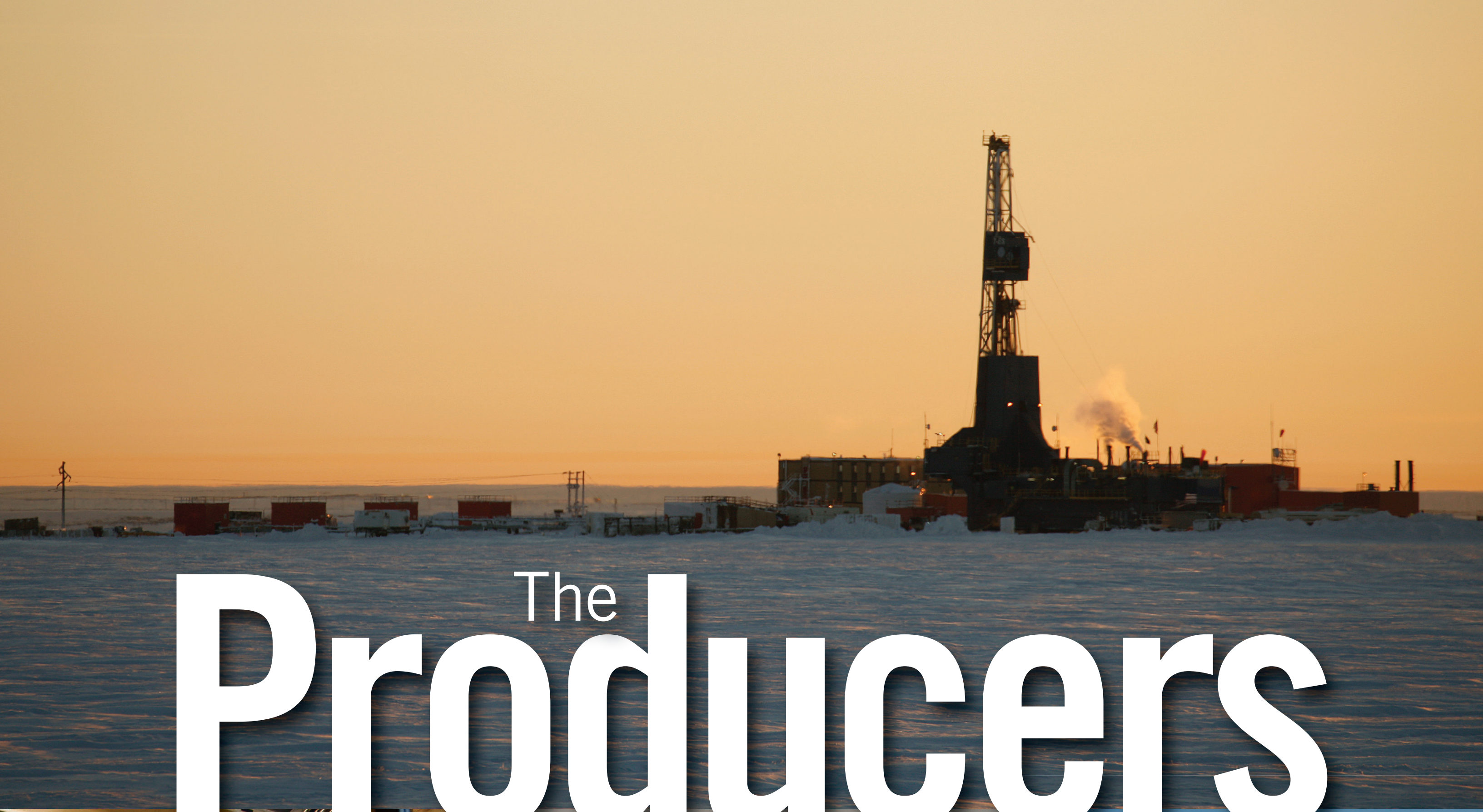
The Producers



The Producers, an annual publication from Petroleum News

Oil & gas companies investing in Alaska's future

Arrivals, expansions, consolidations

By ERIC LIDJI

For Petroleum News

The Producers provides an opportunity to consider the previous year and the upcoming year of oil and gas development across Alaska. As expected, some trends emerge.

The biggest trend this year was the arrival of smaller companies to the North Slope.

The small and privately held Caelus Energy LLC now operates the Oooguruk unit, succeeding the large and publically traded independent Pioneer Natural Resources Inc. The global super-major BP Exploration (Alaska) Inc. is selling much of its North Slope holdings — aside from its flagship Prudhoe Bay unit — to the large and privately held independent Hilcorp Alaska LLC. And the small and publically traded independent Miller Energy Resources Inc. is acquiring the small and privately held independent Savant Alaska Inc. in a deal that would make Miller the operator of the Badami unit.

Another trend is expansion.

Brooks Range Petroleum Corp. and several new partners expect to bring the Mustang field online in 2015. Exxon Mobil Corp. expects to bring the Point Thomson unit online in 2016. ConocoPhillips Alaska Inc. expects to bring the Greater Mooses Tooth unit online by late 2017. ConocoPhillips is also expanding development at its Kuparuk River and Colville River units. And Eni US Operating Co. Inc. has recently completed its initial drilling program at the Nikaitchuq unit and is evaluating several expansion plans.

The most stable presence on the North Slope was the North Slope Borough, which continues to reap benefits from its recent rejuvenation campaign of its three gas fields.

The biggest trend in Cook Inlet is consolidation.

With a few years of exploration and development work behind it, Hilcorp is now beginning to assert its dominance in the basin by securing short-term supply contracts, unifying four regional pipelines into a single system and merging units or facilities.

Having established its presence on the west side, Miller acquired the North Fork unit in the southern Kenai Peninsula from Armstrong Cook Inlet LLC. Miller is also in the running to acquire the Kenai Loop gas field in the northern Kenai Peninsula from Buccaneer Energy Ltd., which filed for Chapter 11 bankruptcy protection in late May 2014.

Aurora Gas, ConocoPhillips and XTO Energy Inc. were largely in holding patterns at the fields in 2014, although ConocoPhillips restarted the Kenai liquefied natural gas terminal, and Aurora is analyzing seismic data with the hope of drilling new wells at the Nicolai Creek unit.

Furie Operating Alaska LLC will become the newest Cook Inlet producer in 2015 when it brings Kitchen Lights online with the first offshore platform in the region since 2000.

Contact Eric Lidji at ericlidji@mac.com

CONTENTS

Petroleum news

MARTI REEVE
SPECIAL PUBLICATIONS DIRECTOR

KAY CASHMAN
PUBLISHER & EXECUTIVE EDITOR

KRISTEN NELSON
EDITOR-IN-CHIEF

ERIC LIDJI
CONTRIBUTING WRITER

STEVEN MERRITT
PRODUCTION DIRECTOR

MAPMAKERS ALASKA
CARTOGRAPHY

MARY MACK
CHIEF FINANCIAL OFFICER

SUSAN CRANE
ADVERTISING DIRECTOR

BONNIE YONKER
ADVERTISING SPECIALIST

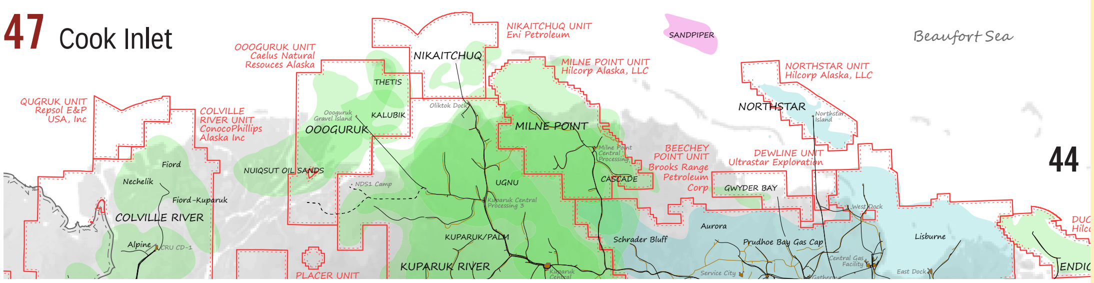
RENEE GARBUTT
ADVERTISING SALES EXECUTIVE

TOM KEARNEY
ADVERTISING DESIGN

HEATHER YATES
BOOKKEEPER

DEE CASHMAN
CIRCULATION REPRESENTATIVE

JUDY PATRICK
CONTRACT PHOTOGRAPHER



The Producers

Released Nov. 16, 2014

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

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

To order additional copies of this special publication, contact Heather Yates, Petroleum News circulation manager and bookkeeper, at hyates@petroleumnews.com

Cover photos courtesy Judy Patrick Photography

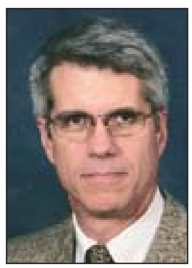
Printed by Journal Graphics, Portland, Oregon

Changing landscapes and the evolution of producers, investors

By BILL BARRON

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

Optimism in Alaska's oil and gas industry is bringing an influx of capital investment into the many units and oil fields on state-leased lands. Companies are working to improve production and bring development opportunities forward. With new drill rigs on the North Slope and the expansion of infrastructure, these companies are working to stem the decline of production, draw more oil from existing fields and begin producing from new fields. Activities and plans are moving ahead to expand into the National Petroleum Reserve-Alaska which will bring the first new oil from federal lands to the Trans-Alaska Pipeline System since the development of Northstar. Likewise, North Slope natural gas is in play as the Alaska Liquefied Natural Gas project moves forward with alignment between the major North Slope gas owners and the state with support for the project signed into law. In Cook Inlet, natural gas and oil production continues to increase as new wells are drilled, wells are reworked and infrastructure improved. And, with success from exploration, new wells are producing.



BILL BARRON

The Division of Oil and Gas is working closely with industry to increase production from state lands and stem the decline. We are doing this in a changing landscape where business models are different. No longer is it just the major oil companies with known publicly traded information, but private oil companies and investment groups joining to develop oil and gas projects or acquire currently producing assets on state-leased land. Being responsive requires a dedicated team of state land managers, scientists, engineers and economists to review the proposed development or acquiring of assets so that the purpose of leasing the land, to produce oil and gas, remains the number one priority.

The interest and investment we are seeing in Alaska's oil and gas shows that strong companies with solid investment plans are succeeding in our state.

The growth of limited liability corporations in the Alaska oil and gas industry reflects how the industry is maintaining flexibility in its portfolio and mitigating financial risk by limiting the liability to parent companies through local entities. This trend is creating new challenges for the division in making decisions that are in the best interest of the state or will not adversely affect the state's interest as required by statute. As the composition of the operators, working interest owners and investors change, the division is working to find the best approach that allows development to move forward.

Being responsive requires a dedicated team of state land managers, scientists, engineers and economists to review the proposed development or acquiring of assets so that the purpose of leasing the land, to produce oil and gas, remains the number one priority.

Asset transfers and new players

With new oil companies and investors, asset transfers are drawing a lot of attention, whether from large producers to smaller producers, as with BP to Hilcorp on the North Slope, privately held companies to publicly traded companies, like Armstrong Energy to Miller Energy's subsidiary Cook Inlet Energy LLC, or from operating companies like Pioneer Natural Resources Alaska to Caelus Energy Alaska LLC. Partnerships amongst new players are increasing as small oil and gas companies team up with investors to bring projects to production. Thyssen Petroleum Corp. acquired investor assets from Brooks Range Petroleum Corp., allowing Thyssen to enter Alaska's oil and gas fields. To further this development, the Alaska Industrial Development and Export Authority and Charisma Energy Services have joined together to finance and develop the new Mustang Operating Center 1 project by providing the processing facility for production. These investments in Alaska, either through asset transfers or financing, underscore new energy and interest in Alaska's oil and gas resources. And it shows confidence as mature fields are managed and new smaller prospects developed and brought to production.

Increased work for knowledgeable service companies

Increased oil field activity in Cook Inlet and the North Slope has helped revive the service companies building oil industry infrastructure, maintaining oil and gas field operations and expanding the North Slope infrastructure. The Alaska Rail Marine saw almost a 30 percent increase in pipe and materials being railed from tidewater to Fairbanks for refurbishing and expanding pipelines and infrastructure on the North Slope and supporting field maintenance. New drill rigs are reworking wells and further developing existing fields. In Cook Inlet, materials for a new pipeline and the new Furie platform are ready for installation in 2015. Similarly, Hilcorp is moving forward on increasing compression in the Cook Inlet Gas Gathering System. All this reflects a strong interest by producers in having knowledgeable service companies expanding infrastructure.

Overall, the focus and activities under way in Alaska reflect a stimulating resurgence of interest, and expectation of success, both in Alaska's legacy fields and in new areas of development. The interest and investment we are seeing in Alaska's oil and gas shows that strong companies with solid investment plans are succeeding in our state.


Where the road ends...
Our Work Begins
Our crews have decades of experience, and the skilled manpower to take on any task.
With our tundra-approved vehicles, we can get your drill rig and project materials to any remote location, and build ice pads and ice roads. And our range of logistics support – hauling fuel and freight – has been broadened with the addition of our marine services division.
From start to finish, we are a partner who can deliver what you need.
Anywhere you need it. Any season of the year.
Cruz
COMPANIES
•ALASKA•
cruzconstruct.com
Main Office (907) 746-3144
North Slope (907) 659-2866
tundra transport • rig moves • rig support • remote camps • ice roads • ice pads • well site trailer units • marine services


From Cook Inlet to Prudhoe Bay,
wherever production happens, we keep you connected.
Hydraulic, Industrial & Arctic Grade Hose Specialists • Domestic Wire Rope, Chain & Synthetic Sling Fabrication • Hydrostatic Pressure Testing & Certification
Petroleum Handling Equipment • Oilfield Fittings & Accessories Hydraulic Component Repair • Sheet Rubber, Gasket Material & Adhesives
100% Employee Owned
ARG
Alaska Rubber Group
Alaska Rubber
& RIGGING SUPPLY
ANCHORAGE • FAIRBANKS • KENAI • WASILLA
www.alaskarubber.com
Member of: Associated Wire Rope Fabricators
NAHAD
GOODYEAR
WireCo WorldGroup
EATON
Powering Business Worldwide


Petroleum
Keeping you covered.
To advertise in Petroleum News, please contact Susan Crane at 907-770-5592, Raylene Combs at 509-290-5903,
Renee Garbutt at 907-522-9469, or Bonnie Yonker at 425-483-9705.

Aurora expects big year at Nicolai Creek in 2015

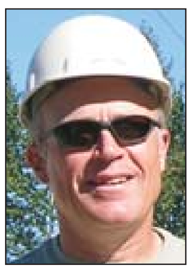
After disappointing wells and some rigless well work the company is expecting an uptick in activities

By ERIC LIDJI

For Petroleum News

After a pair of disappointing wells in 2013, and maintenance work in 2014, Aurora Gas LLC expects to renew efforts at Nicolai Creek next year based on new seismic work.

The Alaska-based independent drilled the Nicolai Creek No. 13 and No. 14 wells in August and July 2013, respectively. Based on the success of previous wells, the company had expected those two wells to yield an average production bump of 3 million cubic feet per day, according to Aurora Gas President Ed Jones, but "neither of the development wells resulted in commercially viable accumulations of hydrocarbons and were plugged and abandoned," according to a plan of development for the year ending in October 2014.



ED JONES

While Aurora did not drill any wells or perform any rigged well work in 2014, the company recently completed several coiled tubing cleanouts and might perform more before the end of the year, according to Jones. "We are awaiting a review of seismic to confirm and prioritize these several drilling possibilities — we are expecting to have a more active year in 2015," Jones told Petroleum News by email in September 2014.

Among the possibilities is a Nicolai Creek No. 12 well, which the company had initially floated as a possibility for its current plan of development but ultimately deferred. The well would target deeper sands not accessible through Nicolai Creek No. 10 or No. 3.

Nicolai Creek acquired in 2000

Aurora acquired the Nicolai Creek unit in 2000 through a trade with Marathon Oil Co., giving up a working interest at Kenai and Cannery Loop in return for operatorship.

"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. Later, a pipeline connected the field to the regional grid. But in the early 1990s a former operator killed the best producing well — Nicolai Creek Unit No. 3 — with drilling mud.

Aurora restarted production in late 2001, after cleaning out the well. In subsequent years, the company also restarted production from the Nicolai Creek No. 1B and No. 2 wells and drilled the Nicolai Creek No. 8 well, which is now known as Nicolai Creek No. 9.

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

The results of those wells were what prompted optimism for No. 13 and No. 14.

Averaging monthly production, Nicolai Creek produced some 1.4 million cubic feet per day in July 2014, according to the Alaska Oil and Gas Conservation Commission.

Cumulatively, the unit produced some 8.5 billion cubic feet through July 2014.

> Aurora Gas, LLC
>
> **NAME OF COMPANY:** Aurora Gas
> **COMPANY HEADQUARTERS:** Houston, Texas
> **ALASKA OFFICE:** 1400 W. Benson Blvd., Ste. 410 Anchorage, AK 99503
> **TOP ALASKA EXECUTIVE:** Ed Jones, executive vice president, oil and gas
> **TELEPHONE:** 907- 277-1006
> **COMPANY WEBSITE:** www.aurorapower.com

Four smaller fields

The utility Aurora Power Resources Inc. created Aurora Gas in 2000 as an exploration and production arm, and Aurora Gas began acquiring properties soon thereafter.

Eventually, Aurora amassed a portfolio of shallow natural gas prospects — developed and undeveloped — located predominately on the west side of Cook Inlet.

Today, the local independent 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 some 2.7 million cubic feet per day in July 2014.

Aurora gets about half of its total production from Nicolai Creek and about half from its other four fields — Lone Creek, Moquawkie, Albert Kaloa and Three Mile Creek.

The company acquired Lone Creek and Moquawkie from Anadarko in 2000. Anadarko and ARCO Alaska discovered Lone Creek in the late 1990s. 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,

continued on next page

AURORA GAS *continued from page 11*

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 the monthly production rate, Lone Creek produced some 952 thousand cubic per day in July 2014 and some 10.3 billion cubic feet, cumulatively, through July 2014.

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. The Moquawkie field produced some 176 thousand cubic feet on average in July 2014 and nearly 5 billion cubic feet, cumulatively, through July 2014, according to the AOGCC.

Pan American Petroleum Co. discovered the Albert Kaloa natural gas field in 1967 while searching for oil. The company brought the Kaloa No. 1 discovery well online in 1970 but suspended operations the following year after sand and mud plugged the well.

In 2004, Aurora drilled Kaloa No. 2. The well was successful and Aurora and returned the field to production in October of that year. Buoyed by its success, Aurora 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 monthly production rates, the field was producing some 23.5 thousand cubic feet per day in January 2014 but appeared to be offline in July 2014. Cumulatively, the field produced some 3.6 billion cubic feet through July 2014, according to the AOGCC.

The Three Mile Creek field is a little ways to the north.

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

Three Mile exploration well

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.

Averaging monthly production, Three Mile Creek produced nearly 190 thousand cubic feet per day in July 2014. Cumulatively, it field produced some 2.4 billion cubic feet through July 2014.

Contact Eric Lidji at ericlidji@mac.com

BP EXPLORATION (ALASKA)

The Central Gas Facility, operated by BP at Prudhoe Bay, processes about 8 billion cubic feet of natural gas, which is produced daily and reinjected back into the reservoir. An Alaska gas project would commercialize that gas through a potential Alaska LNG project.

With sale, BP is more focused than ever on Prudhoe

Near term work at Prudhoe includes a seismic survey in the north and a coordinated West End program

By ERIC LIDJI

For Petroleum News

BP Exploration (Alaska) Inc. shrunk in 2014. The local subsidiary of British giant BP plc started the year as the most active operator on the North Slope, overseeing development at four state units — Prudhoe Bay, Milne Point, Duck Island and Northstar — and the federal Liberty unit, which remains undeveloped.

That changed in April 2014, when BP announced a sale to Hilcorp Alaska LLC. If the deal closes as expected by the end of the year, BP would operate Prudhoe Bay and Liberty and would maintain a 50 percent interest in Liberty and Milne Point, in addition to its pre-existing minority interest in major fields such as the Kuparuk River unit.

JANET WEISS

"BP will be able to focus on maximizing production from Prudhoe Bay and advancing the Alaska LNG opportunity," BP Alaska President Janet Weiss said at the time.

The near term work at Prudhoe Bay includes a seismic survey in the north to identify potential opportunities and a coordinated program in the West End, among other projects.

The sale meant a 17 percent reduction in BP's workforce in Alaska. Of the 475 affected employees, about 200 went to work for Hilcorp and the remainder will be let go in 2015.

NAME OF COMPANY:
BP Exploration (Alaska)
COMPANY HEADQUARTERS: BP, London
ALASKA OFFICE: 900 Benson Blvd., Anchorage, AK 99508
TELEPHONE: 907-561-5111
TOP ALASKA EXECUTIVE: Janet Weiss, BP Alaska regional president
COMPANY WEBSITE: www.bp.com

A long relationship

The deal was the biggest shake-up of North Slope ownership since the consolidation of properties in the wake of industry mergers and acquisitions at the turn of the last century.

But the deal also re-affirmed a relationship between BP and Prudhoe Bay that has been remarkably stable over the past half century and could remain so for decades to come.

BP opened its Alaska office in 1959 — the year Alaska gained statehood.

A decade later, with its confirmation well for the Prudhoe Bay

continued on next page

BP *continued from page 13*

discovery, BP helped launch the North Slope oil industry. The delineation campaign mapped an oil field stretching 45 miles east to west and 18 miles north to south. Geologists initially identified four primary reservoirs — the Kuparuk River formation, the Prudhoe Bay group, the Lisburne limestone and the Kekiktuk Conglomerate — and 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. BP took the Western Operating Area, or WOA; ARCO Alaska took the Eastern Operating Area, or EOA. The split gave each company a manageable workload and divided operations between the oil reservoir and an offset gas cap. But eventually the owners decided to unitize the field to optimize recovery, divide costs more equitably and avoid building unnecessary infrastructure.

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.

Production begins in 1977

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

Prudhoe Bay production topped 1 million barrels per day 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 12.5 billion barrels through July 2014, according to the AOGCC. Original estimates had pegged total recovery at 9.6 billion barrels.

The decades since peak production at Prudhoe Bay have seen reactive and proactive initiatives. In responses to changing production profiles at the field, the working interest owners expanded flowlines between wells and gathering centers, increased gas and produced water capacity at the field and tinkered with gas handling to improve productivity. They also implemented technologies to enhance recovery. Those included waterflooding and miscible injection, and, more recently, multilateral wells, coiled tubing drilling, extended reach drilling and multistage hydraulic fracturing, as well as proprietary technologies such as the Bright Water polymer used

Prudhoe Bay production topped 1 million barrels per day 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.

to sweep oil from reservoirs and the LoSal technique that uses lower salinity water to improve oil recovery.

BP merged with Amoco in December 1998, and BP-Amoco acquired ARCO the following year. The deals triggered a major rearrangement of North Slope holdings to alleviate the concerns the U.S. Federal Trade Commission. By the time the dust had cleared, BP was the sole operator of the Prudhoe Bay unit, a position it retains today.

IPA activities

Today, the Prudhoe Bay unit is a declining oil field that continues to be the largest single source of the oil production, and therefore the largest source of state revenue, in Alaska.

The Prudhoe Bay unit includes the initial participating areas and a series of satellites.

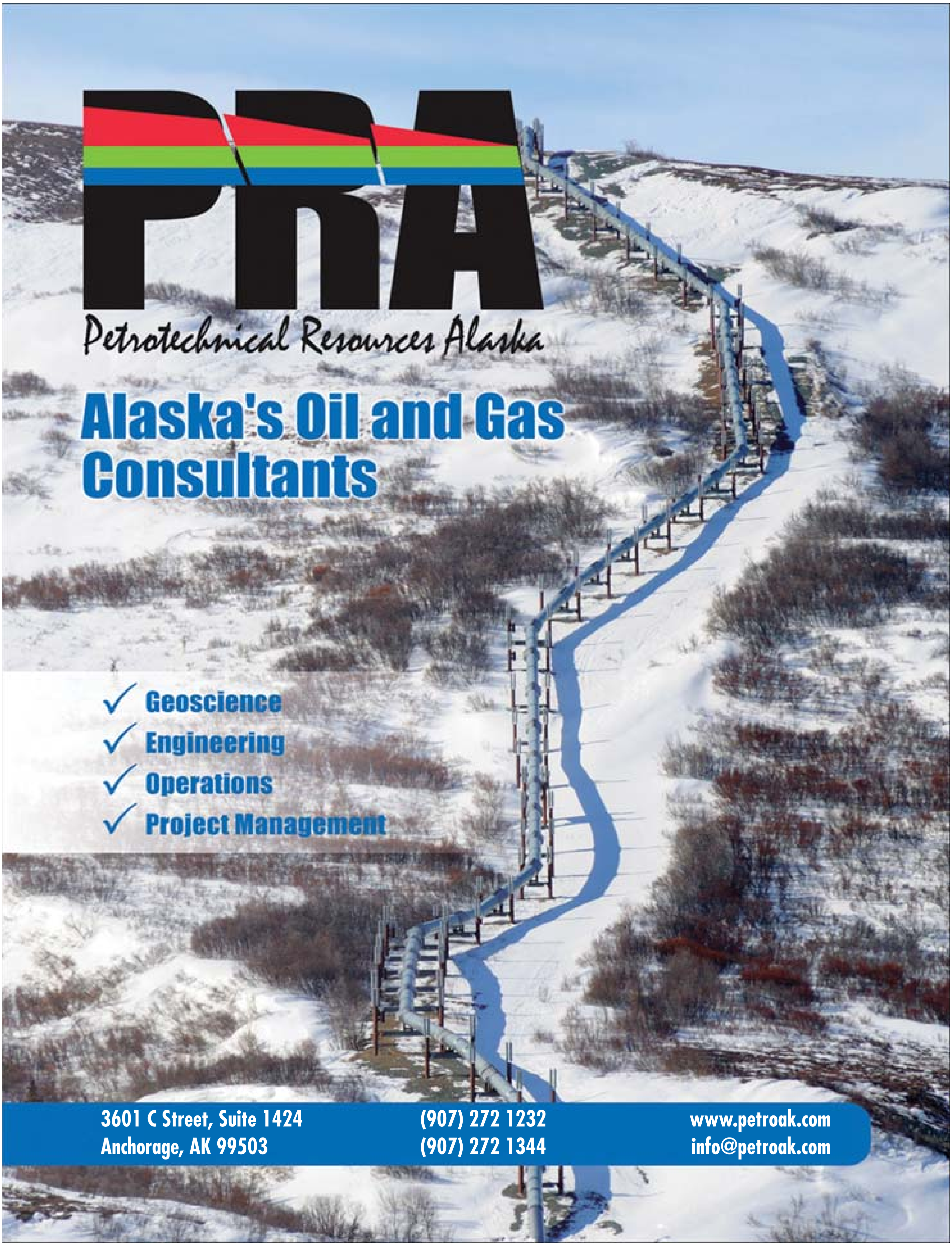
The initial participating areas produced 218,000 barrels of oil per day and 7.145 billion cubic feet of natural gas per day in 2013, according to a recent plan of development.

The Prudhoe Bay initial participating areas also produced some 45,000 barrels of natural gas liquids per day in 2013, of which 31,900 barrels per day went to the trans-Alaska oil pipeline and 13,000 barrels per day went to the Kuparuk River unit, according to BP.

Oil production was down 3.1 percent from 2012. BP expects oil production between 168,000 and 209,000 bpd in 2014 with 36,000 to 44,000 bpd of natural gas liquids.

While liquids produced from Prudhoe Bay are shipped to market through the trans-Alaska oil pipeline — 79.3 million barrels worth in 2013, according to BP — gas lives a more complicated life cycle. Of the 2.6 trillion cubic feet of gas Prudhoe Bay produced last year, BP injected 89.7 percent back into the field, used 5.8 percent for

continued on page 16


PRA
Petrotechnical Resources Alaska
Alaska's Oil and Gas Consultants
✓ Geoscience
✓ Engineering
✓ Operations
✓ Project Management
3601 C Street, Suite 1424
Anchorage, AK 99503
(907) 272 1232
(907) 272 1344
www.petroak.com
info@petroak.com

BP *continued from page 14*

operations and used 3 percent for miscible injectant to enhance oil recover. The remaining 1.5 percent includes flared gas and the limited exports and sales to other units and operators.

BP drilled 57 wells and performed some 1,900 workovers in the initial participating areas in 2013 — up from 45 wells drilled and some 1,700 workovers performed in 2012.

In its most recent plan of development for the initial partial participating area, submitted to regulators in April 2014, BP estimated that its drilling activities for this year would be "similar" to last year — with 50 to 60 penetrations split between rotary and coil rigs. The company also forecast "increased" workover activities for the current year, with the work focused primarily on returning shut-in producing and injecting wells to regular service.

In February 2014, Weiss announced a $1.25 billion capital program for Alaska this year. The budget amounted to a 25 percent increase in total spending and a 40 percent in spending aimed at increasing production, including drilling, workovers and "major projects." Seen another way, BP has committed to spend 90 percent of its profits in Alaska over the next five years, up 60 percent from spending levels in previous years.

"We're drilling more wells and doing significantly more well work jobs in 2013 than 2012, and plan significantly more in 2014 than 2013," she said at the time, in a speech to the Anchorage Chamber of Commerce. "We are focusing on light oil development to ensure we have a healthy business to build the more material opportunities upon."

The near-term capital program also includes funds to bring two rigs to the unit, one by 2015 and one by 2016, which would add between 30 and 40 wells each year, Weiss said.

BP EXPLORATION (ALASKA)

BP and AeroVironment are deploying Unmanned Aerial System technology at Prudhoe Bay, marking the first time the Federal Aviation Administration has granted permission for UAS routine commercial services over land in the United States.

The Aurora field

The Prudhoe Bay field is part of a larger area called the Greater Prudhoe Bay Area that also includes five satellites: Aurora, Borealis, Midnight Sun, Orion and Polaris.

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

As of the end of 2013, BP was developing the Aurora field using 33 wells — 17 producers, 10 water injectors and six water-alternating-gas, or WAG, injectors, according to the 2013 BP annual report. BP drilled the S-110B service well and the S-135 development well at the Aurora field in early 2014, according to AOGCC records.

Of the 200 million barrels of oil in place at Aurora, BP had produced some 37.8 million by July 2014, according to the AOGCC. The field produced an average of 5,913 bpd oil in fiscal year 2013, down from a peak of 14,000 bpd in August 2006.

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

BP conducted a sizable development program at Aurora in 2011 and much of its recent workload for the field aims to follow up on those activities. The work includes developing an oil accumulation in the southwest corner of the field, adding a production and injection well in the eastern edge of the field and sidetracking several injection wells.

The Borealis field

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

Through July 2013, BP had drilled 56 wells at Borealis — 25 from L pad, 22 from V pad and nine from Z pad, according to a plan of development for the field. AOGCC records indicate no additional wells in 2014 through September. Of the 350 million barrels of oil in place at Borealis, BP had produced nearly 74.7 million barrels through July 2014, according to the AOGCC. Borealis peaked at 38,150 bpd in May 2003, according to the AOGCC, and produced 10,253 bpd in the year ending July 2013, according to BP.

BP launched a tertiary recovery program at Borealis in June 2004. As with the work at Aurora, the program alternates cycles of miscible gas injection and water injection.

Since completing an expansion of Z pad in 2011, BP has drilled two producers and two injectors from the field and intends to another producer and injector by early next year.

The Orion field

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

BP originally developed Orion from its V pad and expanded development in mid-2004 to include L pad. Through June 2013, BP had drilled 48 wells at Orion — 25 from V pad and 23-from L pad, although the company also uses facilities at W-Pad and Z pad to develop the field, according to the most recent plan of development for Orion. The company had not drilled at Orion in 2014 through September, according to the AOGCC.

Of the 3.2 billion barrels of oil in place at Orion, BP had produced 30.4 million through July 2014 at a 2013 rate of 6,396 bpd. The field peaked at 14,460 bpd in June 2007.

Orion produces from the same viscous Schrader Bluff formation present at the Milne Point unit to the north and the ConocoPhillips-operated Kuparuk River unit to the west, and the field is part of larger joint efforts to expand the production of heavier oil.

What about I pad?

The futures of Borealis and Orion have long included an 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 2020.

BP has cited technical challenges through the years, but the delays were largely the result of the frequently changing fiscal systems in Alaska over the past decade — BP deferred I pad development after then-Gov. Frank Murkowski proposed combining Prudhoe Bay and its satellites for tax purposes and deferred development again after then-Gov. Sarah Palin approved the Alaska's Clear and Equitable Share produc-

continued on next page

BP *continued from page 17*

tion tax increase.

The proposed I pad also emerged as a crucial point of discussion in debates over Gov. Sean Parnell's recent revision to the production tax code. In hearings and speeches during those debates, executives from both BP and ConocoPhillips pointed to I pad as an example of the short-term investment opportunity that lower taxes could facilitate.

Those changes are now law and I pad appears to be progressing, although slowly.

According to the most recent plan of development, the original location for I pad "proved to be unfeasible" because it was "constrained" by a Milne Point road to the west, a large lake to the east and a subterranean ice lens to the north. BP told the state that it had found an alternative site to the north, which could be accessed from the Milne Point road.

In late 2012, BP conducted vegetation mapping and soil studies for the pad and a proposed pipeline corridor that would connect I pad to facilities at Z pad and L pad.

That said, BP told the state that the future of I pad "depends upon finding ways to more efficiently execute the project and reduce project uncertainty and risks." Ongoing studies in the northwest corner of Prudhoe Bay in 2013 and 2014 include artificial lift, alternative completion designs for wells targeting viscous oil, optimizing pad designs and mapping the N-Sands in the region. All those activities are relevant to I pad, according to BP.

Specifically, BP is using those studies to create a "project concept" that would be reviewed, developed and refined, and also integrated into larger West End projects.

A "generic" timeline given to the state suggested first oil remains many years away.

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

The Polaris field

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

Through June 2013, BP had drilled 28 wells at Polaris — 21 from W pad and seven from S pad. AOGCC records indicate that BP had not drilled any wells at the field in 2014 through September. Of the 1 billion barrels of oil in place at Polaris, BP had produced 17.3 million barrels through July 2014 at a 2013 rate of 5,079 bpd.

BP planned no Polaris drilling for 2013 or 2014. A proposal to expand S pad and M pad to better access oil reserves in the north of the field remains in "the appraisal stage," according to the company. BP is merging the program with its larger West End initiatives. The $3 billion program would add the first new Prudhoe Bay well pad in more than a decade, expand the two existing pads, debottleneck facilities, increase flowline capacity and add surface facilities, according to Weiss. The entire program could add 130 wells and some 200 million barrels of new resources starting in 2018, Weiss said.

The Midnight Sun field

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

Through June 2013, BP had drilled five wells at E pad, the most recent in 2001. The company had not drilled any wells in 2014 through September, according to the AOGCC.

Of the 100 million barrels of oil in place at Midnight Sun, BP had produced more than 20 million barrels through June 2013 but production is currently below 1,000 bpd.

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 has recently told the state it might someday sidetrack existing wells to improve recovery as waterflooding matures.

In October 2014, BP announced plans to drill the P1-122i well at the Midnight Sun field in January 2015. The extended-reach miscible injectant well would support enhanced oil recovery operations at two existing production wells at Midnight Sun

The Lisburne field

On the east side of the unit, the Greater Point McIntyre Area incorporates the Point McIntyre field and four satellites: West Beach, North Prudhoe Bay, Niakuk and Raven.

The facilities in the region also handle Lisburne, which ARCO Alaska discovered in the northeast corner of the Prudhoe Bay field in 1969 and brought online in 1982.

In the year ending March 2014, Lisburne produced some 6,400 bpd of oil, some 660 barrels of natural gas liquids per day and some 124.1 million cubic feet of natural gas per day, according to BP. Cumulatively through July 2014, the field had produced 164.7 million barrels of oil, according to the AOGCC.

According to AOGCC records, BP did not drill at Lisburne in 2014, through September.

The primary activities at the Lisburne field in recent years have involved injection programs to improve recovery. In its most recent plan of development, BP said it was considering several "possible" drilling locations for 2015 but offered no details.

The GPMA satellites

The five other satellites in the Greater Point McIntyre Area are small, produce little oil compared to the unit and have had relatively little development drilling in recent years.

But BP is holding out hope that its recently launched North Prudhoe onshore and nearshore 3-D seismic program will uncover opportunities for investment at these fields.

The two-season seismic program is beginning with nearshore work this year and will advance inland next year to cover some 190 square miles altogether. "Based on preliminary data, it would enable 55 million barrels of new resources and 30 new wells with the potential development," Weiss said in her February 2014 announcement.

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

ARCO and Exxon discovered Point McIntyre in the coastal section of Prudhoe Bay in 1988. The field came online in 1993 and peaked at 172,995 bpd in December 1996.

The field produced 18,520 barrels of liquids per day in the year ending March 2014.

After drilling a well and a sidetrack at Point McIntyre in 2012 and early 2013, BP began 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 and it came online in April 2004.

The field produced 2,300 barrels of liquids per day in the year ending March 2014.

The nearby Raven field produced some 310 bpd of oil in the year ending March 2014, almost entirely from one producer supported by a water injector.

BP said it has no immediate plans for Raven.

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

The West Beach field had produced 3.37 million barrels of oil by the time BP suspended production in 2001 because declining reservoir pressure and increasing gas-to-oil ratio challenged the economics of the field. Over the intervening years, BP has undertaken numerous studies of the field to determine whether it might one day produce again.

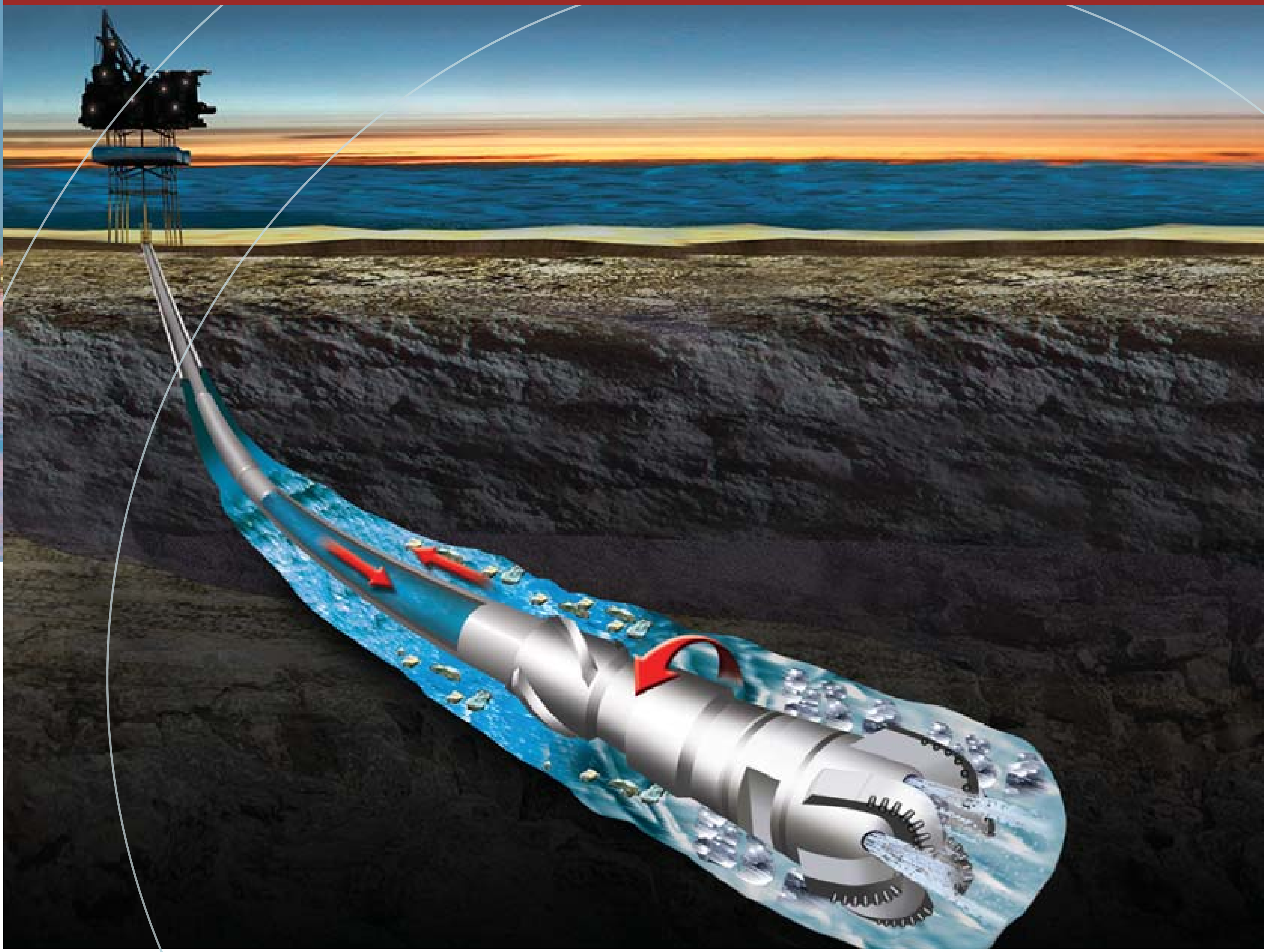
ARCO shut-in the sole North Prudhoe Bay well in February 2000 because the well continued to produce proppant from a fracture stimulation, which posed safety risks, according to the company. BP has said it "may" launch an evaluation of the area this year "to assess the remaining reservoir potential and options for future development."

Contact Eric Lidji at ericlidji@mac.com

Saluting Alaska's Producers

BP Prudhoe Bay flow station

BP EXPLORATION (ALASKA)



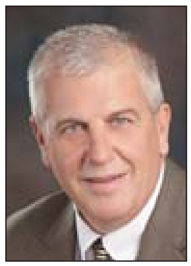
BRPC charts a unique path to oil development

The independent is using public financing for infrastructure and a private joint venture to at Mustang

By ERIC LIDJI
For Petroleum News

NAME OF COMPANY: AVCG/Brooks Range Petroleum Corp.
COMPANY HEADQUARTERS: 510 L St., Ste. 601, Anchorage, AK 99501
TOP ALASKA EXECUTIVE: Bart Armfield, CEO
TELEPHONE: 907-339-9965
COMPANY WEBSITE: www.brooksrangepetro.com

The Alaska Venture Capital Group became one of the most active exploration companies in Alaska over the past decade by assembling joint ventures of small independent players.


BART ARMFIELD

Now, the company is taking a similar approach to development.

Earlier this year, AVCG LLC and its partner Ramshorn Investments Inc. sold a 90 percent stake in their Alaska holdings, and 100 percent interest in their operating arm Brooks Range Petroleum Corp., to a three-company consortium for $450 million.

Thyssen Petroleum North Slope Development LLC, JK Tech Holdings Ltd. and MEP Alaska LLC acquired the North Slope assets for $100 million in cash and a commitment to spend more than $350 million on an initial development program at the Mustang field.

The program includes construction of a 15,000-barrel per day processing facility at the Southern Miluveach unit oil field, and three production wells to be drilled later this year.

Brooks Range Petroleum has previously said that it is aiming to bring Mustang online at a rate between 8,000 to 10,000 bpd sometime in the first quarter of 2016.

Although focused initially on Mustang, the deal also includes exploration prospects in the AVCG portfolio, including the Tofkat unit and Kachemach unit between the Kuparuk River unit and the Colville River, the Beechey Point unit north of Prudhoe Bay and a package of leases on the eastern North Slope near the Savant-operated Badami unit.

An AVCG affiliate Brooks Range Development Corp. (an entity distinct from the operating arm Brooks Range Petroleum Corp.) will retain some of its position.

As of Sept. 4, AVCG and Ramshorn held some 86,621.91 acres of state leases and Brooks Range Development Corp. held some 10,373 acres, according to a state database.

A new joint venture

The deal brings together a diverse group of players from around the world.

Thyssen Petroleum North Slope Development LLC is a subsidiary of Thyssen Petroleum LLC, a privately owned oil and gas exploration company based in the British Virgin Islands, with offices in Monaco and Houston and operations in the U.S. Gulf Coast.

The chairman of the company, a Swiss national named Baron Lorne Thyssen-Bornemisza, "heads a family business with investments in the entertainment industry in California, agriculture in Pakistan and is a major shareholder in IHS, the critical information provider to the oil and gas industry," according to a company website.

"Alaska attracted us because it remains a world-class hydrocarbon basin with considerable untapped potential, near existing infrastructure and because the Parnell Administration has created a very attractive investment climate for independent oil and gas companies," Thyssen Petroleum CEO Hamid Jourabchi said in a statement.

The Singapore-based technology company JK Tech Holdings Ltd. was founded in 1990 to provide products and services to businesses, schools and governments in the country.

But in April 2014, the company announced plans to expand into the oil and gas sector by partnering with SF Ventures Pte. Ltd. and Ezion Holdings Ltd. Through the deal, JK Tech Holdings issued 13 million shares to SF Ventures and 42 million shares to Ezion, and created a wholly owned oil and gas subsidiary called JK E&P Group Pte. Ltd.

Ezion Holdings is already an active investor in Alaska.

In 2011, the Singapore-based marine company Ezion partnered with Buccaneer Energy Ltd. and AIDEA to acquire a jack-up rig for use in shallow offshore waters of Alaska, particularly in Cook Inlet. Earlier this year, Buccaneer sold its stake in the Endeavour jack-up rig to Teras Investments Pte Ltd, a wholly owned subsidiary of Ezion.

In May 2014, AIDEA and the Ezion affiliate CES Oil Services Pte. Ltd. partnered to fund a nearly $225 million oil processing facility to support operations at the Mustang field.

The third partner in the deal, MEP Alaska LLC, is a newly created subsidiary of Magnum Energy Partners LLC, a relatively new exploration company based out of New York City.

An active independent

Long-time oilmen Bart Armfield and John Jay "Bo" Darrah Jr. formed AVCG in 1999.

It was among the first independent oil companies to come to Alaska looking to develop the sizeable oil fields passed over during the first decades of North Slope development.

AVCG struggled in its early years to find partners to fund exploration work and to negotiate access agreements with existing facility operators on the North Slope.

That changed in 2004, when the company formed an operating arm called Brooks Range Petroleum Corp. Over the subsequent years, AVCG established a multi-party joint venture that became among the most prolific exploration companies on the North Slope.

Through various iterations, the joint venture pursued targets at the current Beechey Point and Tofkat units. But in 2010, the com-

continued on next page

BRPC *continued from page 23*

panies farmed-in a group of six Eni Petroleum leases along the western edge of the Kuparuk River unit called the North Tarn prospect.

Brooks Range Petroleum eventually formed the 8,960-acre Southern Miluveach unit around five leases in the area and began calling the prospect the Mustang field.

Over the 2011 and 2012 exploration seasons, Brooks Range Petroleum drilled the North Tarn No. 1 exploration well, the North Tarn No. 1-A sidetrack and the Mustang No. 1 delineation well. The wells tested the Brookian formation and deeper Kuparuk formation. During that time, Brooks Range Petroleum also merged its seismic data with data purchased from ConocoPhillips to consolidate some 570 square miles of 3-D seismic.

Prior to the program, Brooks Range Petroleum estimated that the Brookian might contain some 35 million barrels of oil and that the Kuparuk might contain an additional 6 million barrels of oil. Given the notoriously tricky geology of the Brookian, the company put its bets on the Kuparuk, believing that the smaller accumulation would be the most economic and technical feasible. But the exploration work proved a discovery in the range of 40 million barrels of recoverable oil from the Kuparuk — bigger than expected.

An independent audit by the global consulting firm DeGolyer and MacNaughton lent credence to those figures. The firm estimated that the Mustang prospect contained proved (or P1) gross reserves of 24.7 million barrels of recoverable oil. The firm also estimated that the Mustang 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.

That convinced Brooks Range Petroleum to move toward development.

The wells encountered oil shows in the Brookian sands that were of "lower permeability than anticipated," according to Brooks Range Petroleum. The company said it would study ways to develop the formation, including fracture stimulating long horizontal wells or recompleting depleted Kuparuk production wells into the Brookian using horizontals. The company also said that it wanted to explore a potential extension of the Kuparuk formation to the northwest called Appaloosa that could add reserves and field life.

Looking for partners

The discovery was "bigger than us … bigger than both of us," Alaska Venture Capital Group lead managing member Ken Thompson told Petroleum News in April 2012, referring both to AVCG and its partner Nabors-subsidiary Ramshorn Investments Inc.

The joint venture hired Tudor, Pickering, Holt & Co. to assess strategic options, which included two primary strategies. The first was to have an investor fund all the development costs needed to bring Mustang online, at which point oil sales could fund operations until the company completed an initial public offering. The second was to find a producer willing to invest in return for a majority stake in the business.

But, at the time, Thompson mentioned that the company would prefer a cash-based bonus up front with a commitment to fund the program going forward, which is pretty much what the two companies got through the recent sale to the three-company consortium.

AVCG also took a parallel strategy, involving the public sector.

Alongside those efforts to find private sector partners for Mustang, AVCG and Ramshorn also pursued and obtained public investment in their project through AIDEA.

In late 2012, AIDEA loaned the company $20 million toward a $25 million infrastructure project. The project included 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.

AIDEA funded the program through a newly created joint venture company, Mustang Road LLC. The deal gave AIDEA 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.

Earlier this year, AIDEA and Ezion affiliate CES Oil Services Pte. Ltd. formed Mustang Operations Center 1 LLC to finance a $200 million to $225 million processing facility at the Mustang field. The deal included up to $50 million in AIDEA investment and a commitment from CES Oil Services to provide $1 million in equity funding and arrange for the Mauritius-based Strategic Equipment Inc. to loan the remaining $175 million.

Like the earlier partnership, the deal gave Mustang Operations Center 1 a 20 percent working interest in Mustang. The working interest stake would be adjusted annually. The working interest allows the joint venture to benefit from state tax credits for exploration.

According to information AIDEA provided when it agreed to invest in the processing facility, Brooks Range Petroleum would drill 11 production wells and 20 injections wells in five phases occurring over a three-to-four-year period. The production wells would have 11,000-foot to 22,000-foot vertical sections with 5,000-foot horizontal laterals.

The first phase of the development would have two horizontal producers, one vertical natural gas injector and four vertical water injectors. The second and third phases of development would each have two horizontal producers and four vertical water injectors. The fourth phase would have two horizontal producers and two vertical water injectors. The fifth phase would have three horizontal producers and five vertical water injectors.

In a plan of development for Southern Miluveach filed with the state in October 2013, Brooks Range Petroleum mentioned plans for 13 horizontal producers, up to 21 vertical water injectors and one gas injector. The plan said the pad would accommodate 38 wells.

Thyssen Petroleum North Slope Development LLC, JK Tech Holdings Ltd. and MEP Alaska LLC acquired the North Slope assets for $100 million in cash and a commitment to spend more than $350 million on an initial development program at the Mustang field.

The new facility would connect to the Alpine Pipeline, which is a mere 700 feet away, and carry oil across the existing North Slope network to the trans-Alaska oil pipeline.

AIDEA said that it invested in the project because it saw the potential to increase North Slope oil production and to add a range of temporary and permanent jobs. But AIDEA and AVCG also saw the potential to build a facility that could be useful to other explorers with leases in the region, including Repsol E&P USA Inc. and ASRC Exploration LLC.

"We view the Mustang development as an anchor position that can be expanded with (exploration) success in the immediate area," Armfield told the Commonwealth North Energy Action Coalition in June 2014.

He said that early plans considered a 7,500 bpd facility to accommodate only early Mustang production, but that the company increased the proposed capacity to accommodate additional production in the future. "If we need to increase the size of the facility, that's a great problem to have," he added.

Economic spectrum

With full development, the cost of the project is approaching $700 million.

That includes some $250 million for the pad, road and processing facility, $350 million for the first phase of development drilling and the funds already spent on exploration. Given those costs, and the costs going forward for future phases of development, Armfield said the project needed oil prices in the range of $80 to $120 per barrel for the project to be economic. "Within that spectrum we think this is a viable project," he said.

The prevailing value of Alaska North Slope oil delivered to West Coast markets has been within that spectrum for the past four years, according to the Department of Revenue.

Contact Eric Lidji at ericlidji@mac.com

Buccaneer bankruptcy ends five-year Alaska story

The explorer brought one field online; Kenai Loop now features in bankruptcy and regulatory proceedings

By **ERIC LIDJI**
For Petroleum News

Buccaneer Energy Ltd. was the last company to bring a new field online in Alaska.

But the Australian independent is unlikely to be an Alaskan producer for much longer.

After assembling an ambitious portfolio of exploration prospects across the entire Cook Inlet basin, the company filed for Chapter 11 bankruptcy protection in late May 2014.

As a debtor-in-possession, Buccaneer continues to operate production from its onshore Kenai Loop gas field as it reorganizes. But the field will likely have a new operator when dust settles. Throughout the bankruptcy proceedings so far, Buccaneer has discussed plans to auction off its Alaska assets. AIX Energy LLC, its largest secured creditor, had agreed to be a stalking horse bidder. In September 2014, Miller Energy Resources Inc. said that it had entered into a non-binding letter of intent to buy "substantially all" of Buccaneer's operating assets in Alaska for between $40 million and $50 million.

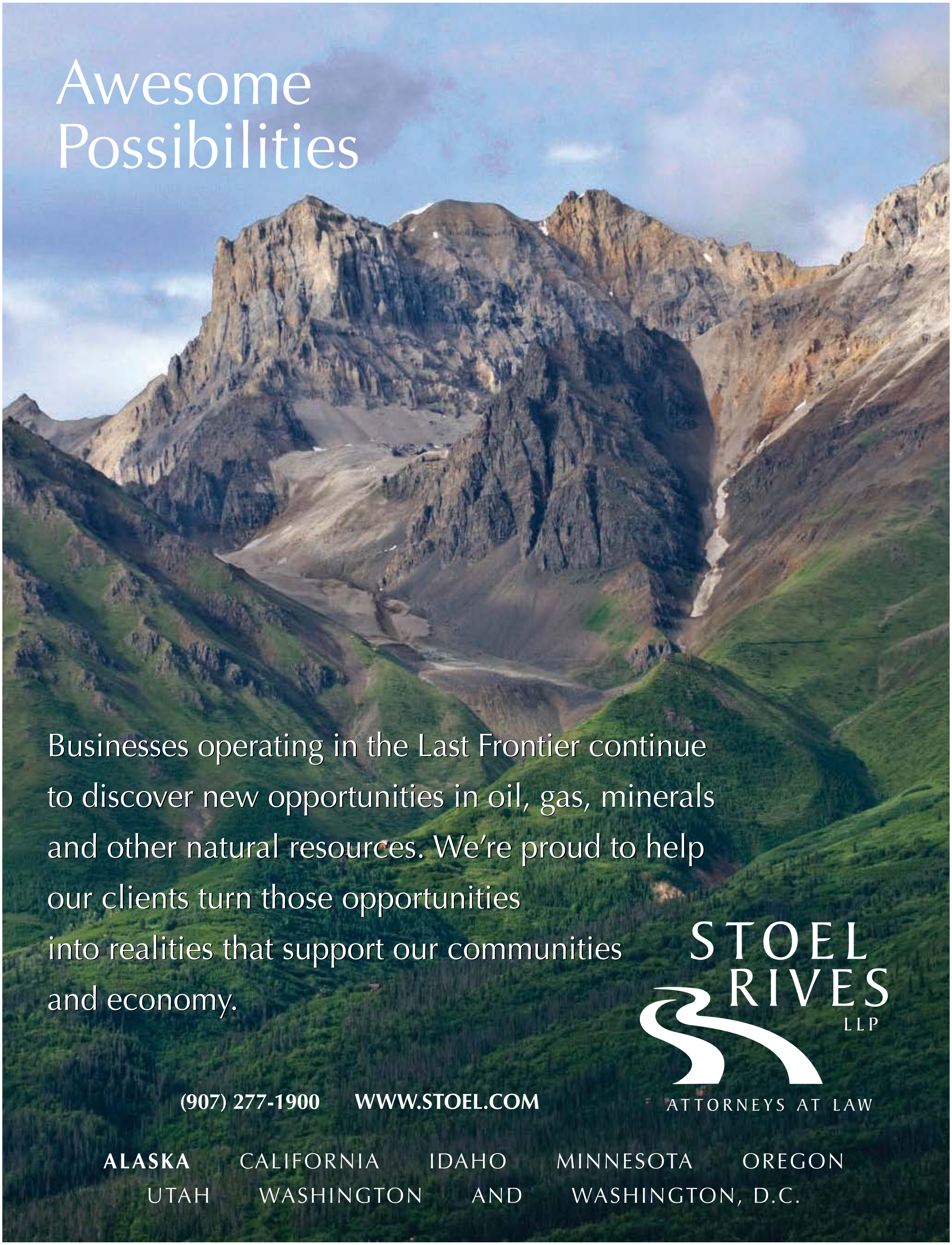
The matter is unlikely to be resolved before the end of the year.

NEWS FLASH

EDITOR'S NOTE: As The Producers went to press, Miller Energy was attempting to buy Buccaneer Energy's Alaska assets.

NAME OF COMPANY: Buccaneer Energy
COMPANY HEADQUARTERS: Houston, Texas
ALASKA OFFICE: 215 Fidalgo Ave., Ste. 100, Kenai, AK 99611
TOP ALASKA EXECUTIVE: Andy Rike, COO, president
TELEPHONE: 713-468-1678 • **WEBSITE:** www.buccenergy.com

continued on page 28


Awesome
Possibilities
Businesses operating in the Last Frontier continue to discover new opportunities in oil, gas, minerals and other natural resources. We're proud to help our clients turn those opportunities into realities that support our communities and economy.
STOEL RIVES
LLP
ATTORNEYS AT LAW
(907) 277-1900
WWW.STOEL.COM
ALASKA CALIFORNIA IDAHO MINNESOTA OREGON
UTAH WASHINGTON AND WASHINGTON, D.C.

BUCCANEER *continued from page 26*

In late September, Buccaneer asked the court for a 30-day extension to the exclusivity period for its reorganization plan. The extension would give Buccaneer until Oct. 28 to file a plan with the court and until Dec. 27 to solicit the plan to its creditors for a vote.

Without the extension, Buccaneer could still propose a plan to its creditors but would have to compete against other proposals. The U.S. Bankruptcy Court for the Southern District of Texas planned to hear the request Oct. 21, after The Producers went to print.

Even without the bankruptcy proceedings, the future of Kenai Loop is complicated by a correlative rights dispute before the Alaska Oil and Gas Conservation Commission.

The two currently producing Kenai Loop wells are located on Alaska Mental Health Trust Authority leases but have also been draining from surrounding acreage owned by the Trust Land Office, Cook Inlet Region Inc. and the state of Alaska. A case before AOGCC — and a related case in Alaska Superior Court — is attempting to fairly allocate production among the various landowners.

> *As a debtor-in-possession, Buccaneer continues to operate production from its onshore Kenai Loop gas field as it reorganizes.*

On May 23, the court required Buccaneer to deposit all future profits from Kenai Loop production into an escrow account until the parties could reach an allocation agreement.

The order was effective June 1. Buccaneer declared bankruptcy on May 31. The bankruptcy proceedings stayed aspects of pre-existing legal and regulatory cases.

In September and October 2014, AIX Energy LLC and Miller-subsidiary Cook Inlet Energy LLC unsuccessfully sought access to a confidential report presented in the case, which they claimed would have helped resolve both the bankruptcy and draining issues.

Four wells

In early 2010, Buccaneer acquired the Cook Inlet assets of Stellar Oil & Gas LLC.

The acquisition 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.

Through October 2014, Buccaneer had drilled four wells at Kenai Loop.

Using the Glacier No. 1 drilling rig, Buccaneer drilled the 10,680-foot Kenai Loop No. 1 well in April 2011. In June, the well flowed at a rate of 10 million cubic feet per day.

In September 2011, Buccaneer used Glacier No. 1 to drill the Kenai Loop No. 3 well to a total vertical depth of 11,000 feet to test the prospective zones identified in the first well.

The well was a dry hole.

Buccaneer brought Kenai Loop into production in January 2012. After an initial ramp up, the well produced at a rate of some 5 million cubic feet per day. Buccaneer increased production to 6 mmcf per day in October 2012 and 6.5 mmcf per day in December 2012 to accommodate two small short-term contracts with unnamed buyers in the region.

The bulk of production — 5 mmcf per day, initially — went to the Enstar Natural Gas Co.-subsidiary Cook Inlet Natural Gas Storage Alaska LLC. The 2011 deal covered a minimum of 12 billion cubic feet with the option to increase supplies to 31.5 bcf. The deal required Buccaneer to drill at least two more Kenai Loop wells by November 2013.

(Over its tenure as operator, Buccaneer also signed a short-term deal to sell Kenai Loop production to the Kenai liquefied natural gas facility. And in October 2013, Buccaneer signed short-term deals with a "large commercial end-user" and with an un-named oil producer "to ensure operation of their oil facilities in the Cook Inlet," respectively.)

In early 2012, with Kenai Loop in production, Buccaneer commissioned a 3-D seismic campaign over 25 square miles around the field. After incorporating the results of the program 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 some 3 mmcf per day. Buccaneer brought the well into regular production in February 2013 at some 2 mmcf per day. By March, Kenai Loop was producing some 10 mmcf per day.

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.

Buccaneer started drilling the Kenai Loop No. 1-4 well in August 2013. The 10,700-foot well targeted 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.

The well flowed at 5.9 mmcf per day during a test in October 2013. Regulatory issues surrounding the well triggered the drainage complaint from CIRI. The well remained suspended as of October 2014 while the parties resolved the ongoing drainage dispute.

Averaging monthly production, Kenai Loop produced some 10 mmcf per day in July 2014. Cumulatively, the field produced some 6.7 bcf through July 2014.

Averaging monthly production, Kenai Loop produced some 10 mmcf per day in July 2014. Cumulatively, the field produced some 6.7 bcf through July 2014.

Slide into bankruptcy

While it developed Kenai Loop, Buccaneer continued to expand.

The company pursued exploration campaigns at other prospects in the portfolio it had acquired from Stellar and acquired additional prospects as they became available.

The buying spree included a stake in the Endeavour jack-up drilling rig.

In early 2014, Buccaneer sold its interest in the offshore Cosmopolitan prospect and its interest in the Endeavour jack-up rig and then relinquished its offshore Southern Cross and North West Cook Inlet units after failing to meet state-imposed work commitments.

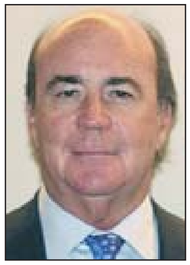
Further setbacks followed, including a dry hole at the West Eagle unit, the resignation of CEO Curtis Burton and the acknowledgement of drainage at Kenai Loop. In conjunction with various debt obligations, those events certainly hastened the bankruptcy filing.

Contact Eric Lidji at ericlidji@mac.com

Caelus seeks to expand pioneering Oooguruk field

Having closed on acquisition and secured financing, the company must now decide whether to sanction Nuna

By ERIC LIDJI
For Petroleum News


JAMES MUSSELMAN

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

Caelus Energy LLC is part of a new trend in Alaska oil and gas development.

Traditionally, new entrants to the state would acquire acreage in lease sales, shoot a seismic campaign, drill exploration wells, sanction development, incrementally expand into satellites and eventually conduct a series of enhanced recovery programs.

But in the past few years, privately held independents like Savant Alaska LLC, Hilcorp Alaska LLC and Miller Energy Resources Inc. have acquired oil and gas fields already in production. In addition to finding new fields, they aim to rejuvenate existing operations.

When Dallas-based Caelus Energy acquired the Alaska assets of Pioneer Natural Resources Inc. in 2014, it not only acquired existing production at the Oooguruk unit on the North Slope but also existing producers — the entire staff of the former operator.

The acquisition gave Caelus a steady base of production — some 15,400 barrels per day in July 2014, according to the Alaska Oil and Gas Conservation Commission — and an experienced staff. "It's obviously a harsh environment," Caelus Energy President and CEO Jim Musselman told Petroleum News in April 2014, after his company closed on the acquisition of the Alaska assets. "The North Slope is a very particular place to work. It's important for us to have a good, solid group of people … and we think we have that."

Who is Caelus?

While Caelus Energy is a relatively new entity, the principals of the company have touted their experience leading two other small independents to various forms of success.

In the 1990s, Musselman and various colleagues acquired a struggling independent called Triton Energy. They oversaw discoveries in Colombia, Southeast Asia and offshore West Africa. Triton brought the West Africa discovery online within 18 months, according to Musselman, which allowed investors to later sell the company to Amerada Hess.

Musselman and his investors later founded the independent Kosmos Energy, which made a discovery offshore Ghana that propelled the company to a public offering in 2011.

Instead of staying with the public company, Musselman struck out on another privately funded venture by forming Caelus Energy. "If you're not nervous and a little bit worried or a bit scared of doing business in hostile places, you're done," he said in October 2013, when Pioneer Natural Resources announced plans to sell its Alaska subsidiary to Caelus Energy for $550 million. In March 2014, the parties lowered the sale price to some $300 million. The amendment cleared the path for the two sides to close in April 2014.

At the October announcement, Musselman said his company would spend at least $300 million on Oooguruk. The first order of business, Musselman said, would be to pursue the proposed Nuna development, a new onshore drilling pad to target offshore resources too far to reach from the existing Oooguruk

continued on page 32

CAELUS *continued from page 30*

gravel island. But, Musselman added, the company hoped to raise more than $1 billion for future development work and saw the potential to spend as much as $1.5 billion in Alaska over a five-to-six-year-period.

To meet those funding goals, Caelus formed a strategic partnership with the international investment company Apollo Global Management in April 2014. The partnership provides a source of funds for the near term and an avenue to access debt financing for the future.

"We feel very comfortable that we can do several billion dollars-worth of development and have the requisite equity and debt financing necessary to go forward with some good-sized developments on the North Slope," Musselman told Petroleum News at the time.

What Caelus inherited

Physically, the Oooguruk unit includes a six-acre gravel island in the nearshore waters of Harrison Bay and a subsea flowline bundle connecting to an onshore tie-in pad, which delivers Oooguruk production to the Kuparuk River unit for processing and delivery.

During its tenure, Pioneer Natural Resources established three participating areas at the unit, each targeting a different horizon: the Nuiqsut, the Kuparuk and the Torok.

Through the end of August 2014, Pioneer Natural Resources had drilled 37 wells within the Oooguruk unit — 21 in the Nuiqsut, six in the Kuparuk, four in the Torok, five exploration and appraisal wells outside the participating areas and one disposal well.

According to a plan of development filed with the state Division of Oil and Gas in June 2014, Caelus plans to drill five wells in the Nuiqsut pool and recomplete five as-yet-to-be-decided wells at the unit during the current year, which runs through August 2015.

The Nuiqsut pool

As those numbers suggest, development to date has been focused most heavily on the Nuiqsut pool, which is both the largest and the deepest of the three pools at the unit.

In the year ending August 2014, Pioneer drilled five horizontal wells into the Nuiqsut pool — four producers and one injector. The company completed the four production wells — ODSN-02, ODSN-04, ODSN-28 and ODSN-48 — using mechanical diversion, which stimulates more of a formation than the dynamic diversion method Pioneer had originally used on Oooguruk wells. The new production wells had "some of the highest initial flow rates seen to rate" from the Nuiqsut participating area, according to the companies. Pioneer also performed a second fracture stimulation on ODSN-24, although production is on hold while the company cleans out the well using a coiled tubing system.

Pioneer also stimulated five injection wells — ODSN-15i, ODSN-26i, ODSN-27i, ODSN-32i and ODSN 34i — to allow them to better match the higher production rates from the mechanically diverted production wells. And the company drilled a new injector, ODSN-03i, which will support the new ODSN-02 and ODSN-04 production wells. Those three wells are in the Ivik fault block at the northern end of the unit.

As part of a nine-well workover campaign during the year, Pioneer Natural Resources replaced failed electric submersible pumps to the ODSN-31 and ODSN-16 production wells, added new electric submersible pumps to the ODSN-01 and ODSN-25 production wells and cleared sand from the laterals of the ODSN-18 and ODSN-37 production wells.

Alongside the busy drilling and workover campaigns, Pioneer Natural Resources conducted an enhanced recovery effort in the Nuiqsut pool. The effort included expanding a waterflood program and continuing an immiscible gas injection program.

Caelus plans to drill four fracture stimulated production wells and one injection well.

The producer ODSN-06 will be in the southwest of the unit, in acreage recently added to the unit near the existing ODSN-48 well. The new ODSN-29 and ODSN-31 wells will be sidetracks of existing wells. The new ODSN-08 will "appraise the southern well row."

The injection well — ODSN-19i — will support the producers ODSN-01 and ODSN-24. Caelus also intends to bring the previously drilled ODSN-03i injection well online in the coming year to support the ODSN-02 and ODSN-04 production wells in the Nuiqsut.

The AOGCC issued a permit on June 16 for Caelus to drill an "ODSN-03" service well and a permit on Sept. 3 for Caelus to drill an "ODSN-43" production well.

The Kuparuk pool

Caelus is currently producing from three wells in the Kuparuk pool.

Pioneer Natural Resources previously shut-in ODSK-33 — the first and, for a while, most dominant well into the pool — because production exceeded 95 percent water.

But the Kuparuk pool continues to see "strong" results from the horizontal production wells ODSK-14 and ODSK-41, according to Caelus. ODSK-41 had "minimal water production." But ODSK-14 experienced breakthrough within the past year, the term describing when isolated injection fluids enter the wellbore. Pioneer Natural Resources previously launched and Caelus continues to monitor a chemical tracer program conducted on two injection wells — ODSK-38i and ODSK-35Ai. So far, the companies have seen "slight tracer return" in water samples taken from associated production wells.

Pioneer replaced a failed electric submersible pump in the ODSK-41 production well.

The Torok pool

While Pioneer Natural Resources was developing the Nuiqsut and Kuparuk pools, it was simultaneously collecting information on a pool in the shallower Torok formation.

The data collection convinced the company to target the Torok specifically.

Caelus is currently developing the Torok formation from the ODST45A and ODST-39 production wells. A third production well, ODST-47, is shut-in until future workover activities can repair a mechanical failure caused during completion work back in 2013.

The horizontal injection well supporting those producers — ODST-46i — "continues to perform well," but Pioneer Natural Resources shut-in the well for an "extended period" while it drilled the nearby ODSN-48 into the Nuiqsut to avoid contact between the wells, according to Caelus. The ODST-46i injection well is, in some sense, a keystone for developing the Torok participating area, according to the companies, and future Torok development will depend on "injection performance and offset producer responses."

Pioneer replaced a failed electric submersible pump in the ODSK-45A production well.

In addition to drilling and workover projects, Pioneer Natural Resources started an enhanced recovery program in the Torok, injecting seawater and immiscible gas.

In the coming year, Caelus plans to continue its enhanced recovery program in the Torok participating area. The company said gas injection for enhanced recovery is "desirable" in both the Nuiqsut and Torok participating areas "but limited volumes are available and it is subject to the ability to acquire an adequate gas supply from a third party."

The Nuna development

The largest potential plans for the coming year involve the proposed Nuna development.

Pioneer Natural Resources drilled two wells to appraise the potential satellite in the southern reaches of the unit. Now Caelus must decide whether to sanction development.

For the coming year, Caelus plans to "integrate the results from drilling, engineering and permitting into determining the commercial viability of the Nuna onshore development."

After analyzing data gathered from deeper wells, Pioneer Natural Resources specifically targeted the Torok formation in 2010 and proposed the Nuna development later that year to develop segments of the formation too far to reach from the existing gravel island. As currently envisioned, the project would use extending-reach drilling from an onshore site.

continued on next page

CAELUS *continued from page 33*

The initial proposal called for as many as two onshore drilling pads and the potential for a standalone production facility. The unit currently utilizes Kuparuk River unit facilities.

In early 2012, Pioneer Natural Resources drilled the Sikumi No. 1 exploration well from an offshore ice island and the directional Nuna No. 1 exploration well from an onshore ice pad. A "deep test" of the Ivishak at Sikumi No. 1 was "basically non-commercial," the company said, but Nuna No. 1 yielded a 50 million barrel discovery from the Torok.

In early 2013, Pioneer Natural Resources drilled the Nuna No. 2 appraisal well and later increased its estimate for the Torok to a range of 75 million to 100 million barrels.

As an early step toward sanctioning Nuna, Pioneer proposed a project in August 2013 to expand operations, improve seawater delivery and accommodate future Nuna facilities.

The expansion program included projects for both Oooguruk Island and the onshore tie-in pad. The offshore expansion was meant to improve transportation into the island. The onshore expansion was meant to accommodate Nuna facilities. Pioneer Natural Resources undertook a range of projects at the tie-in pad in June 2014, including upgrades to the waste heat recovery system, production separator, electrical systems, oil pigging systems and repair and replacement of various valves throughout the facilities.

Before handing Oooguruk over to Caelus, Pioneer Natural Resources also continued early engineering work on roads, pads, pipelines and facilities needed for the Nuna project.

The state also approved several small unit expansions that would assist the project.

In May 2014, Musselman told Petroleum News that Caelus planned to begin work on Nuna in late 2014 with the goal of bringing the satellite into production by the third quarter of 2016. He estimated the project would cost some $1.4 billion, with $550 million to build new onshore facilities and another $800 million to $900 million for drilling.

Industry trends

Oooguruk might be the defining Alaska oil field of the past 20 years.

It symbolizes three major trends.

The first is the introduction of independent oil companies to the North Slope.

ARCO Alaska Inc. discovered what is now known as the Oooguruk unit in 1992 but never sanctioned development. The independent Armstrong Oil & Gas Inc. performed some delineation activities at the field in the early 2000s before partnering with Pioneer Natural Resources and then selling the unit outright to its wealthier partner. The partnership was one of many Armstrong has engineered during its time in Alaska.

After an accelerated delineation campaign, Pioneer brought the unit into production in 2008 and became the first independent operator in the history of the North Slope.

The second trend is the growth of unconventional oil in the Lower 48.

Pioneer invested considerably in bringing technological advancements at Oooguruk, but Alaska proved to be no match for the opportunities available in the Lower 48.

Speaking at Meet Alaska in January 2011, Pioneer Executive Vice President for Domestic Operations Jay Still differentiated between Alaska and the Lower 48. Of the nearly one dozen North Slope exploration wells that the company helped drill between 2003 and 2007, "We did not have a dry hole — every well we found the hydrocarbons. We just didn't find rock that we could make production in commercial quantities," he said.

While the Lower 48 had "a thousand-times worse rock than what's on the North Slope," the prospects were easier to develop. If the Alaska wells could magically be transported to the Lower 48, "we would be all over them," Still said. "There would be no question that the thing could be developed, with horizontal wells, the fracture technology."

Given its lack of magical transportation abilities, Pioneer sold Oooguruk to Caelus, which marks the third trend: the tendency of smaller companies to pursue producing fields.

Contact Eric Lidji at ericlidji@mac.com

At the end of 2013, ConocoPhillips was developing the main Kuparuk field with 817 active wells at 44 drill sites, according to a June 2014 plan of development.

CONOCOPHILLIPS

ConocoPhillips gets busy on North Slope development

The dominant North Slope operator is planning to expand or initiate development at three of its four units

By ERIC LIDJI
For Petroleum News

TROND-ERIK JOHANSEN

ConocoPhillips is in the early stages of what is perhaps its broadest development campaign on the North Slope since the company was created through a 2002 merger.

The Houston-based giant, which bills itself as "the world's largest independent E&P company," is either expanding or initiating development at three of its four North Slope units: the state Kuparuk River unit, the state Colville River unit and the federal Mooses Tooth unit.

The company has also been engaged in exploration at its federal Bear Tooth unit.

The work follows several fallow years. ConocoPhillips attributed the uptick to recent revisions to the state fiscal system for oil production. With that system having recently withstood a ballot measure to repeal it, ConocoPhillips now must prove its

NAME OF COMPANY:
ConocoPhillips Co.
COMPANY HEADQUARTERS:
Houston, Texas
ALASKA OFFICE: 700 G St., Anchorage, AK, 99501
TOP ALASKA EXECUTIVE: Trond-Erik Johansen, president, ConocoPhillips Alaska
PHONE: 907-276-1215
COMPANY WEBSITE: www.conocophillipsalaska.com

continued on page 38

CONOCOPHILLIPS *continued from page 36*

intentions.

Kuparuk history

The Kuparuk River unit includes the main Kuparuk oil field and four satellites.

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

Economics caused the delay. It took crimped domestic oil supplies and the subsequent rise in prices at the end of the decade to persuade top management to develop Kuparuk.

The program called for bringing 20 square miles of the Kuparuk field online by 1982 and working with nearby leaseholders on a longer-term plan to develop 200 square miles.

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

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

In the 22 years since the unit hit peak production, those operators have been pursuing various programs to expand development and improve production through technology.

The entire Kuparuk River unit produced some 2.5 billion barrels through July 2014.

The Kuparuk field

At the end of 2013, ConocoPhillips was developing the main Kuparuk field with 817 active wells at 44 drill sites, according to a June 2014 plan of development.

The field had 821 active wells at 44 drill sites at the end of 2012.

ConocoPhillips drilled 15 wells in the Kuparuk participating area last year — one rotary well and 14 coiled tubing wells with a total of 41 laterals. The program added some 4,520 gross barrels of peak incremental oil production per day, according to the company.

By comparison, the company drilled 14 wells and 53 laterals at the Kuparuk field in 2012, bringing 5,050 gross bpd of incremental production online. A June 2013 plan of development had identified as many as 17 coiled-tubing drilling candidates for last year.

ConocoPhillips also added 2,601 gross barrels per day through a rigged workover program and another 10,300 gross barrels per day through a rigless workover program.

The Kuparuk participating area averaged 85,700 gross barrels per day in 2013.

For the current year, ConocoPhillips said it planned to drill between six and eight new rotary wells and between 13 and 17 new coiled tubing sidetracks. The proposed well locations are scattered across the field with a large cluster along the southern border.

The largest project under way at the Kuparuk field is the construction of Drill Site 2S, which would develop the Kuparuk formation in the southwest corner of the field.

ConocoPhillips began laying gravel at the drill site in February and intends to seek internal and partner approval for the project by the end of the year. If approved, construction would be next year with the goal of bringing the drill site into production by the end of 2015. The project is expected to cost some $595 million, accommodate 24 wells and produce 8,000 gross bpd of oil at its peak, according to the company.

Alongside the drilling program, ConocoPhillips has long been overseeing a miscible water-alternating-gas enhanced recovery program from 26 drill sites at Kuparuk. The miscible injectant currently includes natural gas liquids imported from Prudhoe Bay.

The main Kuparuk field produced 2.33 billion barrels of oil through July 2014.

With the expected increase in activity, ConocoPhillips applied this year to expand the Kuparuk Industrial Center and the Kuparuk Construction Services pads at the unit. The company said it had been outsourcing some work to Deadhorse to make up for the lack of adequate space at the two support pads. ConocoPhillips told regulators that its workload a Kuparuk had increased between 4 and 4.5 percent each year over the past 20 years.

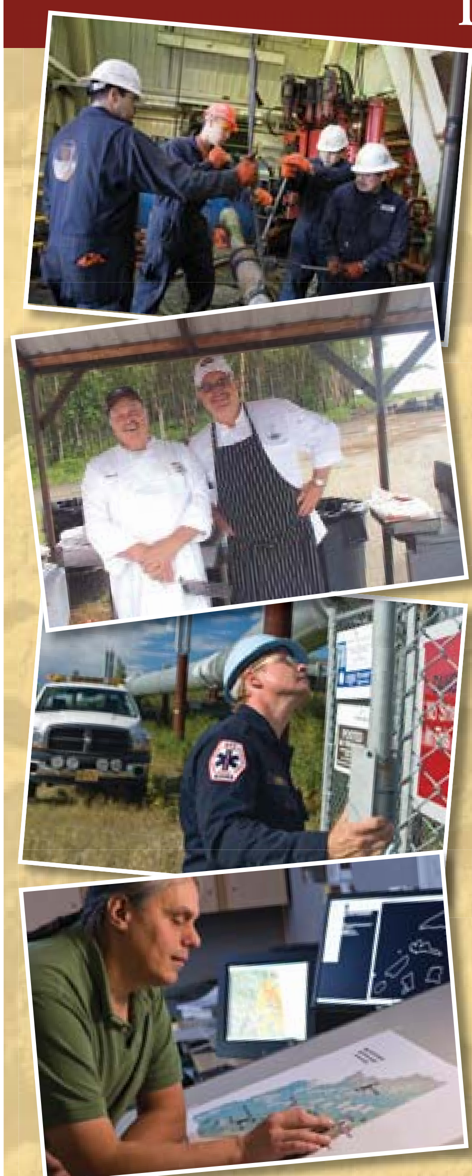
The West Sak field

ARCO discovered the shallow West Sak oil pool in 1971, appraised the feasibility of producing the viscous oil with a 15-well pilot project between June 1983 and December 1986 and brought the satellite into production from Drill Site 1D 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, making it a regional asset of interest to various operators and

continued on page 40

Doyon Oil Field Services



DOYON DRILLING, INC.
Health/Safety/Environment Drilling & Training

Doyon Drilling, Inc. operates on the North Slope of Alaska with seven advanced rigs specifically designed to drill oil wells in northern Alaska conditions.

DOYON ASSOCIATED, LLC
Pipeline Construction Services

Doyon Associated utilizes skilled personnel and an extensive fleet of equipment to contribute to North Slope construction efficiencies while maintaining absolute commitment to safety.

DOYON UNIVERSAL SERVICES
Facility & Security Services

Doyon Universal Service LLC, premier Integrated Facility Management contractor and full spectrum Security Services provider for Alaska's private and public sectors for over 80 years. Remote site medical, fire services response offered also.

DOYON REMOTE FACILITIES & SERVICES
Construction Services, Support & Logistics
Camp Leasing/Maintenance/Administrative Services

Doyon Remote Facilities & Services, committed to providing clean, comfortable and contemporary accommodations and services to Alaska's oil, gas and construction companies.

DOYON ANVIL
Engineering & Consulting Services

Doyon Anvil brings years of combined engineering, procurement, and consulting experience and a thorough knowledge of the needs of Alaska-based clients.

Doyon Anvil
Engineering & Procurement Solutions

www.doyon.com Linked in.

Other Doyon Businesses: Government Contracting • Natural Resource Development • Tourism

CONOCOPHILLIPS *continued from page 38*

working interest owners.

At the end of 2013, ConocoPhillips was developing the West Sak oil pool with 96 active wells at six drill sites, according to the most recent plan of development. West Sak shares all six of its drill sites — 1B, 1C, 1D, 1E, 1J and 3K — with the main Kuparuk field.

West Sak had 102 active wells at the end of 2012.

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

Although "the pace of future West Sak development has slowed while the performance of recent developments in evaluated," as ConocoPhillips told state regulators in the most recent plan of development, ConocoPhillips is poised for another major program. The company is planning six wells for Drill Site 1D and a smaller program at Drill Site 1C.

The company also continues to study a $450 million program to expand the existing Drill Site 1H. The 9.45-acre expansion would accommodate five new production wells and 13 new injection wells, and associated infrastructure. With approval this year, the expansion could come online by early 2017 and would produce some 9,000 gross bpd at its peak.

West Sak produced some 15,772 bpd in 2013, up from 14,185 bpd in 2012. Cumulatively through July 2014, the field had produced some 71.7 million barrels of oil.

To accommodate the expected activities at both Drill Site 2S and Drill Site 1H, ConocoPhillips recently contracted Doyon Drilling to build Doyon 142, the first new-build rotary rig added to the Kuparuk fleet since 2000, according to the company. The rig will have the capability to work at both Kuparuk and at the neighboring Alpine field.

ConocoPhillips added Nabors 7ES and Nabors 9ES to its fleet in May 2013 and January 2014, respectively. Once those three rigs are operational, the fleet could be as large as seven come 2016 — up from an average fleet of four rigs between 2008 and 2012.

The Tarn field

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

At the end of 2013, ConocoPhillips said it was developing the Tarn oil pool with 61 active wells at two drill sites, 2N and 2L. Tarn had 63 active wells at the end of 2012.

ConocoPhillips deferred three grassroots rotary wells and one rotary sidetrack planned for 2013 to this year because of "rig compatibility and availability issues," the company said. The current plan of development lists four rotary wells and two rotary sidetracks on the agenda for this year and next year. All six wells would be horizontal or directional.

The Tarn oil field produced some 5,600 gross bpd in 2013, down from some 7,100 bpd in 2012. Cumulatively, the field had produced 111 million bpd through July 2014.

Tabasco, Meltwater and Palm

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

At the end of 2013, ConocoPhillips was developing Tabasco from seven active wells at Drill Site 2T. Tabasco had eight active wells at the end of 2012. ConocoPhillips has drilled 12 wells at the field — nine producers and three injectors. Of the producers, ConocoPhillips took four offline because of high water production, low oil production or mechanical problems. One of the injectors was taken offline for reservoir management.

Tabasco produced some 1,711 gross bpd in 2013, up from 1,076 bpd in 2012, according to ConocoPhillips. Cumulatively, the field produced 18.2 million bpd through July 2014.

While Drill Site 2T has eight empty slots for production wells and two empty slots for water injection wells, ConocoPhillips is not planning any delineation for the time being.

That said, ConocoPhillips is currently updating its full field model for Tabasco, which could identify potential development opportunities for the satellite going forward.

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

At the end of 2013, ConocoPhillips was developing Meltwater from 15 active wells at Drill Site 2P, the same development profile in place at Meltwater at the end of 2012.

Meltwater produced some 1,971 gross bpd in 2013, down from some 2,719 gross bpd in 2012. Cumulatively, the field had produced nearly 18.1 million bpd through July 2014.

The most recent Meltwater drilling campaign ended in 2004, but ConocoPhillips said it is currently analyzing future development opportunities at Meltwater in light of "new seismic data, recent surveillance findings, absence of injection water supply and business climate." Those opportunities include coiled tubing drilling and converting existing wells.

Phillips Petroleum discovered the Palm accumulation at the far western edge of the Kuparuk River unit in 2001 and ConocoPhillips built the 3S pad 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. In its most recent plan of development, ConocoPhillips said it is still analyzing those results.

CONOCOPHILLIPS

Alpine produced 38,900 bpd in 2013. Cumulatively, the participating area produced 409.5 million barrels through July 2014.

The Colville River unit

The Kuparuk River unit has allowed ConocoPhillips to advance westward and develop fields that might have been uneconomic on their own because of their remoteness.

The nearest of those fields are at the Colville River unit, which includes the main Alpine field at the CD-1 and CD-2 pads, and four satellites: Fiord at the CD-3 pad, Nanuq at the CD-4 pad, Qannik at an expanded CD-2 and Alpine West at the upcoming CD-5 pad.

ARCO Alaska discovered the Alpine oil pool in 1994 and determined commerciality in 1996. Along with partners Anadarko Petroleum Corp. and Union Texas Petroleum Alaska Corp., ARCO proposed a $700 million to $800 million development program.

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

The partners originally estimated that the field contained 365 million barrels of recoverable oil but increased the reserve estimate to 429 million barrels in 1997. By carefully managing the Alpine field and its satellites, ConocoPhillips has been able to develop and expand the Colville River unit using its existing processing facilities.

The unit has five participating areas: Alpine, Fiord Nechelik, Fiord Kuparuk, Qannik and Nanuq. A sixth, Nanuq Kuparuk, has

continued on next page

CONOCOPHILLIPS *continued from page 41*

since been incorporated into Alpine. The entire Colville River unit produced some 473 million barrels of oil through July 2014.

The Alpine field

The initial development of the Alpine participating area from the CD-1 and CD-2 pads ended in November 2005 and a peripheral development program of the Alpine A and C sands began from the CD-4 pad in 2006. Now, the primary activity is completion work.

Not counting sidetracks and re-drills, ConocoPhillips has drilled 142 wells between the two Alpine participating areas — 133 at Alpine and nine at Nanuq Kuparuk.

ConocoPhillips is considering six development wells at the Alpine participating area for the coming year — three producers and three injectors. The company performed nine fracture stimulations at Alpine wells in 2013 and is planning four stimulations this year.

While the Alpine participating area primarily produces from the Alpine reservoir, ConocoPhillips recompleted two CD-1 wells in 2008 to produce from the Kuparuk reservoir on a tract basis. The company is considering additional Kuparuk production.

Alpine produced 38,900 bpd in 2013. Cumulatively, the participating area produced 409.5 million barrels through July 2014. Nanuq Kuparuk produced 1,700 bpd in 2013. In 2012, Alpine produced 45,300 bpd and Nanuq-Kuparuk produced 2,400 bpd.

In August 2014, the Alaska Department of Natural Resources began a mandatory contraction of the Colville River unit, which had been built into the unit agreement. The contraction was supposed to occur after 10 years of development, but the state had agreed to defer the 18,045-acre contraction if ConocoPhillips met a drilling commitment. Even with the commitment, which ConocoPhillips met, the contraction was to occur this year.

With the expected increase in activity, ConocoPhillips applied this year to expand the Kuparuk Industrial Center and the Kuparuk Construction Services pads at the unit.

Fiord, Nanuq and Qannik

ARCO discovered the Fiord oil pool in 1992, although it had encountered the pool through previous drilling as early as 1982. ConocoPhillips sanctioned development in 2004, as it was expanding Alpine facilities, and brought the field online in 2006.

Not counting sidetracks and re-drills, ConocoPhillips has drilled 29 wells between the two Fiord participating areas — 22 at Fiord Nechelik and seven at Fiord Kuparuk.

The company drilled the CD3-127 well at Fiord Nechelik in 2013 and planned to drill two wells this year and two more next year. Of the seven Fiord Kuparuk wells, only five are currently active. ConocoPhillips has no plans to add more in 2014 or 2015. The company fracture stimulated four Fiord wells in 2013, which “resulted in an appreciable production rate increase.” The company “tentatively” planned to fracture stimulate one well this year. The development plan at Fiord calls for as many as 32 active wells.

Fiord Nechelik produced 16,200 bpd in 2013. Cumulatively, the participating area had produced 41.7 million barrels through 2013, according to ConocoPhillips. Fiord Kuparuk produced 2,200 bpd in 2013. Cumulatively, the participating area had produced 12.1 million barrels through 2013, according to ConocoPhillips. Together, the two participating areas had produced 56.7 million barrels through July 2014, according to the Alaska Oil and Gas Conservation Commission, which combines the two for tabulation.

In 2012, the two participating areas produced some 20,100 bpd.

ARCO Alaska discovered the Nanuq oil pool in 1996 and ConocoPhillips brought the field online in 2006. The AOGGC incorporated Nanuq-Kuparuk into Alpine in 2009.

Not counting sidetracks and re-drills, ConocoPhillips has drilled eight wells at Nanuq, including three drilled 2013. The company mentioned no plans for the current year.

Nanuq produced 1,300 bpd in 2013 and 2.3 million barrels through July 2014.

In 2012, the field produced some 1,000 bpd on average.

ARCO encountered the Qannik oil pool as early as 1996 but believed the reservoir was too tight and too thin to be productive. ConocoPhillips proved the feasibility of the pool through an appraisal program in 2005 and 2006 and brought the field online in 2008.

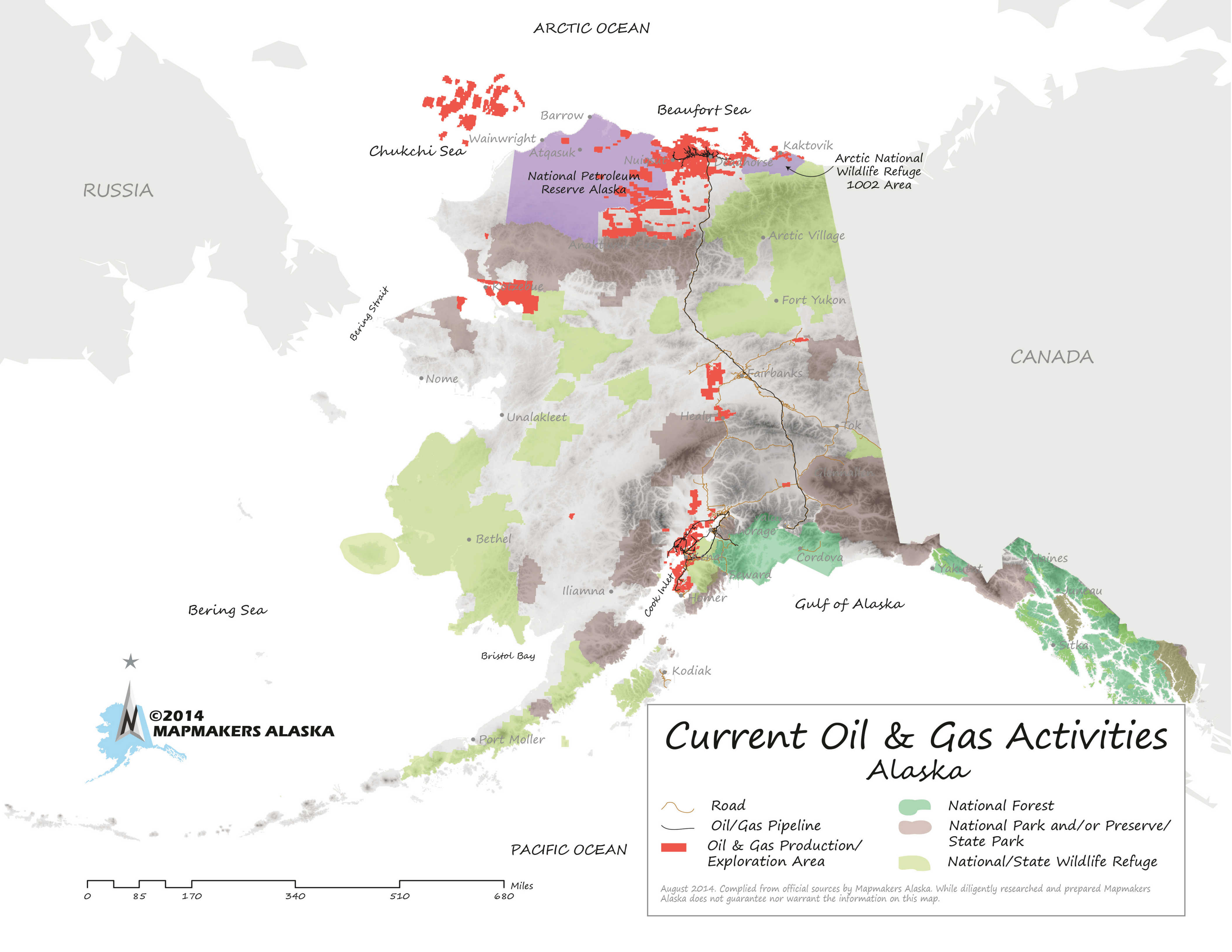
Not counting sidetracks and re-drills, ConocoPhillips has drilled nine wells at Qannik, which might be all for the time being. The company did not drill any new wells at the field in 2013 and had no plans to drill new wells this year. Furthermore, the company has told regulators that it sees “no potential near-term drilling opportunities” for the field.

Qannik produced 1,800 bpd in 2013 and 4.6 million barrels through July 2014. In 2012, the field produced some 1,800 bpd.

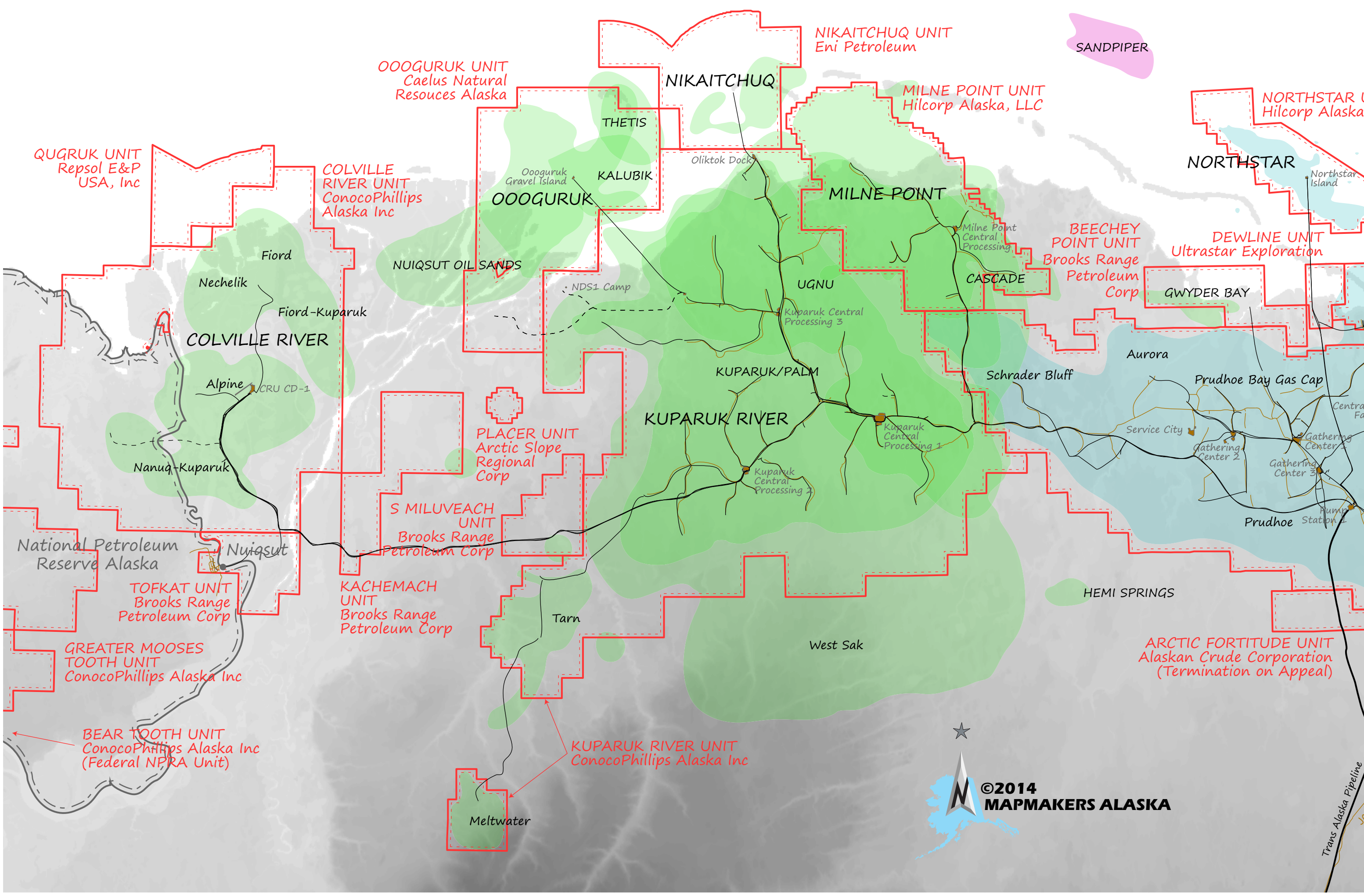
CD-5/Alpine West

In a 2003 environmental impact statement, ConocoPhillips

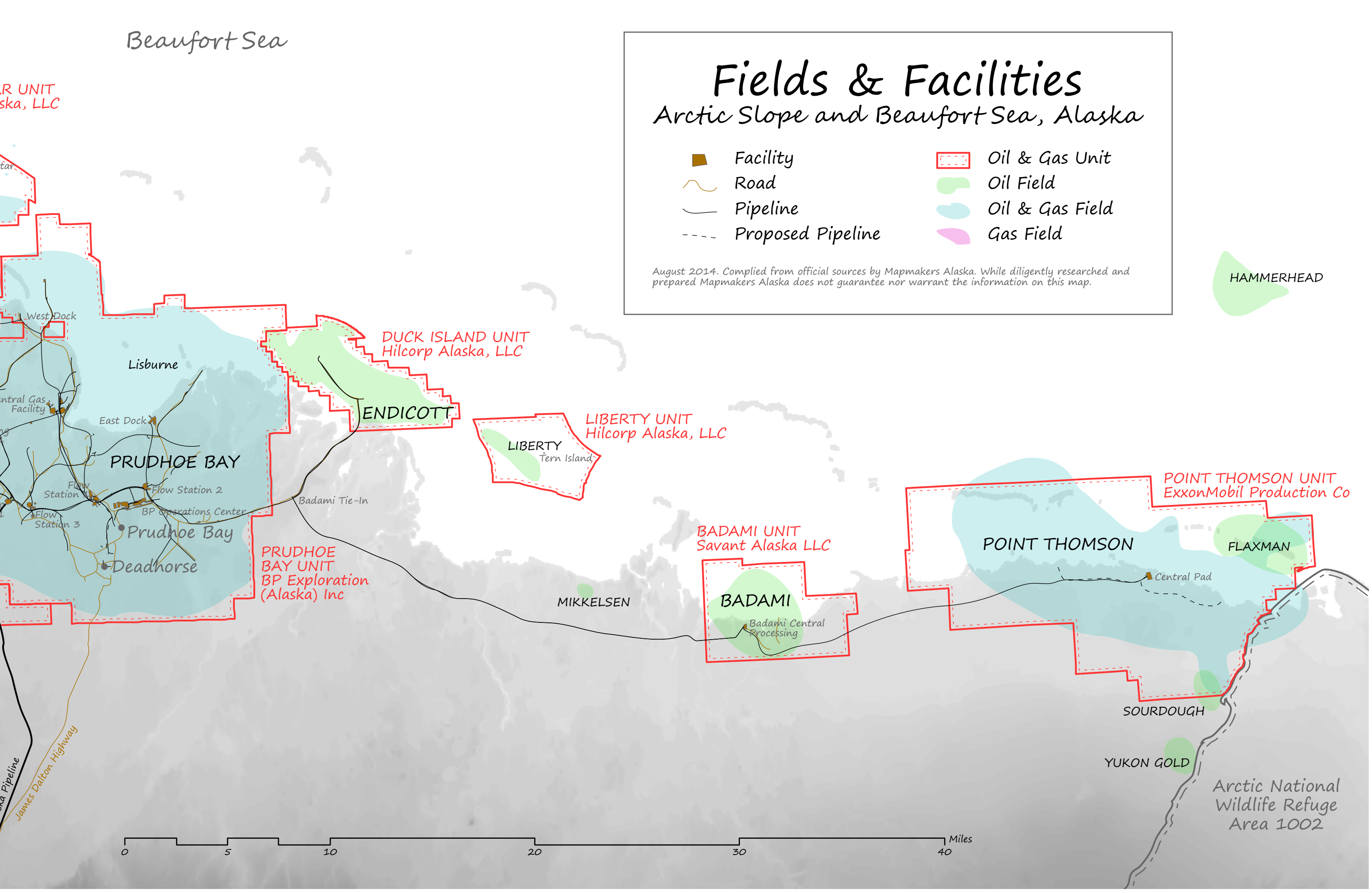
continued on page 47

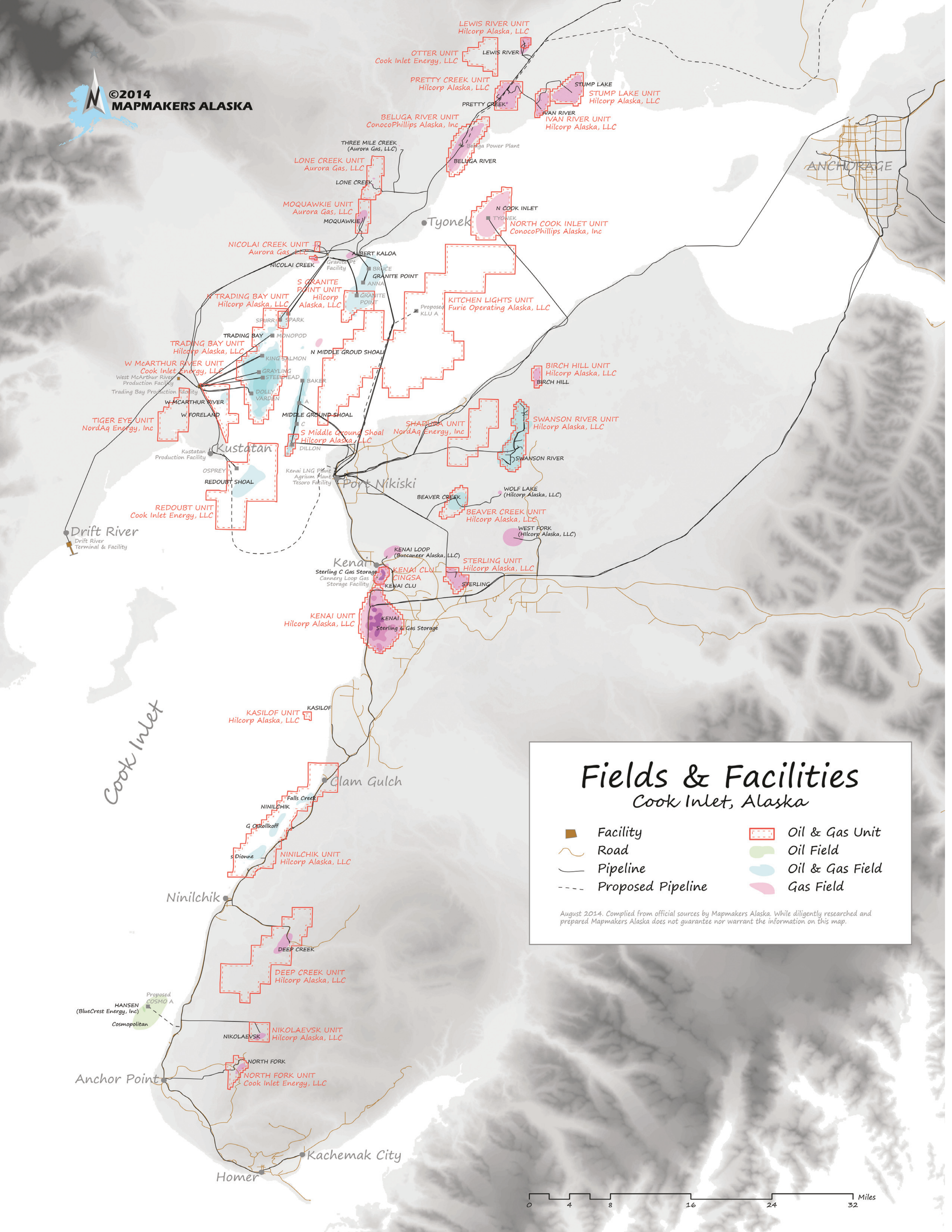

Current Oil & Gas Activities
Alaska
Road
Oil/Gas Pipeline
Oil & Gas Production/ Exploration Area
National Forest
National Park and/or Preserve/ State Park
National/State Wildlife Refuge
August 2014. Complied from official sources by Mapmakers Alaska. While diligently researched and prepared Mapmakers Alaska does not guarantee nor warrant the information on this map.
ARCTIC OCEAN
RUSSIA
CANADA
Chukchi Sea
Beaufort Sea
Bering Strait
Bering Sea
Bristol Bay
Gulf of Alaska
PACIFIC OCEAN
Cook Inlet
Barrow
Wainwright
Atqasuk
Kaktovik
National Petroleum Reserve Alaska
Arctic National Wildlife Refuge 1002 Area
Arctic Village
Fort Yukon
Fairbanks
Nome
Unalakleet
Healy
Tok
Bethel
Iliamna
Cordova
Seward
Homer
Kodiak
Port Moller
©2014
MAPMAKERS ALASKA
0
85
170
340
510
680
Miles


JUDY PATRICK


NIKAITCHUQ UNIT
Eni Petroleum
SANDPIPER
OOOGURUK UNIT
Caelus Natural
Resouces Alaska
NIKAITCHUQ
MILNE POINT UNIT
Hilcorp Alaska, LLC
NORTHSTAR
Hilcorp Alaska
THETIS
QUGRUK UNIT
Repsol E&P
USA, Inc
KALUBIK
Oliktok Dock
NORTHSTAR
Northstar
Island
COLVILLE
RIVER UNIT
ConocoPhillips
Alaska Inc
Ooogururuk
Gravel Island
OOOGURUK
MILNE POINT
Milne Point
Central
Processing
BEECHEY
POINT UNIT
Brooks Range
Petroleum
Corp
DEWLINE UNIT
Ultrastar Exploration
Fiord
NUIQSUT OIL SANDS
Nechelik
NDS1 Camp
UGNU
CASCADE
GWYDER BAY
Fiord-Kuparuk
Kuparuk Central
Processing 3
COLVILLE RIVER
Aurora
KUPARUK/PALM
Schrader Bluff
Prudhoe Bay Gas Cap
Alpine
CRU CD-1
PLACER UNIT
Arctic Slope
Regional
Corp
KUPARUK RIVER
Kuparuk
Central
Processing 1
Service City
Gathering
Center 2
Gathering
Center
Gathering
Center 3
Nanuq-Kuparuk
Kuparuk
Central
Processing 2
S MILUVEACH
UNIT
Brooks Range
Petroleum Corp
Prudhoe
National Petroleum
Reserve Alaska
Nuiqsut
TOFKAT UNIT
Brooks Range
Petroleum Corp
KACHEMACH
UNIT
Brooks Range
Petroleum Corp
HEMI SPRINGS
Tarn
GREATER MOOSES
TOOTH UNIT
ConocoPhillips Alaska Inc
West Sak
ARCTIC FORTITUDE UNIT
Alaskan Crude Corporation
(Termination on Appeal)
BEAR TOOTH UNIT
ConocoPhillips Alaska Inc
(Federal NPRA Unit)
KUPARUK RIVER UNIT
ConocoPhillips Alaska Inc
©2014
MAPMAKERS ALASKA
Meltwater
Trans Alaska Pipeline


EXXONMOBIL
Point Thomson, August 2014


Beaufort Sea
Fields & Facilities
Arctic Slope and Beaufort Sea, Alaska
Facility
Road
Pipeline
Proposed Pipeline
Oil & Gas Unit
Oil Field
Oil & Gas Field
Gas Field
August 2014. Complied from official sources by Mapmakers Alaska. While diligently researched and prepared Mapmakers Alaska does not guarantee nor warrant the information on this map.
HAMMERHEAD
AR UNIT
ska, LLC
West Dock
Lisburne
Central Gas Facility
East Dock
PRUDHOE BAY
Flow Station 2
BP Operations Center
Flow Station 3
Prudhoe Bay
Deadhorse
PRUDHOE BAY UNIT
BP Exploration (Alaska) Inc
DUCK ISLAND UNIT
Hilcorp Alaska, LLC
ENDICOTT
Badami Tie-In
LIBERTY UNIT
Hilcorp Alaska, LLC
LIBERTY
Tern Island
MIKKELSEN
BADAMI UNIT
Savant Alaska LLC
BADAMI
Badami Central Processing
POINT THOMSON UNIT
ExxonMobil Production Co
POINT THOMSON
FLAXMAN
Central Pad
SOURDOUGH
YUKON GOLD
Arctic National Wildlife Refuge Area 1002
James Dalton Highway
0
5
10
20
30
40
Miles



©2014
MAPMAKERS ALASKA
Fields & Facilities
Cook Inlet, Alaska
Facility
Road
Pipeline
Proposed Pipeline
Oil & Gas Unit
Oil Field
Oil & Gas Field
Gas Field
August 2014. Complied from official sources by Mapmakers Alaska. While diligently researched and prepared Mapmakers Alaska does not guarantee nor warrant the information on this map.
0
4
8
16
24
32
Miles
LEWIS RIVER UNIT
Hilcorp Alaska, LLC
LEWIS RIVER
OTTER UNIT
Cook Inlet Energy, LLC
PRETTY CREEK UNIT
Hilcorp Alaska, LLC
PRETTY CREEK
STUMP LAKE
STUMP LAKE UNIT
Hilcorp Alaska, LLC
IVAN RIVER
IVAN RIVER UNIT
Hilcorp Alaska, LLC
BELUGA RIVER UNIT
ConocoPhillips Alaska, Inc
Beluga Power Plant
BELUGA RIVER
THREE MILE CREEK
(Aurora Gas, LLC)
LONE CREEK UNIT
Aurora Gas, LLC
LONE CREEK
MOQUAWKIE UNIT
Aurora Gas, LLC
MOQUAWKIE
ANCHORAGE
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
GRANITE POINT
S GRANITE POINT UNIT
Hilcorp Alaska, LLC
N TRADING BAY UNIT
Hilcorp Alaska, LLC
SPURR
SPARK
KITCHEN LIGHTS UNIT
Furie Operating Alaska, LLC
Proposed KLU A
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
Trading Bay Production Facility
BAKER
DOLLY VARDEN
W MCARTHUR RIVER
W FORELAND
A
MIDDLE GROUND SHOAL
C
TIGER EYE UNIT
NordAq Energy, Inc
S Middle Ground Shoal
Hilcorp Alaska, LLC
DILLON
BIRCH HILL UNIT
Hilcorp Alaska, LLC
BIRCH HILL
SWANSON RIVER UNIT
Hilcorp Alaska, LLC
SHADURA UNIT
NordAq Energy, Inc
SWANSON RIVER
Kustatan Production Facility
Kustatan
OSPREY
REDOUBT SHOAL
Kenai LNG Plant
Agrium Plant
Tesoro Facility
Port Nikiski
REDOUBT UNIT
Cook Inlet Energy, LLC
BEAVER CREEK
WOLF LAKE
(Hilcorp Alaska, 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 UNIT
Hilcorp Alaska, LLC
Sterling C Gas Storage
Cannery Loop Gas Storage Facility
KENAI CLU
CINGSA
KENAI CLU
STERLING
KENAI UNIT
Hilcorp Alaska, LLC
KENAI
Sterling 6 Gas Storage
KASILOF UNIT
Hilcorp Alaska, LLC
KASILOF
Cook Inlet
Clam Gulch
Falls Creek
NINILCHIK
G Oskollkoff
s Dionne
NINILCHIK UNIT
Hilcorp Alaska, LLC
Ninilchik
DEEP CREEK
DEEP CREEK UNIT
Hilcorp Alaska, LLC
Proposed COSMO A
HANSEN
(BlueCrest Energy, Inc)
Cosmopolitan
NIKOLAEVSK UNIT
Hilcorp Alaska, LLC
NIKOLAEVSK
NORTH FORK
NORTH FORK UNIT
Cook Inlet Energy, LLC
Anchor Point
Kachemak City
Homer

CONOCOPHILLIPS *continued from page 42*

proposed five Alpine satellites: Fiord, Nanuq, Alpine West, Lookout and Spark. The company also mentioned 10 additional oil accumulations within 30 miles of Alpine that could be future satellites.

ConocoPhillips drilled an Alpine West exploration well directionally from the CD-2 pad in 2001 but wanted to develop the field from a CD-5 pad. The proposed pad was to be located across the Nigliq Channel of the Colville River from the existing Alpine facilities.

The proposed bridge across the Nigliq Channel spawned years of debate, first with local groups and later with the U.S. Army Corps of Engineers. The sides finally reached an agreement in late 2011 and ConocoPhillips sanctioned the CD-5 project in late 2012.

Construction began in early 2014. ConocoPhillips expects to begin drilling by the middle of next year and bring the satellite into production by the end of next year. The current development program calls for drilling 15 horizontal wells — six producers and seven injectors into the Alpine A sand and one producer and injector into the Kuparuk sands.

Environmental aspects of the development are currently tied up in federal court.

Greater Mooses Tooth

ConocoPhillips originally envisioned Lookout and Spark as Alpine satellites, even though the fields are in the federally managed National Petroleum Reserve-Alaska.

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 state and federal developments.

As CD-5 moved forward, ConocoPhillips updated its plans for CD-6/GMT-1.

In July 2013, the company submitted a proposal to regulators 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, which would ultimately connect back to the existing Alpine facilities. ConocoPhillips expects to bring the field online by late 2017.

The estimated $890 million project would produce 30,000 bpd day at its peak, according to ConocoPhillips, which will seek internal and partner approval by the end of the year.

The proposal was "very similar" to the original Alpine CD-6 pad the BLM approved in its 2004 decision, according to BLM, but included some "notable changes," including a new location for its drill site, which would require longer roads, bridges and pipelines.

Those changes required BLM to produce a supplement to 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.

Contact Eric Lidji at ericlidji@mac.com

ConocoPhillips operates Cook Inlet legacy assets

The Beluga River unit, North Cook Inlet unit and the Kenai liquefied natural gas terminal remain important

By ERIC LIDJI
For Petroleum News

ConocoPhillips' stature in Cook Inlet has shrunk over the past three years.

Hilcorp Alaska LLC is now the dominant producer in the region and several small independents are much more enthusiastic about exploration than ConocoPhillips.

And yet the Houston-based company remains an important player in the basin because it operates two legacy natural gas fields — the coastal Beluga River unit and the offshore North Cook Inlet unit — and a crucial facility: the Kenai liquefied natural gas terminal.

> *As with Beluga River, ConocoPhillips conducted a large development program at North Cook Inlet between 2008 and 2013.*

Those assets underpin two essential Cook Inlet operations: the Beluga River Power Plant and an export operation that increases the market reach of regional gas producers.

The Beluga River unit

Standard Oil Company of California discovered the Beluga River field in December 1962 while looking for oil in deeper formations along the west side of the Cook Inlet basin.

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

Today, ConocoPhillips operates the unit. The ownership is split into thirds, equally, among ConocoPhillips, Hilcorp and the Anchorage utility Municipal Light & Power.

Between 2008 and 2012, ConocoPhillips conducted an expensive campaign to improve the performance — and particularly the deliverability — of the aging field. The program consisted of drilling four wells between 2008 and 2010, upgrading a compressor system in 2011 and drilling two more wells in 2012, in addition to ongoing maintenance work.

Those activities slowed in 2013. Through the end of 2013, Beluga River had 15 producing wells, two operating disposal wells, one plugged and abandoned well and nine shut-in wells, according to a May 2014 plan of development. The unit had an identical profile at the start of the year. ConocoPhillips had not drilled any additional wells in 2014 through September, according to the Alaska Oil and Gas Conservation Commission.

ConocoPhillips has described the field as being "fully delineated."

ConocoPhillips proposed a slate of projects in its 2013-14 plan of development but ultimately deferred some of the work for its current plan, which runs through June 2015.

The current plan includes no drilling activities but calls for rigged workovers on the BRU 244-23, BRU 242-04 and BRU 224-13 wells, and various upgrades and maintenance activities on as many as 11 other wells. The plan also includes plans to re-cylinder seven wellhead compressors and projects to accommodate increased water production.

Averaging monthly production figures, the unit produced some 71.3 million cubic feet per day in July 2014, according to the AOGCC. Cumulatively, the Beluga River unit produced nearly 1.3 trillion cubic feet of gas through July 2014, according to the AOGCC.

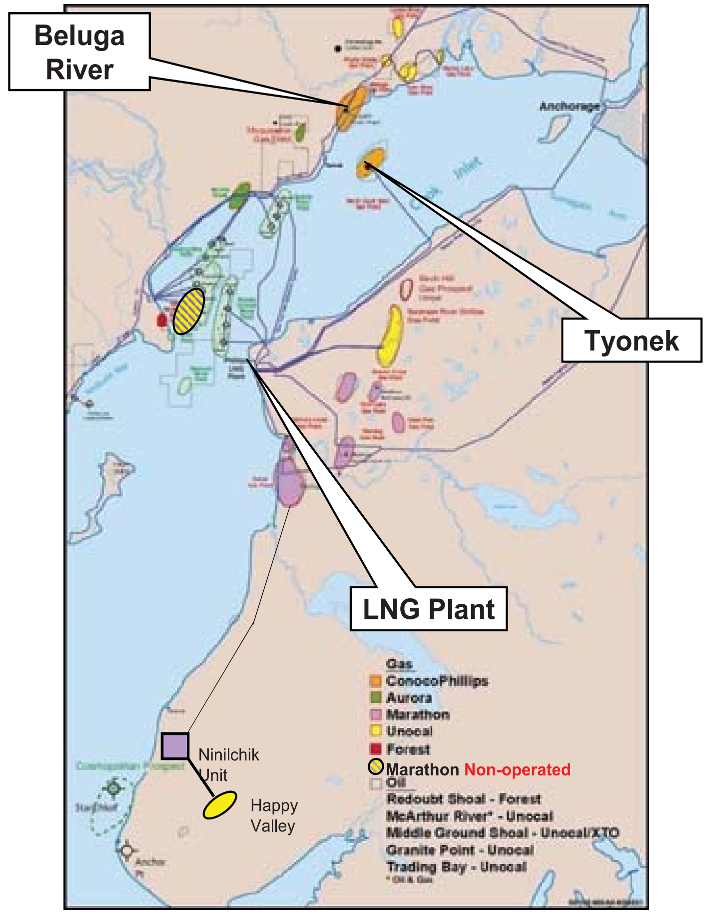
The North Cook Inlet unit

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

North Cook Inlet came online in 1969. Today, ConocoPhillips owns the unit outright.

Averaging monthly production figures, the unit produced some 25.1 mmcf per day in July 2014. Cumulatively, the unit produced nearly 1.9 tcf through July 2014.

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



The 2013 program included a program to install or improve artificial lift at four wells to improve production. The program brought one shut-in well back into production and improved an active well, but the other two wells remain shut-in pending further work.

ConocoPhillips also replaced both of its cranes at the Tyonek platform last year

The current plan of development calls for "a rig work-over

continued on next page

CONOCO COOK INLET *continued from page 49*

program that may or may not include drilling in 2014 or 2015" and "plans to evaluate future drilling opportunities after 2015," language that ConocoPhillips also used in its previous plan of development.

The Kenai LNG terminal

The past three years have been unusual ones for the Kenai LNG terminal.

The export facility was the largest in the world when it began operations in 1969 but was increasingly overshadowed by larger facilities or those closer to East Asian markets.

ConocoPhillips and partner Marathon Oil announced plans in early 2011 to mothball the facility for lack of sufficient Asian contracts. But they ended up keeping the facility open through 2012 and into 2013 to accommodate an unexpected increase in Asian demand. ConocoPhillips bought out Marathon and now is the sole owner of the facility.

Those shipments ended when a federal export license expired in March 2013.

ConocoPhillips decided it would not seek an extension but said it would consider restarting the facility once local needs were met and would also consider alternative uses for the facility, including LNG imports to help meet the short term needs of utilities.

By the end of summer, those utilities had contracts in place to meet their needs through 2018, and so then acting Natural Resources Commissioner Joe Balash asked the company to apply for a new three-year license to connect Cook Inlet to additional markets.

"Without market opportunities for gas discoveries, companies lack the incentive to invest in continued exploration activities," Balash wrote to the company in September 2013.

In October 2013, ExxonMobil, BP, ConocoPhillips and TransCanada chose Nikiski as the home for a proposed LNG terminal to serve their Alaska LNG project, which would serve a large diameter natural gas pipeline from the North Slope.

ConocoPhillips agreed.

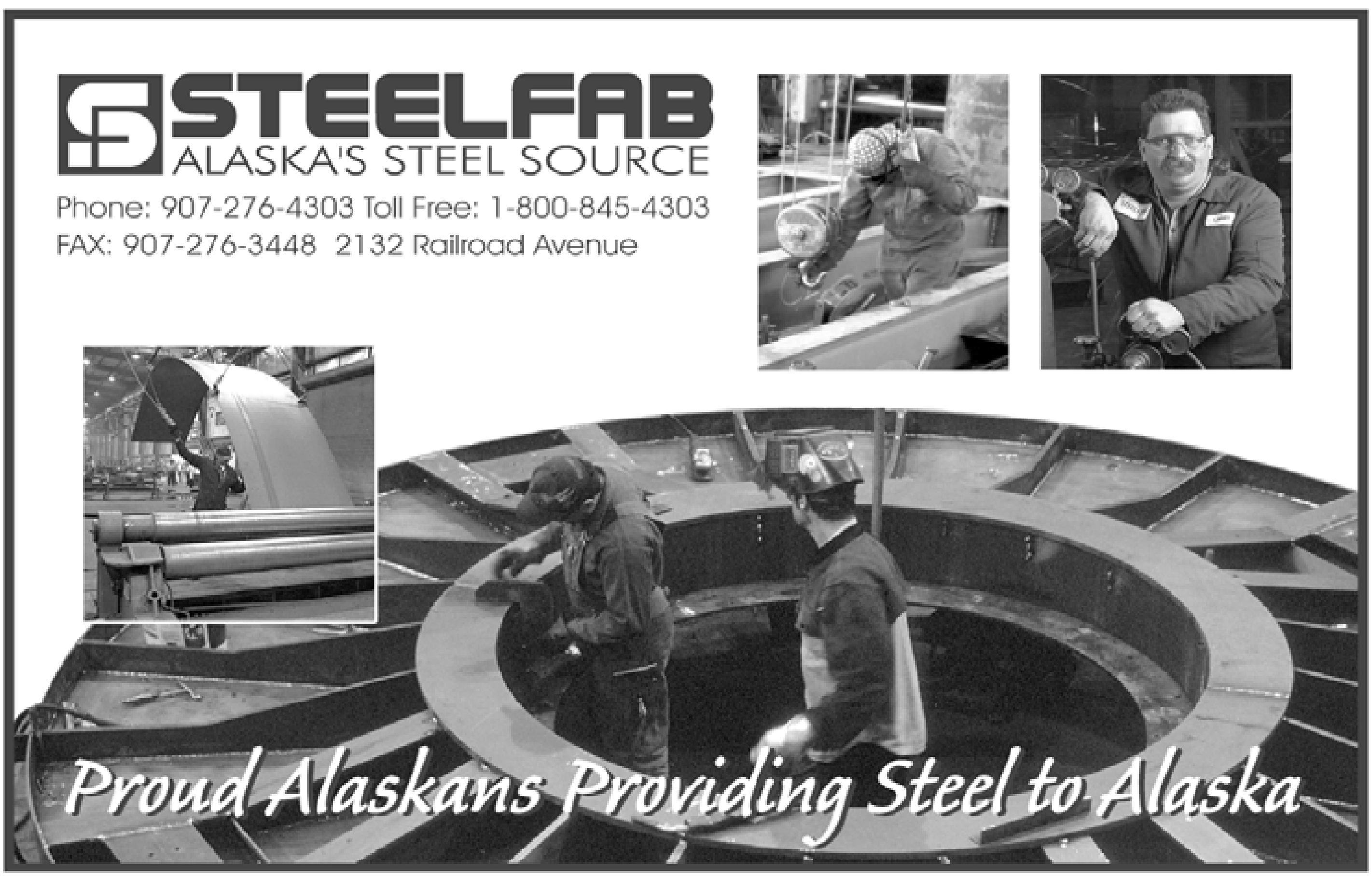
In December, the company applied for a license to export as much as 40 billion cubic feet over two years. The U.S. Department of Energy approved the request in early 2014.

This year, ConocoPhillips plans to deliver six LNG shipments, the company said during a first quarter teleconference for investors. Each shipment would contain some 2.75 billion cubic feet of natural gas, of which some 60 percent is expected to be from third parties, according to ConocoPhillips. The first two cargoes shipped out during the second quarter, according to the company. However, in a report submitted to the Federal Energy Regulatory Commission, ConocoPhillips said it had shipped one cargo load through the first six months of 2014. The company also delivered 55 tanker-truck-loads of LNG to Fairbanks Natural Gas LLC, which operates a small distribution system in Fairbanks.

While the facility remains an important asset for encouraging exploration, its future remains uncertain. In October 2013, ExxonMobil, BP, ConocoPhillips and TransCanada chose Nikiski as the home for a proposed LNG terminal to serve their Alaska LNG project, which would serve a large diameter natural gas pipeline from the North Slope.

Contact Eric Lidji at ericlidji@mac.com


DELTA
LEASING LLC
Better Products. Better Service. Better Results.
Alaska's Premier Leasing Company. DELTA LEASING, LLC.
Anchorage: 907.771.1300 • Prudhoe Bay: 907.659.9056 • www.deltaleasing.com
GMC


STEELFAB
ALASKA'S STEEL SOURCE
Phone: 907-276-4303 Toll Free: 1-800-845-4303
FAX: 907-276-3448 2132 Railroad Avenue
Proud Alaskans Providing Steel to Alaska

Eni starting phase II at Nikaitchuq

With initial drilling program nearly complete, Eni is moving ahead on expansion at its offshore field

By ERIC LIDJI
For Petroleum News

As Eni US Operating Co. Inc. completes its initial development program at the Nikaitchuq unit, it is beginning expansion efforts that could define the future of the field.

The Italian major expects to complete its initial development program at the North Slope field by the end of the year, but will undertake continuous drilling from its Spy Island drill site into 2015 as it pursues several opportunities. Those include a campaign to add dual laterals to existing wells, an expansion into the area just west of its existing development and evaluation of two potential developments yet to be fully sanctioned.

Eni plans to drill more than 20 wells and laterals at the nearshore unit over the next two years, according to a seventh plan of development filed with state officials in July 2014.

The schedule for the remainder of this year at the field in state waters off the North Slope, north of the Kuparuk River unit, calls for drilling four production wells with laterals, three injection wells and four multilateral sidetracks of existing wells. Over the summer, Eni drilled the Spy Island SP12-SE3 well with a lateral and drilled a lateral at the existing Oliktok Point OP16-03, according to the Alaska Oil and Gas Conservation Commission.

NAME OF COMPANY: Eni Petroleum
COMPANY HEADQUARTERS: Eni US Operating Co. Inc, Houston, Texas
ALASKA OFFICE: 3800 Centerpoint Dr., Ste. 300, Anchorage, Alaska 99503
TOP ALASKA EXECUTIVE: Scot Childress, Alaska Eni representative & operations manager
PHONE: 907-929-9377
PARENT COMPANY WEBSITE: www.eni.it

The 2015 program calls for drilling three production wells with laterals, four injection wells and four multilateral sidetracks, plus drilling a new water well into the Ivishak.

Multilateral drilling

Eni completed its initial drilling program from the Oliktok Point Pad in August 2012 and expects to complete its initial drilling program from the Spy Island drill site in November.

With work completed for the time being at the Oliktok Point Pad, Eni plans to cold stack Nabors rig 245 through January 2015,

continued on page 55

ENI *continued from page 53*

when the rig would be used to drill an injection well and a water sourcing well into the Ivishak formation. Eni is also considering a campaign to use the rig to workover a well it had previously drilled from the onshore pad.

The program at the Spy Island drill site would use Doyon rig 15 and a Baker RAM multilateral system. For the foreseeable future, Eni plans to drill all new production wells as multilaterals. (The company would continue to drill injection wells with single laterals.) Once the planned program is completed, around March 2015, according to the company, Eni plans to convert eight single-bore wells at the pad into multilateral wells.

Eni attributes a large jump in production recently to previous multilateral wells.

Nikaitchuq produces from the same oil-bearing sands 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 has estimated that 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.

The development work to date has focused exclusively on the Schrader Bluff OA Sands, but Eni is in the process of "derisking" the shallower Schrader Bluff N Sands.

The company is also deciding whether to commission a second offshore drilling pad farther west, which would allow it to develop a reservoir in the Sag River formation.

And as it pursues those two potential developments, Eni is moving ahead on a westward expansion of the OA Sands into a section of the unit previously considered unfeasible.

Some of the work for the year is under way, although Eni is planning a 36-hour facility shutdown in late August to accommodate "critical maintenance items," the company said.

Transitional phase

Eni is beginning a transitional phase at Nikaitchuq.

The company acquired a minority stake in the unit in 2005 and the remaining working interest in 2007 and conducted a delineation program in 2006 and 2007. The offshore field contained relatively heavy oil, which challenged the commerciality of an otherwise large discovery. To improve the economics of the project, the state agreed to expand Nikaitchuq to include Tuvaaq, and to modify the royalty structure should oil prices drop.

The modification allows Eni to pay the state a 5 percent royalty rate — rather than the most common rate of 12.5 percent — 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 the field.

In February 2008, Eni sanctioned a $1.45 billion development program at Nikaitchuq.

The initial program called for drilling some 73 production and injection wells by 2011, but the company later modified the plan to include some 51 wells: 11 producers and eight injectors from Oliktok Point, 15 producers and 12 injectors from Spy Island, a dis-

continued on next page

ENI *continued from page 55*

posal well at each pad and three water sourcing wells into the Ivishak formation.

After slowing the pace of its development because of weather delays in conjunction with the short Arctic sealift season, Eni brought the Oliktok Point Pad online in late January 2011 and brought the Spy Island drill site online in late November 2011. As the development schematic progressed, Eni contracted two undeveloped leases from the unit.

Through the end of 2014, Eni expects that it will have drilled 53 wells at the unit, largely keeping to its earlier plan but shifting some onshore wells to the offshore drilling pad.

In June 2014, Eni reach its current peak production of 25,000 barrels per day at Nikaitchuq, a rate the company expects to maintain through the end of the year, according to its most recent plan of development. In announcing the milestone, the company said it expected to reach 30,000 bpd within the next year. The Nikaitchuq production facilities were designed to accommodate 40,000 bpd of crude oil.

Speaking about the 30,000 barrel per day goal, Eni executive Federico Arisi Rota said he was "confident we will reach this goal in the same way we have met earlier challenges."

With the initial campaign nearing completion, Eni is beginning to apply advanced technologies to the field, specifically a multilateral and waterflood program launched last year. The program helped increase the average rate of oil production per well to 924 barrels per day, up from 565 barrels per day, throughout 2013, according to the company.

The multilateral program involves drilling laterals in "counter undulation" to existing production wells. The well and the lateral undulate in a mirroring fashion, so that the lateral curves downward where the well curves upward, which covers more formation.

The company claims that these wells, some of which have lateral sections as long as 22,000 feet, "are the most complex wells drilled by the industry to date in Alaska."

Through the end of the year, Eni expects to have added dual laterals to 15 existing or recently drilled wells — eight from the Oliktok Point Pad, five from the Spy Island drill site and two from wells drilled as westward extensions of the Spy Island drill site.

Three expansion opportunities

As Eni advances near-term efforts to expand the use of multilateral technology, the company is also evaluating three geographic or geological expansions at the field.

The company is looking to extend its development of the Schrader Bluff OA sands into the "western area" of the unit. "Originally considered technically beyond drilling reach, this area is now considered a challenging but feasible drilling target," the company wrote in its most recent plan of development. The project involves drilling four wells — two producers and two injectors — from the Spy Island drill site into the western flanks of the field starting this summer. According to the company, the Nikaitchuq field has documented "higher productivity" and "better fluid properties" as it moves to the west.

The plan of development fails to identify the precise extent of the "western area" development, although potential plans for a Sag River development would suggest that the "western area" stops far short of the undeveloped northwest corner of the unit.

In a Nikaitchuq plan of development filed last year, Eni proposed a second offshore drilling pad in the northwest corner of the unit to access a Sag River reservoir and said it intended to submit a proposal to its "upper management" within "12 to 18 months."

In the current plan of development, Eni said it plans to spend the next 12 to 18 months reviewing "geological, petrophysical and seismic information" and monitoring existing and pending wells at the Nikaitchuq unit to "aid in identifying potential exploration and development opportunities, including Sag River and Schrader Bluff N sand."

The company said it plans to submit a proposal for a Sag River development to upper management within the current 12-18 month timeframe. A development would allow Eni to retain all or part of four undeveloped leases currently included in the unit boundaries.

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

Alongside those studies, Eni is also still evaluating another proposal discussed last year.

While Eni sanctioned Nikaitchuq based on the potential of the Schrader Bluff OA Sands, the company has long discussed the possibility of developing the shallower N sand.

Eni claims to have encountered between 40 million and 100 million barrels of "contingent resources" in the N sand in 2012, which prompted the current appraisal program alongside development of the OA sands. The company conducted "sedimentological, petrophysical and reservoir studies," extended the "toe" of several OA sands development wells and drilled a pilot well last year to test completion strategies.

Eni said that it expects those studies to be finished by the end of the year, at which point the company would decide whether to propose a "conceptual project" to management.

Infrastructure work

Aside from drilling, Eni has also been expanding its infrastructure.

The company installed the Black Gold Camp at its onshore Nikaitchuq Operations Center in the third quarter of 2013 and installed a snow fence alongside the center in early 2014 to protect against drifts in the winter. Eni started a second train at its production facilities in February 2014 and installed a permanent load bank at the facility in the second quarter.

In May 2014, Eni started a temporary chiller to re-freeze thawed permafrost at its source water well. Now, the company is working to install a permanent chiller system.

Contact Eric Lidji at ericlidji@mac.com

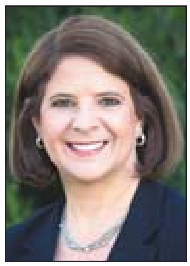
Exxon working on big and small projects in Alaska

The oil giant is working to bring Point Thomson online and, through XTO, operating Middle Ground Shoal

By ERIC LIDJI
For Petroleum News

ExxonMobil is a major player in the Alaska oil industry. But unlike peers BP Exploration (Alaska) Inc. and ConocoPhillips Alaska Inc., the global giant currently operates very little production in Alaska. In fact, Exxon only operates two Alaska fields: the as-yet-nonproducing Point Thomson unit on the eastern North Slope and, through subsidiary XTO Energy Inc., the Middle Ground Shoal field in Cook Inlet.

The fields are distinctly opposite.



KAREN HAGEDORN

Point Thomson is among the largest known yet undeveloped fields in Alaska. It is also strategically important because it would provide supplies for the proposed Alaska LNG project — of which Exxon is a sponsor — and because it would extend North Slope development infrastructure farther to the east, improving the economics of other fields.

By contrast, the small Middle Ground Shoal oil field and its two offshore platforms — called, simply, A and C — are among the oldest and hardiest assets in Cook Inlet.

Point Thomson

Exxon discovered the gas and condensate Point Thomson field in the 1970s but delayed development for decades because of technical, economic, legal and regulatory challenges.

After an initial delineation campaign, Exxon refrained from development work for years, which eventually tried the patience of state officials. A complex dispute ensued. The state and the company debated whether it was economically and technically wiser to prioritize condensate or gas production at the field, a decision that impacted project timelines.

The state initiated termination proceedings in 2008 to take back the leases, saying Exxon had fallen short of its responsibilities as a leaseholder. As a subsequent legal battle played out, the state gave Exxon permission to drill two wells at the unit: PTU-15 and PTU-16.

The parties reached a court-ordered settlement in early 2012 that created a timetable for Exxon to bring Point Thomson online by early 2016 and expand development thereafter.

Currently, Exxon is working on the first part of the deal: the Initial Production System.

Under a plan of operations filed 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.

NAME OF COMPANY: Exxon Mobil Corp.
COMPANY HEADQUARTERS: Irving, Texas
ALASKA OFFICE: 3301 C St., Ste. 400, Anchorage, AK 99503
PHONE: 907-561-5331
TOP ALASKA EXECUTIVE: Karen Hagedorn, Alaska production manager
COMPANY WEBSITE: www.exxonmobil.com

NAME OF COMPANY: XTO Energy
COMPANY HEADQUARTERS: Fort Worth, Texas
TELEPHONE: 817-870-2800
COMPANY WEBSITE: www.xtoenergy.com

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

In 2013, Exxon claimed several "infrastructure milestones."

By September 2013, the company had finished building an airstrip, a service pier and a permanent camp with operational telecommunications and power systems at Point Thomson. The company opened a new gravel mine and installed some 2,200 vertical support members for an above ground pipeline connecting the field to existing North Slope infrastructure. The 2013 program also saw Hyundai Heavy Industries begin construction work on the Point Thomson production modules at its facilities in Korea.

By June 2014, ExxonMobil had finished building a 70,000 bpd pipeline along 22 miles of Beaufort Sea coastline to the existing Badami pipeline, where liquids will flow to the trans-Alaska oil pipeline. ExxonMobil pegged the cost of the pipeline at $250 mil-

continued on page 61


The number one On-Demand Air Charter Company in Alaska.
Operating an all twin-engine aircraft fleet, we are ready to fly when you are.
First in Safety. First in Class
907.248.2677 | www.securityaviation.biz
SECURITY AVIATION

lion.

The pipeline is bigger than what Exxon will need for its initial Point Thomson plans. The excess capacity is meant to accommodate future developments to the east, including the Red Dog, Telemark, Kuvlum-Lonestar, Stinson and Yukon Gold prospects and any potential development from the currently restricted Arctic National Wildlife Refuge.

In July, the Alaska Department of Environmental Conservation preliminarily approved an "air quality control construction permit," a necessity for any development at the field.

Those activities have paved the way for bigger work: barging the production modules to the field mid-2015, installing the modules, directionally drilling a production well and two injection wells and bringing Point Thomson into regular production by early 2016.

Future development

The Initial Production System aims to produce some 10,000 barrels per day of liquid condensate and cycle some 200 million cubic feet per day of residual gas into the field.

That scheme would neither recover the $4 billion Exxon expects to spend on the project by 2016 nor come close to fulfilling the full promise of the Point Thomson field. The estimated 8 trillion cubic feet of gas at Point Thomson constitutes some 25 percent of known North Slope reserves, making the field crucial for the success of future gas sales.

That's why the 2012 settlement also included three future development options.

Under Alternative A, Exxon would sanction a "major" gas sale by June 2016. The sale would have to be at least 500 million cubic feet per day, which would require a large diameter pipeline from the North Slope, a project Alaskans have wanted for decades.

The current project consists of a large diameter gas pipeline connecting Prudhoe Bay facilities to a new liquefied natural gas export facility in Nikiski, on the Kenai Peninsula.

Over the course of 2014, the producers BP, ConocoPhillips and Exxon, the pipeline builder TransCanada and the state of Alaska created a framework for moving ahead on preliminary engineering and for establishing a commercial terms for that project. The Point Thomson settlement helped those efforts, Gov. Sean Parnell told Petroleum News in July 2014. "We were making what I call commensurate proportionate commitments," he said. "Meaning, you take a step. We take a step. You take a step. We take a step."

While those agreements represent the most progress on the project in years — and some would say the most progress ever — a major question persists: cost. In 2012, the three producers and TransCanada estimated the project would cost between $45 billion and more than $65 billion, figures which are unlikely to go anywhere but up over time.

Under Alternative B, the Point Thomson producers would commit to expand liquids production to 30,000 bpd or more by 2019. The alternative is only possible if the Initial Production System proves the feasibility of gas cycling at Point Thomson. The program would require Exxon to drill more wells and expand processing capacity at the field.

Under Alternative C, the producers would integrate Point Thomson and Prudhoe Bay to improve 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 a significant volume of gas for in-state use no later than 2019.

The settlement also requires Exxon to develop a Brookian oil reservoir by 2018.

Middle Ground Shoal

The Point Thomson project is large enough to guide public policy. By contrast, the XTO-operated Middle Ground Shoal field is much more modest.

Shell Oil discovered the field in 1963 with MGS State No. 1, the first offshore oil completion in Alaska, according to the American Association of Petroleum Geologists.

By the time XTO-predecessor Cross Timbers Oil Co. purchased Middle Ground Shoal from Shell in 1998, the offshore field was producing 3,600 barrels per day and falling. By 2006, XTO had drilled 12 penetrations throughout the field, which doubled oil reserves to 24 million barrels and brought oil production into the range of 3,000 to 4,500 bpd.

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

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

Even so, though, Middle Ground Shoal was probably irrelevant to Exxon in late 2009, when it purchased XTO in an all-stock deal worth $31 billion. Instead, Exxon wanted XTO's sizable North American natural gas holdings as an entree to the unconventional boom.

Contact Eric Lidji at ericlidji@mac.com


Today, going the distance means going further.
When the target keeps getting further away, you need tools that will go the distance...whatever your total depth is. Volant's field proven Casing Running Tools and Centralizers are engineered for today's complex wells. The efficient, versatile design of the CRTi™ and CRTe™ puts complete control in the hands of the driller, reducing risk and improving safety. Volant's HydroFORM™ Centralizers help you go the distance and get safely to bottom. Wherever bottom is.
VOLANT®
Doing more with less.
sales@volantproducts.ca volantproducts.ca | sales@volantoiltoolsUS.com volantoiltoolsUS.com
Certified System
SAI GLOBAL
ISO 9001
Quality

Furie inching closer to Kitchen Lights startup

With a decade of planning and four years of exploration behind it, Furie is on the brink of production

By ERIC LIDJI
For Petroleum News

NAME OF COMPANY: Furie Operating Alaska LLC
COMPANY HEADQUARTERS: League City, Texas
ALASKA OFFICE: 1029 W. Third Ave., Ste. 500, Anchorage, AK 99501
TOP ALASKA EXECUTIVE: Bruce Webb, vice president
TEXAS TELEPHONE: 281-957-9812
ALASKA TELEPHONE: 907-277-3726
WEBSITE: www.furiealaska.com

If Furie Operating Alaska LLC brings the Kitchen Lights unit into production sometime next year, as it anticipates, it would mark a new milestone in the Cook Inlet renaissance.

The much-touted rejuvenation of the basin has largely consisted of expanded exploration activities and renewed investment in operating fields. In the past five years, only two new fields have come online: the onshore North Fork unit and the onshore Kenai Loop field.

But with Kitchen Lights, Furie is constructing the first offshore platform in the waters of Cook Inlet since Forcenergy installed the Osprey platform at Redoubt Shoal in 2000.

KLU Platform A would be the 17th offshore platform in Cook Inlet.

In July 2014, Energy Capital Partners Mezzanine Opportunities Fund committed $160 million for the development at Kitchen Lights. “The investment will fund the build-out of infrastructure for the installation of an offshore natural gas production platform, marine pipeline, and onshore production facilities to bring proven natural gas reserves to market from Furie’s Kitchen Lights Unit in the Cook Inlet,” the private equity firm said.

A rocky road

Even by Alaska standards, the Kitchen Lights project has faced many obstacles.

The Houston-based independent Escopeta Oil & Gas Co. spent more than a decade arranging a complicated exploration program over offshore leases in the Cook Inlet.

The biggest complication was bringing a jack-up drilling rig to the waters of Cook Inlet for the first time in some two decades. Getting the rig to Alaska involved not only the expected commercial arrangements but also political will in the form of a waiver of the federal Jones Act that governs foreign-flagged vessels at domestic ports. The way Escopeta went about bringing the rig to Alaska triggered a violation of the Jones Act and yielded a stiff $15 million fine that Furie continues to fight in Alaska federal court.

Those long-running efforts to bring the rig to Alaska caused Escopeta to miss various drilling deadlines at its properties, leading to public disputes with state officials.

In July 2009, the state and the company resolved those disputes by agreeing to form the Kitchen Lights unit. The 83,394-acre unit, the largest in the Cook Inlet basin, combined 40,733 acres from the Escopeta-operated Kitchen unit, 15,930 acres from the Renaissance Alaska LLC-operated Northern Lights prospect and 26,721 acres from the Corsair prospect previously owned by the bankrupt Pacific Energy Resources Ltd. into one unit.

As exploratory drilling got under way in 2011, Escopeta essentially split into Furie Operating Alaska and Cornucopia Oil and Gas Co. Furie now operates the program while Cornucopia owns the majority of the working interest in the leases at the offshore field.

continued on page 65

FURIE *continued from page 63*

An initial exploration campaign in 2011 and 2012 yielded some astounding reserve estimates that Furie later tempered without entirely negating. In 2013, a flow test of the KLU No. 3 well "established proven undeveloped reserves" in the Kitchen Lights area.

Installation in 2015

Furie is nearing the end of the first phase of a two-phase development program.

The first phase involves constructing an offshore gas platform called KLU Platform A with a subsea pipeline connecting to new onshore gas production facilities.

For much of 2014, Furie had been expecting to install the platform sometime before the end of the year. The heavy lift vessel SAL MV Svenja arrived in Homer at the end of July. Installation of a seafloor foundation for the platform was scheduled to begin in August but deferred. In September 2014, Furie pushed the timeline for startup into 2015.

Furie commissioned the platform from an out-of-state company and the components of the large unit arrived in Cook Inlet in late August or early September. The original goal had been to install the platform in September and begin production by the end of the year.

Rather than risk weather troubles, though, Furie decided to delay installation until the waters of Cook Inlet are ice-free in the spring. The company said that all the necessary components for the platform, the onshore processing facility and the pipeline that will connect the two facilities are currently mobilized in Alaska and ready for installation.

The work involves placing a template over the KLU No. 3 well on the seafloor and using the template to guide piles driven 120 feet into the seafloor using cranes on the ship. Once the template is removed, crews would lower the caisson into position among the initial piles and then drive additional piles into the ground to further secure the platform.

With those materials in Alaska, the bigger problem became winter storage, according to Port Mackenzie Port Director Marc Van Dongen. Speaking to the Alaska-Japan LNG Opportunity Summit in Anchorage in September 2014, he said that one of the structures of the platform weighed more than 2 million pounds, making it a logistical challenge.

He said Furie would have to take the

FURIE OPERATING ALASKA LLC

The biggest complication was bringing a jack-up drilling rig to the waters of Cook Inlet for the first time in some two decades.

platform back to Seattle if local crews were unable to figure out a way to offload the facility from the barge and store it at the port. As of early October, the Port was able to get the equipment onto the dock but still needed a consultation and permit from the National Marine Fisheries Service to perform the work.

The matter remained unresolved by the time Petroleum News went to print.

KLU Platform A is a monopod platform with three primary decks.

The first will be an enclosed production deck at 62 feet above sea level. The second will be a main deck some 82 feet above sea level. The third will be a helideck at 100 feet above sea level. Furie intends to drill development wells by cantilevering a jack-up rig over the fixed platform. The wells would pass through the 18-foot-diameter caisson, into the seafloor. The main deck would be able to accommodate a platform workover rig.

The platform would support some 28 employees during drilling activities and fewer during regular operations. They would live in a two-story building beneath the helideck.

Including the platform, the pipeline and the onshore processing facilities, the Kitchen Lights project will have a permanent footprint of 108 acres, of which 97 are

continued on next page

FURIE *continued from page 65*

offshore.

Pipeline and facilities

The pipeline bundle would run 16 miles from the platform to the facilities.

The bundle would include two parallel 10-inch pipelines. They would run approximately 100 feet east of the Cook Inlet Gas Gathering System, using the existing corridor.

The Kitchen Lights unit is in the middle of Cook Inlet and the proposed platform would be in the middle of the unit, which gave Furie some options for transporting gas.

Furie decided to run the pipeline east, to connect to facilities in the area north of the city of Nikiski, which would bring supplies closer to the population centers of the region.

Each pipeline would initially carry up to 100 million cubic feet per day.

The onshore facility would be a 28,000-square-foot compound.

The facilities are planned for an undeveloped plot of land near Nikiski, which Furie previously acquired. Furie is also acquiring a plot of private land immediately to the south of the facilities to use for "temporary activities" in the future, including staging for horizontal directional drilling and storage for pipelines during construction activities.

The facility will separate Kitchen Lights production into gas, water and sand, with the gas sent to the regional grid through a small distribution pipeline and the produced water and sand stored on site until sufficient quantities accumulate to move to off-site disposal.

Well tests to date have indicated minimal condensate production from the reservoir, and so Furie plans to separate any condensate from the gas stream and dispose it off site.

The region is clustered with industry facilities, including an XTO Energy Inc. system about half a mile to the west, the Offshore System Kenai dock and industrial center about half a mile to the east and the CIGGS East Forelands facility some 800 feet to the west.

Next up: Phase two

Once the platform is installed, Furie will shift to phase two of its development.

The second phase involves "continued operations and maintenance of these facilities" through "initial and intermittent production well drilling" with temporary rigs.

Currently, Furie plans to develop Kitchen Lights from the existing KLU No. 3 well.

But, in a February 2014 plan of operation, the company told the state that "up to six wells may be developed" to maximize recovery. This past fall, Furie finished drilling the KLU No. 4 well that it had begun in 2013. In early September 2014, Furie began drilling the 11,800-foot KLU No. 5 well, with plans to finish operations by the end of the year.

Given the consolidated nature of Kitchen Lights, which brought together several distinct prospects, the state divided the unit into four blocks to better disperse future drilling operations: the Southwest and Central blocks in the southern end of the unit, the Corsair block in the center of the unit and the North block at the northeastern end of the unit.

The first three Kitchen Lights exploration wells were in the

Corsair block. KLU No. 4 was in the North block and the new KLU No. 5 well is in the Central block. Those wells align with the requirements of a previously approved plan of exploration for the unit.

Furie expects Kitchen Lights to produce up to 30 billion cubic feet of gas per year.

Expansion opportunities

While Furie is not actively planning any expansion, the current design can accommodate "sufficient space for potential future expansion," according to the company.

The expansion could come in two directions.

The first is the current reservoir. The hypothetical program to develop the reservoir with "up to six wells" includes KLU No. 3, according to the Furie plan of operations.

But Furie also said it might evaluate installing additional platforms in the future.

Prior to the current program, only Corsair had hosted previous drilling activities.

What's in the Kitchen?

Among the biggest unanswered question about the Kitchen Lights project is also among the most basic: just exactly how much oil and natural gas does the offshore unit hold?

In 2001, Escopeta Oil President Danny Davis announced that a new analysis of old seismic information suggested that Cook Inlet contained a major undiscovered resource potential in the Kitchen and East Kitchen prospects. He named the prospects "kitchen" after the geological nickname for the superhot source rocks that produce oil and gas supplies.

In November 2011, after drilling halfway to target depth at its first exploration well, Escopeta announced a discovery of 3.5 trillion cubic feet of natural gas, which would have ranked among the largest discoveries in the 55-year history of the Cook Inlet basin.

The response from state officials ranged from cautiousness to outright skepticism but Escopeta stuck to its estimate, which it noted was based on proprietary drilling results.

Damon Kade took over the presidency of the newly named Furie in late 2011, following a management shakeup. He subsequently provided more modest figures in testimony before the state Senate Resources Committee. Kade told lawmakers that the gas resource encountered with the KLU No. 1 well was closer to 750 billion cubic feet, which would translate to a production rate approaching 30 million cubic feet per day. The lower estimate was based on a smaller geographic drainage area, Kade later told Petroleum News.

An initial exploration campaign in 2011 and 2012 yielded some astounding reserve estimates that Furie later tempered without entirely negating. In 2013, a flow test of the KLU No. 3 well "established proven undeveloped reserves" in the Kitchen Lights area.

In early 2013, Furie parent company Deutsche Oel & Gas AG, out of Germany, released an assessment of "roughly one ninth of its production area in Kitchen Lights unit." The assessment estimated a mid-case scenario of 72.1 million barrels of oil and 543.8 billion cubic feet of gas "classified as 'probable' and 'prospective' exploitable reserves."

Under generally accepted definitions, "probable" indicates 50 percent likelihood of the actual amount meeting the estimate and "prospective" indicates 10 percent likelihood.

Deutsche Oel subsequently pulled the release and never responded to requests for comment.

Before those current estimates, previous operators offered thoughts about the region.

Before forming the Corsair unit in 2003, Forest Oil estimated that the prospect might contain 137 million barrels of oil and up to 480 billion cubic feet of gas. Pacific Energy Resources Ltd. acquired the unit in 2007 and later estimated that recoverable reserves might be as high as 100 million barrels of oil and 500 billion cubic feet of natural gas.

And previous estimates of the Northern Lights prospects were in the range of 111 million to 358 million barrels of oil equivalent.

Corsair and Northern Lights are now exploration blocks in the Kitchen Lights unit.

Contact Eric Lidji at ericlidji@mac.com

Hilcorp hitting early stride in Cook Inlet basin

The dominant producer continues to rejuvenate old oil and gas fields while also improving efficiencies

By ERIC LIDJI

For Petroleum News

The Cook Inlet Anna Platform

HILCORP ENERGY

The speed with which Hilcorp Alaska LLC became the dominant force in Cook Inlet will certainly prove to be among the most important moments in the history of the basin.

The privately held Houston-based independent owned no oil or gas assets in Alaska at the start of 2011. By the end of 2012, it was the largest producer in the Cook Inlet region.

That transition came through two acquisitions.

Hilcorp picked up the Cook Inlet assets of Union Oil Company of California in July 2011 and the Cook Inlet assets of Marathon Oil Co. in April 2012. With those two deals, Hilcorp became the operator of some 20 oil and gas fields across the Cook Inlet basin.

On the west side, Hilcorp operates the Lewis River, Pretty Creek, Stump Lake and Ivan River units. 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 southern Kenai Peninsula, Hilcorp operates the Deep Creek and Nikolaevsk units. In the northern Kenai Peninsula, Hilcorp operates the Birch Hill, Swanson River, Beaver Creek, Sterling, Cannery Loop and Kenai units, as well as the small Wolf Lake and West Fork fields.

Through the deals, Hilcorp also acquired a minority interest in the ConocoPhillips-operated Beluga River unit and the XTO-operated Middle Ground Shoal oil field.

And of course Hilcorp also acquired considerable infrastructure, including several platforms, pipelines and storage facilities. In just one sign of how the deal is changing the region, Hilcorp is now consolidating four independent gas pipelines into a single entity.

The Ivan River unit

Between 1966 and 1979, Unocal, Chevron and Cities Service Oil Co. discovered the four onshore fields Hilcorp now 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.

To date, these fields have not received the same attention Hilcorp has devoted to other assets in its portfolio. But a multiyear field study under way could identify opportunities.

At Ivan River, Hilcorp had considered drilling a new well or sidetrack in 2013. Instead, the company performed some maintenance work on a booster compressor engine.

The proposed well or sidetrack remain possibilities for this year but seem unlikely given that Hilcorp is currently conducting a "comprehensive field study." The company has said it would provide state officials with updates on the field study by the end of the year.

That said, Hilcorp may work over the IR 41-01 well to improve production from the Sterling-Beluga participating area and may convert one of two disposal wells to a producer. Those efforts would come on top of regular maintenance and repair work.

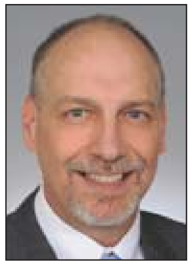
The Ivan River unit produced some 2.28 million cubic feet per day in 2013, which is on par and potentially even a slight increase from production rates in the previous year.

Averaging monthly production, the Ivan River unit produced 1.8 million per day in July 2014. Cumulatively, the unit produced more than 88.7 billion cubic feet through July 2014.

The unit also includes a legacy storage facility on ADL 391556. The state agreed to suspend the storage operations in 2012, after

continued on page 70

HILCORP *continued from page 68*



JOHN BARNES

Hilcorp identified damage at the IRU 44-26 injection well. Hilcorp said it "recognizes the importance of gas storage facilities in Cook Inlet" and is continuing to evaluate options for either converting or reactivating the well.

Lewis River, Stump Lake, Pretty Creek

At Lewis River, Hilcorp did not drill any wells, perform any workovers or conduct any facility improvements in 2013 and said it did not plan any of those activities for 2014.

The unit produced some 1.3 million cubic feet per day in 2013, all from the LCU C-01RD well. The rate is a slight decrease from a 2012 rate of nearly 1.5 mmcf per day.

Averaging monthly production, the Lewis River unit produced nearly 1.2 mmcf per day in July 2014. Cumulatively, the unit produced more than 14.6 bcf through July 2014.

Hilcorp is continuing to analyze ways to bring the Stump Lake unit back online.

After an eight-year shutdown, Chevron returned Stump Lake to production in 2009 by sidetracking the original discovery well. Hilcorp added perforations to the SLU 41-33RD well, but the build-up of solids forced the company to suspend production again.

Cumulatively, the Stump Lake unit produced more than 6.6 bcf through July 2014.

Similarly, the Pretty Creek unit is under evaluation for future development options.

Cumulatively, the Pretty Creek unit produced more than 9.5 bcf through July 2014.

NAME OF COMPANY: Hilcorp Energy Co.
COMPANY HEADQUARTERS: Houston, Texas
ALASKA OFFICE: 3800 Centerpoint Dr., Ste. 100, Anchorage AK 99503
TELEPHONE: 907-777-8300
TOP ALASKA EXECUTIVE: John Barnes
COMPANY WEBSITE: www.hilcorp.com

The Trading Bay fields

At the southern end of the west side, Hilcorp operates three offshore fields: the Trading Bay unit and the nearby McArthur River field and the North Trading Bay unit.

At the Trading Bay unit in 2013, Hilcorp conducted a nine-well workover campaign with Rig 56 at the Monopod platform into the Tyonek and the deeper Hemlock formations.

The program helped increase production to 5,740 barrels of oil equivalent per day by the end of the year, up from 822 barrels of oil equivalent per day at the beginning of the year.

Hilcorp planned a five-well workover campaign for 2014.

Hilcorp drilled the Trading Bay M-34 well in July.

At the McArthur River field in 2013, Hilcorp conducted a 10-well workover campaign, which helped increase production to 4,372 boepd by the end of the year, up from 3,824 boepd at the beginning of the year.

Hilcorp also conducted one workover at the Grayling gas sands, where 2013 production fell to 5,842 boepd from 8,381 boepd.

Hilcorp planned a major workover campaign for the McArthur River field this year, including five wells with the Moncla 404 Rig at the King Salmon platform, seven wells with the MAK No. 1 rig from the Dolly Varden platform, two wells with Rig 428 at the Steelhead platform and five wells with the Moncla 301 Rig at the Grayling platform.

Hilcorp also scheduled considerable maintenance activity for all five platforms this year.

Averaging monthly production, Trading Bay produced nearly 2,900 bpd and McArthur River produced some 4,730 bpd in July 2014. Cumulatively, the unit produced nearly 105 million barrels and the field produced more than 636 million barrels through July 2014.

The North Trading Bay unit was operating under a prior Marathon Oil plan of development through the end of 2013 and Hilcorp performed no drilling or well work.

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. Hilcorp said it is unlikely to return either to production this year. But the company is conducting reservoir engineering and geological studies through the end of 2017 that may identify future opportunities.

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

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

Granite Point

To the north, Hilcorp operates the Granite Point field and South Granite Point unit.

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

Those activities slowed some in 2013.

A sidetrack of the AN-17 well at the Anna platform was the only drilling or workover activity Hilcorp performed at Granite Point in 2013. The resulting production increase offset a small decline in production from the Bruce platform. Granite Point started 2013 at 1,495 boepd and finished the year at 1,603 boepd. This year, Hilcorp planned a three-well workover campaign at the Bruce platform but had no drilling or well work activities planned for the Anna platform.

Hilcorp performed three workovers from the Granite Point platform in 2013, which helped lift production to 1,066 boepd up from 1,019 boepd over the course of the year. The 2014 plans call for some additional work at GP-54, which Hilcorp worked over and brought online at 450 bpd.

While Hilcorp planned various maintenance activities at the three platforms this year, the biggest development at the two fields is an effort to consolidate and expand the units, similar to a scenario the state approved at the Trading Bay unit in August 2013. Hilcorp said that it intended to submit a formal application for the idea sometime this year.

Hilcorp completed the Granite Point State 18742-17A oil well in February 2014.

Averaging monthly production, the Granite Point field produced 2,665 bpd in July 2014. Cumulatively, the unit produced more than 150 million barrels through July 2014.

North and South Middle Ground Shoal

To the east, Hilcorp operates the offshore North Middle Ground Shoal field and Baker platform and the offshore South Middle Ground Shoal field and Dillon platform.

The state approved a plan for abandoning the lighthoused Baker platform in early 2012, but Hilcorp amended the plan later in the year, having decided to reactivate the platform to pursue gas exploration. Early workover efforts failed to yield much optimism, but a workover in 2013 returned the BA-14 well to production. It now provides fuel gas to its majority partner XTO Energy Inc., which operates the nearby Middle Ground Shoal field.

The program for 2014 included additional well work to add electric submersible pumps to existing wells and to conduct subsurface studies to identify future opportunities.

A fire at the Baker platform in October 2014 was fought by the Nikiski Fire Department, the Alaska Department of Environmental Conservation, the U.S. Coast Guard, CISPRI, Offshore Marine Services and Hilcorp. The cause was still unknown as The Producers went to print. Gas production at the platform was shut-in.

Unocal decommissioned the Dillon platform in 2003. But Hilcorp is undertaking a multi-year field study through mid-2016 to evaluate the possibility of reactivating the platform.

The study includes re-mapping relevant horizons, compiling well histories, building reservoir simulation models and potentially shooting 3-D seismic over the field.

The Kasilof unit

Kasilof and Ninilchik are coastal units produced from the shore.

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

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

Hilcorp did not drill any wells or perform any major well work at Kasilof last year after formally acquiring the unit from Marathon in February 2013. The company suspended production from April through October 2013 because of "the seasonal lack of market demand for gas" in the summer

continued on page 73

HILCORP *continued from page 71*

in Southcentral. The well produced 2,299 thousand cubic feet per day at the start of the year but only 1,609 mcf per day by the end of the year.

This year, Hilcorp "anticipates limited production of KAS-1" because "no new drilling programs are justified, and current opportunities to enhance production are limited."

The only maintenance activities Hilcorp had planned for 2014 was to run a capillary string to 13,000 feet to reduce "liquid loading" that has been "inhibiting sustained gas flow" from the KAS-1 well, the company said in a March 2014 plan of development.

Given the declining production and lack of foreseeable opportunities for development, Hilcorp told the state that it might use the Kasilof facilities to assist another asset in its portfolio, probably the nearby Ninilchik unit. "Existing facilities may be downsized to accommodate the reduced production capacity of the (Kasilof participating area) while benefitting the production of Hilcorp's other assets that are currently not producing."

Cumulatively, Kasilof produced some 4.3 bcf through July 2014.

The Ninilchik unit

The Ninilchik unit follows the coastline south of Kasilof.

Chevron discovered a Tyonek gas field in the area in June 1961. Marathon later discovered two other fields in 2001 and 2002 and pursued a development program.

The state formed the Ninilchik unit in 2001 and expanded it to include the former Falls Creek unit in 2003. Also in 2003, the state formed three participating areas at the unit: Falls Creek, Grassim Oskolkoff and Susan Dionne, which was expanded in 2007.

After acquiring the unit in early 2013, Hilcorp devoted considerable attention to Ninilchik, launching an exploration campaign and subsequently expanding existing developments.

Under its 2013 development plan, Hilcorp drilled four exploration wells: Susan Dionne No. 8, Paxton No. 5, Frances No. 1 and Falls Creek No. 5. The program primarily targeted gas but included some of the first oil exploration work at the field in decades.

The program prompted two major developments.

First, Hilcorp built a Bartolowitz pad at the unit and proposed a five-well development program. Second, Hilcorp said it would likely form two participating areas in 2015.

The 12,000-foot Susan Dionne No. 8 well was non-commercial for oil, but Hilcorp completed the well as a producer from both the Susan Dionne participating area and the Beluga formation on a tract basis. The results led Hilcorp to build the Bartolowitz pad in August 2013 and drill the Frances No. 1 exploration well later in the year.

Although Frances No. 1 was also non-commercial for oil, the well showed a "strong potential" for gas production. In August 2014, Hilcorp proposed a five-well development program from the Bartolowitz pad — two this year and up to three more by 2017.

The development proposal called for drilling the 10,000-foot Frances No. 2 well in October and the 10,000-foot Frances No. 3 well in November, with the Frances No. 4, Frances No. 5 and Frances No. 6 wells coming in subsequent years, as necessary.

Another large outcome from the exploration program is the "likely" expansion of the participating areas at the unit. The re-

continued on next page

The Granite Point Platform

HILCORP ENERGY

HILCORP *continued from page 73*

sults of Frances No. 1 and Falls Creek No. 5 have led Hilcorp to consider applying for a Falls Creek Beluga participating area; results of Paxton No. 5 have led Hilcorp to consider forming a Susan Dionne/Paxton Beluga participating area.

In 2013, Hilcorp recompleted the SD-2 and SD-7 wells to help establish the boundaries of the participating area and bolster its application for a new participating area. And Hilcorp added perforations adjacent to existing open intervals in the SD-5 and SD-6 wells. The SD-2 recompletion failed, and Hilcorp drilled a sidetrack in December 2013.

Hilcorp proposed a six-well development program at Ninilchik in its 2014 development plan: Frances No. 2 and No. 3, PAX-6 and PAX-7, Falls Creek No. 6 and GO-8.

The 10,000-foot Frances No. 2 and Frances No. 3 wells form the initial phase of the proposed development program at the Bartolowitz pad. The 9,000-foot Falls Creek No. 6 would follow up on Frances No. 2 to further appraise the Tyonek and Beluga formations north of the Falls Creek pad. The 10,000-foot PAX-6 and PAX-7 wells also would target the Tyonek and Beluga formations and would likely require Hilcorp to expand the existing Paxton pad. The 6,500-foot GO No. 8 would target the Sterling and Beluga formations above the Grassim Oskoloff participating area, west of the GO pad.

The Alaska Oil and Gas Conservation Commission issued permits for a Paxton No. 7 well on Aug. 28, a Paxton No. 8 well on July 30 and a Frances No. 3 well on Aug. 28.

The 2014 program also called for recompleting the Falls Creek No. 3 well, bringing Paxton No. 1 back online or converting it to produce from the Beluga pool and evaluating the GO-7 well with an eye toward converting it to produce from the Beluga pool.

Averaging monthly production, Ninilchik produced some 37.1 mmcf per day in July 2014. Cumulatively, the unit produced 157 bcf through July 2014.

Deep Creek

The Deep Creek and Nikolaevsk units are in the southern Kenai Peninsula.

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 million cubic feet per day and drilled some 13 wells between 2003 and 2009. The early exploration work suggested additional accumulations at the unit. 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.

Since taking over the unit in early 2012, Hilcorp has made Deep Creek one of its early priorities. In 2013, the company drilled the Happy Valley B-14, Happy Valley B-15 and Happy Valley B-16 wells from the existing B pad. The first wells two tested formations above the existing production at the unit, but Hilcorp was unable to reach the target depth of 5,560 feet with the B-16 well and planned to sidetrack the well at the end of this year.

Hilcorp acquired some 47 square miles of 3-D seismic in early 2013. The survey suggested the resources at Happy Valley were "probably three to four times larger than the current participating area," Hilcorp's John Barnes told the Anchorage Energy Task Force in June 2013. The company also improved facilities to "expand and optimize production," as the company told state officials in a March 2014 development plan.

The 2013 drilling campaign convinced the state to defer a pending contraction of the unit until November 2014. Given the exploration work to date, Hilcorp has asked the state to defer the contraction again, this time through the end of 2015. Hilcorp said the expansion would give the company time to complete exploration work and, based on the results of that work, potentially expand the unit or establish additional participating areas.

In August 2014, Hilcorp proposed a four-well development

Drilling in the Swanson River field.

HILCORP ENERGY

program from a to-be-constructed C pad. The program called for drilling the 6,000-foot HVC-17 in the fourth quarter and the 5,000-foot HVC-18 in the first quarter of 2015 to target the Sterling and Beluga formations outside the Happy Valley participating area, and drilling the HVC-19 and HVC-20 wells "in 2015 or later," according to Hilcorp. The company has also proposed a Middle Happy Valley No. 1 exploration well further to the south in 2015.

Hilcorp also planned to work over four wells this year: adding perforations to HVB-12, stimulating the Beluga perforations in HVB-13, running a velocity string in HVB-14 and performing various work on HVA-7. The work was planned for the first three quarters.

Averaging monthly production, Deep Creek produced 8.6 million cubic feet per day in July 2014. Cumulatively, the unit produced 26.5 bcf through July 2014.

Nikolaevsk

Unocal discovered gas from a well at the Red pad at the Nikolaevsk unit in 2004 but never developed the field because of its distance from the 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 conditions and infrastructure limitations.

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

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

Hilcorp brought the field online from the Red No. 1 in December 2012 at 5 mmcf per day. Cumulatively, Nikolaevsk produced some 605 million cubic feet through July 2014.

The well produced 2.5 mmcf per day at the start of 2013. Hilcorp suspended production from April to October 2013 because of seasonal demand restrictions. Production had fallen to

continued on next page

HILCORP *continued from page 75*

796 thousand cubic feet per day by the end of the year. Hilcorp installed extra compression in early 2014 to support a depleted reservoir.

Last year, Hilcorp told the state it was evaluating whether maintenance activities at Red No. 2 could make the well productive. Those activities did not occur in 2013. In a current plan of development running through May 2015, Hilcorp said it anticipates performing the work during this development year. The well work would stimulate open perforations in the Tyonek formation "in an attempt to establish commercial gas production."

Averaging monthly production, Nikolaevsk produced 477 thousand cubic feet per day in July 2014. Cumulatively, the unit produced 605 million cubic feet through July 2014.

The Kenai unit

Hilcorp operates three units near the city of Kenai: Kenai, Cannery Loop and Sterling.

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

Union Oil Company of California and Ohio Oil Co. discovered the onshore field in 1959, a few years after a major oil discovery at the Swanson River unit to the northeast. In Cook Inlet, those companies eventually became Chevron and Marathon, respectively.

They brought the field online in 1961 with a pipeline into Anchorage and later delivered surplus volumes to the Swanson River unit for enhanced oil recovery, to the Kenai liquefied natural gas terminal for export and to the Agrium fertilizer plant in Nikiski.

Through early February 2014, work at the unit was proceeding under an existing plan of development filed by pervious operator Marathon Oil. The U.S. Bureau of Land Management was unable to provide a current plan of development for the current year.

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.

According to AOGCC records, Hilcorp drilled three development wells at Kenai in 2014, through September: Kenai Beluga Unit 43-07Y in May and the Kenai Beluga Unit 11-08Z and Kenai Beluga Unit 23-05 in July. The company also permitted at least three other development wells: Kenai Beluga Unit 32-08, Kenai Beluga Unit 22-32 and the Kenai Deep Unit 10. All six wells are targeting either the Tyonek formation, the upper Tyonek Beluga formation, or, in the case of some wells, both formations simultaneously.

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. A renewed development program starting in 2000 lifted production to 28.5 bcf in 2003, according to the state. Production was down to 11.4 bcf by 2012, according to Marathon.

Averaging monthly production, Kenai produced 54.5 mmcf per day in July 2014. Cumulatively, the unit produced some 2.4 trillion cubic feet through July 2014.

Cannery Loop and Sterling

The Cannery Loop unit is just north of Kenai.

While initially a gas producing field, Cannery Loop currently plays a more important regional function as the home of the Cook Inlet Natural Gas Storage Alaska Inc. facility, also called CINGSA. The storage operation uses the depleted Sterling C reservoir.

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

Those oil-bearing formations flowed small amounts of oil during a 1987 test well, according to Hilcorp, but the zones have "large amounts of risk associated with reservoir productivity" and the well was "under evaluation" in a March 2014 plan of development.

Hilcorp did not drill at Cannery Loop in 2013 and only worked over one well, the CLU 8 into the Beluga. The goal was to test a previously unidentified gas interval, but the well flowed more water than gas. "The well is online at a lower rate," according to Hilcorp.

The 2014 plan of development did not include drilling or well work, although Hilcorp planned to install compression on at least one well and expand infrastructure capacity.

Averaging monthly production, Cannery Loop produced 10.2 mmcf per day in July 2014. Cumulatively, the unit produced 190 bcf through July 2014.

To the east of Cannery Loop is the Sterling unit.

The unit dates to Unocal exploration from the early 1960s. Production has been small-scale and sporadic over the decades, with intervals and reservoirs shut-in at times.

Cumulatively, the Sterling unit produced nearly 14.4 bcf through July 2014.

SUBHEAD: Beaver Creek, Wolf Lake and West Fork

Due north of Sterling is the Beaver Creek unit and the Wolf Lake and West Fork fields.

Marathon discovered gas producing intervals in the Beluga, Sterling and Tyonek formations at Beaver Creek in 1967 and oil pool in 1972. Gas production peaked in 1986 at 17.7 bcf per year and oil production peaked in 1973 at 416,000 barrels per year.

Averaging monthly production, the Beaver Creek unit produced nearly 19 mmcf per day in July 2014. Cumulatively, the unit produced more than 216 bcf through July 2014.

The BLM was unable to provide a plan of development for the current year of

> *Hilcorp planned a major workover campaign for the McArthur River field this year, including five wells with the Moncla 404 Rig at the King Salmon platform, seven wells with the MAK No. 1 rig from the Dolly Varden platform, two wells with Rig 428 at the Steelhead platform and five wells with the Moncla 301 Rig at the Grayling platform.*

work at Beaver Creek. Earlier this year, Hilcorp told the AOGCC that it planned to drill eight wells or sidetrack and perform six well workovers at the unit within the next few years.

In March 2014, Hilcorp completed the Beaver Creek Unit 14A gas production well into the Beluga and the Beaver Creek Unit 1B gas production well into the Tyonek.

This year, through the end of September, Hilcorp applied for permits to drill at least seven additional gas production wells into the Beluga formation at Beaver Creek.

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

The West Fork field dates to exploration from 1960, but has produced sporadically through the years. As of July 2014, cumulative production was nearly 6 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 2014, cumulative production was some 822 mmcf.

Swanson River and Birch Hill

To the north of Beaver Creek are the Swanson River and Birch Hill units.

Richfield Oil Corp. discovered the Swanson River oil field in April 1957. It was the first significant oil discovery in the state and helped Alaska justify its bid for statehood.

Oil production at Swanson River 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. The field was only producing some 300 bpd by the time Hilcorp took over as operator.

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

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

Averaging monthly production, the Swanson River unit produced some 2,200 bpd in July 2014. Cumulatively, the unit produced nearly 232 million barrels through July 2014.

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

Between January 2012 and September 2013, Hilcorp permitted at least 10 wells at the unit and drilled at least eight, completing the latest in September 2013, according to the AOGCC. By late 2013, Swanson River oil production had risen to some 2,500 bpd.

The BLM was unable to provide a plan of development for the current year of work at Swanson River. This year, through September, Hilcorp drilled two oil wells and permitted two more oil wells, all within the first half of the year, according the AOGCC.

Work to date at Swanson River has focused on increasing oil production. But in August 2014, the BLM posted a notice of staking by Hilcorp for a proposed gas production well at the unit — SRU 41B-33. Staking notices show where a company is interesting in drilling. Hilcorp must get an actual drilling permit before it could proceed with the well.

The Birch Hill unit is north of Swanson River.

ARCO Alaska Inc. discovered the Birch Hill field in 1965 and produced some 65 million cubic feet in that initial year. The field has been offline ever since. The BLM was unable to provide a plan of development for the current year of activities at Birch Hill, but Hilcorp had not permitted any new wells at the unit through September 2014, according to the AOGCC.

Contact Eric Lidji at ericlidji@mac.com

Deal with BP brings Hilcorp to the North Slope

If the sale closes by yearend as expected, Hilcorp the operator of Milne Point, Northstar and Duck Island

By ERIC LIDJI

For Petroleum News

By the time The Producers went to print, Hilcorp Alaska LLC had yet to close on its acquisition of four North Slope properties operated by BP Exploration (Alaska) Inc.

Assuming the sale goes through, the privately held Texas-based independent would become the operator and majority working interest owner of the Endicott and Northstar fields, the operator and 50 percent working interest owner of the Milne Point unit.

The deal would also make Hilcorp a 50 percent working interest owner of the offshore Liberty field. Liberty is undeveloped and the companies are preparing a new plan.

The deal would also make Hilcorp a major transportation company on the North Slope.

In June 2014, the local BP pipeline subsidiary asked the Regulatory Commission of Alaska for permission to transfer all or some of its interest in the Northstar Oil Pipeline, the Northstar Gas Pipeline, the Milne Point Oil Pipeline, the Milne Point Natural Gas Liquids Pipeline and the Endicott Pipeline to the Hilcorp subsidiary Harvest Alaska LLC.

The current development plans for Milne Point, Endicott and Northstar reflect BP's visions for the fields. After Hilcorp acquired the Cook Inlet assets of Marathon Oil Co. and Union Oil Company of California in 2011 and 2012, the company dramatically accelerated exploration and development activities in a bid to increase production.

It's safe to assume Hilcorp is planning a similar strategy for its pending Arctic portfolio.

The Milne Point unit

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

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

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

Cumulatively, the unit produced 319 million barrels of oil through September 2014.

After Hilcorp acquired the Cook Inlet assets of Marathon Oil Co. and Union Oil Company of California in 2011 and 2012, the company dramatically accelerated exploration and development activities in a bid to increase production. It's safe to assume Hilcorp is planning a similar strategy for its pending Arctic portfolio.

To improve production, BP ran three trials of its BrightWater technology at the Milne Kuparuk oil pool in recent years, but "results are inconclusive at this time," the company said in 2013.

BP commissioned a seismic program in late 2012 covering some 90 square miles. The program was designed to collect information about the offshore and nearshore potential of the Milne Kuparuk reservoir. BP processed the survey in 2013 and began interpreting the results this year to determine what development opportunities might exist for the future.

Earlier this year, BP conducted significant drilling operations into the Milne Kuparuk, the first development program in more than five years, according to the company. Speaking to the Anchorage Chamber of Commerce in February 2014, BP Exploration (Alaska) President Janet Weiss announced plans for a seven-well coiled tubing drilling program this year.

Through May 2014, BP drilled 14 penetrations this year, according to Alaska Oil and Gas Conservation Commission records. Well names suggest BP drilled three multilateral sidetracks and corresponding service wells at F Pad and a service well at nearby L Pad.

Milne Point: Sag River

BP acquired Milne Point for the lighter oil reserves in the Kuparuk formation, but the future of the unit is with heavier oil in the Sag River, Schrader Bluff and Ugnu.

Conoco tested the Sag River formation at Milne Point as early as 1980 and BP brought the field into production in 1995. Despite occasional spikes through the years, average annual production has generally been less than 700 bpd. Sag River is deepest producing interval at Milne Point, and therefore the oil is lighter than at Schrader Bluff and Ugnu. But high gas-to-oil ratios and poor pump performance have challenged production.

"Sag River faces both technical and economic challenges. But we've made progress toward overcoming some of these challenges," Weiss said in February 2014.

Prior to the sale to Hilcorp, BP had plans to undertake a 15-well program at Sag River in 2015 and 2016, according to Weiss. If the initial program is successful, Weiss said, BP could potentially drill as many as 200 wells, accessing some 200 million barrels of resources with full development.

Milne Point: Schrader Bluff

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

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

Using horizontal drilling, jet pumps and waterflooding to counteract the viscous oil and sandy formation, BP pushed Schrader Bluff production to 23,922 bpd by October 2003.

In late 2011, BP ran two BrightWater treatments in the Schrader Bluff, but the "wells have not showed a noticeable increase in oil production," the company said in 2013.

Last year, BP planned to drill four Schrader Bluff infill wells — one producer and three injectors — that the company had originally planned for 2012. But BP ultimately deferred the program until 2016 "to allow additional planning time due to concerns over reservoir pressure in existing injector wells near the planned targets and complications in defining the completion design," the company wrote in its plan of development for 2014.

Weiss also announced a $1 billion to $2 billion program to develop some 80 million barrels of viscous oil in the Northwest Schrader area. "We are moving forward with some important trials over the next few years to ensure we have an economic project," she said.

Weiss announced the proposed Sag River and Schrader Bluff programs before BP announced its pending sale of Milne Point to Hilcorp. If the sale goes through, the future of the two development programs would depend in part of Hilcorp's idea for the unit.

Milne Point: Ugnu

Ugnu — a 20 billion-barrel reservoir overlying portions of the Prudhoe Bay, Kuparuk River and Milne Point fields — is an even more challenging field than Schrader Bluff.

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

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

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

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

The Duck Island unit

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

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

Oil production peaked at some 118,000 bpd in the early 1990s.

Cumulatively, the unit produced 478 million barrels of oil through September 2014. The unit currently produces about 7,000 barrels of oil per day, according to the AOGCC.

Today, the Duck Island unit includes the Endicott oil field, the Eider and Sag River North participating areas at the northern end of the unit and the Minke tract at ADL 34633.

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

The plan was to use LoSal enhanced oil recovery program now and a carbon dioxide enhanced oil recovery program once gas sales began. "We've rebuilt our reservoir models and have developed a comprehensive depletion plan for Endicott," Alaska Consolidated Team Resource Manager John Denis told Petroleum News in early 2009. "We're into the fourth year of a program to stabilize and improve the reliability of our facilities and wellstock, we have brought (the safety and integrity Operations Management System) to Endicott, and we have a robust program under way to renew our facilities. With the development of new technologies like LoSal and production from the new Liberty field, we're looking ahead to a very bright future for Endicott."

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

The Duck Island unit is currently in a lull. BP drilled no wells or sidetracks at the unit in 2013 and performed only three workovers, all at the Endicott participating area.

Similarly, BP has no definitive drilling or workover plans at the unit through July 2015.

For a time, BP planned to use the Endicott facilities to develop the offshore Liberty field through state-of-the-art ultra-extended reaching wells, but those plans are expected to change when BP and Hilcorp announce their plans for Liberty later in the year.

The Northstar unit

Shell Western E&P Inc. discovered Northstar in 1984.

BP brought the offshore field online in November 2001 after constructing a five-acre gravel island and a subsea pipeline connecting back to shore rather than a causeway.

The state-federal Northstar unit primarily produces from the Ivishak and the Shublik formations, but BP has recently been developing the Fido and Kuparuk reservoirs.

Cumulatively, the unit produced 161.6 million barrels of oil

continued on next page

HILCORP NORTH SLOPE *continued from page 79*

through September 2014 and production has been in the range of 8,000 to nearly 11,000 barrels per day this year.

The current development program involves injecting gas into the Ivishak formation to improve reservoir pressure for enhanced oil recovery, and BP said it might convert one or more production wells at the unit into injection wells to aid with that ongoing effort.

Currently, Northstar uses some imported gas from the Prudhoe Bay unit for fuel and for injection. But BP said that it has been testing the possibility of using Northstar gas as a fuel source, which could mean reducing or eliminating Prudhoe imports in the future.

Earlier this year, BP and its minority partner Murphy Exploration (Alaska) Inc. asked state and federal regulators to expand Northstar to include some 454.62 acres from two state of Alaska leases — ADL 312798 and ADL 312808 along the southern border.

The addition would expand Northstar to include their desired boundaries for a proposed Hooligan participating area, which would cover the Kuparuk reservoir at the unit.

BP requested the Hooligan participating area in late June 2012 and provided additional information to regulators in February and April 2013. The U.S. Bureau of Safety and Environmental Enforcement approved the participating area in February 2014. The Alaska Department of Natural Resource had yet to rule on the request by September.

With the expansion, the Northstar unit would cover a total of 20,134.70 acres.

The Alaska Department of Natural Resources is taking comments through Sept. 22.

To improve production, BP ran three trials of its BrightWater technology at the Milne Kuparuk oil pool in recent years, but "results are inconclusive at this time," the company said in 2013.

When state and federal regulators approved the Northstar unit in January 1990 and the Northstar participating area in October 2001, the agreement included a provision requiring any acreage outside the participating area to contract after 10 years.

By forming the Fido participating area around federal lease OCS-Y-0181, BP was able to reduce the extent of the contraction in the northeast of the unit. But regulators contracted portions of ADL 312798, ADL 312808 and ADL 312809 along the southern border.

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

With approval of the Hooligan participating area, BP said it would continue to test the Kuparuk formation at Northstar through its current development plan, into 2015.

Contact Eric Lidji at ericlidji@mac.com

Miller expanding across Cook Inlet and North Slope

The tiny independent is set to become one of three companies with producing assets in both basins

By ERIC LIDJI
For Petroleum News

NAME OF COMPANY:
Miller Energy Resources
COMPANY HEADQUARTERS:
9721 Cogdill Road, Ste. 302, Knoxville, TN 37932
TOP EXECUTIVE: Scott M. Boruff, executive chairman and board of directors
PHONE: 865-223-6575
COMPANY WEBSITE: www.millerenergyresources.com

NEWS FLASH

EDITOR'S NOTE: As The Producers went to press, Miller Energy was attempting to buy Buccaneer Energy's Alaska assets.

Miller Energy Resources Ltd. was bullish about Alaska when it arrived in the state in 2009, but the Tennessee-based independent became far more bullish over this past year.

The Tennessee independent is the parent company of Cook Inlet Energy, which operates a series of fields and facilities on the west side of Cook Inlet and several exploration licenses and leases in the Susitna basin. Toward the end of 2013, Cook Inlet Energy acquired the North Fork unit from Armstrong Cook Inlet LLC for nearly $65 million.


SCOTT BORUFF

Then, in May 2014, Miller acquired Savant Alaska LLC for some $9 million. The small Alaska independent Savant operates the Badami unit on the eastern North Slope. Miller had initially said it hoped to close the deal by August 2014 but later pushed the deadline to November 2014 and then to December 2014, after The Producers went to print.

And in September 2014, Miller signed a non-binding letter of intent to buy the Alaska assets of Buccaneer Energy Ltd., which filed for bankruptcy protection earlier in the year. That proposition also reached its resolution after The Producers went to print. (For more information about those assets, see the profile on Buccaneer Energy Ltd.)

If completed, the acquisitions would make tiny Miller Energy and its subsidiaries one of only three companies — alongside ConocoPhillips and Hilcorp (whose North Slope deal is also pending) — to operate production on both of Alaska's major basins. As it stands, the opportunities in Alaska have convinced Miller to sell its remaining Tennessee assets.

"While we still believe Tennessee has significant growth potential, our capital is clearly better allocated to our Alaskan operations and the investment opportunities that exist there," former Chief Executive Officer Scott Boruff said in a statement in June 2014.

In August 2014, a third party report from Ryder Scott Co. estimated that Miller had 11.7 million barrels of proved developed and undeveloped oil reserves at its Alaska properties, up from a previous estimate of 10.5 million barrels. Currently, Miller is producing some 2,500 net barrels of oil equivalent per day from the West McArthur River and Redoubt units and some 7.4 million net cubic feet of natural gas per day from the North Fork unit, with an estimated 600 net barrels of oil equivalent per day from the Badami unit.

As of September 2014, Cook Inlet Energy owned some 300,388 acres of state leases, which does not include approximately 25,000 acres of state leases owned by Savant.

In September 2014, Miller Energy announced that Carl F. Giesler Jr. would take over as chief executive officer of the company, a position previously held by Scott Boruff.

While Miller currently operates production in Cook Inlet, the company is primarily funding its expansive drilling program through several large credit facilities. The company has noted that its cost of capital has decreased over the past three years.

Pacific Assets: WMRU

Through Cook Inlet Energy, Miller arrived in Alaska in late 2009 when it acquired several Pacific Energy Resources Ltd. assets for $2.25 million in bankruptcy proceedings.

The assets included 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.

Miller Energy now collectively calls those properties its "Pacific Assets."

When Cook Inlet Energy acquired the properties, the company presented a strategy of repairing existing wells in the short term and drilling new wells over the long-term.

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

In July 2010, Cook Inlet Energy returned the shut-in Kustatan field KF-1 well to production at 70,000 cubic feet per day, which the company used for fuel operations.

continued on next page

MILLER ENERGY *continued from page 81*

Those maintenance initiatives significantly increased oil production at West McArthur River, but Cook Inlet Energy aspired to drill as many as five new wells at the unit, which the company said would have the potential to increase production by some 2,000 bpd.

Cook Inlet Energy has drilled two wells at the unit this year.

The 15,535-foot WMRU-8 well had a primary target in the Hemlock and a secondary target in the pre-tertiary Jurassic oil zone, which some geologists consider to be the source rock for Hemlock and West Foreland oil reservoirs across the Cook Inlet region.

The 14,470-foot measured depth WMRU-2B sidetrack from the non-producing WMRU-2A wellbore came online in June 2014 at an initial rate of 630 barrels of oil equivalent per day, which was "substantially above what we originally anticipated," Hall said.

Cook Inlet Energy is also expanding West McArthur River through exploration work.

Over the latter half of 2013, Cook Inlet Energy drilled the 18,475-foot Sword No. 1 exploration well directionally from land near the unit to a bottom-hole target beneath the inlet. Between November 2013 and June 2014, the well had produced some 116,000 barrels of oil, according to the company. The Alaska Oil and Gas Conservation Commission allowed the company to comingle production from three zones, which the company said would increase flow rates and thus improve the economics of the well.

The results have prompted the company to plan a Sword No. 2 well.

This fall, Cook Inlet Energy hopes to repeat its success with Sword by exploring the nearby Sabre prospect from the existing West McArthur River unit pad. The company sees the potential for a follow up next year and a six-well development program.

Miller wants to drill a second Sabre well this fiscal year and three more next year. As of September, Miller was "evaluating joint venture offers for participation in the project."

A $35 million program (after credits) for fiscal year 2015 includes the Sabre No. 1 well, a WF-3 well at West Foreland and a sidetrack of the WMRU-8 well drilled this year.

Pacific Assets: Redoubt

The Redoubt unit and its associated Osprey platform were offline in 2009.

Cook Inlet Energy brought the platform online in mid-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. The company later shut-in RU-1 because of an equipment problem, but the RU-7 well continued to produce some 230 boe per day.

As with West McArthur River, Cook Inlet Energy launched a program to repair existing wells and drill new wells. The company announced plans to drill four sidetracks off existing damaged wells, which it expected would produce some 2,000 bpd. The company also saw the possibility to drill 13 new wells from the platform, with proper investment.

Using its newly purchased Rig 35, Cook Inlet Energy worked over RU-1 in August 2012, removing some 31,000 pounds of junk from the wellbore to bring the well back online at an initial pro-

continued on page 84


THE TEAM THAT DELIVERS
Safety Health Environment Quality
AFC
Alaska Frontier Constructors, INC.
(907) 562-5303 | akfrontier.com

duction rate of 482 bpd. In late 2012 and early 2013, the company worked over RU-3 and RU-4A, a pair of natural gas wells needed for operational fuel. RU-3 faced some complications, but RU-4A tested at a peak rate of 1.7 million cubic feet per day, which allowed Cook Inlet Energy to suspend some $500,000 in monthly third-party fuel deliveries. By early summer, the company was selling excess gas into the market.

Last summer, in June 2013, 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 barrels per day. In August, the company brought the RU-1A sidetrack online at an initial production rate of 700 bpd. The company also sidetracked the RU-5 well later that year.

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

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

The remaining inventory for fiscal year 2015 — a $75 million program (after credits) — calls for drilling the RU-12 to target a northern block and sidetracking RU-3 and RU-4.

The company is also considering four additional wells at the Redoubt unit in fiscal year 2016: RU-8, RU-13, RU-14 and RU-15, all of which would test additional oil targets.

The wells are targeting four new fault blocks. A series of "positive" drill stem tests from the 1960s confirmed the north and south blocks, RU-1 tested the central fault in 2001 at an initial rate of 1,089 barrels per day and RU-2 tested the central fault in 2002 at an initial rate of 1,954 barrels per day, according to the company. Cook Inlet Energy believes the step-out program could "significantly increase proved reserves."

Trans-Foreland Pipeline

As an oil producer on the west side of Cook Inlet, Miller is well aware of its distance from local markets and also its proximity to the Redoubt volcano, which shut down oil production and distribution for months with a series of eruptions in 2009. That's why, in 2012, the company began toying with the idea of a pipeline across the Cook Inlet.

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

After agreeing to fund some early design work, Tesoro took over the project in late October 2013 by forming the wholly owned subsidiary Trans-Foreland Pipeline Co. LLC.

A deal gave Tesoro sole rights to pursue the project through the end of 2015, at which point Cook Inlet Energy would have the option to reacquire its interest for a set sum.

Construction is expected to begin next year.

North Fork

Standard Oil of California discovered the North Fork field in 1965 while searching for oil. But the value of gas and the distance from Anchorage made the field uneconomic.

A string of companies attempted to develop the field starting in the late 1990s, but none succeeded until a subsidiary of Armstrong Oil and Gas LLC acquired the property.

With four partners, Armstrong drilled the North Fork 34-26 well in June 2008.

"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," Armstrong Vice President of Land and Business Development Ed Kerr told Petroleum News in September 2008.

Kerr publically estimated that North Fork contained between 7.5 billion and 12.5 billion cubic feet of gas reserves, with the "realistic" possibility of reserves as high as 20 billion to 60 billion cubic feet. But Kerr also said that the company would need to negotiate a price between $7 and $10 per thousand cubic feet to make the prospect economic.

Enstar Natural Gas Co. agreed to favorable terms in return for drilling commitments.

In mid-2010, Armstrong re-entered the original NFU No. 41-35 well, drilled the 11,700-foot NFU No. 14-25 directional well and drilled the 12,070-foot NFU No. 32-35 directional well. Armstrong brought the North Fork unit online in late March 2011.

In late 2012 and early 2013, Armstrong drilled the NFU No. 22-35 and NFU No. 23-25 wells. Under a 48th Plan of Development in place for 2013, Armstrong tested NFU No. 23-25 and NFU No. 22-35 and continued to monitor its existing production wells.

With North Fork, Cook Inlet Energy acquired six wells and 15,465 acres, the associated transmission subsidiary Anchor Point Energy LLC and the existing contract with Enstar.

Since the sale closed, in February 2014, Miller Energy acquired the Glacier No. 1 drilling rig (now called Rig 37) for some $7 million and dispatched the carrier-mounted land rig to North Fork. With existing wells "currently choked back," the company said that it was able to immediately increase production in the short-term. The 7.4 million cubic feet per day of net gas production in late August 2014 did not count supplies used from fuel gas.

While Cook Inlet Energy has already performed some early well work at North Fork, the company intends to pursue a more robust program starting this winter. In June 2014, the company said it was planning to work over two existing wells and drill two new wells.

Actual workloads depend on various factors, but Cook Inlet Energy's inventory for fiscal year 2015 calls for working over the existing NFU 14-25 and NFU 32-35 wells, sidetracking the existing NFU 23-25 well and drilling the new NFU-07 and NFU 32-35 wells to target additional gas production from the field. The drilling inventory for fiscal year 2016 calls for drilling three new natural gas wells: NFU-08, NFU-09 and NFU-10.

The current year program is expected to cost some $15 million, after credits.

The long-term plans are more intriguing.

At the time of the sale, Cook Inlet Energy said it saw the potential to drill as many as 24 additional wells at the unit. While many of those would expand gas production at North Fork, the company also sees the potential for oil development and claims to have had "encouraging preliminary results" from an evaluation of the oil potential in the deeper Hemlock formation at the field, conducted while working over an existing gas well.

The original NFU No. 41-35 well tested minor amounts of oil in the Hemlock but not enough to convince Socal to develop the reservoir. Armstrong came up empty-handed when it extended one of its natural gas wells to test the oil potential of the Hemlock.

Badami history

The Badami unit has long been one of the most intriguing fields on the North Slope.

Conoco Inc. discovered the Badami oil pool in 1990 with the Badami No. 1 well. BP Exploration (Alaska) Inc. brought the field online in August 1998. But oil production peaked a month later at 7,450 barrels per day. By January 1999, production had fallen to 3,300 bpd and BP shut-in the field through May 1999 to upgrade facilities. The field produced nearly 5,300 bpd in July 1999 but production was down 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 September 2005 and production was averaging 1,785 bpd by October. But production fell to 1,437 bpd by December 2005 and some 876 bpd by August 2007, when BP again suspended operations to allow the field to recharge.

The Colorado-based independent Savant Resources LLC came to Alaska in 2006 and drilled the Kupcake No. 1 exploration well from an ice island in Foggy Island Bay, some 20-miles west of Badami, in early 2008. The target interval in the Kemik formation "was thinner than anticipated" and the porous Cretaceous sandstone proved to be "water wet," according to a partner on the program, but Savant gained crucial Arctic experience.

In mid-2008, local affiliate Savant Alaska and ASRC Exploration LLC agreed to take on the challenge of restarting Badami in return for a stake in the unit. In early 2012, after years of development work, the partners acquired the field outright and Savant became the newest and smallest operator on the North Slope. In early 2014, BP sold the Badami pipeline system to Nutaaq Pipeline LLC, a partnership of Savant and Arctic Slope Regional Corp.

Given its current status as the easternmost producing field on the North Slope, the Badami unit will provide a crucial link between the Point Thomson unit and the existing North Slope infrastructure once ExxonMobil brings the easterly field into production. Nutaaq Pipeline recently sought a rate increase on its pipelines to better cover costs.

The current program at Badami has been a combination of exploration, development and maintenance work, all of which Miller Energy said it intends to continue and expand.

In early 2010, Savant drilled two Badami penetrations.

The first was B1-18A, a sidetrack of the B1-18 well that BP drilled in 1998. Savant drilled the sidetrack to test whether horizontal drilling techniques could improve production rates from the notoriously complex geology at the field, a series of turbidite sandstones deposited in channels with minimal communication from one to another.

The second was B1-38, an exploration well into the Red Wolf prospect, an interval beneath the Brookian formation, where BP had previously focused development drilling.

The exploration well encountered oil in two horizons.

The first was the Kekiktuk formation, which also contains the oil reservoir for the nearby Endicott unit. In early 2012, Savant targeted the Kekiktuk again with the Red Wolf No. 2 exploration well. The target zone was wet, though, and Savant suspended its pursuit of Red Wolf and transferred the deep zones at those leases to a consortium of independents.

The second horizon was in the shallower late Cretaceous Killian sands, which Savant used to restart sustained oil production from the Badami unit in November 2010.

> *"While we still believe Tennessee has significant growth potential, our capital is clearly better allocated to our Alaskan operations and the investment opportunities that exist there." —former Miller CEO Scott Boruff*

Work since has been primarily maintenance.

Using a conventional rig and an electric submersible pump, Savant added some 54,259 barrels of oil production from the B1-16 well between May 2012 and March 2013. The oil "would not have otherwise been produced" without the work, the company said.

Savant also restored integrity to the B1-28 well by repairing a tubing leak and said that it was planning additional repairs intended to bring the well back into regular production.

The current plan of development for Badami, active through November 2014, also called for Savant to hydraulically fracture the B1-18A sidetrack and the B1-38 well. The work at B1-18A would gauge the economics of hydraulic fracturing at horizontal wells in the Brookian formation at Badami. The work at B1-38 would do the same for the deeper Killian sands, while also gauging the size of the reservoir. The information would underpin an application for a participating area for the Killian sands, Savant has said.

Savant reported oil production averaging some 1,020 bpd through the first six months of 2011 and subsequently topping 1,300 bpd by July 2013. But production is currently around 1,100 bpd from eight wells, according to Miller Energy and AOGCC figures.

Miller's plans

When it acquired Savant, Miller Energy said it intended to "significantly enhance the value" of the assets it was acquiring — both producing assets and exploration properties.

The sale would give Miller a 67.5 percent interest in the Badami unit, 100 percent interest in surrounding exploration leases and a stake in the various Badami unit infrastructures.

"The acquisition of Savant will significantly expand Miller Energy's Alaskan asset ownership, complementing our existing Cook Inlet operations and providing us with additional wellbore diversification," Boruff said at the time. "This transaction increases our profile in the Alaskan oil and gas community, and gives us a credible foothold in the world-class North Slope resource play, including existing production, a developmental runway and substantial mid-stream assets. By utilizing our combined team's expertise and experience, we expect to significantly enhance the value of these assets. This transaction is another example of our ability to identify and acquire assets with substantial upside that Miller can unlock, providing a clear path to increased shareholder value."

Miller's initial plans call for sidetracking the existing B1-14 and B1-28 wells at the unit, at a cost of some $15 million each, according to Miller. The company has estimated that the two wells contain some 2 million barrels of recoverable oil reserves between them.

The fiscal year 2015 program is estimated at $25 million after credits.

Contact Eric Lidji at ericlidji@mac.com

North Slope Borough remains a stable producer

A recent development program has given the small community plenty of breathing room in summer and winter

By ERIC LIDJI
For Petroleum News

While much of rural Alaska copes with the high cost of diesel fuel, the city of Barrow is powered by three nearby natural gas fields: South Barrow, East Barrow and Walakpa.

That gas has drastically changed life in the North Slope Borough's largest city.

"I remember when we first got it my father ordered a brand new stove. The stoves we had were meant for diesel. He bought a gas range and a new heating stove. It was wonderful I didn't have to cut wood anymore or get sacks of coal from next door at the store," state Rep. Ben Nageak told Petroleum News in March 2014. "We kept warm 24 hours a day. It's a long ways from when I grew up. The heat would go out and we would be cold."

Through July 2014, the three fields had produced nearly 60 billion cubic feet of natural gas cumulatively, according to figures from the Alaska Oil and Gas Conservation Commission. The fields were producing at a summer rate of 2.8 million cubic feet per day in July 2014 and a winter rate of 5.4 million cubic feet per day in January 2014.

NAME OF COMPANY:
North Slope Borough
COMPANY HEADQUARTERS:
P.O. Box 69 Barrow, Alaska 99723
TELEPHONE:
907-852-2611
TOP ALASKA EXECUTIVE:
Mayor Charlotte Brower

CHARLOTTE BROWER

South Barrow

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 drilling continued for decades, with 13 wells drilled through 1987 and one subsequently deepened, according to the AOGCC. Production peaked at some 3.5 million cubic feet per day in November 1981.

Cumulatively, the field produced some 23.7 billion cubic feet of gas through July 2014, according to the AOGCC. Originally, the field was expected to produce some 32 bcf.

South Barrow is used to meet demand during peak winter months and suspended in summer. The field produced some 172 thousand cubic feet per day in January 2014.

East Barrow

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

The field produced nearly 380 thousand cubic feet per day in January 2014 and nearly 200 thousand cubic feet per day in July 2014. Cumulatively, the field had produced nearly 9 bcf through July 2014, surpassing the original estimate of 6.2 bcf of gas in place.

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

Walakpa

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

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

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

Cumulatively, the Walakpa field had produced some 26.3 bcf through July 2014, according to the AOGCC. The field is thought to hold some 250 bcf. The field produced nearly 5 mmcf per day in January 2014 and nearly 2.9 mmcf per day in July 2014.

Rejuvenation campaign

Realizing it needed to improve the deliverability of its three fields to meet a forecasted growth in demand, the city of Barrow launched a rejuvenation campaign in recent years.

A pair of voter-approved bond sales allowed the city to launch a $92 million program in 2011. The city drilled the Savik 1 and 2 wells at East Barrow and the Walakpa 11, 12, and 13 wells at Walakpa — the first horizontal drilling campaign at the fields. The city also plugged and abandoned eight depleted wells and upgraded infrastructure.

By improving deliverability, the program gave Barrow the ability to meet its energy needs even during extenuating circumstances such as cold snaps or maintenance; previously, the city had to rely on diesel fuel to meet its energy needs during those times.

Contact Eric Lidji at ericlidji@mac.com