The Explorers

Oil & gas companies investing in Alaska's future

The Explorers, an annual publication from Petroleum News

The slow pace of Alaska allows some work to continue

The Arctic slows decision making. It can be harder to start projects in the far north but harder to stop them as well. The big question at the moment is how $50 per barrel oil will impact resource development across Alaska. The short answer: It's too soon to tell.

Oil prices fell over the second half of 2014, when most companies were finalizing their exploration activities for the coming winter. As such, this edition of The Explorers includes companies who chose to conduct risky, speculative or pioneering exploration and companies who decided to shy away from such unpredictable work for time being. If oil prices stay low this year, the next issue of The Explorers may tell a different story.

...this edition of The Explorers includes companies who chose to conduct risky, speculative or pioneering exploration and companies who decided to shy away from such unpredictable work for time being.

The Explorers profiles companies who either drilled an exploration well or commissioned a seismic survey this year or over the two previous years. Applying that criteria depends upon our knowledge of activities and our classification of those activities. If we missed any companies that deserved to be included this year, the omission was unintentional.

AIX and Caelus were included on the activities of previous operators. ConocoPhillips and Hilcorp conducted appraisal or exploration work while developing existing units.

BlueCrest, Brooks Range Petroleum and Furie are evaluating near-term exploration activities while working immediately to bring new units into production. Apache, Doyon, Linc, Royale and Shell are deciding whether and how to continue previous exploration work. Great Bear, NordAq and Repsol all conducted traditional exploration activities on the North Slope this winter. Usibelli drilled its first exploration well in 2014. ASRC Exploration is preparing to drill its first solo exploration well after years of administrative delays. Miller is focusing on low-risk developments while it considers future exploration.

The exploration license program continues to attract companies interested in frontiers.

—Eric Lidji

Contact Eric Lidji at ericlidji@mac.com

CONTENTS

The Explorers

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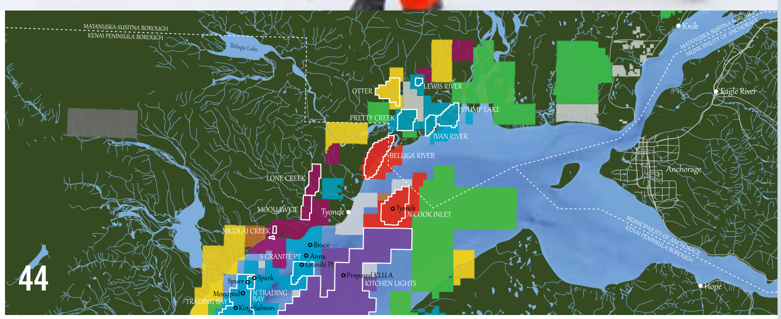
Ad Index

Guest Editorial

Welcome

Maps



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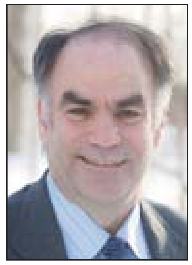
Entering new, exciting period

Mark Myers: Activity continues with low prices; surge in Cook Inlet drilling, North Slope exploration; gas line work ongoing

By MARK MYERS

Commissioner, Alaska Department of Natural Resources



MARK MYERS

Alaska's oil and gas resource basins are entering a new and exciting period.

Assuming that Shell receives the necessary permits, a significant round of exploration drilling is likely to commence on the Arctic Outer Continental Shelf this summer.

In addition, a variety of companies — from small independents to large companies both familiar and new to Alaska — are forging ahead with significant projects in new fields and legacy fields.

We see an upsurge in exploration and development activity under way on the North Slope as well as in Cook Inlet.

With oil prices in a sustained slump, it is gratifying to see these projects continuing to move forward and companies applying for new production units on the North Slope and Cook Inlet. From a geologic and engineering standpoint, the work currently under way in Alaska puts us in a new and more complex period of development in our oil and gas basins.

As the incoming commissioner for the Alaska Department of Natural Resources, I'm excited to see so much of our untapped oil and gas potential — some of it previously thought to be non-economic or non-producible — receiving attention from explorers and investors around the world.

There are many vivid examples of this, including:

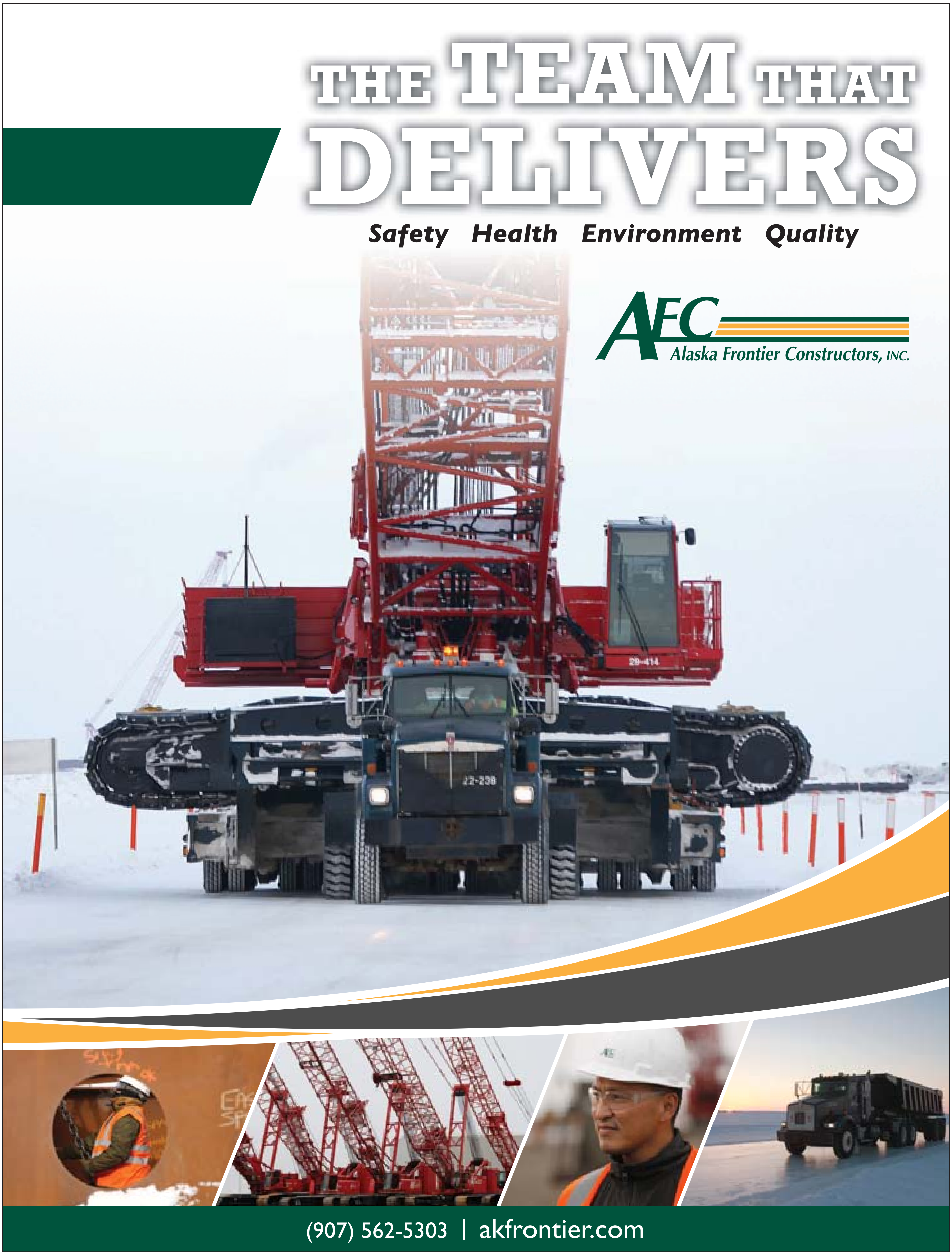
*Between January 2013 and March 2015, 59 new wells were completed in Cook Inlet by seven operators.

Twenty-five of these were completed as gas wells, averaging nearly one gas well per month during this time frame.

*In the past three years, Repsol has drilled 10 oil exploration wells on lands west of Kuparuk, and has recently applied for a large unit to allow it to move forward with developing multiple reservoirs.

*This winter, following a royalty modification, Caelus Energy sanctioned its Nuna project, committing significant capital resources to bring this low-permeability reservoir into develop-

continued on page 10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Exploration program continues to draw applications

State currently managing 5 licenses in the Interior and Southcentral region; has 2 pending

By ERIC LIDJI
For Petroleum News

Even though all oil and natural gas production in Alaska occurs either on the North Slope or in the Cook Inlet basin, the rest of the state is known to contain hydrocarbons.

That's why the state of Alaska maintains an exploration license program, where operators can propose exploration activities in regions without regular lease sales.

Every April, the Alaska Department of Natural Resources accepts applications for exploration licenses over areas between 10,000 and 500,000 acres. The applicant proposes a geographic area as well as a work commitment and a term. The process allows other companies to make competing bids, in an effort to get the best deal for the state.

There are currently five active and two pending exploration licenses.

Cook Inlet Energy LLC operates three licenses, which are discussed in greater depth in the profile for Miller Energy Resources LLC. They are the 62,909-acre Susitna Basin IV license active through April 2021, the 45,764-acre Susitna Basin V license active through April 2022 and the 168,581-acre Southwest Cook Inlet active through October 2018.

Usibelli Coal Mine Inc. operates the 204,883-acre Healy Basin license active through January 2021. The license is discussed in greater detail in the profile of Usibelli.

The two pending licenses are in the Houston-Willow basin and North Nenana basins. The state is still considering the requests and has yet to release the names of those applicants.

Another shot at Glennallen

The remaining license is in the Interior region.

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 have drilled as many as 11 wells. The most recent explorer was the Texas-based independent Rutter and Wilbanks Corp., which discovered a natural gas reservoir between 2005 and 2007 but eventually plugged and abandoned its well because of geological problems.

"Our primary focus is to lower utility costs for most consumers," Ahtna Land and Resource Manager Joe Bovee told the Alaska Support Industry Alliance Meet Alaska conference in January 2014. The high cost of energy is believed to be the cause of a 10-15 percent population decline in the region over the past few years, Bovee said.

The corporation has reprocessed some 80 miles of existing 2-D seismic data and, in October 2014, commissioned Global Geophysical Services to conduct a 2-D seismic survey covering some 40 miles. Early analysis of the seismic is pointing toward a target on the crest of a geologic structure about 14 miles west of Glennallen, according to Bovee, who has expressed a 60 to 70 percent likelihood of encountering natural gas.

The company is currently expecting to drill by early 2016, according to Bovee.

The Ahtna program is focusing on the Nelchina sands, which are a highly pressurized, porous and permeable gas-bearing sandstone in faulted blocks over an area of roughly 120 square miles. Information from the existing seismic data suggests the potential for gas reservoirs between 4,000 feet and 12,000 feet in the exploration area, Bovee said.

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MYERS *continued from page 8*

ment.

Hydrocarbon resources that were passed over 30 years ago are now being developed and produced. We see this with investment in new exploration targets and new fields under development, as well as new drilling and development in the legacy fields.

The technologies enabling Nuna include advanced applications of directional drilling, hydraulic fracturing, and well completion design.

Furthermore, advances in technologies for seismic acquisition processing and analysis are yielding better insight into reservoir and source rock properties, and have increased the success rate in exploring for and delineating these resources. New oil associated with these activities increases our reserve base for the benefit of Alaskans and investors.

The North Slope of Alaska has world-class oil and gas source rocks but a limited number of high-quality reservoirs. Much of the untapped resource potential is within "second-tier" conventional reservoirs with lower porosity and permeability. Even though these reservoirs may be of lower quality than those historically developed on the North Slope, the reservoir quality is significantly superior to that of shale resource plays currently under development in the Lower 48.

The combination of this huge untapped resource, new technology and increased investment by many companies means that the future of the North Slope is bright.

Mega-projects — gas and offshore

We also see reason for optimism regarding two major exploration prizes on the North Slope — our outer continental shelf

continued on next page

MYERS *continued from page 10*

and North Slope gas.

A report recently delivered by the National Petroleum Council to U.S. Secretary of Energy Ernest Moniz recognized the important role that Alaska's Arctic will play in securing domestic energy supplies when the Lower 48 shale revolution plays out. The NPC noted that the U.S. Arctic Outer Continental Shelf is estimated to have 48 billion barrels of oil-equivalent, with more than 90 percent of this in less than 100 meters of water. Despite this vast resource potential, the only U.S. Arctic OCS development to date is the Northstar field, which straddles state and federal waters.

It took 22 years to develop Northstar. It also will take many years to advance other major OCS oil targets — such as Shell's Chukchi Sea Burger prospect — from exploration to development. But the National Petroleum Council advises that we should pursue this exploration now because the energy supplies from Arctic Alaska will sustain the United States when Lower 48 production is projected to be in decline.

The stakes are high and the prize is great for renewed exploration in the OCS.

But the same can be said for our efforts in Alaska regarding large-scale natural gas commercialization.

In the year ahead, Alaskans will be closely watching the efforts by the State of Alaska and North Slope producers to advance a large-scale North Slope gas project.

The gas at Prudhoe and Point Thomson is a mega-resource that has yet to be fully committed to development. Point Thomson alone contains approximately 25 percent of the North Slope's discovered, remaining gas.

Focusing on large-scale LNG exports, the State of Alaska is negotiating with the North Slope leaseholders and engaging with Asian buyers to maximize the value of the gas on State lands for many generations of Alaskans. Right now, the state is pursuing the Alaska LNG Project as well as taking a new look at a backup plan for a gasline if the big project falters.

My department is heavily engaged in the Alaska LNG Project negotiations and is seeking to make the best choices for Alaskans regarding the management of our gas resources.

The LNG project is now in pre-FEED. Moving to FEED will require us to continue the robust dialog between all of the negotiating parties and continue sharing large amounts of technical information needed to make critical decisions.

With large-scale gas commercialization moving forward, it is important to remember that the North Slope is blessed with much additional undiscovered and unleased gas — notably in the North Slope Foothills and the National Petroleum Reserve-Alaska. The U.S. Geological Survey estimates that Alaska's Arctic has more than 200 trillion cubic feet of undiscovered conventional natural gas. This offers significant opportunities for new entrants to acquire acreage in highly prospective portions of the basin.

With all of this work under way in Alaska's resource basins, I see a bright future for explorers and the nation and global energy markets that will benefit from their innovation and hard work.

In closing, I'd like to remind all explorers and investors that the State of Alaska will hold its annual oil and gas lease sale for Cook Inlet on May 6 and will hold its annual North Slope, Foothills, and Beaufort Sea areawide lease sales next fall.

For more information on our lease sales, please visit http://dog.dnr.alaska.gov.

AIX acquires Kenai Loop, exploration plans unknown

Woodlands-based company acquired Buccaneer assets through bankruptcy sale, currently operating production

By ERIC LIDJI
For Petroleum News

Toward the end of 2014, AIX Energy LLC acquired nearly all of the assets of the Australian-based independent Buccaneer Energy Ltd. in a bankruptcy auction.

The most valuable asset in the acquisition was the producing Kenai Loop gas field, northeast of the city of Kenai. Although AIX Energy has yet to publically announce any exploration plans for the field, Buccaneer had been advancing exploration and development projects simultaneously during its tenure as operator of the onshore field.

Prior to the bankruptcy proceedings, Buccaneer had been among the most ambitious exploration companies in the Cook Inlet region. The company was actively pursuing exploration programs at five prospects while developing the Kenai Loop field. The portfolio ultimately proved to be too large for the small independent, and the company sold certain assets, relinquished certain prospects and ultimately filed for bankruptcy.

At the time that Buccaneer filed for bankruptcy protection in late May 2014, the Texas-based AIX Energy was its largest secured creditor. AIX Energy had acquired the debt through a series of transactions over the previous year. An "official committee of unsecured creditors" highlighted those transactions during the bankruptcy proceedings.

In mid-2013, the venture capital firm Meridian Capital International Fund acquired a 19.9 percent interest in Buccaneer, becoming the large stakeholder in the company. By early 2014, Buccaneer began selling off assets to balance its books. Around that time, a Meridian affiliate called Meridian Capital CIS took over some Buccaneer debt operated by another company. On April 30, 2014, Meridian Capital CIS said it was transferring the debt to AIX Energy, which subsequently became Buccaneer's largest secured creditor.

AIX Energy LLC officially registered as a corporation in

continued on next page

AIX *continued from page 12*

Alaska on May 9, 2014, after having reserved the name "AIX Energy LLC" and cancelled the reservation the day before, according to the Division of Corporations, Business and Professional Licensing.

Because of those transactions, which preceded the bankruptcy filing on May 31, 2014, the unsecured creditors wanted to know more about the relationship between Meridian, AIX Energy and Buccaneer. "In order to accomplish indirectly what it could not do directly, Meridian installed AIX — a newly formed shell entity comprised of individual oil and gas operators with whom Meridian had long-standing prior personal relationships — as a 'straw-man' lender to foreclose the debtors' assets," the committee wrote in July 2014.

In August, the two sides reached a settlement, which required AIX Energy to create a trust that would be used to repay unsecured creditors as part of any liquidation plan.

In an October 2014 bankruptcy auction, AIX acquired nearly all of Buccaneer's assets with a $44 million credit bid, which is when a creditor offers its debt against cash bids.

AIX Energy currently leases some 1,048 acres of state lands in the vicinity of the Kenai Loop field and operates four wells — Kenai Loop 1-1, Kenai Loop 1-2, Kenai Loop 1-3 and Kenai Loop 1-4, accord to state reports. In late 2014, the city of Kenai formally assigned a Buccaneer lease on city property in the vicinity of Kenai Loop to AIX Energy.

Those wells are located on Alaska Mental Health Trust leases.

Through the acquisition, AIX Energy also took over supply contracts pertaining to Kenai Loop production. In late 2014, AIX Energy signed a new deal to provide an interruptible supply to Chugach Electric Association Inc., totaling no more than 300 million cubic feet.

Whether AIX Energy intends to develop Kenai Loop, explore the surrounding area, sell the prospect or merely harvest its acquisition is unclear at the moment. Throughout its seismic acquisition and exploration campaign, Buccaneer suggested that the Kenai Loop region might contain additional gas-bearing intervals worthy of further investigation.

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Apache eyeing long game in Cook Inlet exploration

Houston company has been resuming seismic after delays, but corporate strategy favors other regions

By ERIC LIDJI
For Petroleum News

Apache Corp. started its Alaska tenure at full speed but has since decelerated.

The Houston-based independent came to Alaska in mid-2010 after months of speculation about its eminent arrival, quickly proposed a major campaign to revitalize oil exploration activities throughout the Cook Inlet basin and just as quickly slowed those efforts as a response to regulatory delays and weaker-than-expected results from exploration drilling.

JUDY PATRICK

JOHN HENDRIX

Three incidents from 2014 suggest the company remains interested in Cook Inlet.

In February, Apache resumed a 3-D seismic program in the Kenai National Wildlife Refuge. In August, the company applied for federal approval of a five-year program to conduct offshore seismic activities in the upper Cook Inlet through February 2020. Then, in December, the company began permitting construction for three gravel pads for exploration drilling and associated access roads on Native land within the refuge.

"Apache is applying for the necessary permits needed to allow for exploration of oil and gas," Apache Alaska spokeswoman Lisa

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continued on page 16

APACHE *continued from page 14*

Parker told Petroleum News by email at the time. "While no decisions have been made it is critical to have all the permits in place."

Whether such cautious optimism can survive lower oil prices remains to be seen.

In January 2015, Apache replaced its long time Chief Executive Officer G. Steven Ferris, who had been a vocal supporter of the opportunities his company had been pursuing in Alaska, and its Chief Financial Officer Alfonso Leon. The new CEO is John Christmann, who the company had recently hired to oversee development of its North American assets, particularly unconventional opportunities. The new CFO is Stephen Riney, who had previously held a similar position for BP's exploration and production segment.

The shake-up came after Apache, at the urging of investors, sold off some $6 billion in assets over 2014 to narrow its focus to unconventional plays in the United States and Canada. Some felt that Apache was reluctant to make the change, believing that its international holdings generated cash flow that supported North American investments.

In November 2014, in response to declining oil prices, Apache announced a $4 billion budget for its onshore operations in North American in 2015, down from $5.4 billion for the segment in 2014. Some analysts believed the company would spend more than its budget. Those predications, though, came when oil prices were above $70 per barrel. An Apache executive told the Houston Chronicle that the company would be "comfortable … even all the way down to $70." By January, prices had fallen below $50 per barrel.

Apache made no explicit mention of Alaska in a November 2014 event on North American activities, focusing on Canada, Oklahoma, Texas and the Gulf Coast. But executives referenced three unnamed "undercover plays" budgeted for exploration work in 2015. Alaska remained absent from company updates in February and March 2015.

Rumors first

When Apache representatives attended a state-sponsored conference in Anchorage and formed an Alaska subsidiary in early 2010, a wave of optimism crested in the oil patch.

That's not just because Apache is one of the largest oil companies in America.

It's because the company had spent some $10 billion over the previous decade acquiring prospects around the world with an eye toward extending the life of mature oil fields.

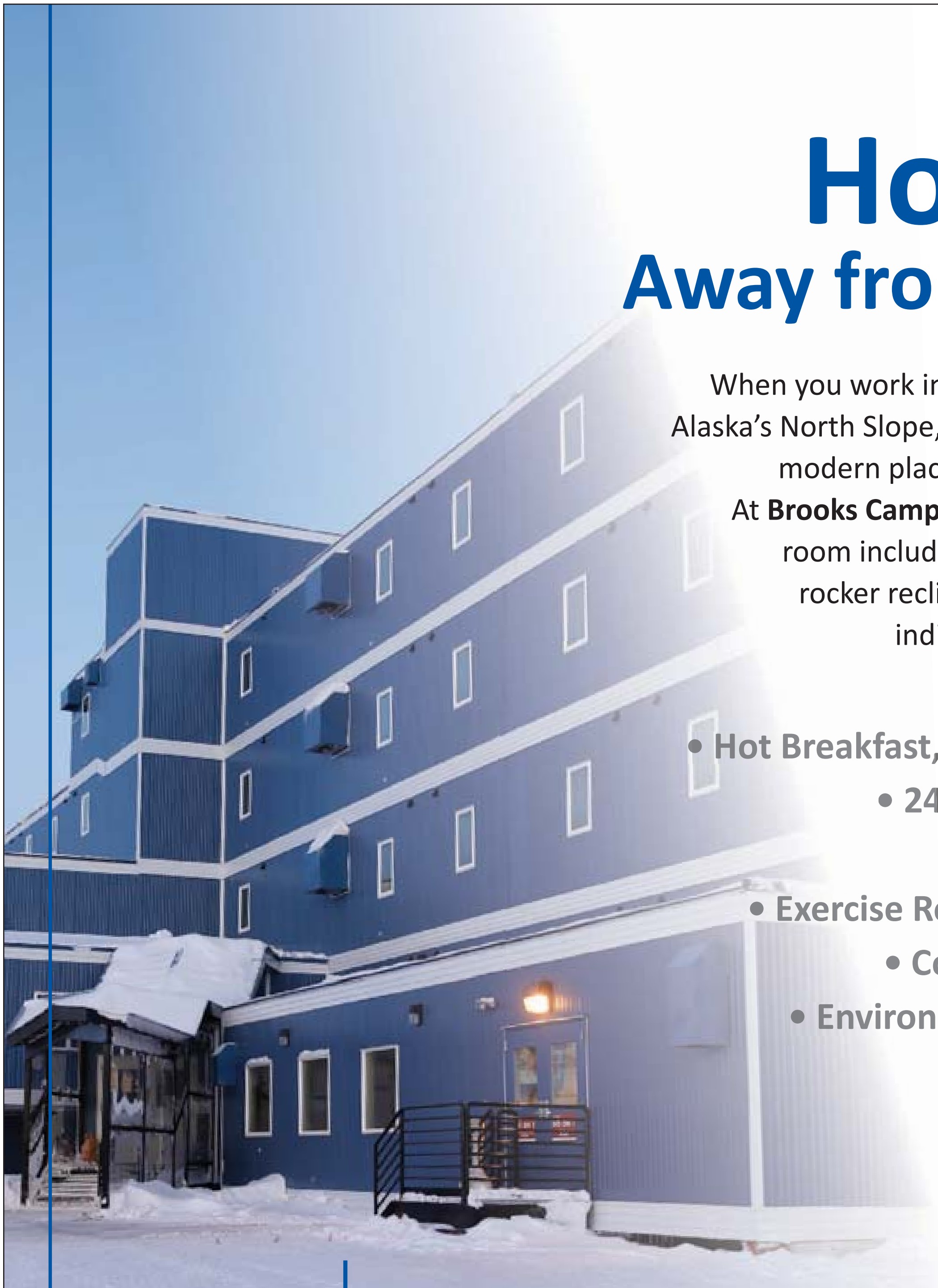
With Alaska in its fifth decade of oil development and its third decade of declining oil production, the idea of a company focused on rejuvenating old fields captured the imagination. At several points in 2010, major news outlets reported that BP was in talks to sell the Prudhoe Bay field to Apache as part of a larger divestment campaign.

That didn't happen.

Later in the year, rumor had it that Apache wanted to buy the Cook Inlet assets of Chevron. Ultimately, Chevron sold those assets to the independent company Hilcorp.

Finally, in late July 2010, Apache arrived. The company acquired 196,524 acres from Samuel H. Cade, Daniel K. Donkel and three other independent investors. The acreage was scattered across the Cook Inlet basin, and included onshore and offshore tracts.

continued on page 19



ASRC Exploration near spudding first operated well

Exploration arm of Arctic Slope Regional Corp. has spent a decade learning and permitting across North Slope

By ERIC LIDJI
For Petroleum News

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A little more than a decade ago, Arctic Slope Regional Corp. decided to expand the scope of its resource-development business to include oil and gas exploration and production.

So the Alaska Native corporation for the North Slope region and a mainstay in the oil field services business created a new subsidiary called ASRC Exploration LLC. While many exploration companies begin by accumulating acreage through lease sales or acquisitions, ASRC Exploration started out looking for knowledge rather than for oil.

In March 2003, ASRC entered into a "mentoring" agreement with BP Exploration (Alaska) Inc. The agreement established "a framework for sharing data and technical knowledge," including information on unit and near-unit oil and gas investment opportunities on the North Slope, the two companies told Petroleum News at the time.


REX ROCK, SR.

The agreement signaled a shift in the development of the North Slope. Negotiations began in 1999, around the time ARCO Alaska was divesting its holdings in the region. Those conversations resumed around 2002, when BP decided it would no longer conduct frontier exploration in Alaska and would instead focus on its existing properties.

For BP, the arrangement created a way to explore and potentially develop prospects around its existing units that might not otherwise make the cut for funding at the corporate level. "This agreement is … hopefully going to provide an opportunity for a company like ASRC to invest where BP would choose not to," former BP Exploration (Alaska) President Steve Marshall said at the time. For ASRC, the agreement promised to become a way to accelerate economic opportunities for its shareholders. "This agreement provides a critical next step in providing ASRC with access to the tools and knowledge we need to become a competitive, independent producer in Alaska," former Arctic Slope Regional Corp. President and Chief Executive Officer Jacob Adams said in July 2003.

The Placer unit

Currently, ASRC Exploration's biggest opportunity is at the Placer unit.

The prospect was among the first outcomes of the company's mentoring agreement with BP. In early 2004, BP, Union Oil Company of California, ChevronTexaco and ExxonMobil partnered on an exploration venture at the western edge of the Kuparuk River unit led by operator ConocoPhillips. ASRC farmed in the BP acreage, gaining a 35 percent interest in the Placer No. 1 well that ConocoPhillips drilled in February 2004.

While ConocoPhillips initially seemed enthusiastic about Placer, and even drilled a second well in April 2004, the company eventually backed away from the project. The first well had encountered some 17 feet of hydrocarbon-bearing sands in the Kuparuk formation. The second delineated the Kuparuk C formation slightly to the northeast.

ASRC acquired the Placer prospect in a March 2006 lease sale and, after years of negotiation, acquired the Placer No. 1 well in June 2010. The company also spent a year negotiating a license over an earlier seismic survey of the region. By early 2011, the five-year leases were about to expire, leaving little time for exploration activities. ASRC asked the state to form the Placer unit over four state leases covering some 8,769 acres.

The original unit request included a four-year exploration program. The plan called for reprocessing existing seismic by the end of 2012 and either re-entering Placer No. 1 or drilling another exploration well by the end of June 2014. According to the company the original well "demonstrated that decent quality oil is present in a thin, but high quality reservoir in the Placer area" particularly in the Kuparuk C sand. The state was skeptical about the proposal, though. In May 2011 the company accelerated its work commitments by one year and shrunk the proposed size of the unit to focus specifically on Placer No. 1.

In September 2011, the state approved a 1,480-acre unit covering a portion of four leases.

After reprocessing the seismic information, ASRC asked the state to expand to unit to the originally requested boundaries. According to ASRC Exploration President Theresa Imm, the seismic showed that the prospect extended beyond the unit boundaries and potentially merged with the Brooks Range Petroleum Corp. Appaloosa prospect to the south.

Because Placer was proving to be "at best, only marginally large enough to develop," a strategic development plan was crucial. The company also asked the state to extend its work commitments by a year because the company was having trouble securing a rig.

continued on page 20

APACHE *continued from page 16*

Over the nearly five years since, Apache has expanded and refined its holdings in Alaska through lease sales, private deals, relinquishments and expirations. At its peak, Apache claimed to hold some 800,000 acres across the basin. As of January 2015, the company was leasing some 419,493 acres from the state of Alaska and more from private owners.

‘An oil museum’

Apache came to Alaska to look for oil.

As it had done in other mature basins such as the western desert of Egypt and the Forties field in the North Sea, the company intended to begin its tenure in Alaska with seismic.

The company launched a small, preliminary 2-D seismic survey in early 2011 covering onshore, offshore and “transition zone” targets. To gauge the effectiveness of wireless nodal recorder technology in the Cook Inlet basin, the company ran the newer technology alongside a conventional seismic recorder. The results intrigued the company. “It’s an exploration play but the guys have wowed me enough for me to believe that it’s a real opportunity,” then-CEO Steve Farris said during a conference call in August 2011.

A few months later, Apache Senior Commercial Advisor Paul Abokhair told state lawmakers that the company was “on a 25- to 30-year plan for the Cook Inlet.”

By that point, Apache had commissioned an ambitious three-year 3-D seismic survey.

The wide-ranging program was supposed to run north to the Susitna Flats and south to Anchor Point. The three-year timetable and the wireless technology would have allowed Apache to work year round: onshore from September to April, offshore from April to November and in transition zones from September to December and March to May.

After a few months, the company was impressed.

“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 in June 2012. “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.

The first 130 square miles of seismic identified eight new leads, according to Bedingfield, suggesting as many as 650 potential leads spread across the leasehold.

Delays and challenges

A regulatory challenge to the program in early 2012 slowed those efforts.

As Apache prepared to move the survey into more fragile transition zones and offshore regions, a coalition of environmental groups challenged a favorable National Marine Fisheries Service opinion about the potential impacts of the program on beluga whale or Steller sea lion populations in Cook Inlet. By the time a May 2013 court order upheld a portion of the appeal, the authorization had expired. The parties agreed to close the case.

A delay over a different authorization for a seismic survey in the Kenai National Wildlife Refuge forced Apache to suspend its program in September 2012. Shutting down the $50 million operation cost Apache $10 million and delayed the overall program by at least a year, Apache Alaska General Manager John Hendrix said in February 2013. Even after Apache got the necessary approvals to continue, the company kept the Alaska seismic survey on hold while it pursued more immediately profitable projects in its portfolio.

Given the expansiveness of its seismic program, Apache decided to drill exploration wells over regions it had surveyed as it continued collecting information for other areas.

In April 2012, the company announced a two-well program — the Aspen well on the west side in the summer and the Captain Boomer well on the east side that fall or winter.

Taking a long view, Apache planned to drill the wells as deep as 16,000 feet, which would have allowed the company to test intervals 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.”

Ultimately, Apache scaled back its efforts, planning a one-well program on the west side of Cook Inlet, where its seismic activities had so far been focused. In No-

continued on next page

ASRC *continued from page 18*

The state denied the request, saying that the company could proceed with exploration work without expanding the unit. The company appealed the decision in February 2013, saying that any well drilled within the smaller unit would be a "twin" of Placer No. 1.

With the additional time, ASRC believed it might be able to piggyback on other development opportunities within the "billion-dollar fairway" between the Kuparuk River unit and the Colville River unit, particularly a public private partnership to develop basic infrastructure to support Brooks Range Petroleum's nearby Mustang prospect.

After the state met with officials from ASRC and Brooks Range Petroleum, who presented a "unified position" for Placer exploration, then-Alaska Department of Natural Resources Commissioner Dan Sullivan conditionally approved the expansion and the extension, requiring ASRC to post a $5.4 million bond to backstop its commitments.

In late 2013, Brooks Range Petroleum began permitting a two-well exploration program at Placer to get a head start on the upcoming season, should a joint plan materialize. After several months, though, the two parties were unable to agree to final terms for a deal.

By that time, in early 2014, the geography of the region had grown more complicated.

Brooks Range Petroleum asked the state to expand its Kachemach unit to include the Placer prospect. Repsol E&P USA Inc. wanted to form the Tapqaq unit nearby.

With those developments, "three lessees intend to drill multi-

continued on page 24

APACHE *continued from page 19*

vember 2012, Apache drilled the Kaldachabuna No. 2 well on Cook Inlet Region Inc. land near Tyonek.

Simasko Production Co. had drilled the 12,890-foot Simpco Kaldachabuna No. 1 well nearby in 1980. Despite finding oil and gas in the Tyonek formation, Simasko abandoned the well because of "low permeabilities and low structural position" and large quantities of water in the formation. Apache wondered whether a generation of advances in well stimulation techniques would have more success producing oil from the formation.

Kaldachabuna No. 2 passed through more than 100 coal seams, including many thicker than 10 feet. The drill bit became stuck several times. Apache 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 but later slowed its exploration plans. "Frankly, we were disappointed in the well results that we had there," Farris told analysts during an August 2013 conference call. "We drilled the well and actually got too close to a fault, so we really didn't evaluate that well." The company would continue seismic efforts while waiting on future drilling. "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."

Renewed interest

The promise of seismic came true.

After getting a U.S. Fish and Wildlife Service special use permit in July 2013, Apache started its onshore survey in the Kenai National Wildlife Refuge in February 2014.

And in March, after getting new approval from the National Marine Fisheries Service, the company resumed its offshore seismic survey. But in May 2014, CIRI Senior Vice President of Land and Development told the U.S. House Committee on Natural Resources that a lack of coordination between federal permitting agencies had caused Apache to scale down a planned major 3-D seismic program in the Cook Inlet basin, to a smaller, discontinuous 2-D program. Apache declined to comment on the announcement.

Apache alleviated some of the uncertainty around its Cook Inlet program through two filings in the second half of 2014. In August, the company applied for National Marine Fisheries Service authorization for a five-year offshore seismic program running from March 2015 to February 2020. The request covered 1,863 square miles of upper Cook Inlet, from south of Kalgin Island to an area west of the northern Kenai Peninsula. The authorization was released for public comment in March 2015. In December, the company applied for a U.S. Army Corps of Engineers permit to build three gravel pads and associated access roads within the Kenai National Wildlife Refuge.

In both cases, the permits would merely give the company options as it budgets exploration activities over the next five years. The company has yet to sanction activities.

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BlueCrest plotting course at Cosmopolitan unit

Independent acquired prospect from partner Buccaneer, now pursuing development while evaluating exploration

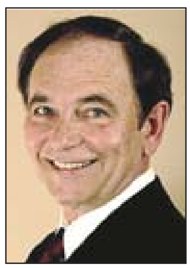
By ERIC LIDJI
For Petroleum News

BlueCrest Energy Inc. graduated into an operator in 2014. The Fort Worth, Texas-based independent came to Alaska in February 2012, when Buccaneer Energy Ltd. acquired the Cosmopolitan prospect in the Cook Inlet basin.

Through the deal, BlueCrest became a 75 percent, non-operating owner of the offshore oil and gas prospect off the coast of Anchor Point in the southern Kenai Peninsula.

Originally, the two companies planned a two-well program using the Endeavour jack-up rig — Cosmopolitan No. 1 in February 2013 and Cosmopolitan No. 2 in April 2013.

A series of technical issues delayed the program. In May 2013, the companies drilled Cosmopolitan No. 1 to 7,599 feet, some 400 feet shallower than intended. The well encountered oil and condensate at 5,600 feet, in the Lower Tyonek, much shallower than expected. A pair of flow tests yielded peak rates of 7.2 million cubic feet and 7.3 million cubic feet per day from the Tyonek but technical restraints prevented an oil flow test.


J. BENJAMIN JOHNSON

In early 2014, as the companies were permitting Cosmopolitan No. 2, Buccaneer sold its interest in the project to BlueCrest for some $41.25 million. The deal initially required BlueCrest to use the Endeavour rig for at least 50 working days each winter for the next three winters, at a rate of $175,000 per day. To backstop the deal, BlueCrest had to file a $5 million letter of credit that would remain in effect until it used the rig for 150 days.

The provision became moot when the owners of the rig sold their stake.

Now, BlueCrest is pursuing a multi-faceted approach at Cosmopolitan: developing deep oil deposits while it creates a strategy for exploring the shallower oil and natural gas.

An enticing prospect

BlueCrest is the sixth company to try its hand at Cosmopolitan.

Pennzoil discovered the field in 1967 with the 12,112-foot vertical Starichkof State No. 1 well. A pair of drill-stem tests at approximately 6,800 and 6,900 feet produced a small amount of oil but the deeper Hemlock formation was wet. The down-dip Starichkof State Unit No. 1 well, drilled to the north, collected full cores in the upper Tyonek and Starichkof sands, finding good-quality sands but not potential for natural gas production.

ARCO Alaska began a second exploration effort at Cosmopolitan in the 1990s. In 2001, after acquiring the Alaska assets of ARCO, Phillips Inc. formed the Cosmopolitan unit over seven state leases and two federal leases. Using an onshore pad, Phillips drilled the Hansen No. 1 well directionally to an offshore target. The well confirmed the presence of oil in the Starichkof sands and found productive sands in the deeper Hemlock formation.

Following a merger, ConocoPhillips Alaska Inc. assumed control of the unit. In 2003, the company drilled Hansen No. 1A, a

continued on page 26

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Saluting Alaska's Explorers

JUDY PATRICK

ASRC *continued from page 20*

ple wells in adjacent leases which are already unitized, or proposed to be unitized, and those wells may be targeting the same potential reservoir or reservoirs," then Natural Resources Commissioner Joe Balash wrote to Imm in March 2014. To avoid inefficient development, "I have decided to defer unit decisions in this area until the end of the drilling season," Balash added.

Finally, in November 2014, under a new administration, the state approved an expansion of the Placer unit, requiring ASRC to post a $2.5 million performance bond by mid-January 2015 and meet a series of commitments culminating in a well by May 2016.

The state formally expanded the unit in March 2015, after ASRC met early conditions.

The Badami unit

While ASRC was in the middle of its long ordeal over Placer, it also became involved in another BP property — the troublesome Badami unit on the eastern North Slope.

Conoco Inc. discovered the Badami oil pool in 1990, and BP brought the field into production in August 1998. But oil production peaked a month later and BP spent the next decade starting and stopping production in an effort to recharge field pressure.

In mid-2008, the state approved a plan where Savant Alaska LLC would restart production on the field on behalf of BP. As part of the mentoring arrangement, BP asked Savant Alaska to bring ASRC Energy Services into the project as a minority partner.

"If the Savant program is successful, and we are hopeful that it is, then we will have revitalized exploration options on the east-side of the North Slope and we will be a player in its future," Mark Kroloff with ASRC wrote to Petroleum News in September 2008.

The two partners aimed to rejuvenate the unit by bringing modern hydraulic fracturing techniques to horizontal wells in the Brookian formation. Savant drilled several development wells and an exploration well and has managed to stabilize production.

Eventually, BP bowed out, transferring the operatorship to Savant Alaska. Toward the end of 2014, Miller Energy Resources Ltd. acquired Savant, making it a subsidiary.

ASRC continues to hold its minority stake in the project.

In addition to Placer and Badami, ASRC has participated in several other exploration programs over the past decade, including Jacob's Ladder and the Nenana basin.

Other endeavors

In addition to Placer and Badami, ASRC has participated in several other exploration programs over the past decade, including Jacob's Ladder and the Nenana basin.

In 2004, ASRC joined a four-company joint venture led by Andex Resources to explore for natural gas in the Nenana basin, in the Interior region southwest of Fairbanks.

The group commissioned a 2-D seismic survey over an exploration license region in early 2005 but postponed the program in 2006 as lawmakers debated the state fiscal system.

Andex left the joint venture in 2007 and the other companies spent some time finding a replacement before finally drilling the Nunivak No. 1 exploration well in 2009. The results of the $15 million well were less than satisfactory to the partners, who left the program. Operator Doyon Ltd. has continued to explore the region independently.

And in 2006, ASRC and London-based BG Group joined operator Anadarko Petroleum Corp. on an exploration program at the Jacob's Ladder prospect south of Badami.

The prospect targeted a geologic featured relatively unexplored in the North Slope: Karst topography, where water has eroded near-surface limestone to form extensive underground caves. These caves can be excellent for trapping oil and gas, as proven by the similar features in the epic Permian basin. The partners completed an exploration well in early 2008 but found "no commercial hydrocarbons" and abandoned the prospect.

As a major North Slope landowner, Arctic Slope Regional Corp. has also been involved in two pioneering exploration efforts: a 2-D seismic program and exploration well in the Arctic National Wildlife Refuge in the 1980s and Anadarko's natural gas exploration program in the foothills of the Brooks Range Mountains over the past decade.

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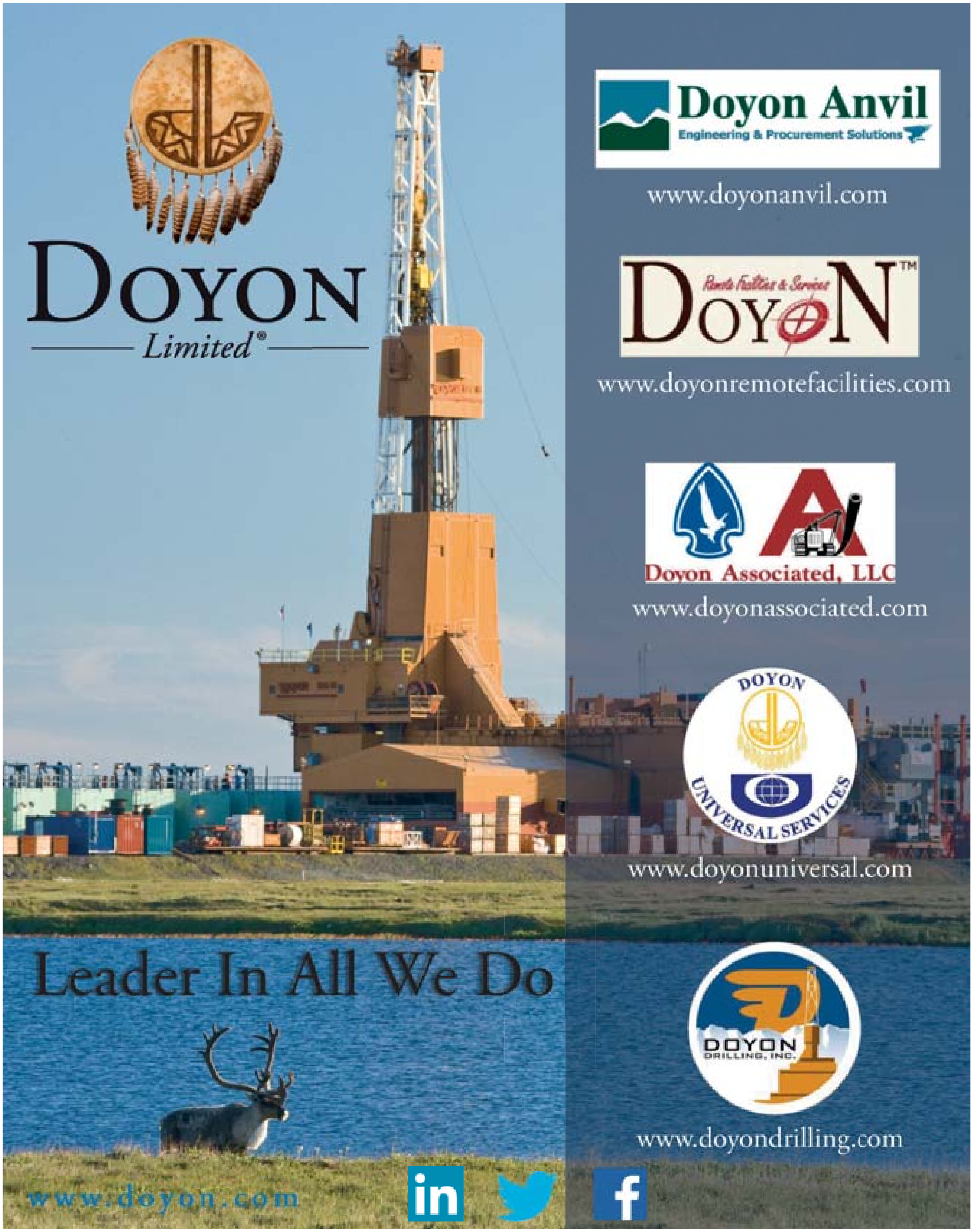

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BLUECREST *continued from page 21*

sidetrack of the original well. The sidetrack provided a deviated penetration into the Starichkof and a lateral penetration into the Hemlock. A flow test produced some 1,000 barrels of oil per day and 14,851 barrels cumulatively.

In 2005, Pioneer Natural Resources Alaska Inc. joined ConocoPhillips on a seismic program at Cosmopolitan. The partners commissioned a 3-D survey covering some 40 square miles of the region. They kept quiet about the results. But according to a recent BlueCrest filing, the seismic program "provided a clear view of the perimeter flanks of an anticlinal structure, but the crestal view of the structure was obscured by a gas cloud, rendering a conclusive description of the reservoir structure unobtainable at the time."

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

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

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

The company even went so far as to propose a development program for Cosmopolitan, but in early 2011 Pioneer decided that "subsequent flow test results and engineering studies indicated that the resource potential was not as large as originally estimated."

As such, Pioneer terminated the Cosmopolitan unit, relinquished all the leases at the prospect except the two held by wells, which it sold to Buccaneer and BlueCrest.

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

Development now

Those previous exploration efforts identified numerous leads.

In March 2015, BlueCrest applied to form a new Cosmopolitan unit over seven leases covering some 22,535 acres off Anchor Point.

By June 2014, BlueCrest had proposed a two-pronged development program for Cosmopolitan. The company decided it would use extended reach drilling to target oil accumulations in the Hemlock and Starichkof formations from an existing onshore drilling pad and install two offshore platforms to develop the natural gas reservoirs.

BlueCrest expects its onshore development program to come into production by early 2016. The future offshore development program is currently at a much more preliminary stage.

In March 2015, BlueCrest applied to form a new Cosmopolitan unit over seven leases covering some 22,535 acres off Anchor Point. The unit would include ADL 18790, ADL 384403, ADL 391899, ADL 391900, ADL 391902, ADL 391903 and ADL 391904.

The application included an August 2014 proposed plan of development calling for 44 wells: 20 onshore oil production wells, 10 onshore injection wells and two onshore disposal wells and 12 offshore wells divided between the proposed monopod platforms.

The application, though, listed other targets worth exploring. The prior exploration activities at Cosmopolitan discovered potentially commercial hydrocarbons within 10 Tyonek formation intervals, according to BlueCrest. Those include oil in the Hemlock, the Starichkof and the Lower Tyonek and gas in the Lower Tyonek and Upper Tyonek.

Under the proposed program, BlueCrest would evaluate a gas development program on leases ADL 391899, ADL 391900 and ADL 391902 in 2015 and 2016. Previously, BlueCrest had said gas development would depend on "a suitable market for gas in the Cook Inlet basin, additional information gained from drilling the first offshore delineation wells, and receipt of all required governmental approvals from the offshore program."

In early 2015, BlueCrest announced a partnership with WesPac Midstream LLC.

"What we're planning to do is design these facilities where the shallow part is (with) WesPac and the deeper part, where the oil lies, is with BlueCrest," President and CEO J. Benjamin Johnson told the Kenai Peninsula Economic Development District. "WesPac would get 100 percent ownership of the gas sands, while BlueCrest will continue to operate them," he said. "Then, at some point, after they've reached the minimum terms and get their money back, BlueCrest will come back in and begin owning the gas."

The program would give WesPac a supply for a proposed two-phase liquefied natural gas project at Port MacKenzie. The first phase would involve a small-scale plant processing 25 million cubic feet per day of Cook Inlet gas for shipment to Alaska communities by rail, truck or boat. The second phase would involve a 150 million cubic foot per day system with tanker-loading facilities for export, in addition to shipments within Alaska.

The August 2014 plan also called for drilling the offshore Cosmopolitan State B1 exploration will this year on ADL 384403 to test oil and gas zones. The oil zones would be plugged and the gas zones suspended for future development, according to the plan.

BlueCrest asked the state to approve the plan for a one-year term, which would allow the company to amend the plan easily based on information gleaned this year. Such amendments would include more detailed plans for delineation and exploration activities.

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Brooks Range Petroleum finally in development

As the company focuses on development campaign, its once-prolific exploration efforts have slowed

By ERIC LIDJI
For Petroleum News

Here are headlines from the three previous editions of The Explorers:

In 2011, “BRPC shifting to development mode.”

In 2012, “Brooks Range on road to development.”

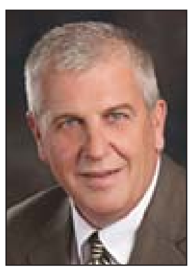
In 2014, “Brooks Range Petroleum moving toward development.”

This year, the story is slightly different. Instead of being in “development mode,” “on the road to development” or “moving toward development,” Brooks Range Petroleum Corp. is actually “in development.” Earlier this year, the company drilled its first wells at the Mustang field, which is the initial development project at its Southern Miluveach unit.

JOHN J. “BO” DARRAH, JR.

The current schedule calls for bringing the unit into production in April 2016.

As those three previous headlines suggest, the Mustang development project has consumed much of Brooks Range Petroleum’s resources over the past four years.



BART ARMFIELD

The company’s last exploration well in Alaska was Mustang No. 1, in early 2012, which appraised a discovery the company had previously made with its North Tarn No. 1 well in early 2011. The last exploration well the company drilled outside of its Mustang project was the North Shore No. 3 well, in the Gwydyr Bay region, in early 2010.

Today, Brooks Range Petroleum and its affiliate Brooks Range Development Corp. operate three units: Southern Miluveach and Tofkat in the fairway between the Kuparuk River and Colville River units and Beechey Point north of the Prudhoe Bay unit.

The company also holds two un-unitized blocks — one between the Kuparuk River and Colville River units and the other between the Badami and Point Thomson units.

To pursue its Mustang development, Brooks Range Petroleum formed a multi-party joint venture with MEP Alaska LLC, TP North Slope LLC and Caracol Petroleum LLC. The joint venture entered into a public-private partnership to fund initial project infrastructure.

To create the joint venture, Alaska Venture Capital Group LLC and its partner Ramshorn Investments Inc. sold a 90 percent stake in their Alaska holdings and 100 percent interest in their operating arm Brooks Range Petroleum Corp. to the three-company consortium for $450 million. Although the new joint venture is currently focused on bringing Mustang into production by 2016, the deal also included the exploration prospects.

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The Beechey Point unit

Alaska Venture Capital Group was among the first independent companies to see opportunity in the aging of the North Slope. The company was created explicitly to develop fields

continued on next page

BROOKS RANGE *continued from page 27*

passed over during the first decades of North Slope development.

The Kansas-based company initially struggled to find partners to share the cost of exploration activities and to negotiate access agreements with existing facility operators on the North Slope, although in 2004, after forming an operating arm called Brooks Range Petroleum Corp., the company established a multi-party joint venture.

The joint venture became among the most prolific exploration outfits on the North Slope, drilling in the Gwydyr Bay region north of Prudhoe Bay and the fairway between the Kuparuk River and Colville River units and amassing leases south of Point Thomson.

The joint venture started its exploration efforts 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 through a 2001 land swap with Phillips Petroleum and 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.

After a year and a half of challenges — searching for partners to defray costs, negotiating access to existing infrastructure and finalizing farm-in agreements and licensing for seismic — Alaska Venture Capital Group cancelled the program and disbanded the unit.

The company acquired the acreage again in 2005. "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."

The company planned a two-well exploration program for early 2007.

The 10,319-foot North Shore No. 1 targeted an oil accumulation in the Ivishak formation that was first tested by Mobil Oil with the Gwydyr Bay South No. 1 well in 1974. The well encountered "approximately 70 feet of oil-charged Ivishak sandstone formation."

The 11,348-foot Sak River No. 1 followed up on a prospect previously included in the BP-operated Sak River unit. The well proved to be a dry hole, although the results were intriguing enough for the joint venture to consider returning to drill a sidetrack.

That winter, the joint venture also commissioned a 130-square-mile 3-D seismic survey.

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 Energy Inc. Those results started the company along its current path — finding a way to string together several marginally economic prospects into a single, profitable development. TG World Energy described the strategy as "establishing a threshold" for development. Potential solutions included two production pads or extended reach drilling.

In early 2008, Brooks Range Petroleum re-entered North Shore No. 1 to test the Ivishak and the shallower Sag River formations. The Ivishak flowed at 2,092 barrels of oil per day. A mechanical problem downhole compromised the Sag River test, although TG World estimated that an unencumbered test 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. The acquisition provided an additional opportunity for bundling several prospects together.

After forming the Beechey Point unit in 2009, and settling a dispute between partners that prevented drilling that year, Brooks Range Petroleum returned to Gwydyr Bay in early 2010. The company drilled the Sak River No. 1A sidetrack and the North Shore No. 3 delineation well. TG Energy World reduced its presence in the joint venture following the results of Sak River No. 1A. The remaining partners suspended North Shore No. 3.

"Sak River No. 1A was truly an exploration project with a pre-drill risk factor of 1 in 5, unfortunately the well encountered mainly water from the Kuparuk formation," Brooks Range Petroleum Chief Operating Officer Bart Armfield wrote in a completion report for the season, which was released after a mandatory two-year delay. Although the company had plugged and abandoned the original Sak River No. 1 well, it decided to suspend the sidetrack, which would allow it to be used to provide pressure maintenance for future wells in the Sag River formation. The company said it was considering plans for a second sidetrack, which would aim for an "up-dip target of the Kuparuk," Armfield wrote.

North Shore No. 3 "identified a common oil/water contact between the Sag and Ivishak formations and presents a reduced reserve base for the North Shore development," Armfield wrote, adding that the company had now discovered reserves at North Shore No. 1, North Shore No. 3 and Pete's Wicked, which would guide future activities.

By the following winter, though, the joint venture was focused on the North Tarn prospect, which became the basis for its current development at Southern Miluveach.

Terminate or proceed?

The Beechey Point unit is currently in limbo.

The state formed the unit in 2009. The unit included 25 leases covering some 52,876 acres along the coastline north of Prudhoe Bay. The unit contained five exploration blocks, and the initial unit agreement required Brooks Range Petroleum to drill at least one well in two different exploration blocks by December 2010 and December 2012, respectively.

The North Shore No. 3 well satisfied the first work commitment. The state subsequently extended the deadline for the second work commitment, giving the company until 2014.

With the Mustang development increasingly occupying the company's attention, Brooks Range Petroleum relinquished some 42,119 acres on the western side of the Beechey Point unit in September 2012, leaving a seven-lease unit covering some 10,757 acres.

The company focused on other project for the next two years.

In September 2014, the state initiated termination proceedings for the unit because the company had failed to meet its work commitments before the end of its initial five-year plan of development, according to then-Natural Resources Commissioner Joe Balash.

Balash said he was unable to justify an extension because the unit had neither a well certified as capable of economically producing oil or gas or an approved plan of development beyond the initial term, either of which can serve as ground for extension.

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BROOKS RANGE *continued from page 28*

The company disagreed. In a late September letter, Vice President for Exploration Larry Vendl named two certified wells at the unit and asked for a chance to negotiate a plan of development. The company could potentially start work as early as 2015, Vendl wrote.

The area contained within the Beechey Point unit undeniably includes two wells certified as capable of producing hydrocarbons in commercial quantities: Gwydyr Bay South No. 1 from 1974 and North Shore No. 1 from 2007 and 2008. Both wells, though, were drilled before the state approved the Beechey Point unit. To the state, that made them irrelevant for extending the terms of the unit. To the company, it made no difference.

The state certified the North Shore No. 1 well in July 2008, approved the Beechey Point unit in August 2009 and told the company to apply for a recertification by August 2010.

To Brooks Range Petroleum, this request for a "recertification" signified a changing standard. No other operator had been asked to perform a similar task, according to the company. In 2010, the company asked the state to reconsider the requirement. The state never responded, according to the company, which is why the two sides now disagree.

The Beechey Point unit agreement required the company to file annual reports with the state, permit a North Shore Development Project, apply to form an initial participating area and drill two wells. Brooks Range Petroleum met the first three requirements, although the state had yet to rule on the participating area application at the time the termination proceedings began. Failure to drill the second well was the sticking point.

Given that it had invested more than $85.5 million in the unit, Brooks Range Petroleum felt it should be given the opportunity to negotiate an extended plan of development.

"The potential for successful exploration and development in this area requires the compilation of several prospects with known reservoir reserves in close proximity to one another," Vendl told the state. "The smaller prospects need to be a part of a larger program; each independent prospect does not support an economic development model."

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BROOKS RANGE *continued from page 29*

The current strategy involves combining various prospects in the region, including the East Shore prospect at Beechey Point, the ConocoPhillips-operated Kup Delta lease and the UltraStar Exploration-operated Dewline unit, all of which are in the immediate vicinity. At the time of the letter, in September 2014, Brooks Range Petroleum was involved in discussions with both ConocoPhillips and UltraStar, according to Vendl.

Another opportunity, Vendl noted, was the 3-D seismic survey BP Exploration (Alaska) Inc. commissioned for the northern end of Prudhoe Bay, including Beechey Point.

In October 2014, Balash agreed to reconsider the termination. The decision came shortly before the election of Gov. Bill Walker, which prompted a turnover of the cabinet. The new commissioner, Mike Myers, had yet to issue a ruling when Explorers went to print.

The Tofkat unit

The second major area of exploration for Brooks Range Petroleum is the region between the Kuparuk River and Colville River units, also known as the "billion-dollar fairway."

The name reflects the potential of the region, rather than the actual payout. Wedged between the second and third largest fields on the North Slope, and the infrastructure associated with those fields, the region is thought to be primed for oil development.

In early 2008, Brooks Range Petroleum conducted a major exploration program in the area near Nuiqsut. The company drilled the 13,174-foot Tofkat No. 1 exploration well and two sidetracks deviating to the northeast and southwest, respectively. All three encountered oil in the Brookian formation and "secondary targets above the Kuparuk."

The company estimated that the Tofkat prospect held about 40 million barrels of recoverable oil in the Kuparuk C sands and another 20 million in the Jurassic sands.

Brooks Range Petroleum also commissioned a 210-square-mile 3-D seismic survey, which Vice President of Land Jim Winegarner said the company intended to analyze before it would decide whether, when and where it would drill another well. The company was still analyzing by early 2009 and exploring other prospects by early 2010.

To avoid losing acreage to expiration, the company 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 state ultimately formed two units. 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 nine remaining leases stayed un-unitized.

The second major area of exploration for Brooks Range Petroleum is the region between the Kuparuk River and Colville River units, also known as the "billion-dollar fairway."

The Tofkat unit agreement required Brooks Range Petroleum to complete a Tofkat No. 2 well and 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.

Although the company floated the possibility of drilling the delineation well and sidetrack at the Tofkat prospect in early 2013 to confirm the size of the previous discovery in the Kuparuk formation and to test a deeper target in the Jurassic formation, the Mustang project delayed those drilling plans. As of April 2015, the state had yet to decide whether to advance termination proceedings or extend the term of the unit.

The company relinquished the Putu unit in September 2012, saying it wanted to focus its resources on bringing Mustang into production and exploring other prospects.

The Kachemach unit

Over the 2011 and 2012 exploration seasons, Brooks Range Petroleum drilled the North Tarn No. 1 exploration well, the North Tarn No. 1-A sidetrack and the Mustang No. 1 delineation well. The wells tested the Brookian formation and deeper Kuparuk formation.

During that time, the company also merged its seismic data for the region with data purchased from ConocoPhillips to consolidate some 570 square miles of 3-D seismic.

The exploration work confirmed a discovery in the range of 40 million barrels of recoverable oil from the Kuparuk, which was much bigger than expected. The discovery prompted the company to seek public financing for initial project infrastructure and a new joint venture to fund ongoing development activities, which are currently under way.

As the project advanced, Brooks Range Petroleum asked the state to form the Southern Miluveach unit. Instead, the state formed two smaller units: the 8,960-acre Southern Miluveach unit over five leases and the 16,487-acre Kachemach unit over 11 leases.

The Kachemach unit agreement split the area into two exploration blocks and required the company to complete two wells in Block A by May 31, 2013, and a third well in Block B by May 31, 2014. Those wells were competing with other prospects for financing. "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," Thompson told Petroleum News in mid-2012.

After discussing the project with Department of Natural Resources officials toward the end of the year, the company said it was continuing to "re-process and merge acquired seismic data to identify optimal drilling location and target" and planned to drill an exploration well in early 2014, after discussing the project with working interest owners.

By that point, the unit was in default, which occurred in mid-2013 when Brooks Range Petroleum missed the deadline for its initial two wells. As is common in Alaska land management, the

continued on page 31

BROOKS RANGE *continued from page 30*

state gave the company a chance to cure the default by drilling both wells by May 31, 2014, with a year extension for the second if the first was a dry hole.

The state initiated termination proceedings in June 2014, after the company failed to cure the default. The company proposed four alternatives, which involved various configurations to either shrink the unit or enlarge it to encompass nearby prospects.

Specifically, Brooks Range Petroleum wanted to coordinate exploration activities at Kachemach with those at the nearby Placer unit, operated by ASRC Exploration LLC.

ASRC Exploration and Brooks Range Petroleum executives had met with state officials in September 2013 to present "a unified position" for exploring the greater Placer area.

The meeting convinced the state to give ASRC Exploration some leeway for its efforts.

The joint program never materialized, though. By early 2014, Repsol E&P USA Inc. was discussing plans to form the Tapqaq unit in the region. With the Placer unit, the nearby Kachemach unit and the proposed Tapqaq unit, "three lessees intend to drill multiple wells in adjacent leases which are already unitized, or proposed to be unitized, and those wells may be targeting the same potential reservoir or reservoirs," Balash wrote in a March 2014 letter. Given the potential for inefficient development, "I have decided to defer unit decisions in this area until the end of the drilling season," he added. That decision failed to protect Kachemach, which the state terminated in October 2014.

The South Thompson prospect

The other prospect in the Brooks Range Petroleum portfolio is the eastern North Slope.

By early 2006, the company was touting the Slugger prospect south of the Point Thomson unit as one of many prospects it hoped to pursue in the years to come. The company picked up additional leases in the area the following year. Low snow cover in early 2008 led the companies to postpone a 130-square-mile 3-D seismic program.

The six years since then have mostly seen administrative issues.

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.

In early 2012, Brooks Range Petroleum proposed the Telemark unit over nine leases covering some 16,235 acres. The proposal included plans to commission a 3-D seismic survey by the end of 2012 and drill an exploration well by the end of March 2014.

The company deferred 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.

Administrative delays have kept that project from advancing.

Contact Eric Lidji at ericlidji@mac.com

Caelus sanctions Nuna; acquires exploration acreage

Royalty relief leads to Nuna development; exploration focused on acquisition of leases on eastern North Slope

By ERIC LIDJI
For Petroleum News

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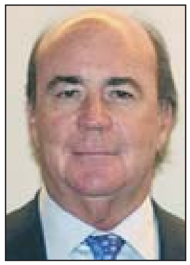
COMPANY HEADQUARTERS: Dallas, Texas
TOP EXECUTIVE: James C. Musselman, president and CEO
TELEPHONE: 214-368-6050 • **WEBSITE:** www.caelusenergy.com


JAMES MUSSELMAN

Exploration begins with lease sales, fieldwork, seismic surveys and wells and, ideally, ends in development. Caelus Energy Alaska LLC is currently working on two ventures at the opposite ends of that spectrum. Earlier this year, the company officially sanctioned a development at the Nuna satellite of its Oooguruk unit. At the same time, the company has been quietly preparing to explore acreage it recently acquired through lease sales.

The former is a project at the threshold between exploration and development. The latter is more of an opportunity than an exploration venture with publicly defined details.

The former is a project Caelus inherited when it acquired the Alaska assets of Pioneer Natural Resources Inc. in 2014. The latter is an opportunity the company deliberately pursued by submitting some $15 million in high bids on some 322,795 fairly contiguous acres in the North Slope and Beaufort Sea areawide lease sales in November 2014.

The Dallas-based Caelus Energy LLC is a relatively young company created by principals with a history of guiding two independents through short-term projects.

Jim Musselman and various colleagues acquired a struggling independent called Triton Energy in the 1990s and sold it to Amerada

continued on next page

CALEUS ENERGY *continued from page 33*

Hess in 2001 for $3.2 billion on the strength of several projects, particularly a quick effort to bring a West Africa discovery online.

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

In both cases, Caelus executives highlight similar accomplishments: quickly raising large sums of money on the private market, making exceptionally quick turnarounds from discovery to development in difficult operating environments and producing large profits for investors by eventually taking a company public or selling it to a larger company.

In 2011, instead of staying with Kosmos after taking the company public, Musselman formed another privately held independent called Caelus Energy. The company made its first big move in October 2013 when it struck a deal with Pioneer Natural Resources, which decided to sell its Alaska assets to free up capital for its operations in West Texas.

Showing his willingness to tackle Alaska, Musselman said, "If you're not nervous and a little bit worried or a bit scared of doing business in hostile places, you're done."

The parties originally agreed to make the sale for $550 million and dropped the price to some $300 million in March 2014, clearing the way for the deal to close in April 2014.

Through its first year in Alaska, Caelus started the process Musselman has undertaken twice before. When Caelus announced the acquisition in October 2013, Musselman said his company would spend at least $300 million developing the Oooguruk unit, specifically its Nuna satellite, which Pioneer had spent considerable money appraising.

But, Musselman added, the company hoped to raise more than $1 billion for future development work and saw the potential to spend as much as $1.5 billion in Alaska over a five-to-six-year period. When it closed on the sale in April 2014, Caelus also formed a strategic partnership with the international investment company Apollo Global Management, which provides short-term funds and an avenue for future borrowing.

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

Royalty relief

When Caelus announced its arrival in Alaska, in October 2013, Musselman said the company would begin work on developing the Nuna satellite "pretty much immediately."

And after the company finally closed on the acquisition, Musselman said the company was aiming to bring the field into production by mid-2016. "We've got the funds committed and we're moving forward as quickly as we can," Musselman said, estimating some $550 million on new facilities and $800 million to $900 million for drilling wells.

By the time Caelus submitted its latest plan of development for Oooguruk in June 2014, though, the company told state officials it was still determining the economics of Nuna.

Through a previous appraisal program, Pioneer Natural Resources had estimated that the Torok formation reservoir contained between 75 million and 100 million barrels of oil.

The reservoir, though, is too far south to be developed economically from the existing Oooguruk Island, which means Caelus would need to construct new onshore facilities near Oliktok Point. "There's a tremendous amount of oil in place," Caelus Senior Vice President for Alaska Operations Pat Foley told an industry audience in November 2014. "And the question on Torok is: What is the recoverable portion going to be?"

In July 2014, Caelus asked the state to modify the royalty structure at Nuna, saying it would be unable to proceed with development without help. The company requested a flat 5 percent royalty rate on 11 leases associated with the satellite until the project reached payout — meaning revenues covered upfront costs. At that point, rates would increase by 1.875 percent annually, for four years, and then returned to original levels.

Instead, the state offered a 5 percent royalty rate on five Nuna leases if Caelus met various sanctioning, spending and development targets through early 2017. The preliminary decision came as Gov. Sean Parnell lost a re-election bid, which prompted Rep. Les Gara to ask the state to give the final decision to incoming Gov. Bill Walker.

In late January, the state approved the

continued on next page

royalty reduction. The ruling required Caelus to sanction the project by the end of March 2015, begin spending money by the end of September 2015, spend at least $260 million and bring the field into sustained production by the end of September 2017. The final decision also retained early requirements for Caelus to provide public reports to extend knowledge about developing similar geology.

In a March 2015 letter to Alaska Department of Natural Resources Deputy Commissioner Marty Rutherford, Foley wrote that the Caelus Energy Alaska board of directors had, in September 2014, sanctioned the project and committed $76 million of its 2014 capital budget to it, subject to the approval of its pending request for royalty modification. With the favorable January 2015 ruling, the company had "fully sanctioned" the Nuna project.

As such, Caelus began initial construction activities earlier this year. The work primarily consisted of gravel mining for an access road, drill site and pad expansion. The company told state officials it has already "prepared and executed" 16 authorizations for expenditure totaling more than $480 million and intended to prepare another 31 authorizations for well activities, totaling, in aggregate, more than $800 million.

Exploration prospects

While much of its first year in Alaska was publicly focused on Nuna, Caelus was also eyeing potential exploration opportunities on the other side of the North Slope.

"I don't have anything I can tell you specifically about where our first exploration well will be," Musselman told Petroleum News in April 2014, when the company closed on its purchase. "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."

In November 2014, through a month-old subsidiary called Caelus Alaska Exploration Co., the company acquired 322,795 state-owned acres, comprising more than half of the acreage receiving bids in the North Slope and the Beaufort Sea areawide lease sales. The total acquisition included 263,674 acres from the North Slope sale and 59,120 acres from the Beaufort Sea sale. Prior to the sales, Caelus held some 40,373 acres of state leases.

The leases mostly stretch across a somewhat contiguous area running from south of the Prudhoe Bay unit to south of the Point Thomson unit, mostly east of the Dalton Highway.

The large block includes several former prospects.

The region south of the Prudhoe Bay unit includes the Toolik No. 1 well, which was a dry hole ARCO drilled in the 1960s to determine how far south the Prudhoe Bay field extended. Some 10 miles to the east is the Jacob's Ladder C well and Jacob's Ladder C-A sidetrack, which Anadarko Petroleum Corp. drilled in 2007 and 2008 to evaluate Karst topography. The wells found "no commercial hydrocarbons," according to Anadarko.

About a mile northeast of the Jacob's Ladder wells is the Lake 79 No. 1 well, a Shell operation from early 1968 that also unsuccessfully tried to piggyback on Prudhoe.

The results of those wells might lead one to wonder what Caelus saw in the region south of Prudhoe Bay. The answer perhaps lies much deeper than those early efforts thought to explore — in the stacked geology thought to contain the source rocks for Prudhoe Bay.

The remaining acreage Caelus acquired in the sales is set back slightly from the coast line south of the Duck Island unit, the Liberty unit, the Badami unit and the Point Thomson unit.

> *"That's one of the main reasons we're in Alaska. We do want to explore. We think there are tremendous opportunities remaining."*
> *—Jim Musselman, Caelus Energy President and CEO*

There has been relatively little previous exploration in the region, although the eastern North Slope has always attracted ambitious companies, particularly independents. The pending development of the Point Thomson unit and the recently stability of the Badami unit operation could make the eastern North Slope more economic for marginal fields.

"One thing you'll find about Caelus: We're not going to let the grass grow under our feet," Foley said at the Resource Development Council's annual meeting on Nov. 18, the day before the lease sales. "Pace is everything. We're not going to be careless, but we're going to go as fast as we can."

Using nearly $1 billion in available funding from Apollo, Caelus planned a $500 million capital for Alaska this year. The majority of that funding is going toward expanding the existing facilities serving the Oooguruk unit and developing new facilities for Nuna.

But Caelus also earmarked some money for exploration. The company commissioned two 3-D seismic programs, including one targeting the acreage grabbed at the lease sales.

Caelus is keeping an eye out for potential partnerships, Foley said at the meeting.

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ConocoPhillips staying close to home for the time being

The company is appraising accumulations in existing units and saving NPR-A development for a later date

By ERIC LIDJI
For Petroleum News

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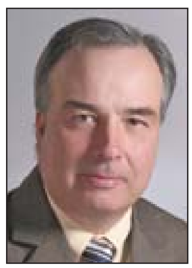
Since ConocoPhillips Alaska Inc. was created through a 2002 merger, the company has been looking for oil and natural gas in two general directions — outward and inward.

"Outward" characterizes the exploration activities designed to extend North Slope development to the west of the Prudhoe Bay unit. "Inward" characterizes a quieter inclination to increase development activities within producing oil and gas units.

ConocoPhillips has generally been the most active exploration company in Alaska over the past decade. This year, though, the company has been focused on existing units.



JOE MARUSHACK

ConocoPhillips operates four North Slope units: the Kuparuk River unit and the Colville River unit on state land and the Greater Mooses Tooth unit and Bear Tooth unit on federal land. The company also holds considerable exploration acreage in the Chukchi Sea. And ConocoPhillips is a major working interest owner in the Prudhoe Bay unit.

The projects ConocoPhillips completed last year and funded for this year are relatively risk averse and generally development oriented. At the Kuparuk River unit, the company is increasing development drilling, building a new drilling pad and conducting some appraisal drilling at an undeveloped accumulation within the unit. At the Colville River unit, the company is finishing the long-delayed CD-5 drilling satellite of the Alpine field.

Those two units already have production.

ConocoPhillips was more cautious at its two units without production. The company postponed activities for the first development in the Greater Mooses Tooth unit for the year and proposed no work for the Bear Tooth unit. And the company has generally put any Chukchi Sea exploration on hold pending more regulatory and legal certainty.

ConocoPhillips is also one of the most important producers in the Cook Inlet basin — operating the legacy Beluga River and North Cook Inlet units and the associated Kenai liquefied natural gas export terminal. But it has been several years since the company drilled development wells at either unit and much longer since the company conducted traditional exploration activities — drilling or seismic — anywhere in the basin.

The Kuparuk River unit

ConocoPhillips' current activities at the Kuparuk River unit can be divided into three general categories: delineating existing accumulations, appraising recent discoveries within the unit and pursuing development of viscous oil in the West Sak formation.

Of those, the second is closest to what is traditionally considered "exploration."

Sinclair Oil and Gas discovered the Kuparuk River oil pool in 1969. ARCO Alaska sanctioned development about a decade later, prompted by rising international oil prices.

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 main field, 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. The same four companies own the Kuparuk satellites, albeit in slightly different percentages.

Since Kuparuk production peaked at 339,386 barrels per day in December 1992, activities have included infill drilling, satellite development and enhanced oil recovery.

The current appraisal activities at Kuparuk emerged from recent seismic activity. The company commissioned the Western Kuparuk 3-D seismic survey in 2011, which led to an "infrastructure-led exploration strategy" focusing on drilling opportunities near existing infrastructure. That strategy is the opposite of the wildcat exploration ConocoPhillips conducted in the early 2000s in the far-flung corners of the NPR-A.

In early 2012, ConocoPhillips drilled Shark Tooth No. 1 to appraise an oil discovery in the southwest corner of the unit. ARCO had discovered the accumulation in the Kuparuk reservoir in the late 1980s with the KRU 21-10-08 well but never pursued development.

Toward the end of 2012, ConocoPhillips said the well had "discovered hydrocarbons in the Kuparuk sands, in accordance with expectations, and confirmed mapped volumes."

Developing Shark Tooth from any of the three existing drill sites in the southwest corner of the unit — 2L, 2M and 2K — would have pushed the limits of existing drilling technology, according to ConocoPhillips. Therefore, the company proposed the first new drill site at the Kuparuk River unit in nearly 12 years,

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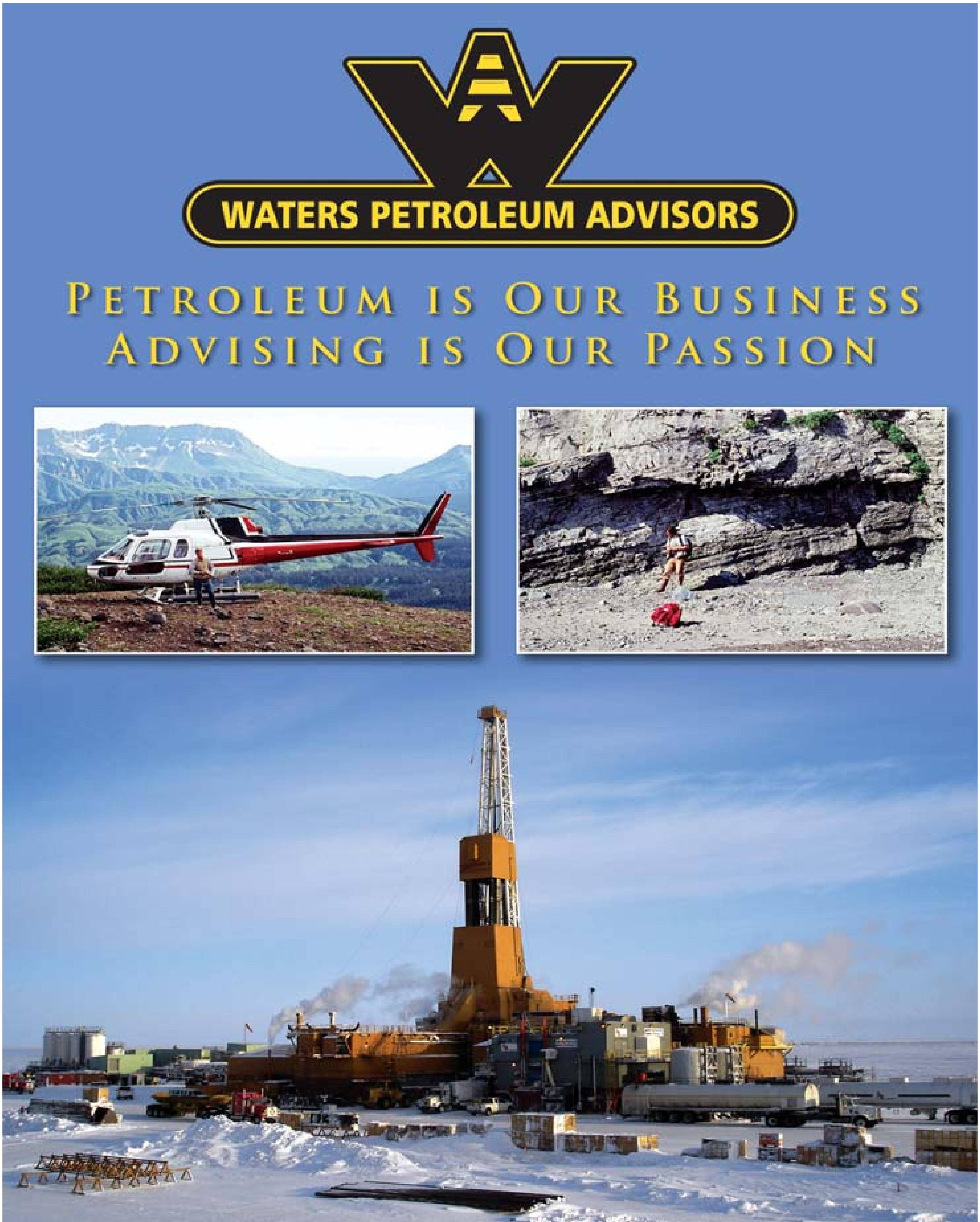
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CONOCOPHILLIPS *continued from page 36*

Drill Site 2S. The company began laying gravel early in 2014 and officially sanctioned the project in November 2014.

The $500 million project includes a pad, a new gravel road and associated power lines, pipelines and surface facilities. Pad construction occurred over the winter, with drilling expected to begin this summer and startup planned for the end of the year, according to a company timeline. The site is expected to produce some 8,000 barrels per day at its peak.

In late 2014, ConocoPhillips began permitting a similar appraisal project to the north, near the Palm satellite, (which had been the newest drill site, before the 2S project).

Phillips Alaska Inc. discovered the Palm satellite at the western edge of Kuparuk in 2001.

ConocoPhillips brought the satellite online in November 2003 from Drill Site 3S. The accumulation is in a Kuparuk C4 interval now known to be in communication with the main Kuparuk reservoir. Palm is generally managed as part of the main Kuparuk field.

Over the winter of 2012-13, ConocoPhillips conducted a pilot test on DS 3S-19, one of the original Palm development wells drilled in 2003. The test involved adding a perforation to the well and performing hydraulic fracturing operations to gauge the potential of developing the overlying Cretaceous Brookian Moraine interval.

"Any development would, of course, require adequate appraisal and study to prove commerciality," the company told state officials in its 2013 plan of development, a sentiment the company reiterated in its 2014 plan of development this past June.

ConocoPhillips proposed no exploration for the Colville River unit in its current plan of development and said it was "evaluating exploration opportunities to conduct in 2016."

The current project involved drilling two wells to appraise the commerciality of the Moraine interval. The first was the DS3S-620 Moraine well drilled from an ice pad on ADL 025528 and connected back to Drill Site 3S using a 2.5-mile ice road. The second was the Moraine No. 1 well "to acquire core, logs and fluid samples," which will be used "to delineate the Moraine reservoir" in the region, according to a December 2014 filing.

ConocoPhillips had intended to commission a 3-D seismic survey this year over some 103 square miles near Oliktok Point, at the northern end of the unit, but postponed the project, saying the area was too crowded with activity this winter to guarantee a quality shoot. The company said it would consider the project again in a future budget cycle.

The Colville River unit

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

ARCO Alaska discovered the Alpine oil pool in 1994 and brought the field online in November 2000. 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 the Kuparuk River unit, ConocoPhillips has been expanding development drilling at the main

continued on next page

CONOCOPHILLIPS *continued from page 38*

Alpine field while bringing a series of satellites into production.

ConocoPhillips initially developed Alpine from the CD-1 and CD-2 pads. In 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.

Those three satellites brought the company to the edge of the Colville River.

A proposal to cross a channel of the river to develop the Alpine West satellite with the CD-5 pad first yielded local opposition and then, after ConocoPhillips had addressed local concerns, federal obstacles. 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 2015 and first oil in late 2015.

ConocoPhillips proposed no exploration for the Colville River unit in its current plan of development and said it was "evaluating exploration opportunities to conduct in 2016."

The NPR-A

The remaining Alpine satellites are now treated as NPR-A projects.

In May 2001, Phillips Alaska Inc. announced the first NPR-A discoveries since the federal government re-opened the region to 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, which had targeted 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."

The development of CD-5 should make it easier to pursue those NPR-A prospects, which are also on the other side of the Colville River from the Alpine processing facilities.

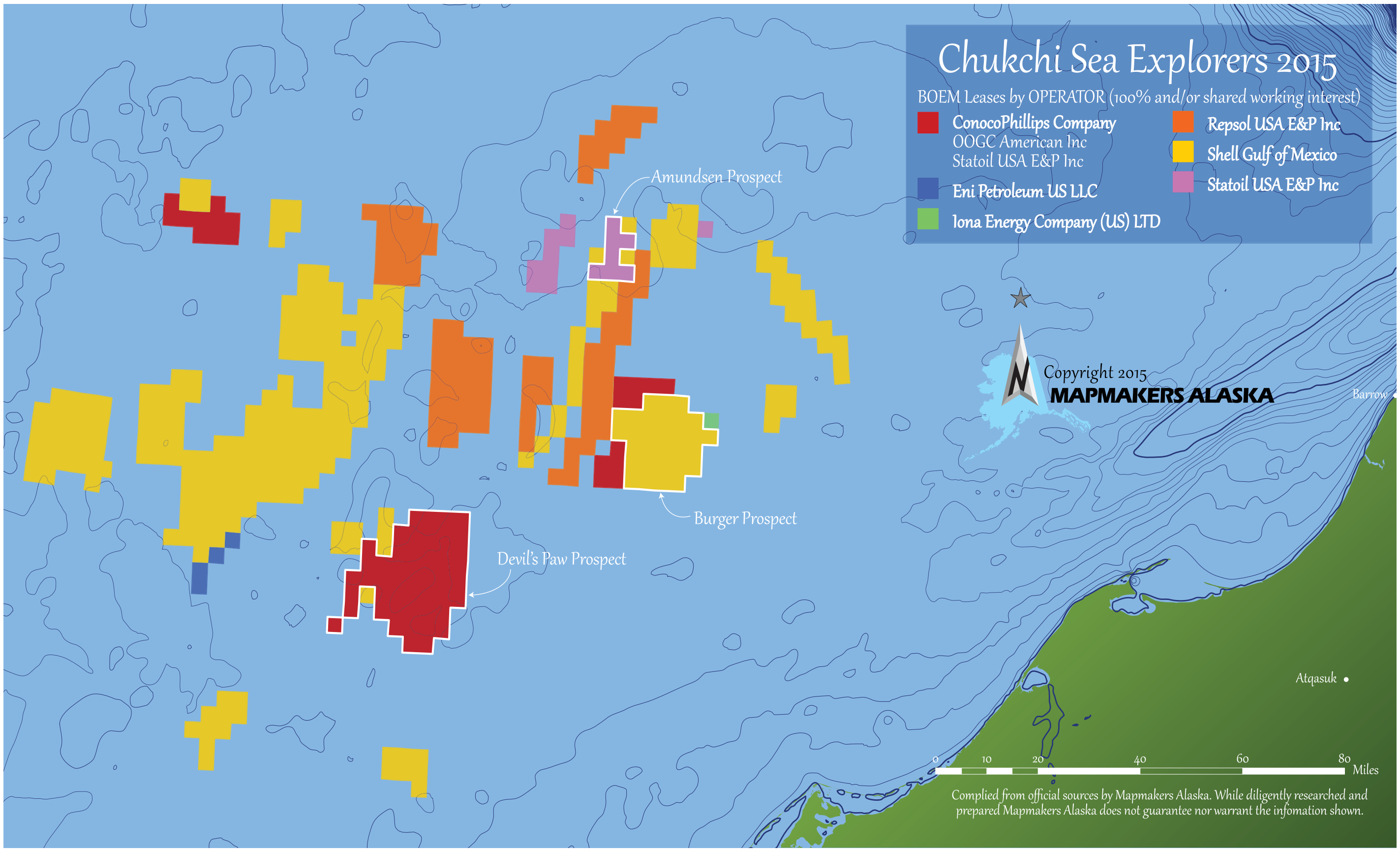
The GMT-1 project is a modified version of the former Lookout satellite, which would have been the CD-6 pad. The company changed the name and the scope of the project after the U.S. Bureau of Land Management formed the Greater Mooses Tooth unit in 2008. The revised application described an 11.8-acre gravel pad with the capacity for 33 wells, although the company has initially planned an eight-well development program.

The $890 million development was expected to come online by late 2017, producing some 30,000 bpd and employing at least 400 people plus support positions at its peak.

In late January 2015, ConocoPhillips deferred the project. "The project is challenged by permitting delays and requirements, as well as the current oil price development. In 2015, we will continue to shoot seismic over the GMT1 area and progress engineering," ConocoPhillips Alaska President Trond-Erik Johansen said in a statement. As of mid-February, the company said seismic was nearly done and engineering work continued.

continued on page 46

JUDY PATRICK


Chukchi Sea Explorers 2015
BOEM Leases by OPERATOR (100% and/or shared working interest)
ConocoPhillips Company
OOGC American Inc
Statoil USA E&P Inc
Eni Petroleum US LLC
Iona Energy Company (US) LTD
Repsol USA E&P Inc
Shell Gulf of Mexico
Statoil USA E&P Inc
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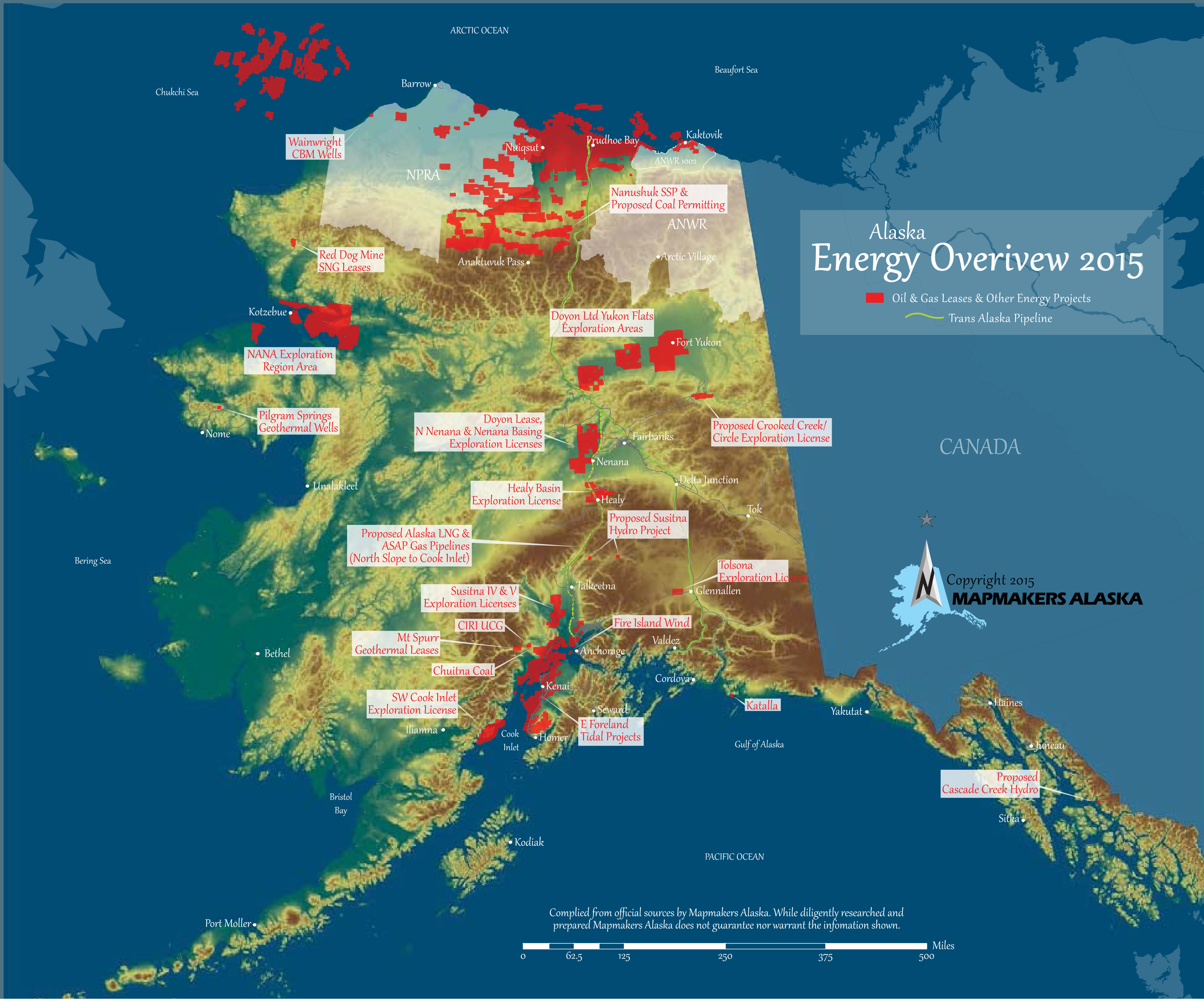

Alaska
Energy Overivew 2015
Oil & Gas Leases & Other Energy Projects
Trans Alaska Pipeline
ARCTIC OCEAN
Chukchi Sea
Beaufort Sea
Bering Sea
Gulf of Alaska
PACIFIC OCEAN
CANADA
Barrow
Nuiqsut
Prudhoe Bay
Kaktovik
ANWR 1002
NPRA
ANWR
Wainwright
CBM Wells
Nanushuk SSP &
Proposed Coal Permitting
Red Dog Mine
SNG Leases
Anaktuvuk Pass
Arctic Village
Kotzebue
NANA Exploration
Region Area
Doyon Ltd Yukon Flats
Exploration Areas
Fort Yukon
Pilgram Springs
Geothermal Wells
Nome
Doyon Lease,
N Nenana & Nenana Basing
Exploration Licenses
Fairbanks
Nenana
Proposed Crooked Creek/
Circle Exploration License
Unalakleet
Delta Junction
Healy Basin
Exploration License
Healy
Tok
Proposed Susitna
Hydro Project
Proposed Alaska LNG &
ASAP Gas Pipelines
(North Slope to Cook Inlet)
Tolsona
Exploration License
Talkeetna
Glennallen
Susitna IV & V
Exploration Licenses
CIRI UCG
Fire Island Wind
Mt Spurr
Geothermal Leases
Anchorage
Valdez
Bethel
Chuitna Coal
Kenai
Cordova
SW Cook Inlet
Exploration License
Seward
Katalla
Yakutat
Haines
Iliamna
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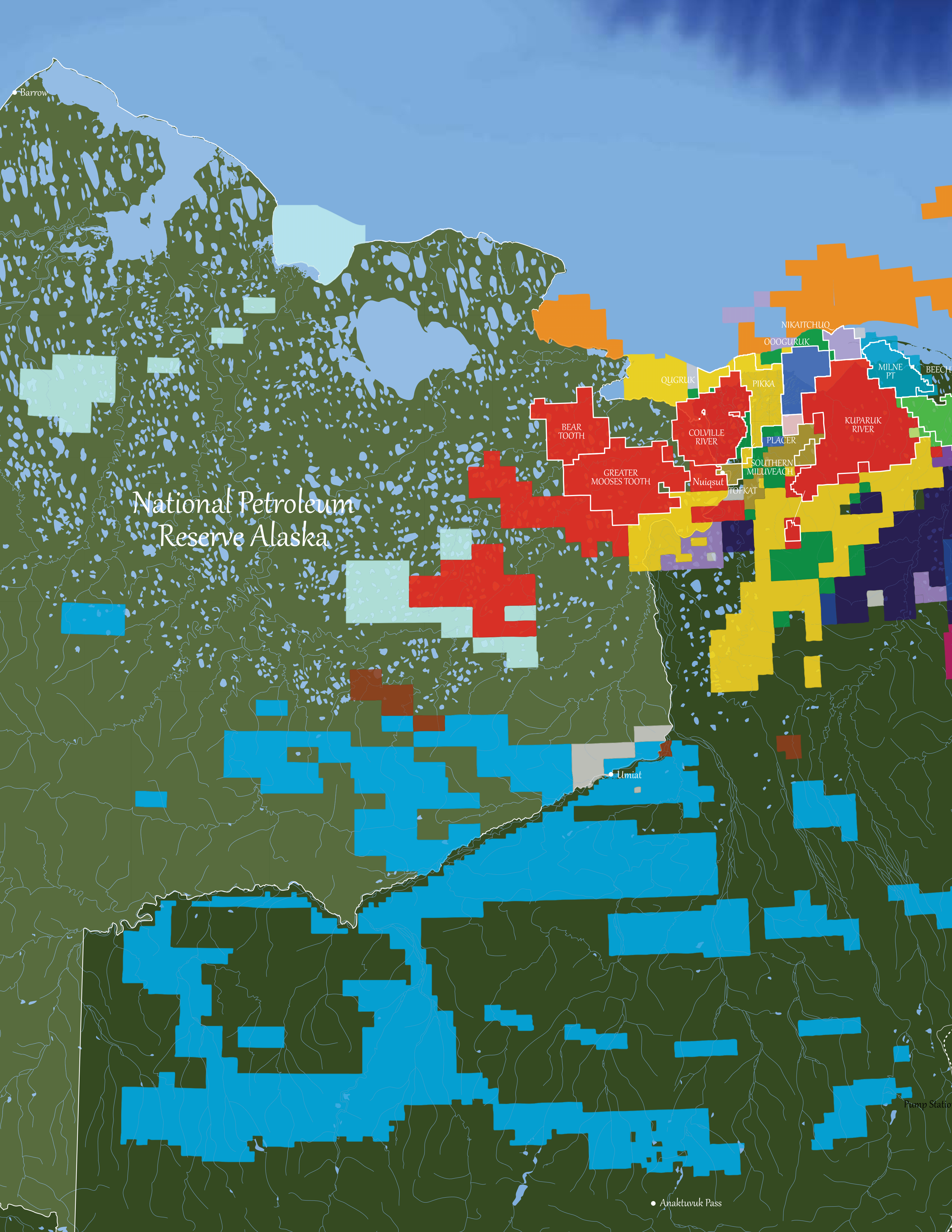
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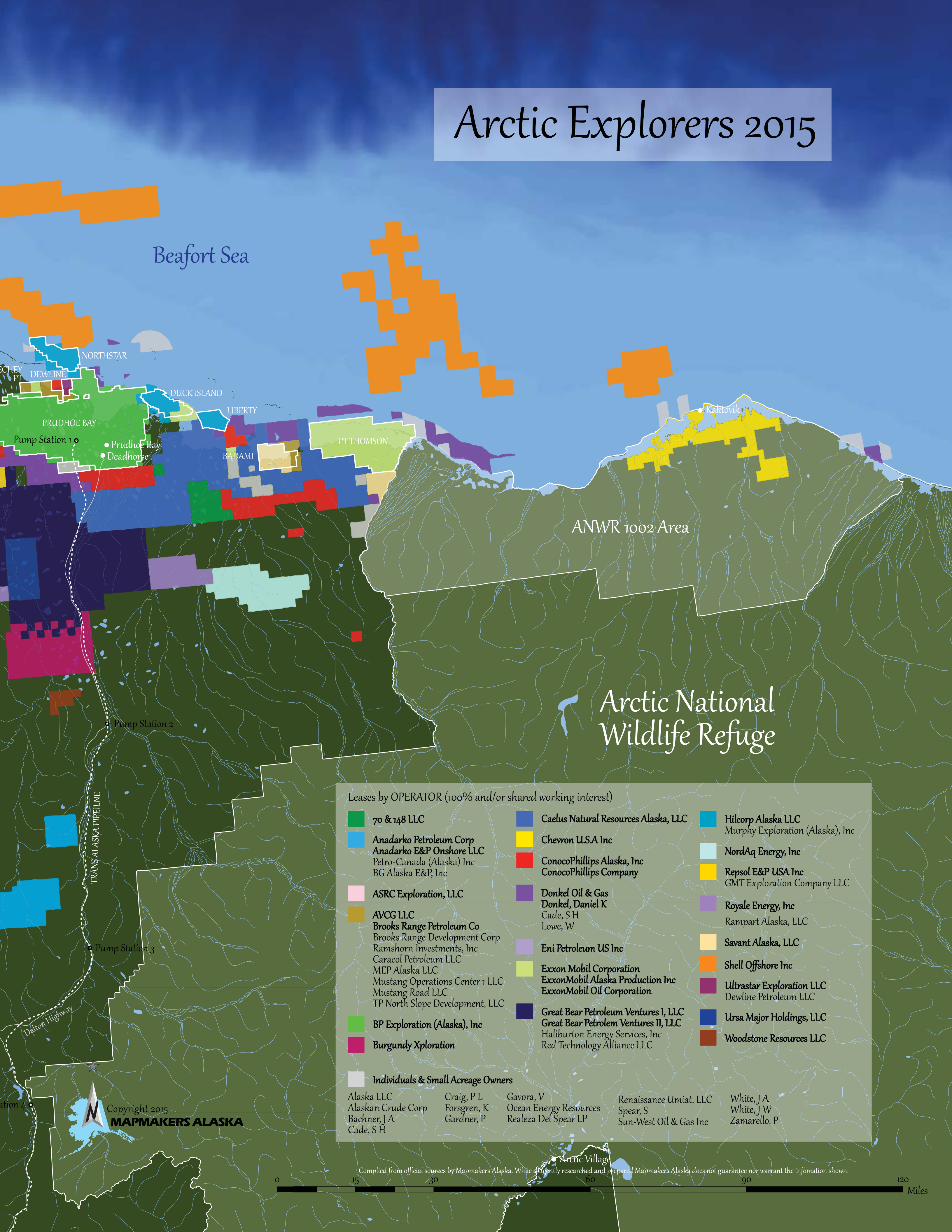

Arctic Explorers 2015
Beafort Sea
NORTHSTAR
DEWLINE
DUCK ISLAND
LIBERTY
PRUDHOE BAY
Pump Station 1
Prudhoe Bay
Deadhorse
BADAMI
PT THOMSON
Kaktovik
ANWR 1002 Area
Arctic National Wildlife Refuge
Pump Station 2
TRANS ALASKA PIPELINE
Pump Station 3
Dalton Highway
Arctic Village
Leases by OPERATOR (100% and/or shared working interest)
70 & 148 LLC
Anadarko Petroleum Corp
Anadarko E&P Onshore LLC
Petro-Canada (Alaska) Inc
BG Alaska E&P, Inc
ASRC Exploration, LLC
AVCG LLC
Brooks Range Petroleum Co
Brooks Range Development Corp
Ramshorn Investments, Inc
Caracol Petroleum LLC
MEP Alaska LLC
Mustang Operations Center 1 LLC
Mustang Road LLC
TP North Slope Development, LLC
BP Exploration (Alaska), Inc
Burgundy Xploration
Caelus Natural Resources Alaska, LLC
Chevron U.S.A Inc
ConocoPhillips Alaska, Inc
ConocoPhillips Company
Donkel Oil & Gas
Donkel, Daniel K
Cade, S H
Lowe, W
Eni Petroleum US Inc
Exxon Mobil Corporation
ExxonMobil Alaska Production Inc
ExxonMobil Oil Corporation
Great Bear Petroleum Ventures I, LLC
Great Bear Petrolem Ventures II, LLC
Haliburton Energy Services, Inc
Red Technology Alliance LLC
Hilcorp Alaska LLC
Murphy Exploration (Alaska), Inc
NordAq Energy, Inc
Repsol E&P USA Inc
GMT Exploration Company LLC
Royale Energy, Inc
Rampart Alaska, LLC
Savant Alaska, LLC
Shell Offshore Inc
Ultrastar Exploration LLC
Dewline Petroleum LLC
Ursa Major Holdings, LLC
Woodstone Resources LLC
Individuals & Small Acreage Owners
Alaska LLC
Alaskan Crude Corp
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Craig, P L
Forsgren, K
Gardner, P
Gavora, V
Ocean Energy Resources
Realeza Del Spear LP
Renaissance Umiat, LLC
Spear, S
Sun-West Oil & Gas Inc
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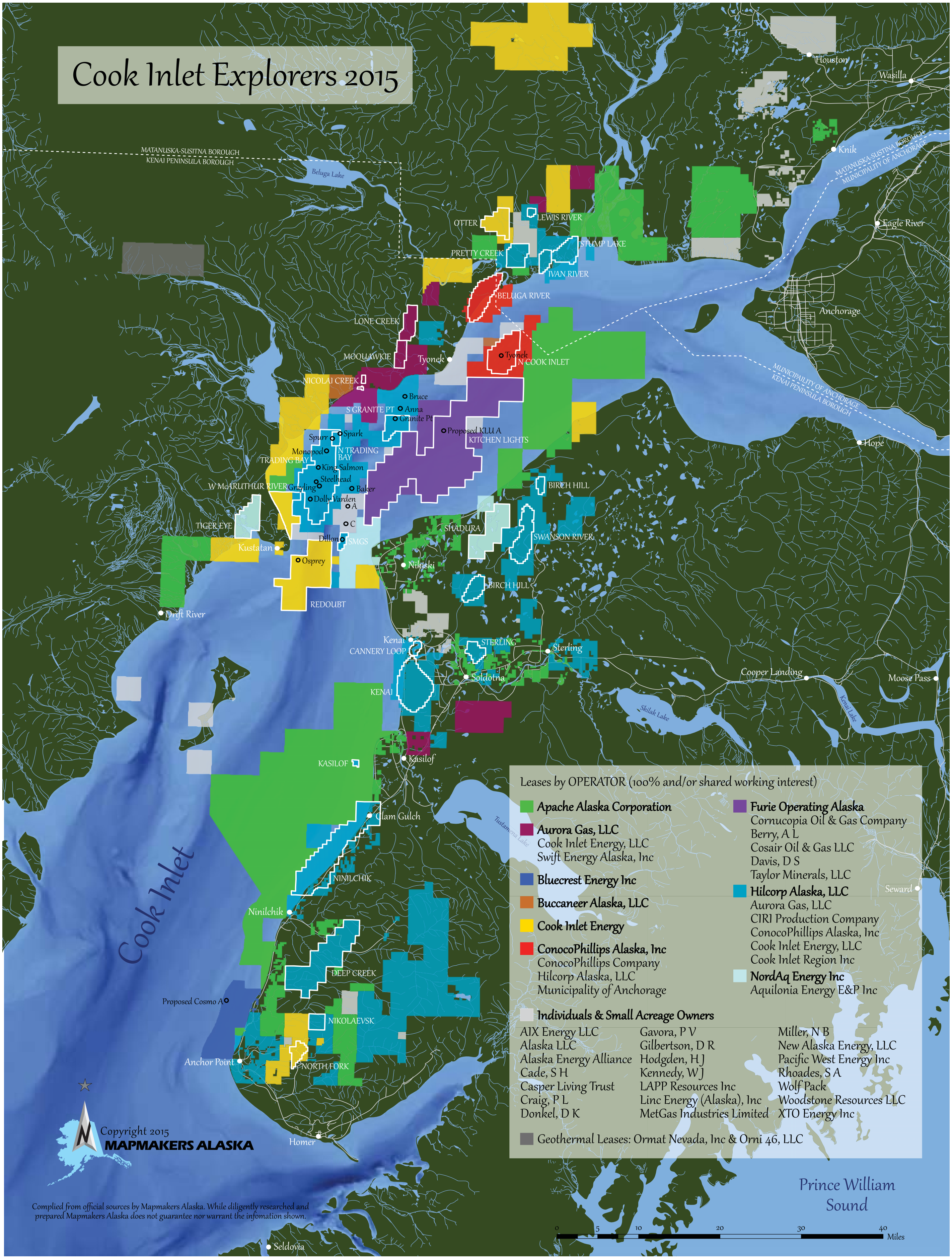

Cook Inlet Explorers 2015
Leases by OPERATOR (100% and/or shared working interest)
Apache Alaska Corporation
Aurora Gas, LLC
Cook Inlet Energy, LLC
Swift Energy Alaska, Inc
Bluecrest Energy Inc
Buccaneer Alaska, LLC
Cook Inlet Energy
ConocoPhillips Alaska, Inc
ConocoPhillips Company
Hilcorp Alaska, LLC
Municipality of Anchorage
Furie Operating Alaska
Cornucopia Oil & Gas Company
Berry, A L
Cosair Oil & Gas LLC
Davis, D S
Taylor Minerals, LLC
Hilcorp Alaska, LLC
Aurora Gas, LLC
CIRI Production Company
ConocoPhillips Alaska, Inc
Cook Inlet Energy, LLC
Cook Inlet Region Inc
NordAq Energy Inc
Aquilonia Energy E&P Inc
Individuals & Small Acreage Owners
AIX Energy LLC
Alaska LLC
Alaska Energy Alliance
Cade, S H
Casper Living Trust
Craig, P L
Donkel, D K
Gavora, P V
Gilbertson, D R
Hodgden, H J
Kennedy, W J
LAPP Resources Inc
Linc Energy (Alaska), Inc
MetGas Industries Limited
Miller, N B
New Alaska Energy, LLC
Pacific West Energy Inc
Rhoades, S A
Wolf Pack
Woodstone Resources LLC
XTO Energy Inc
Geothermal Leases: Ormat Nevada, Inc & Orni 46, LLC
Houston
Wasilla
Knik
Eagle River
Anchorage
Hope
MATANUSKA-SUSITNA BOROUGH
KENAI PENINSULA BOROUGH
MATANUSKA-SUSITNA BOROUGH
MUNICIPALITY OF ANCHORAGE
MUNICIPALITY OF ANCHORAGE
KENAI PENINSULA BOROUGH
Beluga Lake
OTTER
LEWIS RIVER
STUMP LAKE
PRETTY CREEK
IVAN RIVER
BELUGA RIVER
LONE CREEK
MOQUAWKIE
Tyonek
Tyonek
N COOK INLET
NICOLAI CREEK
Bruce
S GRANITE PT
Anna
Granite Pt
Proposed KLU A
KITCHEN LIGHTS
Spurr
Spark
Monopod
N TRADING BAY
TRADING BAY
King Salmon
Steelhead
W McARUTHUR RIVER
Grayling
Baker
Dolly Varden
A
C
TIGER EYE
Dillon
SMGS
Kustatan
Osprey
SHADURA
SWANSON RIVER
BIRCH HILL
Nikiski
BIRCH HILL
REDOUBT
Drift River
Kenai
CANNERY LOOP
STERLING
Sterling
Soldotna
Cooper Landing
Moose Pass
Skilak Lake
Kenai Lake
KENAI
KASILOF
Kasilof
Clam Gulch
Tustumena Lake
NINILCHIK
Ninilchik
Seward
Cook Inlet
DEEP CREEK
Proposed Cosmo A
NIKOLAEVSK
Anchor Point
NORTH FORK
Homer
Seldovia
Prince William Sound
0 5 10 20 30 40 Miles
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CONOCOPHILLIPS *continued from page 39*

Also in February, the BLM issued a record of decision for the project and selected the development strategy proposed by ConocoPhillips and approved by the U.S. Army Corps of Engineers. The BLM had previously endorsed a different development alternative.

As it is currently doing at the Colville River unit, ConocoPhillips appears to be pursuing a step-out strategy at the Greater Mooses Tooth unit. The company drilled two exploration wells west of GMT-1 in early. The Rendezvous No. 3 well was on lease AA-81784, and the Flattop No. 1 well was on lease AA-87896. The former delineated one of the original May 2001 discoveries. The latter fulfilled a work commitment related to a 2009 expansion of the unit. The company has yet to release results from either well.

In 2009, the BLM formed the Bear Tooth unit over 23 leases covering some 105,655 acres in the area northwest of the Greater Mooses Tooth unit. 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," according to the company. Additional details have been scarce.

The Chukchi Sea

After Shell, ConocoPhillips is the second-most active company in the Chukchi Sea.

The distinction is faint praise, especially given the regulatory, legal and logistical matters that have delayed activities off the northwest coast of Alaska over the past seven years.

After acquiring some seismic and conducting some field-

As it is currently doing at the Colville River unit, ConocoPhillips appears to be pursuing a step-out strategy at the Greater Mooses Tooth unit.

work, ConocoPhillips spent some $504 million in high bids on 98 tracts in a federal lease sale in the Chukchi in early 2008. ConocoPhillips later sold a 25 percent working interest in its Devil's Paw prospect to Statoil of Norway and 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.

A legal challenge to the lease sale delayed a drilling program proposed for 2011. The company later outlined a drilling program for 2014, although it later canceled those plans.

"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," 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."

A large discovery in the Chukchi Sea would extend infrastructure across the NPR-A, which would improve the economics of many marginal fields throughout the reserve.

Contact Eric Lidji at ericlidji@mac.com

Doyon adds oil to its targets for Nenana exploration

The results of exploration for natural gas have yielded some intriguing possibilities for finding oil

By ERIC LIDJI
For Petroleum News

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TOP ALASKA EXECUTIVE: James Mery, Doyon Ltd. senior vice president, lands and natural resources
PHONE: 888-478-4755 • **COMPANY WEBSITE:** www.doyon.com

Doyon Ltd. began searching for natural gas in the Nenana Basin in the 2000s, hoping to alter the existing dynamics for fueling homes and businesses in Interior communities.

The Interior is largely dependent on oil for space heating. A small discovery in the Nenana basin would provide a local source of relatively cheap fuel. A large discovery would be hundreds of miles closer to Outside markets than North Slope reservoirs.

Geology, politics and economics have changed that plan somewhat.

To date, the company has drilled two exploration wells in the region and recently commissioned a 2-D and a 3-D seismic program in the area surrounding its two wells.

In March 2015, Doyon Vice President of Lands and Natural Resources Jim Mery told state lawmakers that the company was "looking hard" at drilling a third well in 2016.

This time, though, the company would also be looking for oil.

"We view the chance of success in the next well for oil as somewhere between one in five and one in 10," Mery said. The minimum economically viable field size would be between 25 million and 50 million barrels, depending on the price of oil, Mery said.

The company is still optimistic about finding gas. "Gas is so de-risked at this point, we believe, based on work that we've done, that there is 50-50 chance of commercial success next time we drill," Mery told lawmakers. But current plans to truck North Slope natural gas into the Interior could strand Nenana gas for a decade or longer, according to Mery.

A future large-diameter gas pipeline coming down from the North Slope could potentially grab Nenana production along the way but would require some technical considerations.

The current Nenana exploration program follows previous forays into the region by other companies. Unocal drilled the 3,062-foot Nenana No. 1 well in 1962. ARCO drilled the 3,590-foot Totek Hills No. 1 well in 1984. "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 2002. "Reports of oil seeps in the basin are unconfirmed." Given the considerable coal quantities in the region, the state expected the basin to be gas-prone.

Doyon was created through the Alaska Native Claims Settlement Act of 1971. Seeing the opportunities both for revenues and for a cheaper local energy source for the Interior, the company took an interest in the resource potential of the region. When industry interest in exploration dimmed in the late 1990s, Doyon began organizing an exploration program.

Exploration license

As with all exploration activities outside of the North Slope or Cook Inlet, the current program in the Nenana basin started through the Alaska exploration license program.

The program allows companies to nominate regions for exploration activities and creates the opportunity for turning portions of the license area into traditional mineral leases.

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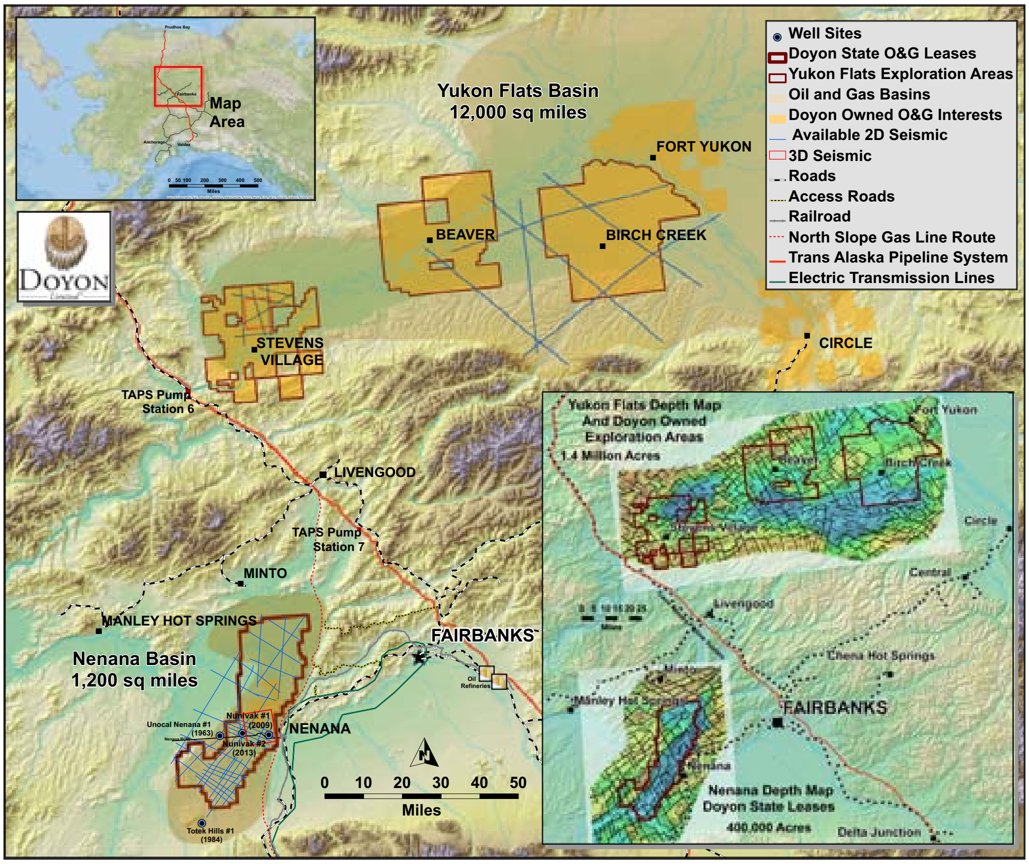
DOYON *continued from page 47*



Doyon and the Houston-based independent Andex Resources LLC formed a joint venture in late 2001 to explore a section of the Nenana basin. The partners intended to commission a seismic survey in the winter of 2002 and 2003 and drill in early 2004.

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 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 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.

Early optimism

Even though Andex was initially bullish about the program, telling state lawmakers in January 2002 that it expected to spend $18 million to drill three exploration wells and $6 million for seismic, a series of obstacles prevented drilling for a number of years.

Andex wanted state lawmakers to extend a 10-year gas exploration incentive program set to expire in 2004. The program offered credits in return for geophysical information. That provision had scared one exploration company away and made another ineligible but proved enticing for the Nenana basin. The state agreed to extend the program until 2007.

In December 2004, Andex and Doyon partnered with the Usibelli Coal Mine affiliate Usibelli Energy LLC and the Alaska Native corporation Arctic Slope Regional Corp.

Eager to get started, the joint venture commissioned a 2-D seismic survey from PGS Onshore for early 2005 with the intention of drilling as soon as 2006. The $3 million campaign covered some 218 square miles of the region. Andex said it planned to spend another $3 million acquiring information from previous seismic surveys over 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 that central Alaska contained some 500 billion to 7.3 trillion cubic feet of technically recoverably reserves with a mean of 2.8 tcf.

Early wells were shallow. The joint venture planned to drill deep, at least 10,000 feet. "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."

Political obstacles

As the financial and technical components of the program were coming together, the joint venture faced a series of political obstacles, which delayed the program for years.

Andex postponed its 2006 exploration program while lawmakers debated the Petroleum Profits Tax and postponed its 2007 program after the Petroleum Profits Tax became law.

Evolving state policy overlooked the Interior. The Petroleum Profits Tax excluded the Interior from a tax break for Cook Inlet production. At the same time, a proposed contract for producing and marketing North Slope natural gas also excluded the Interior basins.

The Alaska's Clear and Equitable Share law, approved in late 2007, expanded the Cook Inlet tax credit to include any gas produced for use within Alaska. By then, though, Andex had lost interest, leaving Doyon and its two partners to search for another partner.

continued on next page

DOYON *continued from page 48*

The delay created a regulatory obstacle. The seven-year exploration license was set to expire in September 2009. In late 2008, the state approved a three-year extension.

The Denver-based independent Babcock & Brown Energy became the operator of the joint venture in early 2009 and announced plans to drill at least one 10,500-foot well that summer. Babcock & Brown subsequently changed its name to Rampart Energy Co. Andex executive Jim Dodson even returned to Alaska as an executive for Rampart.

A fifth company, Cedar Creek Oil and Gas Co., also joined the joint venture.

Going it alone

By scheduling its program for summer, the joint venture was able to secure the Arctic Wolf No. 2 rig after the end of the winter exploration season of the North Slope.

The joint venture drilled the 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. The roughly $15 million 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.

To get a wider understanding of its large license area, Doyon commissioned a seismic survey over the northern end of the basin. "Other than a few gravity measurements at the northern end of the basin, there really isn't any exploration," Mery said in April 2010.

The program ran into political obstacles.

As Interior utilities looked to truck liquefied natural gas from the North Slope and lawmakers talked about uniting the Railbelt utilities, Doyon postponed its seismic program until it had more certainty about its position in the statewide energy market.

In March 2015, Doyon Vice President of Lands and Natural Resources Jim Mery told state lawmakers that the company was "looking hard" at drilling a third well in 2016.

Doyon also began searching for additional investors. The other four joint venture partners in the program had lost interest after the lackluster results of the Nunivak No. 1 well.

Ultimately, Doyon decided to go it alone. The company commissioned its 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 state helped by approving an incentive program specifically for "frontier basins" in early 2012. The program included exploration credits and lower production taxes.

Once again, though, Doyon was nearing the end of its exploration license. The company began converting sections of the area into traditional leases, which it still maintains.

In mid-2013, Doyon drilled the 8,667-foot Nunivak No. 2 well using the Nabors rig 105.

As before, the well encountered encouraging geology but no commercial volumes of oil or 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 statement. "Despite the disappointment of a non-commercial effort, other results from the well clearly indicate the potential for significant commercial dis-

continued on page 52

Furie developing and exploring simultaneously

The company is continuing its exploration work at Kitchen Lights as it moves toward first oil at the unit

By ERIC LIDJI
For Petroleum News

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If all went well, Furie Operating Alaska LLC began installing a natural gas production platform in waters of the Cook Inlet this spring, after The Explorers went to print.

Although the company had originally planned to install the platform last summer, the parts only arrived in Alaska in September 2014 — too close to the onset of winter. The company eventually moved the components for the platform to Seattle for the winter.

Installation is now planned for early 2015, after the breakup of sea ice in Cook Inlet.

The installation will bring the total number of offshore platforms in the region to 17 and will allow the Alaska subsidiary of the German independent Deutsche Oel & Gas AG to begin development drilling and eventually bring its Kitchen Lights unit into production.

Many projects in Alaska move from exploration to development then into an extended effort to delineate producing reservoirs. The Kitchen Lights unit is somewhat unique.

The state created the unit in 2009 by combining three smaller prospects. The unit is currently the largest in the Cook Inlet basin. The current development project covers only a portion of the total area. The remainder requires further exploration and development.

The current plan of exploration divides the unit into four exploration blocks: North, Corsair, Central and Southwest. The production platform targets the Corsair block.

As Furie nears the third-quarter target for starting production, it is studying ways to finance both the development and future exploration activities at Kitchen Lights.

Furie is currently using equity from its parent company, from private German funds and through a $160 million credit facility from the private equity firm Energy Capital Partners to finance the development operations. The company recently asked the Alaska Industrial Development and Export Authority for as much as $50 million in financing.

The loan would cover the remaining costs to install the offshore platform, the subsea pipelines and the onshore production facility. "Getting the AIDEA financing allows us to shift some of our present equity over to the exploration side," Vice President for Government and Regulatory Affairs Bruce Webb told Petroleum News in January 2015.

The Kitchen Lights unit exploration plan expires in early 2016. In a March 2015 plan, Furie said it would drill two development wells this year but postpone completion to 2016. The delay will allow the company to accommodate changes in its schedule for installing the production platform, will result in "significant cost savings by focusing on drilling operations" and will improve the effectiveness of completion activities by giving the company a chance to analyze the results of its 2015 drilling plans, according to Furie.

The plan also calls for Furie to either drill another exploration well in one of the unexplored blocks at the unit or to acquire 3-D seismic information over the entire unit.

Getting into the Kitchen

The optimistic situation at the Kitchen Lights unit is remarkable given its history.

The Houston-based independent Escopeta Oil & Gas Co. spent more than a decade acquiring a lease position in upper Cook Inlet, securing a jack-up rig and bringing the rig to Alaska to conduct an exploration program. All the while, the company had to contend with the regulatory consequences of missing deadlines. Although successful, the company had many bumps and bruises by the time it was ready to start drilling.

For one, a corporate shuffle in 2011 essentially divided Escopeta's assets between operator Furie Operating Alaska LLC and primary working interest owner Cornucopia Oil and Gas Co. Also,

continued on page 53

FURIE OPERATING ALASKA, LLC

Furie's Spartan 151 jack-up drilling rig, seen in the background, is moved into in position in May for the operation of threading the field's gas gathering pipeline through an underground borehole to the onshore facilities.

DOYON *continued from page 49*

coveries 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 reasons 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.

New seismic

Still optimistic, Doyon began permitting another seismic program in mid-2014.

The program described in permitting papers included both 3-D and 2-D components. The 3-D survey would cover some 30 square miles in an area just west of the town of Nenana where it drilled its two wells. The 2-D survey would cover two transects to the northeast.

The 3-D survey was targeting a geologic feature identified in previous 2-D surveys, according to Mery. "The feature is certainly large enough to potentially hold the minimum field size … for an economic project. So we're going to image it and hopefully go out and drill it," Mery told Petroleum News in August 2014. The results of the 3-D survey will determine whether and where Doyon will drill in the basin in the future. The 2-D surveys would expand on previous 2-D surveys and give Doyon a better picture of the depths of the basin in the area north of its wells, Mery told Petroleum News.

In March 2015, Mery said the wells had encountered propane, butane and pentane, which typically indicate a petroleum system conducive to oil. "We have all the elements of an active and prolific wet gas, condensate and hopefully oil system," he said. "Through modeling we really believe that the basin, given the thick packages of source rock, really could have produced billions of barrels of oil and trillions of cubic feet of gas."

The Yukon Flats

With its Nenana leases set to expire in 2020, Doyon is focusing its exploration resources on the Nenana basin rather than allocating some resources to the Yukon Flats region.

For five years, the Doyon and the U.S. Fish and Wildlife Service worked on a proposal to swap resource-rich acreage in the Yukon Flats National Wildlife Refuge with nearby Doyon acreage. The two parties dropped the plan in 2010, amid public opposition.

After the setback, Doyon reassessed its existing acreage using a 2010 seismic survey and other existing data. The second look suggested that the region was much more prospective than originally thought, with the potential for an Alpine-sized reservoir. "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, although those plans are currently on hold while Doyon pursues its Nenana leases.

A 2004 USGS study 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 trillion cubic feet of natural gas, which exceeded earlier estimated for the entire central Alaska region.

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FURIE *continued from page 50*

the federal government hit the company with $15 million fine for violating the Jones Act, which regulates foreign ships such as the heavy lift vessel Escopeta used to transport its jack-up rig. Furie has been fighting the fine in court.

One benefit to all the wrangling, though, was the actual unit.

In July 2009, the state and the company resolved an ongoing dispute over missed work commitments by forming the Kitchen Lights unit. The 83,394-acre unit combined 40,733 acres from the Escopeta-operated Kitchen unit, 15,930 acres from the Renaissance Alaska LLC-operated Northern Lights prospect and 26,721 acres from the Corsair prospect previously owned by the bankrupt Pacific Energy Resources Ltd. into one unit.

Using the Spartan 151 jack-up rig, Furie drilled the Kitchen Lights Unit No. 1 well in 2011 and 2012. Because the jack-up arrived in Cook Inlet in summer 2011, Furie stopped drilling at approximately 8,805 feet when the end of the drilling season neared. The company had intended to drill to 16,500 feet. The company suspended operations, in part, because the state asked the company to slow the pace of its operations to ensure safety.

Even though the first well was only halfway to total depth, Furie announced a major discovery: approximately 46.7 billion cubic feet of gas in place, which, extrapolated over a larger area, suggested some 3.5 trillion cubic feet of natural gas present at the unit. If correct, those figures would rank among the largest discoveries ever for the Cook Inlet basin. 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 on 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.

In early 2013, Deutsche Oel & Gas 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 and “prospective” indicates 10 percent likelihood. The company subsequently pulled the release and never responded to requests for comment.

Such assessments would be interesting for any undeveloped field. But the intrigue is increased at Kitchen Lights because of previous grand predictions. In 2001, Escopeta President Danny Davis announced that a new analysis of old seismic information suggested that Cook Inlet contained a major undiscovered resource potential in the Kitchen and East Kitchen prospects. He named the prospects “kitchen” after the geological nickname for the superhot source rocks that produce oil and gas supplies.

Previous leaseholders in the region have also offered thoughts.

Before forming the Corsair unit over a portion of the current Kitchen Lights unit in 2003, Forest Oil estimated that the prospect might contain 137 million barrels of oil and up to 480 billion cubic feet of gas. Pacific Energy Resources Ltd. acquired the unit in 2007 and later estimated that recoverable reserves might be as high as 100 million barrels of oil and 500 billion cubic feet of natural gas. And previous estimates of the former Northern Lights prospects were in the range of 111 million to 358 million barrels of oil equivalent.

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

KLU No. 2 through No. 6

Toward the end of it first season of drilling, Furie realized it would be unable to complete all its work commitments before the Kitchen Lights unit agreement expired in early 2012.

The company sought a four-year extension, through early 2016.

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 the wells to assess various small prospects across the unit area. 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 north block.

The actual wells have been spread out in a different configuration. Furie drilled Kitchen Lights Unit No. 1, No. 2, No. 2A and No. 3 in the Corsair Block, drilled Kitchen Lights Unit No. 4 in the North block and Kitchen Lights Unit No. 5 in the Central Block.

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

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 a second well.

The Kitchen Lights Unit No. 2 well reached some 9,000 feet by

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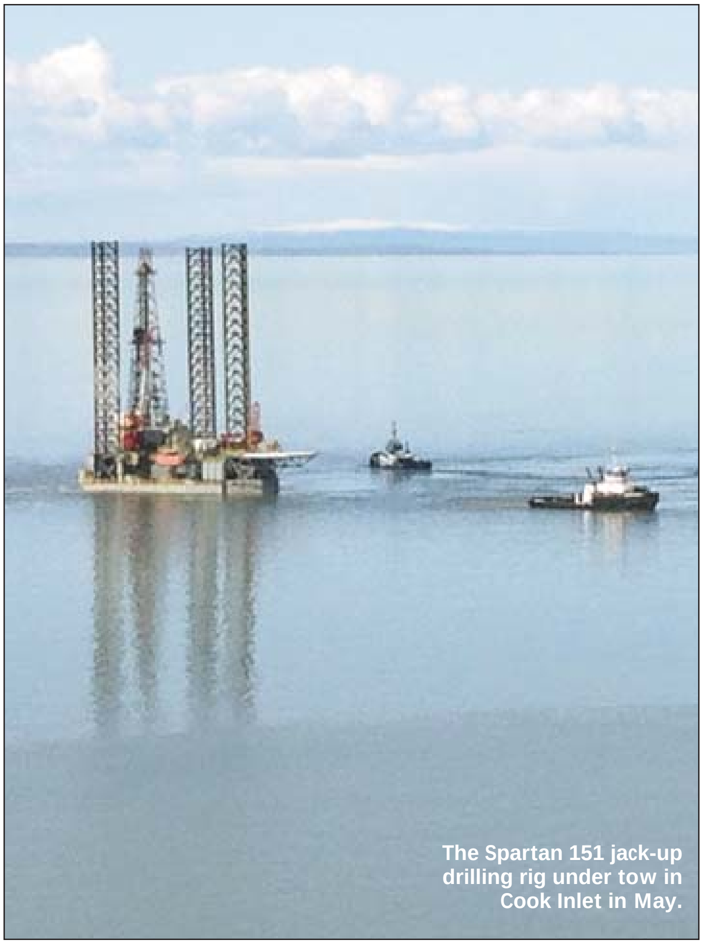
FURIE OPERATING ALASKA, LLC



The Spartan 151 jack-up drilling rig under tow in Cook Inlet in May.

FURIE *continued from page 53*

the end of the season, according to Petroleum News sources. Around October 2012, Furie told the state it had finished sidetracking the well and planned to test several gas-bearing zones in the Beluga.

In mid-2013, Furie drilled the 10,393-foot Kitchen Lights Unit No. 3. The company completed the well with "mini-frac packs" in two Sterling zones and two Beluga zones to delineate the initial Kitchen Lights Unit No. 1 discovery. "We had a good test," President Damon Kade told Petroleum News in July 2013. Kade declined to release results at the time. In a November 2014 plan of development, Furie said the well had produced 15.83 million cubic feet during a four-point test, which confirmed a commercial discovery. The samples taken during the test were 99 percent methane, according to the company.

The well was the justification for sanctioning a development program and will become the first development well at the unit when production begins later this year. The company has said expects the well to produce 15 million to 18 million cubic feet per day.

Soon after testing Kitchen Lights Unit No. 3, Furie began drilling Kitchen Lights Unit No. 4. The company suspended the well when 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 survey — independent of Furie — covering a similar region around the Kitchen Lights unit.

Furie drilled the 11,800-foot Kitchen Lights Unit No. 5 well in mid-2014. The well was a dry hole, according to information in a November 2014 unit plan of development.

The company plans to drill Kitchen Lights Unit No. 6 in the southwest block this spring.

The exploration work planned for this year — either drilling or seismic — will guide future activities at the unit, according to Furie. The working interest owners will either commit to drilling "one or more delineation or exploration wells in one or more exploration blocks outside the Corsair block" or will sanction a development for "one or more" blocks outside the Corsair block. Those activities would occur in future years.

That said, the results of the exploration activities planned for this year "may be the basis for redefining or contracting portions of exploration blocks" before the end of the year, according to Furie. If the company fails to meet any of the work commitments described in the plan of exploration, the company will contract one exploration block from the unit.

Is there a market?

All exploration is predicated on the promise of future sales.

In early 2015, Furie announced that it had previously secured a multiyear contract to supply more than 4 billion cubic feet per year to an unnamed utility starting Jan. 1, 2016.

With the unit expected to come online in August 2015, the company is looking for a short-term or interruptible contract to provide cash flow through the end of the year.

In addition to the 2016 contract, Furie said it has negotiated term sheets for two other contracts. Ideally, the company wants to contract some 85 million cubic feet per day.

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Great Bear returning to exploration drilling

A need to bolster existing knowledge of its leases led the company to conduct two years of intense fieldwork

By ERIC LIDJI
For Petroleum News

After several seasons of fieldwork and evaluations for its North Slope exploration program, Great Bear Petroleum Operating LLC returned to drilling wells this year.

In late 2014, the Alaska-based independent permitted a three-well exploration program along the Dalton Highway, its first drilling activity since drilling a pair of wells in 2012.

The company had spent the interim evaluating well results and conducting fieldwork.

ED DUNCAN

This year, the program targeted both conventional and unconventional accumulations simultaneously. While Great Bear remains committed to its long-term goal of launching a source rock development program in Alaska, that goal is complex. It would require the company to adapt still-evolving Lower 48 development techniques to the unique environment of the North Slope. A conventional discovery would provide cash flow in the near term and would allow the company to start building infrastructure on its leases.

The Great Bear program sits close to existing infrastructure, which has allowed the company to continue working after most companies have packed up their supplies for the winter. As a result, the program was unfinished when The Explorers went to press.

In a lease plan of operations submitted to the state in October 2014, Great Bear detailed plans to use Nabors rig 106AC to drill the Alkaid No. 1, Phecda No. 1 and Talitha No. 1 wells just west of the Dalton Highway and trans-Alaska oil pipeline corridor. The proposed locations were southwest of the two vertical wells Great Bear drilled in 2012.

Great Bear began drilling the Alkaid No. 1 well in mid-February, which was later than the company had intended to start the program. As such, the company said it would likely drill only two wells this season, rather than three. Through March, the company had yet to receive an Alaska Oil and Gas Conservation Commission permit for the second well.

Coming on strong

Great Bear proved its bearishness at a North Slope areawide lease sale in October 2010.

As its introduction to Alaska, the company took more than 500,000 acres across a broad swath of the central North Slope, just south of the Prudhoe Bay and Kuparuk River units.

The size of the leasehold and the location of the leases suggested the company was pursuing something unique. The five principals of Great Bear formed the company to develop the source rock potential of the North Slope. Great Bear President and COO Ed Duncan had met Vice President of New Ventures Bob Rosenthal 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,” Duncan said in October 2010.

While most North Slope independents have been pursuing relatively large conventional reservoirs passed over by the

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NAME OF COMPANIES:
Great Bear Petroleum Ventures (three LLC entities, I, II and III)
Great Bear Petroleum Operating LLC
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GREAT BEAR *continued from page 55*

major companies, Great Bear saw an opportunity to develop the source rocks responsible for the giant oil fields of the North Slope — just as other industrious independents were doing with the Eagle Ford shale formation of south Texas.

A conventional reservoir is usually the result of oil and natural gas migrating through porous rocks until they reach a seal. Exploration companies use surface geology, previous wells and seismic surveys to make informed guesses about where to drill wells. Some wells are dry holes, some encounter non-commercial volumes and some lead to big finds.

An unconventional exploration program, such as the one Great Bear is undertaking, targets the source of the oil in those reservoirs. The North Slope contains three stacked source rock intervals at depths between 8,000 and 13,000 feet. They are, from deepest to shallowest, the Shublik, the Kingak and the HRZ/Hue shale system. The Prudhoe Bay and Kuparuk River oil fields are believed to have migrated from these source rocks.

Instead of drilling wildcat wells in search of a “gusher,” Great Bear is trying to devise an economic way to tackle a massive resource. That means searching for “sweet spots” where the slow geologic process of making hydrocarbons, known as “thermal maturity,” has converted organic materials into oil but not yet converted the oil into natural gas.

If successful, the Great Bear program — and similar efforts by other companies, particularly Royale Energy Inc. — would bring a new development model to Alaska.

Testifying before state lawmakers in February 2011, Duncan presented “a factory type drilling” model, where development wells would be drilled and completed quickly.

Great Bear Petroleum commissioned 3-D seismic surveys over various portions of its large leasehold in 2012, 2013 and 2014 in search determining “sweet spots” for drilling and said it expected to commission another survey over the area this year.

To illustrate this 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. This system would require some $2 billion each year in capital, Duncan told lawmakers.

In terms of rigs operating, wells drilled, oil produced and capital spent, those figures would make the Great Bear program the largest development on the North Slope.

At the time, then-Gov. Sean Parnell had set an ambitious goal of increasing throughput on the trans-Alaska oil pipeline to 1 million barrels per day within a decade. When policymakers asked whether Great Bear could single-handedly produce 1 million barrels per day from its leases 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.”

Slowing down

The Great Bear exploration program has moved slower than the company would like.

Eager to start, the company figured it could drill two test wells in the winter of 2010 and 2011 by starting the permitting process while the state completed its lease review. But by January 2011, logistics appeared to be dictating a slower timeline. The state had said it expected to issue the leases in April or May. Great Bear pushed its plans to late 2011.

Once Great Bear discovered it could drill year round, its ambitiousness accelerated. The company 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 vertical.

A September 2011 lease plan of operation outlined a yearlong program to determine a “proof of concept” for commercial source rock development. The plan proposed six drill sites along a 15-mile industrial area along the Dalton Highway. The company named the proposed wells after the stars in the Ursa Major (or “Great Bear”) constellation: Alcor No. 1, Merak No. 1, Mizar No. 1, Megrez No. 1, Dubhe No. 1 and Alioth No. 1.

By November 2011, Great Bear had announced a technical partnership with the oil field services company Halliburton Co. With a successful proof of concept program, Duncan said, the companies could initiate a pilot development by late 2012. By January 2012, Great Bear had obtained preliminary permits but

continued on next page

GREAT BEAR *continued from page 56*

still needed a rig. The company eventually scaled back its plans to a three well program for the second half of 2012.

Once drilling began, Great Bear became somewhat tight-lipped about the results.

By July 2012, the Alcor No.1 well had almost reached the HRZ, and crews were preparing to take core samples. At a shale conference, in August 2012, Duncan said, "The results to date are within our expected outcome." Looking ahead, he added, "We expect to be testing and producing and … selling produced hydrocarbons potentially by the end of the year, and certainly early next year." With good results, Duncan believed Great Bear could produce at least 100,000 barrels per day in five years. By September, when the company was drilling the Merak No. 1 well, he said, "I can tell you with absolute confidence that where we thought we would find oil in these source rocks, we found oil."

Great Bear suspended its drilling operations for the season in December 2012, having drilled the vertical sections of two wells and conducted a small 3-D seismic survey around the well locations. At the time, 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."

Collecting data

In early 2013, Great Bear said it needed to complete a technical analysis of its drilling results and its 3-D seismic acquisition before deciding the next steps for its program.

The same held true that fall. "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," Duncan said.

Great Bear Petroleum commissioned 3-D seismic surveys over various portions of its large leasehold in 2012, 2013 and 2014 in search determining "sweet spots" for drilling and said it expected to commission another survey over the area this year. The company also commissioned two LIDAR, or Light Detection And Ranging, surveys, which use laser beams to precisely map surface topography, which speeds the pace of planning.

One of the reasons Great Bear took a two-year hiatus from drilling to conduct field work is to bolster a somewhat flimsy data set for the area. Compared to unconventional plays in the Lower 48, the region where Great Bear is exploring is relatively underdeveloped, which means there is little previous information upon which to build an drilling program, according to Vice President of External Affairs and Deputy General Counsel Pat Galvin.

The program this year used the information from those surveys to choose locations. The Talitha No. 1 well, for instance, was discovered from the 2013 survey. It required the company to acquire an additional lease, which was only recently available at auction.

Asked how oil prices would impact the program, Galvin said investors are willing to risk funding exploration wells now in the hopes of prices rising in the future. Development is another story. With a breakeven price of around $50 per barrel, Great Bear would need to look at its economics if the prices stay at their lower level for an extended period of time.

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Hilcorp exploring at two Cook Inlet units

Although primarily interested in development, some units are thought to contain undiscovered accumulations

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For Petroleum News

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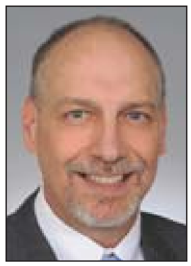
Hilcorp Alaska LLC amassed much of its Alaska leasehold through three purchases: acquiring the Cook Inlet assets of Union Oil Company of California in 2011, the Cook Inlet assets of Marathon Oil Co. in 2012 and a large portion of the North Slope assets — not including the massive Prudhoe Bay field — of BP Exploration (Alaska) Inc. in 2014.



JOHN BARNES

To date, the Texas-based independent has been focused on revival. The company has been repairing existing development wells and drilling new development wells to either improve production rates at producing fields or restore production at suspended fields.

That strategy has left little time for traditional exploration activities.

But previous operators appear to have underinvested in some fields, leaving Hilcorp with the opportunity to conduct exploration work within existing units and near infrastructure.

In terms of exploration, Hilcorp has been most active at two Cook Inlet units in the southern Kenai Peninsula — the

continued on page 60

HILCORP *continued from page 58*

Ninilchik unit and, to a lesser extent, the Deep Creek unit. The company closed on its acquisition of the North Slope properties in late 2014 and had yet to present any firm exploration plans by the time The Explorers went to print.

Ninilchik in 2013

The current program at Ninilchik involves expanding existing participating areas and exploring potential oil and gas accumulations contained within the unit boundaries.

The unit follows a section of coastline between Clam Gulch and Ninilchik. The slender unit currently includes three non-overlapping participating areas with accumulations in the tertiary Tyonek formation: Falls Creek, Grassim Oskolkoff and Susan Dionne-Paxton.

In June 1961, Chevron discovered a Tyonek gas field in the area, which became the Falls Creek unit. Marathon discovered two nearby fields in 2001 and 2002 and pursued development. The state formed the Ninilchik unit in 2001 and expanded it to include the old Falls Creek unit in 2003. Also in 2003, the state formed the three participating areas.

The unit currently includes eight drilling pads with plans in the works for a ninth.

Hilcorp drilled four exploration wells at the Ninilchik unit under its 2013 plan of development: Susan Dionne No. 8, Paxton No. 5, Frances No. 1 and Falls Creek No. 5.

The 12,000-foot Susan Dionne No. 8 well was the first explicit attempt at oil exploration at the unit in decades. Although Hilcorp ultimately deemed the well as non-commercial for oil, the company completed the well as a producer from both the Tyonek formation within the Susan Dionne participating area and from the Beluga formation on a tract basis. Paxton No. 5 was a shallow well from the Paxton pad to the south of the Susan Dionne pad. Hilcorp completed the well as a producer from the Beluga formation on a tract basis. Given the Beluga production from the two wells, Hilcorp told the state it planned to form the Susan Dionne/Paxton Beluga participating area sometime this year.

Those activities took place in the southern end of the unit. Toward the end of 2013, Hilcorp also conducted exploration work on leases at the north end of the unit.

Inspired by its efforts at Susan Dionne, Hilcorp built the Bartolowitz pad just south of the Falls Creek pad in August 2013 and later drilled the Frances No. 1 well to look for oil.

As with Susan Dionne No. 8, the well was non-commercial for oil, but showed "strong potential" for gas production from the Tyonek and Beluga formations. The Falls Creek No. 5 well encountered gas in the Tyonek and Beluga. Hilcorp brought both wells into production from an undefined Tyonek reservoir in the second and third quarters of 2014 and intends to expand the Falls Creek participating area to include the Beluga formation.

Ninilchik in 2014

The company initially proposed a six-well exploration program at Ninilchik for 2014, although toward the end of the year it expanded the program to include 11 wells.

The initial program called for two wells at the Paxton pad. The 10,000-foot Paxton No. 6 and Paxton No. 7 wells would target the Tyonek and Beluga formations, 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. The expanded program added an 11,000-foot Paxton No. 8 to test the structural apex of an undefined Tyonek formation northeast of the pad.

The company completed Paxton No. 7 in November 2014 and Paxton No. 8 and No. 9 in January 2015, according to Alaska Oil and Gas Conservation Commission records.

The expanded program also called for building a Kalotsa pad this year to support a two-well exploration program. The Kalotsa No. 1 and Kalotsa No. 2 exploration wells would test the Tyonek and Beluga formations between the Susan Dionne and Paxton pads.

At the other end of the unit, the 2014 program included the 10,000-foot Frances No. 2 and Frances No. 3 "appraisal" wells targeting the Tyonek and Beluga. 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.

The 9,000-foot Falls Creek No. 6 would follow Frances No. 2 to further appraise the Tyonek and Beluga formations area north of the Falls Creek pad. The expanded program included a second well with the name Falls Creek No. 6, this one described as an 11,000-foot "delineation" well to prove up a Beluga reservoir

continued on next page

HILCORP *continued from page 60*

north of the Falls Creek pad.

Hilcorp permitted a Falls Creek No. 6 well in October 2014 and completed the 9,060-foot gas development well before the end of the year, according to AOGCC reports.

While those wells and proposed wells all expanded upon exploration activities Hilcorp launched in 2013, the expanded 2014 plan also called for work in the vicinity of the Grassim Oskolkoff participating area, between Susan Dionne-Paxton and Falls Creek.

The initial program included plans for drilling a 6,500-foot GO No. 8 well to target the Sterling and Beluga formations above the existing, west of the existing GO pad. The expanded program called for building a Blossom pad just north of the existing Grassim Oskolkoff pad to support a 12,000-foot Blossom No. 1 exploration well. The state approved the pad and a two-well gas exploration program toward the end of 2014.

In its 2015 plan of development, filed in March 2015, Hilcorp proposed three grassroots wells for the Ninilchik unit: a 12,000-foot Blossom No. 1 (originally planned for 2014), a 12,000-foot GO-8 (deeper than the 2014 proposal) and a Kalotsa No. 1 development well.

The Deep Creek unit

Hilcorp has also been exploring at the Deep Creek unit, to the southeast.

Following successful exploration by Standard Oil Company of California in 1958, 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. Then, investment flagged. In an eighth

The company closed on its acquisition of the North Slope properties in late 2014 and had yet to present any firm exploration plans by the time The Explorers went to print.

plan of development, from December 2010, Unocal offered no plans for further exploration but said it wanted to farm out exploration acreage in the south of the unit.

Believing the unit to contain additional accumulations, Alaska 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. By the time Hilcorp acquired the unit, the state and CIRI 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.

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

The program discovered commercial quantities of gas in the Sterling and Beluga formations, shallower than the producing

continued on next page

HILCORP *continued from page 61*

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

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

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

The plan also called for drilling the Middle Happy Valley No. 1 well in 2015. The well would have targeted the Sterling, Beluga and Tyonek formations and would have required a new road and pad, plus associated facilities and pipelines to access the area.

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

In July 2014, Hilcorp proposed construction of a Happy Valley C pad and an accompanying four-well appraisal program to prove up and possibly develop a shallow natural gas accumulation. If successful, Hilcorp said it would initially develop the pad using existing facilities at B pad and potential construct new facilities at the C pad.

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Linc pursuing two complex exploration projects

One effort would develop the Umiat oil field; the other would generate synthesis gas from coal seams

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For Petroleum News

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In some ways, the future of the Umiat oil field has never been more certain.

Having completed the first flow test at the field in decades, the Australian independent Linc Energy Ltd. is currently compiling information for an environmental impact statement, which the company will need before it can develop the North Slope field.

In other ways, though, the future of the field has never been more uncertain.


CRAIG RICATO

Linc has yet to announce whether it intends to develop the field independently, bring on a joint venture partner or sell the field to an interested third party. The current stretch of low oil prices further complicates a remote and technically challenging project. And a recent decision by the state to abandon plans for a road to the isolated region in the foothills of the Brooks Range Mountains have made an expensive project even costlier.

While those decisions and evaluations continue, Linc is also moving forward on exploration drilling for a potential underground coal gasification program in Cook Inlet.

Early gas exploration

When Linc Energy acquired 123,000 acres in the Cook Inlet region from San Francisco-based GeoPetro Resources in March 2010, the company saw the potential to use conventional gas production to finance unconventional exploration and development.

The acreage was split between two blocks — one near Point MacKenzie along the western bank of Knik Arm and the other at Trading Bay on the west side of Cook Inlet.

By that summer, Linc was already moving forward on a well in the Point MacKenzie region, building on rudimentary permitting and infrastructure work from GeoPetro. The goal was to bring the Point MacKenzie acreage into production quickly and proceed to an exploration and development program at the Trading Bay acreage in the near future.

Using pre-existing seismic information and a handful of previous exploration wells going back to the 1960s, Linc drilled the 6,323-foot LEA No. 1 well in October 2010.

The well encountered "a number of gas bearing horizons" and "a number of significant coal seams," the company announced in November. But, after additional testing, Linc decided the structure was "too tight" to be developed 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. While "disappointed," CEO Peter Bond expressed optimism in Alaska, calling exploration "a numbers game," adding, "the more smart wells you drill the more likely you are going to be successful."

The expiration of much of the initial lease acquisition, in 2012, more or less eliminated the possibility of pursuing Cook Inlet gas without acquiring additional leases elsewhere.

Umiat obstacles

By that time, though, Linc was already pursuing a much bigger project.

In June 2011, the company acquired Renaissance Alaska LLC for some $50 million. The small independent company held an 84.5 percent interest in Renaissance Umiat LLC, which owned the main leases at the Umiat oil field. The deal gave Linc some 19,358 gross acres over two federal leases and one state lease straddling the Colville River.

The Umiat oil field is among the largest known yet undeveloped oil fields in Alaska. The U.S. Navy discovered the field in 1946, during an exploration campaign in the National Petroleum Reserve-Alaska to find more domestic oil supplies following World War II.

Even though early resource estimates were high, the initial exploration campaign encountered two obstacles that still present challenges for developing the field.

The first was isolation.

Developing the field would likely require standalone processing facilities and a 100-mile road and pipeline bundle to reach the Dalton Highway and trans-Alaska oil pipeline.

Eager to spur resource development in the region, then-Gov. Frank Murkowski proposed a state-sponsored road to Umiat as part of his Roads to Resources program. Preliminary permitting efforts on the project continued under the Palin and Parnell administrations.

The project came under political pressure from Native groups

continued on next page

LINC ENERGY *continued from page 63*

concerned about impacts to subsistence activities in the region and politicians concerned about "corporate welfare."

In mid-2013, the Alaska Department of Transportation and Public Facilities backed away from the project. The U.S. Army Corps of Engineers closed the project in January 2015.

Although Linc was certainly in favor of the state footing the bill for the expensive project, the company always said the Umiat field would be economic regardless.

The second obstacle was geology.

The unusually shallow reservoir at Umiat is partially embedded in permafrost, which reduces reservoir pressure and complicates efforts to produce from oil-bearing rocks.

"Behavior of the wells during testing was unpredictable," U.S. Bureau of Mines petroleum engineer Oren C. Baptist wrote in a 1960 study of 11 U.S. Navy wells drilled at Umiat between 1945 and 1952. "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 returned to Umiat in 1979 to drill Seabee No. 1, a deeper test well in the vicinity. That was the last exploration work conducted in the region for nearly 30 years.

Those obstacles, although formidable, seemed surmountable by 2001, when Colorado-based independent Arctic Falcon Exploration acquired the Umiat leases from a sister company. Through a series of deals, Renaissance Alaska LLC and Rutter and Wilbanks Corp. acquired a stake in the leases in 2007, and created Renaissance Umiat LLC.

A combination of historically high oil prices and 70 years of advances in drilling technologies made the companies believe they could economically develop the field.

Ambitions and setbacks

Ultimately, they handed the task over to Linc Energy in mid-2011

The four years since have proceeded in bursts.

In early 2012, "logistical and weather issues," including "low snow levels which affected snow road development," forced the company to defer a five-well exploration program in the region. By August, 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.

In early 2013, light snowfall combined with extreme cold snaps once again delayed exploration. Instead of a four-to-five well program with a pair of side-by-side wells designed to directly compare completions from vertical and horizontal wells, Linc was forced to scale back the program to two wells: Umiat No. 18 and Umiat No. 23H.

The limited program would still allow the company to meet its "key objectives" for the season: providing a side-by-side comparison 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 mechanical problems prevented a flow test. After attempts to clear the blockage were unsuccessful, Linc suspended operations for the season. The company cold stacked the Kuukpik No. 5 rig at the permanent Seabee drilling pad in order to get a head start on drilling in early 2014 and avoid more weather-related delays.

Technical breakthrough

The limited program yielded important technical information.

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 had at 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.

A subsequent analysis of Umiat No. 18 rock samples gave the company considerable optimism about the quality of the Lower Grandstand formation, which

continued on next page

LINC ENERGY *continued from page 64*

Bond described as being "completely saturated with hydrocarbons." The company cancelled the Umiat No. 18 flow test in favor of drilling a horizontal well at the field as quickly as possible.

Even so, Linc eased slightly from its timeline for the project. The company had initially said it intended to bring Umiat online by late 2017. By October 2013, the company was saying it "plans to aggressively develop this field once commerciality is determined."

In early 2014, Linc drilled the Umiat No. 23H well to target depth of 4,100 feet, the first horizontal well at the field. A subsequent flow test produced a sustained rate of 250 barrels per day — or 650 barrels total during four flow tests over a seven-day period at the field — and a peak rate of 800 bpd, according to the company. The company estimated the well would have produced as much as 2,000 bpd with a gas drive installed.

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

The flow test also proved the efficacy of the completion method the company had proposed during its work on Umiat No. 18. "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."

How to develop

Given the daunting size and isolation of Umiat, Linc began studying the best way to proceed with such a development — from both a corporate and a technical standpoint.

In September 2014, Linc said it had received "unsolicited expressions of interest" to sell the Umiat field and conventional assets in Wyoming. In response, Linc launched "a formal process to work with additional parties who have expressed an interest in the potential acquisition of the company's entire USA based oil and gas portfolio."

"There is no assurance that these activities will result in a formal offer or binding arrangement," the company warned, noting that any sale of "core assets" would require the approval of shareholders. Bond added a cautiously optimistic note: "It is early days on the oil asset negotiations but it is always nice to receive unsolicited approaches on our assets that reconfirm the underlying value and provide third party validation. We will work with the parties and update the market if we can agree final and binding terms."

Linc initially expected to make a decision by the end of 2014. Those efforts have gone more slowly than expected. In an early 2015 financial statement for the second half of 2014, Linc said it "continues to engage with these parties in confidential negotiations while continuing to progress its permitting and development plans for the field."

The company has given no reason for the delay. One mitigating circumstance might be executive. In late 2014, Bond stepped down to become executive chairman of the board and general counsel. Company secretary Craig Ricato moved into the leadership position.

In early 2014, Linc drilled the Umiat No. 23H well to target depth of 4,100 feet, the first horizontal well at the field.

Soon thereafter, in an annual report, Linc said it had wrapped up the "select engineering" for a potential Umiat development. That first phase "identifies and analyses road options, pipeline routes, and environmental assessments of various development options." The report estimated that an initial development program could include as many as 70 wells.

The current phase involves incorporating the results of the flow test into a reservoir simulation model, collecting additional information for a future environmental impact statement and deciding whether it needed to bring on a partner to assist with development.

The third phase involves completing the environmental impact statement, choosing a development scenario, building infrastructure and figuring out project financing.

Still pursuing UCG

Even though the company has been more public about its efforts at Umiat, Linc Energy has also been quietly appraising the feasibility of developing deep coal deposits.

Coal gasification is a relatively common industrial process. Linc is pursuing "underground coal gasification," which 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, which is the primary ingredient in natural gas.

Early on, 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.

In February 2011, the Alaska Mental Health Trust Land Office gave Linc an underground coal gasification exploration license over 181,414 acres. The license covered three contiguous 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 Healy and Nenana.

Linc drilled the TYEX01 well in late 2011 and the associated TYEX01X well in early 2012 in the Tyonek area. 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.

The company called the results of the core hole "very encouraging."

In 2011 and 2012, Linc acquired 2-D seismic over all three exploration license areas.

Using a custom rotary-core rig from Buffalo Custom Manufacturing, Linc drilled the KEEX02 well on the west side of Cook Inlet in 2012. After delays caused by inclement weather, Linc completed the 1,700-foot hole in December 2012, according to the state.

In mid-2014, after taking a year off from drilling, the company began permitting a five-well exploration program on its two exploration license areas on the west side of Cook Inlet. The com-

continued on next page

LINC ENERGY *continued from page 65*

pany planned to drill the first well in the program — TYEX02 — in 2014.

"The main objectives of the TYEX02 core hole are to provide confirmation of the geological structure, provide geotechnical information about the coal seams and surrounding rock, provide gas content and whole coal analysis of the two prospective target coal seams, obtain hydrological characteristics from geophysical logs and perform drill stem tests in and adjacent to the targeted coal seams," Linc said in its application.

According to state records, the company completed the TYEX02XX well last year. The results of that well will determine whether Linc drills the TYEX03 well nearby.

Now, the company is considering marketing options. This year, the company expects to finalize a commercial pathway for a proposed synthesized natural gas hub in the region and to enter "several supplier agreements" to provide both synthesized natural gas and carbon dioxide. The company estimates there is 35 billion cubic feet of local demand for synthesized natural gas in the region "with the potential for export in the form of liquefied natural gas further increasing demand," the company said in October 2014.

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Miller focusing on gas in current price climate

Ambitious exploration company operating at all four corners of Cook Inlet as well as on the North Slope

By ERIC LIDJI
For Petroleum News

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Miller Energy Resources Ltd. is among the most ambitious explorers in Alaska.

Through its subsidiary Cook Inlet Energy LLC, the Tennessee-based independent is exploring three regions in Cook Inlet — at its developments near Trading Bay on the west side, at the producing North Fork unit in the southern Kenai Peninsula and in the Susitna basin exploration license region. The company is also seeking an exploration license in the Iniskin Bay region, to the south. Through its subsidiary Savant Alaska LLC, Miller is planning an exploration program at the Badami unit on the North Slope.

SCOTT BORUFF

Whether a small independent company can pursue all those projects with oil prices at $50 per barrel remains to be seen. "Given the continued pressure on oil prices, we're redirecting our drilling effort towards lower-risk and predominantly gas wells," recently appointed Miller CEO Carl Giesler said in a December 2014 statement. "We're fortunate — and we think unique — as a company to have a solid inventory of gas wells and the ability to sell gas at a price greater than $6 per mcf. Because of the closed-loop nature of the Cook Inlet area in which we operate, gas trades for north of $6 per mcf and the state of Alaska shares via cash tax credits in 35 percent to 65 percent of our well costs."

Otter and Olsen Creek

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.

The company initially focused on reviving older Cook Inlet properties, which included investment and activities at the West McArthur River oil field, the West Foreland gas field, the offshore Redoubt unit and its Osprey platform and the onshore Kustatan production facility, as well as a minority stake in the Three Mile Creek gas 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.

The company always kept an eye on exploration opportunities, though.

An early list included prospects investigated in a wide-ranging 3-D seismic survey across the region, such as Tutna, Tazlina, North Alexander, Stingray, Olsen Creek and Otter.

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.

continued on next page

MILLER ENERGY *continued from page 67*

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

Cook Inlet Energy began permitting a three-well Stingray exploration program in late 2010 to test shallow gas targets on the West Foreland peninsula near the Trading Bay production facilities on the west side of Cook Inlet. The program never materialized, though, and the company ultimately relinquished some of the acreage without drilling.

Instead, in mid-2012, Cook Inlet Energy used its Rig 34 to drill the 5,680-foot Otter No. 1 well. The well tested gas targets in the Beluga and Tyonek in the northwest corner of the Susitna Flats State Game Refuge. Even though mud pump problems prevented the $7 million well from testing the Tyonek, and some of the Beluga, the company said that mud loggers reported "two significant hydrocarbon gas shows in the zone of interest."

"We're very excited about the Otter No. 1," Hall said at the time. The company touted a third-party engineering reserve report estimating 45 billion cubic feet of gas at Otter.

In early 2013, as it was preparing for a deeper follow-up, Cook Inlet Energy applied to form the Otter unit over some 5,855 acres at portions of four leases at the prospect. 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. Following a back and forth, the state approved the unit, but required Cook Inlet Energy to post a $1.2 million bond and provide drilling dates, surface locations and bottomhole locations.

By November 2013, the company had met those terms, according to the state.

The initial plan of exploration required Cook Inlet Energy to drill two wells. The first would either be a deepening of Otter No. 1 using a coiled-tubing unit by March 31, 2014, or a grass roots exploration well slightly to the east of the original well by March 31, 2015. The second well would have been a delineation of either well by March 31, 2016.

The company met the first requirement by completing the 7,021-foot Otter No. 1A sidetrack in December 2013. Plans for the second well were delayed when the company realized it would need a larger rig, which in turn required a pad expansion. The current plan of exploration calls for drilling a well from the expanded pad by March 31, 2016.

While it was exploring Otter, Cook Inlet Energy was also considering Olsen Creek.

The gas prospect is some seven miles northeast of Otter. The company saw the potential for a 24-well development program that could produce as much as 84 billion cubic feet according to company estimates, Hall told Petroleum News. The company initially planned to drill an exploration well in late 2012 but pushed the schedule to mid-2013.

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.

The company drilled the Olsen Creek No. 2 follow-up well in late 2014. The two wells proved to be disappointments, though, prompting a $13.4 million write off. The failure at Olsen Creek prompted a bit of soul searching from Miller CEO Carl Giesler in December 2014. "Simply put, our operational credibility is low at best and we get that," he said.

Sword and Sabre

As it was pursuing Otter and Olsen Creek at the northern end of the region, Cook Inlet Energy also began contemplating prospects farther south along the west side coast.

In September 2012, the company farmed in a 30 percent interest in the Sabre and Sword prospects from Hilcorp Alaska LLC. Combined with its previously held 70 percent interest, the deal gave Cook Inlet Energy total control over the prospects near the West McArthur River unit. "Sword and Sabre prospects show great potential," Hall said, touting estimates of up to 20 million barrels of oil and 14.3 billion cubic feet of gas.

Using the Patterson-UTI Drilling Co. rig 191, Cook Inlet Energy drilled the 18,475-foot Sword No. 1 well from June to October 2013. 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. After bringing the well into production in November 2013, the company began talking about developing additional intervals and perhaps even drilling a Sword No. 2 follow-up well.

Instead, Cook Inlet Energy turned its attention to the nearby Sabre prospect. The company believed the prospect would eventually require a six-well development program at a cost of some $25 million to 30 million for the first well. The cost perhaps proved to be an impediment because in September 2014, and again in December 2014, the company said it was "evaluating joint venture offers for participation in the project."

In early 2015, the state approved a simultaneous contraction and expansion of the West McArthur River unit. The change brought the Sword and Sabre prospects into the unit and eliminated some unproductive acreage from the southernmost lease at the unit.

The 23rd plan of development for the unit, from early 2014, envisioned drilling a Sword No. 2 well and a Sabre No. 1 well by April 30, 2016, depending on rig availability. In its development plan for 2015, Cook Inlet Energy said it might drill a Sword No. 2 appraisal well in April 2017. The company also said it was "still evaluating" a Sabre well, although, as an extended reach exploration well, the prospect conflicts with the current strategy of "developing lower risk targets." The company said it expects to delay any work until after it has finished developing proven prospects and may seek out a partner.

Susitna basin exploration

Through its acquisition from Pacific Energy, Cook Inlet Energy inherited a 471,474-acre exploration license in the Susitna basin, west of the Parks Highway, south of Talkeetna.

The Susitna Basin Exploration License No. 2 was nearing the end of its seven-year term when the sale closed. In late 2010, the Alaska Division of Oil and Gas agreed to a three-year extension in return for $750,000 in work commitments. The extension allowed Cook Inlet Energy to either collect additional 3-D seismic or drill an exploration well.

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. The following April, the company picked up Susitna Basin 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 April 2012. "We are currently evaluating the acreage and developing a work program."

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MILLER ENERGY *continued from page 68*

By early 2013, Cook Inlet Energy was preparing a two-well exploration program at the Kroto Creek prospect in Susitna Basin Exploration License No. 2. The company was interested in the prospect because Kroto Creek infrastructure could improve access to other prospects the company holds in the region, like Moose Creek and Big Bend. The company constructed a winter access trail and a two-well pad at Kroto Creek that year.

Toward the end of the year, Cook Inlet Energy changed its plans to a three-well program, with two wells at Kroto Creek and the third farther west at Moose Creek. Having met its spending commitments in the region, the company converted some of the license area to conventional leases, which is a common step in the exploration license program. With the conversion, the state officially terminated Susitna Basin Exploration License No. 2.

In mid-2014, Cook Inlet Energy changed its plans again. This time, the plan called for exploring three prospects in the Susitna basin — Kroto Creek and Moose Creek on ADL 390078 and Kahiltna on nearby acreage in Susitna Basin Exploration License No. 4.

Toward the end of the year, the company began permitting the 6,000-foot Kahiltna No. 2 exploration well to follow-up on the 7,265-foot Pure Kahiltna Unit No. 1 well drilled in the early 1960s. The state approved the Kahiltna exploration program in early 2015.

Iniskin Bay exploration

Cook Inlet Energy is also pursuing exploration through another license.

In August 2014, the company made a $1.5 million work commitment in return for an exploration license over 168,581 onshore and offshore acres in the Alaska Peninsula. The work commitment stemmed from a competitive bid the state hosted that summer.

The state accepts exploration license proposal once each year. The special process gives the applicant anonymity and gives other companies the chance to make a better deal.

The state received an application for an Iniskin Bay exploration license in April 2013 and the subsequent public comment period yielded a competing proposal and then the auction.

Although the region remains undeveloped, it is among the oldest exploration regions in Alaska, with observable oil seeps recorded as early as 1853 and a well drilled in 1902.

More recently, SAExploration Inc. conducted a 41-mile 2-D seismic survey between Chinitna Bay and Iniskin Bay on behalf of Hilcorp Alaska in the summer of 2013.

Any plans for exploration remain tentative until the state finalizes the license, although Miller officials have said they might pursue independent exploration or find a partner.

In a March 2015 presentation, Miller listed Sword, Sabre and the Susitna and Iniskin basin as "long-term" projects that could be developed independently or in a joint venture.

North Fork gas

In recent years, Miller has picked up two properties with exploration potential.

Miller acquired the North Fork unit from Armstrong Cook Inlet LLC for nearly $65 million in late 2013 and acquired Savant Alaska LLC for some $9 million in early 2014.

Standard Oil of California discovered the North Fork field in 1965 while searching for oil. Given the low value of gas at the time, the field went undeveloped for decades, until Armstrong Oil and Gas LLC acquired the property from an independent operator.

In August 2014, the company made a $1.5 million work commitment in return for an exploration license over 168,581 onshore and offshore acres in the Alaska Peninsula.

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

"I am 100 percent positive we have a gas well — in any other part of the world that's what I would say, but we still have to get a pipeline to it," Armstrong Vice President of Land and Business Development Ed Kerr told Petroleum News in September 2008.

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

After securing a favorable contract with Enstar Natural Gas Co., Armstrong drilled additional wells, built a pipeline and brought the unit into production in March 2011.

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

After completing the acquisition in February 2014, Cook Inlet Energy became operator of the onshore unit in the southern Kenai Peninsula and filed an updated development plan.

Soon after taking over, the company proposed short-term and long-term plans. A proposed drilling inventory for fiscal year 2015 included working over the existing NFU 14-25 and NFU 32-35 wells, sidetracking the existing NFU 23-25 well and drilling the new NFU-07 and NFU 32-35 wells to increase gas production. A proposed fiscal year 2016 program called for drilling three new gas wells: NFU-08, NFU-09 and NFU-10.

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

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

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

As of March 2015, the company had completed the NFU No. 24-26 and NFU No. 42-35 on time and on budget and was preparing to drill three workovers planned for the unit.

For the current plan of development, which runs through March 2016, Miller said it intended to continue the delineation

continued on page 72

NordAq pursuing targets in two Alaska basins

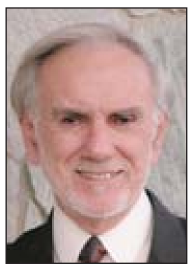
Small independent is looking for gas on both sides of Cook Inlet and looking for North Slope oil

By ERIC LIDJI
For Petroleum News

NordAq Energy Inc. is one of only four companies actively working in the two major Alaska basins — the North Slope and Cook Inlet — and almost certainly the smallest.

This winter, the Anchorage-based company launched a one-well exploration program at the Tulimaniq prospect in Smith Bay off the coast of the National Petroleum Reserve-Alaska while progressing two programs in Cook Inlet — the Shadura prospect in the Kenai National Wildlife Refuge and the Tiger Eye prospect in the Trading Bay region.

NordAq arrived in the Cook Inlet region with a wave of independents in early 2010 by picking up state acreage at lease sales and acquiring Cook Inlet Region Inc. leases. The principals of the company have been well known in the Alaska oil industry for years. NordAq President Bob Warthen boasts nearly 45 years of Cook Inlet experience, including a quarter century of senior management for Union Oil Company of California.


BOB WARTHEN

After pulling together its two Cook Inlet exploration programs, NordAq is now being funding through a partnership with the Chinese private investment group Chinanx. The firm agreed to invest $90 million and provide a $150 million debt facility to help NordAq develop "gross unrisked potential recoverable reserves" of 1.2 billion barrels of oil and 115 billion cubic feet of gas across its Alaska portfolio, according to the companies.

Following FEX

After several years focused exclusively on its Cook Inlet properties, NordAq began amassing its leasehold across the North Slope at lease sales in 2011, 2012 and 2013.

The acreage was concentrated in Smith Bay and the northwest planning area of the NPR-A. Those areas are far from existing North Slope infrastructure. Smith Bay is roughly 150 miles from Kuparuk River unit Drill Site 2P and some 70 miles from Barrow. The NPR-A leases were even more remote, with some as far as 200 miles from Drill Site 2P.

Exploration in the region would be hard to justify if not for its impressive geology.

In 2006, Division of Oil and Gas geologist Paul Decker described the area as a natural oil trap where Brookian topset sands come up against shale in an ancient incised canyon. The region is famous for oil seeps in the Cape Simpson area, which Decker said were likely to have originated from an "oil kitchen" to the north in the lower Cretaceous source rock system known as the HRZ. That would put the Smith Bay "area squarely in between the kitchen and the seeps," Decker told Petroleum News at the time. "So you probably have a pretty good plumbing story to be able to charge this with nice light oil."

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All told, the acquisition bucked the recent trend of companies pursuing relatively small accumulations near existing developments in favor of a larger and more difficult find.

The Talisman Energy Inc. subsidiary FEX explored a similar region in the 2000s, commissioning a seismic survey in Smith Bay and drilling three NPR-A wells — Amaguq No. 2, Aklaqyaaq No. 1 and Aklaq No. 6. The company found oil at all three wells, and later touted a sizeable reserve potential, but left the state toward the end of the decade without pursuing development. The company was disheartened by the challenging logistics of the region and an inconsistent federal leasing program. The company plugged and abandoned Amaguq No. 2 and suspended Aklaqyaaq No. 1 and the Aklaq No. 6.

While FEX considered Amaguq No. 2 to be "subcommercial given current infrastructure," the company pegged the "initial estimate of contingent resources present" at the two suspended wells between 300 million and 400 million barrels net to FEX, which had an 80 percent working interest in the leases. The wells had encountered more than 225 feet of net hydrocarbon-bearing sandstones, according to FEX. Talisman also touted "significant follow-up potential on many similar structures on Talisman's acreage if commercial productivity is proven," based on log analysis and "strong gas and oil shows, including oil staining and free oil in the drilling mud in one of the wells."

NordAq permitted an eight-well program running over two winters — 2013-14 and 2014-15. 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. While the company hoped to begin drilling in the region in early 2014, logistical issues forced the company to delay its exploration work by one year.

In late 2014, NordAq proposed a one-well program for the coming winter. The Tulimaniq No. 1 exploration well near the delta of the Ikpikpuk River would be a vertical stratigraphic test

continued on next page

NORDAQ *continued from page 70*

well to collect rock samples and conduct a vertical seismic profile, according to the company. Should the well encounter liquid hydrocarbons, the company said it would conduct a flow test to evaluate hydrocarbon performance characteristics.

The results of the first well would determine future drilling, the company said.

The proposal drew opposition from a coalition of environmental groups worried about the potential impact of exploration in the Teshekpuk Lake region, among other concerns.

The Alaska Oil and Gas Conservation Commission issued a permit for Tulimaniq No. 1 in late February 2015. NordAq is using the Doyon Arctic Fox rig to drill the well.

Headway at Shadura

As it pursues that big North Slope prize, NordAq is also working on two projects in Cook Inlet: Shadura in the Kenai National Wildlife Refuge and Tiger Eye near Trading Bay.

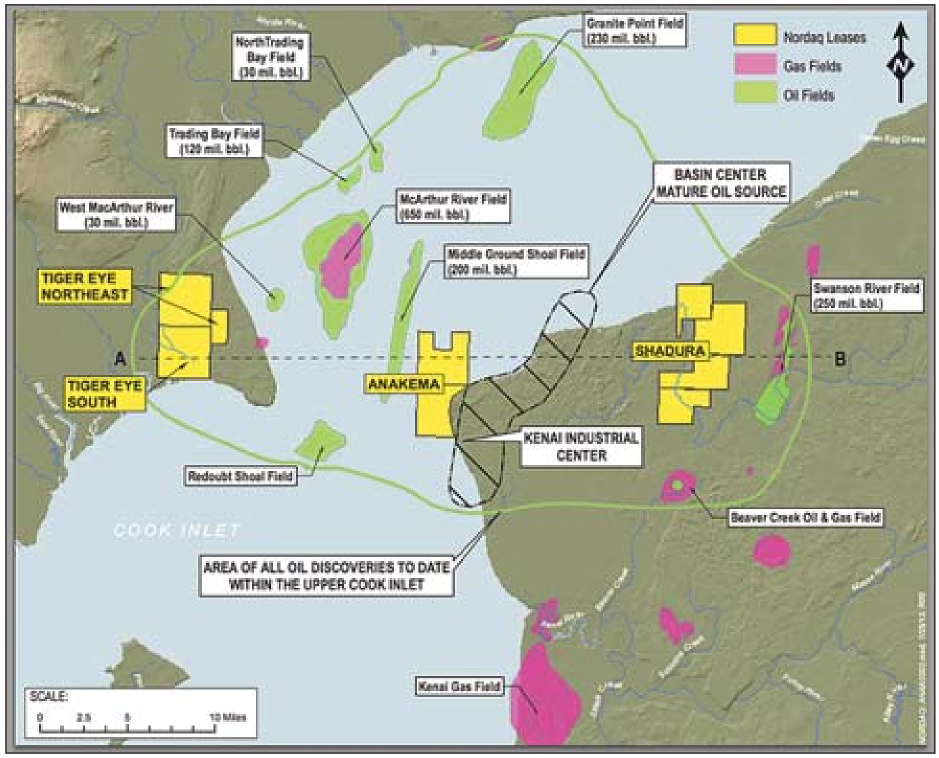
The Shadura prospect is west of the Swanson River field, on subsurface land owned by Cook Inlet Region Inc. The Alaska National Interest Lands Conservation Act created a mechanism for CIRI to allow access to lands within the refuge for resource development.

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 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. The company later tempered any excitement by saying that the 50 million cubic feet per day figure measured the "facility design volume," rather than the actual production volume.

By April 2012, NordAq was proposing a flow test and an appraisal well to assess the discovery, followed by a six-well development program. Although Warthen warned that the appraisal well might take as long as two years, because the 16,000-foot directional well would require a fairly large rig, he appeared to be serious about moving forward.



COURTESY NORDAQ

"We wouldn't be here if it's not a go. Going through an EIS process is not inexpensive," he said, referring to the federally mandated environmental impact statement process.

The comment proved to be prescient.

A draft EIS presented a two-phase development plan. NordAq would build a short gravel access road and a "minimal" pad to support one well in June 2013, which the company would either expand or remove and remediate, depending on the results of the well. The goal was 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.

The 538-page final EIS proposed five alternatives for development, including NordAq's preference. Among the remaining alternatives were plans for accessing the prospect from the south or the east, respectively, out of the Hilcorp-operated Swanson River unit.

NordAq believed these options would have made the project economically or logistically unfeasible, which would have violated the ANILCA provision allowing development.

While acknowledging that the two alternatives were "not ideal from NordAq's perspective," the U.S. Fish and Wildlife Service believed that both were "feasible." In July 2013, the agency allowed NordAq to pursue its preferred development scheme.

The decision allowed NordAq to start on the Shadura No. 2 appraisal well, which the company believes is key for determining the viability of the project. With an eye toward seasonal restrictions in the refuge, the company had said it intended to start building the gravel road in mid-July and start drilling in mid-September, according to the company.

Those plans were delayed for unknown reasons. In late September 2014, the Alaska Oil and Gas Conservation Commission issued a drilling permit for the well. As of early 2015, the Shadura No. 2 (23-19) well had yet to appear as "completed" in AOGCC reports.

Tiger Eye moving slowly

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.

The company initially proposed a one-well program targeting the Tyonek and Hemlock formations in an area about 1.8 miles southwest of the Trading Bay facilities. In May 2012, the company expanded the program, proposing two exploration wells toward the end of summer and commissioning a 3-D seismic survey over the

continued on next page

NORDAQ *continued from page 71*

area in early 2013.

With its leases set to expire at the end of September 2012, NordAq asked the state to form the Tiger Eye unit over two leases covering some 8,480 acres. The application proposed a two-well program — the Tiger Eye Central No. 1 well in the second quarter of 2013 and the Tiger Eye North No. 1 well in the second quarter of 2014. The wells would have started from the same pad to different bottomhole locations, one in each lease.

The company revised its application in August 2012, switching out Tiger Eye North No. 1 for the Tiger Eye Central No. 2 well, which had a bottomhole location slightly to the east. The revision also sped up the deadlines by nine months to a year — the third quarter of 2012 for Tiger Eye Central No. 1 and the second quarter of 2013 for Tiger Eye Central No. 2. The revised application maintained the early 2013 timeline for shooting seismic.

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.

As part of the application process, Apache Alaska Corp. asked the state to include three of its adjacent leases into the unit, saying they shared a reservoir. The state rejected the request, saying Apache did "not conclusively prove that the potential hydrocarbon accumulation" 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."

The adjacent Apache leases expired at the end of their primary term in May 2013. The leases included Shell's Kustatan River No. 1 and PanAm's Bachatna Creek No. 1.

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.

The company amended the Tiger Eye unit plan of operations in early 2013 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 and connecting the two pads by road, as well as conducting exploration activities. The plan called for drilling as many as eight 4,000-foot wells on the TEC-1 pad before expanding it and potentially bringing the pad into production by October 2013.

The NordAq portfolio includes other prospects, including Anakema and Akema.

Anakema is located offshore of the Kenai Industrial Center, roughly halfway between Shadura and Tiger Eye. The two leases in the prospect are set to expire in February 2018.

Akema is southeast of Shadura. The one lease in the prospect expires in April 2017.

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MILLER ENERGY *continued from page 69*

program while also analyzing results within an eye toward a potential drilling program outside the North Fork Gas Pool No. 1 participating area. Lower risk gas targets at North Fork are a major focus for Miller in 2015, given the attractiveness of gas compared to oil in the current commodity price environment.

The Badami unit

With its acquisition of Badami, Miller became one of only three companies to operate production both on the North Slope and in Cook Inlet, along with ConocoPhillips and Hilcorp.

While Miller acquired the North Fork unit from Armstrong and its partners, it acquired Savant Alaska outright, making the small independent a wholly owned subsidiary.

The biggest component of the acquisition is control of the Badami unit on the eastern North Slope. The deal also came with pipelines and associated exploration acreage.

Conoco Inc. discovered Badami in 1990, and BP Exploration (Alaska) Inc. brought the field online in August 1998. While BP had high hopes for the field, oil production peaked a month later at 7,450 barrels per day. The next decade involved a series of starts and stops, during which time BP upgraded facilities and allowed field pressure to improve.

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

Through its acquisition of Savant, Miller acquired a 67.5 percent interest in Badami with ASRC Exploration LLC holding the other 32.5 percent. At the time, the unit was producing some 1,100 barrels per day. "We're excited about that acquisition," Hall said at the time. "I think it gives us a good launch pad for the North Slope. We've been eying that field for a while and think there's lots of room for growth within the Badami field and also, too, some of the exploration acreage that comes along with the acquisition."

Initial plans called for sidetracking the existing B1-14 and B1-28 wells, at a cost of some $15 million each, according to Miller. The company estimated the wells contained some 2 million barrels of recoverable oil reserves between them. After closing on the deal in December 2014, the company announced plans to drill two Badami wells this summer.

The company is also touting exploration acreage south of the ExxonMobil-operated Point Thomson unit to the east, although it has not yet made any definitive plans for the region.

Low oil prices have dulled the luster of the unit for the time being.

In its March 2015 presentation, Miller placed its activities at Badami "on hold" for this year and said it would look for "well enhancements" opportunities "in the interim." The company listed the project as a potential for a joint venture, farm-out or sell-down.

Hungry for prospects

Those exploration projects (and its development work) will likely keep the company busy, but Miller has shown a willingness to pursue available opportunities in Alaska.

In September 2014, Miller signed a non-binding letter of intent to buy the Alaska assets of Buccaneer Energy Ltd., which had filed for bankruptcy protection earlier in the year.

Ultimately, Cook Inlet Energy bid $35 million through a bankruptcy auction. Although it was the largest cash bid, Buccaneer sold its assets to its largest creditor, AIX Energy LLC, for a $44 million "credit bid," which involve bidding debt against other cash offers.

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Repsol finishes fourth Alaska exploration season

The company has spent nearly $1 billion drilling a dozen wells and permitting at least three seismic programs

By ERIC LIDJI
For Petroleum News

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A year ago, Repsol E&P USA Inc. seemed to be on the verge of development.

The American subsidiary of Spanish supermajor Repsol SA had announced three discoveries following its third season of exploration activities in Alaska. Officials described development as being something of an inevitability, to be delayed only by the uncertainties of regulatory systems and taxation. With voters subsequently upholding a fiscal system favored by the company, what else could possibly stand in the way?

Over the past year, though, instead of sanctioning development, Repsol continued its exploration program. The company conducted a large 3-D seismic survey over the region and permitted three new wells among a cluster of nine previous wells and sidetracks.

That this program is the most geographically concentrated Repsol has conducted to date in Alaska suggests the company is narrowing its focus as it decides how best to develop the region. Added to that are recent comments from Chief Executive Officer Josu Jon Imaz, who told analysts, during a March 2015 earning call, that there was "a high probability" of Repsol making a final decision and drafting a development plan in early 2016. But, he warned, any decision depended on the results of the current drilling season.


GREG SMITH

Toward the end of March, Repsol applied to form the Pikka unit over 31 state and Arctic Slope Regional Corp. leases covering some 63,304 acres in the Colville River Delta and the shallow waters of Harrison Bay. In an initial plan of exploration, the company said unitization would allow for "the orderly development of four discovered reservoirs."

Through its first three seasons, Repsol spent approximately $650 million drilling nine wells and conducting two 3-D seismic surveys, according to the company. The three-well program and associated seismic planned for this winter were estimated at $240 million.

In November 2014, Ed Kerr, who is vice president of the Repsol partner Armstrong Oil & Gas said, "In 10 or 15 years people will talk about Repsol the same way they talk about BP and ConocoPhillips today, in terms of … contributing to Alaska's economy."

Sniffing around

After the state owned Repsol was privatized in the 1980s and acquired the Argentinean company YPF in 1999, it became one of the largest oil companies in the world.

The company quickly expanded, particularly throughout Latin America, until it maintained upstream, midstream and downstream assets in more than 50 countries.

Over the next decade, though, Repsol shifted its focus. The company increasingly looked for opportunities to pursue oil development in developed economies, which is why the company partnered with Shell and Eni on a block of federal leases in the Beaufort Sea in 2007 and bid $15.6 million on 104 tracts — including $14.4 million in high bids on 93 tracts — in the record-breaking federal lease sale in the Chukchi Sea in early 2008.

A combination of regulatory uncertainty and legal challenges has prevented either of those offshore programs from coming to fruition. The company later claimed to have turned down other opportunities in Alaska due to an "uncompetitive tax structure."

Some opportunities are too interesting to pass up, though. In March 2011, with the same tax structure in place, 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 were eager to get to work.

Four seasons

The exploration program recently completed its fourth season.

For its first season, in early 2012, Repsol's ambitions outpaced its activities. The company wanted to drill five wells, permitted four to accommodate local concerns and ultimately completed only two because a blowout delayed operations for weeks. The two were the Qugruk No. 4 well in the Qugruk unit, north of the Colville River unit, and the Kachemach No. 1 well, southeast of the Meltwater satellite of the Kuparuk River unit.

For its second season, in early 2013, Repsol again attempted its original ambitions. The company planned a three-well program, which included the Qugruk No. 1 well proposed the year earlier,

continued on next page

COURTESY REPSOL

REPSOL *continued from page 73*

the Qugruk No. 6 well near the site of the blowout and the Qugruk No. 3 well. The first two wells were near the coast. The third was some 10 miles inland, to the south. All three wells found hydrocarbons. Repsol performed drill stem tests on Qugruk No. 1 and Qugruk No. 6 and performed some early geotechnical work needed for development.

For its third season, in early 2014, Repsol appraised those discoveries with a two-well program. The company drilled the Qugruk No. 5 well and Qugruk No. 5A sidetrack and the Qugruk No. 7 well about halfway between Qugruk No. 1 and Qugruk No. 3. (The company also drilled the Tuttu No. 1 well on a lease just south of the Prudhoe Bay unit.)

The Qugruk wells "finished with positive results," Chief Financial Officer Miguel Martinez said in May 2014. "We are working toward defining the most economical way to develop the area," he said, adding that it was too soon to provide further details.

As he spoke, Repsol was completing a major 3-D seismic program. In its 2013-14 plan of exploration, the company told the state it planned to collect 140 square miles of 3-D seismic across its onshore holdings, with the potential to add an offshore survey. In reality, the company ended up collecting 208.4 square miles across its coastal holdings.

In an August 2014 letter, Repsol told the state it was working to "fast track" its analysis of the seismic information to identify the best location for an appraisal of Qugruk No. 4.

Toward the end of 2014, the company began permitting five locations for a three-well exploration program, saying it wanted flexibility as it evaluated previous well results.

The proposed Qugruk No. 101 and Qugruk No. 9 wells were nestled between Qugruk No. 1 and Qugruk No. 6 drilled in early 2013 and Qugruk No. 5 and Qugruk No. 7 drilled in early 2014. The other three locations are clustered around previous exploration. The proposed Qugruk No. 301 well was nearly identical to Qugruk No. 3 drilled in early 2013. The proposed Qugruk No. 8 and Qugruk No. 801 wells were roughly one mile and five miles to the south, respectively, into as-yet-unexplored sections of the leasehold.

Ultimately, Repsol selected Qugruk No. 8, Qugruk No. 9 and Qugruk No. 301 and

continued on page 77

Lawsuit delays Royale exploration program

Financial dispute between partners pushes source rock exploration program into 2016 at the earliest

By ERIC LIDJI
For Petroleum News

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This year, Royale Energy Inc. was supposed to become the second company to drill wells explicitly targeting source rocks on the North Slope. Instead, a lawsuit between partners forced the San Diego-based company to postpone its plans until next year, at the earliest.

In 2014, Royale began permitting a two-year exploration program. The company planned to drill as many as four wells over two North Slope prospects: the Aki prospect south of the Colville River unit and the Central prospect south of the Kuparuk River unit. In late July 2014, Royale cancelled a contract with Kuukpik Drilling after its partner, Rampart Energy Inc., declined to fund a cash advance on the rig, according to the companies.

The financial matter spawned legal claims and counterclaims between the partners.

"Because the case is only a number of months old, we are unable to provide an evaluation of the likelihood of an unfavorable outcome nor can we estimate the amount or range of potential loss," Royale wrote in its most recent annual report, filed on March 31, 2015.

Sohio legacy

Although new to Alaska, Royale is building on old credentials.

Vice President for Exploration and Production Mohamed Abdel-Rahman came to Alaska in the early 1980s, while working as a geologist for Sohio. He initially focused on the southern half of the state and eventually became the district geologist for the entire state.

Abdel-Rahman was working for Sohio in 1983, when the company drilled the Mukluk well in Harrison Bay. The $1 billion well was the most expensive dry hole in history.

Abdel-Rahman led 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.

With Royale, Abdel-Rahman decided to pursue a source rock exploration program on the North Slope. The company initially

COURTESY ROYALE

wanted to get a sufficient amount of "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 if it wanted to enter the region. "We were caught by surprise when Great Bear Petroleum took that much acreage. It forced us to move quickly," co-CEO Stephen Hosmer told Petroleum News in early 2012.

In December 2011, the company spent $2.7 million on nearly

continued on next page

REPSOL *continued from page 74*

proposed micro-seismic fracture mapping on the Qugruk No. 301 and Qugruk No. 8.

The process uses the vibrations that occur during drilling operations to conduct seismic operations. “This micro-seismic fracture mapping will allow Repsol to understand the azimuth orientation of the maximum principal stress within the productive reservoir,” the company told state officials in an October 2014 plan of operations. “This azimuth orientation will ultimately dictate the trajectory of the horizontal laterals planned for production wells to optimize reservoir production over the life of the reservoir.”

Qugruk, Tapqaq, Pikka

Alongside field work, Repsol has been making administrative moves.

In October 2011, the company applied to form the 98,852-acre Qugruk unit over 49 leases in the T-shaped bundle running up the narrow fairway between the Kuparuk River and Colville River units and then spreading along the state waters of the Beaufort Sea.

The state ultimately approved a 12,065-acre unit over six leases but required Repsol to post a $20 million bond to be returned if the company completed the Qugruk No. 4 well by June 30, 2012, and increased rental rates on four leases set to expire in August 2012.

In mid-2013, taking advantage of a recently passed law, Repsol asked the state to extend the primary terms of five un-unitized leases in the Qugruk area by three-to-four years. The state ultimately gave Repsol two additional years on the leases but required the company to drill an additional well, post a $100,000 bond and collect new seismic.

Over 2014, Repsol also toyed with the idea of forming a second unit. Apparently, the company asked the state to form the Tapqaq unit over the segment of its leases containing Qugruk No. 5. The application never reached public notice and was only mentioned in passing as part of unit decisions for other leaseholders in the somewhat crowded region.

Instead, in early 2015, Repsol applied to form the Pikka unit. The proposed plan of exploration called for drilling three wells over the next five years. All three wells mentioned in the application — Qugruk No. 8, Qugruk No. 9 and Qugruk No. 301 — were wells Repsol permitted in January 2015 for the recently completed season.

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ROYALE *continued from page 76*

100,000 acres of North Slope leases prospective for source rock development. The leases were in the Franklin Bluffs region, south of Kuparuk and south of Nuiqsut along the Colville River.

The central North Slope has three stacked shales: the Triassic-age Shublik formation, the Jurassic-age Kingak shale and the Cretaceous-age Hue, or HRZ, shale. Of those, Royale has been most excited about the Shublik, which the company believes is similar in its composition to the booming Bakken formation of North Dakota. “Everything we picked is optimum for oil generation — in all three shales,” Abdel-Rahman said in 2012.

As with Great Bear, Royale intends to pursue conventional oil targets on its acreage, which would allow the company to earn some revenue while it pursues the larger target.

The small company also holds interests in the 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 concept with the Monterey shale of California, the company wanted to take another stab at unconventional resources, which is what led it to consider the possibilities of the three Alaska source rocks.

Seismic results

In early 2012, Royale announced plans to look for a joint venture partner to help fund a six-well program — two wells on each of its three lease blocks — for the following winter. In early 2013, Australia-based Rampart Energy agreed to spend $43 million on exploration in return for a large stake in the Royale land position on the North Slope.

The deal allowed Rampart to acquire between 10 percent and 75 percent working interest in the western block of leases and a 75 percent working interest in the Central Block by making various payments and funding various seismic programs by specific deadlines.

The partners commissioned SAE Exploration to conduct a 3-D seismic survey over 120 square miles of the North Slope. A preliminary interpretation “identified a large conventional target, covering an area of up to 20,000 acres,” according to Royale.

Rampart said that the results also suggested some source rock potential.

“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 CEO Torey Marshall said in an April 2014 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.

Permitting and delays

After the survey, Rampart committed some $50 million to upcoming exploration.

In an oil discharge prevention and contingency plan released for public comment in August 2014, Royale described “plans to conduct a regional, multi-year onshore oil and gas exploration drilling program during the winter months on the North Slope.”

The Aki and Central Exploration Drilling Program included plans for two areas.

The company said it had identified locations for eight potential wells at its Aki prospect along the Colville River south of the village of Nuiqsut and for six potential wells on its Central prospect south of the Kuparuk River unit. The company said it intended to “drill up to four exploratory well locations during the two winter seasons between 2014 and 2015; with potential additional locations drilled within the lease blocks in future years.”

The Aki wells would have been drilled from a temporary ice pad accessed by a snow/ice road from Kuparuk River unit Drill Site 2P. A separate snow-ice road from the Franklin Bluffs staging area along the Dalton Highway would have accessed the Central wells.

The Aki and Central prospects have “both conventional and unconventional formations,” according to Royale, which listed the conventional formations as Upper Jurassic, Kuparuk and Brookian and the unconventional as Shublik, Lower Kingak and shale.

continued on page 81

Shell pressing ahead in Chukchi after setbacks

Company is mobilizing fleet after three-year hiatus, still waiting for final approval of exploration plan

By ERIC LIDJI
For Petroleum News

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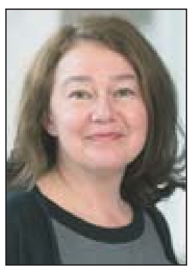
After a tiny step forward and many large leaps backward, Royal Dutch Shell plc is once again planning to explore its Burger prospect in the Chukchi Sea this summer.

"We have retained a very significant capability to be ready this year to go ahead," CEO Ben van Beurden said during a January earnings call. "And we've kept all our capability in place, tuned it, upgraded it just to be ready to drill this coming summer season."

By "capability," van Beurden was referring to the fleet required for conducting drilling operations in the remote Chukchi Sea off the northwest coast of the Alaska.



LAURIE SCHMIDT

If Shell moves ahead, the program would cost more than $1 billion, Shell Chief Financial Officer Simon Henry said. If the company is once again stymied, as it has often been in the past, the program would still cost nearly $1 billion, as all the drilling ships must be mobilized early in the season to meet timelines.

Following the announcement, Shell took several steps toward the program.

The company asked the National Marine Fisheries Service for authorizations to disturb marine mammals in the Chukchi and Beaufort seas by aircraft. The company wants to conduct as many as five fixed-wing flights covering a total distance of 1,500 nautical miles in the Chukchi Sea or the Beaufort Sea between June and July to observe freeze up.

Shell also asked the U.S. Department of Transportation for permission to use a foreign-flag anchor handling vessel, the Tor Viking, in the Beaufort Sea or Chukchi Sea.

The company cleared another hurdle in late March, when the Department of the Interior upheld the 2008 lease sale where Shell acquired its leasehold in the Chukchi Sea.

Old history, recent history

Shell was among the first companies to explore Alaska, including pioneering work across the Chukchi Sea, the Beaufort Sea, the Gulf of Alaska, the Bering Sea and Cook Inlet.

The company left the state in 1998, only to acquire additional leases in 2001 and relinquish those in 2004 with the promise of returning when the offerings were justified.

Officials made it clear that the company wanted to pursue giant targets in complex environments around the world. "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," Global Exploration Director Matthias Bichsel said in September 2004.

The current campaign started in 2005, when Shell spent some $44 million on 86 tracts in a federal Beaufort Sea lease sale. The acreage included two fields discovered between 1986 and 1992: the Hammerhead field off the coast of the Point Thomson unit and the Kuvlum field farther east. Shell initially intended to drill as early as 2007, although a legal challenge prevented the company from mobilizing equipment until early 2010.

Subsequent legal and regulatory challenges delayed the program until 2012, when the weather took over as the primary obstacle. By the end of the 2012 drilling season, the company had managed to complete only the 1,500-foot top-hole of the Sivulliq well.

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 had drilled in 1989 and 1990. The company intended to explore the Burger, Crackerjack and Southwest Shoebill prospects in 2010, but a federal moratorium on offshore drilling imposed in the aftermath of the Deepwater Horizon oil spill in the Gulf of Mexico ended those plans. A lawsuit in the Beaufort expanded to include the Chukchi, which prevented the company from exploring in 2011.

During the weather contracted 2012 season, Shell completed the top-hole for Burger-A.

The two top-holes represented the most exploration activities undertaken in either the Beaufort Sea or the Chukchi Sea in decades, which made the company optimistic about its prospects for exploring the two regions going forward. "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."

continued on next page

SHELL *continued from page 78*

Problems and delays

But later in the year, while being towed 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 Kodiak Island without reporting any fuel or oil spills, although some seawater had entered the vessel.

Shell also had to tow its Noble Discoverer drillship to a more robust shipyard to fix its propulsion systems, as well as equipment related to safety and pollution prevention.

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," Shell Oil Co. President Marvin Odum said. "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."

An initial 60-day review from the U.S. Department of the Interior placed most of the blame for the incident on Shell, saying that the company had inadequately prepared for the program and mismanaged its contractors. "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.

In late 2013, Shell began planning another program, which it soon cancelled in the face of legal and regulatory challenges. "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," van Beurden told investor in January 2014. "We will look to relevant agencies and the Court to resolve their open legal issues as quickly as possible."

By that time, Shell had spent more than $5 billion on its recent

continued on next page

BOEM approves Shell's Chukchi Sea plan

BREAKING NEWS

The Bureau of Ocean Energy Management announced its conditional approval of Shell's Chukchi Sea exploration plan May 11. Starting this year, the company proposes drilling up to six wells in the Burger prospect, about 70 miles northwest of the Chukchi coastal village of Wainwright. The BOEM approval is subject to several conditions, including Shell obtaining all of the permits needed for its operations and the company complying with the requirements of the Marine Mammals Protection Act and the Endangered Species Act.

Shell hopes to start moving its drilling fleet into the Chukchi in early July. An approved exploration plan is a key requirement for implementing the drilling program.

Among the permits and approvals Shell still needs are permits to drill from the Bureau of Safety and Environmental Enforcement. Shell has also applied to the National Marine Fisheries Service for approval for minor unintended disturbance of marine mammals.

SHELL *continued from page 79*

venture into the Arctic OCS, with only two top holes to show for it. "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 2014. He suggested that the company might forgo other opportunities around the world for the sake of pursuing its target in the Alaska Arctic. When the company announced its $1 billion program for Alaska this year, it also said it would reduce spending outside Alaska.

Given all those delays over the past decade, Shell recently asked the federal government for a five-year extension of its offshore leases in the Alaska outer continental shelf. The government had yet to rule on the request by the time The Explorers went to print.

Given the long lead-time needed in the Arctic, Shell filed its plan with the Bureau of Ocean Energy Management in late August, before it had decided whether to proceed.

The plan called for deploying the Noble Discoverer drillship and the Polar Pioneer semi-submersible rig to the Chukchi Sea. An earlier plan had called for stationing the Polar Pioneer in Dutch Harbor in the Aleutian Islands as a backup rig. While each rig would be capable of backing up the other, the plan allows Shell to drill two wells simultaneously.

The exploration program will target the Burger prospect, which is known to contain a large natural gas reservoir and which Shell believes also contains oil. The administrative issues surrounding the appeal of the lease sale delayed approval of the exploration plan.

Other changes

The past year has seen other developments for Shell.

In mid-2014, Shell formed a joint venture with Arctic Inupiat Offshore LLC.

The Native corporations Arctic Slope Regional Corp., Ukpeagvik Inupiat Corp., Tikigaq Corp., Olgoonik Corp., Kaktovik Inupiat Corp., Atqasuk Corp. and Nunamiut Corp. formed Arctic Inupiat Offshore to pursue economic opportunities in the Chukchi Sea.

"Our region has always been a leader in strategic partnerships that provide meaningful benefits to our shareholders, to our people," ASRC President and CEO Rex A. Rock Sr. said in a statement in late July 2014. "I am humbled to acknowledge that this arrangement balances the risk of OCS development borne by our coastal communities with the benefits intended to support our communities and our people."

Through the deal, Shell would assign Arctic Inupiat Offshore an overriding royalty interest in oil and natural gas produced from specific Chukchi Sea leases. Arctic Inupiat Offshore also would be able to participate in project activities by acquiring a working interest whenever Shell decides whether to proceed with development and production.

In March 2015, Shell appointed Laurie Schmidt as its top executive in Alaska. She replaced Pete Slaiby, who took a new position with the company in its Houston office.

What about the regs?

As a company committed to the Arctic, Shell is at the center of a larger debate about the best way to regulate and monitor (or even allow) offshore exploration in the icy north.

Those conversations gained general relevance after the Deepwater Horizon oil spill in the Gulf of Mexico in 2010 and immediate relevance after a Shell drilling ship ran aground.

Shell was among the first companies to explore Alaska, including pioneering work across the Chukchi Sea, the Beaufort Sea, the Gulf of Alaska, the Bering Sea and Cook Inlet.

The Bureau of Safety and Environmental Enforcement began preparing new regulations for Arctic exploration in the wake of Deepwater Horizon. In September 2014, in a meeting with officials, Shell criticized the nature of the changes as being too prescriptive, rather than giving operators the freedom to meet performance-based safety targets.

Specifically, the company questioned three features of the proposed regulation. The first would require operators to have a backup rig available for drilling a relief well before the end of a drilling season, if needed. The second would impose a drilling blackout period at the end of each season to provide time for drilling a relief well, if needed. The third would require an operator to have the resources necessary to mechanically recover all the oil spilled during a worst-case scenario. The company believes these three provisions would increase exploration costs without necessarily improving safety.

For the first two provisions, Shell questions the efficacy of relief wells, which the company believes are less effective at stopping a spill than simply capping the well.

For the third provision, Shell believes in-situ burning or oil dispersants might be a more effective and efficient way to remove oil spilled in open water than mechanical recovery.

The federal agencies released proposed regulations for public comments in late February.

The proposal would require offshore operators to file an integrated operations plan for their proposed operations, acquire a capping stack and containment dome for responding to an out-of-control well and have a second rig on hand for drilling a relief well.

The operations plan would essentially provide specifications for the program, in order to give regulators a sense of the activities and equipment. The capping stack would need to be available with 24 hours and the containment dome within seven days. The agency also stood behind its endorsement of a relief well. "We understand that the same-season relief rig is somewhat controversial," BSEE Director Brian Salerno said in late February. "From our perspective that sets a level of protection for the Arctic that is necessary."

The proposed regulations also mandate mechanical recovery in the event of a spill.

Given that the regulatory process won't be completed by summer, the new rules won't apply to the exploration program Shell is hoping to complete this year. However, the current regulation structure includes various provisions that mirror those in the proposal.

"We support regulations that further these imperatives in the Arctic, provided they are clear, consistent and well-reasoned," Shell spokeswoman Megan Baldino told Petroleum News in late February. "While we review the draft Arctic regulations put forward by the Department of Interior, we will continue to work with federal agencies, the State of Alaska, local communities, and contractors to develop a 2015 drilling program that achieves the highest technical, operational, safety and environmental standards."

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Usibelli drills first coalbed methane well

Venerable coal mine company exploring for natural gas on its lands near Healy to look for a cheap fuel source

By ERIC LIDJI
For Petroleum News

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Usibelli Coal Mine Inc. completed the HC No. 1 exploration well in September 2014.

The 1,265-foot well followed more than a decade of regulatory and legal wrangling over the coalbed methane program in the Middle Tanana basin, near the town of Healy.

Although the company has been engaged primarily in coal mining operations since Emil Usibelli and his partner T.E. Sanford began operating in the region in 1943, the company has recently been interested in using the nearby methane in coal seams to fuel operations.

In April 2004, the company requested an exploration license, which allows for exploration in areas excluded from the annual areawide lease sales. In an August 2005 preliminary best interest finding, the Department of Natural Resources determined that the potential benefits of exploration outweighed the possible adverse impacts.

The decision came as a different coalbed methane exploration program was abandoned in the Matanuska Valley over concerns about the potential for environmental harm. In 2006, the Denali Borough Assembly banned natural gas exploration over some 40 percent of the proposed exploration license area, an action the state considered to be illegal. The Denali Citizens Council asked the state to exclude all lands west of the Nenana River.

In June 2010, the Department of Natural Resources approved the program, under its original specifications — and even easing some of requirements for mitigating impacts.

The Denali Citizens Council appealed the ruling to the Alaska Superior Court, saying that the state failed to show why shrinking the proposed license area would render the project uneconomic and challenging the changes to the proposed mitigation measures. The court rejected the appeal in February 2014, which allowed Usibelli to proceed with exploration.

Four-well program

In July 2014, Usibelli permitted a four-well program along an abandoned airstrip seven miles east of Healy to explore shallow natural gas prospects in the region. The plan called for drilling one well toward the end of summer and returning the following summer to conduct additional testing of the initial well and drill as many as three delineation wells.

The company said it would conduct the program on lands mined in the 1950s and 1970s and would utilize existing roads to reach the proposed Healy Creek Site No. 1 pad. The 150-foot by 150-foot pad was built on a fill area previously used as an airstrip to support mining operations. The pad is smaller than most gas exploration pads because shallower coalbed methane exploration wells require smaller rigs, according to the company.

While Usibelli is primarily interested it reducing its internal energy costs, the company has said it would consider selling gas to other companies if it found large enough volumes. A major discovery would be a boon to the Interior, which currently relies heavily on diesel fuel and heating oil and has been the center of state-backed efforts to truck liquefied natural gas from the North Slope until a major pipeline is completed.

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ROYALE *continued from page 77*

After Royale cancelled the rig contract, Rampart launched a "Strategic Partnering Process" to "identify funding partners" for the program. The company said it wanted to perform additional technical work "to present the true potential of the opportunity to prospective industry and financial partners, and secure favorable commercial terms."

By late October, discussions on how best to advance the exploration program were still "continuing," according to Rampart. In a statement at the time, the company said, "The parties have differing views on a number of key issues regarding the joint venture and there is no guarantee that a mutually acceptable resolution will be reached. As a result, the board is considering all options regarding its future involvement in the project."

Royale placed a lien against Rampart in November 2014. Rampart filed a counterclaim against Royale in December, "alleging breach of contract, violation of the covenant of good faith and fair dealing, unjust enrichment, defamation, violations of the Alaska Securities Act and seeking to undo the filing of the lien claims," according to Royale.

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