The Explorers

Oil & gas companies investing in Alaska's future

The Explorers, an annual publication from Petroleum News



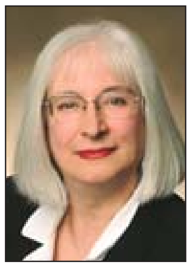

A more accurate picture

BY MARTI REEVE & KAY CASHMAN

Petroleum News special publications
Petroleum News publisher & executive editor

Welcome to The Explorers magazine for 2014, an annual publication put out by Petroleum News (Alaska).

MARTI REEVE



KAY CASHMAN

For the first time this magazine is being released at the end of the major North Slope exploration season versus just before it begins.

The actual well count is in, versus only the planned wells.

So we can offer a more complete picture of an exploration season, but paradoxically it's not necessarily up-to-date. While Eric Lidji was writing this issue's articles several had to be updated because news from the companies, which we track weekly, is coming in very quickly.

For example, Buccaneer filed bankruptcy and Miller bought Savant while he was writing.

Still, with an actual exploration well count, it is a more accurate publication.

Producer elements gone

Another change that contributes to the magazine's accuracy is splitting out the producers — i.e. oil and gas production activities — into a separate annual magazine, The Producers, released in November at the annual Resource Development Council conference.

Some companies are in both The Explorers and The Producers, but there are no more "looking for new oil in old places" features that skewed the exploration picture. Keeping the exploration and production activities separate offers a more accurate representation of the industry in Alaska.

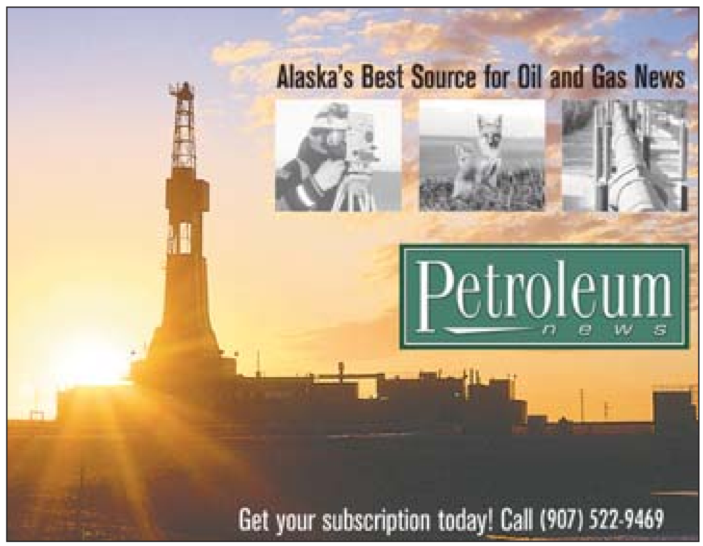
Udelhoven, Lounsbury

Finally, Lounsbury is advertising on this page. The company was the second advertiser to sign an annual contract with Petroleum News (Alaska) back in 1996 when the newspaper was founded.

Udelhoven, our very first contracted advertiser, is also still with us (see page 81).

Both companies were, and are today, strong supporters of the industry.

Special thanks to Udelhoven and Lounsbury — and to all the other advertisers that are part of the magazine. Your support of the industry and Alaska's exploration companies is appreciated.



CONTENTS

The Explorers

Released July 20, 2014

THE EXPLORERS 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

The Explorers

82

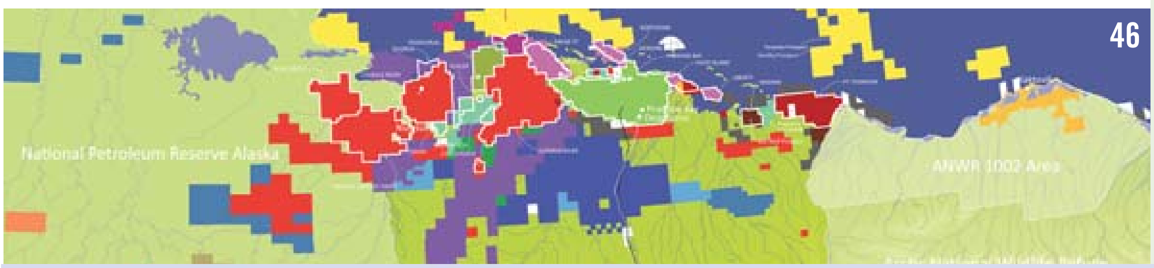
Ad Index

Guest Editorial

Welcome

Maps

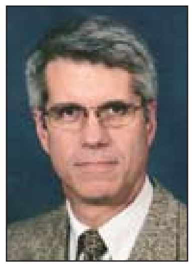
Overview



State sees strong interest in Alaska's oil and gas

By BILL BARRON

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



BILL BARRON

An influx of capital investment reflects a strong and broadening interest in Alaska's oil and gas basins. In Cook Inlet, declining natural gas production and uncertainty over future supplies has now evolved to a state of market-constrained abundance. Companies new to the Inlet apply their skills and novel business approaches to explore leases, expand drilling programs and rework assets to ensure the supply of natural gas to Southcentral Alaska. Similarly, companies new to the North Slope are acquiring leases, building partnerships, expanding exploration and progressing existing projects. Companies including Hilcorp, Apache, Repsol and Linc Energy now have a footprint in Alaska. Other companies, including Furie Alaska, BlueCrest Energy and Caelus Energy are building on resource finds and business opportunities. At the Department of Natural Resources' Division of Oil and Gas, we see positive new activity supporting the state's goals of maintaining a robust oil and gas industry and healthy Alaska economy.

At the Department of Natural Resources' Division of Oil and Gas, we see positive new activity supporting the state's goals of maintaining a robust oil and gas industry and healthy Alaska economy.

New companies capitalizing on Alaska's world-class basins

The abundance of Alaska's oil resources is evidenced by the continuing development of North Slope fields — far beyond the original 9 billion barrel estimate — as well as the development of newer fields. Exploration on the North Slope by players such as Repsol, Linc, Caelus and Nordaq will expand the understanding of the placement, expanse, and structure of conventional resources and

continued on page 10

Exploration licensing program still draws interest

The state currently has four active and three pending licenses for exploration activities in frontier basins

By ERIC LIDJI
For Petroleum News

The vast majority of oil and gas exploration in Alaska occurs through the annual lease sales conducted in prolific basins, but the state also maintains an exploration licensing program through which companies can propose activities for other areas of the state.

The program requires companies to make specific work commitments in return for access to a set area for a pre-determined length of time, usually five, seven or 10 years. Once the license has expired, the state can end it, extend it or convert it into traditional leases.

The state currently has four active licenses and three pending licenses.

In April 2011, the state issued a 10-year license in the Susitna basin to Cook Inlet Energy LLC. The Susitna Basin IV license covers 62,909 acres and requires a $2.25 million work commitment. In April 2012, the state issued a five-year license in the Susitna basin to Cook Inlet Energy. The Susitna Basin V license covers 45,764 acres and requires a $250,000 work commitment. The two areas are directly north and south, respectively, of the former Susitna Basin II license that Cook Inlet Energy partially converted to leases.

The Susitna basin covers a broad swath of land west of the Susitna River between the community of Skwentna and the Parks Highway communities of Willow and Houston.

Healy basin license

In January 2011, the state issued a 10-year license in the Healy basin to Usibelli Coal Mine Inc. The license covers 208,630 acres and requires a $500,000 work commitment. The license stretches east and west of the Parks Highway near Denali National Park, in the region of the Interior where Usibelli maintains its long-running coal operation.

The license only allows Usibelli to explore for natural gas in the license area, although it can search for both conventional reservoirs and unconventional coalbed methane. The company is hoping to find an energy supply to power its coal mining operations, but said it might be able to export supplies into Southcentral if it discovered a large quantity.

The Denali Citizens Council appealed the license, saying it opposed exploration near communities and areas important for the tourism industry. The case ultimately went to the Alaska Supreme Court, which rejected the appeal in a February 2014 decision.

Usibelli first sought an exploration license in the Healy area in 2004, but the request faced considerable local opposition, including drilling restrictions imposed by the Denali Borough. The opposition delayed momentum on the project for years, but the state eventually overturned those restrictions and ruled in favor of Usibelli in June 2010.

Tolsona Lake area license

In December 2013, the state issued a five-year license in the Tolsona Lake area to Ahtna Inc., the Alaska Native corporation for the Glennallen region. The license covers 43,492 acres west of the community of Glennallen and requires a $415,000 work commitment.

The license is in the Copper River basin, where previous exploration companies, most notably the Texas independent Rutter and Wilbanks Corp., have searched for gas.

The three pending licenses are in the Houston-Willow basin, the North Nenana basin and the Southwest Cook Inlet basin. The state has not released the names of those applicants.

Contact Eric Lidji at ericlidji@mac.com

BARRON *continued from page 8*

the potential of unconventional resources on state lands. Seismic work by CGG Lands Inc., SAE Alaska, Global Geophysical Services, and others is expanding the three-dimensional seismic data set to further understand the resource potential across the North Slope.

Strong companies with solid investment plans are making a difference

The expansion of strong companies into new parts of the state reflects broad confidence in the opportunity for success. Beyond the well-established, world-class fields of Prudhoe and Kuparuk, focused exploration and development activities are expanding the oil and gas footprint. ExxonMobil is rapidly developing Point Thomson and has established pipeline connectivity from the North Slope's easternmost Badami field to the western border of the Arctic National Wildlife Refuge (ANWR), with plans to have natural gas liquids (NGL) into the Trans-Alaska Pipeline (TAPS) by 2016. On the North Slope's westernmost boundary, ConocoPhillips is expanding the Alpine and Greater Moose's Tooth units in the NPR-A, furthering the westward expansion of the North Slope infrastructure. Linc Energy is also drilling in the NPR-A, while Repsol is exploring shallow coastal opportunities across the Colville River Delta. Nothing speaks more strongly of the positive outlook for continuing North Slope resource availability than the investment in both eastward and westward infrastructure expansion.

continued on next page

BARRON *continued from page 10*

Sustaining the Trans-Alaska Pipeline and aligning Alaska's LNG (AKLNG) interest

The reworking of existing infrastructure and expansion into new areas is showing promise in stemming the declining flow through TAPS. As the state and industry increase production, throughput in TAPS will follow. As the investment in the North Slope improves our oil and natural gas liquids production, it is important to also recognize the alignment of BP, ConocoPhillips, ExxonMobil and the State of Alaska in moving forward on the Alaska LNG project. This mega-project will bring Alaska's world-class, stranded natural gas resource by pipeline from the North Slope to Cook Inlet for Alaska's domestic markets, as well as liquefaction and export to world markets. The agreement to move forward on this $45-$65 billion project creates great opportunities — both to market our natural gas, and explore for more oil and gas across the North Slope.

Expanding infrastructure and knowledgeable service companies

Increased activity in Cook Inlet and optimism regarding the North Slope provides fresh opportunities for service companies building in oil industry infrastructure, maintaining oil and gas field operations, and applying proven and demonstrating new capabilities.

Successful exploration in Cook Inlet is also continuing to upgrade and expand infrastructure in the Southcentral region. Due to recent jack-up rig work in the Inlet, Furie is planning a new platform in the Kitchen Lights Unit, the first in 50 years, while BlueCrest Energy considers plans for the Cosmopolitan prospect.

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.

Hilcorp's wells are being reworked and new wells drilled both onshore and off. New oil and gas pipelines have been constructed and more are in the works, including the Cook Inlet Gas Gathering System and the lines for the Furie platform.

New horizons for exploration

As explorers look beyond areas of current and increasing production, the Division has an active role in exploration licensing. This program offers exploration licenses outside of established oil and gas leasing boundaries for areas of 10,000-500,000 acres and for up to 10 years, with a specified work commitment. To date, the state has issued four exploration licenses, and is processing three new exploration license applications. Exploration licenses can be noncompetitively converted to leases — with completion of the work commitment — as recently accomplished by Cook Inlet Energy. The licensing of exploration areas also provides an effective way for the state to acquire data on the resources underlying state lands.

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 Alaska.

Apache seeks long-term oil developments in Cook Inlet

The independent is in the early days of an exploration program it believes will unlock great resources

By ERIC LIDJI
For Petroleum News

NAME OF COMPANY: Apache Corp.
COMPANY HEADQUARTERS: Houston, Texas
ALASKA OFFICE: 510 L St., Ste. 310, Anchorage, AK 99501
TOP ALASKA EXECUTIVE: John Hendrix
TELEPHONE: 907-272-2722
COMPANY WEBSITE: www.apachecorp.com

After Apache Corp. representatives attended a state-sponsored conference in Anchorage in early 2010, rumors began swirling in the oil patch about the future of the company.

JUDY PATRICK

JOHN HENDRIX

The Houston-based independent had spent some $10 billion over the previous decade acquiring prospects around the world and was interested in extending the life of mature oil fields. Apache formed a local subsidiary — Apache Alaska Corp. — in May 2010.

The rumors went in many directions.

Escopeta Oil Co. confirmed that Apache made an offer to buy the offshore Kitchen Lights unit in the Cook Inlet, but the offer never led to a deal. At several points during the year, major news outlets reported that BP was in talks to sell the Prudhoe Bay field to Apache as part of a larger divestment campaign. Ultimately, Apache spent $7 billion on BP assets in Canada, Egypt and the Permian basin, but the deal bypassed Alaska. Later in the year, talk emerged that Apache was sniffing around Chevron's Cook Inlet assets, but Chevron ultimately sold its Cook Inlet holdings to the independent company Hilcorp.

Finally, in late July, Apache said that it was acquiring 196,524 acres from Samuel H. Cade, Daniel K. Donkel and three other independent investors. The acreage was scattered across the entire Cook Inlet basin, and included both onshore and offshore tracts.

Apache claimed to be eager to expand its presence in the basin and soon backed up its claim. By October 2011, after dominating numerous lease sales and conducting some private deals, Apache claimed to hold some 800,000 acres across the Cook Inlet basin.

Over the past three years, Apache has lost a smattering of state acreage across its holdings as it relinquished some leases and others reached the end of their primary terms, but the company was the top bidder in the May 2014 Cook Inlet areawide lease sale.

The company primarily used the sale to bolster its existing holdings, Apache Alaska Government Relations Manager Lisa Parker told Petroleum News after the sale.

‘An oil museum’

While cognizant of the natural gas potential of the region, Apache said it came to Cook Inlet to pursue oil potential thought to have been passed over by previous operators.

Specifically, the company cited a U.S. Geological Survey estimating that nearly 1 billion barrels of oil remained in the Cook Inlet basin, waiting to be discovered.

“When you go up there, it’s kind of like going back into time. It’s like an oil museum, is kind of how I’d describe it,” Apache Vice President for Exploration and New Ventures John Bedingfield told analysts at June 2012 event. “It’s interesting, but things have just been frozen for 40-plus years.” To make the claim even more intriguing, Bedingfield added that Apache believed there was as much oil still to be discovered in the basin as has already been produced in the 55 years since the first discovery well in the region.

Following its strategy at the other mature basins — like the western desert of Egypt and the Forties field in the North Sea — Apache planned to start its tenure in Alaska by conduct a broad seismic survey in 2011 and drill an exploration well as early as 2012.

“It’s an exploration play but the guys have wowed me enough for me to believe that it’s a real opportunity,” CEO Steve Farris said during a conference call in August 2011.

Starting with seismic

In early 2011, Apache launched a small 2-D seismic survey.

The survey covered onshore targets up to 20,000-feet deep, offshore targets and “transition zone” targets. Apache ran a wireless nodal recorder alongside a conventional recorder to see whether the newer nodal technology worked it the Cook Inlet basin.

It worked, and Apache subsequently announced a three-year 3-D seismic survey.

The program covered acreage running north to the Susitna Flats and south to Anchor Point. The three-year timetable and the wireless technology allowed Apache to work year round: targeting onshore regions from September to April, offshore regions from April to November and transition zones from September to December and from March to May.

The survey began in late 2011 with an onshore program along the west side of Cook Inlet and provided information for determining future drilling locations. “We’re going to operate here for many, many years — we’re on a 25- to 30-year plan for the Cook Inlet,” Apache Senior Commercial Advisor Paul Abokhair told lawmakers in October 2011.

continued on next page

APACHE *continued from page 13*

Echoing that sentiment, Apache Alaska General Manager John Hendrix told Petroleum News in June 2012 that the company wanted to be in Cook Inlet "30 years from now," adding: "You don't come in and buy this much acreage with a short-sighted plan. We're not a one-well wonder and we don't have to bet the farm on one well. … It's a proven basin and we think it's been underexplored. But it's not an easy basin. It's a very complex basin. It's very complex to drill and it's very complex from the geology (standpoint)."

Instead of focusing seismic around specific targets, Apache conducted a broad survey, which allowed it to connect new data with existing information about known fields and also to collect higher resolution images of the specific area it eventually plans to target.

The first 130 square miles of seismic indentified eight new leads, Bedingfield said in June 2012, suggesting as many as 650 potential leads spread across the leasehold.

Regulatory delays

As Apache prepared to move the survey into more fragile transition zones and offshore regions in early 2012, the National Marine Fisheries Service Alaska Region issued a favorable opinion about the proposed program, determining that it was "not likely to jeopardize the continued existence of the Cook Inlet beluga whale or Steller sea lion populations, nor to destroy or adversely modify Cook Inlet beluga whale critical habitat."

Soon after, though, the Natural Resources Defense Council, the Center for Biological Diversity, the Center for Water Advocacy and the Native Village of Chickaloon challenged the finding, saying the survey warranted an environmental impact statement.

A May 2013 court order upheld a portion of the appeal, although by then the authorization had already expired. The parties ultimately agreed to close the case.

A delay in receiving a separate National Marine Fisheries Service authorization for a survey in the Kenai National Wildlife Refuge forced Apache to suspend its seismic program in September 2012, after collecting some 316 square miles of 3-D seismic.

"We shut down a $50 million seismic program and it cost Apache $10 million to do that," Hendrix said in February 2013, saying the matter delayed the program by at least a year.

Even after Apache got its National Marine Fisheries Service permit, it kept the seismic program on hold while it financed other projects in its portfolio, New Ventures Exploration Manager David Allard told the Alaska Geological Society in March 2013.

"Like most independents, you live within your cash flow," he said.

The U.S Fish and Wildlife Service issued a separate permit in July 2013 allowing Apache to use surface lands in the Kenai National Wildlife Refuge for its seismic program.

While those tensions remain, Apache took pride in earning the Chairman's Stewardship Award from the Interstate Oil and Gas Compact Commission in November 2013.

Apache resumed its program in February 2014 and launched an onshore seismic survey in the Kenai National Wildlife Refuge in the northern end of the Kenai Peninsula.

Having received a National Marine Fisheries Service authorization for its 2014 program, Apache also began planning a survey in the area just offshore from the onshore program.

continued on page 16


NORTH SLOPE
Unlocking Alaska
COOK INLET

APACHE *continued from page 13*

Early drilling uncertain

In April 2012, after completing its initial onshore 3-D seismic acquisition, Apache announced plans to drill two onshore wells during the second half of the year.

Apache envisioned drilling exploration wells as deep as 16,000 feet, which would allow the company to test beneath the Tertiary strata of the basin. "We don't want anybody coming back behind us and saying 'look what I've got,'" Hendrix told Petroleum News in June 2012. "You're down there. You're drilling. You might as well go the extra mile, or a thousand feet, or whatever it is."

The program called for drilling the Aspen well on the west side of Cook Inlet in July 2012 and the Captain Boomer well on the west side of Cook Inlet in the fall of winter.

The Aspen well would be some four miles west of the village of Tyonek, near several previous exploration wells including the 4,485-foot Aspen No. 1 that Aurora Gas drilled in 2005, the 13,600-foot Tyonek Reserve No. 1 well that Humble Oil drilled in 1965 and the 10,852-foot Simpco East Moquawkie No. 1 well that Simasko drilled in 1979.

The Captain Boomer well would be four miles southwest of Moose Point, northeast of the 10,058-foot Moose Point Unit No. 1 well that Amarex Inc. drilled in early 1978.

Because its seismic acquisitions had been focused on the west side of Cook Inlet up to that point, Apache later decided to drill both wells on the west side during the fall. And as the season slowly progressed, Apache ultimately scaled the program back to one well.

Kaldachabuna No. 2

Apache drilled the Kaldachabuna No. 2 well on Cook Inlet Region Inc. land near Tyonek in November 2012. The well followed the 12,890-foot Simpco Kaldachabuna No. 1 well that Simasko Production Co. drilled in 1980. Despite finding oil and natural gas in the Tyonek formation, Simasko abandoned the well because of "low permeabilities and low structural position," and because tests showed large quantities of water in the formation.

Apache wanted to use modern well stimulation techniques to see whether it could produce oil from the formation and to collect data to enhance its seismic modeling.

The Kaldachabuna No. 2 well passed through more than 100 coal seams, including 24 seams that were thicker than 10 feet, and the drill bit became stuck in coal seams several times. Apache ultimately suspended the well in April 2013 at 11,389 feet, according to Alaska Oil and Gas Conservation Commission records. Apache declined to offer any well results at the time, but the company decided to slow its exploration plans for the region.

"Frankly, we were disappointed in the well results that we had there," Farris said in August 2013, during a quarterly conference call with analysts. "We drilled the well and actually got too close to a fault, so we really didn't evaluate that well."

While Apache would continue the seismic program, Ferris said it would hold off on making other plans for the time being. "I am personally still very positive about the Cook Inlet," he said. "Obviously we're directing cash to different things right now. So, we've slowed down that activity but in terms of its prospectivity, I still think it has good value."

Contact Eric Lidji at ericlidji@mac.com

Brooks Range Petroleum moving toward development

The active independent could be sold soon as part of a larger financing plan for the Mustang development

By ERIC LIDJI
For Petroleum News

JOHN J. "BO" DARRAH, JR.

Brooks Range Petroleum Corp. spent a decade as one of the most active exploration companies on the North Slope, but its future exploration plans in Alaska are unknown.

The uncertainty comes from two sources.

First, the operating arm of Kansas-based Alaska Venture Capital Group LLC is currently working to bring its first North Slope development online by early 2016. The development program at the Mustang field of the Southern Miluveach unit includes a $225 million processing facility partially funding by public investment and a $350 million drilling campaign taking place in five phases over a three-to-four year timeline.

Second, as of press time Alaska Venture Capital Group and its partner, the Nabors-subsidiary Ramshorn Investments Inc., were in the process of selling Brooks Range Petroleum to the privately owned independent company Thyssen Petroleum USA Corp.

NAME OF COMPANY: AVCG/Brooks Range Petroleum Corp.
COMPANY HEADQUARTERS: 510 L St., Ste. 601, Anchorage, AK 99501
TOP ALASKA EXECUTIVE: John J. "Bo" Darrah, Jr.
PHONE: 907-339-9965
COMPANY WEBSITE: www.brooksrangepetro.com

Who is Thyssen?

Thyssen Petroleum USA is the American subsidiary of Thyssen Limited, a privately owned company based in the British Virgin Is-

continued on next page

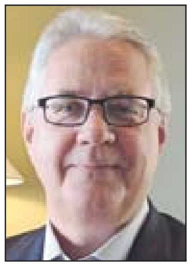
BROOKS RANGE *continued from page 17*

lands, with offices in Monaco and Houston.

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.

Thyssen Petroleum USA formed a subsidiary called TPNorthSlope LLC on March 14, 2014, according to the Division of Corporations, Banking and Professional Licensing.

In addition to buying Brooks Range Petroleum, which held no state leases as of April 7, 2014, according to the state, Thyssen would also buy a 90 percent working interest in the Southern Miluveach unit from the Alaska Venture Capital Group and Ramshorn. The remaining 10 percent interest would be split between Brooks Range Development Corp., which holds nearly 9 percent, and Mustang Road LLC, which holds 1 percent.



KEN THOMPSON

Brooks Range Development Corp. is a wholly owned Alaska Venture Capital Group subsidiary formed in 2010 to acquire the interests of a previous investor in the program.

Mustang Road LLC is a joint venture between the Alaska Industrial Development and Export Authority and the Alaska Venture Capital Group. The partners formed the company in 2013 to construct a road and pad to support operations at the Mustang field.

AIDEA and the private company CES Oil Services Pte. Ltd are forming a new company, Mustang Operations Center 1 LLC, to finance a $200 million to $225 million processing facility for Mustang. AIDEA will spend up to $50 million on the project. The joint venture will get a 20 percent annually adjusted working interest in the Mustang field.

The sale is a pre-condition for the financing, according to AIDEA.

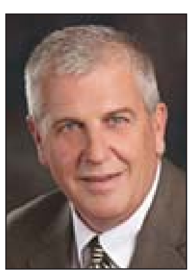
As of May 2014, Alaska Venture Capital Group, Ramshorn and Brooks Range Development Corp. held nearly 105,000 acres of state leases across the North Slope.

The acreage included four units and one pending unit: the Southern Miluveach, Kachemach and Tofkat units near the Colville River, the Beechey Point unit north of Prudhoe Bay and the proposed Telemark unit on the eastern North Slope.

The Beechey Point unit

Alaska Venture Capital Group came to Last Frontier at a dynamic time.

A wave of mergers and acquisitions in the late 1990s changed the face of the oil industry, and long-time oilmen John Jay "Bo" Darrah Jr. and Barton Armfield formed their company in 1999 to pursue relatively large but overlooked prospects on the North Slope.



BART ARMFIELD

The company quickly acquired properties and drew up exploration plans, but kept delaying those efforts because of difficulties, including funding and facilities access.

From 2004 to 2006, Alaska Venture Capital Group regrouped. It acquired additional leases, created Brooks Range Petroleum Corp. and formed a multi-partner joint venture.

Exploration efforts began in the Gwydyr Bay area in 2007.

The Alaska Venture Capital Group had initially picked up a minority working interest in several leases in the Gwydyr Bay area in a 2001 land swap with Phillips Petroleum. The company formed the Sakonowyak River unit that summer with majority interest owner BP Exploration (Alaska). The partners planned to drill two exploration wells by May 2004, but Alaska Venture Capital Group faced numerous challenges over the following 18 months — including difficulty finding partners, difficulty negotiating access to existing infrastructure and difficulty finalizing farm-in agreements and seismic licensing.

Alaska Venture Capital Group cancelled the program and disbanded the unit, but the company remained interested in Gwydyr Bay and acquired the acreage again in 2005.

Testing Gwydyr Bay

"Initially we were just going to drill in one prospect," former President Ken Thompson told Petroleum News at the time. "We then acquired seismic and reviewed well records and identified a second prospect." First, the company drilled the North Shore No. 1 to gather more information about an oil accumulation in the Ivishak first tested by Mobil in the Gwydyr Bay South No. 1 well in 1974. Next, the company drilled the Sak River No. 1 to follow up on a prospect previously included in the BP-operated Sak River unit.

The 11,348-foot Sak River No. 1 was a dry hole, but the results were intriguing enough for the joint venture to consider returning to drill a sidetrack. The 10,319-foot North Shore No. 1 found "approximately 70 feet of oil-charged Ivishak sandstone formation."

That winter, Brooks Range Petroleum also collected 130 square miles of 3-D seismic and the results "identified two small satellite prospects to North Shore No. 1 that can be reached from the North Shore No. 1 drilling pad," according to a partner, TG World.

Brooks Range Petroleum re-entered North Shore No. 1 in early 2008 to test the Ivishak and the shallower Sag River formations. The Ivishak flowed at 2,092 barrels of oil per day, but a mechanical problem down hole compromised the Sag River test. One partner estimated that the Sag River, unencumbered, could have flowed at 1,000 barrels per day.

That summer, the joint venture acquired the nearby Pete's Wicked prospect, a discovery BP made in 1997 and Pioneer Natural Resources Inc. acquired in a 2003 lease sale.

Around that time, TG World Energy said the joint venture was "establishing a threshold" for development, or searching for a way to improve the economics of the region by connecting several smaller satellites within relatively close proximity of one another. The potential solutions at the time included two production pads or extended reach drilling.

In 2009, the state formed the Beechey Point unit over 25 leases covering some 52,876 onshore and offshore acres. The unit included five exploration blocks and a commitment drill in one block by December 2010 and drill in another block by December 2012.

A dispute between partners kept the joint venture from drilling in early 2009, but Brooks Range Petroleum drilled the Sak River No. 1A sidetrack and the North Shore No. 3 delineation well in early 2010. Sak River No. 1A prompted TG Energy World to pull back from the joint venture. The results of North Shore No. 3 remain proprietary.

North Shore No. 3 satisfied the first work commitment and the state subsequently gave Brooks Range Petroleum until 2014 to drill a well in another exploration block.

In September 2012, Brooks Range Petroleum relinquished some

42,119 acres on the western side of the Beechey Point unit, leaving seven leases covering some 10,757 acres.

The move allowed Brooks Range Petroleum to focus its resources on bringing the Mustang field into production. Chief Operating Officer Bart Armfield said at the time that the company remained interested in its exploration properties, including the Gwydyr Bay region, but would need to conduct appraisal drilling before moving forward.

The Tofkat and Putu units

Exploration efforts continued at the Tofkat prospect.

After re-entering North Shore No. 1 in early 2008, Brooks Range Petroleum drilled the 13,174-foot Tofkat No. 1 exploration well and two sidetracks in the area near Nuiqsut.

Early testing showed a 10-foot interval of gross pay with between four and six feet of net pay. Using a modular formation dynamics tester, Brooks Range Petroleum took 10 oil samples from four sandstone reservoirs. The sampling found 22.9-24.0 degree API oil in the Brookian Topset 1 at 6,128 feet, followed by 13.4-14.7 degree API oil in the Brookian Topset 2 at 6,294 feet, then 36.6-38.2 degree API oil in the Brookian Turbidites at 11,000 feet and finally 41.8-42.0 degree API oil in the Kuparuk zone at 11,943 feet.

The two sidetracks targeted bottom-hole locations 3,500 feet to the southeast and 4,500 feet to the northwest of the main well in an attempt to delineate the reservoir. The well and both sidetracks all also "encountered oil in secondary targets above the Kuparuk."

Brooks Range Petroleum also shot a 210-square-mile 3-D seismic survey over the region.

By August 2009, Brooks Range Petroleum was showing an interest in revisiting Tofkat, but Vice President of Land Jim Winegarner told Petroleum News that, "whether we do it this year or next is subject to the 3-D seismic we shot. … We're prospecting that data now. … We're not sure if we will be ready to drill there in time for this winter or not."

By early 2010, Brooks Range Petroleum was exploring other prospects.

The joint venture lost three leases at the prospect to expirations. To avoid losing more acreage, Brooks Range Petroleum applied to form the Putu unit in mid-2011. The proposal included 39 leases covering some 39,993 acres of state and Native land.

The unit application split the proposed unit into three exploration blocks and proposed drilling al least one well in each block by March 2013, 2014 and 2015, respectively, with the option to localize those wells if focused exploration seemed more productive. The application envisioned a second unit plan down the road with more drilling commitments.

The companies said they had spent $25 million exploring the unit up to that point.

The state split the proposed unit into two. The Tofkat unit included 21 leases owned jointly by the state and ASRC covering some 9,131 acres. The Putu unit includes nine state leases covering some 21,946 acres. The remaining leases stayed un-unitized.

The Tofkat unit agreement required Brooks Range Petroleum to complete the Tofkat No. 2 well and the Tofkat No. 2-A sidetrack into the Kuparuk formation by May 2013, and sanction a Tofkat development by October 2013. The Putu unit agreement required the company to post a $10 million bond to backstop a four-well drilling commitment.

By mid-2012, Brooks Range Petroleum floated the possibility of drilling a delin-

continued on next page

BROOKS RANGE *continued from page 19*

eation well and a sidetrack at Tofkat the following winter to confirm the size of the previous discovery in the Kuparuk formation and test a deeper target in the Jurassic formation. The company had previously estimated that Tofkat held about 40 million barrels of recoverable oil in the Kuparuk C sands and another 20 million in the Jurassic sands.

In September 2012, Brooks Range Petroleum dropped the Putu unit. The company said it wanted to focus its resources on the Mustang development and three exploration targets.

The plans firmed up toward the end of the year, but by March 2013 the company had delayed the program until the following winter while it worked "with area stakeholders to obtain the required permitting for drilling." The company did not drill at Tofkat this year.

The Kachemach unit

The Kachemach unit remains underexplored.

Just as the state segmented the proposed Putu unit to create the Tofkat unit, it segmented the proposed Southern Miluveach unit to create the Kachemach unit. The smaller Kachemach unit included 11 leases covering some 16,487 acres of state and Native land.

The unit agreement split the Kachemach area into two exploration blocks and required Brooks Range Petroleum to complete two wells in Block A by May 31, 2013. The first well would target the Caribou trend and the second well would target the Moonlight trend. If the company met those commitments, it would then be required to complete one well in Block B, targeting a different prospect in the Moonlight trend, by May 31, 2014.

The two Kachemach wells were competing for financing against other prospects in the Brooks Range Petroleum portfolio. "Decisions on proceeding — or not proceeding — with some or all of these wells will be made in the next few months and will be based on working interest owners' technical and capital budgeting priorities," Alaska Venture Capital Group lead member Ken Thompson told Petroleum News in August 2012.

Brooks Range Petroleum seemed optimistic about Kachemach by early October, but in December 2012 the company told Petroleum News that the program "remains under consideration within the (Department of Natural Resources), and we are not at liberty to speculate as to the response that may come from the decision issued by the DNR."

By March 2013, the company said it was continuing to "reprocess and merge acquired seismic data to identify optimal drilling location and target" and plans to drill an exploration well next winter, after discussing the project with working interest owners.

The eastern North Slope

Concurrent to those efforts, Brooks Range Petroleum has eyed the eastern North Slope.

By early 2006, the company was touting the Slugger prospect south of the Point Thomson unit as one of the many prospects it hoped to pursue in the years to come. The company picked up additional leases in the area the following year and planned to acquire 130 square miles of 3-D seismic over the region in early 2008, but low snow cover that winter led the companies to postpone the program until the following year.

The legal challenges between partners forced the joint venture to postpone the program again in early 2009 and other exploration opportunities have since taken precedent.

In early 2011, Brooks Range Petroleum proposed the Greater Bullen unit including 68 leases covering some 200,179 acres between the Point Thomson and Badami units. The proposed unit included the Friezen, Red Dog and Telemark prospects. The proposal included plans for two 3-D seismic surveys in advance of exploration and development.

Brooks Range Petroleum ultimately withdrew the application in September 2011 and surrendered approximately 100,000 acres in the area in order to focus on a smaller area.

Among the acreage Brooks Range Petroleum retained were the leases comprising one of the six exploration blocks proposed for the original unit. In early 2012, the company proposed to form the Telemark unit over those nine leases covering some 16,235 acres.

The company proposed to shoot a 3-D seismic survey over the region by the end of 2012 and to drill a well by the end of March 2014. The company justified the unit by saying a development would lower the cost for future projects across the eastern North Slope.

Later in the year, with a decision about the unit still pending, Brooks Range Petroleum decided to defer any Telemark exploration until early 2014 "pending negotiations for a joint drilling agreement with Savant Alaska in the adjoining Badami unit." By late 2012, Savant and Brooks Range Petroleum proposed expanding the Badami unit to include the East Mikkelsen prospect, with plans for Savant to drill an exploration well in early 2014.

The state approved a partial expansion, but the exploration well has been on hold while Savant has been appealing the decision to exclude segments of the prospect from the unit.

Contact Eric Lidji at ericlidji@mac.com

Buccaneer undergoing major restructuring in Alaska

The ambitious Australian independent has slashed its portfolio to better finance its remaining operations

By ERIC LIDJI
For Petroleum News

Buccaneer Energy Ltd. has been the most ambitious exploration company in Cook Inlet in recent years, but recently its ambitions have surpassed its economic wherewithal.

The Australian independent relinquished flagship prospects, sold key assets and is currently conducting a financial restructuring to help pay bills and fund future work. This restructuring has included management changes at the top ranks of the company.

Buccaneer was founded in 2006, raised $17 million in an initial public offering in late 2007 and began developing a prospect in the Gulf Coast of Texas in early 2008. Using several loans, the company later acquired other prospects in Texas and Louisiana.

In March 2010, Buccaneer acquired 57,600 gross acres in Cook Inlet and a six-man management team from the Texas-based independent Stellar Oil and Gas LLC. The company cited state tax credits and higher commodity prices for its interest in Alaska.

The deal included at least three prospects: the offshore Southern Cross prospect near Middle Ground Shoal, the offshore Northwest Cook Inlet prospect adjacent to the North Cook Inlet unit and the onshore West Eagle prospect in the southern Kenai Peninsula.

After that, Buccaneer acquired at least four additional Cook Inlet prospects: the onshore West Nicolai Creek prospect on the west side of Cook Inlet, the onshore Kenai Loop prospect near the city of Kenai, the offshore Cosmopolitan prospect off the coast of Anchor Point and deep oil rights at the ConocoPhillips-operated North Cook Inlet unit.

Today, after recent divestments, Buccaneer operates existing gas production at Kenai Loop and continues to permit an offshore oil exploration program at North Cook Inlet.

Starting offshore

Exploring offshore prospects in Cook Inlet generally requires a jack-up rig.

The mobile unit allows for drilling in relatively shallow waters. Jack-ups were once a regular sight in Cook Inlet, but with the construction of permanent offshore drilling platforms and a decline in exploration activities, the basin had been without a jack-up rig for almost two decades by the time Buccaneer arrived, leaving prospects unexplored. A state law around that time hoped to create a "stampede" of exploration to the region by offering large incentives for the first company to drill a well in Cook Inlet using a jack-up.

In mid-2010, as the company was considering ways to get a jack-up rig to Alaska — an expensive and intricate undertaking — Buccaneer applied to form two offshore units.

The Southern Cross unit would include five leases covering 10,109 acres in a region where Buccaneer had 180 miles of 2-D seismic and 51 square miles of 3-D seismic.

In a proposed five-year plan of exploration, Buccaneer said it would provide evidence by Sept. 30, 2011, of its intention to drill an exploration well, and would complete the well by Sept. 30, 2012, or risk losing the unit and two leases nearing their expiration dates.

If it was successful in its initial program, Buccaneer said it would determine the commerciality of the prospect by Sept. 30, 2013, drill a second well or acquire more seismic by Sept. 30, 2014, and start permitting development work by Sept. 30, 2015.

A report from Netherland, Sewell and Associates Inc. in early 2011 estimated that the Southern Cross leases could overlie some 27.4 million barrels of oil equivalent.

The Northwest Cook Inlet unit would include six leases covering 10,008 acres in a region where Buccaneer had some 1,000 miles of 2-D seismic and access to earlier well logs.

The plan of exploration proposed a work schedule and poten-

continued on page 23

Buccaneer files for Chapter 11

COMPANY UPDATE

On May 31, 2014, as The Explorers went to print, Buccaneer Energy Ltd. and its eight subsidiaries filed for Chapter 11 bankruptcy protection. As part of the initial batch of filings, Buccaneer said it had reached an agreement in principle with a secured lender to sell "substantially all" of its remaining assets. The move would allow Buccaneer "to satisfy obligations owed to its principle secured lender and other secured creditors, and will conclude in an outcome that could result in some recovery for the company's unsecured creditors," according to a June 2 press release from the company. The future of an escrow account for the proceeds of Kenai Loop production remains uncertain.

NAME OF COMPANY: Buccaneer Energy
COMPANY HEADQUARTERS: Houston, Texas
ALASKA OFFICE: 215 Fidalgo Ave, Ste. 100, Kenai, AK 99611
PHONE: 713-468-1678
COMPANY WEBSITE: www.buccenergy.com

Saluting Alaska's Explorers

JUDY PATRICK

BUCCANEER *continued from page 21*

tial penalties at Northwest Cook Inlet identical to Southern Cross, starting with an initial well by Sept. 30, 2012.

A Netherland, Sewell and Associates report from late 2010 estimated that Northwest Cook Inlet contained some 46.7 million barrels of oil equivalent in three intervals.

The state approved the units in early 2011.

The approval decisions split both units into two explorations blocks each.

The Southern Cross ruling required Buccaneer to drill one well to pre-Tertiary depths in Block A by Sept. 30, 2012, and a second well in Block B by Sept. 30, 2014. The Northwest Cook Inlet unit required Buccaneer to drill one well into the Beluga formation in Block A by Sept. 30, 2012, and a second well in Block B by Sept. 30, 2014. If Buccaneer missed any of those deadlines, it would risk losing the units and some acreage.

Buying a jack-up

While other operators such as Escopeta Oil Co. had attempted to lease a jack-up rig for their proposed exploration programs in Cook Inlet, Buccaneer took a different approach.

It started in mid-2010, when Buccaneer asked the Alaska Industrial Development and Export Authority to help finance an offshore drilling program using a short-lived tax-exempt private activity bond created through the 2009 federal stimulus program.

The bond financing fell through, but over the following year the two parties negotiated a deal to buy, upgrade and mobilize a jack-up rig for long-term use in Alaska waters.

Buccaneer created a consortium called Kenai Offshore Ventures LLC to own the rig and a separate subsidiary to operate it. The consortium would make money by leasing the rig to the operating company, which would in turn market it to leaseholders. The deal gave Buccaneer priority on the rig, but made it available to other exploration companies, too.

When Buccaneer started discussing the program, in November 2010, it expected to have the rig in Alaska by May 2011, but the actual program took much longer to enact.

By early 2011, Buccaneer said it hoped to have the rig in Alaska by June, but despite the small delay it still expected to beat the state-imposed drilling deadlines by a year.

The AIDEA board approved the $85 million Project Endeavour in April 2011. The project included $24 million to $30 million in AIDEA funding and $5 million from the partners of Kenai Offshore Ventures, but the bulk would come from a private lender.

The deal required Buccaneer to drill at least four wells using the rig.

A "lengthy and tough negotiation process" continued through the summer and AIDEA changed the schedule to give Buccaneer until mid-2012 to start drilling its initial wells.

By July 2011, Buccaneer said it expected to drill one well each at Southern Cross and Northwest Cook Inlet in 2012 and a second well at each in 2013, before releasing the rig.

The deal finally came together toward the end of the year.

In September 2011, Kenai Offshore Ventures purchased the GSF Adriatic XI jack-up rig from Transocean Offshore Resources Ltd. for $68.5 million and renamed it "Endeavour — The Spirit of Independence." In November, Kenai Offshore Ventures and AIDEA closed on the deal for the state-back portion of the funding. Kenai Offshore Venture negotiated the remaining project fi-

continued on next page

BUCCANEER *continued from page 23*

nancing with the Oversea-Chinese Banking Corp.

Delays and lawsuits

The next step was getting the rig to Alaska.

After undergoing "substantially" more work than Buccaneer had originally expected, the jack-up rig departed from an Asian shipyard in late July 2012 en route to Cook Inlet.

Those delays started a domino effect.

While Buccaneer felt confident it could meet the September deadline for drilling at Northwest Cook Inlet, it asked the state for an extra year to drill at Southern Cross.

In late August 2012, the rig finally pulled into the Port of Homer, where Buccaneer said it would undergo some "very minor" work before heading north to start drilling wells.

The work took longer than expected, though. The rig stayed at the dock for months.

The state placed the Southern Cross and Northwest Cook Inlet units in default in October 2012, when Buccaneer failed to meet its initial deadlines for drilling. The state gave Buccaneer until Oct. 31, 2013, to cure the defaults by completing one well at each unit.

The reason for those delays became public in December 2012.

First, Kenai Offshore Ventures fired its rig operator Archer Drilling LLC "for cause," accusing the company of dropping work commitments and failing to pay subcontractors.

Archer responded, saying it had fired Buccaneer — not the other way around. Archer sought some $6 million in damages, saying Kenai Offshore Ventures "undermined and underfunded" the project. Buccaneer then sought $30 million in damages from Archer.

The result of the dispute — aside from lawsuits — was that the parties parted ways and Kenai Offshore Ventures hired Spartan Drilling LLC to take over as the rig operator.

The end of the road

After completing work at a different Buccaneer prospect in Cook Inlet, the Endeavour jack-up rig arrived at the Southern Cross unit in late August or early September 2013.

The original drilling location proved untenable, though.

Buccaneer had already installed a 30-inch diverter and well-control equipment on the conductor pipe when it noticed some settling of the rig legs on the seabed. The "scouring" was apparently the result of strong currents, common to shallow drilling.

Buccaneer moved the rig some 450 feet to the southeast, but by early October the company realized it wouldn't be able to drill by the traditional seasonal deadline — usually the end of October — and cancelled its offshore program for the rest of the year.

The cancellation meant that Buccaneer risked losing the two defaulted units.

Buccaneer blamed its failure to cure the defaults on justifiable delays. The discovery of oil and gas at the Cosmopolitan prospect had required extra time on the rig to conduct flow tests. A complicated farm-out deal had also caused delays, as had the "scouring."

The delays at Southern Cross had of course made Northwest Cook Inlet drilling impossible. Having spent some $14 million on the units, Buccaneer believed it had made "good faith, diligent efforts" to meet its commitments and should be allowed to keep the units. Ultimately, though, Buccaneer voluntarily relinquished both units in early 2014.

Acquiring Kenai Loop

To help generate cash flow while it pursued those larger offshore projects, Buccaneer began expanding its holdings in the northern Kenai Peninsula over the course of 2010.

The initial acquisition of Stellar assets had included some leases in the so-called North Sterling prospect. Buccaneer later expanded its holdings in this area by leasing acreage from the Alaska Mental Health Trust Land Office and from Cook Inlet Region Inc.

By late 2010, Buccaneer was permitting a three-well program at what it was now calling the Kenai Loop field. The program envisioned drilling an initial well by early 2011.

Buccaneer drilled the 10,680-foot Kenai Loop No. 1 well in April 2011 using the truck-mounted Glacier No. 1 drilling rig. The well tested at 10 million cubic feet per day, which led Buccaneer to launch a development program and permit additional wells.

Various supply contracts

In mid-2011, Buccaneer signed a contract with Enstar Natural Gas Co. to sell 5 million cubic feet per day into the new Cook Inlet Natural Gas Storage Alaska LLC facility, for a total of 12 billion cubic feet. The deal allowed for increased deliveries up to 31.5 bcf.

In late 2011, Buccaneer signed a separate deal with ConocoPhillips. The deal allowed Buccaneer to sell supplies into the aging Kenai liquefied natural gas facility in the months between the start of Kenai Loop production and the launch of the CINGSA facility.

To keep its options open, Buccaneer extended the terms of the ConocoPhillips contract even after it began making regular deliveries to the CINGSA facility in April 2012.

In October 2012, Buccaneer opened the choke on the Kenai Loop No. 1 well to increase production by 1 mmcf per day — to 6 mmcf per day total — to meet a two-month contract with an unnamed third party in the Cook Inlet. Buccaneer increased production to 6.5 mmcf per day in December to accommodate a one-month third-party contract.

After the Kenai Loop No. 4 well came online, Buccaneer and Enstar signed a second deal providing up to 5 mmcf per day through the summer months, when demand shrinks. The two parties signed a third deal in early 2013 to provide supplies into the winter months.

Buccaneer signed two more short-term gas supply agreements in October 2013, one to deliver up to 2 mmcf per day to an unnamed "large commercial end-user" for five months, and the other to provide back-up fuel to an un-named Cook Inlet oil producer "to ensure operation of their oil facilities in the Cook Inlet" during the winter.

The deals highlighted the trouble a smaller producer can face in the Cook Inlet.

Over its short tenure in Alaska thus far, Buccaneer has often claimed that the Cook Inlet natural gas shortage has been solved and that the state must promote programs to expand Cook Inlet supplies into other markets, such as exports and local transportation use.

"We need growth in the market to really allow that additional activity to move forward," former Buccaneer Alaska President and COO Jim Watt said in September 2013. "Just meeting local demand should not be the goal of development for our industry."


BUCCANEER ENERGY

Buccaneer also joined several small producers in challenging a proposed contract between Enstar and Hilcorp Alaska LLC. The producers worried that the contract would shut them out of the market. "Hilcorp has effectively locked up the utility market," Buccaneer Vice President of Land and Business Development Mark Landt wrote to the Regulatory Commission of Alaska, "so the RCA and Enstar should not be surprised when the remaining independent producers either choose alternative markets for their gas, seek to provide direct sales to Enstar's customers or not fund drilling programs targeting natural gas." Those "alternative markets" could include exports, Landt added.

Kenai Loop development

The Enstar deal required Buccaneer to drill two Kenai Loop wells by November 2013.

Buccaneer drilled the 11,000-foot Kenai Loop No. 3 well — which, despite its name, was actually the second well in the program — in September 2011, but it was a dry hole.

The Kenai Loop field came online in January 2012.

The following month Buccaneer shot a 25-square-mile 3-D seismic campaign to improve its understanding of the field. The program yielded a U.S. Army Corps of Engineers violation when the contractor disposed of shot hole material before getting the necessary Clean Water Act permit, which both shrunk and delayed the program to some degree.

Around the same time, some of the companies Buccaneer had contracted to complete work at Kenai Loop began complaining to local officials about delinquent payment and NANA Construction even filed a $5.1 million lien against Buccaneer for unpaid bills.

In April and May 2012, Buccaneer announced $50 million in financing — a $20 million loan and a $30 million revolving credit facility — that allowed it to pay outstanding bills.

The financing also allowed Buccaneer to secure a three-year lease of the Glacier rig.

With the seismic completed, the rig contracted and the outstanding bills starting to get under control, Buccaneer began planning a third Kenai Loop well — Kenai Loop No. 4.

"The fault previously thought to have separated the Kenai Loop No. 1 and Kenai Loop No. 3 well but which could not be identified on the 1970's 2-D seismic used to locate that well, is now clearly visible on the new 3-D seismic and has been confirmed as the basis for the unsuccessful Kenai Loop No. 3 well," the company said in a July 2012 statement.

Buccaneer drilled the Kenai Loop No. 4 well in September 2012, targeting a bottom-hole location slightly deeper and further to the northwest than Kenai Loop No. 1. "Severe weather

continued on next page

BUCCANEER *continued from page 25*

conditions" delayed the drilling and completion to some degree, but tested at 3 mmcf per day in January 2013 and came online at 2 mmcf per day in February.

Kenai Loop controversy

Over the latter half of 2012, Buccaneer asked the state to form a Kenai Loop unit.

The state rejected the application in March 2013, saying the purpose of the request appeared to be "lease extension and not the efficient development of the unit area."

The decision also revealed that CIRI had terminated its Kenai Loop lease in January.

In August 2013, Buccaneer spud the Kenai Loop 1-4 well — having renamed its wells by their pad locations — targeting what it said "appears to be a fault separated from the current producing zones in the Kenai Loop No. 1-1 and Kenai Loop No. 1-3 wells," which had previously been known as the Kenai Loop No. 1 and Kenai Loop No. 4 wells.

The well tested at a rate of 5.9 mmcf per day in October 2013.

The well, though, soon became tangled in a legal dispute.

When Buccaneer applied for an Alaska Oil and Gas Conservation Commission spacing exemption, several parties protested. CIRI and the state of Alaska accused Buccaneer of illegally draining gas from their neighboring properties. The dispute also involves the Mental Health Trust, which owns the land on which Buccaneer has been producing its gas. The battle continues to play out at the AOGCC and the Alaska Superior Court.

Pursuing Cosmopolitan

The initial prospects Buccaneer acquired from Stellar would have been enough to keep it busy for years, but Buccaneer continued to grab opportunities as they became available.

In February 2012, Buccaneer and a subsidiary of the privately held BlueCrest Energy Inc. acquired the Cosmopolitan prospects from Pioneer Natural Resources Alaska Inc.

The deal made Buccaneer the operator and 25 percent working interest owner of the oil and gas prospect off the coast of Anchor Point. The Fort Worth-based BlueCrest held the remaining 75 percent. Cosmopolitan had previously been a unit, but Pioneer terminated the unit and relinquished all but two core leases — ADL 384403 and ADL 18790.

Pennzoil discovered the prospect in 1967, but never developed it. ConocoPhillips took another stab in the early 2000s. Toward the middle of the decade, Pioneer joined the project as a partner before taking over as operator. Pioneer conducted some exploration activities and launched an innovative pilot project before giving up on the prospect.

All those recent activities used directional drilling from an onshore pad, and Buccaneer believed it would have greater success at the prospect by using its jack-up rig to drill offshore. "As a more advanced project with an existing well and some infrastructure already in place, Cosmo provides nearer term oil and gas production potential than our two other Cook Inlet offshore projects, which will still be developed in parallel," Buccaneer Director Dean Gallegos said in a statement at the time of the acquisition.

Originally, Buccaneer envisioned an exploration campaign using the rig to target shallower natural gas deposits and directional drilling to target deeper oil deposits.

The prospect would also allow Buccaneer to make more efficient use of its jack-up rig, according to the company, because it could drill at Cosmopolitan later in the year. While Southern Cross and Northwest Cook Inlet would become impassible by late October, the more southerly Cosmopolitan prospect could be explored much later into the winter.

Toward the end of 2012, Buccaneer began permitting a two-well program that called for drilling Cosmopolitan No. 1 by early February 2013 and Cosmopolitan No. 2 by April.

The rig remained in Homer through the first quarter of 2013, as upgrades and inspections continued. Buccaneer made progress on its permitting efforts, particularly its spill plan.

Buccaneer finally spud the Cosmopolitan No. 1 well in May 2013, but asked the state for nearly three extra years — until April 2016 — to complete the full two-well program.

The well encountered oil and condensate at 5,600 feet, in the Lower Tyonek, much shallower than expected, which caused Buccaneer to rethink its strategy. Buccaneer drilled the well to 7,599 feet, some 400 feet shallower than it had originally intended.

A pair of flow tests of the natural gas potential produced peak rates 7.2 mmcf and 7.3 mmcf per day from the Tyonek — and an "absolute open flow potential" test of 16 mmcf per day — but technical restraints prevented an oil flow test.

After failing to drill at Southern Cross and Northwest Cook Inlet, Buccaneer started work on a Cosmopolitan No. 2 well to delineate the gas-bearing zones from the first well, but Buccaneer ultimately sold its stake in the prospect before beginning work on the well.

North Cook Inlet oil

Eager for additional Cook Inlet prospects for its jack-up rig, Buccaneer farmed-in the deep oil rights of the ConocoPhillips-operated North Cook Inlet unit in May 2013.

The deal required Buccaneer to drill one well by the end of 2014 and a second well by the end of 2015. North Cook Inlet is a legacy gas field thought to contain deeper oil deposits.

A June 2013 report from Netherland, Sewell & Associates estimated that the deep oil deposits at North Cook Inlet unit contain some 9.8 million oil equivalent barrels in proven reserves. Buccaneer hopes to begin drilling at the offshore field in mid-2014.

The unit is now the only offshore prospect remaining in the Buccaneer portfolio. The company recently revised its request for a federal incidental harassment authorization to focus on the Tyonek Deep No. 1 and Tyonek Deep No. 2 wells at North Cook Inlet.

Disappointment at West Eagle

The southern Kenai Peninsula presented a puzzle when Buccaneer arrived.

The cluster of communities around the city of Homer represented the most-populated area of the Southcentral region without access to natural gas for space heating. While people in Anchorage, the Mat-Su and Kenai had enjoyed low-cost gas for decades, people in Homer, Kachemak City and Anchor Point were forced to rely on heating oil.

To make matters worse, the region contained several known gas prospects, but various companies had either been unable or unwilling to develop those prospects over the years. The general belief was that developing any one of those prospects would improve the commerciality of all the others, but no company could make the case for going first.

By mid-2010, Buccaneer was talking about shooting a 2-D seismic survey over its West Eagle leases in the fall in preparation for an exploration well in late 2011. The company spoke of the potential for a 12-well development program somewhere down the line.

Buccaneer acquired and reprocessed some 233 square miles of 2-D seismic over the region in 2011 and in early 2012 discussed its desire to shoot 3-D seismic, but the program continued to take a backseat to other prospects in the Buccaneer portfolio.

By October 2012, Buccaneer said it was "poised to drill," but wanted the state to form a unit over its leases in the region that were nearing expiration. "It simply makes no commercial sense to drill the proposed well, prove up the resource, and then watch the surrounding acreage that overlies the prospect expire," Buccaneer said in its application.

While Buccaneer had originally requested a 46,395-acre unit over nine leases, the state ultimately approved an 8,843-acre unit over three leases, allowing the others to expire.

The unit approval required Buccaneer to post two $600,000 bonds to backstop work commitments. The state agreed to return the first bond if Buccaneer spud a well by September 2013 and return the second if Buccaneer completed a well by the same date.

Buccaneer initially intended to drill the West Eagle No. 1 well in late August, but delays kept the company from meeting its deadlines and the state put the unit into default. The cure the default, Buccaneer needed to spud by Dec. 1 and complete the well by Jan. 31.

Ultimately, Buccaneer missed both deadlines. The company started the well in late January and completed it in February. Adding insult to injury, West Eagle No. 1 proved to be a dry hole and Buccaneer suspended the well without testing deeper formations.

Commercial restructuring

Signs of financial strain increased throughout 2013.

In April 2013, as Buccaneer juggled three offshore projects and two onshore projects with only minimal revenue, the company hired a financial advisor to pursue alternatives.

"Everything's on the table, including farm-ins, investments at the company level, a dual listing on a North American stock exchange or possibly a change of control transaction," Buccaneer Director Dean Gallegos recently told the Wall Street Journal about the review.

The news came around the time two institutional shareholders — Pacific Hill International Ltd. and Harbour Sun Enterprises Ltd. — called for shareholder meeting to decide whether to replace the entire Buccaneer board of directors. The two shareholders believed Buccaneer had "lost its way," citing a growing portfolio and funding problems.

The July 2013 meeting yielded interesting results.

The shareholders elected three outside directors while retaining two of the four existing directors. A subsequent appointment made the board evenly split between the two sides.

Asked whether Buccaneer was unfocused, then CEO Curtis Burton said, "We've painted a big vision from the day we (made our Initial Public Offering), and we've said we can achieve big results, but we've tried to do that systemically." The only thing Buccaneer had misjudged, according to Burton, was how the market would respond to its activities.

Soon after the shake-up, Buccaneer announced a deal: the California-based independent EOS Petro Inc. would fund two wells each at West Eagle, Southern Cross and the deep oil deposits at North Cook Inlet in return for a 50 percent stake in the prospects. The deal also included an opportunity to extend the farm out to include Northwest Cook Inlet.

The farm-out deal closed in September, but Buccaneer later terminated the deal because of "amongst other things, failure by EOS to fund its obligations under the agreement."

In August 2013, the three new directors resigned from the board without explanation. The Australian Stock Exchange suspended trading of Buccaneer stock for two days because the company didn't have enough board members to satisfy Australian corporation law.

Buccaneer filled the vacancies, but the shakeup continued. In December, Buccaneer fired the president and vice president of exploration and development of its Alaska subsidiary.

To streamline its operations and ease its financial burden, Buccaneer went on a selling spree in January 2014. The company sold its stake in the Cosmopolitan field to partner BlueCrest Energy Inc. for $41.25 million; sold its equity stake in Kenai Offshore Ventures LLC to Teras Investments Pte. Ltd. — a subsidiary of partner Ezion Holdings Ltd. — for $23.95 million; and pursed some $116.3 million in financial instruments.

Even with the restructuring, Buccaneer said it "will need to have access to additional working capital in the short term" to pay debts and obligations, and fund its workload.

In March, Buccaneer suspended Burton with pay "allowing for a review to be conducted," and, after completing the review, "determined that cause exists for terminating Mr. Burton's employment agreement." After being suspended, Burton sued the company for breach of contract, but he later also resigned as chief executive officer and managing director. A Texas court recently required to the parties to enter arbitration.

In an open letter to shareholders on May 7, Burton claimed that he and his management team had submitted a plan to the board of directors and to lenders back in January that had aimed "to revitalize the stock and pay off the company debt," but that new board members had "elected to pursue a different course and removed me from the CEO position. Since that time they have pursued liquidation of assets as an alternative. Since those decisions were made I have not been in a position to alter the course of the company nor contribute in any meaningful way to the ultimate fate of the organization."

In response, Buccaneer said it "does not authorize this communication in any way."

As of May 2014, Buccaneer said it intended to continue working with its Chief Restructuring Officer John T. Young Jr., of Conway Mackenzie Inc., to determine how best to restructure the company to meet its financial commitments going forward.

Contact Eric Lidji at ericlidji@mac.com

Caelus Energy takes over Pioneer assets in Alaska

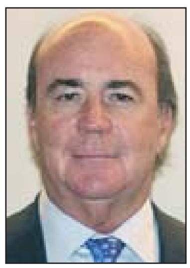
The privately held independent Caelus believes Oooguruk will be the basis for much Alaska exploration

By ERIC LIDJI
For Petroleum News

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

As its name implies, Pioneer Natural Resources Inc. has led trends.

The Texas-based independent arrived in Alaska in the early 2000s determined to bring a leaner and more agile approach to resource development in the Arctic. The mid-sized company had recently accomplished as much in the U.S. Gulf of Mexico and saw an opportunity to tackle another tough but rewarding domestic basin: the North Slope.


JAMES MUSSELMAN

The move proved to be prescient.

Since Pioneer became the first independent operator on the North Slope in 2008, several other newcomers to the state have joined its ranks and several more promise do the same in the next few years. The North Slope had two operators in 2007, but currently has five.

Now, Pioneer is leaving the state. Its decision includes two factors that could also become trends for Alaska in the near future: the impact of unconventional oil production in the Lower 48 and the emergence of smaller independent companies in the energy industry.

Having seen its Permian Basin assets grow increasingly valuable in recent years, Pioneer has freed up capital by selling its Alaska assets to the privately held Caelus Energy Alaska LLC. After some delays and amendments to sale, the deal closed in April 2014.

Growth and contraction

The 12 years Pioneer spent in Alaska could be graphed as a diamond shape: a focused effort that grew to an expansive search and later shrunk back down to a focused effort.

In 2002, the company acquired a stake in the Armstrong Resources-operated Northwest Kuparuk prospect in the Beaufort Sea. The prospect is currently called Oooguruk.

Over the next five years, Pioneer expanded its holdings through lease sales, acquisitions and joint ventures until it had more than 1.6 million acres across the state. After several disappointing exploration ventures, Pioneer relinquished considerable acreage to focus on the Oooguruk unit on the North Slope and the Cosmopolitan unit in Cook Inlet.

In 2011, Pioneer sold the core Cosmopolitan prospect and dedicated more resources to expanding its operations at Oooguruk into additional intervals and nearby satellites. In late 2013, Pioneer sold the Oooguruk unit and its remaining Alaska assets to Caelus.

Bringing Oooguruk online

Shortly before Pioneer came to Alaska, the company had brought two deepwater Gulf of Mexico fields into production just two-to-four years after making initial discoveries.

Bolstered by that success, Pioneer also believed it could also reduce "cycle times" on the North Slope, which was entering an era of maturity after four decades of development.

As Executive Vice President of Worldwide Exploration Chris Cheatwood told Petroleum News in early 2003, "You see those kinds of cycle times in other parts of the country, and that's what companies want to see in Alaska. We go in and make substantial investments in wells and leases and we want to be able to bring those prospects into production as soon as possible. … The independent model is to quickly turn investment into cash flow."

Alaska, though, can be uniquely difficult among domestic basins.

All three wells in a 2003 appraisal program encountered oil in the Kuparuk C sands, but the sands "were too thin to be considered commercial." While a deeper test "encountered thick sections of oil-bearing Jurassic-aged sands," lingering concerns about permeability, the size of the resource and recovery rates made a decision to proceed far from certain.

Even after Pioneer fast-tracked development and formed the Oooguruk unit, the company spent two-and-a-half years trying to figure out the most economic way to develop an oil field underlying shallow waters of a remote sea along a coastal edge of the Arctic Ocean.

Ultimately, Pioneer decided to build a six-acre gravel island, which it connected to existing facilities at the Kuparuk River unit using a 5.7-mile subsea bundle of pipelines.

Construction finished in mid-2007, development drilling began toward the end of the year and Pioneer became the first independent operator on the North Slope in June 2008.

Pioneer initially developed two oil pools: the Kuparuk and the Nuiqsut. Using primary and secondary methods, Pioneer expected to recover between 4 million and 8 million barrels from the Kuparuk and 37 million and 90 million barrels from the deeper Nuiqsut, which represented about one third of the original oil in place estimated for the pools.

The resource estimates for those pools increased over the first

continued on page 30


nabors.com
Safer. Smarter.
Better.
Our CDR2-AC rig reflects the latest innovations in Arctic drilling to provide our customers with incident free performance and operational and technical excellence.
CDR2-AC is the first Arctic rig designed and built by Nabors specifically for Coil Tubing Drilling operations. The rig was built to optimize CTD managed pressure drilling to provide precise control of wellbore pressures for improved safety, decreased costs, and increased wellbore lengths.
Combining safety and environmental excellence with greater efficiency means CDR2-AC can deliver the high value results customers have come to expect from Alaska's premier drilling contractor.
Learn more about Nabors' new drilling technologies at Nabors.com.
NABORS – MISSION TO ZERO
Safer, Smarter - Incident Free

CAELUS *continued from page 28*

two years of development, as Pioneer analyzed production rates and conducted a 3-D seismic survey over the unit.

Targeting the Torok

Essentially every well drilled at the Oooguruk field passed through a third, shallower interval — the Torok formation. Intrigued by this formation, Pioneer specifically targeted the Torok in early 2010 and proposed the Nuna development project later in the year.

The proposal called for expanding the unit to the south, building as many as two onshore drill sites in the Colville River Delta to access sections of the prospect too far to reach from the gravel island, and potentially building a standalone onshore production facility.

After the state agreed to expand the unit, Pioneer drilled two exploration wells in early 2012: the Sikumi No. 1 from an offshore ice island and the directional Nuna No. 1 from an onshore ice pad. A "deep test" of the Ivishak at Sikumi No. 1 was "basically non-commercial," but Nuna No. 1 yielded a 50 million barrel discovery from the Torok.

Pioneer drilled the Nuna No. 2 appraisal well in early 2013 and later increased its estimate for the Torok to a range of 75 million to 100 million barrels, up from 50 million.

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.

In May 2014, the state approved a third expansion of the Oooguruk unit. The expansion added three small Torok prospective leases surrounded by the existing unit boundaries.

Other exploration ventures

Over the decade Pioneer spent acquiring, appraising, developing and expanding the Oooguruk unit, the company also undertook other exploration ventures across Alaska.

The initial three-well program at Oooguruk in 2003 included the 6,900-foot vertical Oooguruk No. 1, the 7,500-foot directional Natchiq No.1 and the 6,943-foot Ivik No. 1.

At the North Slope and Beaufort Sea lease sales that October, Pioneer submitted nearly $3.9 million in high bids, around two-thirds of the $5.8 million in high bids at the sales.

The leases included a large block of acreage south of the Prudhoe Bay and Kuparuk River units. "You've got to get established first," Cheatwood told Petroleum News after the sale, "so we just needed to look at a variety of different opportunities up here and establish a land position." After acquiring seismic over the area, Pioneer would "put some plans together and see what we can do on those lands," Cheatwood said.

By mid-2004, Pioneer was touting four prospects: the Storms prospect south of Prudhoe Bay, the Gwydyr Bay prospect north of Kuparuk, the offshore Caribou prospect north of Point McIntyre and Oooguruk. Pioneer also held a stake in the Tuvaaq unit, adjacent to Oooguruk, but later transferred its 40 percent working interest to operator Kerr-McGee.

Around the same time, Pioneer also acquired Evergreen Resources to improve its Midcontinent holdings in the Lower 48. The deal included coalbed methane prospects in Southcentral, but Pioneer dropped the controversial acreage before closing the deal.

Despite some initial plans between 2004 and 2006, the Caribou and Gwydyr Bay wells never came to pass, and Pioneer later relinquished or transferred its leases in both areas.

2006 exploration wells

In early 2006, though, Pioneer drilled three exploration wells: Hailstorm No. 1 at the Storms prospect, and Cronus No. 1 and Antigua No. 1 south of the Kuparuk River unit.

"We expect to have a very, very active drilling program on the North Slope over the next several winters. … We're looking forward to a long relationship in Alaska," Pioneer Chairman and CEO Scott Sheffield told the Meet Alaska conference in January 2006.

To support its plans, Pioneer commissioned the Arctic Fox rig on a four-year term from Doyon Akita J.V., a joint venture between Doyon Drilling Inc. and Akita Drilling Ltd.

With its 50 percent partner ConocoPhillips, Pioneer conducted a 3-D seismic survey over 278 square miles of the Storms prospect in early 2005, formed the 16,500-acre NE Storms unit later in the year and proposed a one-to-two well program for early 2006.

While keeping somewhat vague about its specific locations and plans, Pioneer said the potential targets for the well "may include but are not limited to the Ivishak formation."

Ultimately, the Hailstorm No. 1 well proved to be unsuccessful.

Cronus was originally part of the ConocoPhillips-operated SE Delta unit in the area southwest of Kuparuk. The state dissolved the unit after ConocoPhillips failed to meet work commitments, but ConocoPhillips applied to form the Cronus unit over a similar area in 2004. ConocoPhillips farmed out the prospect to Pioneer the following year. The target was Albian-aged submarine fan turbidite sands in the Torok formation.

As Pioneer was preparing to drill the Cronus No. 1 well in early 2006, it was also permitting three additional Cronus wells to get a head start on appraisal drilling. The decision proved to be too optimistic. Cronus No. 1 encountered thick oil-bearing sands in the Torok and thin oil-bearing sands in the Kuparuk C, but Pioneer decided that the formation was "too tight to produce" and terminated the unit the following year.

Like the Cronus well, Pioneer also participated in the Antigua well on ConocoPhillips acreage using the Arctic Fox No. 1 rig and also decided that the well was "unsuccessful."

NPR-A exploration

While Pioneer pursued those projects on state land, it also pursued opportunities on federal land in the National Petroleum Reserve-Alaska and associated federal waters.

In 2004, Pioneer acquired a 20 percent interest in some 167,000 acres of ConocoPhillips and Anadarko Petroleum leases in the northeastern planning area of the NPR-A. The following year, Pioneer expanded the joint venture by acquiring a 20 percent interest in some 452,000 acres held by the two companies. At a 2004 lease sale in the northwest planning area, Pioneer acquired 20 to 30 percent working interests in some 808,000 acres.

Altogether, the deals gave Pioneer the third-largest land position in Alaska.

The partners drilled two wildcats at the Kokoda prospect in early 2005. The wells were remote even by Alaska standards, requiring a 70-mile ice road, but the companies saw the opportunity for a discovery that would be large enough to support standalone facilities and the partnership allowed all three companies to share the risk of the expensive wells.

The partners kept relatively mum about the results of the Kokoda No. 1 and Kokoda No. 5 wells, but ConocoPhillips and Pioneer teamed up again in early 2007 to drill Noatak No. 1 and Intrepid No. 2. The wells were also remote NPR-A wildcats, each costing some $60 million to drill. ConocoPhillips ultimately called both wells “non-commercial.”

Slowing investment

After those disappointing seasons, Pioneer grew skeptical about Alaska exploration.

“Based on the lack of success … we’re definitely slowing down our investments, until we make the next decision on where to go in terms of exploration,” Pioneer President and Chief Operating Officer Tim Dove told Petroleum News in late 2007. To those ends, Pioneer and its partners relinquished some 300,000 acres in the NPR-A in late 2007.

For the next three years, Pioneer focused on two Alaska projects: bringing the Oooguruk unit into production and appraising the Cosmopolitan prospect in Cook Inlet.

In mid-2005, at the height of its optimism about Alaska exploration, Pioneer acquired a 10 percent minority interest in the Cosmopolitan unit off the coast of Anchor Point.

In 1967, Pennzoil drilled the 12,112-foot Starichkof State No. 1 at the prospect and encountered oil at 6,800 feet and 6,900 feet. ConocoPhillips returned to the region in 2001, forming a joint state-federal unit and drilling a well and associated sidetrack.

Those wells “tested at a stabilized rate of 600 to 800 barrels a day over different intervals that lasted three to four months,” Dove said in 2005, as Pioneer was acquiring a greater working interest in the prospect and eventually became its operator. In late 2007, after acquiring seismic, the company drilled the Hansen 1A L1 well from an onshore pad.

The well was a horizontal lateral off the initial ConocoPhillips sidetrack to appraise a different interval. The lateral flowed at 400 to 500 barrels per day, according to Pioneer.

After pausing its appraisal efforts in 2008, to wait out the worst of the financial crisis, Pioneer returned to Cosmopolitan in early 2010 to fracture stimulate the lateral.

The well and the workover yielded a unique pilot project.

Pioneer trucked the flow test production some 75 miles up the Sterling Highway to the Tesoro refinery in Nikiski. The pilot project underpinned a development scenario Pioneer presented to state officials in April 2010: a trucking operation averaging 14 trips per day.

By early 2011, Pioneer was less enthusiastic. While calling its lateral and workover results “encouraging,” the company said “subsequent flow test results and engineering studies indicated that the resource potential was not as large as originally estimated.” So Pioneer cancelled its development plans, terminated the Cosmopolitan unit and surrendered its leases except ADL 384403 and ADL 18790, which had wells certified as capable of paying in paying quantities. Pioneer sold those to Buccaneer Energy Ltd.

Thus, after a decade of active onshore and offshore exploration activities on the North Slope, in the NPR-A and in Cook Inlet, Pioneer was back where it started: Oooguruk.

An unconventional threat

During that decade, Pioneer also overhauled its portfolio outside Alaska.

When Pioneer arrived in the state in the early 2000s, it talked of four exploration centers in its portfolio: Alaska, the deepwater Gulf of Mexico, north Africa and west Africa.

While the company added and subtracted regions from its portfolio over the years, it signaled a shift in June 2005 when it spent some $177 million acquiring additional properties in the Permian basin of

continued on next page

CAELUS *continued from page 31*

west Texas and the Eagle Ford shale of south Texas.

Those acquisitions came during the early days of the unconventional boom that is still upending the Lower 48 oil market. The financial crisis greatly reduced the cost of drilling in 2009, which allowed Pioneer to act quickly as crude oil prices started to recover.

The west Texas project began to gobble up capital.

Of the $960 million Pioneer budgeted for drilling operations in 2010, $120 million went to Alaska, while $580 million went to west Texas and $100 million went to the Eagle Ford shale. And of the $1.6 billion Pioneer budgeted in 2011, $115 million went to Alaska, $1.1 billion went to west Texas and $110 million went to the Eagle Ford shale.

The budgets kept climbing into 2012 and 2013, as did production. For the first quarter of 2013, Alaska produced some 4,000 barrels per day of the total company rate of 171,000 bpd while the Permian and Eagle Ford accounted for 16.3 percent growth year-over-year.

Speaking at the Meet Alaska conference in January 2011, Pioneer Executive Vice President for Domestic Operations Jay Still made the distinction explicit. 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."

The Spraberry play of west Texas and the Eagle Ford shale of south Texas more than doubled Pioneer's resource base, Still said, from proven reserves of about 1 billion barrels of oil equivalent at the end of 2009 to 2.3 billion barrels of oil equivalent in 2011.

Plus, the wells to develop those resources were cheaper than Alaska wells, the cycle times were quicker than Alaska projects and the costs were lower than Alaska, he said.

Those disparities spawned rumors of a sale.

Asked in August 2011 whether Pioneer was still interested in frontier plays like South Africa and Alaska, Sheffield said "it's always an option in regard to whether or not to look at divesting those two assets," but also added that the company saw South Africa as "running out" and saw Alaska as "growing significantly over the next several years."

After Pioneer sold its South Africa holdings in early 2012, analysts continued asking Sheffield whether Alaska was next. In May 2012, he said the decision would be made "down the road," but he noted that despite the encouraging results of recent completion program at Oooguruk, productions rates had been flat or declining for about a year.

"If the team up there can show us they have huge potential to grow production and frack several more Nuiqsut wells and look at some Torok, then we'll look at keeping and keep growing it," Sheffield said. "And so that's the key: Do we have enough upside on growth to able to reinvest the cash flow and grow the asset. And we love growing assets."

In August 2012, as Pioneer sought partners for its Wolfcamp program, the analysts asked what the thirst for capital meant for Alaska. "All of our assets are for sale for the right price. So we will continue to look at performance of those assets and make that determination in the future, whether or not we should be selling an asset," Sheffield said.

Selling to Caelus

The right price came in October 2013, when Pioneer sold its entire Pioneer Natural Resources Alaska Inc. subsidiary to Caelus Energy Alaska LLC for some $550 million.

The two companies amended the terms of the sale in March 2014, down to some $300 million. The revision opened the door for the parties to close the deal in April 2014.

The cash allowed Pioneer to increase its rig count in the Spraberry and Wolfcamp of west Texas in 2014 to better chase the estimated 3 billion barrels of oil equivalent at the plays.

With two principals each hailing from small independents, Caelus currently describes itself as a "privately held diversified international energy group focused on the identification, pursuit and development of unique opportunities across the energy sector."

The principals specifically tout two previous efforts: first, acquiring the independent Triton Energy, developing a major oil discovery offshore West Africa and selling the company to Amerada Hess; second, founding the independent Kosmos Energy and making a discovery offshore Ghana that propelled the company into a public offering.

A decade ago, Pioneer saw an opportunity to turn investment into cash flow by reducing the cycle time for Alaska development. Caelus wants to avoid cycle times altogether. The acquisition gives the company cash flow and an experienced crew in a prolific basin.

"We think there's an opportunity, swimming against the stream a little bit, going back to more conventional type stuff," Caelus President and CEO James Musselman told Petroleum News at the time of the sale. "That's what brought us here to begin with."

Caelus would spend $300 million on Oooguruk, Musselman said in October 2013, and hoped to raise more than $1 billion in equity and debt to invest in Alaska, potentially spending $1.5 billion over the next five to six years. In March 2014, the company said it would take on a $300 million second-lien term loan and a $115 million asset based loan facility to fund the purchase and to provide working capital for operations. The money is coming from a partnership with the investment firm Apollo Global Management.

Among the initial investments Caelus is planning for its new Alaska assets is Nuna, which Musselman said the company would start developing "pretty much immediately."

Shortly after closing the sale, Caelus said it would begin work on the Nuna development in the fall with the goal of bringing the satellite into production by third quarter 2016.

"We've got the funds committed and we're moving forward as quickly as we can," Musselman told Petroleum News in May, estimating that the development would require some $550 million on new facilities and $800 million to $900 million for drilling wells.

"I don't have anything I can tell you specifically about where our first exploration well will be," he said. "I would like to think that we would drill two to three exploration wells per year, starting hopefully this coming winter. … That's one of the main reasons we're in Alaska. We do want to explore. We think there are tremendous opportunities remaining."

The sale largely involves ownership changes. Caelus "extended job offers to and have acceptances back from virtually all of the (Pioneer) employees," Musselman said.

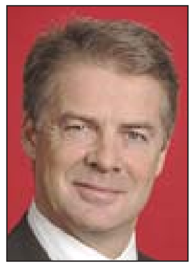
Contact Eric Lidji at ericlidji@mac.com


PTS
Production Testing and Services Inc.
A FULL SERVICE WELL TESTING COMPANY
PTS is ready for your next Well Test, Flowback, or Intervention.
PTS is an Alaskan Company that has been providing services both domestically and internationally since 1988. PTS is committed to total performance, providing safe operations, proven technology, cost effective services and solutions.
For more information on how PTS can provide an integrated Well Testing Package for your project, please visit us at: www.pts-technology.com
WELL TESTING
WATER TREATMENT
WIRE LINE SERVICES
SUBSEA LANDING STRINGS
SUBSEA TEST TREE SERVICES
DRILL STEM TESTING SERVICES
TUBING CONVEYED PERFORATING SERVICES
PTS
PTS Inc. Alaska & Sales Office
440 East 100th Avenue
Anchorage, AK 99515
Sales@pts-technology.com
Ptshouston@ptssite.com
907.344.2024

ConocoPhillips still leads North Slope exploration

A two-well exploration program earlier this year came amid considerably expanded development programs

By ERIC LIDJI
For Petroleum News


TROND-ERIK JOHANSEN

ConocoPhillips Alaska Inc. is the past, present and future of North Slope exploration.

Its predecessor companies drilled some of the earliest exploration wells responsible for launching oil development in northern Alaska. Since 2000, the subsidiary of the Houston-based company has been the most active explorer in the state, having drilled 60 exploration wells including 22 in the National Petroleum Reserve-Alaska. And the company is widely used as a marker of industry health when policymakers debate ways to make the state fiscal regime induce investment while yielding state revenues.

This year has been one of the busiest for ConocoPhillips in perhaps a decade, which the company attributes to recent revisions to the fiscal system. Those projects include exploration, appraisal and development activities across its four North Slope units: the Kuparuk River, the Colville River, the Greater Mooses Tooth and the Bear Tooth units.

ConocoPhillips is also one of a handful of federal leaseholders in the Chukchi Sea, although the company recently postponed exploration plans in the wake of uncertainties.

And ConocoPhillips is a major player in Cook Inlet, operating the Beluga River unit, the North Cook Inlet unit and its associated Tyonek platform and the liquefied natural gas export terminal in Kenai. But its exploration efforts in Cook Inlet have flagged recently.

Expanding Kuparuk

The Kuparuk River unit started the westward expansion of Alaska oil development.

Sinclair Oil and Gas discovered the Kuparuk River oil pool in 1969 with the Ugnu No. 1 well, but it took another decade before tightening domestic oil supplies and rising international oil prices convinced ARCO Alaska to sanction development of the field.

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

Kuparuk 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.

Since then, Kuparuk activities have included infill drilling, satellite development and enhanced oil recovery. Those activities have yielded a 76 percent increase over the total amount of oil engineers expected to recover from the field. The original estimate at startup was some 1.5 billion barrels, but total production is already past 2.5 billion barrels.

While the main Kuparuk oil field is responsible for some 2.3 billion of the 2.5 billion barrels of oil produced from the Kuparuk River unit through July 2013, the past two decades have been focused on developing the satellites responsible for the remainder.

ARCO began production from the West Sak, Tarn and Tabasco satellites in 1997, from the Meltwater satellite in November 2001 and from the Palm satellite in November 2003.

ConocoPhillips' activities at the Kuparuk River unit over the past decade have mostly been about applying improved technologies to those producing areas. Those include hydraulic fracturing, enhanced oil recovery, coil-tube drilling and 4-D seismic surveys.

2012 Shark Tooth

In early 2012, ConocoPhillips used Doyon rig 141 to drill the Shark Tooth No. 1 well from an ice pad four miles from Drill Site 2K, which is associated with the Tarn satellite.

The well appraised a discovery ARCO had previously made with the KRU 21-10-08 well in the late 1980s. It was "critical for any future development of this part of the Kuparuk reservoir," as ConocoPhillips told regulators, because it would "provide additional reservoir information in this area and narrow uncertainty around reservoir description parameters including oil-water contact, sand quality and thickness, and oil viscosity."

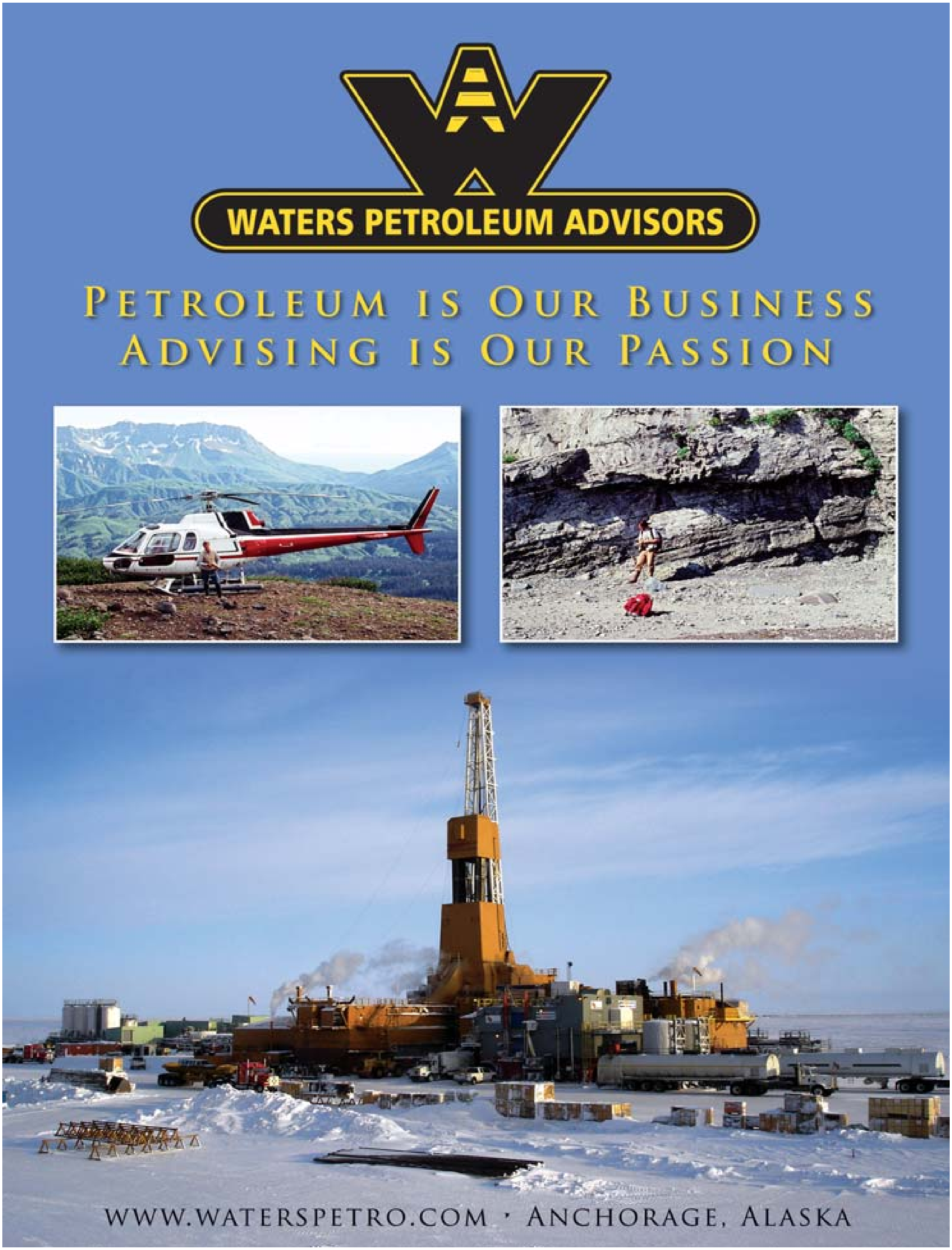
The well "discovered hydrocarbons in the Kuparuk sands, in accordance with expectations, and confirmed mapped volumes," ConocoPhillips said in late 2012.

ConocoPhillips considered developing the prospect from its existing 2L, 2M or 2K drill sites in the southwest corner of the unit, but the company decided those plans would have taxed existing drilling technology and instead began permitting the new Drill Site 2S.

While ConocoPhillips started laying gravel in early 2014, it will

continued on page 36

NAME OF COMPANY: ConocoPhillips Co.
COMPANY HEADQUARTERS: Houston, Texas
ALASKA OFFICE: 700 G St., Ste. 1950, Anchorage, AK 99501
TOP ALASKA EXECUTIVE: Trond-Erik Johansen
PHONE: 907-276-1215
COMPANY WEBSITE: www.conocophillipsalaska.com


WATERS PETROLEUM ADVISORS
PETROLEUM IS OUR BUSINESS
ADVISING IS OUR PASSION
WWW.WATERSPETRO.COM · ANCHORAGE, ALASKA

CONOCOPHILLIPS *continued from page 34*

not seek internal or partner approval until the fourth quarter. If the working interest owners sanction the project, facility construction would begin at the end of the year, followed by drilling in mid-2015 and startup sometime toward the end of next year, according to the company.

The Drill Site 2S development would cost some $595 million and employ some 240 people at the height of construction. ConocoPhillips has described plans for a 24-well pad at the drill site, to support estimated peak production of 8,000 barrels of oil per day.

Alongside those efforts, ConocoPhillips is also undertaking a renewed effort to apply enhance oil recovery techniques to the viscous oil deposits at the Kuparuk River unit with an expanded 1H pad in the Northeast West Sak of NEWS area of the unit. The goal is to spend $50 million to produce some 9,000 barrels of oil per day gross of peak production.

To support those and other infill drilling programs, ConocoPhillips recently commissioned the Nabors 7ES and Nabors 9ES rigs at a combined cost of $109 million.

Expanding Alpine

The Colville River unit continued the westward expansion of the North Slope.

ARCO Alaska discovered the Alpine oil pool in 1994 with the Bergschrund No. 1 well, announced commerciality in 1996 and brought the field online in November 2000. After mergers and acquisitions, ConocoPhillips now operates and owns a 78 percent working interest in the unit. Anadarko Petroleum Corp. owns the remaining 22 percent interest.

Similar to its strategy at Kuparuk, ConocoPhillips has been expanding development at the main Alpine oil field while also bringing a series of satellites into the production.

ConocoPhillips initially developed Alpine from the CD-1 and CD-2 pads, but in a 2003 the company proposed five Alpine satellites called Fiord, Nanuq, Lookout, Spark and Alpine West, and hinted at 10 potential satellites within 30 miles of the Alpine field.

ConocoPhillips brought the Fiord satellite (CD-3) and the Nanuq satellite (CD-4) online in 2006, and brought the Qannik satellite online from an expanded CD-2 pad in 2008.

NPRA exploration wells are drilled in winter, utilizing ice roads for access and ice pads to support operations.

CONOCOPHILLIPS

Those three satellites brought the company to the edge of the Colville River, which created problems for future satellites. An attempt to cross a channel of the river to develop the Alpine West, or CD-5, satellite initially yielded some local opposition.

After negotiating a preferred route with nearby communities, ConocoPhillips ran into regulatory opposition. The U.S. Army Corps of Engineers finally approved a bridge across the channel in late 2011 and now ConocoPhillips is completing site work and fabrication in advance of installation in early next year and first oil in late 2015.

Into the NPR-A

The remaining satellites are now being treated as related NPR-A developments.

The potential developments all involve discoveries Phillips Alaska Inc. announced in May 2001. They were the first discoveries made in the NPR-A since the federal government re-opened the region to oil and gas exploration in 1999. The company had drilled six wells and a sidetrack over the previous two seasons. Spark No. 1 and Spark No. 1A, Moose's Tooth C, Lookout No. 1, Rendezvous A and Rendezvous No. 2 all encountered hydrocarbons. The sixth well, targeting a different interval, was a dry hole.

"These discoveries mark an important milestone in the Alaska oil industry," Phillips Alaska President Kevin Meyers said. "Though the results are preliminary, we're confident the discoveries will prove to be of commercial quantities. We believe that the five successful wells have encountered three separate hydrocarbon accumulations."

With the recent ruling allowing ConocoPhillips to cross the Colville River, the company has also begun preparing GMT-1, which would be the first development in the NPR-A.

ConocoPhillips had originally proposed the development as Lookout/CD-6, but changed the name and the scope after the U.S. Bureau of Land Management formed the Greater Mooses Tooth unit in 2008. The revised application calls for an 11.8-acre gravel pad with the capacity for 33 wells, although the company is planning an initial eight-well program.

The $890 million development is expected to come online by late 2017. It would produce some 30,000 bpd and employ at least 400 people plus support positions at its peak.

Western exploration

The GMT-1 project would be in the eastern edge of the Greater Mooses Tooth unit.

Earlier this year, ConocoPhillips drilled two exploration wells a little farther west into the Greater Mooses Tooth unit: Rendezvous No. 3 on lease AA-81784 and Flattop No. 1 on lease AA-87896. The company said it is still evaluating the results of those two wells.

The ConocoPhillips predecessor Phillips Alaska Inc. drilled the Rendezvous A well on lease AA-81803 in April 2000, drilled the Rendezvous No. 2 well on lease AA-81781 in April 2001 and returned to test Rendezvous No. 2 in early 2009. Both wells found oil.

An un-stimulated test of the Rendezvous A in 2001 flowed at a rate of 360 barrels per day of liquid hydrocarbons and 6.6 million cubic feet per day of gas. A test of Rendezvous No. 2 in early 2008 "ranged from about 500 barrels of oil per day to as high as 1,300 barrels of oil per day of high API gravity oil" and gas production rates "averaged about 1.5 million cubic feet per day for each well," according to the company.

ConocoPhillips and its predecessor Phillips Alaska have staked several wells in the vicinity of the current Flattop No.1 well since 2001, but never drilled any until this year.

When BLM expanded Greater Mooses Tooth in 2009 to include four leases along the eastern edge — AA-87896, AA-81797, AA-81796 and AA-81795 — it required ConocoPhillips to spud an exploration well, into the upper Jurassic, on the additional acreage, by the third quarter of 2015, which suggests the target depth for Flattop No. 1.

A supplemental environmental impact statement meant to consider changes to the CD-6/GMT-1 application is also considering future developments, such as a GMT-2 pad.

Future activities

Those developments could also spur activity to the northwest.

After forming Greater Mooses Tooth in 2008, BLM formed the Bear Tooth unit in 2009, which allowed ConocoPhillips to retain some 105,655 acres on 23 leases.

The original unit agreement required ConocoPhillips to drill a well in a section called Unit Area A and test the previously

continued on next page

CONOCOPHILLIPS *continued from page 37*

drilled Scout No. 1 well by June 2012, but the federal agency later extended the deadline by a year because ConocoPhillips had "established that producible hydrocarbons have been encountered in the Scout No. 1 well sufficient to demonstrate that a prudent operator would maintain the lease for future development."

ConocoPhillips included well locations in the Bear Tooth area in its environmental assessments of the region for 2006-11 and 2007-12, but never drilled. The company staked seven well and sidetrack locations in the Bear Tooth unit in late 2012 and drilled the Cassin No. 1 well in early 2013. The well, which the company had referred to as a "wildcat," made "a new oil discovery," but additional details have remained scarce.

In late 2013, Kuukpik SAE LLC — a joint venture between the seismic firm SAExploration Inc. and the Native corporation Kuukpik Corp. — launched a three-year 3-D seismic campaign across the Colville River, Mooses Tooth and Bear Tooth units, and other acreage in the so-called "billion-dollar fairway," on behalf of "multiple clients."

Chukchi plans uncertain

While the past three decades have been a slow and steady march west for ConocoPhillips, the company has also pursued opportunities much farther afield in that frontier direction.

The efforts included some remote wildcats near Barrow, but the wells failed to yield discoveries large enough to justify the infrastructure needed to bring them to market.

The westward push also includes efforts to explore the Chukchi Sea.

Shell is generally considered to be leading the way on Chukchi Sea exploration, but ConocoPhillips is definitely second. Given the delays and difficulties in bringing those plans to fruition, the companies are generally running neck-and-neck in their efforts.

Among the reasons ConocoPhillips is so interested in the Chukchi Sea — aside from the potential for a huge discovery — is infrastructure. If any company ends up building a pipeline through the NPR-A to connect a Chukchi Sea discovery to the trans-Alaska oil pipeline, it would improve the economics of many marginal fields through the reserve.

ConocoPhillips commissioned a 3-D seismic survey in the Chukchi in 2006, but, in an attempt to pacify local communities by reducing the amount of activity in the region, it cancelled plans to return to collect additional seismic information the following year.

In early 2008, ConocoPhillips spent some $504 million in high bids on 98 tracts in a federal lease sale in the Chukchi, second only to $2.1 billion in bids from Shell.

While Shell took most of the prized Burger prospect in a bidding war, ConocoPhillips nabbed the Klondike well and immediately prioritized the region over its leases in the Beaufort Sea. "Chukchi is definitely our offshore focus right now," Michael Faust, offshore exploration manager for ConocoPhillips, told Petroleum News in September 2008. "We're spending the bulk of our time offshore working in the Chukchi."

The early efforts included a two-ship program to collect baseline environmental information about the region and a shallow hazards survey of the specific leases.

Partners in Chukchi

In early 2010, ConocoPhillips sold a 25 percent working interest in 50 Chukchi leases at Devil's Paw to Statoil, the Norwegian company that also bid on Chukchi acreage during the 2008 sale.

ConocoPhillips later farmed out a 10 percent working interest of its leases in the Chukchi to OOGC, the U.S. subsidiary of the Chinese National Offshore Oil Corp.

By January 2009, ConocoPhillips was aiming to drill at the Devil's Paw prospect near the Klondike well as early as 2011, but just a few months later the U.S. Court of Appeals for the District of Columbia upheld an appeal against the federal lease sale program. By November 2009, ConocoPhillips was discussing plans for a 2012 exploration program.

President Barack Obama affirmed his support for offshore exploration in a policy announcement early 2010, but the administration subsequently imposed a moratorium on offshore activities following the Deepwater Horizon oil spill in the Gulf of Mexico.

The legal challenge against the original lease sale program continued throughout 2010, and by early 2011 ConocoPhillips had pushed its exploration to 2013, at the earliest.

In early 2012, ConocoPhillips submitted an exploration plan to federal agencies. The plan called for drilling at least one well, but possibly two, at the Devil's Paw prospect in the summer of 2014, using a custom-built state-of-the-art jack-up rig from Noble Corp.

"They're building six of them and we're getting one of the rigs fresh out of the yard," Faust said in early 2013. "We're not going to bring up a 30-year-old piece of equipment. We're bringing up state-of-the art new stuff that is meant to work in the Arctic."

In April 2013, though, ConocoPhillips canceled the 2014 program. "While we are confident in our own expertise and ability to safely conduct offshore Arctic operations, we believe that more time is needed to ensure that all regulatory stakeholders are aligned," ConocoPhillips Alaska President Trond-Erik Johansen said at the time.

At an earnings call around the same time, Executive Vice President of Exploration and Production Matt Fox said ConocoPhillips had been "on the cusp of having to make some very significant commitments" for equipment, but felt unconfident about making those commitments without more regulatory certainty. "We felt that the prudent thing to do was to take a pause there and let things evolve a little bit before decide to drill those wells."

With Shell and Statoil also halting their Chukchi programs for the time being, and several lawsuits still playing out, it is unclear when ConocoPhillips might resume work.

Even with the delay, ConocoPhillips has been undertaking activities in the region. In September 2013, the company made the first approved commercial use of an unmanned aircraft, or drone, when it sent the ScanEagle on a 36-minute flight over the Chukchi.

Cook Inlet exports resume

ConocoPhillips is also a major player in Cook Inlet, but its exploration activities have waned in recent years. Instead, the company has focused resources on three development-related assets: the onshore Beluga River unit, the offshore North Cook Inlet unit and its associated Tyonek platform and the liquefied natural gas export terminal in Nikiski.

ConocoPhillips spent more than $80 million drilling four wells at the Beluga River unit between 2008 and 2010 and spent another $60 million in 2011 dispersing compressor stations to improve the pressure and increase the quality of the machines at the field. The current development plan, valid through June 2014, calls for no additional drilling.

In 2008 and 2009, ConocoPhillips spent $75 million drilling three wells at the North Cook Inlet unit, but the company later called those wells disappointing. ConocoPhillips recently told regulators it "plans to evaluate future drilling opportunities after 2015."

While ConocoPhillips is not actively exploring in Cook Inlet, it is certainly encouraging exploration in the basin by maintaining its LNG export terminal. The plant went idle when its federal export license expired in March 2013, but in April 2014 the U.S. Department of Energy gave the company permission to export of up to 40 billion cubic feet of gas per year from the plant to non-free-trade-agreement countries, such as Japan.

ConocoPhillips has said it plans to send six cargo loads to Asian markets this year. Each would contain some 2.75 billion cubic feet, of which some 60 percent is expected to come from third parties, according to ConocoPhillips. Thus, the facility is creating market opportunities for smaller producers in the region who felt shut out of Southcentral when Hilcorp Alaska LLC and Enstar Natural Gas Co. signed a four-year supply deal.

Contact Eric Lidji at ericlidji@mac.com

Cook Inlet Energy quickly racking up exploration

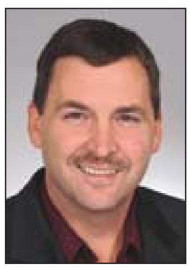
The small independent has consistently pursued numerous exploration projects while it expands development

By ERIC LIDJI
For Petroleum News

The principals of Cook Inlet Energy LLC formed the company in 2009 to acquire Cook Inlet assets made available during the bankruptcy of Pacific Energy Resources Ltd.

Since then, the local subsidiary of Tennessee-based Miller Petroleum Inc. has primarily focused on bringing older Cook Inlet properties back into production. But the company has also conducted exploration and amassed a portfolio of exploration license acreage.

And recently, Miller acquired Savant Alaska LLC, the small independent responsible for bringing Badami unit on the eastern North Slope back into sustained production.


DAVID HALL

After months of legal proceedings, Cook Inlet Energy submitted a winning bid in late 2009 to acquire Pacific Energy properties on the west side of Cook Inlet. A $2.25 million bid, plus $2.2 million to cover other obligations, bought the West McArthur River oil field, the West Foreland gas field, the offshore Redoubt unit and its Osprey platform, the onshore Kustatan production facility and a 30 percent stake in the Three Mile Creek field.

"Our initial strategy will be to restore base production at the West McArthur River field by repairing a couple of our champion wells, but our long-term strategy is to significantly raise oil and gas production at the properties through new drilling. This will allow us to bring proven reserves to market and prove up new additional reserves through sound geological principles and advanced drilling," CEO David Hall said in December 2009.

Cook Inlet Energy has worked over numerous wells at West McArthur River and Kustatan to increase production and brought the dormant Osprey platform back online.

In late 2013, Cook Inlet Energy acquired the North Fork field for $65 million from operator Armstrong Oil & Gas Inc. and its four partners. Cook Inlet Energy wants to expand the onshore gas field in the southern Kenai Peninsula north of the city of Homer.

Cook Inlet Energy acquired a selection of tracts around its existing acreage at lease sales in 2010 through 2013, but also sold some offshore acreage to Buccaneer Energy Ltd.

Early exploration ideas

While it pursued development opportunities, Cook Inlet Energy began discussing a wish list of exploration prospects it hoped to undertake if it could secure some financing.

Those included Tutna, Tazlina, Stingray, North Alexander,

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

Olsen Creek and Otter, all of which had been covered by a wide-ranging 3-D seismic acquisition across the region.

As it analyzed the seismic data, Cook Inlet Energy also began renewing its Oil Discharge Prevention and Contingency Plan with the Alaska Department of Environmental Conservation. The plan was anchored with the Tutna prospect, but covered all six prospects.

The plan was to explore the prospects using the retrofitted and winterized truck-mounted Miller Rig 34, an Atlas Copco RD20 rig sent to Alaska by its Tennessee parent company.

In late 2010, Cook Inlet Energy began permitting a three-well exploration program at Stingray. The program would have tested shallow gas targets on the West Foreland peninsula near the Trading Bay production facilities on the west side of Cook Inlet.

The proposed 2,000 to 2,500-foot Stingray No. 1 would have tested "the gas producing potential of Beluga sands identified in an offset well, the West Foreland State A1, and mapped seismically," Cook Inlet Energy said in filings with the state. The proposed Stingray No. 2 would have been about a quarter mile southwest of Stingray No. 1. The proposed Stingray No. 3 would have been some half a mile northeast of Stingray No. 1.

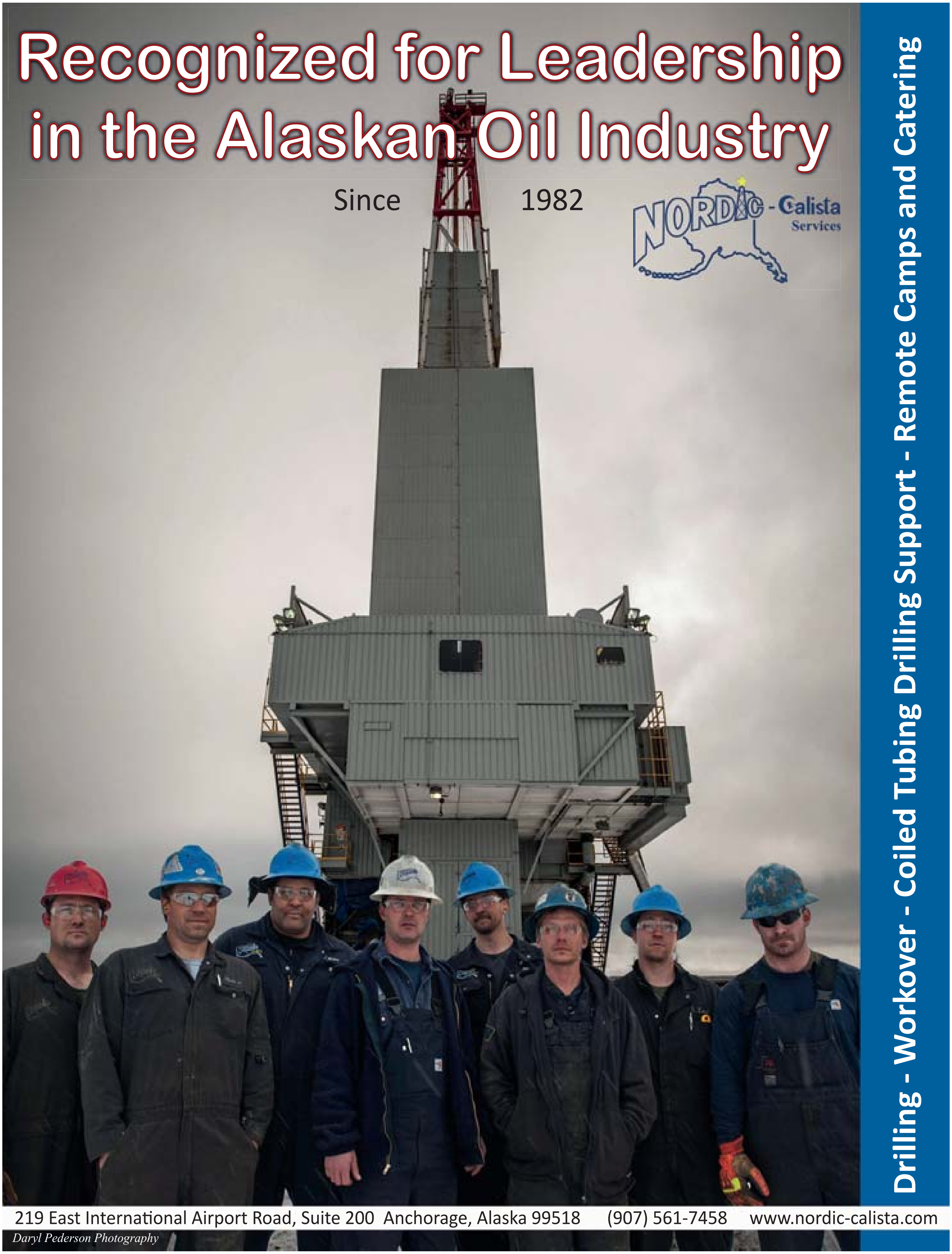
The program was far along in the permitting process by early 2011, but never advanced. Cook Inlet Energy surrendered five leases around the prospect in March 2012, but held on to ADL 390735 and ADL 391608, which included its proposed location for Stingray No. 1.

Starting with Otter

By September 2011, Cook Inlet Energy was permitting an exploration program at the Otter prospect in the northwest corner of the Susitna Flats State Game Refuge.

Cook Inlet Energy drilled the 5,680-foot Otter No. 1 well in mid-2012 to test gas targets in the Beluga formation. Early permitting documents for the well had proposed a 7,000- to 7,500-foot well targeting the Lower Miocene Sterling and Beluga formations and the Upper Oligocene-Lower Miocene Tyonek formation. Mud pump problems prevented the well from testing

continued on page 42


Recognized for Leadership
in the Alaskan Oil Industry
Since 1982
NORDIC - Calista
Services
Drilling - Workover - Coiled Tubing Drilling Support - Remote Camps and Catering
219 East International Airport Road, Suite 200 Anchorage, Alaska 99518 (907) 561-7458 www.nordic-calista.com
Daryl Pederson Photography

COOK IKNLET ENERGY *continued from page 40*

the Tyonek and some of the Beluga, but the company was optimistic.

"The mud loggers reported two significant hydrocarbon gas shows in the zone of interest," Hall said at the time. "We're very excited about the Otter No. 1."

The well cost some $7 million, according to Miller Energy Resources executives.

Cook Inlet Energy subsequently conducted a hydraulic fracturing operation on the well and acquired more robust mud pumps in preparations for a 7,500-foot follow-up.

But in early 2013, before drilling the second well, Cook Inlet Energy asked the state to form the Otter unit covering some 5,855 acres over portions of four leases at the prospect.

A unit would have extended two leases on the verge of expiring, but Cook Inlet Energy said unitization would also reduce the number of drilling pads needed to explore the area.

The company proposed re-entering and deepening the Otter No. 1 well, drilling a second well by March 2015 and drilling a delineation well to the northeast by March 2016.

The state rejected the application in May 2013, saying Cook Inlet Energy had failed to prove it had a viable reservoir and should proceed with exploration lease-by-lease.

Cook Inlet Energy appealed the decision and accused the state of creating a "new policy" running counter to existing rules and established precedent. The policy was against "exploration units," or using unitization to hold leases during the exploration work. The company said drilling was unlikely on a lease-by-lease basis because "investors simply are not going to commit capital for a project unless the acreage position is secure."

The state ultimately approved the unit, but required Cook Inlet Energy to post a $1.2 million bond and provide drilling dates, surface locations and bottom-hole locations.

Olsen Creek and others

Cook Inlet Energy turned its attention to the Olsen Creek prospect in late 2012.

The gas prospect is some seven miles northeast of Otter, west of the Beluga River gas field. The company saw the potential for drilling as many 24 wells on its leases to produce an estimated 84 billion cubic feet from the reservoir, Hall told Petroleum News.

After striking a deal with the Alaska Mental Health Trust to add some 1,660 acres to the prospect, Cook Inlet Energy drilled the 7,500-foot Olsen Creek No. 1 well in June 2013.

In July 2012, three Cook Inlet Energy leases expired at the North Alexander prospect, near the mouth of the Susitna River, although the company kept other leases nearby.

Cook Inlet Energy has yet to pursue drilling at the Tutna or Tazlina prospects.

Sabre, Sword and more

Cook Inlet Energy has also mentioned Sabre, Sword, Raptor and Valkyrie prospects.

The company already held a 70 percent working interest in two leases constituting the Sabre and Sword prospects adjacent to the West McArthur River unit, and, in September 2012, the company farmed in the remaining 30 percent from Hilcorp Alaska LLC.

At the time, Cook Inlet Energy said it intended to explore the two prospects within three years and ideally gain the complete 100 percent working interest ownership over both.

"Sword and Sabre prospects show great potential," Hall said, touting internal company estimates of up to 20 million barrels of oil and 14.3 billion cubic feet of natural gas.

Cook Inlet Energy secured the Patterson-UTI Drilling Co. rig 191 in May 2013 and drilled the 18,475-foot Sword No. 1 well from June to October. The extended-reach directional well targeted an offshore structure adjacent to the West McArthur River unit thought to contain some 800,000 barrels of recoverable oil, according to the company.

The well encountered "many identified potential zones behind pipes" and the company planned test the Hemlock followed by shallower zones. "Based on log results, our Sword well has extraordinary potential and we believe it could double the reserves currently reported for the West McArthur field while providing us a launch pad for drilling into Sabre, which is an even larger identified prospect," Boruff said in a statement at the time.

In November 2013, Cook Inlet Energy brought the well online at a rate of 883 barrels of oil equivalent per day over a 96-hour period, according to the company. In May 2014, Cook Inlet Energy said the well had penetrated three zones, but was only producing from the Hemlock, at a rate of about 600 barrels of oil per day. "The two additional zones are expected to add significantly to the Hemlock production," the company said. A subsequent test of the Tyonek G zone averaged some 290 bpd, according to the company.

The initial Sword results convinced Cook Inlet Energy to consider a second Sword well, but first the company turned its attention to the adjacent Sabre prospect. The company had planned to drill in early 2014, but those plans had yet to come to pass by May 2014. The company recently bought a $3.25 million Baker Process Inc. rig for the prospect and said that "several potential joint venture partners" have expressed in the Sabre prospect.

Cook Inlet Energy recently said a Sabre development would require up to six wells and "we expect that the preliminary gross cost to drill, test and complete the first well in this prospect will be in the range of approximately $25-30 million," according to Miller.

Cook Inlet Energy has yet to detail plans for Raptor or Valkyrie.

In June 2011, Cook Inlet Energy secured a two-year $100 million credit facility with New York-based Guggenheim Corporate Funding LLC and others. The company said it would use the facility to fund construction of the $19.5 million Miller Rig 35, a National 1320 model built for Osprey, plus drilling new wells and working over existing wells.

In July 2012, Miller Energy Resources Inc. secured a five-year $100 million credit facility to fund existing operations, to drill new wells and to work over existing wells.

Susitna Basin exploration

Alongside this work, Cook Inlet Energy has been eyeing an underexplored basin.

The original sale included an exploration license covering 471,474 acres west of the Parks Highway between the Houston and Talkeetna communities in the Susitna basin.

The Susitna Basin Exploration License No. 2 was nearing the end of its seven-year term when the sale closed, and in late 2010 the Alaska Division of Oil and Gas agreed to a three-year extension in return for $750,000 in work commitments. Given the exploration history of previous operators, Cook Inlet Energy could have converted all or some of the license area to traditional leases, but chose an extension to provide more flexibility.

The extension allowed Cook Inlet Energy to either collect additional 3-D seismic over the region or to use existing seismic to inform a one-well exploration drilling campaign.

In October 2011, Cook Inlet Energy said it was studying 2-D seismic shot by a previous operator in 2006 and had conducted "boots on the ground" survey of outcroppings, but was still trying to decide whether to shoot more seismic or move directly to drilling.

By early 2013, Cook Inlet Energy was preparing an exploration program in the Susitna basin. The program envisioned as many as two gas exploration wells at its Kroto Creek prospect, some 12 miles northwest of Willow Creek Landing on the Susitna River.

The roads for Kroto Creek could also improve access to other Cook Inlet Energy prospects in the region, like Moose Creek and Big Bend, the company said.

The company completed a winter access trail and a two-well pad at Kroto Creek in March and April 2013, and announced plans to drill during the following winter.

By November 2013, Cook Inlet Energy was discussing plans to drill up to two wells at Kroto Creek and a third well farther west at Moose Creek. Having met its $750,000 work commitment for the exploration license, the company also asked the state to convert the portion of the license area covering those prospects to traditional leases. The exploration license expired in October 2013 and the state issued 25 traditional leases to the company.

Cook Inlet Energy maintains two other exploration licenses in the Susitna basin.

In April 2011, the company picked up Susitna Basin Exploration License No. 4, a 10-year license covering 62,909 acres with a $2.25 million work commitment.

And in April 2012, Cook Inlet Energy picked up Susitna Basin

In its brief tenure in Alaska, Cook Inlet Energy has been an advocate for small producers.

Exploration License No. 5, a five-year license covering 45,764 acres with a $250,000 work commitment.

"We elected to pursue the new license in the Susitna Basin based on its proximity to our existing acreage and the potential to leverage our onshore drilling program in this area," Boruff said in an April 2012 statement. "We are currently evaluating the acreage and developing a work program."

The state is also eager for companies to explore the basin.

With an eye toward reducing the high infrastructure costs required to access the surprisingly remote western end of the basin, the Alaska Department of Transportation and Public Facilities commissioned a study to look at ways of improving access to the region. A February 2014 report identified five potential routes for development.

The original sale also included more than 600,000 acres of exploration lands.

The sale included two Alaska Mental Health Trust Authority leases adjacent to the Three Mile Creek field. Under a deal announced in late 2010, Cook Inlet Energy agreed to drill an exploration well on one lease by the end of 2011 or risk losing acreage and an exploration well on the other lease by the end of 2012 or risk paying a $250,000 fine.

In December 2012, Cook Inlet Energy sought to expand its Alaska Mental Health Trust leasehold in the area to include a portion of two recently expired Apache Corp. tracts.

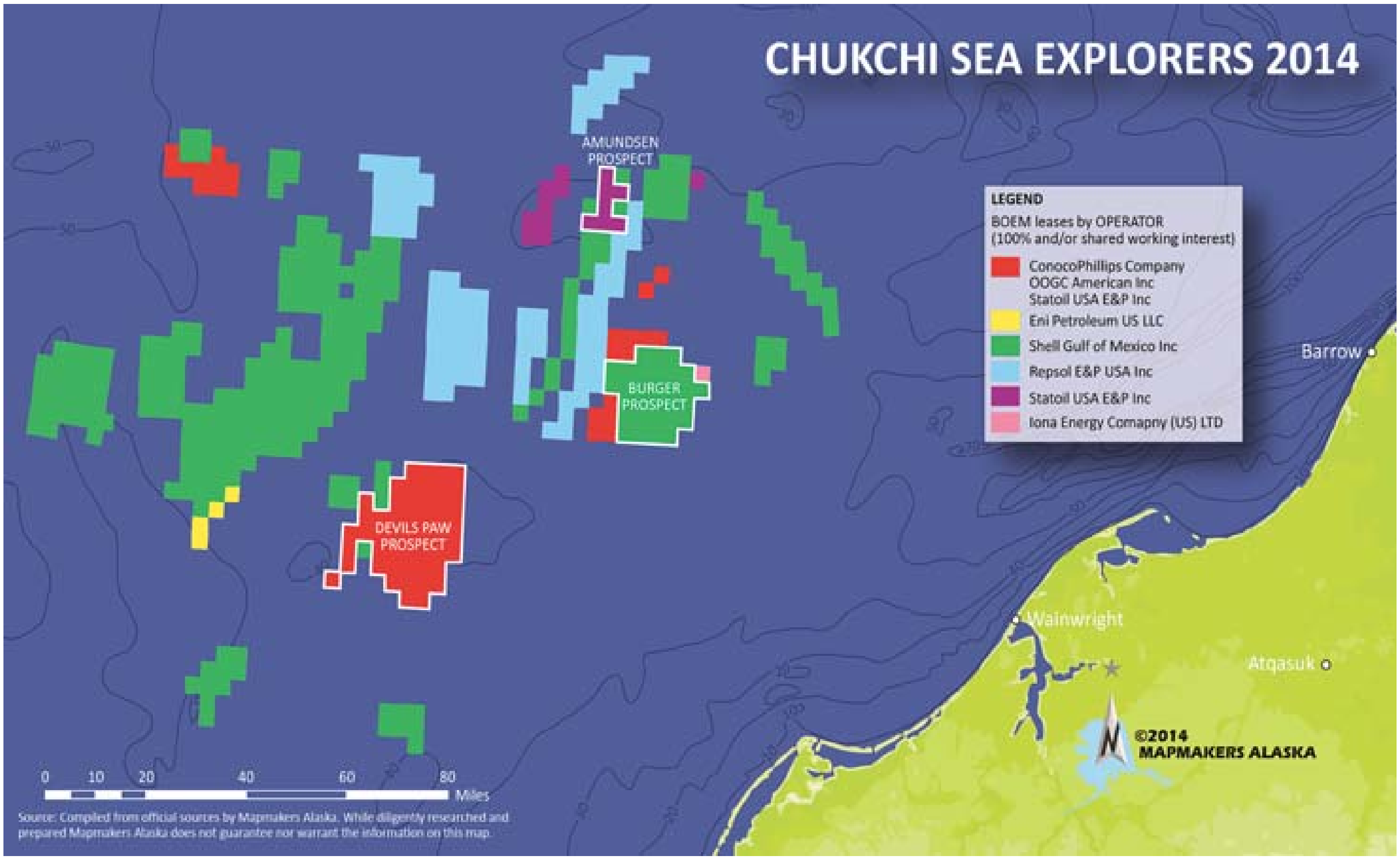
Advocating for little guys

In its brief tenure in Alaska, Cook Inlet Energy has been an advocate for small producers.

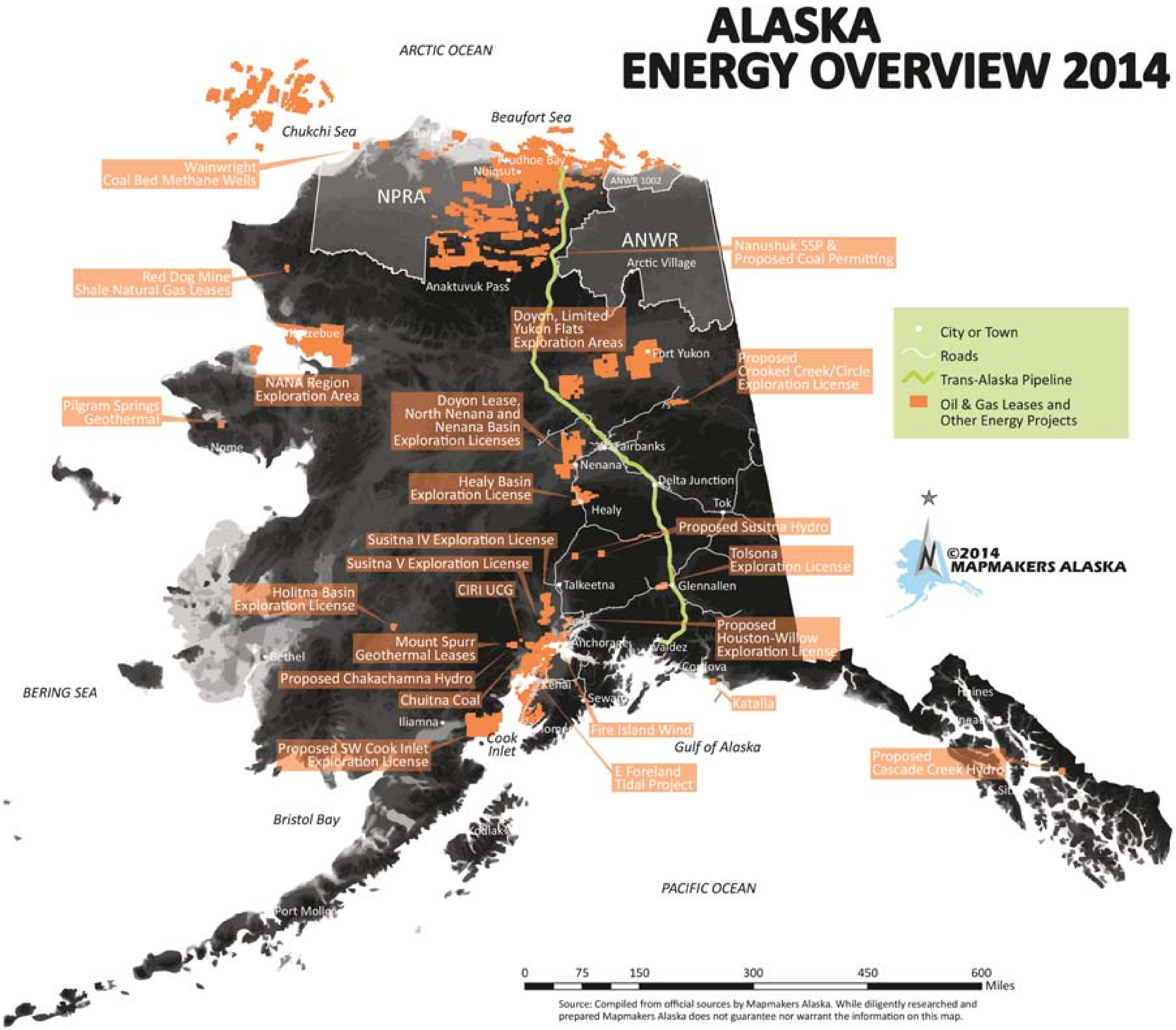
"Small producers, while not doing the big sexy projects, are actually giving you your bread and butter production," President J.R. Wilcox said at the Meet Alaska conference in 2011.

While asking the state to improve access and simplify permitting and taxation, Cook Inlet Energy also joined other small producers in challenging a four-year supply contract between Hilcorp Alaska LLC and Enstar Natural Gas Co. Cook Inlet Energy acknowledged the benefit of the contract for the supply-constrained region, but asked regulators to guarantee small producers would always be able to sell into the market.

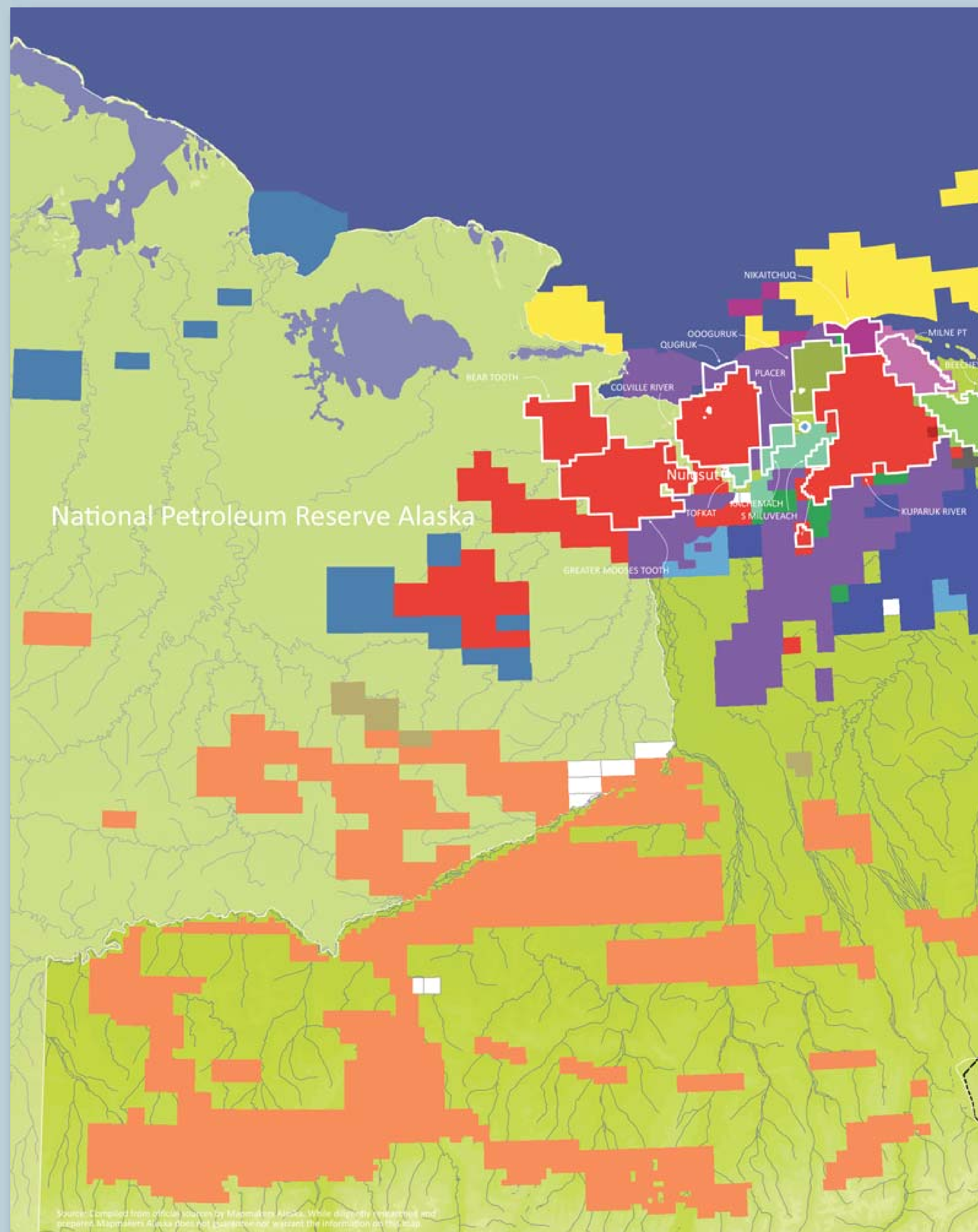
Contact Eric Lidji at ericlidji@mac.com


CHUKCHI SEA EXPLORERS 2014
AMUNDSEN PROSPECT
BURGER PROSPECT
DEVILS PAW PROSPECT
LEGEND
BOEM leases by OPERATOR
(100% and/or shared working interest)
ConocoPhillips Company
OOGC American Inc
Statoil USA E&P Inc
Eni Petroleum US LLC
Shell Gulf of Mexico Inc
Repsol E&P USA Inc
Statoil USA E&P Inc
Iona Energy Comapny (US) LTD
Barrow
Wainwright
Atqasuk
©2014
MAPMAKERS ALASKA
0 10 20 40 60 80
Miles
Source: Compiled from official sources by Mapmakers Alaska. While diligently researched and prepared Mapmakers Alaska does not guarantee nor warrant the information on this map.

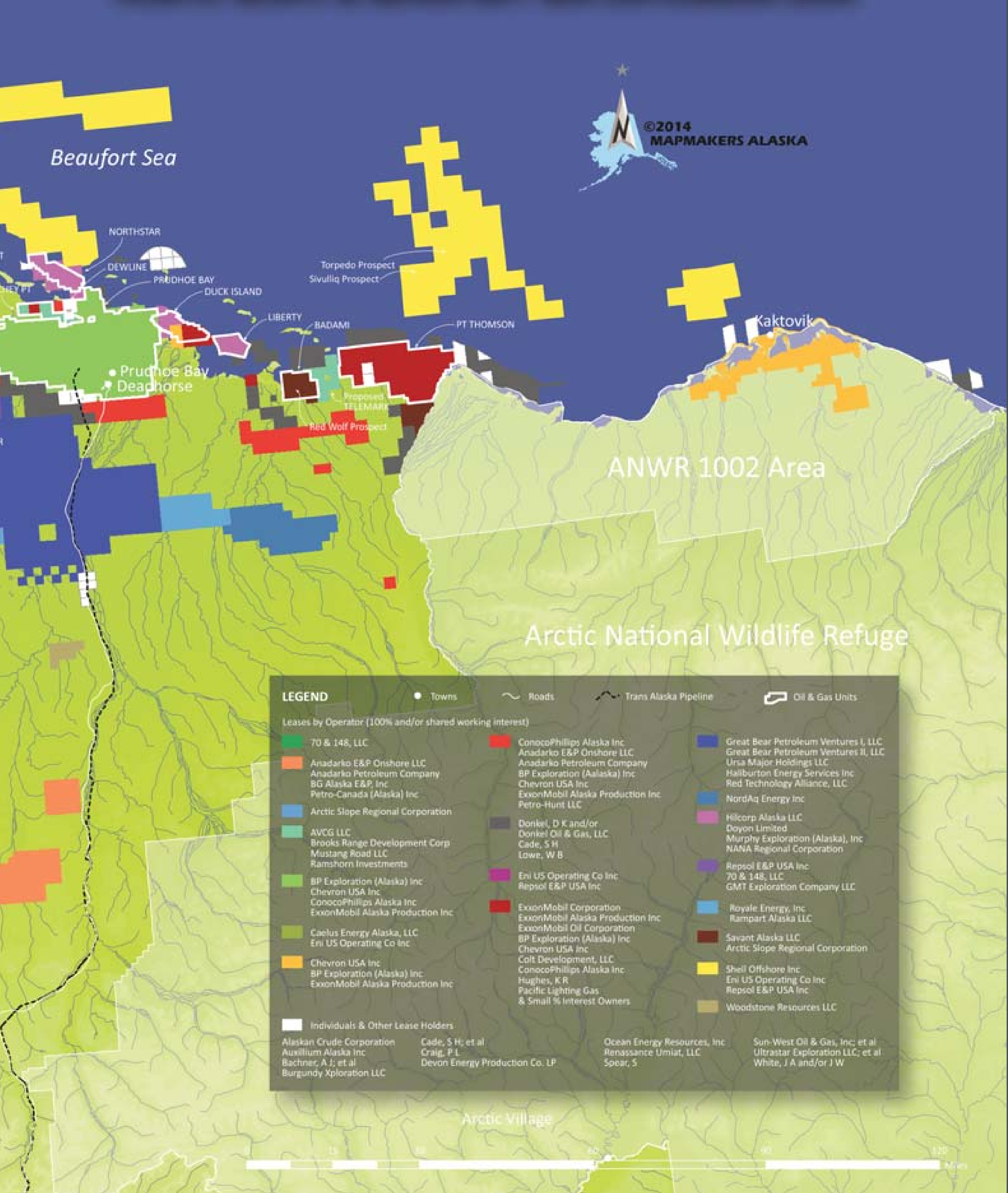
ALASKA ENERGY OVERVIEW 2014

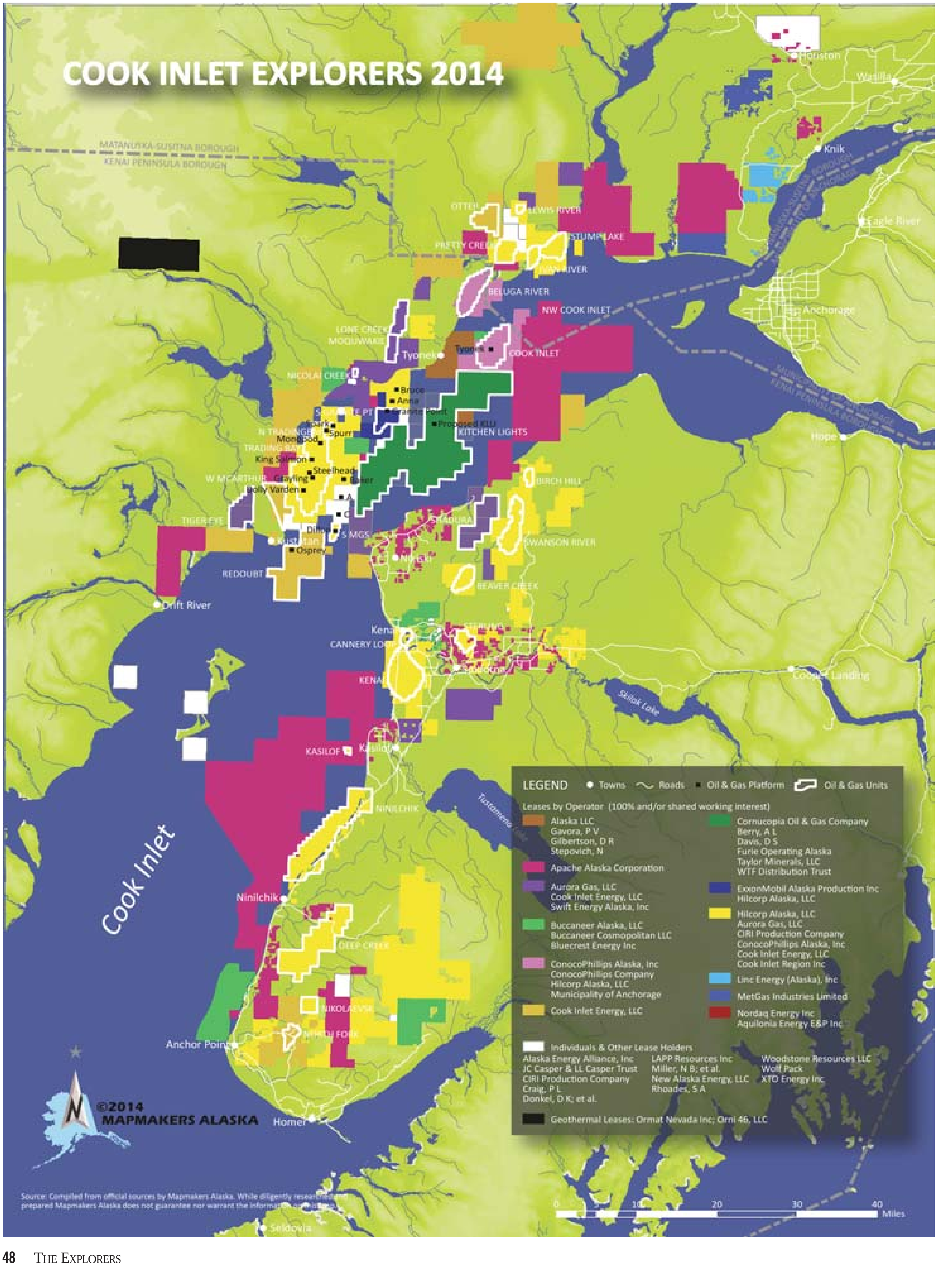


Source: Compiled from official sources by Mapmakers Alaska. While diligently researched and prepared Mapmakers Alaska does not guarantee nor warrant the information on this map.


National Petroleum Reserve Alaska
NIKAITCHUQ
OOOGURUK
QUGRUK
MILNE PT
BEAR TOOTH
COLVILLE RIVER
PLACER
TOFKAT
KUPARUK RIVER
GREATER MOOSES TOOTH
Source: Compiled from official sources by Mapmakers Alaska. While diligently researched and prepared, Mapmakers Alaska does not guarantee nor warrant the information on this map.

NORTH SLOPE & BEAUFORT SEA EXPLORERS 2014




COOK INLET EXPLORERS 2014
MATANUSKA-SUSITNA BOROUGH
KENAI PENINSULA BOROUGH
Houston
Wasilla
Knik
Eagle River
Anchorage
Hope
Cooper Landing
OTTER
LEWIS RIVER
STUMP LAKE
PRETTY CREEK
IVAN RIVER
BELUGA RIVER
NW COOK INLET
LONE CREEK
MOQUAWKIE
Tyonek
COOK INLET
NICOLAI CREEK
Bruce
Anna
Granite Point
Proposed KLU
KITCHEN LIGHTS
Spark
Spurr
Monopod
King Salmon
Steelhead
Grayling
Baker
W MCARTHUR
Holly Varden
TIGER EYE
Dillon
S MGS
Osprey
REDOUBT
BIRCH HILL
SWANSON RIVER
BEAVER CREEK
Drift River
CANNERY LOOP
STERLING
KENAI
Skilak Lake
KASILOF
Kasilof
NINILCHIK
Tustumena Lake
Cook Inlet
Ninilchik
DEEP CREEK
NIKOLAEVSK
NORTH FORK
Anchor Point
Homer
Seldovia
©2014
MAPMAKERS ALASKA
LEGEND
Towns
Roads
Oil & Gas Platform
Oil & Gas Units
Leases by Operator (100% and/or shared working interest)
Alaska LLC
Gavora, P V
Gilbertson, D R
Stepovich, N
Apache Alaska Corporation
Aurora Gas, LLC
Cook Inlet Energy, LLC
Swift Energy Alaska, Inc
Buccaneer Alaska, LLC
Buccaneer Cosmopolitan LLC
Bluecrest Energy Inc
ConocoPhillips Alaska, Inc
ConocoPhillips Company
Hilcorp Alaska, LLC
Municipality of Anchorage
Cook Inlet Energy, LLC
Cornucopia Oil & Gas Company
Berry, A L
Davis, D S
Furie Operating Alaska
Taylor Minerals, LLC
WTF Distribution Trust
ExxonMobil Alaska Production Inc
Hilcorp Alaska, LLC
Hilcorp Alaska, LLC
Aurora Gas, LLC
CIRI Production Company
ConocoPhillips Alaska, Inc
Cook Inlet Energy, LLC
Cook Inlet Region Inc
Linc Energy (Alaska), Inc
MetGas Industries Limited
Nordaq Energy Inc
Aquilonia Energy E&P Inc
Individuals & Other Lease Holders
Alaska Energy Alliance, Inc
JC Casper & LL Casper Trust
CIRI Production Company
Craig, P L
Donkel, D K; et al.
LAPP Resources Inc
Miller, N B; et al.
New Alaska Energy, LLC
Rhoades, S A
Woodstone Resources LLC
Wolf Pack
XTO Energy Inc
Geothermal Leases: Ormat Nevada Inc; Orni 46, LLC
0
10
20
30
40
Miles

Doyon doggedly pursuing exploration in the Interior

ANC has drilled two wells and conducted several seismic surveys in the Nenana area and the Yukon Flats

By ERIC LIDJI
For Petroleum News

The vast majority of oil and gas exploration in Alaska takes place on the North Slope and in the Cook Inlet basin, but Doyon Ltd. has been searching in the middle of the state.

The Alaska Native corporation has spent more than a decade collecting information about underexplored and even some unexplored areas of the Interior. Doyon has primarily been exploring the Nenana Basin, but is also eyeing the Yukon Flats area.

Exploration companies have long sensed many advantages to the Interior.

A commercial discovery in the center of the state could take advantage of the existing road and rail system, could avoid some of the harsher aspects of Arctic exploration and development, and would be several hundred miles closer to markets in the Lower 48.

Unocal drilled the Nenana No. 1 to a total depth of 3,062 feet in 1962 and ARCO drilled the Totek Hills No. 1 to a total depth of 3,590 feet in 1984, but neither led to development. “Except for minor amounts of gas associated with coal beds no hydrocarbon shows were observed in the wells,” the Alaska Division of Oil and Gas reported in early 2002. “Reports of oil seeps in the basin are unconfirmed.” Given the considerable quantities of coal in the region, the state expected the basin to be gas-prone.

The Alaska Native Claims Settlement Act of 1971 allotted considerable acreage across the region to Doyon, the Alaska Native corporation for the Interior region. Seeing the opportunities both for revenues and for a cheaper local energy source for the Interior, Doyon took an interest in the possibilities of the region. When industry interest tapered off in the late 1990s, Doyon began pursuing exploration opportunities on its own.

In recent years, Doyon has helped drill two exploration wells in the Nenana basin.

Initial joint venture

In late 2001, Doyon formed a joint venture with the Houston-based independent Andex Resources LLC to explore a section of the Nenana basin through an exploration license.

While most exploration occurs on leases acquired at annual sales, the state exploration license program allows companies to nominate lands for exploration and make specific work commitments over a given period of time. If the exploration is successful, the company can convert the license into traditional leases and continue exploring the area.

At the time, Doyon estimated that the Nenana basin contained 250 million barrels of recoverable oil and between 250 billion and 1 trillion cubic feet of recoverable natural gas, enough to meet the needs of Fairbanks with some potential leftovers for Anchorage.

“When industry explored the basin in the early ’80s, their focus

NAME OF COMPANY: Doyon Ltd.
COMPANY HEADQUARTERS: 1 Doyon Pl., Ste. 300, Fairbanks, AK 99701
TOP ALASKA EXECUTIVE: James Mery, Doyon Ltd. senior vice president, lands and natural resources
PHONE: 888-478-4755 • **COMPANY WEBSITE:** www.doyon.com

was oil but they knew it was a gas-prone basin and thought there was also a good shot at oil. Andex’s focus is gas,” Andex Resources Executive Vice President Jim Dodson told Petroleum News in August 2001. “We’d be happy if we found oil, but our focus is traditional natural gas.”

The program envisioned applying for an exploration license in early 2001, shooting seismic in the basin in the winter of 2002 and 2003 and drilling as early as 2004.

The Alaska Department of Natural Resources issued a seven-year license to Andex Resources in August 2002. The license covered 482,942 acres in the Nenana basin and required Andex to post bonds and spend at least $2.525 million exploring. The joint venture grew its land position several months later when the Alaska Mental Health Land Trust leased it 9,500 acres adjacent to the exploration license area in January 2003.

In January 2002, Andex told lawmakers that it expected to spend $24 million on the program, including $18 million to drill three exploration wells and $6 million for seismic.

Andex Resources came to Alaska, in part, because of a 10-year natural gas exploration incentive program approved in 1994. The program allowed the state to issue extensive tax credits in return for access to geophysical information, but the program had yet to

continued on next page

DOYON *continued from page 49*

issue any credits by the time Doyon and Andex came onto the scene. The data sharing provision kept Anadarko Petroleum Corp. from accepting credits for National Petroleum Reserve-Alaska exploration. The state rejected a second application from a different company because it already had geophysical information for the proposed region.

During the 2002 legislative session, Andex Resources and Doyon advocated for the state to continue the program beyond 2004 to ensure they would be able to drill a well under the program. Seeing the benefit, lawmakers extended the credits until 2007. The program eventually gave way to the exploration credits in Alaska's Clear and Equitable Share.

"Although the Nenana basin is a good place to look for gas, the exploration risks are still very high. The credits help temper those risks, including the 'Alaska factor' of high costs, compared to opportunities in the Lower 48. It would be a shame if this program is allowed to expire just as it begins to fulfill its initial promise," Doyon Vice President of Lands and Natural Resources Jim Mery told Petroleum News in February 2002.

Growing optimism

Andex began searching for joint venture partners to help shoulder the cost.

In December 2004, Andex and Doyon announced a partnership with the local Usibelli Coal Mine affiliate Usibelli Energy and Arctic Slope Regional Corp., which is the Alaska Native corporation for the North Slope region. The joint venture planned to drill a well in early 2006. With a commercial discovery, the companies believed they could move into development by early 2007, with an eye toward building a pipeline to Fairbanks in 2008.

PGS Onshore began conducting a $3 million 2-D seismic campaign over some 218 square miles of the region on behalf of Andex in early 2005. Andex planned to spend another $3 million acquiring seismic information from previous surveys in the region.

Even before the seismic program was complete, Andex was growing optimistic about the region. Measuring just the thermogenic gas, Andex believed the basin could contain 3 trillion cubic feet of recoverable reserves and 10 tcf of total reserves. "That number was based on some very, very conservative inputs," Andex Vice President of Exploration for the Northern Region Bob Mason told Petroleum News in March 2005. In addition to the thermogenic supplies, he said, "We know that there's biogenic gas in this basin."

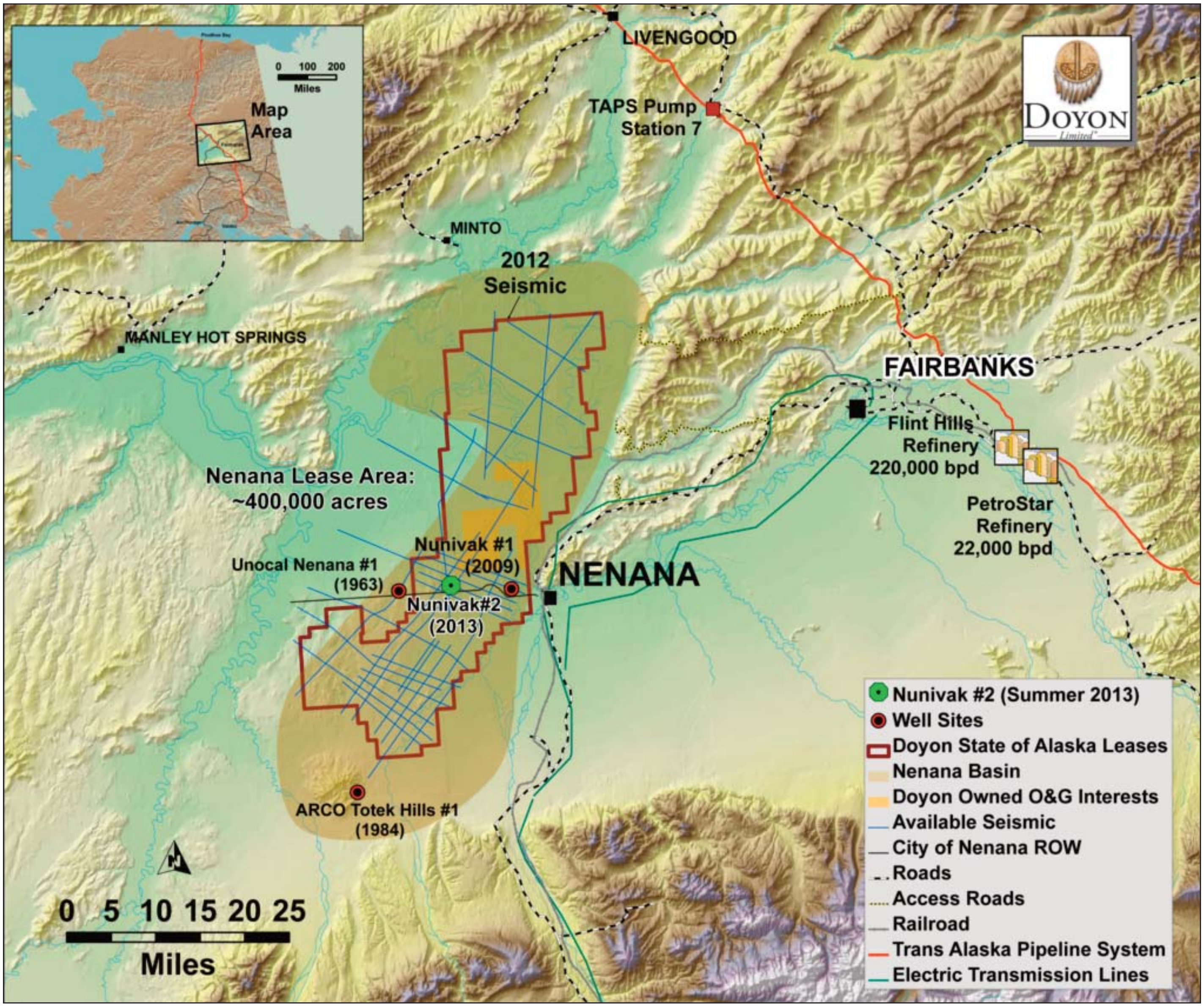
The U.S. Geological Survey had estimated technically recoverably reserves for central Alaska at 500 billion to 7.3 trillion cubic feet with a mean of 2.8 tcf.

Unlike the early shallow wells, the joint venture planned to drill to 10,000 feet or deeper. "I want to take a look at structures that preserve a very thick layer for my initial well," Mason said. "We are evaluating structures deeper in the basin where we don't have to worry about flushing, we don't have to worry about section missing — that sort of thing."

Delays and more delays

Andex delayed the program in early 2006, saying it would wait for a resolution of the proposed Petroleum Profits Tax debate before deciding whether to explore. When the tax became law in August 2006, the joint venture delayed its plans for early 2007, too.

The joint venture felt squeezed. The new fiscal system taxed Cook Inlet production at a lower level than North Slope production, but the provision excluded the Interior. And a proposed fiscal con-



tract for North Slope natural gas also excluded the Interior basins.

When the state revisited the fiscal system in late 2007 to pass ACES, lawmakers included a provision that taxed any gas used within Alaska at the lower Cook Inlet level. The provision underpinned efforts at the time to build a "bullet line" connecting a northern gas supply to Southcentral communities to offset declining Cook Inlet gas production.

The changes ultimately proved untenable to Andex, though.

The operator pulled out of the joint venture in late 2007, leaving Doyon and its two partners to find another independent willing to grab a 50 percent stake in the program.

A new partner

Even so, Doyon was aiming to drill in early 2009. The timeline, though, pushed against the September 2009 deadline of the exploration license. In late 2008, the state agreed to give the three-company joint venture until September 2012 to operate under its license.

Around the same time, the Denver-based independent Babcock & Brown Energy joined the joint venture as operator and announced plans to drill at least one 10,500-foot well in the summer of 2009. Babcock & Brown subsequently changed its name to Rampart Energy Co. A fifth company, Cedar Creek Oil and Gas Co., also joined the joint venture.

The summer drilling schedule made it easier to find a rig. The joint venture was able to schedule time with the Arctic Wolf No. 2 after North Slope winter exploration finished.

As summer approached, Rampart told lawmakers that a dry hole would be disappointing and a producing well would be exciting, but neither would dictate the fate of the project.

"Finding that we have an active petroleum system, meaning oil and/or natural gas being generated, would be a significant success in this first well," said Jim Dodson, the former Andex Resources executive who returned to Alaska as an executive for Rampart Energy.

The joint venture was now estimating that the basin contained 1 tcf to 6 tcf of gas, with the Nunivak prospect containing a median estimate of 60 billion cubic feet. "It could be smaller; it could be larger. We just don't know," Mery told Petroleum News in August 2009, adding, "We just felt that this was the best first place to look."

The joint venture drilled the roughly $15 million Nunivak No. 1 well about three miles west of the town of Nenana in July and August 2009 to a total depth of 11,100 feet.

continued on next page

DOYON *continued from page 51*

The well failed to find commercial volumes of gas, but information collected during the drilling suggested that the basin was much deeper and cooler than previously expected and offered tantalizing clues about high resource potential in the basin, Doyon said.

Going it alone

The information convinced Doyon to continue exploring the basin.

Eager for a wider understanding of its large license area, Doyon announced planned to conduct a seismic campaign focused on the northern end of the Nenana basin during the winter of 2010 and 2011. "Other than a few gravity measurements at the northern end of the basin, there really isn't any exploration," Mery told Petroleum News in April 2010.

The announcement came as Interior utilities started looking to truck liquefied natural gas from the North Slope and as lawmakers discussed plans to unite the Railbelt utilities.

Those uncertainties led Doyon to hold off on its Nenana plans, as did the need to find new investors. The joint venture partners had lost interest after the Nunivak No. 1 well.

Ultimately, Doyon decided to go it alone. The company conducted the 2-D seismic survey in the northern end of the basin in the winter of 2011 and 2012, and announced plans to drill the Nunivak No. 2 exploration well some seven miles west of its first well.

The venture got a boost in early 2012 when lawmakers approved a "frontier basins" incentive program, including tax credits for exploration and lower production taxes.

With the end of its exploration license fast approaching, Doyon began converting much of the license area to leases starting in mid-2012. In the summer of 2013, the company drilled the Nunivak No. 2 well to a total depth 8,667 feet using the Nabors rig 105.

Like the first well, the second encountered geologic features that suggested an oil and gas system in the basin, but failed to find commercial volumes of oil or natural gas.

"The Nunivak No. 2 drill program was only the second deep test of this basin," Doyon CEO Aaron Schutt said in a November 2013 announcement. "Despite the disappointment of a non-commercial effort, other results from the well clearly indicate the potential for significant commercial discoveries of oil and gas and we consider it a success. Follow-on studies are under way which will assist us in the development of our forward program."

The results that indicated a reason for optimism included "excellent potential reservoirs, competent top seals, source rocks actively expelling wet gases and similar shows of likely migrated gas which are indicative of an oil and/or gas-condensate system," Doyon said.

Now, Doyon is permitting a seismic survey scheduled for the winter of 2014 and 2015.

In the Yukon Flats

Throughout all this, Doyon has also been sniffing around the Yukon Flats.

Originally, the U.S. Fish and Wildlife Service and Doyon proposed to swap resource-rich acreage in the Yukon Flats National Wildlife Refuge with nearby Doyon acreage, but the proposal proved controversial and ended in 2010 after more than five years of wrangling.

After the setback, Doyon reassessed its existing acreage using a 2010 seismic survey and existing geological and geophysical data, and found the region to be much more prospective than originally thought — potentially an Alpine-sized accumulation. "So we're kind of happy that land exchange didn't happen," Schutt said in September 2013.

SAExploration conducted a 3-D seismic survey in the Stevens Village region of the Yukon Flats in the winter of 2012 and 2013, on behalf of Doyon. As of December 2013, Doyon was studying the results of the survey to determine potential drilling locations.

A 2004 USGS estimate of the 13,500 square mile lowland between the trans-Alaska oil pipeline and the Canadian border estimated mean technically recoverable resources of 173 million barrels of oil, 127 million barrels of natural gas liquids and 5.5 tcf of natural gas, which exceeded earlier estimated for the entire central Alaska region.

Contact Eric Lidji at ericlidji@mac.com

Furie nearing the finish line at Kitchen Lights unit

Installation of an offshore platform this fall would set the stage for production in third quarter

By ERIC LIDJI
For Petroleum News

Furie Operating Alaska LLC could become the newest producer in Alaska this year.

The local subsidiary of Texas-based Furie Petroleum Co. recently completed four exploration wells at the offshore Kitchen Lights unit and is beginning development work.

While Furie is a relatively new name in the Cook Inlet, it has a long history. The company started as Escopeta Oil Co., but changed its name and its management as the small independent was bringing a long-desired jack-up rig to the Cook Inlet basin.

Escopeta had spent more than a decade arranging an offshore exploration project in the upper Cook Inlet, but Furie executed the program and is now seeing it to completion.

The details of the deal are private, but Furie and its German owners had been investors in Escopeta. "Let's just say we got to the point where we wanted to control our own destiny," Furie President Ed Oliver told Petroleum News in September 2011. "We took it over in Vancouver. We have funded it all the way. It's been our money from day one."

Considerable preparations

The current program is the latest step in a long journey.

Under the leadership of its former president, Danny Davis, Escopeta had managed to arrange a complicated exploration program in upper Cook Inlet. The program required amassing leases, finding funding and bringing a jack-up rig to the region.

The complexity proved controversial.

The lengthy efforts to find funding and secure the jack-up rig repeatedly pushed the exploration program beyond the state-mandated deadlines for work commitments.

What might normally have been a procedural debate between a company and regulators grew when lawmakers accused the state of jeopardizing exploration as existing supplies were dwindling. The relatively commonplace issue took on an even greater magnitude because of concurrent efforts to get ExxonMobil to develop the Point Thomson unit.

As if all that weren't enough, as Escopeta was finalizing its

continued on next page

FURIE Operating Alaska LLC

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: Damon Kade
TEXAS TELEPHONE: 281-957-9812
ALASKA TELEPHONE: 907-277-3726

FURIE *continued from page 53*

long-standing effort to secure a jack-up rig, the Alaska Industrial Development and Export Authority and Buccaneer Energy Ltd. announced a separate partnership to purchase a jack-up for the Cook Inlet.

To make matters even more complicated, Escopeta drew fire from marine groups — and later from the federal government — for violating the federal Jones Act by using a foreign ship to bring its jack-up rig from the Gulf of Mexico to Cook Inlet in 2011.

Despite those conflicts and challenges, Escopeta managed to bring the Spartan 151 jack-up rig to the Cook Inlet in summer 2011 and drilled the first half of an exploration well at Kitchen Lights before docking the rig in Port Graham for upgrades during the winter.

A big announcement

Because the rig arrived in summer, Furie only had to time to drill the planned 16,500-foot Kitchen Lights Unit No. 1 well to 8,805 feet before suspending operations for the season.

The suspension, in part, came from state requests to slow the pace of drilling for safety.

Even so, the company made waves.

"Furie came; we drilled; and we found gas," drilling engineer Bob Laule said at the annual RDC conference in December 2011, adding that testing of the unfinished well "gave us some very good indications of gas in the Sterling and in the Beluga formations."

Specifically, Furie said, the well discovered approximately 46.7 billion cubic feet of gas in place, which, extrapolated over a larger area, suggested some 3.5 trillion cubic feet.

If correct, the figures would rank among the largest discoveries ever for the Cook Inlet basin, but some state officials and industry watchers expressed skepticism, saying that the announcement pushed the upper limits of what geologists expected the basin to contain.

Speaking to lawmakers in March 2012, Furie President Damon Kade estimated probable gas reserves of 750 billion cubic feet and peak production of 30 million cubic feet per day from Kitchen Lights, far lower than the blockbuster November 2011 estimate. The lower figure was based a smaller geographic drainage area, Kade later told Petroleum News.

The announcement made sense, given that Kitchen Lights had unified several smaller prospects. Kade said a deeper well might encounter additional gas, as well as oil.

Extension granted

The long process of deadlines and defaults had yielded a deal where Escopeta agreed to drill into the Jurassic formation by Oct. 31, 2011. While Furie began drilling in early September, the state asked it to suspend operations to accommodate additional safety inspections and gave the company the go ahead to continue on Oct. 13. Even with a later than expected freeze-up, Furie was unable to complete the well by the end of the season.

After the season, Furie asked the state for a four-year extension — until Jan. 31, 2016 — to meet its drilling commitments, citing both the discovery and the suspension of work.

The state approved the extension, which came with a four-to-five-well plan of exploration as well as talk of a future plan of development with an offshore platform.

The exploration component of the plan proposed spreading out drilling to assess various small prospects within the unit. The initial Kitchen Lights Unit No. 1 and No. 2 wells would be in the Corsair prospect. The Kitchen Lights Unit No. 3 well would be in the central block. The Kitchen Lights Unit No. 4 and No. 5 wells would be in the southwest block. A proposed Kitchen Lights Unit No. 6 well would be in the northern block.

Actual drilling, to date, has been more focused. Furie drilled the Kitchen Lights Unit No. 1, No. 2 and No. 3 wells, plus a sidetrack, in the Corsair Block. Furie started drilling the Kitchen Lights Unit No. 4 well is in the northern block in 2013. The company suspended the well last winter and had not completed drilling as of press time.

A single well in the upper Cook Inlet costs some $25 million to $30 million, according to Kade, and the initial two-well program and wintering expenses would cost $80 million.

Drilling under way

The Spartan 151 returned to Kitchen Lights in late April 2012.

Having cemented the well to 4,800 feet, Furie needed to redo some drilling, but by late May the company had finally deepened the well beyond its initial suspended depth.

By August, drilling had stopped at 15,298 feet, more than 1,000 feet shy of the target depth and also shy of the target pre-Tertiary rock, to leave time to begin the second well.

While drilling began at Kitchen Lights Unit No. 2, the well only reached some 9,000 feet, according to Petroleum News sources. By October 2012, Furie told the state that it finished sidetracking the well and planned to test several gas-bearing zones in the Beluga.

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

FURIE OPERATING ALASKA LLC

Furie Operating Alaska’s Kitchen Lights unit Platform A departs Ingleside, Texas, on June 4, en route by barge to Alaska’s Cook Inlet.

By June 2013, Furie had completed the Kitchen Lights Unit No. 3 well. The well targeted natural gas at a depth of some 10,000 feet in an attempt to delineate the initial discovery.

While Furie tested the well, it declined to release results.

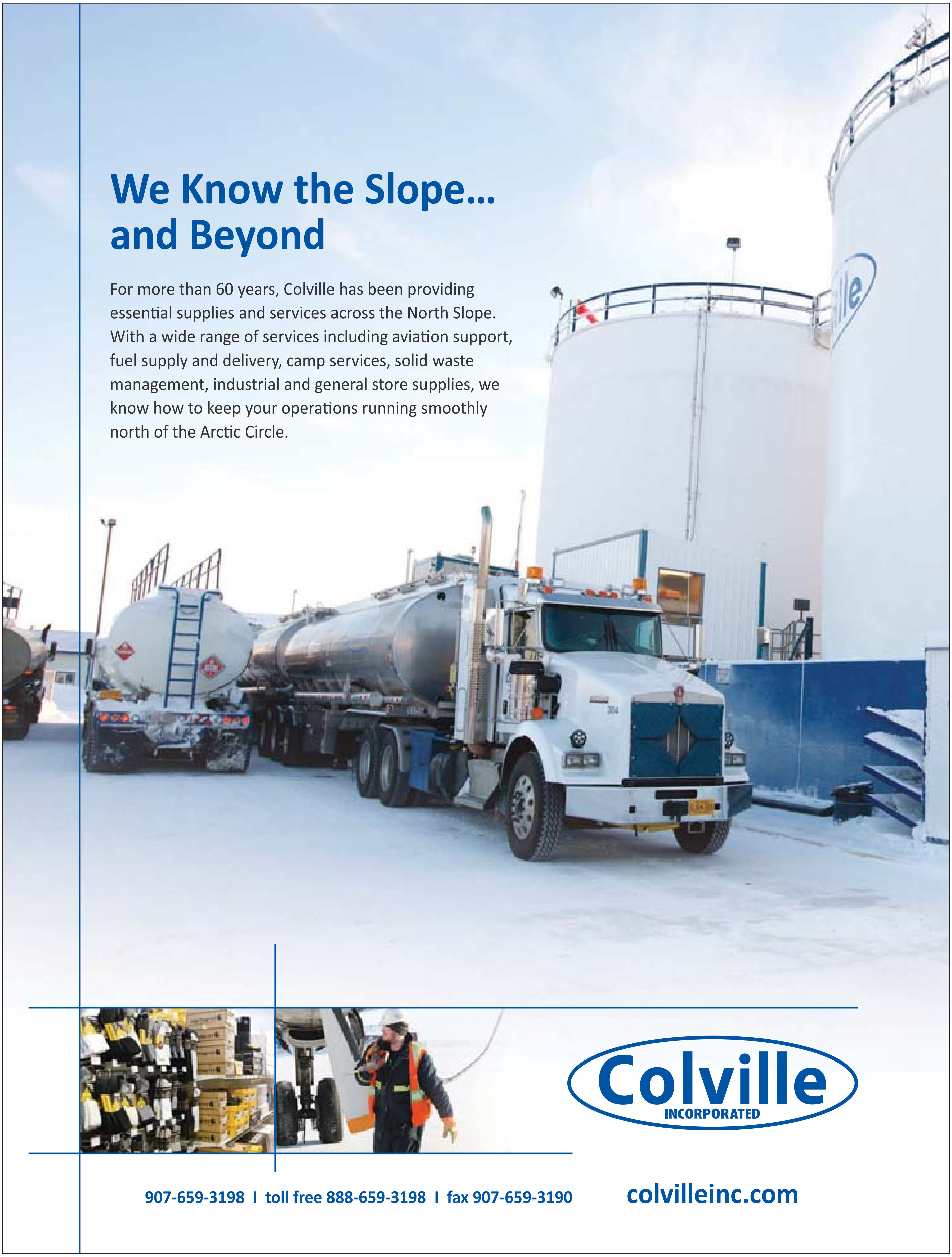
“We had a good test,” President Damon Kade told Petroleum News in July 2013.

The company began drilling the Kitchen Lights Unit No. 4 well soon after, but only reached halfway to total depth by the time the summer drilling season ended.

Saying it had “encountered potential oil and gas reserves,” Furie permitted a 3-D seismic campaign as it completed the well. The campaign would “characterize the subsurface geological structure and confirm exploration and drilling targets and reservoirs.”

Several months later, SAE Exploration began permitting a separate 3-D seismic

continued on page 57


We Know the Slope…
and Beyond
For more than 60 years, Colville has been providing essential supplies and services across the North Slope. With a wide range of services including aviation support, fuel supply and delivery, camp services, solid waste management, industrial and general store supplies, we know how to keep your operations running smoothly north of the Arctic Circle.
Colville
INCORPORATED
907-659-3198 I toll free 888-659-3198 I fax 907-659-3190
colvilleinc.com

FURIE *continued from page 55*

survey — independent of Furie — covering a similar region around the Kitchen Lights unit.

Development plans

The drilling results convinced Furie to consider development strategies.

In filings with the U.S. Army Corps of Engineers, Furie described the proposed KLU Platform A as having a 64.5-foot by 72-foot deck, an 18-foot diameter caisson and two subsea gathering lines connecting to a new production facility. The company said it hoped to begin construction in early 2014 and begin production by the end of that year.

By the end of 2013, Furie said it had completed engineering design and was ordering certain materials for the platform. "We're well beyond the design phase," Kade said. "Our target is to get that installed next year and get gas to the beach by fourth quarter."

In a plan of operations filed in early 2014, Furie said the Kitchen Lights Unit No. 3 well had proved up the undeveloped gas reserves in the region. The company estimated 30 billion cubic feet of gas per year. The production would start from the KLU No. 3 well, but Furie said it might drill as many as six wells to maximize production. The plan also said the two pipelines would initially transport up to 100 million cubic feet per day.

Permitting and construction posed challenges enough, but Furie was also thinking about market conditions. The company joined several smaller producers in the region to protest a proposed four-year contract between Hilcorp Alaska LLC and Enstar Natural Gas Co.

The contract provided short-term supplies for the Southcentral region, but the smaller producers worried about being shut out of the market until the contract ended in 2018.

The contract came out of a solicitation that Enstar sent to producers and potential producers in the region. In a letter to the Regulatory Commission of Alaska, Furie said it had responded to the solicitation and offered to provide gas starting in late 2014.

To prove its credentials, Furie offered to show Enstar "confidential well flow test data" from its Kitchen Lights drilling, plus its plans for the facilities it intended to install, according to Kade. But "when Furie followed up with Enstar just over a month later, Enstar stated that it had already contracted for all of the volumes it required."

As of May 2014, Furie said fabrication work was nearing completion. The company expected the platform to arrive in the Cook Inlet in July, with onsite installation to be completed in September and production starting sometime during the third quarter.

Jones Act issue unresolved

Throughout all this, Furie has continued to deal with the Jones Act violation.

U.S. Customs and Border Protection levied a $15 million fine against Escopeta in October 2011 for moving the rig to Alaska without a valid waiver of the Jones Act.

The fine represented the assessed value of the rig.

Escopeta appealed the decision, saying the fine should only be $675,000, or 5 percent of the value of the rig, because the company needed to get the equipment to Alaska to help bolster flagging natural gas supplies and had been unable to find a domestic ship.

While Escopeta had secured a Jones Act waiver in 2006, it was no longer valid by the time Escopeta brought the rig to Alaska, although the company denied any wrongdoing.

In mid-2012, Furie sued the U.S. Department of Homeland Security, calling the $15 million fine "unwarranted and unprecedented," and a violation of the "excessive fines" clause of the Eighth Amendment to the U.S. Constitution. Furie believes the fine is the largest ever assessed for a Jones Act violation, although the federal government said it had previously assessed a similar fine, which, with inflation, would now be larger.

Even though the initial 2006 Jones Act waiver had been deemed invalid by the time the exploration campaign began in 2011, Furie argued that the factors behind the waiver — the need for additional energy supplies in Alaska to fuel military bases — remained.

After the federal government sought to have the suit overturned, Kade complained that the fine had "made it difficult for Furie to secure investors in its resource exploration and development venture," which in turn was slowing the pace of bringing supplies online.

The tangle of suits and countersuits continues to play out in court.

Contact Eric Lidji at ericlidji@mac.com

Great Bear still pursuing source rock development

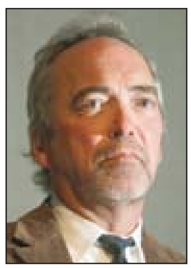
The Alaska company sees great potential in the geology just south of the giant North Slope oil fields

By ERIC LIDJI
For Petroleum News

The public policy discussion around Great Bear Petroleum LLC describes the company as the future of the North Slope, but it may be more accurate to describe it as the past.

The local independent and its investors want to develop source rocks, the ancient geologic formations believed to have generated the massive North Slope oil fields.

If successful, Great Bear could usher a new era of development in Alaska. Source rocks could contain enough oil to fuel the Alaska economy for decades, but developing those resources will require the state and the industry to adapt many long-standing practices.


JUDY PATRICK

ED DUNCAN

'Very bullish'

Great Bear came growling into Alaska in October 2010, when it took more than 500,000 acres with more than $8 million in apparent high bids at the North Slope lease sale.

The first clue that Great Bear was up to something new was the location of its bids. The company took a broad swath of acreage across the central North Slope, just south of the Prudhoe Bay and Kuparuk River units. While exploration companies have sniffed around those regions for decades, Great Bear President and COO Ed Duncan told Petroleum News in October 2010 that he believed the leasehold contained "expansive new plays."

While Duncan thought the industry as a whole had a "general malaise" about the North Slope, he said Great Bear had "almost polar opposite positions, it appears." The results of the lease sale reinforced the distinction: Great Bear took every lease on which it bid, and took 92 percent of all the leases bid on during the sale. "We're very bullish," he said.

The five principals of Great Bear formed the company to chase the source rock potential of the North Slope. Duncan and Vice President of New Ventures Bob Rosenthal met while working at the BP-predecessor Sohio during the early 1980s and gained insights about North Slope petroleum systems. "We believe that there are expansive new plays and we've captured a very significant piece of what we came here to do," he said. The idea was to develop the source rock, just as producers had done with the Eagle Ford shale of south Texas.

In a tantalizing statement for policymakers concerned about production, Duncan said that "through the success of our program and the exploitation of the North Slope's resource plays that we're going to establish long-term, growing and stable production in the state."

NAME OF COMPANIES:
Great Bear Petroleum Ventures (three LLC entities, I, II and III)
Great Bear Petroleum Operating LLC
Note: Leases formerly held by Great Bear Petroleum LLC
ALASKA HEADQUARTERS:
601 W. Fifth Ave., Ste. 505, Anchorage, AK 99501
TOP ALASKA EXECUTIVE: Edward A. Duncan, president and chief operating officer
PHONE: 907-868-8070
COMPANY WEBSITE: http://greatbearpetro.com

Program different

From the start, the Great Bear program differed greatly from traditional North Slope exploration. A conventional reservoir is the result of oil and natural gas migrating into porous rocks trapped by a seal. For decades, exploration companies have used surface geology and seismic information to make informed guesses about where to drill wildcat wells. Sometimes, they drilled dry holes and sometimes they found massive oil fields.

While hopeful about conventional resources, Great Bear wanted more. "It's going to be unlucky if we don't have conventional potential in that lease position, but that's not why we're here," Duncan said. "We're not here exploring for these conventional resources."

In a source rock "reservoir," the oil or natural gas is contained within the rock itself.

The North Slope is home to three stacked source rock intervals: the Shublik, the Kingak and the HRZ/Hue shale system, from deepest to shallowest. These source rocks exist some 8,000 to 13,000 feet underground, in the area south of Prudhoe Bay and Kuparuk.

Existing seismic and well data had already confirmed the oil-bearing source rock south of those fields, though. Great Bear just needed to figure out how to produce it. As such, Great Bear said it could start drilling without conducting prospect-specific 3-D seismic.

Eager to start, Great Bear planned to drill two test wells in the winter of 2010 and 2011. "We'll begin the permitting process almost immediately," Duncan said in late October 2010. "We'll let that run in parallel with the lease review. … As soon as the leasehold is cleared we would be in a position to drill, if the clearance occurs early enough."

Four core-holes planned

By January 2011, logistics seemed to demand a slower timeline. With the state saying it expected to issue the leases in May, Great Bear pushed its drilling plans to late 2011.

Great Bear planned to drill vertical wells into the North Slope source rocks with laterals extending through actual formations and use fracturing stimulation to extract the oil. To start, Great Bear envisioned drilling at least four 11,000-foot vertical test wells, or narrow diameter "core-holes" to better determine the rock depths and to collect rock samples.

Among the factors unique to source rock exploration is thermal maturity, which measures the slow geologic process of making hydrocarbons. The maturity must be high enough to turn organic materials into oil, but low enough to keep the oil from becoming natural gas.

With the right test results, Great Bear planned to drill an initial lateral into one of the formations. If it worked, Great Bear said it could produce oil by mid-2012. Using on-site production equipment and its proximity to the road system, Great Bear would be able to truck any oil production to existing infrastructure along the trans-Alaska oil pipeline.

A 'factory' model

Given the success of source rock development in the Lower 48, Great Bear turned heads as soon as it announced its intentions for Alaska. But the company really captured the imagination of policy makers when it hypothesized about what the future could hold.

When Duncan testified before lawmakers in February 2011, he envisioned drilling two production tests in early 2012. He described the wells as "full exploration style wells," but, he said, full development would be unlike anything currently under way in Alaska.

As unconventional plays become understood, he said, "industry tends to move toward a factory type drilling," where wells can be drilled and completed at a much quicker rate.

To illustrate this "factory" model, Duncan said Great Bear wanted to use 20 rigs to drill some 200 wells each year over three 15-year phases targeting two of the three source rock formations. Those wells would produce 200,000 barrels per day by 2020, 350,000 bpd by 2035, 450,000 bpd by 2041 and peak at 600,000 bpd in 2056 before dropping to a sustained long-term production rate of 450,000 barrels per day out as far as 2074.

"It's going to be unlucky if we don't have conventional potential in that lease position, but that's not why we're here." —Great Bear President and COO Ed Duncan

While the initial startup capital for Great Bear came from friends and family, the full proposal would require some $2 billion each year in capital, Duncan told lawmakers.

When asked if Great Bear could single-handedly produce 1 million barrels per day from its leasehold by drilling as many as 1,000 wells each year, Duncan said, "Two hundred wells a year is a lot, but it's scalable. If the capital is there, if the development infrastructure is there, and the ability to move that produced oil into the pipeline is there — all of those are challenges — but if all of those are there, it can be done. There's nothing that we're waiting for from a technology perspective. The ability to drill and complete these wells is proven. It will be better a year from now than it is today."

For comparison, only about 1,000 wells have been drilled in the main Prudhoe Bay field since 1968, throughput on the trans-Alaska oil pipeline is currently around 550,000 barrels per day and the state is usually home to between 20 and 30 rigs at any given time.

A paradigm shift

Clearly, the Great Bear model would require major changes in how the oil industry operates in Alaska, which would mean major changes in how the state regulates industry.

Speaking in March 2011, Nabors Alaska Drilling's Dave Hebert told Petroleum News it would be "no small task by any means, but certainly not impossible" to provide the 20 rigs needed for the program. In November 2011, Great Bear announced it was partnering with the oil field services giant Halliburton Co. on technical aspects of the program.

Testifying before lawmakers in March 2011, Alaska Oil and Gas Conservation Commission Commissioner Cathy Foerster said the existing system of units, participating areas and pool rules may be

continued on next page

GREAT BEAR *continued from page 59*

irrelevant for source rock exploration. What constitutes a pool when the oil is distributed somewhat evenly throughout miles and miles of rock?

Source rock wells drain from a limited area, and so correlative rights are less of a concern than in conventional drilling, according to Foerster. “The only time that unitization might be warranted in this kind of development is if there are economies that could encourage greater ultimate recovery. In other words, stopping competition between checkerboard small leases and having one set of facilities, one gathering system, rather than everybody going out on their own little patch of land and building the whole shebang,” she said.

Year-round exploration

The Great Bear program changed again in the summer of 2011.

Originally, Great Bear had planned a two-phase program. In late 2011 it would drill four 11,000-foot vertical core holes and in early 2012 it would drill two 11,000-foot production test wells, each with at least one 4,000-foot horizontal lateral. Depending on the results, the company planned to drill additional wells in the winter of 2012 and 2013.

When a contractor identified previously used gravel sites along the Dalton Highway, though, Great Bear no longer needed to wait for seasonal tundra openings to begin operations, which meant the company was able to accelerate its plans considerably.

The Alaska Department of Natural Resources issued 99 leases to Great Bear in April 2011. Great Bear decided to drill as many as three vertical wells between October and December 2011, and return the following spring to drill a horizontal sidetrack from each.

In September 2011, Great Bear filed a lease plan of operation outlining a yearlong program to determine a “proof of concept” for commercially producing oil from source rock. The plan proposed six drill sites along a 15-mile industrial area following the Dalton Highway and the trans-Alaska oil pipeline. The company named its proposed wells after the stars in the Ursa Major constellation, which is also known as Great Bear: Alcor No. 1, Merak No. 1, Mizar No. 1, Megrez No. 1, Dubhe No. 1 and Alioth No. 1.

The corridor was important. If Great Bear moved farther west on its leases, it would reach an area where the preponderance of wetlands shifted permitting dominance from the Alaska Department of Natural Resources to the U.S. Army Corps of Engineers.

While the plan would accommodate six wells with a lateral at each well, Great Bear said told the state it would be unlikely to drill more than four wells, each with one lateral.

By November 2011, when Great Bear announced the Halliburton deal, Duncan said that a successful proof of concept program could yield a pilot development by late 2012.

The pilot program would use a modular processing unit to bring crude oil up to the standards required for the trans-Alaska oil pipeline. The one-year program would give Great Bear “a collection of well production curves for North Slope shale oil development,” which Duncan said would inform Great Bear’s decisions about a full development scheme. “One year from now we’ll be going to pilot development; a year after that we’ll have tight curves in front of us and we’ll be sanctioning then, hopefully, corridor development — that’s the 200 hundred wells a year,” he told lawmakers.

The initial program, though, came during a bumper year for North Slope exploration, which placed a strain on the supply of drilling rigs available for winter activities.

In December 2011, Great Bear offered nearly $3 million in high bids in the North Slope lease sale to bolster its leasehold in the area south of the Kuparuk River unit.

By late January 2012, Great Bear was still looking for a rig, but it had obtained all the preliminary federal, state and local permits needed for a year-round drilling program, and planned to conduct site preparations in March or April with drilling scheduled to begin sometime thereafter, Division of Oil and Gas Director Bill Barron told lawmakers.

By May 2012, as Great Bear was preparing to drill, Duncan presented a more conservative view to lawmakers. While previously outlining plans for 9,000 wells over 45 years, Duncan spoke of the play being “drilled out at a very high rate for at least the next 10 or 15 years, maybe longer” with 200 wells per year for a total of 3,000 wells.

And while remaining optimistic in the ability of technology to solve problems, he acknowledged that the program might determine that Alaska source rock was not yet commercial. "Technology is evolving very, very rapidly," he said. "I am a great believer that if we put the challenge out to the Halliburtons, the Schlumbergers, the Baker Hughes, the Weatherfords and the others of the world, that it'll get cracked — the code will get cracked. Whether today, next year, or subsequent, I am a great believer in that."

Drilling under way in 2012

Great Bear planned a three well program for the second half of 2012.

The original goal was to drill an 11,000-foot vertical well bore at the Alcor No. 1 site, move south to drill a vertical well bore and a horizontal lateral at the Merak No. 1 site and send the rig the north again to complete a horizontal lateral at Alcor No. 1. Great Bear also wanted to drill a vertical at its Mizar No. 1 location before the end of the year.

After spudding the Alcor No.1 in late June or early July, Great Bear announced on July 9 that it had almost reached the HRZ and was preparing to start take core samples. But Duncan was cautious at a shale conference in August 2012. Describing the program in his conference speech, Duncan said, "The results to date are within our expected outcome."

Asked about his near term expectations, Duncan said, "We expect to be testing and producing and … selling produced hydrocarbons potentially by the end of the year, and certainly early next year." With a successful testing and development program, Duncan believed Great Bear could produce at least 100,000 barrels per day within five years.

Speaking at an industry conference in September, by which time Great Bear was in the process of drilling the Merak No. 1 well, Duncan said, "I can tell you with absolute confidence that where we thought we would find oil in these source rocks, we found oil."

The results prompted Great Bear to accelerate its program.

Great Bear asked the state for permission to extend its proposed production test on the two wells to 180 days, from its initial timeline of 15 days. Having studied similar wells in the Lower 48, Great Bear believed the initial 15 days of production would mostly consist of flowback water from hydraulic fracturing operations. A longer test would also provide a better sense of the decline curve for shale wells in Alaska, Great Bear told the state.

A longer test would eliminate the need for a pilot well pad for production testing, which would speed up the entire timeline for the project, Duncan said. Great Bear could potentially make a decision about full-scale development in mid-2013, instead of 2014.

Great Bear also asked the state for permission to drill a second well at the Alcor pad, saying that complications prohibited it from drilling a horizontal lateral at the first well.

By December, having drilled only the vertical sections of the two wells and conducted a small 3-D seismic survey around the well locations, Great Bear suspended its drilling operations for the season. "Certainly operations took a little bit longer than we expected, particularly on Alcor, and the lab analysis quite frankly has taken much longer than we had hoped," Duncan told the Alaska Geological Society. Great Bear drilled Alcor No. 1 to 10,813 feet and Merak No. 1 to 11,094 feet, collecting more than 600 feet of rock core.

Even with the slower than expected schedule, Duncan expressed confidence in the initial results of the program. "We have drilled through all of our targeted source rock units," he said. "We've proven those (to be) present at the depths predicted and in the state of thermal stress or thermal maturity, certainly within the range of expected outcomes."

Speaking to the Alaska Public Radio Network in early October, Duncan said Great Bear would conduct a 3-D seismic survey in early 2014 and present its development plan at the end of the year.

Pursuing seismic

Great Bear remained quiet in early 2013, as it analyzed the results from its program.

"We have not yet determined our activities for the rest of the year," Vice President for External Affairs Patrick Galvin told Petroleum News by email in early April. "When the technical analysis of our drilling results is complete, bolstered with the 3-D seismic data, we will be in a strong position to determine the next steps in our exploration program."

That plan held firm for most of the year.

Speaking to an industry conference in September 2013, Duncan said Great Bear would hold off on making further drilling plans until it finished analyzing the rock samples it collected the year before. "We are right on the original timeline. So our hope would be that you'll see us sanction a full-field development in the next year or so," he said. Speaking to the Alaska Public Radio Network in early October, Duncan said Great Bear would conduct a 3-D seismic survey in early 2014 and present its development plan at the end of the year.

In late 2013, CGG Land Inc. announced the Great Bear and Niksik 3-D seismic programs, which together covered some 280 square miles south of the Prudhoe Bay unit.

Contact Eric Lidji at ericlidji@mac.com

Hilcorp is aiming to rejuvenate two Alaska basins

A recent acquisition of BP properties on the North Slope follows extensive activities in the Cook Inlet

By ERIC LIDJI
For Petroleum News

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

Hilcorp Energy Co. is the dominant company in the Cook Inlet basin. And with a recent acquisition of some BP properties, Hilcorp is now an important player on the North Slope.


JOHN BARNES

The privately held Houston-based independent exploration and production company gained its Cook Inlet dominance by acquiring the assets of Union Oil Company of California in 2011 and Marathon Oil Co. in 2012. With a business model of "acquire and exploit," the deal excited policymakers worried about declining investment in the basin.

"Hilcorp is enthusiastic about the opportunities it sees in Alaska, and it has an aggressive plan to invest in required well maintenance and in-field drilling to restore and increase production from existing fields, as well as pursue the many exploration targets it has identified around the Cook Inlet basin," Sen. Tom Wagoner, R-Kenai, said in a statement after news of the 2011 acquisition broke. "Hilcorp's entry into Alaska is further confirmation of the fact that tremendous oil and gas opportunities remain in the basin."

Asked at a Commonwealth North meeting in December 2012 if Hilcorp planned to conduct exploration activities in the Cook Inlet, Senior Vice President John Barnes said the company had come to Alaska with an eye toward development and did not have an exploration budget for 2013. That said, Barnes also acknowledged the exploration potential of the basin and anticipated pursuing those opportunities in the future.

On the west side of Cook Inlet, Hilcorp operates the Lewis River, Pretty Creek, Stump Lake and Ivan River 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 Wolf Lake and West Fork fields. In the southern Kenai Peninsula, Hilcorp operates the Deep Creek and Nikolaevsk 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.

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

To date, Hilcorp has focused mainly on increasing production from the 20-odd fields in its portfolio, but the company has also launched two exploration projects inside existing units: the Deep Creek unit in the southern Kenai and the Ninilchik unit along the coast.

In April 2014, Hilcorp acquired a stake in four BP Exploration (Alaska) Inc.-operated fields on the North Slope. The estimated $1.25 billion deal gave Hilcorp operatorship of the Endicott, Northstar and Milne Point fields and a 50 percent stake in the Liberty field, which will now move forward after long delays.

To date, Hilcorp has focused mainly on increasing production from the 20-odd fields in its portfolio, but the company has also launched two exploration projects inside existing units: the Deep Creek unit in the southern Kenai and the Ninilchik unit along the coast.

"We are excited about this acquisition," Hilcorp Senior Vice President of Exploration and Production John Barnes, said in a statement. "Our ability to bring new life to mature basins is a great fit for these assets."

The Deep Creek unit

Hilcorp started its exploration activities at the Deep Creek unit.

Standard Oil Company of California discovered the field in 1958 with the Deep Creek Unit No. 1 well, but never developed it. Unocal returned to the field in the early 2000s.

The Alaska Department of Natural Resources and Cook Inlet Region Inc. formed the Deep Creek unit at the end of 2001 and formed the Happy Valley participating area in November 2004. The unit covers some 20,000 acres located about five miles inland.

After acquiring seismic and drilling exploration wells, Unocal announced a discovery in November 2003. The discovery justified extending the Kenai Kachemak Pipeline.

Unocal brought the unit online in 2004 at 3 million to 4 million cubic feet per day and drilled some 13 wells between 2003 and 2009, but investment flagged. In an eighth plan of develop-

continued on next page

HILCORP *continued from page 63*

ment, from December 2010, Unocal offered no plans for further exploration, but said it was looking to farm out exploration acreage at the southern end of the unit.

Division of Oil and Gas Director Bill Barron required the ninth plan of development to include plans for exploring parts of the unit outside the Happy Valley participating area.

The unit is believed to contain additional accumulations.

"Unocal's interpretation of the data also indicates a potential accumulation south of the Happy Valley reservoir that Unocal refers to as the Middle Happy Valley Prospect," the division wrote in a 2004 decision concerning the unit. Unocal took steps toward exploring the prospect, but the plans never materialized. A 2007 report from Netherland, Sewell & Associates estimated probable reserves of 22 billion cubic feet for the unit area.

By the time Hilcorp acquired the unit, the landowners were on the verge of contracting it.

Instead, they extended the eighth plan of development to give Hilcorp time to make plans for the unit. The extension gave the company until February 2013 or six months after closing, whichever came first, to file a ninth plan of development with exploration plans.

New wells

To start, Hilcorp drilled three wells at the unit: The Happy Valley B-14, Happy Valley B-15 and Happy Valley B-16. The program discovered commercial quantities of gas in the Sterling and Beluga formations, shallower than the producing Beluga/Tyonek pool.

The 2,005-foot B-14 exploration well tested the Sterling formation shallower than the existing participating area. The 3,069-foot B-15 exploration well tested the Upper Beluga formation, also shallower than the existing participating area. The 4,857-foot B-15 development well targeted the Beluga formation, but "rig limitations" prevented it from reaching its target depth, the company said in filings with the Division of Oil and Gas, and Hilcorp plans to take another stab at the exploration target at the end of this year.

In early 2013, Hilcorp acquired nearly 50 square miles of 3-D seismic over the unit.

Speaking in June 2013, Barnes said the field was "making more now than it was shortly after Unocal discovered and developed it" and estimated that the resource at Happy Valley is "probably three to four times larger than the current participating area."

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

Hilcorp also grabbed acreage around the unit at May 2012 and May 2013 lease sales.

Hilcorp eventually asked the state and CIRI to expand the unit to include CIRI leases to the south, but Hilcorp withdrew the request, calling the discussions "unsuccessful."

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

Hilcorp also plans to drill Middle Happy Valley No. 1 well in 2015. The exploration well would target the Sterling, Beluga and Tyonek formations. The program would require a new road and pad, plus associated facilities and pipelines to access state and CIRI land.

The Ninilchik unit

Hilcorp turned its attention to the Ninilchik unit in 2013.

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

After picking up a share of the coastal unit through the Unocal acquisition, Hilcorp grabbed the remaining interest and the operatorship through the Marathon acquisition.

In addition to development work, Hilcorp completed a four-well exploration program in 2013: the Susan Dionne No. 8, Paxton No. 5, Frances No. 1 and Falls Creek No. 5.

Surprisingly the program included oil exploration in addition to expanding existing gas production. "We do have plans that include oil development in that area," External Affairs Manager Lori Nelson said. "True to Hilcorp's prior success we intend to leave no stone unturned within our existing asset base in order to maximize production. The Cook Inlet basin as a whole is a world-class asset that we are excited to revitalize and develop."

In early 2013, Hilcorp sought to amend its plan of operations for the Susan Dionne pad at the unit to accommodate a 12,000-foot oil exploration well, with the potential for a second well if the first proved to be successful. While previous operators had drilled at least six oil exploration wells at the unit, including one that encountered minimal oil shows, the Hilcorp well would be the first to do so in many years, according to Nelson.

Hilcorp drilled the Susan Dionne No. 8 toward the middle of the year, but the well was non-commercial for oil. The company completed it for gas production from the Tyonek formation in the Susan Dionne participating area and from the Beluga on a tract basis.

The results led Hilcorp to drill the Frances No. 1 well later in the year from the new Bartolowitz pad. The well was also non-commercial for oil, but showed "strong potential" for gas production from the Beluga and Tyonek formations. Hilcorp now plans to test the well toward the middle of the year with the aim of starting production in the third quarter. The company expects to form a Falls Creek participating area next year.

Hilcorp drilled both wells using the Saxon 147 drilling rig.

The Paxton No. 5 well was a shallow well from the Paxton pad. Hilcorp completed the well as a producer from the Beluga formation and is considering additional activities. The company expects to form the Susan Dionne/Paxton Beluga participating area next year.

The Falls Creek No. 5 well encountered gas in the Tyonek and Beluga, and now Hilcorp plans to conduct additional testing this year to gauge the way forward for development.

The 2013 program convinced Hilcorp to continue exploration activities through 2015, and the company is asking the state to defer unit contraction until December 2015.

Six wells planned

This year, Hilcorp is planning a six-well exploration program at Ninilchik.

The 10,000-foot Frances No. 2 and Frances No. 3 wells would target the Tyonek and Beluga formations. The former would be east of the Falls Creek participating area and north of the Bartolowitz pad. The latter would be south of the Falls Creek participating area and east of the Bartolowitz pad. Hilcorp has described both wells as "appraisal."

The 9,000-foot Falls Creek No. 6 would follow up on the Frances No. 2 well to further appraise the Tyonek and Beluga formations in the area north of the Falls Creek pad.

The 10,000-foot Paxton No. 6 and Paxton No. 7 wells would also target the Tyonek and Beluga formations. They would both be south of the Paxton pad. Paxton No. 6 would be an "appraisal" well and Paxton No. 7 would "follow up" on the results of Paxton No. 6.

Hilcorp is also permitting Paxton No. 8 and Paxton No. 9 wells.

Hilcorp is currently permitting an expansion of the Paxton pad and is planning a noise abatement study of the pad. It is also considering construction of a Bartolowitz gas facility to support Frances No. 1 gas production. The facility would in turn require boring a pipeline under the Sterling Highway connecting to the existing Kenai-Nikiski Pipeline.

The 6,500-foot GO No. 8 would target the Sterling and Beluga formations above the existing Grassim Oskoloff participating area in the area west of the existing GO pad.

Other opportunities

A recent slate of Hilcorp news suggests additional exploration opportunities.

*Hilcorp is considering an exploration well at the Cannery Loop unit targeting oil in the Hemlock and West Foreland formations encountered in a 1987 well. Hilcorp described the zones as having "large amounts of risk associated with reservoir productivity."

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

*Hilcorp is conducting a comprehensive field study of the Ivan River unit and evaluating a "grass roots well or sidetrack" to further develop the Sterling and Beluga reservoirs.

*Hilcorp recently acquired the remaining 50 percent working interest in two Buccaneer Alaska LLC leases at the former Southern Cross unit in the waters of the Cook Inlet.

*If and when the sale closes, Hilcorp is almost certain to announce some exploration, appraisal or development activities at its newly acquired assets on the North Slope.

Contact Eric Lidji at ericlidji@mac.com

Linc sees a 'clear path' for Umiat oil development

Australian independent wants to develop the remote field after a successful flow test earlier this year

By ERIC LIDJI
For Petroleum News

In the old days, exploration companies used seismic information, geophysical clues, wildcat wells and a lot of luck to find reservoirs of oil or gas hidden beneath the surface.

Today, companies like Linc Energy Inc. are pursuing energy sources discovered decades ago, but left undeveloped because older technologies prohibited economic development.

The Australian independent is currently pursuing two such projects in Alaska: an effort to synthesize methane from deep coal deposits and an effort to develop the Umiat oil field.

CORRI FEIGE

After two seasons actively exploring Umiat, Linc recently completed the first flow test in decades at the Umiat field and believes it has "a clear path" to commercial development.

Wasting no time

The subsidiary Linc Energy (Alaska) Inc. arrived in Alaska in March 2010 when it acquired 123,000 acres in Cook Inlet from San Francisco-based GeoPetro Resources.

The acreage was split between a block near Point MacKenzie along the western bank of Knik Arm and a block at Trading Bay on the west side of Cook Inlet, and included State of Alaska, Cook Inlet Region Inc. and Alaska Mental Health Trust Authority leases.

The acreage allowed Linc to pursue a two-pronged strategy.

The company planned to drill a conventional exploration well on the Point MacKenzie acreage and use the proceeds from any resulting natural gas production to offset the cost of unconventional exploration into promising coal deposits in the Trading Bay region.

By summer, Linc was already preparing a well.

The region was home to early exploration by Union Oil Co. of California, Atlantic Richfield and Pan American Petroleum going back to the 1960s. While those exploration companies found promising coal seams, none found commercial amounts of oil or gas.

GeoPetro never drilled in Alaska, but the independent had built a pad and an access road for a proposed Frontier Spirit No. 1 well in the Point MacKenzie region. The 8,000-foot well would have tested for conventional gas prospects in the middle and lower Tyonek formations. A nearby Enstar Natural Gas Co. line improved the economics of the project.

After studying existing seismic information, though, Linc drilled the LEA No. 1 well in October on nearby acreage, building a new gravel pad but using existing access roads.

The 6,323-foot well into "basement volcanic rocks" encountered "a number of gas bearing horizons" and "a number of significant coal seams," the company announced in November. The well collected gas samples from 31 intervals between 1,500 feet and 6,323 feet, all containing "dry natural gas" between 99 and 100 percent purity, which could theoretically be delivered into the nearby Enstar line with little to no processing, the company said in February, after conducting early analysis. The results "confirmed three significant sand formation intervals that appear to be gas charged and which possess apparent permeable values indicating they are good candidates for a flow test," Linc said.

The actual flow test provided disappointing results, though. After testing the three sandstones, Linc decided the structure was "too tight" to produce without "swabbing" the well with large amounts of formation water. "The conclusion from the testing is that although gas is trapped within the coal, there is not sufficient natural fracturing in the coal to allow for the recovery of commercial quantities of gas," the company said in May.

Although disappointing, LEA No. 1 encountered a "significant" coal seam that "appears to be highly suitable for Underground Coal Gasification," according to the company.

While "disappointed" about the results, Linc CEO Peter Bond called exploration "a numbers game," adding, "the more smart wells you drill the more likely you are going to be successful."

"Linc Energy has an extraordinary record of getting our exploration targets right the majority of the time," he added, "and I still think the coal measures we've discovered via the LEA No. 1 program will add a lot of value to the company in the longer term."

Seeking an 'Angel'

Even with the setback, Linc promised to continue its program "at an aggressive pace"

continued on page 68

NAME OF COMPANY:
Linc Energy Ltd.
COMPANY HEADQUARTERS:
Brisbane, Australia
ALASKA OFFICE: 3000 C St., Ste. 103, Anchorage, AK 99503
TOP ALASKA EXECUTIVE: Corri Feige
PHONE: 907-868-8660
COMPANY WEBSITE: www.lincenergy.com

LINC ENERGY *continued from page 66*

Toward the middle of 2012, Linc asked the state to form the 1,932-acre Angel unit over one state of Alaska lease and one Alaska Mental Health Trust Authority lease located just a quarter-mile south of where the company had drilled the LEA No. 1 well in 2010.

The proposed unit represented only a small portion of the 14,758 acres Linc was leasing in the Point MacKenzie area, but the company pointed to state regulations requiring a unit to cover the minimum area needed to cover a potential hydrocarbon accumulation.

The company proposed a two-year plan of exploration to support its application.

In the first year, Linc would shoot a 2.64-square mile 3-D seismic survey over the proposed unit and a 12.7-linear mile 2-D survey extending east of the unit boundaries.

In the second year, Linc would drill a well to investigate a geologic "feature" of the Pittman Anticline that extends into both the Tyonek and Hemlock formations.

Previous seismic acquisitions, according to the company, showed "strong amplitude anomalies" and "apparent velocity-induced depressions of seismic reflectors over the crest of the feature" that "would be expected in the presence of gas charged sands."

Calling itself "the only company that has expressed any interest at any time within the past 40 years in developing the acreage within the proposed Angel unit," Linc said that rejecting the unit application would be "tantamount to condemnation" for the region.

"While other lessees and potential lessees have been unwilling or unable to develop that Angel prospect, Linc is willing to make that commitment," Linc wrote to the state.

As the sole working interest owner of the leases, Linc worried it might be denied a unit because the state prefers to use unitization as a way to simplify private negotiations. The company said unitization would ease logistics between the two landowners at the unit.

A month later, the majority of the acreage Linc acquired from GeoPetro expired at the end of its primary term — 16 leases near Point MacKenzie and 10 leases in Trading Bay.

The deadline ended plans for any exploration on the Trading Bay acreage, but Linc held out hope it would get the Angel unit and could continue to explore at Point MacKenzie.

Those hopes ended in September, when the state denied the request, saying the proposed exploration plan "does not propose activity that would result in greater economic benefit to the state if leases were unitized than if the activities were conducted on a lease-by-lease basis," according to the ruling from Division of Oil and Gas Director Bill Barron.

As for the intriguing geologic feature, Barron concluded that, "At this time, Linc Energy has not presented a structural trap that is reasonably defined and delineated, and therefore has not identified a potential hydrocarbon accumulation for the proposed Angel unit."

The rejection followed a similar decision about the Cohoe unit, which Aurora Gas LLC had proposed previously, and suggested the state was getting stricter about unitization.

Going deep for coal

Concurrent with this conventional work, Linc began an unconventional program.

While coal gasification is a common industrial process on the surface, Linc wanted to pursue "underground coal gasification." The process involves igniting underground coal deposits and injecting air and water into the seams. The mixture of heat and oxygen converts the carbon in the coal into methane, the primary ingredient in natural gas.

With half of the known coal reserves in the country, Alaska was an intriguing place for a company looking to conduct a UCG pilot project. "Linc Energy has been studying the potential of Alaskan resources for some time and we have been quietly looking for the right opportunity to enter the region," Bond said in March 2010.

Specifically, Linc envisioned a three-phase program: a single gasifier on a 90-day trial monitored for one year, a panel of three to six gasifiers on a one year trial and finally a working underground coal gasification project combined with surface gas-to-liquids technology to produce some 20,000 barrels per day of various synthetic diesel products.

The company greatly expanded its holdings in February 2011 when the Alaska Mental Health Trust Land Office gave Linc Energy an underground coal gasification exploration license over 181,414 acres of Southcentral and Interior Alaska. The license covered three areas: on the east side of Cook Inlet near Nikiski, on the west side of Cook Inlet near the Beluga Power Plant and in the Interior region around Anderson, Healy and Nenana.

Linc drilled the TYEX01 in late 2011 and the TYEX01X in early 2012 in the Tyonek area, less than three miles from the Beluga Power Station. The 1,450-foot stratigraphic core hole targeted coal seams previously encountered in the nearby Phillips Petroleum North Tyonek State 58848 No. 1 well from 1973 and the nearby Superior Oil Three Mile Creek No. 1 well from 1967. Linc called the results of the core hole "very encouraging."

Between September 2011 and April 2012, Linc acquired 2-D seismic over its Interior and Cook Inlet underground coal gasification acreage and also called those results "very encouraging." The company specifically highlighted its seismic acquisition in the Interior "where there is very little previous exploration drilling and very few well logs exist."

To support future drilling, Linc commissioned a fit-for-purpose rotary-core rig from Buffalo Custom Manufacturing. The dual capabilities of the rig would allow it to "drill at a faster rate and offer greater borehole stability and control than a traditional core rig."

Linc drilled the KEEX02 core hole on the west side of Cook Inlet in 2012. "A series of unseasonably early, strong winter storms" required "road and facility repairs," but Linc eventually completed the 1,700-foot hole in December 2012, according to state reports.

While Linc previously discussed plans for several additional wells, it did not drill any core holes in 2013. Instead the company said it has been studying development schemes and expected to reach a commercial agreement to sell synthesis gas sometime this year.

Success at Umiat

Alongside those two natural gas projects, Linc has also been looking for oil.

In June 2011, Linc picked up a controlling interest in the Umiat oil field by acquiring Renaissance Alaska LLC for $50 million plus adjustments. The small independent held an 84.5 percent interest in Renaissance Umiat LLC, which held the main leases in the prospect. The deal included 19,358 gross acres over two federal leases and one state lease straddling the Colville River in the western foothills of the Brooks Range Mountains.

The U.S. Navy discovered the Umiat field in 1946, during an exploration campaign in the National Petroleum Reserve-Alaska to find more domestic oil following World War II.

While prodigious, the field remains undeveloped because of its location and its geology.

The Umiat area is far from existing North Slope infrastructure and would likely require a 100-mile road and pipeline bundle, in addition to standalone processing facilities.

Those enormous undertakings made the field uneconomic during periods of lower oil prices, but a state plan to build a road to Umiat and several seasons of exploration from other companies in the region suggested the possibility of finding economies of scale.

(The road to Umiat project has since faced some local opposition, as well as the routine delays expected for any major Arctic project. While Linc would like the state to build the road, the company has said it believes the Umiat field would be economic without it.)

Even under the current high price environment, though, Umiat presents problems. The unusually shallow reservoir is partially embedded in permafrost, which reduces reservoir pressure and also creates challenges for establishing an effective completion method.

The U.S. Navy drilled 11 wells at Umiat between 1945 and 1952. "Behavior of the wells during testing was unpredictable," U.S. Bureau of Mines petroleum engineer Oren C. Baptist wrote in a 1960 study. "For example, one well was abandoned as a dry hole after all tests failed to recover any oil, yet an offset well, only 200 feet from the dry hole, produced 400 barrels of oil a day." He hypothesized that drilling mud had thawed the permafrost, allowing water into the formation, which froze the sand and plugged the well.

The U.S. Navy drilled the Seabee No. 1, deeper test well in the region, in 1979, after which the region remained unexplored except for some seismic over the past decade.

Slower than anticipated

Leveraging previous permitting work, Linc planned an aggressive five-well exploration program for early 2012. The program included a Class II injection well, but primarily intended to compare various drilling and completion methods and collect field data.

Ultimately, Linc had to postpone the entire program for a year because of "logistical and weather issues" including "low snow levels which affected snow road development."

By August, though, Linc had announced an "aggressive timeline" to bring Umiat into production in five to seven years, estimating peak production of 50,000 barrels per day.

The initial program was similar to the work the company had planned for the previous year, but Linc said its efforts were enhanced by a year of additional technical work, 3-D seismic processing and interpretation, project development and community engagement.

The program called for drilling one disposal well, one or two shallow vertical wells, one deep vertical well and one horizontal well — the first horizontal ever drilled at the field.

Specifically, Linc planned to drill the Umiat DS No. 1 disposal well first, followed by the Umiat No. 16 and Umiat No. 16H well, a vertical and horizontal pair into the same interval to compare effects of the two drilling and completion strategies on the reservoir.

After drilling the side-by-side wells, Linc would move its rig eastward to drill Umiat No. 23, which would target natural gas in the deeper horizons below the Lower Grandstand.

While many companies hope to find gas to fuel operations, Linc planned to inject cold gas into the Upper and Lower Grandstand to maintain reservoir pressure and temperature.

After testing and potential producing the deeper gas found from the Lower Grandstand, Linc planned to plug the Umiat No. 23 well back to the oil sands for another flow test.

While those four wells formed the core of the program, Linc also permitted the Umiat No. 18 and Umiat No. 19 wells, and said it might drill "one or both" with enough time.

Deferred again

Ultimately, though, the Arctic interfered again.

A period of light snowfall early in the season combined with extreme cold snaps kept Linc from starting the Umiat No. 18 well until March 2013, which made a four-to-five well program impossible before the thawing tundra would end the exploration season.

continued on next page

LINC ENERGY *continued from page 69*

The delay forced Linc to defer much of its program.

The revised plan called for finishing Umiat No. 18 and drilling Umiat No. 23H, which the company said would meet its "key objectives" for the season: providing a side-by-side comparison of vertical and horizontal techniques and searching for a deep gas supply.

Umiat No. 18 collected 300 feet of core and encountered 100 feet of net oil pay in the Lower Grandstand, but Linc postponed a flow test because of mechanical problems.

"An apparent blockage formed in the perforation tunnels during the early stages of the campaign," the company said at the time, adding later that it had unsuccessfully "employed multiple techniques to clean the perforations such as methanol, solvents, and surfactants to remove any ice or other debris in an attempt to re-establish flow."

After attempts to clear the blockage were unsuccessful, Linc suspended operations for the season rather than start on the Umiat No. 23H and risk stranded its rig at the drilling pad.

Instead, Linc cold stacked the Kuukpik No. 5 rig at the permanent Seabee drilling pad, which would give it a head start on 2014 drilling and avoid more weather-related delays.

Even with the second consecutive set back, Bond said he remained "very confident that we will be able to unlock the vast potential that exists at Umiat. We will utilize the considerable lessons we have learned by undertaking drilling in the permafrost this year and, combined with the additional time available next winter due to the rig being stacked on location, to complete the appraisal of the potential of Umiat," Bond said.

To avoid thawing permafrost, Linc used a chilled mineral oil based mud system for drilling and a "progressive cavity pump" for its flow test "in order to prevent heat in the borehole from establishing a 'thaw bubble' in the permafrost and potentially destabilizing the well bore and surface facilities," said Linc President of Oil and Gas Operation Scott Broussard. "We were also careful to make sure that the pump was below the perforated zone in order to make sure that heat was not introduced at the perforated zone," he added.

Even so, Linc said it intended to use an open-hole completion technique on future wells, as the U.S. Navy did on its original wells at the field. By drilling without casing or lining, an open-hole technique allows fluids from a reservoir to flow directly into a well bore.

Finally flow testing

The program changed again this year.

Over the summer, Linc analyzed the Umiat No. 18 samples, which it described as "dripping oil." The samples indicated "outstanding rock properties" for a lighter oil reservoir, including 16-18 percent porosity, air permeability of 70-270 millidarcies, and "friable" (soft) sandstones "preferred for optimal oil flow," according to the company.

The results convinced Linc that the Lower grandstand was "completely saturated with hydrocarbons," the company said in a statement. Eager to complete a horizontal well, the company cancelled the Umiat No. 18 flow test. Flowing oil from horizontal wells could potentially "prove" some of the "probable" reserves at the field, according to Bond.

While optimistic, Linc backed away from its concrete timeline. The company had previously said it intended to bring Umiat online by late 2017, but by October 2013 was saying it "plans to aggressively develop this field once commerciality is determined."

As winter approached, Linc permitted two addition well locations — Umiat No. 24H and Umiat No. 25 — primarily to have some flexibility as the exploration season progressed.

In February, Linc drilled the Umiat No. 23H well to target depth of 4,100 feet. A subsequent flow test produced a sustained rate of 250 barrels of oil per day — or 650 barrels total during four flow tests conducted over a seven-day period at the field, according to the company. The well flowed at a peak rate of 800 bpd, Linc said. With a gas drive installed, the company believes the well would produce as much as 2,000 bpd.

On-site analysis suggested that the well produced light, sweet 38.5-degree API oil with no water, but Linc said that it intended to perform more in-depth laboratory analyses.

"I'd read stories of how the U.S. Navy was known to put the Umiat crude oil straight from the well head into their trucks and drill rigs," Bond, who was on site for the flow test, said in a March 31 statement. "And after seeing and experiencing the oil for myself I can see why they would do this, as the Umiat oil looks like and has the consistency of diesel fuel, just fantastic quality oil that did not change throughout the flow test."

In addition to the successful flow test, the Umiat No. 23H well proved-up the proposed completion method, according to Linc. "We have now proved that the oil flows easily from the Umiat reservoir with very good permeability and that the drilling process of utilizing horizontal wells with slotted liners with ESP down well pumps as per our commercial design has been a success," Bond said. "And with this success and the knowledge gained from last year's drilling program, Linc Energy now has clear a path for the commercial development of the billion barrel (original oil in place) Umiat field."

With the season now completed, Linc said it is moving forward on environmental studies, permitting and engineering for proposed surface facilities and finalizing the best routes for an Umiat pipeline and road. The company recently said it "is also evaluating the advantages of introducing an industry partner to assist us in the future development."

Contact Eric Lidji at ericlidji@mac.com


LEADER In All We Do
Committed to providing exceptional oil field services throughout Alaska
DOYON Limited®
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 DRILLING, INC.
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 UNIVERSAL SERVICES
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
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
More info at www.doyon.com
Other Doyon Businesses: Government Contracting | Natural Resource Development | Tourism

NordAq is working on North Slope and in Cook Inlet

The tiny Alaska independent has drilled two wells since 2010 and is pursuing an ambitious North Slope program

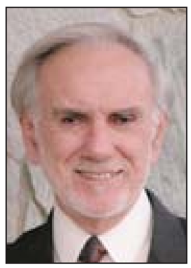
By ERIC LIDJI
For Petroleum News

NAME OF COMPANY: NordAq Energy Inc.
ALASKA OFFICE: 3000 A St., Ste. 410, Anchorage, AK 99503-4040
PHONE: 907-646-9315
TOP ALASKA EXECUTIVE: Bob Warthen, president
COMPANY WEBSITE: www.nordaqenergy.com

NordAq Energy Inc. is one of the smallest exploration companies working in Alaska, but it has been diligently pursuing prospects in Cook Inlet and on the North Slope.

The Anchorage-based company arrived with a wave of independents in early 2010 by picking up state acreage at lease sales and acquiring Cook Inlet Region Inc. leases, but the principals of the company have been well known in the Alaska oil industry for years.

NordAq President Bob Warthen boasts of nearly 45 years of Cook Inlet experience, including a quarter century of senior management for Union Oil Company of California.



BOB WARTHEN

NordAq is currently pursuing the Shadura prospect in the Kenai National Wildlife Refuge, the Tiger Eye prospect in the Trading Bay region and a prospect in the Smith Bay region of the North Slope, but holds leases at several other prospects in both basins, including the Anakema prospect located just offshore of the Kenai Industrial Center.

An early discovery at Shadura

After building an ice road through the Kenai National Wildlife Refuge, NordAq spud the Shadura No. 1 exploration well in February 2011 using the Glacier No. 1 drilling rig.

The prospect was west of the Swanson River field, on subsurface land owned by Cook Inlet Region Inc. The Alaska National Interest Lands Conservation Act created a mechanism for CIRI to allow access to lands within the refuge for resource development.

The onshore well primarily targeted natural gas objectives in the upper and middle Tyonek formation between 11,000 and 14,500 feet, and included a secondary target in the shallower Beluga formation between 6,000 and 11,000 feet, according to state filings.

Toward the end of the year, rumors swirled about a potentially large discovery. NordAq announced a "significant natural gas discovery" in November 2011 and later suggested that the prospect could produce up to 50 million cubic feet per day over 30 years.

In April 2012, though, Warthen tempered enthusiasm for the Shadura discovery, saying that the 50 million cubic feet per day figure measured the "facility design volume." The actual production rate could be a lot less, and would depend on the quantity of gas NordAq could sell into the local market, but he declined to offer specific discovery size.

To assess the discovery, NordAq began permitting a flow test and an appraisal well in early 2012, By April 2012, NordAq was proposing a six-well development program.

Asked at the time whether the company had sanctioned Shadura, Warthen said, "We wouldn't be here if it's not a go. Going through an EIS process is not inexpensive." He also said the appraisal well could take as long as two years to come to fruition because the directional well would extend more than 16,000 feet, requiring a fairly large rig.

In November 2012, NordAq began permitting a 49-square mile onshore 3-D seismic program around the Shadura prospect. The survey used a cable-free recording system.

A brief EIS debate

Given its location in the Kenai National Wildlife Refuge, Shadura required the U.S. Fish and Wildlife Service to prepare an environmental impact statement. While the process could not prevent NordAq from developing the prospect, it threatened to impede it.

The draft EIS presented a two-phased development plan. NordAq said it planned to build a 4.3-mile gravel access road and a "minimal" pad to support one well in June 2013.

If the results were "unfavorable," NordAq would remove the infrastructure and restore the area. If the results were good, though, NordAq would expand the pad to 500 feet by 550 feet and drill five additional gas wells, an industrial water well and a waste well. The goal would be to bring the field into production by June 2014, selling the gas into the pipeline connecting the Tyonek A platform to the Kenai liquefied natural gas plant.

That development scenario accounts, at least in part, for NordAq publically supporting plans to resume LNG exports from the mothballed ConocoPhillips facility in Nikiski.

"In the absence of an LNG option natural gas prices will continue to remain artificially low and create a disincentive for exploration and development," Warthen wrote to the Regulatory Commission of Alaska in late 2013. If third parties supplied the plant to a greater degree, Warthen said, NordAq "believes that an export renewal should not be the singular burden of one operator to support. All companies with surplus gas reserves should be considered as candidates for providing gas to manufacture and export LNG."

The 538-page final EIS proposed five alternatives for development, including the one NordAq preferred: a 4.3-mile access road from the north and buried pipelines and fiber optic cables.

The EIS also included two options to access that prospect from the south or the east, respectively, out of the Hilcorp-operated Swanson River unit. According to NordAq, either of these options would have made the project economically or logistically unfeasible and would therefore violate the ANILCA provision allowing development.

While acknowledging that the alternatives were "not ideal from NordAq's perspective, the (U.S. Fish and Wildlife Service) believes that both alternatives remain feasible."

By July 2013, though, the agency had given NordAq its preferred development scheme.

Now, NordAq plans to drill a well in a different part of the prospect this fall to determine whether to pursue development, according to NordAq Land Manager Chick Underwood.

"It'll really hinge on this second well," Underwood told Petroleum News in May 2014.

Environmental protections seasonally restrict certain activities in the Kenai National Wildlife Refuge, which means construction of a gravel road cannot begin until mid-July and drilling is unlikely to begin until mid-September, according to the company.

Shadura No. 2 will require a small drilling pad that would either be expanded for future development or removed and remediated if the well results prohibit development.

Tiger Eye on the west side

Around the time NordAq announced the Shadura discovery in late 2011, it also launched an exploration program at the Tiger Eye prospect, located on the west side of Cook Inlet.

A proposed 12,000-foot Tiger Eye North No. 1 well would have targeted the Tyonek and Hemlock formations in an area about 1.8 miles southwest of the Trading Bay facilities.

NordAq expanded the program in May 2012. The revised program envisioned drilling the 11,500-foot Tiger Eye Central No. 1 in August 2012 and the 10,175-foot Tiger Eye Central No. 2 in September 2012, and a shooting 3-D seismic in the area in early 2013.

In July 2012, NordAq asked the state to form the Tiger Eye unit over two leases covering some 8,480 acres. The unit application proposed drilling the Tiger Eye Central No. 1 in the second quarter of 2013 and the Tiger Eye North No. 1 in the second quarter of 2014.

Without unitization, the leases were set to expire at the end of September 2012.

In a revised application in August, NordAq proposed drilling the two wells in 2012 and 2013, respectively, but kept the proposed 3-D seismic campaign for early 2013. The company intended to drill the first well in September, but faced "severe weather" delays.

NordAq also faced a challenge from Apache Alaska Corp., which asked the state to include three of its adjacent leases into the unit, saying they shared a reservoir.

The Alaska Department of Natural Resources approved a 7,680-acre unit in October 2012, and required NordAq to drill an initial well at the unit by the end of the year.

The state rejected the request from Apache, saying that the information Apache had provided to justify its claim did "not conclusively prove that the potential hydrocarbon accumulation"

continued on next page

NORDAQ *continued from page 73*

extended onto its leases, which meant there was "no evidence that Apache has an interest in the potential hydrocarbon accumulation to be included in the unit."

Shortly after getting the unit, NordAq used Nabors Alaska Drilling Rig 106AC to drill the Tiger Eye Central No. 1 well, targeting the Tyonek and Hemlock formations.

In early 2013, NordAq amended its plan of operations at the Tiger Eye unit to include additional exploration and development activities. The changes envisioned expanding the TEC-1 pad to accommodate a 60-man camp and production facilities, constructing the TEC-2 pad, connecting the two pads by road and conducting exploration activities.

The plan called for drilling up to eight 4,000-foot wells on the TEC-1 pad before expanding it, and potentially bringing the pad into production by October 2013. But the program has proceeded more slowly and a development decision remains unmade.

Smith Bay work next year

While pursuing those Cook Inlet projects, NordAq also looked north.

NordAq picked up 11 tracts covering 58,880 acres of Smith Bay off the coast of the National Petroleum Reserve-Alaska in a December 2011 lease sale for some $1.3 million, and grabbed additional onshore and offshore acreage in November 2012 and 2013 sales.

The Smith Bay area is highly prospective for oil, but far from existing infrastructure.

By July 2013, NordAq had applied for an oil discharge prevention and contingency from the Alaska Department of Environmental Conservation, a key component for exploration.

NordAq proposed drilling as many as eight exploration wells on its Smith Bay area leases during the winters of 2013-14 and 2014-15. The wells would be divided between coastal waters and onshore sections of the northwest planning area of the NPR-A.

The proposal included 14 potential well locations — 10 Tulimaniq wells in Smith Bay and four NPR-A wells: Aklaq Nos. 2A and 6A, Aklaqyaaq No. 1 and Amaguq No. 2A.

The program would follow recent exploration by the Talisman-subsidiary FEX.

In 2007, the Canadian company drilled three nearby wells: the Amaguq No. 2, the Aklaqyaaq No. 1 and the Aklaq No. 6. FEX plugged and abandoned the Amaguq No. 2 well, saying it was "subcommercial given current infrastructure," but suspended the Aklaqyaaq No. 1 and the Aklaq No. 6 wells and offered encouraging early estimates.

Specifically, FEX said that "initial estimate of contingent resources present" at Aklaqyaaq No. 1 and Aklaq No. 6 was "300-400 million barrels" net to FEX. The company held an 80 percent working interest in the relevant leases at the time.

While FEX planned to return to the region the following year, it ultimately cancelled those plans when federal agencies slowed the schedule of lease sales in the NPR-A.

Like the FEX program, the NordAq program would have to negotiate the rigors an isolated area. The Smith Bay wells would be 149-157 miles from Drill Site 2P and 68-77 miles from Barrow and the NPR-A wells would be even farther from existing fields.

NordAq had originally envisioned drilling in the Smith Bay region as soon as March 2014, but the program is currently scheduled to begin in the winter of 2014-15.

Contact Eric Lidji at ericlidji@mac.com

REPSOL E&P USA

Repsol feeling 'positive' about Alaska exploration

Having completed its initial three-season exploration program the Spanish major is eying development

By ERIC LIDJI
For Petroleum News

GREG SMITH

Repsol E&P USA Inc. recently finished its most important season in Alaska to date.

After announcing three discoveries last year, the Spanish major completed a three-well program this winter — a pair of appraisal wells in the Colville River Delta and an exploration well south of the Prudhoe Bay and Kuparuk River units. Those wells "finished with positive results," Chief Financial Officer Miguel Martinez said at a first quarter earnings call on May 12. "We are working toward defining the most economical way to develop the area," he added, saying it was too soon to comment further.

With the two appraisal wells, Repsol attempted to alleviate uncertainties around the earlier discoveries with the goal of sanctioning a major development, Repsol Alaska Project Manager Bill Hardham told the Alaska Support Industry Alliance on Jan. 23.

While declining to offer a timeline for development, Hardham said, "I feel confident it's coming. It's not a matter of if, but when."

NAME OF COMPANY: Repsol E&P USA Inc.
COMPANY HEADQUARTERS:
2001 Timberloch Pl., Ste. 3000,
The Woodlands, TX 77380
PHONE: 832-442-1000
TOP ALASKA EXECUTIVES: Greg Smith, director U.S. Business Unit, and Bill Hardham, Alaska Project Manager
ALASKA OFFICE: 1029 W. Third Ave., Ste. 260,
Anchorage, AK 99515
PHONE: 907-375-6900 • **WEBSITE:** www.repsol.com

But Hardham also warned, "The predictability of the regulations and tax structure is key to making these big investment decisions."

It's certainly no surprise to hear an oil company advocate for low and stable taxes over high and shifting taxes, and Repsol has never given a straightforward ultimatum about what might happen if voters overturn the new fiscal system in a referendum this summer, but Hardham listed taxation alongside geophysical analysis

continued on next page

REPSOL *continued from page 75*

and stakeholder engagement as the major "uncertainties" Repsol must resolve before it could sanction development.

To the west, to oil

Repsol started as a state-owned monopoly created before the Spanish Civil War, but reorganized over the following decades and became a private company in the late 1980s.

Repsol was primarily a European downstream company before it acquired the Argentinean company YPF in 1999 and created the multinational Repsol YPF S.A. After that, the company began rapidly expanding, particularly across Latin America.

Today, Repsol maintains assets in more than 50 countries around the world.

The growth made Repsol a major player, but over the past decade the company decided to take a different approach by focusing on the West and on increasing its oil production.

With its portfolio weighted toward South America and Africa, Repsol decided to grow its presence in developed economies. In a four-year plan announced in early 2008, the company set a goal to have at least 55 percent of its assets in OECD countries by 2012.

Global events subsequently supported the move. Repsol temporarily lost its largest source of production during the recent uprising in Libya. The company cancelled plans for a $10 billion investment in an Iranian natural gas venture because of the threat of sanctions over the Iranian nuclear program. Argentina essentially nationalized the YPF portion of the company, and several other South American countries changed their fiscal terms.

The strategic plan also favored oil production.

Over the 2000s, Repsol had invested heavily in liquefied natural gas, becoming the third largest LNG company in the world. Of the 2 billion barrels of oil equivalent in total reserves the company reported in 2009, only 890 million barrels came from oil.

With import terminals in Spain and eastern Canada, and export terminals in Trinidad and Tobago and Peru, Repsol's LNG assets were focused in the Atlantic Ocean, where there was talk of surpluses. By placing a priority on oil in its strategic plan, Repsol could diversify its portfolio and take advantage of the historic, decade-long rise in oil prices.

First steps north

This strategic plan is why Repsol first dipped its toe in Alaska waters. It started in 2007, when Repsol partnered with Shell and Eni on a block of federal leases in the Beaufort Sea. (Shell operated the joint venture.) Repsol said "exploration activities" could begin as early as 2009-10, but lawsuits delayed any activities.

At the time, Repsol stayed quiet about its larger intentions in Alaska, which allowed rumors to swirl. Given the outreach efforts of the Palin administration, some thought Repsol might invest in a North Slope natural gas pipeline under the Alaska Gasline Inducement Act, which had recently become law and was then accepting applications.

Ultimately, Repsol did not submit an AGIA application, but the company still invested in Alaska. In early 2008, Repsol bid $15.6 million on 104 tracts in the record-breaking federal lease sale in the Chukchi Sea, including $14.4 million in high bids on 93 tracts.

The leases were clustered into three groups. The first was north of the Popcorn well that Shell drilled in 1990. The second was between the Popcorn well and the Burger well to the east. The third was to the north, in a region thought to contain Brookian potential.

A big joint venture

Even with those bold moves into the Arctic, Hardham insisted that Repsol remained cautious about the state, saying that the company "turned down several opportunities to come in further into Alaska, largely because of the uncompetitive tax structure."

In March 2011, though, Repsol acquired a 70 percent working interest in North Slope leases held by the Armstrong Oil & Gas subsidiary 70 & 148 LLC and its fellow Denver-based independent GMT Exploration LLC. The joint venture covered 494,211 acres in the White Hills region south of the Kuparuk River unit and near the Oooguruk unit.

The $768 million deal earmarked some $750 million for exploration, according to Petroleum News sources, suggesting that all three parties wanted to get to development.

Why was Repsol skeptical about Alaska in 2009 but ready to invest heavily in 2011? It was a combination of the right opportunity and the winds of change, according to Hardham. "Repsol felt that this was the right time, things were changing, it was a good opportunity — they don't come along very often. It fit with the strategy," he said.

Less than a month before announcing the deal, Armstrong Vice President Ed Kerr had submitted a letter to state lawmakers in favor of House Bill 110, which was the legislative vehicle under discussion at the time for changing the fiscal system for oil production.

"The improved fiscal terms as proposed by HB 110, particularly the portions of the bill that apply to activities outside of existing units, will give us the needed incentive to not only drill multiple new wildcat and delineation wells, but the motivation to drive certain projects to development," Kerr wrote, saying his company had "more than a dozen ideas outside of existing producing units" that it was eager to explore in the coming years.

What about gas?

Alaska provided a unique opportunity for Repsol.

"This deal is a perfect fit in our efforts to balance our exploration portfolio with lower risk, onshore oil opportunities in a stable environment. We are confident that our worldwide experience combined with a partner with an extensive local knowledge is going to deliver value in the near future," Chairman Antonio Brufau said at the time.

As a politically low-risk onshore oil opportunity, the Alaska leases offset Repsol's large liquefied natural gas trade and also its exploration in prolific but technically challenging oil-rich basins such as the deepwater Gulf of Mexico and the Santos basin off Brazil.

Even so, some still wondered whether Repsol might also be interested in natural gas.

Chevron drilled five shallow wells across the White Hills region in 2008 and 2009. The company never released well results, but the state of Alaska believed the region to be both oil and gas prone, and Alaska Oil and Gas Conservation Commission well logs suggested Chevron was targeting oil and natural gas prospects in the Brookian formation.

A poster child

Just as Pioneer Natural Resources Alaska Inc. became a poster child during debates over Alaska's Clear and Equitable Share in 2007, Repsol E&P USA is getting stuck in a tug-of-war over the More Alaska Production Act, which replaced the ACES system last year.

The debates over ACES often featured Pioneer Natural Resources.

The large independent operated under three tax systems during the five years it took to reach first oil at its Oooguruk unit, but also earned considerable tax credits in the process.

While much bigger than Pioneer, Repsol also falls in the middle of the spectrum for international oil companies. It is smaller than Shell, Exxon, BP, ConocoPhillips or even Eni, but much larger than the smaller independents working on the North Slope, like Brooks Range Petroleum Corp. or Savant Alaska LLC. As such, some consider it a bellwether: if Repsol wants to invest in Alaska, the investment climate must be good.

When Repsol arrived on the North Slope in March 2011, the company promised to spend it initial exploration budget over "several years." Lawmakers such as Sen. Bill Wielechowski, an Anchorage Democrat, believed that the deal vindicated ACES, which expanded tax credits for exploration but also increased the tax rate when oil prices rise.

To some, the deal suggested that even with higher taxes, the developed world might be more attractive because of its lower politi-

continued on next page

REPSOL *continued from page 77*

cal risks. "They want to enlarge their portfolio (in areas) that are politically stable," Rep. Paul Seaton, a Homer Republican, told Petroleum News in March 2011. "Even as we, Norway and other countries have higher tax rates than some Third World countries, the political stability is very beneficial."

Those comments came as lawmakers were beginning to debate changes to ACES. By the time Repsol announced its discoveries in early 2013, those changes had become the law.

Did SB 21 help?

In announcing the discoveries, Repsol called the recent tax changes "a critical factor in ensuring the development of this project," a claim that Gov. Sean Parnell proudly touted.

"Can you say they made this investment because of the tax change?" House Speaker Mike Chenault, a Kenai Republican, told Petroleum News in May 2013, referring to Repsol. "I don't know if you can really say that, but it's going in the right direction. We are hearing about projects that have a chance of coming online versus where they were pulling projects off the board because they didn't make economic sense under ACES."

As the passage of Senate Bill 21 prompted a voter referendum to repeal it, Rep. Les Gara, an Anchorage Democrat, questioned drawing any link to the development plans. "Repsol announced two years ago they were going to invest at least three quarters of a billion dollars in Alaska, and if they found oil, more than that," he told Petroleum News in August 2013. "Well they found oil in the spring and the governor said, hey this is because of SB 21. Folks who are going to try to stop the referendum will say anything they can."

Today, Repsol claims that its decision to invest so heavily in Alaska in early 2011 was more of an informed risk than vote of confidence. "It was really about timing. … If you wait too long you can't get the opportunity," Hardham said. "So Repsol took a bit of a risk. They saw that there was change afoot. There was an opportunity, so we came."

According to Hardham, Repsol believes the current system brings Alaska closer to the Lower 48, where it maintains operations in the Gulf of Mexico and in the Midcontinent

"If you're not competitive it gets really tough to develop these projects," he said.

The Qugruk unit

The Repsol leasehold is spread across three chunks of the central North Slope.

The first is a T-shaped bundle running up the fairway between the Kuparuk River and Colville River units and spreading along the state waters of the Beaufort Sea. The second is a diagonal swath running south from Kuparuk nearly to the Brooks Range. The third is a smaller bundle hugging a bend in the Colville River south of the village of Nuiqsut.

In October 2011, Repsol and its partners applied to form the 98,852-acre Qugruk unit over 49 leases in the T-shaped bundle and proposed a four-well plan of exploration.

The region had been home to considerable exploration in previous decades, including six wells within the proposed unit boundaries going back to 1966 as well as 2-D and 3-D seismic, according to Repsol. The company described the primary objectives for the proposed unit as "sands within the upper portion of the Jurassic Kingak Shale, the Cretaceous Kup 'C' sand and several sands within the Cretaceous Nanushuk Group."

In January 2012, the Alaska Department of Natural Resources approved a 12,065-acre unit over six leases just east of the Colville River unit, required Repsol to post a $20 million bond that would be returned if the company completed the Qugruk No. 4 well by June 30, 2012, and increased the rental rates on four leases set to expire in August 2012.

The smaller unit, the large bond and the relatively quick drilling commitment was meant to protect the state. The state felt that Repsol had "identified numerous high quality prospective targets over a large area in multiple stratigraphic intervals which will need to be drilled in order to prove up, which they propose to do in part during the proposed initial unit plan," but also believed that unitization was "not technically supported."

In mid-2013, Repsol asked the state to extend the primary terms of five un-unitized leases in the Qugruk area by three or four years. The request came after lawmakers passed House Bill 198, which gave state regulators additional authority to extend lease terms.

The law was designed to accommodate exploration companies that had spent considerable time and money exploring, but needed additional time to bring leases into production. Repsol had spent some $200 million exploring the leases since 2011, according to estimates from the company and the Department of Natural Resources.

The state ultimately gave Repsol an additional two years on the leases, but required the company to drill an additional well, post a $100,000 bond and collect new seismic. The decision made Repsol the first company to benefit from the law.

A three-year program

Repsol initially planned a five-well program for early 2012, but narrowed its efforts to four wells to alleviate local concerns. Those wells were the Qugruk No. 1, Qugruk No. 2 and Qugruk No. 4 along the Colville River Delta and just offshore and the Kachemach No. 1 much further south, near the Meltwater satellite of the Kuparuk River unit.

For the work, the company built 48 miles of ice roads in two segments. The first started at the Kuparuk River unit Drill Site 3S (or Palm satellite) and ran over the frozen coastal waters of the Beaufort. The other ran south from Drill Site 2S (or Meltwater satellite).

After a blowout at the Qugruk No. 2 well delayed its operations for several weeks, Repsol was only able to complete two wells: Qugruk No. 4 and Kachemach No. 1.

For early 2013, Repsol planned a three well program. Those wells were a second attempt at Qugruk No. 1, a Qugruk No. 2 redrill called Qugruk No. 6 and Qugruk No. 3.

The company built an ice airstrip near Kuparuk Drill Site 2M and 38 miles of ice roads snaking north to Qugruk No. 1 and Qugruk No. 6 and south to Qugruk No. 3.

All three wells encountered hydrocarbons. Repsol performed drill stem tests on Qugruk No. 1 and Qugruk No. 6 and performed some early geotechnical work for development.

This winter, Repsol appraised those earlier discoveries with the Qugruk No. 5 and Qugruk No. 7 wells. Repsol also built a four-mile ice road south from Kuparuk to drill the Tuttu No. 1 exploration well on a lease just south of Prudhoe Bay and Kuparuk.

To bolster those activities, Repsol also contracted two 3-D seismic surveys. SAE Exploration conducted the Niglik Fiord survey covering some 222.39 square miles just offshore of the Colville River Delta, including the Repsol-operated Qugruk unit.

And Global Geophysical Services conducted the Schrader Bluff survey covering some 293.45 square miles south of Prudhoe and Kuparuk, including the Tuttu No. 1 well.

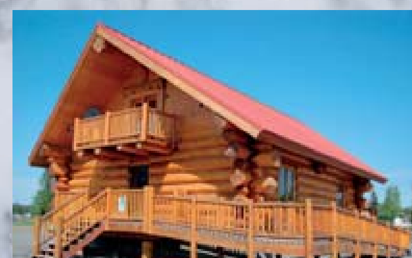
Contact Eric Lidji at ericlidji@mac.com

Buying or Selling in Alaska?

- Vacant Land
- Recreational Properties
- Residential
- Investment
- Commerical
- Vacation Homes


35085 Betty Lou • $2,600,000


39823 Valley View • $499,900


35021 Sterling • $675,000

Gene Fitzgerald

2912 Seawind • $370,000

8460 Berry Patch • $340,000

Top Producer in 2012 & 2013

I look forward to helping you with all of your real estate needs. Please call, text, or e-mail me today!

Cell: (907) 351-9606
Email: gfitzgerald@jackwhite.com
www.GeneFitzgeraldHomes.com

Jack White Real Estate

Royale is studying seismic and planning exploration

Royale and partner Rampart have competed a seismic program and secured a $50 million credit facility

By ERIC LIDJI
For Petroleum News

NAME OF COMPANY: Royale Energy, Inc.
COMPANY HEADQUARTERS: 3777 Willow Glen Drive, El Cajon, CA 92019
TOP ALASKA EXECUTIVE: Stephen Hosmer, Co-president, Co-CEO and CFO
PHONE: 619-383-6600 • **WEBSITE:** www.royl.com

Royale Energy Inc. recently completed its first seismic acquisition in Alaska and the results will determine exploration drilling in the near future, according to the company.

"We are pleased with the progress of this important step in the development of (Royale's) Alaska property, and look forward to analyzing the data to select drilling locations for the coming winter season," Co-CEO Stephen Hosmer said in a statement in March.

Royale is partnering on the program with Denver-based Rampart Energy Inc., which recently committed $50 million to upcoming exploration activities on the acreage.

"The preliminary results available to date are showing excellent data quality and clearly highlight the key interpretable intervals such as the Brookian and HRZ packages, and near top Kingak Formation. We look forward to reporting on interim processing deliverables, and our early interpretation, in due course," Rampart CEO Torey Marshall said in an April 2014 statement, adding that the partners plan to drill two wells next year.

The San Diego-based Royale arrived in Alaska in December 2011, when it spent some $2.7 million in high bids on nearly 100,000 acres of North Slope leases thought to be prospective for source rock development.

A recent arrival

The San Diego-based Royale arrived in Alaska in December 2011, when it spent some $2.7 million in high bids on nearly 100,000 acres of North Slope leases thought to be prospective for source rock development. The leases were in three blocks: in the Franklin Bluffs region, south of Prudhoe Bay, and south of Nuiqsut along the Colville River.

The small company also holds interests in Sacramento basin and San Joaquin basin of California, as well as in Utah and Texas, and produces some 15 million cubic feet of natural gas per day from its wells. After testing the waters with the Monterey shale of California, the company wanted to take another stab at unconventional resources.

"I believe in the oil shale opportunities here (in Alaska), so we decided to give it a shot and I'm happy that it looks like we have succeeded," Royale Vice President for Exploration and Production Mohamed Abdel-Rahman told Petroleum News in late 2011.

Abdel-Rahman arrived in Alaska in the early 1980s, while working for Sohio. He started as a geologist focusing on the southern half of the state and became the district geologist for the entire state as the company was drilling the Mukluk well in Harrison Bay, in 1983.

The $1 billion well was the most expensive dry hole in history. Sohio picked Abdel-Rahman to lead a post-mortem investigation. "At the time it was not fashionable to talk about biomarkers — organic compounds that are characteristic of the organisms from which the oil is generated — but we did biomarkers work in Mukluk and compared it to all the other oils that had been discovered on the North Slope. We found an astounding match of the Mukluk oil and Kuparuk oil," Abdel-Rahman told Petroleum News in early 2012, adding, "In my view there is no doubt that the Mukluk oil went to Kuparuk."

The work convinced Abdel-Rahman about the nature and location of the North Slope source rocks, which would have "charged" Prudhoe Bay, Kuparuk and other big fields.

While Royale claims to have been interested in Alaska source rock potential for some time, the company said it wanted to get more "internal infrastructure" in place before bidding on acreage. But after Great Bear Petroleum LLC took some 500,000 acres of source rock prospective acreage in an October 2010 lease sale, Royale decided it had better make its move. "We were caught by surprise when Great Bear Petroleum took that much acreage. It forced us to move quickly," Hosmer told Petroleum News in early 2012.

Even though Royale came in second, it believes it got a good land position. "Everything we picked is optimum for oil generation — in all three shales," Abdel-Rahman said.

The central North Slope is home to three stacked shales: the Triassic-age Shublik formation, the Jurassic-age Kingak shale and the Cretaceous-age Hue, or HRZ, shale.

Of those, Royale told Petroleum News that it was most excited about the Shublik, which the company believes in similar to the booming Bakken formation of North Dakota.

The company has said it also intends to pursue conventional oil targets on its acreage.

Building a joint venture

Royale's exploration efforts since its initial lease acquisition have been measured.

By early 2012, Royale said it wanted to find a joint venture partner to help it drill as many as six wells the following winter — two wells on each of its three lease blocks.

In early 2013, Australia-based Rampart Energy Ltd. agreed to spend $43 million on exploration in return for a large stake in the Royale land position on the North Slope.

Under the deal, Rampart could earn a 10 percent working interest in the western block of leases by paying Royale $3.4 million in two chunks by deadlines in June and December 2013. Rampart could earn an additional 20 percent interest by acquiring 3-D seismic over both the western and central Blocks by March 31, 2014, and could earn another 45 percent interest (for a total working interest of 75 percent) by drilling, testing and completing two wells, including horizontal sections into target formations, by March 31, 2015. The deal also allowed Rampart to earn a 75 percent working interest in the Central Block by completing a 3-D seismic survey and paying an additional $1.7 million by June 30, 2014.

Rampart has met the first targets, paying Royale $3.4 million last year and hiring SAE Exploration to conduct a 3-D seismic survey over 120 square miles of the North Slope.

The processing is expected to take between six and 12 weeks, according to Royale, and will determine where the company drills, should it return to the region next winter.

A preliminary interpretation of the seismic "identified a large conventional target, covering an area of up to 20,000 acres," according to Royale, but Rampart suggested some source rock potential, too. "The preliminary results available to date are showing excellent data quality and clearly highlight the key interpretable intervals such as the Brookian and HRZ packages, and near top Kingak Formation," Rampart's Marshall said in a statement, referring to the Brookian formation that is producing at various places across the North Slope and also to two of the three source rock formations present in the region.

Rampart has repeatedly praised the exploration tax credits available under the Alaska's Clear and Equitable Share fiscal regime. Portions of the production tax code were replaced earlier this year, but the segments relating to exploration credits remained largely in place. Rampart used its ACES credits to secure its $50 million credit facility from an affiliate of the New York-based lending firm Melody Capital Partners LP.

Contact Eric Lidji at ericlidji@mac.com

The Badami pad SAVANT ALASKA

Focused on production, Savant has exploration options

The smallest producer on the North Slope is in the process of becoming a subsidiary of Miller Energy

By **ERIC LIDJI**
For Petroleum News

Over the past decade, Savant Alaska LLC has turned North Slope exploration into sustained development activities, but not in the way such transitions usually occur.

Instead of drilling a prospect and bringing it into production, the one-time affiliate of Colorado-based Savant Resources LLC came to the state in 2006 to pursue the Kupcake prospect in Foggy Island Bay, some 20 miles west of the Badami unit. After an unsuccessful exploration campaign, Savant applied its Arctic experience to Badami.

GREG VIGIL

Now, Savant Alaska is preparing to enter new hands. In May 2014, the Tennessee-based independent Miller Energy Resources Inc. agreed to by the company for $9 million.

NAME OF COMPANY:
Savant Alaska LLC
COMPANY HEADQUARTERS:
Castle Pines, CO
TOP EXECUTIVE OFFICER: Greg Vigil, president
ALASKA OFFICE: 4720 Business Park Blvd., Anchorage, AK 99507
PHONE: 907-868-1258 • **WEBSITE:** www.savantalaska.com

Biting into Kupcake

The Kupcake prospect is near the much more famous Liberty prospect.

After BP drilled the Liberty No. 1 well in 1997, the company mapped the Kupcake prospect using 3-D seismic acquired in 1995. BP allowed the leases to expire in 2005, and several former BP executives working for Savant took an interest in the prospect.

Savant acquired the Kupcake leases in a March 2006 sale, licensed some 200 square miles of 3-D seismic nearby and intended to drill the Kupcake No.1 well by early 2007.

Savant envisioned “a conventional exploration well targeting several hundred feet of Beaufortian-age sediments located at a depth of approximately 10,600 feet,” according to filings. The

continued on page 84

SAVANT *continued from page 82*

name Kupcake came from the targets, as Savant consultant Erik Opstad explained to Petroleum News in 2006: "KUParuk zone-C and KEkiktuk = KUPCAKE. The Kuparuk-C age Beaufortian sands are the sweet icing atop the Kekiktuk."

In December 2006, Savant and nearby leaseholder True North Energy Corp. pooled their leases to enlarge the surface area of the prospect by 120 acres. True North estimated the prospect contained some 200 million barrels of oil, of which half might be recoverable.

The partners were unable to secure a rig and postponed plans to drill in early 2007, but contracted the Kuukpik No. 5 rig over the summer and set their sights on winter. The goal of the program was to learn more about the size and shape of the reservoir, and to determine whether it was communicating with BP's nearby Liberty prospect.

The agreement terminated in early 2008 when True North failed to come up with its share of the funding for the Kupcake No. 1 well, but the companies quickly signed a new deal.

During the interim, though, Savant signed a deal with the Calgary-based Bordeaux Energy Inc. to share the cost of drilling Kupcake No. 1 and acquiring seismic data.

A Bordeaux-commissioned study estimated that Kupcake contained 170 million barrels of oil in place, with 68 million barrels listed as "recoverable." The figure was lower than previous assessments, but Savant said the estimate only covered a portion of the prospect.

With Kupcake located some three miles from shore, under 14 feet of water, Savant built an ice island and ice road to access the prospect. The magnitude of the construction effort, and harsher-than-expected Arctic weather, delayed drilling until late March 2008.

Ultimately, the target interval in the Kemik formation "was thinner than anticipated" and the porous Cretaceous sandstone was "water wet," according to partner Bordeaux.

Approaching Badami

In mid-2008, Savant Alaska and ASRC Exploration LLC signed a deal with BP Exploration (Alaska) Inc. to work on Badami in return for a stake in the unit.

The partnership was primarily focused on restarting sustained oil production from the Brookian formation using horizontal drilling and hydraulic fracturing, but an initial plan of development under the deal also required an exploration well by September 2009.

Savant saw Badami as an opportunity to apply technology to a known reservoir.

"We're taking technical risk as opposed to exploration risk in the Brookian sands," Savant Chief Operating Officer Greg Vigil told Petroleum News in August 2008.

While Savant pursued those development activities in the Brookian, though, the exploration well would target the Red Wolf prospect in the deeper Kekiktuk formation.

In early 2010, Savant drilled the B1-38 well, which found oil in the Kekiktuk and also the shallower late Cretaceous Killian sands. In early 2012, Savant drilled the Red Wolf No. 2 well about two miles northwest of the bottom-hole location for B1-38. The target zone in the Kekiktuk was wet, though, which led Savant to suspend its pursuit of Red Wolf.

In May 2013, Savant transferred a 10 percent working interest in deep zones at four Badami leases to Red Wolf Exploration LLC, a Wyoming-based independent created in April 2012 by eight small independent companies. The leases were ADL 367005, ADL 367006, ADL 367010 and ADL 367011, but in July 2013 Savant relinquished ADL 367005 and ADL 367010 as part of a new plan of development and the leases expired.

Other opportunities

While Savant appears to be cold on exploration at the moment, it continues to hold some intriguing exploration acreage at the Yukon Gold prospect of the eastern North Slope.

In 1993, BP drilled the Yukon Gold No. 1 well on state land adjacent to the Arctic National Wildlife Refuge 1002 area. While the well is on the extended confidentiality list, previous estimates placed the recoverable oil reserves at some 120 million barrels.

Savant acquired three leases south of the Point Thomson unit in an October 2009 sale.

"We like the area and feel like we understand the Brookian," Vigil told Petroleum News in mid-September 2012. "The biggest impediment is lack of infrastructure — i.e. roads."

The Yukon Gold leases expire in 2017, 2022 and 2023.

The 10th Plan of Development for Badami — running through November 2014 — also calls for Savant to drill an exploration well at the East Mikkelsen prospect at the unit.

In March 2013, the Alaska Department of Natural Resources expanded Badami to include two Alaska Venture Capital Group LLC leases along the eastern edge of the unit.

The expansion included the East Mikkelsen No. 1 well that Humble Oil drilled in 1971, but excluded five other leases that the companies also wanted to add to the unit. The companies had argued that adding all seven leases would "connect subsurface potential and surface infrastructure" for the two companies. By combining the leases into a single unit, "drilling targets could be reached more easily and development could occur more efficiently and safely with less environmental impact on the area," Savant told the state.

The expansion decision required Savant to drill a well at East Mikkelsen by the following winter — early 2014. The directional well would have targeted the Hue Shale, allowing Savant to test the entire Canning formation, including the Badami and Killian intervals.

Those plans were put on hold when Savant appealed the expansion decision.

Sale under way

It is too early to say what the proposed sale will mean for those prospects.

The sale would give Miller a 67.5 percent working interest in Badami, with ASRC Exploration LLC holding the remaining stake. But Miller would get also 100 percent working interest in the exploration acreage and a 25 percent working interest in the underutilized Badami pipeline, which creates the potential for future exploration work.

So far, Miller has said that its initial plans for the Badami unit include drilling two sidetracks at an estimated cost of $15 million per well. But the company made note of "several prospective horizons" within the Badami unit and exploration acreage nearby.

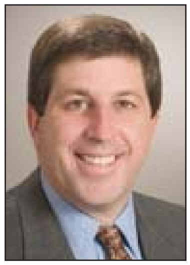
The sale is "subject to due diligence and regulatory approval" and is expected to close by August 2014. If the sale were successful, Savant Alaska would become a subsidiary of Miller. Another Miller subsidiary called Cook Inlet Energy is active in the Cook Inlet.

Contact Eric Lidji at ericlidji@mac.com

It's try, try, try again for Shell in the Arctic

Shell has cancelled its past two exploration programs in the Arctic and the 2015 program is uncertain

By ERIC LIDJI
For Petroleum News


PETE SLAIBY

NAME OF COMPANY: Shell
COMPANY HEADQUARTERS: The Hague, The Netherlands
ALASKA OFFICE: 3601 C St., Ste. 1334, Anchorage, AK 99503
TOP ALASKA EXECUTIVE: Pete Slaiby, vice president
PHONE: 907-770-3700 • **COMPANY WEBSITE:** www.shell.com

As Royal Dutch Shell plc nears the end of its first decade back in Alaska, the company is only slightly ahead of where it started. But it's still aiming for the bounty of the Arctic.

After four decades of exploration — including pioneering work across the Chukchi Sea, the Beaufort Sea, the Gulf of Alaska, the Bering Sea and Cook Inlet — Shell left Alaska in 1998. The company acquired a bundle of onshore leases in the central North Slope in 2001, but put the leases on the market a year later and ultimately dropped them in 2004.

Shell actively resumed its interest in the Alaska outer continental shelf by acquiring Beaufort Sea leases in 2005 and Chukchi Sea leases in 2008. The company has spent the past decade trying to explore those two regions, only to be stymied by permitting delays, legal challenges, Mother Nature, technical problems and its own operational failings.

After starting wells in the Beaufort and Chukchi in 2012, Shell cancelled its 2013 and 2014 drilling plans. The future of its exploration program in Arctic Alaska is uncertain.

continued on next page

SHELL *continued from page 85*

The easiest way to tell the tangled story is year-by-year.

2004: Gone but not forgotten

Even as Shell dropped its leases in 2004, it insisted it remained interested in the state.

"We felt that the potential of the area did not meet our investment criteria and the rentals have not been paid. But I want to stress, our decision to surrender what we consider to be a small, non-material leasehold does not affect our goal to continue evaluating investment opportunities in Alaska," spokeswoman Kelly op de Weegh said in October 2004.

Somewhat cryptically, Global Exploration Director Matthias Bichsel said Shell was interested in the "western part" of Alaska, which suggested the National Petroleum Reserve-Alaska or the Chukchi Sea. He placed Alaska alongside interests in Sakhalin and West Siberia. "You have a bit of a theme there — Sakhalin, West Siberia and Alaska — which is the Arctic, which requires big funds, which requires technology, tenacity, staying power, which I think companies like ours are very well suited to," he said.

2005: Acquiring leases

Shell made its bid for the Alaska Arctic in 2005.

That year, the company spent some $44 million on 86 tracts in a federal Beaufort Sea lease sale. The leases were in the "northern part" of Alaska, more than the west, but definitely fit the bill of complex Arctic prospects requiring big technology to develop.

The acquisition included two fields discovered during exploration work between 1986 and 1992: the 100 million to 200 million barrel Hammerhead field off the coast of the Point Thomson unit and the 160 million to 300 million barrel Kuvlum field farther east.

Shell expanded its Beaufort Sea holdings that year by acquiring 19 leases from Encana Corp. The leases were in a wildcat region off the coast of the NPR-A near Smith Bay.

2006: Making plans

Shell wanted to move quickly.

The company appointed its top three Alaska officials in January 2006. By October 2006, the company was touting its plans to drill as many as four wells the following summer.

"The new thing we're doing in 2007 will be drilling activities," Shell Operations Manager Paul Smith said. "We have four wells planned for the Camden Bay area."

The four wells would be split between the Sivulliq field, which had previously been known as Hammerhead and Kaktovik, and at the Olympia field to the east of Sivulliq.

Shell planned to drill the wells using the refurbished Kulluk and Discoverer drill ships and support the program using the Vladimir Ignatyuk and the Kilabuk icebreakers.

Shell also began a seismic program in the Beaufort and Chukchi seas in 2006, but heavy sea ice forced the company to push some of the program to the following year.

2007: Success and delays

Initially, Shell found success in its permitting efforts.

The U.S. Minerals Management Service approved Shell's exploration program at Sivulliq in February 2007, and in July 2007, after some negotiations, Shell and the Alaska Eskimo Whaling Commission came to terms on measures to avoid bowhead whales in the region.

Soon after the agreement, the state up-

continued on page 88

SHELL *continued from page 86*

held a ruling that the exploration work was consistent with the Alaska Coastal Management Plan, which set the stage for drilling.

Before work began, though, a coalition of groups including the North Slope Borough sued the federal government, claiming that regulators had failed to adequately consider the impact of industrial noise and potential oil spills. The U.S. Court of Appeals for the 9th Circuit told Shell to suspend its activities until the case was settled. The Bush Administration promised to stand behind its regulatory decisions, but with a hearing scheduled for December, the ruling prevented any possibility of exploration in 2007.

2008: Into the Chukchi

Shell greatly expanded its Arctic ambitions in Alaska in February 2008 when it spent $2.1 billion on high bids at a record-breaking federal lease sale in the Chukchi Sea.

The 275 blocks included acreage where Shell drilled in 1989 and 1990. The company anticipated exploring the Burger, Crackerjack and Southwest Shoebill prospects in 2010.

Western Geco conducted seismic surveys in the Beaufort and Chukchi in 2008 and Shell collected shallow hazard survey data and pipeline survey work in the Beaufort.

The Beaufort Sea drilling program remained tied up in court, though.

The open water season arrived without a decision from the 9th Circuit. Then, a coalition of groups appealed an air quality permit that the Environmental Protection Agency had issued for the program. By June 2008, Shell postponed its drilling plans for another year.

2009 and 2010: A moratorium

The legal challenges prevented drilling in 2009, as well.

Responding to those challenges, Shell pared down its initial drilling program in the Beaufort Sea. The revisions called for a one-year, one-rig, two-well program taking place during the 2010 open water season, instead of a three-year, two-rig, four-well drilling program.

The story got increasingly complicated in 2010.

Shell effectively resolved the challenges against its program and, in early 2010, the company began mobilizing equipment for a five-well program in the Beaufort and Chukchi, but the company was subsequently stymied by a federal moratorium on offshore exploration after the Deepwater Horizon oil spill in the Gulf of Mexico.

The lawsuits also expanded to cover the Chukchi program.

In July 2010, the federal District Court for Alaska blocked all lease-related exploration work in the Chukchi until the Bureau of Ocean Energy Management, Regulation and Enforcement, the agency which replaced the Minerals Management Service, updated the original environmental impact statement for the 2008 lease sale.

Shell spent $25 million to upgrade the exhaust system on the Noble Discoverer drillship and planned to support the ship with a fleet that included an onsite spill response unit. Shell also planned to mobilize the Kulluk, its floating drilling platform, to serve as a backup rig in the event that a blowout on the main well requires drilling a relief well.

2011: Optimism

The federal agency suspended its review of exploration plans while the case proceeded.

Without federal approval, Shell was forced to postpone its drilling plans again in 2011, by which time the company said it had spent nearly $4 billion since the 2005 lease sale.

In late 2011, BOEMRE published a supplemental EIS for the 2008 lease sale addressing the concerns raised in the court case and later published a final decision on the matter.

Although focused on the Chukchi, Shell continued to pursue the Beaufort. It submitted a plan of exploration to drill as many as four wells at the Sivulliq and Torpedo prospects starting in the 2012 open water season, alongside a six-well program in the Chukchi.

BOEMRE granted conditional approval for the Beaufort Sea plan in August 2011, but a coalition of Native and environmental groups appealed the ruling to the 9th Circuit.

EPA, though, issued new air quality permits for the program, and the company grew optimistic. “We feel we have some very strong permits and we feel there is reason to be optimistic that our permits will survive a court challenge,” Vice President for Shell in Alaska Pete Slaiby told Petroleum News in September 2011. “Litigation will always be a risk we have. When we make the decision (to deploy), it will be (dependent) on how strong we think our permits are … and we think our permits are strong.”

2012: Exploration begins

The regulatory and legal stars finally aligned in 2012.

Shell won approval from the Bureau of Safety and Environmental Enforcement, which along with the Bureau of Ocean Energy Management replaced BOEMRE, for its Chukchi oil spill contingency plan in February and its Beaufort oil spill contingency plan in March.

To preemptively combat further litigation, Shell asked the District Court for Alaska to uphold the Chukchi and Beaufort oil spill plans. Shell also won a restraining order against Greenpeace, which kept the environmental group from obstructing operations.

Shell began mobilizing its drilling fleet in April 2012, even as opponents of the program appealed the Bureau of Ocean Energy Management decision to approve the Chukchi Sea exploration plan and later appealed the air permits that the EPA had issued for both the Nobel Discoverer and Kulluk drill ships. In May 2012, the 9th Circuit rejected the appeals against the Chukchi and Beaufort exploration plans.

That was when nature and technology refused to cooperate.

An abundance of sea ice kept the fleet from leaving Dutch Harbor in early July, as planned, and further delays related to adding an oil containment system to the Arctic Challenger barge pushed the start of drilling in the Chukchi Sea to early September.

With the delays, Shell scaled back its five-well program to two wells — one well each in the Chukchi and Beaufort — followed by a series of “top holes” for future wells.

Shell only got two days into the program before a massive hunk of approaching sea ice began drifting toward the operations. Shell also announced that its containment system had been damaged during testing, thus preventing anything deeper than “top holes.”

The top holes were the initial 1,500-foot section of each well. They were far shallower than the intended target, but would give the company a head start on drilling — as much as two weeks for each well — once it returned in another season. “We would have liked to have drilled through the objectives (in 2012), but I think we have done some really important things with respect to setting the precedent about being able to work safely in Alaska,” Shell Vice President for Alaska Pete Slaiby told Petroleum News in September 2012. "Overall it's clearly the most success we've had in Alaska in the last six years."

2013: Repercussions

By the time the 2012 drilling season ended, Shell managed to complete top-holes for two of its five wells: the Burger-A well in the Chukchi and the Sivulliq well in the Beaufort.

Still, Shell took comfort in making more progress in the waters of the U.S. Arctic than any company within the past 20 years, and it looked forward to a fruitful 2013 season.

Instead, the project grew even more complicated.

While en route from Dutch Harbor to the U.S. West Coast for maintenance work, the Kulluk drillship ran aground at Sitkalidak Island to the southeast of Kodiak Island.

An emergency team managed to get the Kulluk to Kiliuda Bay on Kodiak Island without reporting any fuel or oil spills, although some seawater had entered the vessel. Naval architects later determined that the damaged ship could safely stay in Kiliuda Bay.

Shell also had to have the Noble Discoverer towed to a more robust shipyard to fix its propulsion systems, as well as equipment related to safety and pollution prevention.

Ultimately, Shell decided to dry tow both rigs to Asia for maintenance and repairs.

In late February 2013, Shell canceled its upcoming exploration program while it addressed the problems with its rig fleet. "We've made progress in Alaska, but this is a long-term program that we are pursuing in a safe and measured way," said Shell Oil Co. President Marvin Odum. "Our decision to pause in 2013 will give us time to ensure the readiness of all our equipment and people following the drilling season in 2012."

Governmental investigations

The grounding set off a series of governmental investigations, and opponents of the drilling program saw the incident as proof of the foolishness of offshore exploration.

An initial 60-day review of the 2012 exploration program from the U.S. Department of the Interior placed the bulk of the blame for the failures on Shell, saying that the company had inadequately prepared for the program and mismanaged its contractors.

The report recommended a "comprehensive integrated plan" for any upcoming work.

"We're asking them to go another step and to provide us with a great deal of detail around their entire operation in an integrated way, including not only drilling operations but their maritime operations as well," said Tommy Beaudreau, principal deputy assistant secretary for land and minerals management and leader of the federal review team.

The U.S. Coast Guard subsequently held a nine-day hearing on the grounding. And Beaudreau returned to Alaska in the summer to hold a public "listening session."

All the while, Shell and the federal government continued to defend elements of the permitting regime covering the program, and proceeded on future permitting, while the EPA issued fines relating to the air quality violations discovered back in 2012. At the same time, the federal government was preparing new safety rules for offshore work.

2014: Future uncertain

Toward the end of 2013, Shell began planning a drilling program for the following year.

The loss of the Kulluk made drilling in the Beaufort Sea untenable until the ship was repaired or a replacement could be secured, but Shell planned to use the Noble Discoverer in the Chukchi, with the Polar Pioneer serving as the required backup ship.

Shell submitted the plan to the Bureau of Ocean Energy Management in early November, but the agency asked for additional information in December and again in January.

Shell responded to those requests, but in late January, after the 9th Circuit upheld an appeal against parts of the original 2008 lease sale where Shell had acquired its Chukchi Sea acreage, the company canceled its proposed offshore exploration program for 2014.

"This is a disappointing outcome, but the lack of a clear path forward means that I am not prepared to commit further resources for drilling in Alaska in 2014," Shell Chief Executive Officer Ben van Beurden told investors on Jan. 30. "We will look to relevant agencies and the Court to resolve their open legal issues as quickly as possible."

The Bureau of Ocean Energy Management is currently reworking the environment impact statement for the sale, under a proposal approved by the District Court for Alaska.

By early 2014, Shell had spent more than $5 billion on its recent venture into the Arctic OCS and had only the top hole of two wells to show for it. The company continues to promote the Arctic as an important area for future growth. "There's a clear capital ceiling in the company and so we need to take some hard choices, and this means looking more closely at our options at an earlier stage and asking ourselves 'are these indeed the projects? Are these projects really a good fit for Shell?'" Van Beurden said in March, suggesting that Shell may forgo other opportunities for the sake of pursuing the Arctic.

The logistics issue

In April 2014, the Coast Guard finally issued its report on the Kulluk incident. The report described a series of events leading to the grounding, but determined that the most significant factor was inadequate risk assessment for a logistically complex program.

"In this case, the risks associated with a single-vessel tow by a new purpose-built vessel of a unique conical-shaped hull, with people aboard, in winter Alaskan waters where weather systems and seas are expected to rapidly develop, were extremely high," Coast Guard Assistant Commandant for Prevention Policy Rear Adm. Joseph Servidio said.

The report included a list of recommendations to make towing activities safer.

The combination of the report, the continued appeals and the ongoing delays over permitting make it impossible to say whether Shell will continue its program in 2015.

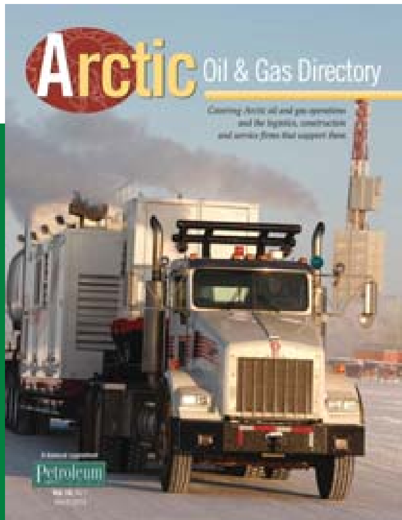
"In the next 10 years, oil exploration activity is expected to be limited and the impact on the levels of maritime traffic appears uncertain," the Government Accountability Office concluded in a recent report on commercial activity in the Arctic over the coming decade.

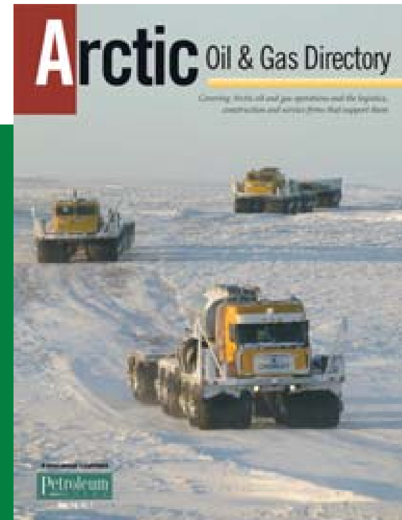
Still, Shell expects to be among the few companies operating in the basin.

"We are looking currently at what it will take to be certain of drilling in 2015, and there are still some open question marks, both legal and regulatory systems, that we need to move through," Chief Financial Officer Simon Henry said in a first quarter earnings call.

Contact Eric Lidji at ericlidji@mac.com

Want to be a part of this oil and gas directory?





Qualified Petroleum News advertisers have full access to all the benefits included in this biannual magazine, which include the following:

- **Exposure.** The Arctic Oil & Gas Directory is distributed twice a year to every one of our newspaper subscribers, in addition to its presence at trade shows and conferences nationally and internationally.

- **A company profile.** A full page, full color Q&A profile of your company. You'll be involved in the editing and choose the pictures. Once it's printed, you own the piece and you'll receive an electronic copy to use as a company brochure or however you see fit.

- **Access to free news coverage.** Submit announcements, new hires, special projects, new technologies, company photos, and more. Let current and potential new clients keep track of your company's milestones.

- **Unique company listings.** With over 130 categories to choose from, you'll be able to list your company name, contact information and a brief description of the products and services you offer.

- **Additional opportunities** to feature your company and its people – including feature stories, photo spreads, cover shots, and more.

Petroleum news

Get listed and be noticed.

Contact Marti Reeve in Anchorage, Alaska, at (907) 522-9469 or mreeve@petroleumnews.com

Only pay for the speed you need... Dynamic Routing!℠

At Lynden, we understand that plans change but deadlines don't. That's why we proudly offer our exclusive Dynamic Routing system. Designed to work around your unique requirements, Dynamic Routing allows you to choose the mode of transportation — air, sea or land — to control the speed of your deliveries so they arrive just as they are needed. With Lynden, you only pay for the speed you need!