc. operation.

Deep Creek

The two remaining units in the Hilcorp portfolio are in the southern Kenai Peninsula.

For nearly a decade, the Deep Creek unit was the southern terminus of the regional grid.

Socal drilled the Deep Creek Unit No. 1 well in 1958 in pursuit of oil in the Hemlock formation and a secondary target of Tyonek gas, but chose not to pursue development.

Unocal returned to the field in the early 2000s, forming a unit, acquiring seismic and drilling exploration wells into the Happy Valley gas field at the unit. A discovery announced in November 2003 justified an extension of the Kenai Kachemak Pipeline.

Unocal brought the Happy Valley field online in November 2004 at 3 million to 4 mmcf per day and drilled some 13 wells between 2003 and 2009. The early exploration work suggested additional accumulations at the unit, and a 2007 report from Netherland, Sewell & Associates estimated probable reserves of 22 bcf for the unit area.

The Happy Valley participating area covers only the northern end of the 20,000-plus acre Deep Creek unit. By late 2010, the Unocal parent company Chevron announced plans to sell in Cook Inlet holdings, which stalled plans for exploring the southern end of the unit.

Deep Creek early priority

After Hilcorp took over the Chevron properties in January 2012, the company made Deep Creek one of its early priorities, drilling three wells and working over another four wells.

The wells tested producing and non-producing formations. The 2,005-foot B-14 exploration well tested a target in the Sterling formation above the existing participating area. The 3,069-foot B-15 exploration well tested a target in the Upper Beluga formation, also above the existing participating area. The 4,857-foot B-15 development well targeted the Beluga formation, but "rig limitations" prevented it from reaching its target depth.

The workover program added horizons at existing wells: B-12, B-13, A-11 and A-3.

Hilcorp also commissioned a 3-D seismic survey over 50 square miles of the unit. The survey suggested the resources at Happy Valley were "probably three to four times larger than the current participating area," Hilcorp's Barnes told the Anchorage Energy Task Force in June 2013.

Finally, Hilcorp asked the Department of Natural Resources and Cook Inlet Region Inc. to expand the unit to include CIRI leases to the south. The proposal included a drilling commitment, but Hilcorp withdrew the request, calling the discussions "unsuccessful."

The current plan calls for completing the B-16 well, and drilling two exploration wells from a new C pad into a Sterling and a deeper Beluga target outside the participating area. If successful, the program would justify a new participating area, Hilcorp said.

The plan also calls for numerous workover jobs, including acid treatments.

The Happy Valley field produced some 11 mmcf per day as of early 2013, according to Hilcorp, but the summer rate was closer to 3.7 mmcf per day, according to July 2013 AOGCC figures. Cumulatively, Deep Creek produced 22 bcf through July 2013.

Nikolaevsk

The southernmost field shows how Hilcorp differs from its predecessor.

Unocal discovered gas from the Red pad at the Nikolaevsk unit in 2004, but never developed the field because of its distance from the grid terminus at Happy Valley.

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 and infrastructure conditions. With the development of the North Fork field to the south cutting the distance to market, Unocal reached an agreement with the Department of Natural Resources in early 2011 to study a pipeline to North Fork rather than its earlier plan to connect to the grid at Happy Valley.

The evaluations became moot when Hilcorp took over on January 2012.

Instead, in September, Hilcorp and the Enstar affiliate Alaska Pipeline Co. announced an $8.4 million 10-mile pipeline connecting the field to the Anchor Point Pipeline, an extension of the Kenai Kachemak Pipeline that connects to the North Fork Pipeline.

Hilcorp brought the field online from the Red No. 1 in December 2012 at 5 mmcf per day. Cumulatively, Nikolaevsk produced some 378 mmcf through July 2013.

While Hilcorp has no plans to drill new wells during the current development plan that runs through March 2014, the company is evaluating whether work at Red No. 2 could make the well productive. Unocal drilled Red No. 2 in 2004, when it drilled the discovery well.

Hilcorp also plans to acquire seismic over the unit this winter.

How far can Hilcorp go?

When Hilcorp achieved its goal of doubling by 2010, the company gave all its employees a new car. If it meets of its goal of doubling by 2015, each employee will get $100,000.

So, will they get the bonus?

By late 2012, Hilcorp had increased oil production 8 percent at McArthur River, 27 percent at Granite Point, 36 percent at Trading Bay and 122 percent at Swanson River, Hilcorp President Greg Lalicker told the Resource Development Council in November 2012. By May 2013, Hilcorp was touting a 36 percent increase across all fields, including a 412 percent increase at Swanson River and a 157 percent increase at Trading Bay.

However, gas production initially lagged. By late 2012, Hilcorp's share of Beluga River production was down 11 percent, Trading Bay was down 33 percent and Ninilchik was down 6 per-

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HILCORP *continued from page 67*

cent. The small Deep Creek unit was up 102 percent and a collection of smaller fields primarily located on the west side of Cook Inlet was up 39 percent.

After taking over for Marathon in early 2013, though, Hilcorp pushed its assets to their limits. The test increased gas production from some 65 mmcf per day at the end of January to almost 180 mmcf per day in February, according to Barnes.

Those figures convinced Hilcorp it could supply unmet local demand for the near term.

Gas supply agreements

In the second half of the year, Hilcorp signed agreements to supply Enstar Natural Gas Co., Chugach Electric Association and Matanuska Electric Association into March 2018.

The contracts have been a big relief to local utilities, which have been considering imports to meet local needs, but the region remains on edge. For starters, the lead time needed to arrange imports mean the utilities are continuing to study the matter.

Hilcorp also must deliver on the contracts.

In June 2013, before signing the contracts, Hilcorp Alaska Vice President of Midstream Kurt Gibson told the Anchorage Energy Task Force that some of the gas it expected to deliver was already behind pipe, "but not much. Some of it can be found very quickly if we need to. ... And still another tranche of it is going to require ... more of an effort." He added, "What we're saying is, the gas is there and we'll go get it if you tell us to."

Once Hilcorp delivers, the contracts will likely impact the local market.

Smaller independents concerned

For starters, smaller independents like Buccaneer Alaska LLC, Cook Inlet Energy LLC and Furie Operating Alaska LLC worry that the contracts will push them out of the market, should they prove up considerably natural gas reserves over the next four years.

The Regulatory Commission of Alaska acknowledged the concern when it recently approved the Enstar contract, but said the contract still served the public interest.

The contracts will also impact pricing in the Cook Inlet.

To resolve competitive concerns after the company acquired the Marathon assets, Hilcorp and Alaska Attorney General Michael Geraghty agreed to a consent decree in November 2012 that prohibits gas exports unless all local needs are met and caps prices through late 2017.

The Enstar contract used the maximum pricing allowed under the consent decree, with base-load prices ranging from $6.86 per mcf at the start to $8.03 per mcf toward the end of the contract, and higher prices from emergency gas supplies and for "swing load" gas.

Those prices have already become benchmarks in the region.

For instance, Buccaneer recently proposed a contract priced 20 cents higher than the consent decree cap, saying it would offset the premium with a 30-cent savings in tariffs.

Still, after worrying for years about the regional system holding out through extreme cold snaps each winter, the utilities certainly want Hilcorp's employees to get those bonuses.

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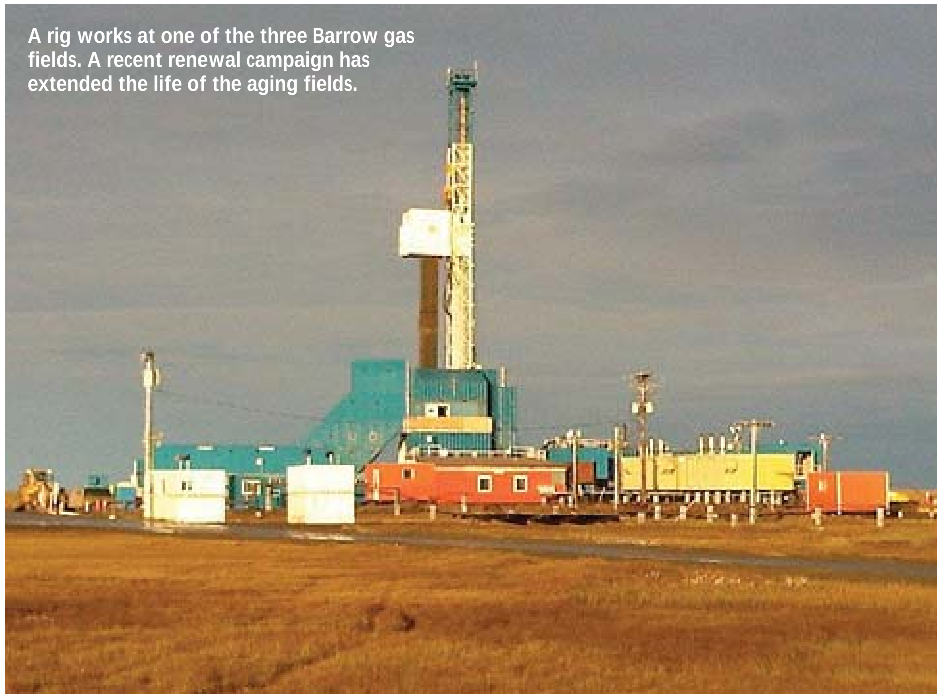
No decline for Barrow gas fields

A major drilling campaign has allowed the fields to produce at peak rates in recent years at the northernmost city in America

By ERIC LIDJI
For Petroleum News



A rig works at one of the three Barrow gas fields. A recent renewal campaign has extended the life of the aging fields.

COURTESY NORTH SLOPE BOROUGH

For decades, three natural gas fields near Barrow have allowed the largest city in the North Slope Borough to avoid the crippling energy costs plaguing much of rural Alaska.

The production comes from three fields: South Barrow, East Barrow and Walakpa.

The U.S. Navy discovered South Barrow with the 2,505-foot South Barrow No. 2 well in 1948, during its initial wave of National Petroleum Reserve-Alaska exploration. Production began the following year, but development continued for decades, with 13 wells drilled through 1987, according to the Alaska Oil and Gas Conservation Commission. The field peaked at some 3.5 million cubic feet per day in 1980 and 1981.

In the early winter months of 2012, South Barrow was still producing 1 mmcf per day or more, but production rates have been lower in 2013. Cumulatively, the field produced nearly 24 billion cubic feet of gas through July 2013, according to the AOGCC.

The original estimate for the field was some 32 bcf of natural gas.

East Barrow discovered in 1974

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. Regular production began in December 1981, but drilling continued through 1990, with eight wells altogether. East Barrow production initially peaked at some 2.75 mmcf per day in early 1984.

In the winter of 2012, East Barrow production ranged from 200 thousand cubic feet to 900 mcf per day, with production in the winter of 2013 holding at a steadier rate of about 350 mcf per day. Cumulatively, the field produced more than 8.8 bcf through July 2013, surpassing the original estimate of 6.2 bcf of gas in place.

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

Working under a Navy contract, Husky Oil discovered Walakpa with the 3,666-foot Walakpa No. 1 in the 1980s. Production began in the early 1990s. The field has peaked above 5 mmcf per day numerous times over its history, including earlier this year.

Cumulatively, the Walakpa field had produced nearly 25 bcf through July 2013, according to the AOGCC. The field is believed to hold some 250 bcf of gas.

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Drilling program

The three fields have kept Barrow warm and lit for more than half a century, but eventually the demands of those long Arctic winters started depleting the wells.

In recent years, the community realized it needed to improve deliverability at the Barrow gas fields if it wanted them to accommodate the expected growth in future demand. So the North Slope Borough launched a program in 2010 to drill as many as six wells at East Barrow and Walakpa, and to plug and abandon as many as eight depleted wells at the two fields.

After voters approved two bond sales, the borough launched the $92 million program in 2011, conducting a major summer sealift and starting drilling activities through that winter.

Over the course of the winter, the borough ultimately used the Kuukpik No. 5 rig to drill five horizontal wells — the first wells to be drilled horizontally at the fields. These were the Savik 1 and 2 wells at East Barrow and the Walakpa 11, 12, and 13 wells at Walakpa.

The program also included an effort to upgrade aging gas pipelines and install modern wellhead housing at the fields, which not only improved the integrity of

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BARROW GAS FIELDS *continued from page 69*

the infrastructure but has also allowed the community to increase deliverability by increasing pipeline pressures.

The program successfully plugged and abandoned the eight depleted wells, but the community would like to someday plug a nearby legacy well and convert an older well for disposal.

The greatest accomplishment of the program in the short term has been to give Barrow some breathing room during winter weather emergencies or future well problems.

Production varies considerably from winter to summer: According to figures provided by the municipality, production averaged 5.9 mmcf per day in January of 2013, and 2.9 mmcf per day this June.

Previously, Barrow was forced to rely on expensive diesel fuel when field maintenance required engineers to take multiple wells offline at once. Now, the combined production from the new wells far exceeds peak winter demand. As such, "we can essentially meet the coldest day demand for Barrow with two of the Walakpa wells," Dudley Platt, oil and gas liaison for the North Slope Borough, told Petroleum News in August 2012.

From a technical standpoint, the results from the drilling campaign convinced the AOGCC to slightly expand the area of the Walakpa gas pool based on new information.

Are hydrates producing?

The program may also have produced an unexpected outcome.

In the early 2000s, when East Barrow production surpassed its original gas in place estimated without reservoir pressure declining, geologists began wondering whether methane hydrates might be "replenishing" the conventional gas reservoir at the field.

In the early 2000s, when East Barrow production surpassed its original gas in place estimated without reservoir pressure declining, geologists began wondering whether methane hydrates might be "replenishing" the conventional gas reservoir at the field.

Within a certain range of temperatures and pressures, such as those across much of the North Slope, methane molecules can become trapped inside "cages" of ice. A change in temperature or pressure can "unlock" these hydrates, yielding huge volumes of methane.

The geologists wondered whether the normal decline in reservoir pressure from sustained East Barrow production was "unlocking" hydrates, which in turn increased field pressure.

A preliminary study in 2006 suggested the East Barrow and Walakpa reservoirs might exist at least partially within the stability zone required for producing hydrates. The U.S. Department of Energy announced plans to drill a well at East Barrow to test those suspicions, but withdrew funding for the project in 2010, leaving the matter inconclusive.

While other test wells in northern Canada and Alaska have shown the technical feasibility of depressurizing hydrate reservoirs to stimulate production, the tests have yet to demonstrate the commercial viability of this method. With the Barrow upgrades, "We believe we have the first commercial gas hydrate production in the world," Platt said.

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The Oooguruk drill site

Pioneer rejuvenating Oooguruk

The Texas independent keeps finding oil at its Oooguruk development but needs to make sure it can economically develop it

By ERIC LIDJI
For Petroleum News

Pioneer Natural Resources Inc. is in the early stages of its second phase in Alaska.

About a decade ago, the Texas-based independent arrived in the state eager to bring a new business model to the North Slope. Having succeeded, the company is now trying to improve the economics of its offshore oil field with technology and infrastructure.

Using completion techniques borrowed from its unconventional oil operations in the Lower 48, Pioneer believes it can improve production rates at its offshore gravel island at Oooguruk.

And now the company is looking to expand the island to accommodate more wells, and complement it by building onshore facilities to target a reservoir south of the island.

The Oooguruk unit currently comprises 22 leases covering some 52,000 acres.

Pioneer operates the unit and holds a 70 percent working interest in the leases, while the Italian major (and neighboring operator) Eni Petroleum holds the minority interest.

The Oooguruk unit was averaging some 7,476 barrels per in July 2013. Cumulatively, Pioneer produced some 13.7 million barrels of oil at Oooguruk through July 2013.

An independent mindset

When Pioneer acquired a stake in an Armstrong Resources prospect in the Beaufort Sea in 2002, the company wanted to reduce the "cycle time" for North Slope developments.

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NEWS FLASH

EDITOR'S NOTE: As The Producers went to press, Pioneer Natural Resources sold its Alaska holdings to Caelus Energy Alaska LLC. The deal is scheduled to close by the end of 2013.

The first four decades of North Slope oil development involved some of the largest oil companies in the world spending many years to develop some of the largest oil fields in the world, in one of the harshest and most expensive petroleum basins in the world.

Having recently brought two deepwater Gulf of Mexico fields into production just two-to-four years after making their initial discoveries, Pioneer believed northern Alaska could accommodate quicker turnaround times as well, Chris Cheatwood, the executive vice president of worldwide exploration for Pioneer, told Petroleum

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PIONEER *continued from page 71*

News in early 2003.

"You see those kinds of cycle times in other parts of the country, and that's what companies want to see in Alaska. We go in and make substantial investments in wells and leases and we want to be able to bring those prospects into production as soon as possible. … The independent model is to quickly turn investment into cash flow," he said.

Cheatwood was primarily referring to the Northwest Kuparuk prospect — Armstrong's original name for the Oooguruk field — but Pioneer acquired more than 1.6 million acres during its first few years in the state, giving the company numerous prospects to pursue.

Concurrent with its exploration at Oooguruk, Pioneer undertook a range of exploration ventures — some alone and some through joint ventures. But a multiwell exploration program in the winter of 2005-06 and a subsequent venture in the National Petroleum Reserve-Alaska were both disappointing. In late 2007, Pioneer relinquished the majority of its NPR-A acreage and suspended its Alaska exploration program to focus on two developments: Oooguruk and the offshore Cosmopolitan prospect in Cook Inlet.

Pioneer spent several years trying to make Cosmopolitan economic before relinquishing the ancillary acreage of the prospect in early 2011 and selling the core leases to Buccaneer Energy Ltd. and BlueCrest Energy Inc. the following year. With the transaction, Pioneer focused its Alaska efforts entirely on growing the Oooguruk field.

Bringing Oooguruk online

At Oooguruk, Pioneer saw the potential for a new business model.

"How many basins have had a second, third or fourth exploration and development lives after the majors wind down growth investment in an established basin? — almost every basin," Pioneer CEO Scott D. Sheffield told Petroleum News in November 2002.

A three-well program in early 2003 provided some early challenges.

The 6,700-foot to 6,900-foot (true vertical depth) wells all encountered oil in the Kuparuk C sands, but the sands "were too thin to be considered commercial," Pioneer said. A deeper test "encountered thick sections of oil-bearing Jurassic-aged sands," but questions about permeability, the size of the resource and recovery rates tempered any enthusiasm.

Even so, Pioneer fast tracked development.

After the state formed the Oooguruk unit in July 2003, Pioneer spent the next two-and-a-half years studying development schemes to find an economic way to produce oil from the technically challenging project in the shallow nearshore waters of the Beaufort Sea.

Gravel island development

Ultimately, Pioneer decided to build a six-acre gravel island connecting back to the existing facilities at the Kuparuk River unit. To protect Pioneer against a drop in oil prices, the Department of Natural Resources agreed to a royalty reduction program.

Pioneer sanctioned Oooguruk in early 2006, by which point the Italian major Eni SpA had acquired the 30 percent minority stake in the prospect from Armstrong Resources.

At the time, Pioneer expected to spend as much as $525 million building facilities and drilling some 40 horizontal wells to develop an estimated 50 million to 90 million barrels of gross oil resources. It expected the field to remain economic for at least 25 years.

The construction was challenging.

In addition to a gravel island rising 23 feet from the ocean floor, the project required a 5.7-mile three-phase pipeline bundle that was entrenched to protect against sea-ice, encased to protect against leaks and insulated to keep from thawing the permafrost.

The state originally approved a 20,394-acre unit covering 12 leases, but in early 2007 agreed to add seven leases to the unit, which increased the size to some 50,883 acres.

Pioneer finished building the island and installing the pipeline infrastructure by mid-2007 started drilling development wells near the end of the year using Nabors Rig 19 AC.

After a season of drilling, Pioneer brought the Oooguruk unit online in June 2008, becoming the first independent oil company to operate production on the North Slope.

Building facilities

Oooguruk tested the principles of the Charter for the Development of the Alaskan North Slope, a 1999 agreement signed in the wake of BP's acquisition of ARCO and agreement to sell ARCO's Alaska assets to Phillips Petroleum. To make the North Slope friendlier to independents, the state forced the majors to provide access to their facilities.

After long negotiations, Pioneer and ConocoPhillips reached an "agreement in principle" on a facility sharing arrangement in 2006, but various complications, including changes associated with Alaska's Clear and Equitable Share, the tax change enacted in 2007, added months of delays. The companies finally signed the agreement in early 2008, with Oooguruk drilling under way.

While not the first such deal on the North Slope, it became the first to be utilized and it has informed how other independents and newcomers have developed their prospects.

While the facility sharing agreement kept Pioneer from having to build expensive production facilities, it has left the company vulnerable to complications outside its control. For example, within weeks of startup, Pioneer was forced to suspend Oooguruk production to accommodate planned maintenance work at the Kuparuk River unit.

And difficulties getting enough water for enhanced oil recovery from its usual supply at Kuparuk forced Pioneer to scale back its production for several weeks in early 2009.

The arrangement spawned another first.

The Alaska Oil and Gas Conservation Commission allowed Pioneer to use multiphase flow meters at Oooguruk, the first time the technology was used in Alaska between units operated by different companies. A multiphase flow meter allows operators to measure oil, gas and water production without having to separate the stream into its constituents.

The meters can be less accurate than traditional LACT, lease automatic custody transfer, meters, but the conditions at Oooguruk minimized the possibilities of significant errors, according to the AOGCC.

Three oil pools

The initial development scheme focused on two oil pools, the Kuparuk and the Nuiqsut.

Using primary and secondary methods, Pioneer originally expected to recover between 41 million and 98 million barrels from the 265 million to 325 million barrels of original oil in place between the two reservoirs. A breakdown attributed 4 million to 8 million barrels to the Kuparuk and 37 million to 90 million barrels to the deeper Nuiqsut.

The Oooguruk tie-in pad.

COURTESY PIONEER NATURAL RESOURCES

The Kuparuk performed better than expected, though, and a 3-D seismic shoot suggested more opportunities within reach of the island. So in early 2009, Pioneer increased its resource estimate for the entire Oooguruk unit to 150 million barrels of recoverable oil.

Through the remainder of the year and into 2010, Oooguruk production rose as Pioneer saw good results from the Kuparuk and drilled dual lateral wells into the Nuiqsut.

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PIONEER *continued from page 73*

All this initial drilling at Oooguruk — including the early exploration work — passed through a third, even shallower reservoir en route to deeper targets. In early 2010, Pioneer specifically targeted this reservoir, known as the Moraine or Torok formation.

The potential resources in the Torok formation underpinned the decision to bump the resource estimates for the field, but created a technical challenge. The formation extended quite far south from the gravel island, meaning Pioneer would either need to drill extended-reach wells or construct a second, onshore pad to access the additional resources.

The Nuna development

By late 2010, Pioneer proposed the Nuna development project.

The proposal called for expanding the unit to include leases to the south and building as many as two onshore drill sites in the Colville River Delta. The increased oil production might even justify building a standalone production facility, the company hypothesized.

The state approved the expansion request in early 2011, but required the company to decide by June 2014 whether it would sanction the Nuna development.

To inform its decision, Pioneer drilled two exploration wells in early 2012: the Sikumi No. 1 from an offshore ice island and the directional Nuna No. 1 from an onshore ice pad.

A “deep test” of the Ivishak at the Sikumi well was “basically non-commercial” despite a gas show, but the Nuna well yielded a 50 million barrel discovery from the Torok.

The results prompted Pioneer to test Nuna No. 1 and drill the Nuna No. 2 appraisal well in early 2013. Again, the results prompted Pioneer to increase its resource estimate for the Torok, this time to a range of 75 million to 100 million barrels, up from 50 million.

Operations expansion proposed

In August 2013, Pioneer proposed significantly expanding both its offshore and onshore operations to improve seawater-delivery and to accommodate Nuna drill site facilities.

The project calls for adding 4.15 acres to the six-acre offshore gravel island, adding 1.4 acres to its onshore tie-in pad south of Oliktok Point along the Colville River Delta, and building a 5.2-mile seawater flowline connecting the island to a new tie-in pad to be located some two miles north of Central Processing Facility 3 at the Kuparuk River Unit.

The Oooguruk island expansion would accommodate additional wells to increase oil production and improve logistics for the helicopters required to serve the offshore unit.

The expansion would accommodate 12 additional well slots in two rows of six.

The renovation is also designed to accommodate a new helicopter sling loading operation on the northwest side of the island, near an existing gravel loading ramp for barges.

The expansion of the existing tie-in pad would accommodate facilities for a Nuna drill site. By placing the Nuna drill site facilities at the existing tie-in pad, Pioneer would be able to maximize its existing infrastructure and avoid some duplication. The expansion would include a short 12-inch three-phase flowline from the tie-in pad to Kuparuk River Unit Drill Site 3H, where production from Nuna would join Oooguruk production.

The seawater delivery system would allow Pioneer to improve its water sourcing for drilling operations. The seawater flowline and the new tie-in pad would serve both sites.

To accommodate both the existing Oooguruk drill site and the proposed Nuna drill site, the proposed seawater flowline would be larger and more reliable than the existing flowline, according to Pioneer. The new flowline would connect to an existing ConocoPhillips 30-inch supply header coming from the Seawater Treatment Plant.

The expansion request suggests Pioneer is moving toward a yes-vote for Nuna, but the company had yet to sanction the project by its second quarter earnings report in May.

Mechanical diversion

In early 2012, Pioneer also tested a new completion strategy at its development wells.

By using a “mechanical diversion” fracturing system borrowed from its Eagle Ford shale operations, Pioneer was able to stimulate a larger portion of the Nuiqsut reservoir than it had using a “dynamic diversion” fracturing system. The completion technique yielded “by far our best Nuiqsut well,” Pioneer Chief Operating Officer Tim Dove said in May 2012.

With widespread application, the technique should help turnaround lagging production, according to Pioneer. After peaking above 10,000 bpd in the summer of 2010, the Oooguruk unit produced some 7,100 bpd in the summer of 2012 and less in early 2013.

With July 2013 production nearing 7,500 bpd, the technique appears to be working.

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An aerial view of the Badami field, March 2011.

COURTESY SAVANT ALASKA

Savant: small, quiet, very active

The smallest producer-operator in the history of the North Slope is working at one of the most challenging fields in the basin

By ERIC LIDJI
For Petroleum News

In the coming year, Savant Alaska LLC plans to finish work it originally scheduled for this past winter and undertake other activities to increase production at the Badami unit.

GREG VIGIL

Weather delays and a shortage of oilfield services forced the independent to leave some of its 2012 agenda for the Badami unit unfinished for the year, but Savant still managed a slight increase in oil production by working over an existing well at the easternmost producing unit on the North Slope and expects another bump this coming year as well.

In a two-year ninth plan of development running through November 2013, Savant had proposed to hydraulically fracture both the B1-18A sidetrack and the B1-38 well, but the company said it was unable to secure the necessary services for the work during the previous two winters. However, during the past plan, Savant was able to perform a propellant frack stimulation on the B1-38 well "to break down all perforated intervals."

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Savant is now aiming to complete those completion projects this year.

Alaska Oil and Gas Conservation Commission data indicate average production of 1,340 bpd in July of this year.

Economics of fracturing

The B1-18A program aims to gauge the economics of hydraulically fracturing horizontal wells into the Badami sands interval of the Brookian formation. The B1-38 program aims to do the same for the deeper Killian sands, while also measuring the extent of the sands and the size of the reservoir, and corroborating previous seismic over the area. The information would underpin an application for a participating area for the Killian sands.

Savant expects those activities to yield a bump in production over the expected decline rate. Oil production has been relatively steady in the two and a half years since Savant brought the field back online, but has gradually been declining over the past year.

The 10th plan of development, running from July 2013 to November 2014, also calls for Savant to drill an exploration well into the East Mikkelsen oil prospect in the Killian sands, but the program first requires Savant to successfully appeal a prior state decision to exclude segments of the prospect from a unit expansion approved in March.

As part of the current plan, Savant recently relinquished some 6,000 acres from the western edge of the unit, acreage located outside the Badami Sands participating area.

Other work completed

Savant completed several other tasks from the ninth plan, to various degrees.

The plan originally called for using a coiled-tubing rig to sidetrack the B1-16 and B1-28 wells into the Brookian to further test the effectiveness of horizontal drilling at the unit.

With the coiled-tubing rig unavailable, Savant used a conventional rig and an electric submersible pump on B1-16, which yielded 54,259 barrels of oil between May 2012 and March 2013 that the company said “would not have otherwise been produced.”

Savant restored integrity to the B1-28 well by repairing a tubing leak and the company said it was planning additional repairs needed to bring the well back online this summer.

Savant had also proposed to use a paraffin inhibitor to increase oil production at existing wells, but “issues related to cold weather impacted the efficacy of the paraffin inhibitor.”

In many ways, Savant’s biggest accomplishment during the

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ninth plan was taking over unit operatorship from BP, becoming the smallest producer-operator on the North Slope.

Kupcake to Badami

Colorado-based Savant Resources LLC came to the state in 2006 to pursue the Kupcake prospect in Foggy Island Bay, some 20-miles west of the Badami unit.

Savant drilled the Kupcake No. 1 exploration well from an ice island in early 2008, but the results fell short of expectations. The target interval in the Kemik formation "was thinner than anticipated" and the porous Cretaceous sandstone proved to be "water wet."

In mid-2008, the local affiliate Savant Alaska and ASRC Exploration LLC signed a deal with BP Exploration (Alaska) Inc. to take on Badami in return for a stake in the unit.

Conoco Inc. discovered the Badami oil pool in 1990 with the Badami No. 1 well. BP started development drilling in 1997 and brought the field online in August 1998.

Oil production peaked at 7,450 bpd in September 1998, but fell to 3,300 bpd by January 1999 and BP shut-in the field through May 1999 to upgrade facilities. The field produced nearly 5,300 bpd in July 1999, but production fell to 3,000 bpd by the end of the year and 1,300 bpd by July 2003, when BP suspended operations for two years.

BP restarted the field in September 2005 and by October production was averaging 1,785 bpd, but by December it was down to 1,437 bpd and when BP suspended operations in August 2007 to allow the field to recharge, production was averaging some 876 bpd.

2010 drilling

In early 2010, Savant drilled two penetrations at Badami, the B1-18A sidetrack of the B1-18 well BP drilled in 1998 and the B1-38 well into the Red Wolf prospect, located in a deeper interval than previous Badami development in the Brookian formation.

The goal of the sidetrack was to see if horizontal drilling could improve production at Badami. The production troubles at the field come from its notoriously complex geology, a series of turbidite sandstones deposited in channels with minimal communication.

The B1-38 well found oil in two horizons, the deeper Kekiktuk formation and the shallower late Cretaceous Killian sands. The Kekiktuk also contains the oil reservoir for the Endicott unit. Savant used the Killian sands to restart Badami in November 2010.

The unit produced 1,020 bpd through the first six months of 2011.

In early 2012, Savant drilled the Red Wolf No. 2 exploration well about two miles northwest of the bottomhole location for B1-38. The well also targeted the Kekiktuk, but the target zone was wet. The dry hole led Savant to suspend its pursuit of Red Wolf.

In May 2013, Savant transferred a 10 percent working interest and 8.75 percent royalty interest in deep zones at four Badami leases to Red Wolf Exploration LLC, a Wyoming-based independent created in April 2012 by eight small companies. The largest members, each with 25.54 percent ownership, are Nerd Gas Co LLC and Jonah Gas Co. LLC, two companies with minority stakes in the North Fork field in the southern Kenai Peninsula.

The transfer covered ADL 367005, ADL 367006, ADL 367010 and ADL 367011.

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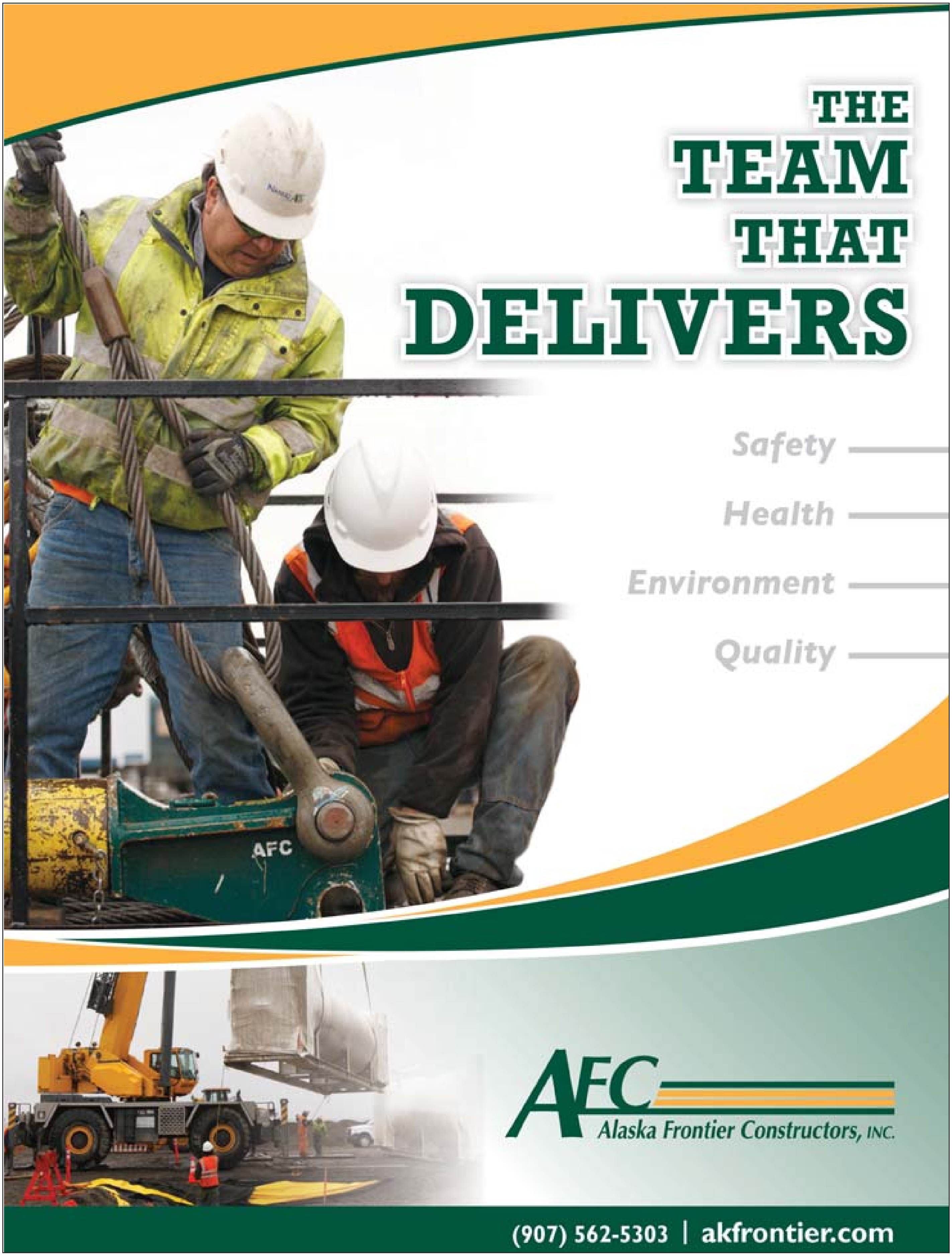
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XTO steady at MGS field

The Exxon subsidiary has managed to keep the aging Middle Ground Shoal field alive and kicking for 15 years, but investment lags

By ERIC LIDJI
For Petroleum News

The name XTO Energy Inc. rarely comes up when policymakers discuss Cook Inlet, but for 15 years the small company has been a consistent oil producer in the basin.

The Fort Worth, Texas-based company operates the Middle Ground Shoal field and its two platforms, A and C. Hilcorp Alaska owns a 22.92 percent working interest in the field.

Middle Ground Shoal produced an average of 2,610 barrels of oil per day in July 2013, making it the second most productive oil field in the Cook Inlet basin. Cumulatively, the Middle Ground Shoal field had produced more than 200 million barrels of oil through July 2013, according to figures from the Alaska Oil and Gas Conservation Commission.

While the Middle Ground Shoal field has always been a small part of the XTO portfolio, the role became much smaller when ExxonMobil acquired the company in late 2009.

Rejuvenation

The Middle Ground Shoal field came online in 1967, but by the time XTO-predecessor Cross Timbers Oil Co. purchased the offshore field from Shell Oil in 1998, it was producing only 3,600 bpd and with production falling needed work to remain relevant.

The Middle Ground Shoal field fit into the larger XTO strategy of seeking out aging North American oil and gas fields operated by large companies with high overhead and using the flexibility of an independent to increase reserves and ultimately production.

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The Kenai platform

COURTESY XTO ENERGY

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By 2006, XTO had drilled 12 penetrations at Middle Ground Shoal, doubled the oil reserves to 24 million barrels and brought production in the range of 3,000 to 4,500 bpd.

XTO also became an important player in the local economy. As of 2012, the company was the sixth largest taxpayer in the Kenai Peninsula Borough, although since Hilcorp has acquired the assets of Marathon and Unocal, XTO is now probably the fifth largest.

Focus on west flank

While Shell had focused on the shallow east flank of the crested Tertiary Tyonek formation at Middle Ground Shoal, XTO focused on the steeper (and trickier) west flank by drilling directionally through the formation and subsequently penetrating the formation again on the bottom side of the well. In 2002, an XTO executive called the west flank "the big opportunity we've been working on for the last three or four years."

Increasingly, though, Middle Ground Shoal took a back seat to other projects in the XTO portfolio. In 2006, XTO deferral several sidetracks while it invested in other regions.

While the Middle Ground Shoal field has always been a small part of the XTO portfolio, the role became much smaller when ExxonMobil acquired the company in late 2009.

While the company initially thought it might drill the sidetracks in 2007, AOGCC records show the company hasn't drilled since 2005.

Instead, XTO focused on maintenance. "Our focus over the past few years has been maintaining production through coil tubing work on producers, injection well workovers, and artificial lift optimization," XTO executive Kyle Hammond said in October 2007.

Also in 2007, XTO replaced its pipeline surveillance system at the field. "This is a system designed to provide immediate notice of any problem with the pipeline 24 hours per day," Hammond said. "We are constantly doing maintenance on our facilities to identify, repair or replace worn or aging vessels, equipment, pipes, and/or valves."

As far as drilling, though, XTO spent money in other areas in its portfolio.

Exxon arrives

Those other areas were what attracted ExxonMobil to XTO.

The global oil giant acquired XTO in late 2009, in an all-stock deal worth $31 billion, in a bid to increase its North American natural gas holdings at the start of the shale boom.

The acquisition gave Middle Ground Shoal much more competition for capital funding and production has declined well below the level it was at when XTO acquired it.

In 2012, XTO faced two small setbacks at the field.

In January, a faulty gasket on a tank at its onshore facility in Nikiski caused a 6,300-gallon crude oil and processed water spill into a secondary containment area, which the company was able to clean up within two weeks. In November, XTO was forced to temporarily suspend production from its two platforms because of a shortage of fuel gas.

However, July 2013 production was up some 12.5 percent from July 2012 rates.

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