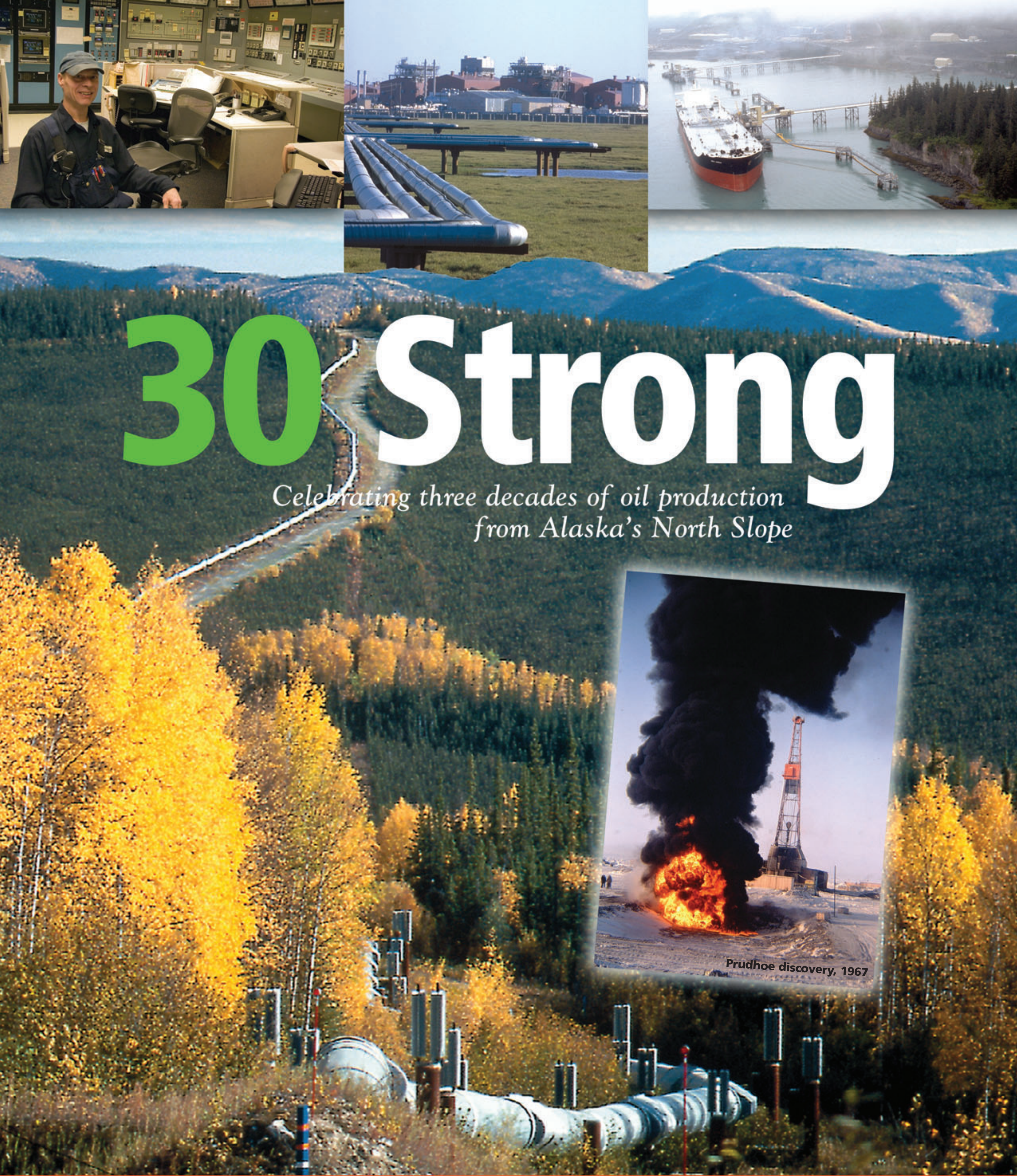
30 Strong

Celebrating three decades of oil production from Alaska's North Slope



Prudhoe discovery, 1967

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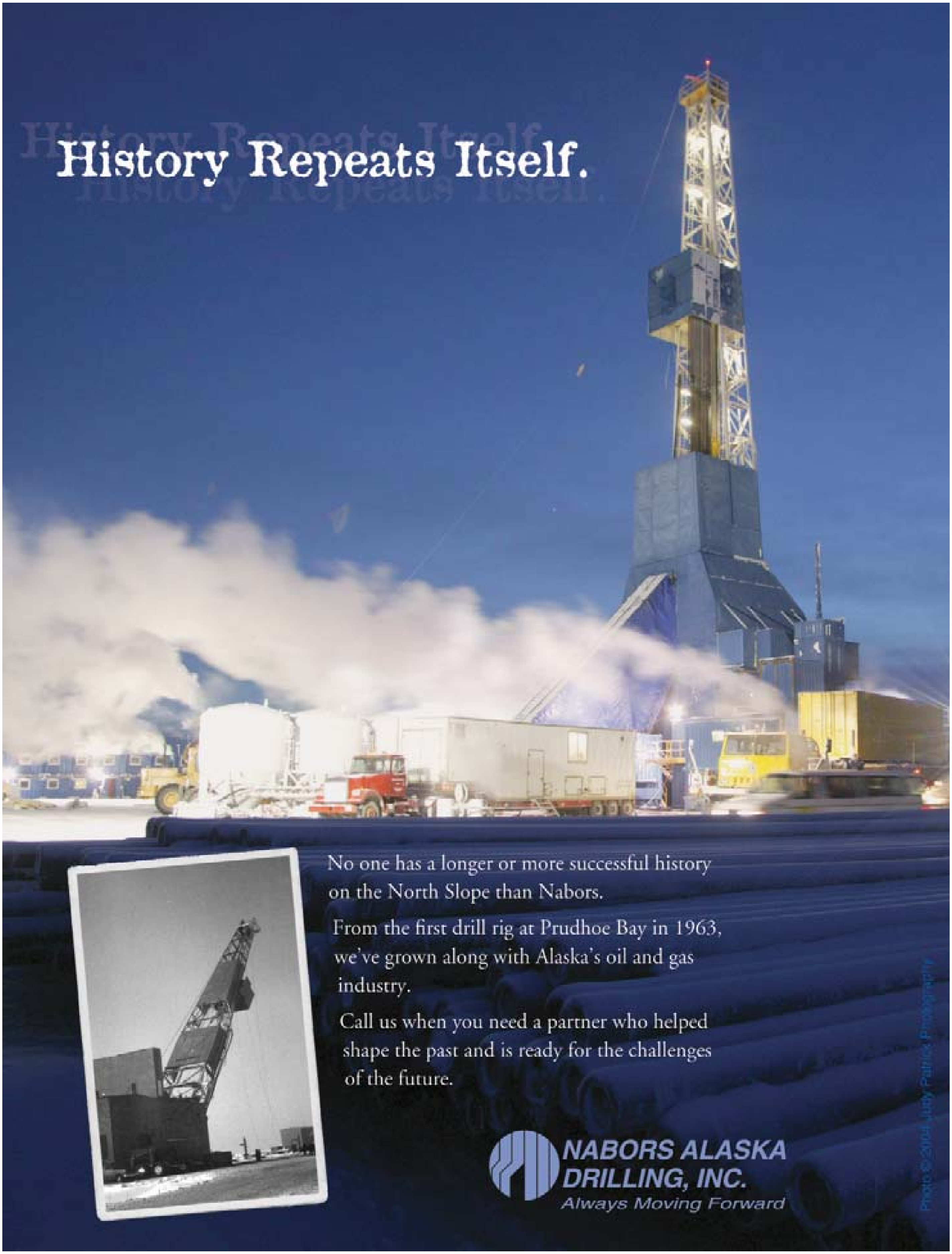
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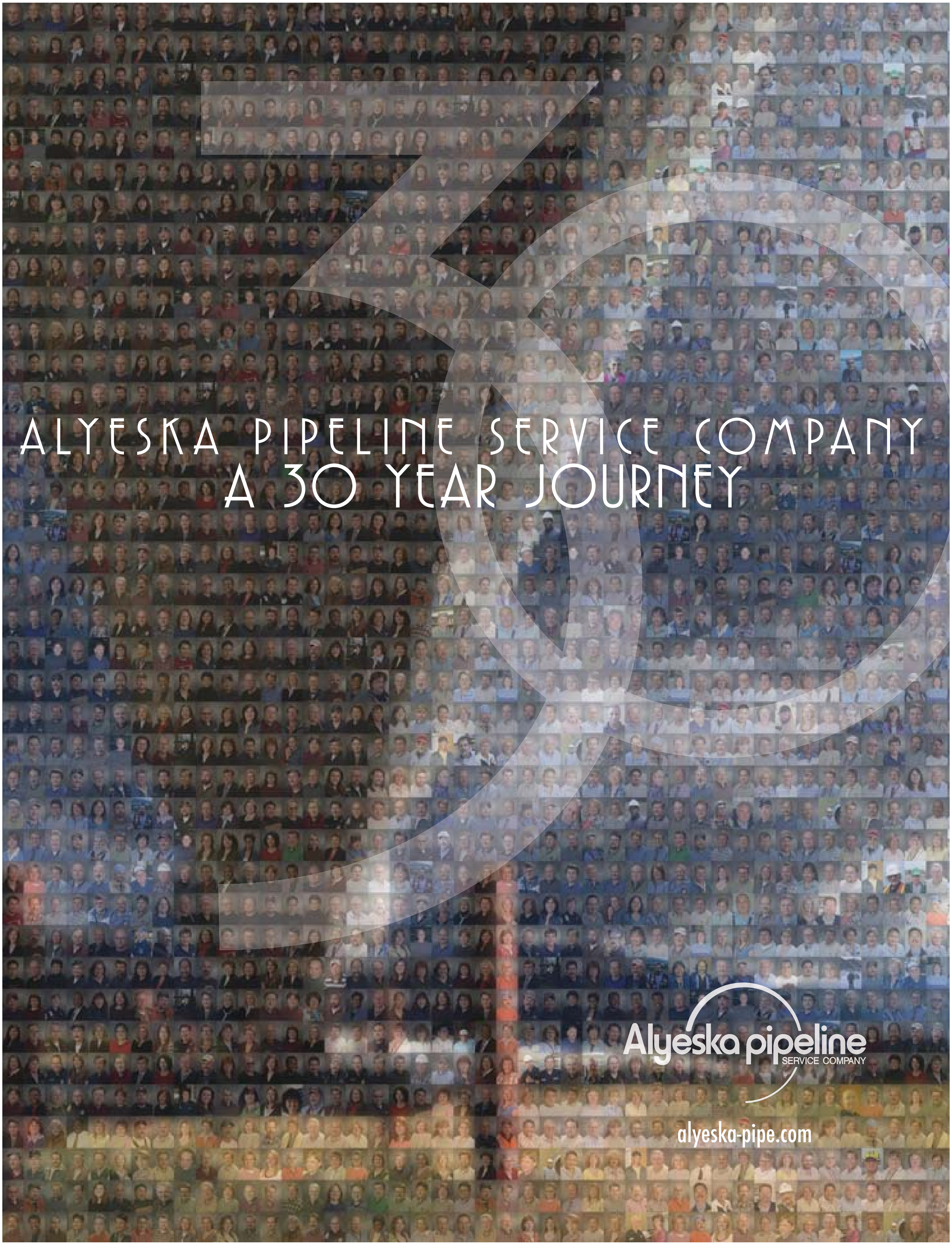
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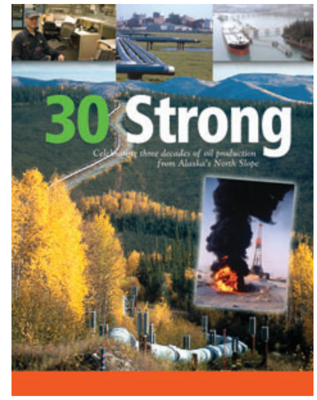

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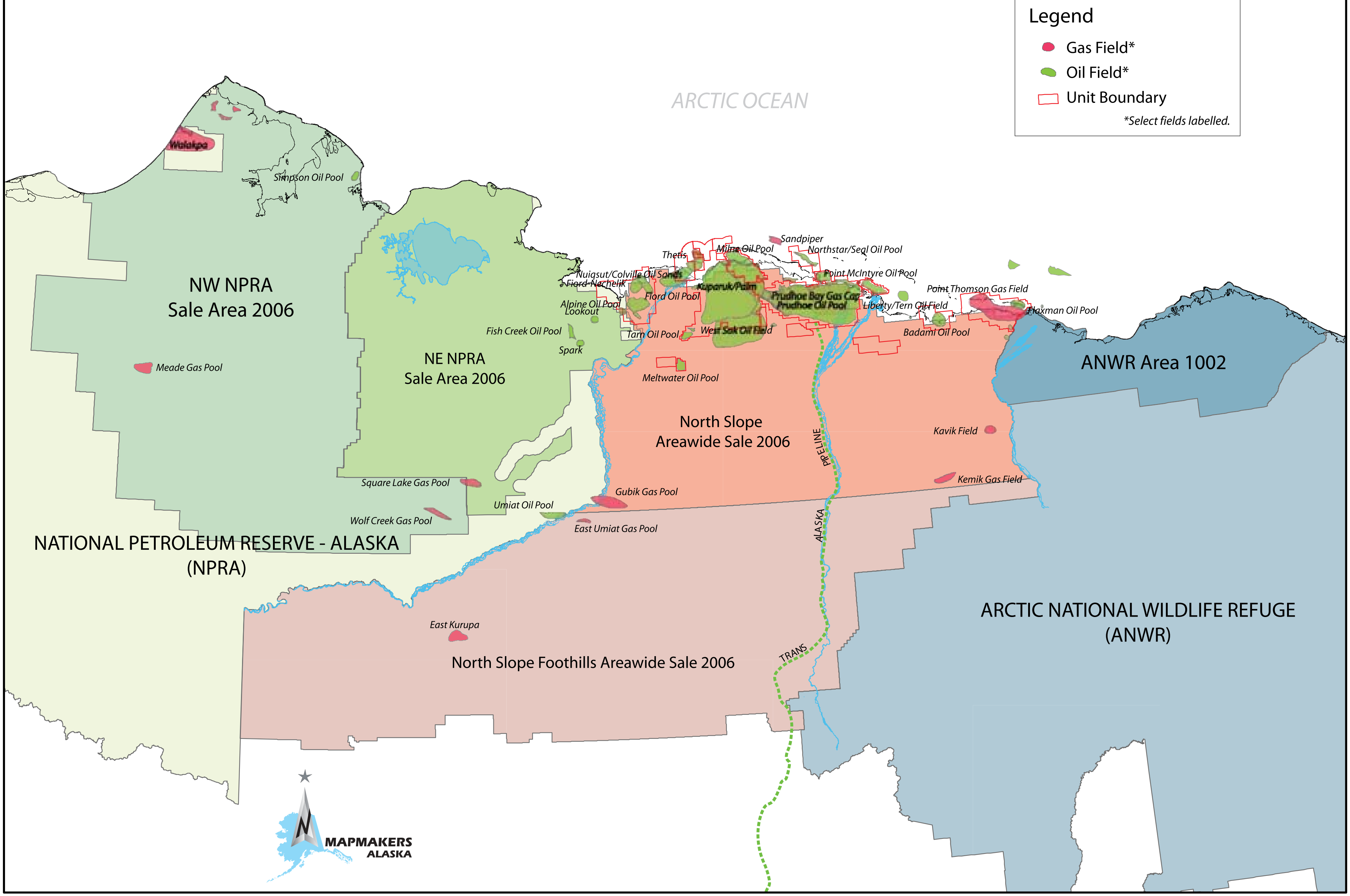
92

North Slope Oil & Gas Fields



North Slope oil and gas fields. Alaska Department of Natural Resources, Division of Oil & Gas, July 2006. Prepared by Mapmakers Alaska, March 2007.

JUDY PATRICK

The 800-mile trans-Alaska pipeline system starts at Prudhoe Bay and terminates at the Port of Valdez.

Mega-line drives industry technology

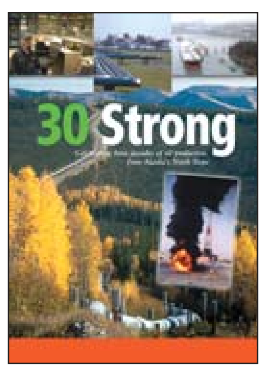
30-year old trans-Alaska pipeline adopts best new technology for safe, reliable operation

By ROSE RAGSDALE

In the 30 years since operators moved the first barrel of Prudhoe Bay oil down the trans-Alaska pipeline in 1977, improvements in technology have illuminated the path forward on Alaska's North Slope.

Beginning in the exploration years leading to the 1968 discovery of the giant Prudhoe Bay field, explorers and their contractors faced unprecedented challenges in coping with the fragile tundra with its shallow overburden and deep layer of permafrost and the other effects of frigid temperatures that dipped as low as minus 70 degrees Fahrenheit.

"It was a place unlike any other from which oil had yet been recovered," wrote Pulitzer Prize-winning author Daniel Yergin in commenting on the times. "The technology did not exist for production in such an environment. Normal steel pilings would crumble like soda straws when driving into the permafrost."



More than 20 years later, Yergin marveled at the changes wrought by the industry with the aid of technology. "This industry … can, at $15 or $16 a barrel, do things that it thought it couldn't do at $30 a barrel a decade ago. It's an industry that's being transformed by technology and computers. It's an industry that can do much better at lower prices. It's an industry that's surprised itself."

Over three decades, industry activity on the North Slope has mushroomed from just Prudhoe Bay, still North America's largest oil discovery. Today, the slope is home to an industrial complex that stretches from the 1 billion-barrel Alpine field near the National Petroleum Reserve-Alaska in the west some 60 miles to the east where the Badami field produces oil just 23 miles from the border of the Arctic National Wildlife Refuge.

For oil companies operating in Alaska's Arctic, getting from 1977 to 2007 is an untold story of ingenuity and technological advancements. Operators and their contractors pursued development of oil fields on the North Slope with vigor and optimism. First, they pulled out the stops to ramp up crude production to a peak of

2.15 million barrels per day in the late 1980s and then to adopt and create new technologies in the aftermath of the catastrophic Exxon Valdez oil spill and to cope with declining ANS production and the effects of exploration and production activities on the fragile tundra.

Between 1985 and 1989, for example, the U.S. Fish and Wildlife Service and BP Exploration (Alaska) Inc. worked jointly to restore the habitat along the 10-mile-long Endicott road. Researchers transplanted native grasses and successfully re-vegetated disturbed aquatic sites.

Innovation poorly documented

Each new problem spawned a solution, often involving new or improved technology. Increasingly innovative, the industry developed better and better ways to conduct economic, efficient and environmentally benign operations in the sensitive Arctic.

"There are just thousands of things. We've not well-documented the innovations up there," longtime Alaska oil industry executive Jim Weeks said of the history of technological advancements on the North Slope. Today, Weeks is co-owner of two of Alaska's few oil independents, Winstar LLC and Ultrastar LLC, but he remembers the

GIL MULL

Drill stem test No. 5 on Feb. 18, 1968, recovered both gas and oil and clearly showed that oil could be produced from Prudhoe Bay State No. 1

1980s when he worked as general manager of ARCO Alaska-operated Kuparuk, North America's second-largest oil field.

At one point, recalled Weeks, "I was signing patent applications at a rate of two a month for the guys in ARCO's coiled tubing group. "I got a kick out of those guys. We were doing some downsizing at the time, and they would say, 'If you don't want to have your job cut, you should stay close to the coil.'"

New technologies were developed or acquired and applied as the need arose in every discipline: exploration, development and production. Some technologies, such as

see **TAPS** *page 10*

continued from page 9

TAPS

the use of ice roads and ice pads for exploration wells and the Arctic Drilling Platform, are unique to the Arctic and were largely developed in Alaska.

Other advances, however, such as 3-D seismic-data acquisition, horizontal and multilateral drilling, measurement while drilling, low ground-pressure vehicles (rolligons) and remote sensing, were developed elsewhere and adapted for use on the North Slope.

Though some of these newer technologies have been used extensively, and the newer fields (such as Alpine) use them almost exclusively, older technologies are still integral parts of the older portions of the Prudhoe Bay and Kuparuk fields.

If the entire Prudhoe Bay oil field had been built with today's technology, its surface area would be 64 percent smaller than its current size, regulators say. Drilling pads would be 74 percent smaller and roads would cover 58 percent less area, while oil and gas separating facilities would take up half the space they currently occupy. Today's fields also are constructed more quickly, at less cost and with less surface disturbance.

*Wouldn't it be great if we could see underground oil or gas like Superman? We can, using **direct hydrocarbon indicators** in seismic data. To learn more, see page 32.*

North Slope operators now use new seismic and remote sensing technologies, including satellite and aerial surveying, to improve their odds of finding oil and gas. This cuts the cost of drilling and lessens the environmental impact of exploration.

Drilling technologies have advanced until wells can be drilled in any direction with multiple completions from the same well bore that can reach different zones of a reservoir without disturbing surface ecosystems. The use of smaller diameter holes and new drilling techniques is also reducing waste, noise, visual effects, fuel consumption and emissions, regulators say.

Triumph at Colville River

Operators continuously encounter and overcome new challenges with the help of technology.

A big hurdle, for example, at the Alpine field, which was built in the late 1990s, was the need to build oil and gas transmission pipelines across the Colville River, an ecologically important tributary that drains about 60 percent of the North Slope into the Beaufort Sea during breakup and is nearly a mile wide.

Alpine's owners, with the help of contractors, succeeded in using horizontal directional drilling technology to lay 4,000 feet of pipeline 100 feet below the river bottom. The HDD technology had been used all over the world, but the Colville River crossing was its first application in the frozen ground of the Arctic.

TAPS encourages innovation

Alyeska Pipeline Service Co., operator of the 800-mile trans-Alaska oil pipeline system, took a leadership role in developing technologies to improve the pipeline's operations, especially in corrosion control, leak detection and petroleum transportation. From the pipeline's first day of operation, June 20, 1977, Alyeska engineers and technicians have developed and adapted numerous applications that have established new and improved standards for safety and reliability.

After the Exxon Valdez oil spill in 1989, for example, Alyeska improved its tanker escort system by commissioning powerful tugboats equipped to prevent marine accidents by stopping oil tankers within seconds if necessary. These vessels also boast the latest in firefighting technology.

Government regulators and policy makers applaud the industry for its use of technology to reduce the impact of oil field operations on the environment, especially in waste management, and in minimizing the size of production facilities, the use of gravel, and the number of wells required to find and evaluate a new field.

"There have been many good examples on the North Slope of exactly what former Governor (Tony) Knowles calls 'Doing it right,'" said Michelle Brown, former commissioner of the Alaska Department of Environmental Conservation and longtime environmental activist.

Brown, speaking to a group in 2000, cited as examples injection technologies that have virtually eliminated surface waste, insightful and effective research studies that help regulators track the effects of oil field activities, and advances that have greatly reduced the surface area required for oil field drilling and development.

Another example, remote sensing tech-

see **TAPS** *page 12*

COURTESY ALYESKA PIPELINE SERVICE CO.

The first oil is shipped on the ARCO Juneau from Valdez on Aug. 1, 1977.

continued from page 10

TAPS

niques, have improved early detection and tracking of spills, and have helped with recognition of key habitat for caribou, she said.

Technology no panacea

But Brown and other regulators are quick to add that technology has not solved all of the industry's problems in the Arctic. Nor has it removed all risk associated with oil field operations. The newer technologies have resulted in increased protection for the environment, but they have not eliminated the potential for accidents, they say.

Gov. Sarah Palin issued a statement in May 2007, acknowledging the role technology has played in North Slope operations, but also pointing out that innovation must be viewed as part of a bigger picture as the oil fields mature:

Still, a solid track record of forward momentum in technological improvements in Alaska suggests that innovators will continue to overcome challenges as they arise. New materials such as advanced titanium alloys and advanced metal-free composites will improve the reliability, performance, and corrosion-resistance, weight and cost-effectiveness of drilling and production facilities.

Advancements in biotechnology, nanotechnology and, more immediately, information technology, such as computing power, automation, remote sensing and miniaturization also could potentially transform oil field operations. ◆

DAVID PREDEGER/ALYESKA PIPELINE SERVICE CO.

The trans-Alaska oil pipeline viewed from the Haul Road in northern Alaska. An unrivaled engineering feat, the pipeline has emerged as a technology leader in Alaska's oil industry.

TAPS: Young after 30 years

Over past 10 years Alyeska achieved 99.5% pipeline mechanical reliability rate

By ROSE RAGSDALE

It is an unrivaled engineering marvel compared by some with the Great Wall of China. It has safely and reliably delivered incomparable wealth in petroleum riches to the American people over three decades. And it continues to transport oil and natural gas liquids some 800 miles from Alaska's North Slope to the marine terminal in Valdez, for shipment by tanker to the U.S. West Coast and elsewhere.

The trans-Alaska pipeline accepted its first barrel of oil at pump station 1 at Prudhoe Bay on June 20, 1977. Since then this 48-inch-diameter steel conduit that snakes its way across three major mountain ranges, 834 rivers and streams and numerous creeks has quietly moved more than 15 billion barrels of North Slope crude towards market.

The pipeline was first conceived in the late 1960s after the discovery of the giant Prudhoe Bay oil field. The concept soon evolved into the world's largest ever privately funded construction project. A massive engineering achievement, it cost about $30 billion in today's dollars. That includes $24 billion in initial capital investment, plus ongoing costs.

Oil flow through the line peaked at 2.15 million barrels per day in January 1988. But a gradual decline in production from North Slope oil fields has since curtailed oil flow to about 800,000 barrels per day. At its peak, oil put through the pipeline was a major component of the total U.S. and West Coast oil supply, and it still represents 16 percent of total U.S. domestic production.

Alyeska Pipeline Service Co. operates the pipeline and Valdez terminal on behalf of five owner companies, BP Pipelines (Alaska) Inc., ConocoPhillips Transportation Alaska Inc., ExxonMobil Pipeline Co., Unocal Pipeline Co. (now part of Chevron) and Koch Alaska Pipeline.

A construction milestone

It took just two years to build the pipeline, with six years of construction planning before the first shovel bit the earth — a total of 515 federal and 832 state permits was required to secure use of the right of way and meet other requirements.

About 2,000 contractors and subcontractors were chosen to work on the project. Five contractors were each given responsibility for different sections of the pipeline. These were Morrison-Knudson-Rivers, Perini Arctic Associates, H.C. Price, Associated Green and Arctic Constructors. And construction contractors hauled a variety of earthmoving equipment into the wilds of Alaska, from backhoe loaders to tractors, excavators and trucks, for everything from clearing the right of way to digging trenches, cutting through bedrock and erecting bridges.

A total of 70,000 contractor personnel worked on the pipeline over the life of the project, from 1969 to 1977. At its peak, in October 1975, the project involved 28,072 people, including Alyeska employees and contractors. There were 31 fatalities directly related to the construction, including Alyeska, contractors and subcontractors.

The pipeline crosses several high mountain passes, requiring pumping of the crude up the mountain slopes. Four different pump stations, for example, successively raised the pressure of the oil to push it over Atigun Pass, at an elevation of nearly 4,800 feet.

More than 225 access roads were built, linking state roads to pump stations and 14 temporary airfields.

Thirteen bridges were built for the pipeline system, including two suspension bridges.

Three million tons of materials, including 0.5-inch-thick pipes manufactured in Japan, were shipped to Alaska for the pipeline construction.

And because the oil entering the pipeline is hot, about 420 miles of the pipeline is elevated on 78,000 specially designed vertical support members, to protect the underlying permafrost. The remaining 376 miles of pipeline are buried.

Many upgrades

The pipeline system involves a complex assembly of mechanical components, together with supporting computer systems. And over the years Alyeska has made many upgrades, in response to operational, maintenance, safety and environmental needs.

But Alyeska personnel have tended to adopt innovations from others, rather than inventing untried solutions.

"We are following the development of technology," said Mike Joynor, vice president of oil movements at Alyeska. "We never want to be on the absolute edge of technology, but once it's mature, we reach a point when it's hard to find support for our legacy technology."

That attitude is grounded in a certain amount of common sense.

"We want to avoid having to create our own design. The way we say that is 'serial number 0001.' We don't want our own designs because they usually have issues when they are first deployed. We like to go to people who have done this kind of work and have proven technology," explained Greg Jones, Alyeska's senior vice president of operations.

Some needs have surfaced naturally over the years, reflecting the toll that time can take on any large and complex mechanical system. Examples include repairs that have resulted from the pipeline shifting and settling over time and complications brought on in recent years by the decrease in oil flow in the pipeline.

But other challenges have burst upon the scene on the wings of disaster. Incidents such as the 16,000 barrels of oil spilled in an act of sabotage in February 1978, and the 260,000 barrels of crude spilled in Prince William Sound when the Exxon Valdez oil tanker ran aground on Bligh Reef in March 1989, three days before the system would complete its 9,000th tanker loading. These events haunt the memories of Alyeska Pipeline's longtime employees, especially those charged with scouring the earth for better and safer technologies with which to operate the pipeline system. Their goal is to prevent future disasters and to be ready if, by some fluke, the worst should happen again.

"We've made some pretty bold technological changes since the Exxon Valdez spill," said Jones. "I think our biggest lesson learned is that you cannot have that spill. We just cannot let that happen ever again."

Toward that end, Alyeska's marine and emergency preparedness departments have assembled an impressive inventory of the world's most sophisticated oil spill prevention and response equipment.

30 years young

But, at 30, the pipeline is relatively young by industry standards. Some oil and gas pipelines built in the Lower 48 before 1950 are still in operation.

And although external forces have conspired against the pipeline's integrity a handful of times, no corrosion-related oil spill has ever occurred on the main line of the trans-Alaska oil pipeline. Because dry oil passes through the pipeline, internal corrosion isn't as much of a concern as external corrosion.

"If you look at our history over the past 30 years, as we do our inline surveillance and our inline pigging runs … what we always have seen and continue to look for is the impact of external corrosion, primarily as a result of water getting underneath the insulation," said Kevin Hostler, president and CEO of Alyeska.

Alyeska's ongoing corrosion detection program began shortly after startup.

The company requires pipeline repair or replacement in any area where surveillance discovers a corrosion anomaly affecting more than 40 percent of the pipeline wall, Hostler said.

That standard applies to the whole length of the pipeline, despite the fact that only about one-third of the pipeline lies in "high-conse-

see **THE PIPELINE** *page 16*

continued from page 15

THE PIPELINE

quence" areas where the U.S. Department of Transportation would mandate that 40 percent limit, Hostler said. In less critical areas, DOT requires repair or replacement when corrosion anomalies affect 80 percent of the pipeline's one-half inch wall thickness, he said.

Alyeska does worry that the aging infrastructure issues that have surfaced on the North Slope also might apply to the pump stations. So, the company is running a continuous monitoring program in the pump stations, using inline investigation tools. For example, an analysis of monitoring data collected since the summer of 2006 has indicated that the infrastructure in pump stations 1 to 4 is in good condition, Hostler said.

Strategic reconfiguration

As well as monitoring the mechanical condition of the pipeline system, Alyeska has been engaged in a major upgrade of the pump stations and the Valdez Marine Terminal. Known as strategic reconfiguration, the upgrade is replacing 1970s-era turbine-powered pumps with state-of-the-art electrically powered pumps. And in February 2007 Pump Station 9, the first pump station to convert to the new technology, switched over to the electrical system (see "TAPS switches to 21st century" in the March 4 edition of Petroleum News).

"The technology that built the pump stations was the same technology that was in my Mercury Comet and now

ALYESKA PIPELINE SERVICE CO.

Pipe being buried during construction. In most cases, pipelines are buried, but almost half of the trans-Alaska oil pipeline is above ground because a lot of the ground where it runs is underlain by permafrost. The heat from the oil, which comes out of the ground at 150-180° F, could thaw the frozen soil if the 48-inch pipeline was buried, possibly causing the pipe to buckle and break. The pipeline runs approximately 420 miles above ground and approximately 380 miles underground.

May 31, 1977: Final pipeline weld near Pump Station 3.

we're dealing with technology and capability that's more like … one of these electrical hybrids that we're all looking at," Hostler said.

Strategic reconfiguration is about increasing the efficiency of how Alyeska operates the pipeline system — both the pumping and the control of the line, said spokesman Mike Heatwole.

"It's really about applying current pipeline technology to TAPS — much more efficient … and better performance," he explained. "It also helps us with maintenance as we get a lot more real time data on what is happening with each piece of new equipment. The system is designed to be modular and scalable — greatly improving our ability to operate through changes in pipeline throughput — both increases and decreases."

Also, the variable frequency drive that sends power to each new pump allows much greater control of pumping over a wide range of pipeline throughputs, unlike the original configuration, which does not allow much variability in the speed of the pumps.

"We're either going at full speed or we're off line," Heatwole said. "We were very challenged in how we operated the pipeline at the low throughputs presented during last year's shutdown of the Prudhoe Bay field. If we had had the new equipment on line, we would have had significantly better performance of the system."

In fact, Alyeska will be able to adjust the operation of new pump systems to any oil throughput up to 1.1 million barrels per day, using just four pump stations, plus a relief station on the south side of the Brooks Range. The addition of more pumps at each of those pump stations could up the throughput to 1.5 million barrels per day. In the event of a large new oil find, the reinstatement of old pump stations using new equipment could increase throughput to 2 million

see **THE PIPELINE** *page 18*

continued from page 17

THE PIPELINE

barrels per day.

At the Valdez Marine Terminal, Alyeska is reducing the number of oil storage tanks from 18 to 14 or 15. The company is also redesigning and reconfiguring the ballast water treatment facility, to significantly reduce the ballast and storm water capacity, Hostler said.

And the heightened pump station efficiency, together with size reductions at the marine terminal, will all result in reduced emissions, Hostler said.

Control and monitoring of all operations will take place from a single control room after strategic configuration, thus enabling greatly enhanced efficiency in the pipeline operations and maintenance — day-to-day control of the original pump systems resides in the individual pump stations, with the Valdez control room providing general operational oversight.

And the company is moving the pipeline control room from Valdez to Anchorage, into the Government Hill offices of AT&T, Alyeska's communications service provider, Hostler said.

Wax buildup new challenge

While Alyeska upgrades the pipeline architecture, the company is also dealing with a new technical issue: the increasing amount of wax that is precipitating from the oil in the line. Some of that wax passes through the system and eventually dissolves back into the oil when the oil is later warmed up. However, some wax requires collection and separate shipment.

The wax started appearing in 1989, primarily because, as the oil movement through the pipeline slowed with decreasing throughput, the oil became cooler. The changing mix of crude in the pipeline, as production from the mature North Slope oil field declines and new fields come on stream, is also resulting in more wax formation, Hostler said.

"We're pigging more often. We're monitoring it," Hostler said. "… We continue to look for opportunities to deal with it."

The reconfigured pump stations also have the capability of cycling and warming the oil, to dissolve some of the wax, he said.

Dedicated but aging staff

Successful operation of the pipeline system over the years has depended on personnel who have responded to challenges facing them with energy and ingenuity.

"We have a tremendous staff, really talented," said Alyeska President and CEO Kevin Hostler.

And, with a successful Native hire program, 20 percent of the Alyeska staff consists of Alaska Natives, he said.

But, along with declining oil throughput, Alyeska staff numbers have decreased from about 1,300 workers and contractors in the early 1990s to some 800 today. And that work force is aging.

"The issue with staffing is more to do with the aging work force," Hostler said. "Fifty percent of my work force is retirement eligible."

Hostler isn't so much concerned with replacing individual employees who might leave the company as he is with the looming need to fill substantial vacancies in the ranks.

"We do know that on a competitive basis we can go out and replace, like-for-like, a number of our staff," Hostler said. "… But now we're starting to look at renewing our work force by targeting critical skills and bringing in people early in their career development."

But the institutional knowledge that comes with years of experience enjoyed by the current staff becomes a significant issue as people start to retire.

"We've got people who've been here almost 30 years and know a lot about how to operate the pipeline," Hostler said.

Alyeska is also taking a close look at its contracting strategy and is re-evaluating the question of what work to do inside the company and what work to contract out.

"Finding the right level of internal capability and third-party capability is a real challenge," Hostler said. "… We've looked at our contracting strategy and thought through where we want to bring some of these skills back in house. And we have done that. And where we want to rely on the external market we're going to continue to do that."

High reliability

Alyeska particularly wants to maintain the pipeline's exemplary performance record. Over the past 10 years the company has achieved a pipeline mechanical reliability rate of 99.5 percent, Hostler said.

"That is terrific," Hostler said. "… As we've seen declining throughput and we've seen some of the challenges associated with that, we've been able to maintain a high degree of operations confidence."

But operating the aging pipeline will continue to require careful management.

And the pipeline needs to operate cost effectively, to maintain the viability of North Slope oil production. So, as the company builds its budget each year, the management seeks areas for increased operational efficiency, while at the same time managing risk mitigation.

"We see the challenge, but at the same time our process is intended to provide a stopgap against taking undue risk," Hostler said. "And that's what you'd expect of us, that we'd put that priority on the security of supply, maintaining safety and protecting the environment."

And "no oil to ground" is a company mantra, Hostler added. ◆

—Petroleum News staff writer Alan Bailey contributed to this article.

Seismic moves into 21st century

Technical progress enables assembly of increasingly detailed subsurface information

By ALAN BAILEY

Way back in the early days of oil and gas exploration in northern Alaska, seismic crews would wend their way across the tundra in Cat trains. Dynamite was the technology of choice for creating the sound waves that echo off subsurface rock formations to provide information about underground structures. And the end products of the surveys were printed, two-dimensional seismic cross-sections of the subsurface, containing only enough detail to depict major geologic features.

COURTESY CONOCOPHILLIPS ALASKA INC.

The evolution of vibroseis vibrator trucks between the 1980s and the early 2000s: Low-pressure rubber tracks with articulated steering have replaced steel tracks with skid steering.

COURTESY CONOCOPHILLIPS ALASKA INC.

Change in the 1970s

But by the 1970s, the approach toward surveying was starting to undergo radical change, as people became increasingly aware of the importance of protecting the delicate Arctic environment and as evolving seismic technologies began to improve the quality of the seismic images.

Instead of using ground-damaging dynamite, people started to create seismic sound waves using a technique known as vibroseis, in which a vibrator pad below a purpose-built truck transmits sound vibrations into the ground, Jon Anderson, ConocoPhillips Alaska chief geophysicist, exploration and land, told Petroleum News.

Vibroseis has now become the standard sound source for on-land seismic surveys, with the equipment and its hydraulic-powered vibration systems becoming increasingly reliable, Anderson said.

Offshore, air guns near the sea surface rather than explosives have become the standard source for seismic sound — a seismic survey vessel moving along a survey line tows an array of air guns and streamers of geophones, the devices that surveyors use to detect the seismic sound signals.

And along the seacoast off Alaska's North Slope, where the water is too shallow for a traditional marine survey, a technique called ocean bottom seismic, in which surveyors lay cabled geophones along the seafloor, has enabled geophysicists to bridge what used to be a gap in coverage between onshore and offshore seismic coverage, Tom Walsh, principal partner and manager of Petrotechnical Resources of Alaska, told Petroleum News.

At the same time, dramatic advances in computer and recording technology, including the miniaturization of components and the ability to use small devices to record vast amounts of data, have greatly reduced the size and weight of the recording equipment that needs to be deployed on the tundra.

"The dog house where all the recording is done … used to be the size of a semi-trailer, filled with equipment," Anderson said. "Now there's a guy in this fairly small box with a computer."

"The recording equipment itself is probably a tenth of the weight that it was 15 years ago, 10 years ago even," said Michael Faust, offshore exploration manager for ConocoPhillips Alaska.

Improved vehicles

And coupled with the reduction in weight of the equipment have come major improvements in vehicle designs, to enable seismic crews to operate on the tundra in the winter without marking or, worse still, tearing up the tundra surface.

"One of the biggest things is the fact that back in the old days everything was steel tracked vehicles and they were all skid steered," Faust said. "Nowadays everything's articulated steering — rubber tracked vehicles with very low pressure on the tundra."

The growing awareness of environmental protection that has accompanied these equipment improvements has led to an expectation nowadays of zero environmental impact. In the 1970s people just went out and shot seismic; in the 1980s it became a question of trying not to cause damage during a seismic survey; today, companies won't shoot seismic if they may cause any damage, Faust said.

And that's in part been a question of changing people's attitudes — for example, nowadays a crewmember will always pocket a used cigarette butt, rather than drop it onto the ground, Faust said.

Improved efficiency

Surveying efficiency has also improved greatly over the years.

Thirty years ago a survey crew would place wooden stakes in the ground using triangulation techniques, to mark out source and receiver locations, Anderson said. But GPS receivers that can instantly pinpoint equipment locations have done away with the need for that time-consuming manual survey procedure.

And the designs of the surveys themselves have improved, thanks to the availability of technology that enables the recording and processing of vast amounts of seismic data.

So, whereas years ago crews would obtain more data by setting off more seismic shots, nowadays people can increase data quantities by using more geophones. In fact it is possible to reduce the number of sound source shots needed to obtain high-resolution data.

"Now you can get great data with very little source impact," Faust said.

And by the judicious placement of the vibrator points and the geophones, it is also possible to reduce the amount of ground traversing done by the seismic survey vehicles. Increasing the number of recording points, for example, might make it possible to increase the spacing between adjacent routes taken by the vibrator vehicle from, say, 500 feet to 1,500 feet while still obtaining the same quality of seismic image, Faust explained.

Geophone development

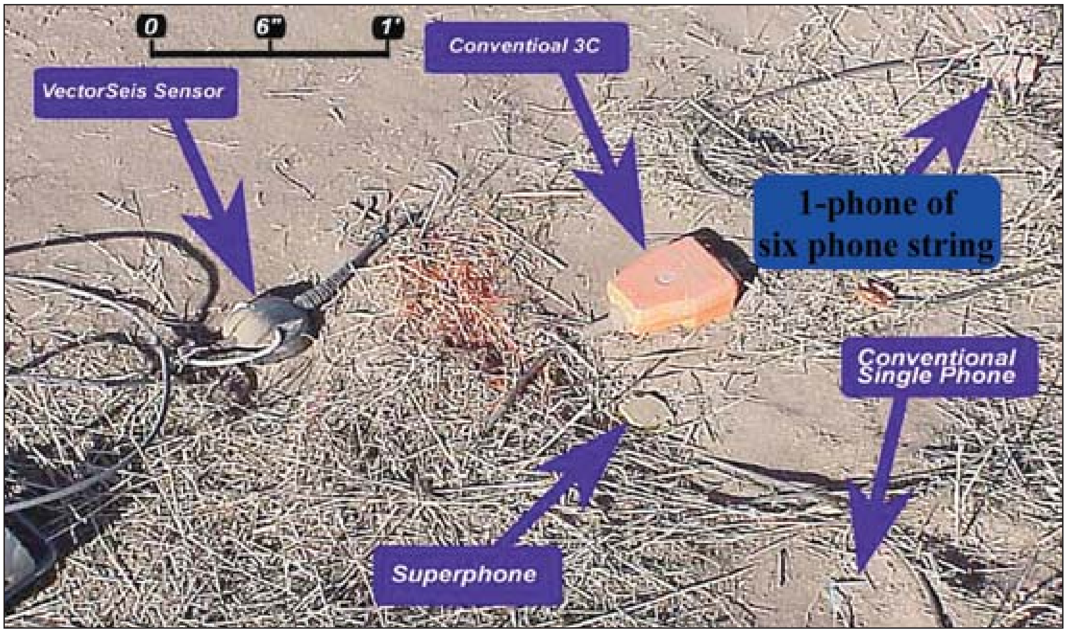
The last few decades have seen major improvements in geophone technology, with digital recording now replacing older analogue technologies. Modern electronics have reduced the size of these devices, Anderson said. The devices are now more robust and reliable than they used to be — whereas a survey crew used to deploy at least a dozen geophones at each recording location to ensure the capture of usable data, crews have reduced that number now almost down to one per station, Anderson said.

Geophones are strung out across the ground along cable runs, rather like a huge string of Christmas tree lights — the logistics of transporting cable and managing the cable runs forms a significant component of carrying out a seismic survey on land. But a new generation of wireless geophones has just come on the market. These use lithium batteries, have built in GPS receivers and contain miniature recorders with 10 gigabyte flash drives, Faust said.

The wireless geophones offer the enticing prospect of being able to simply drop geophones in position on the tundra, without the need for vehicles to transport and lay cabling. However, there are problems with battery life in the low temperatures of the Arctic winter, Faust said. And finding the devices in the snow of a North Slope winter seismic survey season might present some interesting challenges.

A fairly recent development that has seen some use on the North Slope is a type of geophone that can simultaneously record sound vibra-

see **SEISMIC** *page 22*



COURTESY CONOCOPHILLIPS ALASKA INC.

A variety of types of geophone that are laid on the ground to record seismic signals. Over the years geophones have reduced in size and increased in reliability.

continued from page 21

SEISMIC

tions in three different directions, rather than just the single sound pressure variations recorded by a traditional device, Faust said. The three-component geophones enable geophysicists to distinguish between pressure waves and shear waves in the seismic signals. That distinction enables data processing that provides invaluable insights into the physical properties of the subsurface rocks.

The use of state-of-the-art, high-resolution 3-D seismic surveying for oilfield development has introduced a new problem for seismic surveyors: how to deal with ambient industrial noise that can obscure the seismic signals detected by the geophones, Jon Konkler, senior development geophysicist for BP Exploration (Alaska), told Petroleum News.

The seismic industry has developed technologies for determining the noise at an oilfield location and extracting that noise from the seismic recordings.

"We can't stop the noise in the field, but as long as we know when it is and where it is and can pinpoint where it's coming from that helps a lot in processing that noise," Konkler said.

Computer technology

Alongside improved field acquisition technology, modern computer and communications technology probably represents the biggest single enabling factor in the huge strides that the seismic industry has made in the past few decades.

PGS ONSHORE

A set of PGS Onshore rubber tracked vibrators operating in the Brooks Range Foothills of the North Slope.

The ability to record and process the vast amount of data originating from many thousands of geophones responding to multiple pulses from a vibroseis unit or underwater airgun array has opened the door to ever increasing data resolution from a decreased environmental footprint. And state-of-the-art computer technology has revolutionized seismic processing, visualization and interpretation (see "Computer technology has revolutionized seismic" in this publication).

"Computer power has enabled a lot of advances in all technologies, and seismic is one of the benefactors," Konkler said.

And those advances in computer processing have led to a vastly improved ability to locate and pinpoint oil and gas reservoir, leading to improved drilling success rates and the ability to locate the more elusive pools of subsurface oil and gas.

But the demands for interactive viewing of seismic and other data are driving a need for ever-more-powerful computer networks, to shunt massive quantities of data between server computers and computer workstations. Nowadays, rather than wanting to move one or two gigabytes of data around the network, you might want to move several hundred gigabytes, or maybe even a terabyte, all at once, Konkler said.

"And you want it right now," Konkler said. "You don't want to have to sit there and wait for an hour for it to load up on your machine and then find out that your machine can't hold all that data."

The rapid evolution of computer technology has also led to some interesting issues relating to the use of old seismic data, perhaps acquired several decades ago. That old seismic can represent a high-dollar exploration investment and can often prove invaluable when reassessing a region for new exploration. And modern processing can often extract more information from the data than was apparent to the geoscientists who originally interpreted the data.

But the old data was typically stored on reels of magnetic tape using a variety of recording formats, several of which have become obsolete. So, a whole industry has evolved around services that enable the retrieval of data from old tapes. And ConocoPhillips, for example, transfers its old data onto modern media about every five years, rather than risk losing valuable data that could have a future use, Faust said.◆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JUDY PATRICK

A North Slope drilling rig (Nabors 2-ES rig). The rig is enclosed, apart from the upper part of the derrick, to protect the crew from the Arctic weather. The beige, box-shaped structures in the foreground house wellheads.

Extending the drilling envelope

Evolving technologies enable extraction of more and more oil from Alaska's North Slope

By ALAN BAILEY

In these days of high-speed computers, modern home comforts and rapid transportation, many people are probably unaware of something that's critical to maintaining their standard of life: high-tech oil and gas drilling technology. Without space-age drilling techniques we'd likely be short many billions of barrels of oil production from increasingly challenging oil accumulations. And oil provinces such as Alaska would languish in a world of hurt, as remaining recoverable reserves dwindle to uneconomic levels.

Rotary drilling

In its simplest form, rotary drilling involves turning a drill string in a well bore, with a drill bit at the bottom of the string grinding its way through the rock. That technique, dating back many decades, results in near-vertical wells.

But what if you want to deviate the well sideways, to penetrate an oil pool that is offset from the drilling pad or platform?

Back in the 1960s and 1970s wells could be deviated somewhat from the vertical, perhaps up to about 30 degrees, Randy Thomas, Greater Kuparuk Area drilling team lead for ConocoPhillips told Petroleum News. Early deviation techniques involved the placement of a steel wedge in the hole (called a whipstock) to deflect the bit to one side of the hole, and the fitting of a stabilizer on the drill string in the well bore — the stabilizer would act as a fulcrum to tilt the string as the well deviated, Gary Christman, director, Alaska drilling and wells, for BP Exploration (Alaska), told Petroleum News.

The first major innovation in this technique involved pulling the drill string from the well and fitting a motor at the bottom of the string to turn the drill bit. The motor was set to a small angle or "bend" that caused an accurate directional change. Drilling mud, a heavy fluid that is pumped through the well during drilling to maintain well pressure and remove rock cuttings, drove the motor.

The next step in technical development came when people worked out how to avoid having to pull the drill string from the well when changing direction.

"The step change then was the directional assembly that gave you the bend that you needed to point in the right direction with your surveys, but that assembly was able to rotate and drill ahead so you didn't have to trip it out," said Jerome Eggemeyer, ConocoPhillips engineering team lead.

With this type of assembly a change in direction was achieved by stopping the rotation of the drill string, rotating the

JUDY PATRICK

The Nordic-Calista No. 2 rig is a coiled tubing rig that specializes in drilling coiled tubing sidetracks. The blue box-shaped structure at the back of the rig contains a large spool of coiled tubing. The tubing passes from the spool to a slot in the side of the derrick housing, from where it is guided down into the well.

motor to the desired direction and then pushing the string forward without rotation while the motor-driven bit augured its way to the new direction. After completion of the change in direction, the drillers could resume the rotation of the drill string when drilling continued. But friction between the non-rotating drill stem and the sides of the well during this procedure imposed significant limitations on well lengths.

"When you try to get out to these extended reach limits you no longer have enough push to be able to slide it against that friction," said Terry Lucht, ConocoPhillips manager, drilling and wells.

A major breakthrough came in the mid-1990s, with what drillers call "rotary steerable technology." Using intelligence within the downhole drilling tool the drillers could steer the drilling direction of the bit while the drill string continued to rotate.

These evolving drilling techniques gave rise to progressively larger amounts of well deviation over the years, with the ratio of bottom hole displacement to well vertical depth increasing from around one to one in the 1960s and 1970s to three to one in the early 2000s. Nowadays drillers have perfected the techniques to the point where five-to-one ratios are being achieved, with six-to-one ratios a possibility in the near future, Thomas said.

At the same time, drillers perfected techniques for drilling wells horizontally through the rock strata.

The viable drilling of horizontal oil wells originated in France in the early 1980s. The technique reached Alaska's North Slope in 1985 with the drilling of BP's experimental JX2 well (the company had previously proved the horizontal drilling techniques in the Braun Weiding well in Texas), Christman said.

These early horizontals only extended a few hundred feet, but subsequent refinement of the technique has greatly extended well lengths. Nowadays horizontal distances of up to 10,000 feet have been achieved in the Alpine field on the North Slope, for example.

Top drives

The introduction of the top drive in the 1980s also proved to be a breakthrough in drilling technology.

In a traditional drilling rig a device called a Kelly bushing on the rig floor grips and rotates the drill pipe. Individual 30-foot lengths of drill pipe are attached to the top of the drill string as the string moves downward into the ground.

"You would pick up single joints of pipe, drill down 30 feet and make a connection," Thomas said.

A top drive consists of an explosion-proof electric motor suspended near the top of the drilling derrick. Drill pipe is attached to the drive in 90-foot stands, with each stand consisting of three connected 30-foot sections. As the drive turns the piping, auguring the drill string into the ground, the drive is lowered downwards. A driller controls the drive from a console, Lucht said.

The ability of a top drive to handle mul-

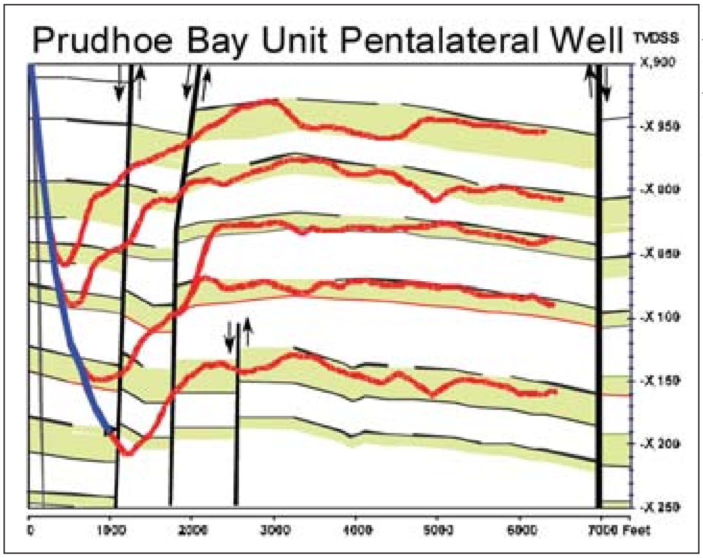
see **ENVELOPE** *page 26*

continued from page 25

ENVELOPE

tiple lengths of drill pipe greatly increases drilling speeds. And, unlike a Kelly bushing, the top drive can rotate the drill string when pulling the string from the well, thus adding flexibility and control to drilling operations.

Top drives underpin advanced drilling techniques such as rotary steerable drilling, Christman said. In fact, the top drive first appeared in Alaska as an enabling technology for horizontal drilling, he said.



Horizontal multilateral wells greatly improve well production rates and make the development of viscous oil possible.

BP EXPLORATION (ALASKA) INC.

Coiled tubing

The use of coiled steel tubing, 2 inches or two-and-three-eighths inches in diameter and reeled off drums in continuous lengths, has also revolutionized horizontal drilling. Coiled tubing drilling techniques, particularly directionally drilled sidetracks with coil, were pioneered in Alaska in the 1990s, Christman said.

Conventional drilling involves the use of 30-foot lengths of larger diameter steel drill pipe that need to be assembled when drilling and disassembled when pulling the drill string from the hole. Coiled tubing, on the other hand, feeds continuously into the well when drilling is in progress and can be rapidly pulled from the well when necessary.

"When you pull out of a hole to change the bottom hole assembly … you just basically reel it up,"Thomas said.

Using a drill bit powered by a mud motor, coiled tubing can worm its way out the side of an existing well bore and thread its way through a thin reservoir sand, for example. In addition to enabling access to sand bodies that were bypassed by the original well, coiled tubing enables re-use of old wells during field development.

"Instead of having to drill a completely new well from the surface you can enter an old well and drill a lateral off of that," Lucht said.

A coiled tubing sidetrack might cost just 20 to 25 percent of the cost of a complete new well, Christman said.

Although coiled tubing drilling is cheaper and more convenient than conventional drilling, it is also more limited in what it can do — the record distance for horizontal coiled tubing drilling is only about one-third of the record for rotary directional drilling, Thomas said.

Viscous oil and multilaterals

The production of viscous oil from huge deposits of this material at relatively shallow depths in the central North Slope has necessitated the use of multilateral, horizontal wells, in which up to five horizontal well bores extend sideways from one central, vertical bore that connects to the surface.

In the West Sak field, for example, viscous oil in a pay zone 75 to 100 feet thick would not produce in viable quantities into a traditional near-vertical well. But horizontal well bores have now exposed as much as 20,000 feet of pay in one well, thus making economic production feasible from an oil pool discovered many years ago, Eggemeyer said.

"By exposing that much reservoir rock you're able to open the door on this whole new development of West Sak oil," Eggemeyer said. "It's strictly a technology discovery."

And the multilateral technology further increases that horizontal well productivity — the technology enables each branch of the multilateral to be individually isolated, Christman explained.

"The drilling techniques are very conventional," Christman said. "The key in these is the junction technology — how we set these wells up so that we actually have a hydraulic seal at that junction."

Measuring and logging

Traditionally, drillers and well logging companies surveyed and logged wells by lowering wireline tools down well bores. But the use of wireline tools required the pulling of the drill string from the well, thus delaying the drilling operations. Additionally, the drilling of increasingly deviated wells rendered the lowering of wireline tools increasingly difficult.

"It's like trying to slide down a flat hill,"Thomas said.

A major technical breakthrough came in the early 1980s with the use of "measurement while drilling," in which pressure pulses transmit data through the drilling mud, thus enabling continuous monitoring of well measurements while the drilling is in progress. This technology evolved in the late 1980s into "logging while drilling," in which well log data could be transmitted to the surface using the same technique.

And the "Morse code through the mud" technology reached its logical conclusion with the ability to send signals down the well to control the tools at the bottom of the well and steer the drill bit.

"The tools are now interactive,"Thomas said. "You can send a signal down and tell them what to do and they'll do it."

The combination of interactive downhole tools and high-tech rotary steerable drilling has enabled the development of extended reach drilling in which the horizontal departure of the well can amount to 25,000 feet or more.

Precision surveying

Surveying the underground trajectory of a well involves measuring how the orientation of the well bore changes along the length of the well bore. Computer software translates these underground survey measurements into a plotted well path.

In general, well orientation measurements are made using a kind of three-dimensional magnetic compass. Measurements near the surface, where a large number of closely packed steel well casings may distort the Earth's magnetic field, may also require the use of a gyroscope.

But the proximity of the Earth's magnetic north pole to northern Alaska poses particular problems when doing magnetic surveys in North Slope wells: The magnetic pole moves continuously.

"When you're as close to the (magnetic) North Pole as we are, if the North Pole moves a little bit, it changes our survey a lot," Eggemeyer said.

To deal with this problem, stations isolated from the drilling operations continuously monitor the Earth's magnetic field and provide calibration data to correct the magnetic survey readings.

And the end result?

Stunning accuracy, with drillers able to penetrate a target a few tens of feet across several miles from the drilling rig (well logging techniques also enable a well to remain within a sand body just a few feet thick).

Seismic, computer technology

State-of-the-art seismic surveys now provide many of the drilling targets. Nowadays 3-D seismic surveys, involving the deployment of arrays of huge numbers of seismic receivers, routinely produce high-resolution sound reflection images of oil fields — it's a bit like taking an X-ray photo of an oil field using sound vibrations transmitted from the surface.

A 4-D seismic survey involves repeating the same survey at regular time intervals and then comparing the results. A difference in a seismic reflection between two successive surveys might, for example, pinpoint a pocket of oil that has eluded production. That pocket of oil might then become the target for a coiled tubing sidetrack well, Lucht said.

And computer systems support all of the drilling activities by modeling the friction in the hole, the torque on the drill string and by monitoring the progress of the drilling operation. Nowadays, drilling engineers use computer systems to plan a well before the drilling starts. Engineers on the drilling rigs then continuously refine the plan, using data obtained from the drilling operation.

"At the planning stage we'll model the well, but as we're drilling we'll collect data every day and plug it back into the model, update the model and project ahead, so we can make adjustments as we go," Thomas said. "So, we keep fulltime drilling engineers on the rigs today, just to keep up with that modeling."

A thorough understanding of the location and physical characteristics of the subsurface rocks is especially critical to success in horizontal drilling, Christman said.

Combined impact

The combined impact of all of these technologies — steerable drill assemblies, top drives, coiled tubing, mud data transmission, magnetic monitoring and so on — has resulted in dramatic productivity benefits. Precision wells, including horizontal wells, are enabling drillers to thread the drill strings through elusive pockets of oil, thus greatly increasing the volume of oil recoverable from oil fields.

Improved drill bits reduce the frequency with which drill strings have to be pulled from a well during drilling, while advances in the design of drilling mud have greatly improved the stability of the well bores — that stability is critical to the drilling of long wells, Christman said.

And, combined with enhanced oil recovery techniques, all these new drilling techniques translate to more oil. The original estimate of recoverable oil from the Prudhoe Bay field was 9 billion barrels. So far the field has delivered 11.5 billion barrels and the current estimate for ultimate recovery is 13 billion barrels, BP spokesman Daren Beaudo told Petroleum News.

But Eggemeyer credits the various service companies involved in the drilling industry for much of the continuing success in expanding the drilling envelope.

"We've got a lot of service companies that are just pushing everything they can to get to the next step on technology," Eggemeyer said. "It's certainly an industry effort." ◆

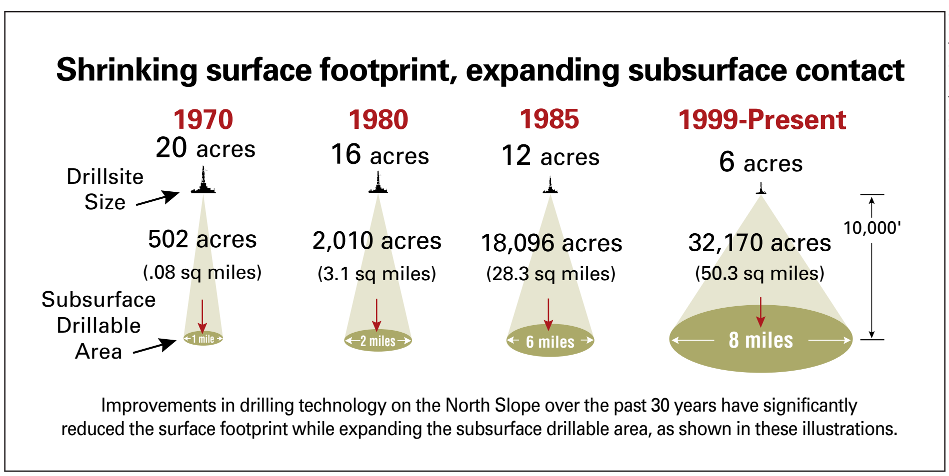
JUDY PATRICK

The cantilevered drilling platform on a rig such as the Nordic-Calista No. 2 rig, shown here, minimizes the spacing necessary between the wellheads on a well pad.

Reducing development footprint

Directional drilling, technical innovations dramatically reduce environmental impact

By ALAN BAILEY



BP EXPLORATION (ALASKA) INC.

Improved drilling and drilling rig technologies have dramatically reduced the required surface footprint for North Slope drilling.

For anyone wanting to see a case-book example of how environmental protection can make perfect business sense, Alaska's North Slope oil industry makes a pretty good place to look. Technical innovations such as highly deviated directional drilling and high-resolution seismic data acquisition have not only improved business efficiency, they have also limited the environmental impact of a massive industrial operation in a sensitive Arctic setting.

Back in the 1970s, the huge Prudhoe Bay field was designed as a series of gravel pads, from which wells spread out like deep tree roots tapping the oil reservoir thousands of feet below the surface of the tundra. But the drill rigs in use at the time required relatively widely spaced surface wellheads in large well pads. Drilling waste was dumped into manmade ponds called reserve pits at the sides of the pads. And limitations on the amount of deviation from the vertical that a well could drill drove the need for a relatively large number of pads.

In the early days, when an Arctic oil industry hadn't yet developed, people drilled just like they did in the Lower 48, Jerome Eggemeyer, engineering team lead for ConocoPhillips, told Petroleum News.

"They brought those rigs up here and dug big reserve pits and made holes in the ground the old way," Eggemeyer said.

But a drive for efficiency and the need to access ever more elusive pieces of the oil reservoirs led to fundamental changes in the whole approach to drilling on the

North Slope.

"When you look at the original development plan and what folks thought was going to happen, it changed pretty dramatically and that change was facilitated in a large way by drilling advances and the applications … that enabled us to become more efficient and increase the recoverability rates," Gary Christman, director of Alaska drilling and wells for BP Exploration (Alaska), said.

Increased well deviations

The invention of mud motors to drive drill bits around bends in well bores and the later development of rotary steerable technology enabled ever increasing amounts of well deviation — the bottom hole horizontal displacement from the well head maxed out at a distance of about the depth of the well in the 1960s, Eggemeyer said. But the ratio of the bottom hole displacement to the well depth then increased steadily to reach five to one or more today. And the introduction of horizontal drilling in the 1980s enabled wells to undulate their way through underground reservoir rock at horizontal distances of many thousands of feet from a surface well head.

At the same time more compact drill rig designs with cantilevered drilling platforms enabled well heads to be packed more closely together on a drilling pad, thus reducing the area of gravel pad needed to be able to drill a given number of wells.

"The evolution of the rig design helped us decrease the pad size … but it also increased the efficiency of the rig moves to where you can get more wells drilled in a year," Randy Thomas, Greater Kuparuk Area drilling team lead, told Petroleum News.

Coiled tubing drilling techniques such as directionally drilled sidetracks were pioneered on the North Slope and involved the use of a mud-motor powered drill bit and continuous small diameter tubing, rather than a conventional rotating drill string assembled from multiple lengths of rigid drill pipe. The coiled tubing technique enables drillers to punch a sidetrack well into new segments of an oil reservoir from the bore of an existing well.

That dramatically reduces drilling costs. But it also reduces the need for new surface wellheads and the associated need for an additional area of well pad.

Reduced footprint

All of these drilling developments have together led to a progressive increase in the subsurface rock area that drillers can access from a single well pad, while at the same time reducing the required well pad area. According to BP a 20-acre well pad in 1970 could access about 502 acres of reservoir at a depth of 10,000 feet; nowadays a pad of just six acres can access about 32,000 acres of reservoir at the same depth.

The Alpine and Badami fields demonstrate this phenomenon, with wells accessing complete oil reservoirs from minimal-sized pads — just two pads in the case of Alpine and one at Badami.

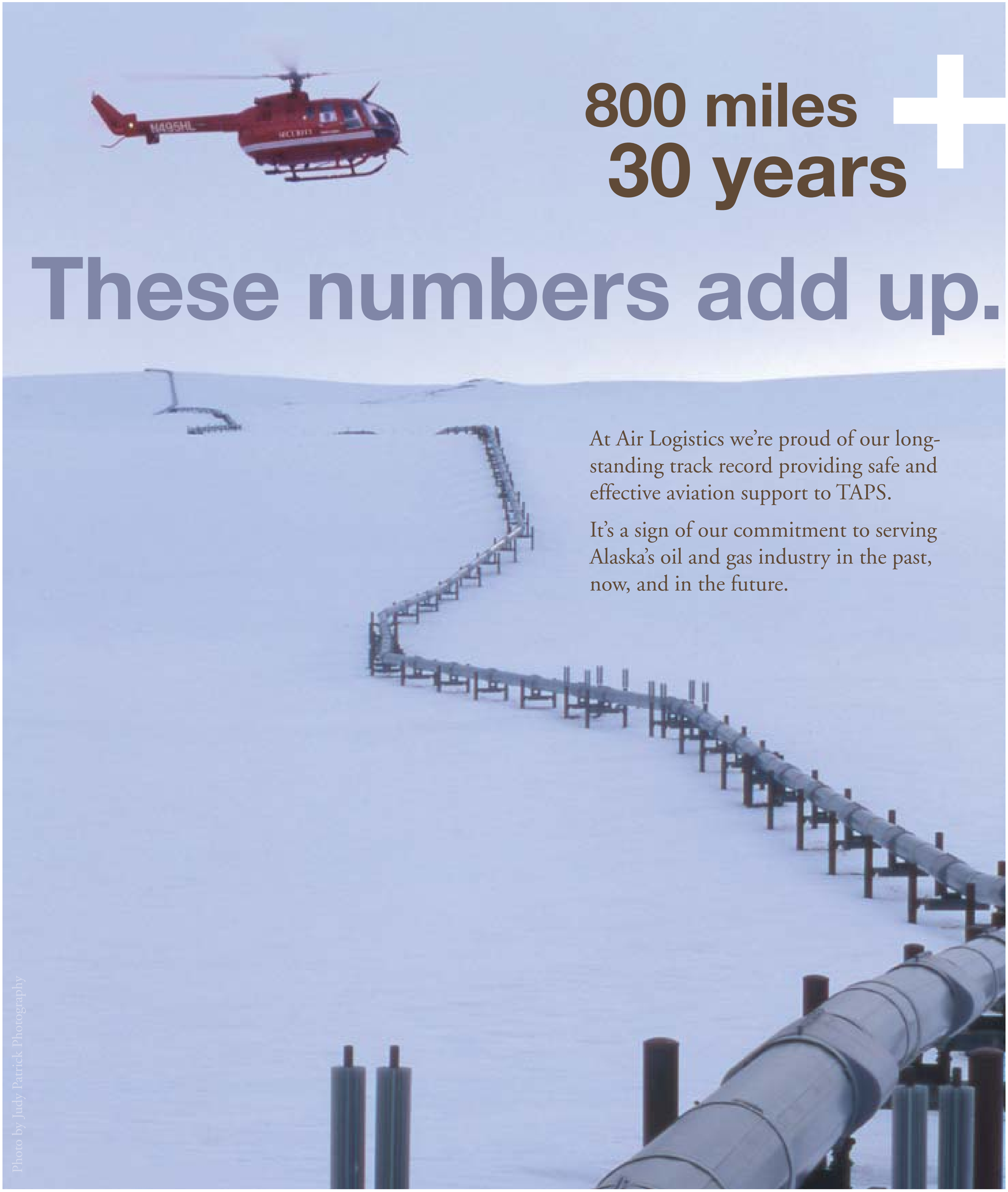
Another North Slope-invented technique in which well cuttings are ground down and injected into a dedicated waste disposal well has eliminated the need for reserve pits, Christman said. That has further reduced the surface impact of drilling operations.

And drill rigs in the North Slope fields now use electrical power from the North Slope electrical grid, rather than using their own diesel power. That has significantly reduced diesel exhaust emissions on the slope.

"The North Slope is almost exclusively high line power," Eggemeyer said.

Ultra extended reach drilling, with horizontal displacements in excess of perhaps

see **FOOTPRINT** *page 31*


800 miles
30 years
These numbers add up.
At Air Logistics we're proud of our long-standing track record providing safe and effective aviation support to TAPS.
It's a sign of our commitment to serving Alaska's oil and gas industry in the past, now, and in the future.
Photo by Judy Patrick Photography

continued from page 29

FOOTPRINT

40,000 feet, is taking the whole concept of directional drilling to a new paradigm. BP has pioneered the technique at its Wytch Farm oil field on the south coast of England and now plans to use the technique to develop the Liberty oil field in the Beaufort Sea.

The use of ultra extended-reach drilling at Liberty will enable field development and production without the need to construct an offshore gravel island, Christman said. Instead, BP plans to make a relatively small extension to an existing gravel island at the Endicott field for the Liberty development.

Exploration drilling

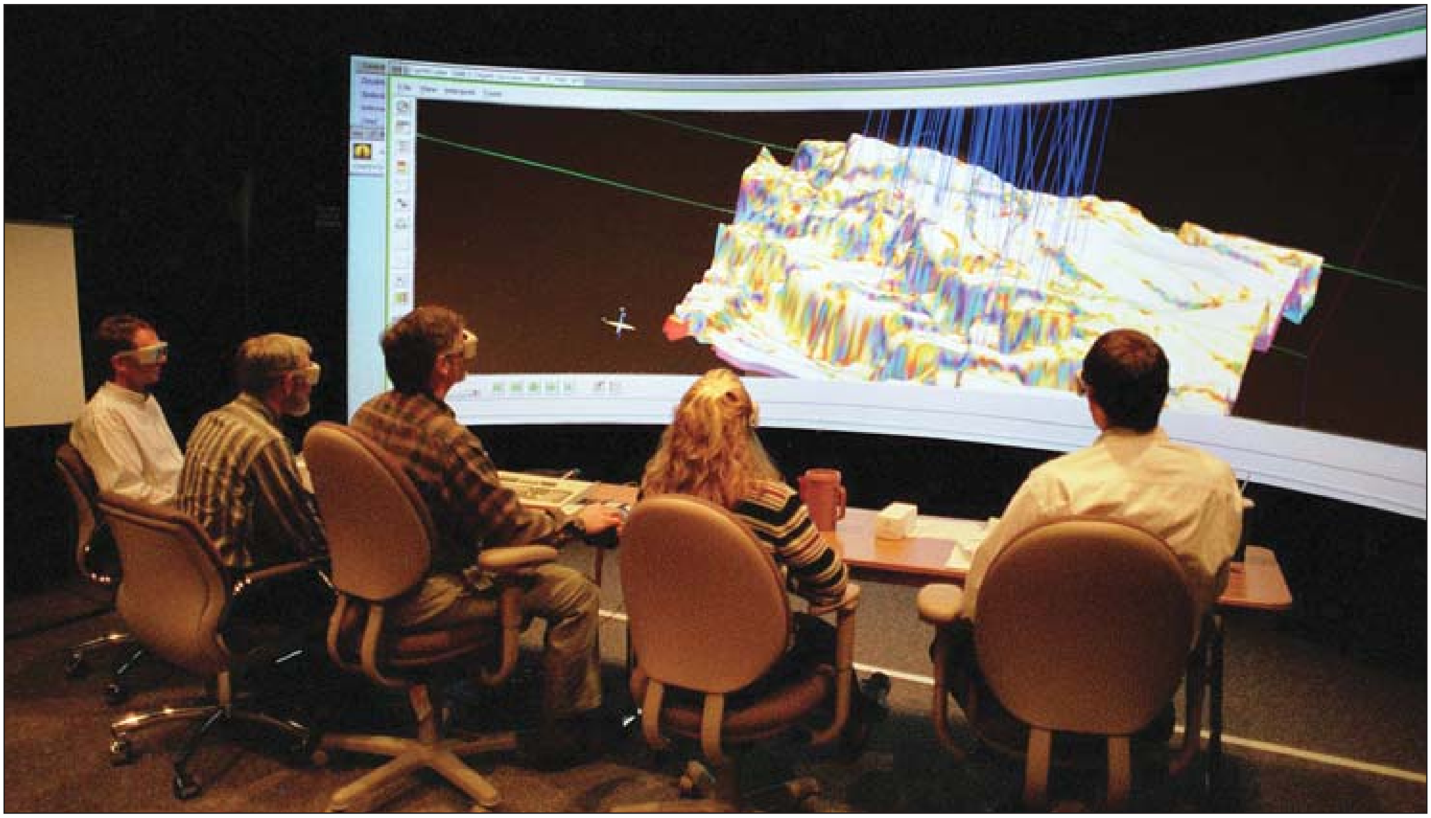
When it comes to exploration, the past 30 years have seen a progression to drilling techniques that involve virtually no environmental impact. Nowadays a lone wellhead in the midst of pristine tundra will likely be the only visible remnant of a suspended or abandoned exploration well. No one now uses gravel pads for drilling in untouched tundra — an ice pad that melts in the summer, leaving no trace, provides the platform for an exploration drilling rig. And an ice road that also completely disappears during the summer typically provides access to an exploration drilling site.

In addition, state-of-the-art 3-D seismic survey techniques have revolutionized the search for oil and gas prospects and reduced the risk of drilling a dry exploration well. That reduced risk translates to the need for fewer exploration wells, Michael Faust, offshore exploration manager for ConocoPhillips Alaska, told Petroleum News.

Improved safety

The period since the 1970s has also seen a greatly increased emphasis on safety during drilling operations, Eggemeyer said. Drilling equipment has become safer and the rigs now have safer and more comfortable working spaces than in earlier days on the slope, he said.

"Safety and environmental is a priority at the rig site," Terry Lucht, manager, drilling and wells, for ConocoPhillips Alaska, said. "We model our drilling operations around how to do it safely and be environmentally friendly, and still accomplish what we want to do. … As an industry we've made huge strides, I think." ◆



ALAN BAILEY

A geoscience team in BP's Anchorage HIVE facility using special eye glasses to view subsurface data in three dimensions.

Computer tech revolutionizes seismic

Better data resolution, high-tech processing create collaborative approach to subsurface

By ALAN BAILEY

Wind back 30 years in the seismic industry, and you'd probably have seen an expert geophysicist huddled with a bunch of colored pencils over a long sheet of paper covered with the squiggly plots of seismic traces. The interpreter would mark up his or her ideas on how those squiggles represented underground geologic structures, before handing off the interpreted plot to, say, a geologist as an authoritative assessment of what lay under the ground.

Those days are long gone. A quantum leap in the amount of detailed information that geoscientists and others have been able to glean from the seismic data has revolutionized seismic interpretation.

"The days of having a seismic interpreter sit at his workstation in a cubicle and just basically do his interpretation and hand it off to someone — that type of thing just isn't done any more because you really need to be working in an integrated fashion with everyone," Tom Walsh, principal partner and manager of Petrotechnical Resources of Alaska, told Petroleum News.

The seismic process

A seismic survey involves sending sound waves from a surface vibrator or, offshore, from an array of air guns into the subsurface rocks. The sound waves bounce off the boundaries between different types of rock strata and devices called geophones on the surface detect the resulting echoes.

The echoes appear as peaks in plots of the sound signals received at a geophone. And by laying side by side the plots from an array of geophones, it is possible to use those echo "peaks" to pick out the images of subsurface rock structures.

To minimize unwanted noise that can obliterate the echoes, surveyors shoot multiple recordings for the same survey point, using sound sources and geophones located over a range of different offsets from that point. Adding together the results of the multiple recordings has the effect of canceling out random noise while enhancing the coherent signals from the echoes.

The signals from the geophones are computer processed and plotted.

Massive data volumes

The vast amount of data from a seismic survey used to place severe limitations on how many recordings, or channels, could be made from a single sound source shot. But rapidly evolving computer and recording technology over the past few decades has enabled an exponential increase in the number of channels that a seismic survey can gather — data are now recorded on small computer disk drives, rather than on roomfuls of magnetic tape reels, while modern high-power computers can organize and process the data very rapidly.

In 1977 you might have had 200 channels if you were lucky but nowadays a survey typically involves around 10,000 channels, Jon Anderson, chief geophysicist, exploration and land for ConocoPhillips Alaska, told Petroleum News.

The vast increase in the number of channels has enabled the distances between geophones to be reduced and the resolution of the images of the subsurface to be greatly increased — the effect is a bit like increasing the pixel density in a digital camera.

That improved resolution has resulted, for example, in an ability to resolve small geologic faults that can cause significant disruption to the reservoirs of oil fields — knowing the fault locations assists with precision well planning and improved reservoir modeling.

"That's been a great success story for North Slope fields which are fairly well shattered by faults," Walsh said.

2-D, 3-D, 4-D

The increase in the number of seismic channels recorded during a survey has also helped in the development of a technique known as 3-D surveying.

In a traditional survey, known as a 2-D survey, seismic signals are triggered and the corresponding geophone recordings made along a single line. The data collected then results in a two dimensional image of the subsurface below the line of the survey. Multiple 2-D surveys along lines in different directions across a region then give a picture of the subsurface geology.

In a 3-D survey, the seismic sound sources and geophones are placed in a surface grid, rather than along a line. The resulting data enables a three-dimensional image of the subsurface to be produced.

It's a bit like the difference between a CAT scan and a regular X-ray, Michael Faust, offshore exploration manager for ConocoPhillips Alaska, told Petroleum News.

"Now you can see a three-dimensional image and you can rotate it around and slice through it in any direction and really see what's going on," Faust said.

Jon Konkler, senior development geophysicist for BP Exploration (Alaska), said that the use of 3-D seismic started as a technique to assist with oilfield development, rather than for oil and gas exploration.

The pioneering use of 3-D seismic on Alaska's North Slope dated back to 1978, when a 3-D survey was first used to image the Prudhoe Bay gas cap, Konkler said. Since that time 3-D seismic has been shot at least once in every field on the slope and in some fields there have been three or four surveys of this type.

And, as in other types of seismic survey, the spatial resolution has continuously improved over time, as geophone spacings have shrunk.

Early 3-D surveys proved beneficial in mapping geologic structures but only had a horizontal resolution of perhaps 400 to 500 feet. A 3-D survey in a field such as Prudhoe Bay now typically involves thousands of geophones, resulting in a resolution as small as 55 by 55 feet, Konkler said.

"In doing that we found that we were able to pinpoint our faults a lot better, understand what faults might be there … and which ones aren't," Konkler said.

And with well spacings becoming ever shorter in a mature field such as Prudhoe Bay, 3-D seismic data have become critical in determining where the remaining oil is located.

"We want to make sure that we drill the most economic target that we can find," Konkler said.

The most recent stage of evolution in seismic technology involves what is termed 4-D surveying, in which a 3-D survey is conducted periodically in the same oil field. By finding subtle differences between the data from one survey to the next, interpreters can try to glean information about the movement of oil, gas and water through a field reservoir.

The frequency with which 3-D surveys are done to form a 4-D survey depends on the speed of migration of fluids through

see **SEISMIC EVOLUTION** *page 34*

continued from page 33

SEISMIC EVOLUTION

the reservoir — in a mature field such as Prudhoe Bay a 3-D survey might be carried out every three to five years, but surveys might be done more frequently in a newer field, Konkler said.

But 4-D surveying is very much in its infancy as a technique that could make a major impact on oilfield development.

"The North Slope is one of those places where we've started investigating, does it work?" Konkler said. "We've got a couple of places where we've overlain successive surveys and we're in the process of evaluating can we see the fluid movements and, if we can … how do we use that."

Improved processing

As well as enabling the collection of vast amounts of data, modern computer technology has opened the door to a whole new world of seismic data processing and display.

People can now evaluate workstation displays of many different attributes of the data, including the sound wave amplitudes, signal coherence, signal frequency and signal phase, Anderson said. And the raw sound data from the seismic survey can be converted into inferred rock properties such as the rock density or the sound velocity in the rock — interpreters can then link those rock properties back to similar properties that are measured in wells in the area of a survey, Walsh said.

Those linkages to well data, combined with sophisticated computer processing and display, now enable interpreters to use seismic data to determine much more about the subsurface geology than just the basic structure of the rock strata.

Computer displays can overlay different types of seismic data, well data and petroleum engineering data in composite plots that enable new insights into the data. And data depicted in three dimensions can be rotated and tilted, so that people can assess whether faults and other geologic interpretations appear to make sense, Konkler said.

And this ability to simultaneously view several different types of data has driven the need for teams of different specialists to work collaboratively on seismic interpretations.

"Four-D doesn't just stand for the fourth dimension in time; it stands for the — at least — four disciplines in takes to interpret that data," Konkler said. "You need a team of different disciplines to do 4-D interpretation, because you have to have a geophysicist to understand what's making the signal change; and you have to have your reservoir engineer and your petroleum engineer, and your driller sometimes, and your geologist, to talk about the geology, the production history, etc."

And as data interpretation becomes more multi-disciplinary, experts within each discipline tend to need some level of understanding of the other disciplines.

"As geophysicists we have to learn a lot of things outside of geophysics," Konkler said. "We have to learn about reservoir engineering. We always have to understand and be able to know geologically that our interpretation makes sense. We have to understand petrophysics to understand what the (well) logs are telling us, versus what we think is in the reservoir."

A team of specialists now often uses a purpose-built room to meet and discuss how to interpret data. Simultaneous or overlaid computer displays of seismic, well and geologic data, coupled with interactive interpretation software, facilitate the discussions and enable the interpretations to be captured as the discussions progress.

BP uses rooms that it calls "collaborative visualization environments," or COVEs. Communication links between

COVEs at different BP sites, such as Anchorage and Houston, enable specialists across different sites to assess the same data collaboratively, Konkler said.

BP also has a facility known as the "highly interactive visualization environment," or HIVE, in which a team can view and manipulate large three-dimensional images of subsurface data.

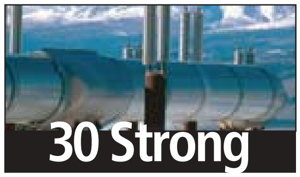
Exploration

Traditional 2-D seismic surveying 30 years ago was the primary exploration technique, used to find large underground structures that might trap oil and gas.

"We used to just look for big trapping structures, big major features that were easy to see on half-a-dozen seismic lines," Faust said.

But success with 3-D seismic in oilfield development led to the subsequent use of 3-D techniques in exploration. And the use of high-resolution 3-D seismic exploration has really come into its own on the North Slope, where many of the major structures have been drilled and companies now tend to focus on the search for small stratigraphic traps.

"Alpine is a great example of very significant leveraging



What if we could flush more oil out of a reservoir by reducing the salt content of seawater? We may soon be able to, thanks to ***low salinity enhanced oil recovery*** *experiments under way at the Endicott oil field.* *To learn more, see page 80.*

using seismic data," Walsh said. "That whole NPR-A area is now something that people are using very sophisticated tools to do their interpretations. … We're not just looking for bumps any more. We are looking for those stratigraphic traps. And to find those you have to use these more sophisticated tools."

Walsh also cited the Tarn field as an example of a situation where high-resolution 3-D surveying proved critical to exploration success — after drilling several unsuccessful wells, ConocoPhillips used 3-D seismic to find the Tarn reservoir, Walsh said.

"The 3-D seismic of Tarn is fascinating in what it tells you about the architecture of that reservoir," Walsh said. "It really dramatically shows exactly where the reservoir channels are and where the high-quality reservoir is."

Still use 2-D

Not that 2-D seismic has disappeared from exploration programs. The use of 2-D seismic is much cheaper than 3-D seismic when it comes to surveying large areas of territory. So, companies tend to shoot 2-D seismic survey over relatively wide areas, and then use 3-D seismic to home in on specific prospects, Faust said.

But the ability of high-resolution, 3-D techniques, coupled with modern visualization techniques, to pinpoint drilling targets really has opened up a world of exploration that was not available 30 years ago. In fact the use of 3-D seismic has significantly improved the success rate for exploration wells. The average exploration well success rate 20 years ago was 10 percent, Faust said.

"With the advent of 3-D data that jumped to almost 50 percent," Faust said. "So suddenly you were drilling far fewer wells to find the same amount of oil."

"Obviously we're very dependent on 3-D seismic on the slope," Walsh said. "Pretty much everything that is prospective is now shot with 3-D seismic data." ◆

Can seismic detect oil and gas?

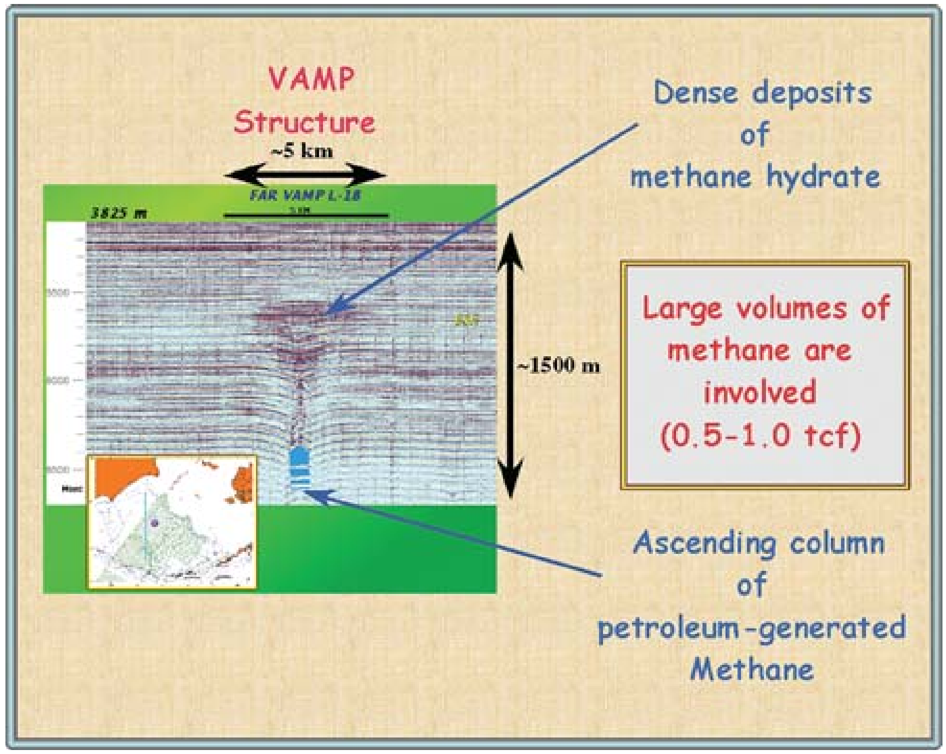
Direct hydrocarbon identification has progressed; still possible to drill a duster

By ALAN BAILEY

Drilling a wildcat exploration well has always been a risky proposition. And even drilling a well within a known oil field involves some level of uncertainty about what is under the ground. But advances in seismic surveying and data processing over the past few decades have refined the identification of what geophysicists call "direct hydrocarbon indicators" to a point where that drilling risk may at least be reduced, given an appropriate geologic situation.

In a seismic survey, sound waves from a sound source partially reflect off boundaries between different underground strata, to form echoes that are detected at the surface by receivers called geophones. Those echoes provide information about the subsurface geology, including the locations of potential oil and gas traps.

But it's long been known that oil and gas occupying rock pores in an oilfield reservoir affect the physical properties of the rock in a way that could alter those sound echoes and thus provide direct evidence of subsurface oil and gas pools.



DAVID SCHOLL

Detects gas

In particular, a quite modest amount of natural gas inside a rock will significantly reduce the velocity of sound passing through the rock. That velocity reduction can increase the acoustic contrast between the gas-bearing rock and the adjacent rock formations. And the increased contrast can in turn cause an abnormally high amplitude seismic reflection, giving rise to what geophysicists refer to as a "bright spot" in a seismic section.

The relatively low velocity of sound through the gas-bearing rock also causes strata underneath that rock to appear deeper underground than they actually are. That effect results in an apparent down-warping of the lower strata in a seismic section, something that geophysicists call "push-down."

For example, a near-vertical column of pushed down seismic reflections often indicates the presence of a gas chimney, a vertical zone in which natural gas bubbles upwards through the strata from a source that is deep underground.

Because, however, there can be more than one possible explanation for a seismic phenomenon such as a bright spot, this type of indicator suggests but does not prove the existence of subsurface hydrocarbons.

And things become much more difficult when trying to use seismic data to detect oil. Oil has a much lower acoustic contrast with rock than does gas. And, to make things even more tricky, there's quite a low acoustic contrast between oil and water, thus making these two liquids difficult to distinguish.

When analyzing exploration seismic data people have a much better chance of saying whether there's gas or a liquid underground, rather than oil versus water, Michael Faust, offshore exploration manager for ConocoPhillips Alaska, explained.

Over the years, increased seismic resolution and an improved ability to extract unwanted noise from seismic data have improved geophysicists' ability to locate possible hydrocarbon indicating anomalies in the seismic data. But in Alaska, the high acoustic contrast between reservoir rocks and the surrounding rock formations in the relatively old, deeply buried reservoirs of fields such as Prudhoe Bay and Kuparuk has severely limited the use of hydrocarbon detection techniques — that high contrast simply swamps the subtle acoustic contrasts caused by the presence of hydrocarbons, Tom Walsh, principal partner and manager of Petrotechnical Resources of Alaska, told Petroleum News.

Walsh thinks that the hydrocarbon detection techniques will prove more valuable in the younger and shallower Brookian horizons that have become an exploration focus in the past few years. The difference between the acoustic properties of shales and sands is not as great in the Brookian as it is in the older rocks; so any change in fluid properties will likely have an impact, Walsh said.

AVO

However, a modern seismic technique known as amplitude variation with offset, or AVO, has seen some use in Alaska for delineating subsurface oil and gas reservoirs.

AVO is a bi-product of the way in which a seismic survey involves recording underground sound reflections using sound sources and geophone sound detectors in a series of increasing offsets from a single survey point. Seismic surveyors record the data from different offsets so that they can add the data together. This addition tends to remove random noise while enhancing coherent signals from underground sound reflections.

However, geophysicists have discovered that by examining how the amplitudes of the signals from a single subsurface reflection point vary with those increasing recording offsets, it is possible to obtain insights into the subsurface geology. In fact, surveyors now tend to use larger geophone offsets than they used to, to enable this type of AVO analysis.

And, as with other aspects of modern seismic analysis, interpreters can view computer graphics of the AVO data, to gain subtle insights into the underground geology.

"The difference between what you see on the close receivers and the far receivers … changes with the type of fluid you have in the ground and the type of rock present," Faust said.

Walsh said that AVO analysis essentially enables an assessment of the porosity of underground rocks. For example, analysts might perform an AVO analysis on an unproven section of a known field pay zone, to test for adequate porosity and thus reduce the risk level associated with reservoir development.

4-D seismic

Another technique with the potential to detect underground hydrocarbons, at least in the context of an operational oil field, is known as 4-D seismic. This technique involves shooting several 3-D seismic surveys over the same area over a time period of perhaps several years (a 3-D survey is a type of survey that results in a three-dimensional image of the subsurface geology). Changes in seismic signals from one survey to the next can provide insights into the movement of fluids such as oil and gas within the field reservoir.

As a technique, 4-D seismic is still relatively young, although results so far show promise.

"It's going to be huge as far as economics goes, because then you're looking for unswept oil, changes in gas caps, watching waterflood movements," Jon Anderson, chief geophysicist, exploration and land for ConocoPhillips, told Petroleum News.

Because changes over time in the seismic signals can result from a variety of causes, such as the chemical alteration of the rocks or subsurface pressure changes, the linking of the seismic data to field reservoir data forms a critical component of 4-D analysis, Anderson said. But given that linkage, it is possible to use 4-D seismic to test predictions that reservoir engineers make about reservoir fluid movements in response to field production.

"That's the beauty of 4-D," Anderson said. "You know that the fluids are there and you know they're moving and you integrate that with all the reservoir information."

Detecting fluid movements using 4-D surveying has proved particularly successful in offshore oil fields, where surface conditions remain relatively constant from one survey to the next. But onshore 4-D surveying is still in its infancy and has yet to be fully proven to work, Jon Konkler, senior development geophysicist for BP Exploration (Alaska) told Petroleum News.

"The North Slope is one of those places where we've started investigating, does it work." Konkler said. "… We've got a couple of places where we've overlain successive surveys and we're in the process of evaluating — can we see the fluid movements and, if we can, how do we use that?"

4-D surveys have been done in both the Prudhoe Bay and Kuparuk fields, Anderson said.

Konkler sees the use of 4-D surveys as a "game changer" in the use of seismic data, with the possibility of assessing fluid saturation volumes rather than just structure volumes in a field reservoir.

"This really is a different way of looking at things," Konkler said.

Gas hydrates

Although people are far from determining whether the vast deposits of gas hydrates that underlie parts of the North Slope can ever form a viable source of natural gas, the use of seismic techniques to directly detect the hydrates is proving to be one of the particularly useful outcomes of a multi-year gas industry, government and university gas hydrate research program on the slope. Gas hydrate consists of a white crystalline substance that concentrates natural gas by trapping methane molecules inside a lattice of water molecules at certain pressures and temperatures.

The seismic detection of gas hydrates works in a similar manner to that of natural gas, in that the hydrates tend to cause amplitude anomalies in the seismic signals. However, gas hydrate has a relatively high sound velocity, as opposed to the low velocity of gas. So, the presence of hydrates tends to pull up the seismic reflections, rather than push them down.

A gas hydrate stratigraphic test well at Milne Point on the North Slope in February 2007, drilled by BP as part of the gas hydrate research program, verified the effectiveness of seismic gas hydrate detection techniques.

And Walsh sees the potential for increasing use of this type of seismic direct detection technique in Alaska for detecting shallow gas deposits.

"We're looking shallower and shallower and how to directly detect these hydrates and coalbed methane deposits," Walsh said. ◆

COURTESY OF THE ALASKA DEPARTMENTS OF FISH AND GAME AND NATURAL RESOURCES

Alaska state biologists have monitored this rehabilitated gravel mine since it was converted to fish habitat in 1986. An experimental population of less than 100 Arctic grayling was established in the pond in 1989. In 2002, biologists estimated numbers of Arctic grayling inhabiting the pond at more than 1,000 fish.

Gravel use has technical challenges

Oil industry, regulators join forces on slope, convert mines into fish, waterfowl habitat

By ROSE RAGSDALE

Among the most visible and enduring signs of the oil industry's presence on the North Slope are the gravel roads, pads and airstrips scattered across the tundra. While these piles of pulverized rock from ancient rivers appear to be as ordinary at the gravel roads and structures crisscrossing other populated areas of Alaska, they actually have evolved and challenged the oil industry for the past 30 years.

Gravel is abundant on the North Slope. Industry officials say the entire region is underlain by about 2,000 feet of frozen gravel and sand once you get below 18 inches of organic soils, lichens, sedges and various Arctic grasses.

No one knows how much gravel has been mined on the North Slope, but educated guesses put the amount in excess of 40 million cubic yards, covering roughly 10,000 acres.

That may sound like a lot, but it's actually a fraction of 1 percent of the entire 15 million-acre central North Slope and less than 3 percent of the operating oil fields, said Bill Streever, environmental studies leader for BP Exploration (Alaska) Inc.

Put in perspective, gravel infrastructure on the North Slope covers roughly twice the acreage occupied by Atlanta International Airport. Moreover, these pads, roads and airstrips are scattered across an expanse the size of West Virginia.

In the 1970s, gravel seemed to be the answer for building and maintaining oil field facilities in a frozen land of harsh weather and harsher conditions.

But gravel, abundant and benign, still presented technical challenges to North Slope oil field operators.

ARCO Alaska Inc., for example, soon faced a learning curve in road-grading technology.

The gravel, initially mined from the bottom of riverbeds, was rounded rock that did not compact well and over time, loosely compacted gravel would fall apart, creating cracks and fissures in the roads, according Jim Weeks, a top ARCO executive on the North Slope in the 1970s and 1980s.

One innovative ARCO employee thought the roads would compact and hold their shape better if the gravel was more angular, Weeks said in a recent interview.

"So we bought a gravel crusher, crushed the native gravel and no more problems," Weeks recalled.

Riverbed gravel a concern

More questions about gravel use arose in the 1980s.

Regulators became concerned about the impact of gravel mining in riverbeds on Arctic fish populations even though the actual excavation occurred in winter.

"It soon became obvious that there was a hydrological impact to rivers from this practice," said Bill Morris, a biologist with the Division of Habitat Restoration of the Alaska Department of Natural Resources. "During breakup, isolated pools would be left behind in gravel-scraped areas, creating a problem with fish entrapment."

Morris said the industry's extensive use of water taken from deep pools in the rivers in winter to build ice roads and pads also had a potentially harmful effect on fish over-wintering habitat, and could even result in fish kills.

Fish habitat is extremely limited in the Arctic, especially in winter where temperatures typically drop to minus 60 Fahrenheit and up to six feet of water in most rivers, lakes and ponds freezes solid.

In summer and winter, the industry also encountered problems with actually sucking fish out of the water with water and gravel, Morris said.

To avoid these potential environmental hazards, the oil companies stopped taking water from the rivers in winter and started using intake screens when they pumped out water in summer. These changes reduced hazards to fish significantly, Morris said.

CRAIG GEORGE, NORTH SLOPE BOROUGH DEPARTMENT OF WILDLIFE MANAGEMENT

Biologist Bill Morris says the rehabilitated gravel mines on Alaska's North Slope are a win-win for the environment.

Mines become fish habitat

Land-based gravel mining, meanwhile, brought new challenges when all of the gravel was removed from a pit.

BP's Streever said DNR biologists, then a part of the Alaska Department of Fish and Game, hit upon the "clever idea" of converting the gravel pits into additional fish habitat.

Today, the oil industry partners with state biologists to do just that.

"We had figured out the basics by 2000," Morris said. "One of the things that turned out to be fairly important is how close to the shore a gravel mine site is. If it's too close, it backfills with seawater and becomes useless as fish habitat.

"We also figured out that if you put the gravel mine near a river, chances are very good that a lot of fish will find the pit once it is rehabilitated. In those pits located a great distance from a river or creek, the wait likely will be longer," he said.

Still, the wait can be worth it.

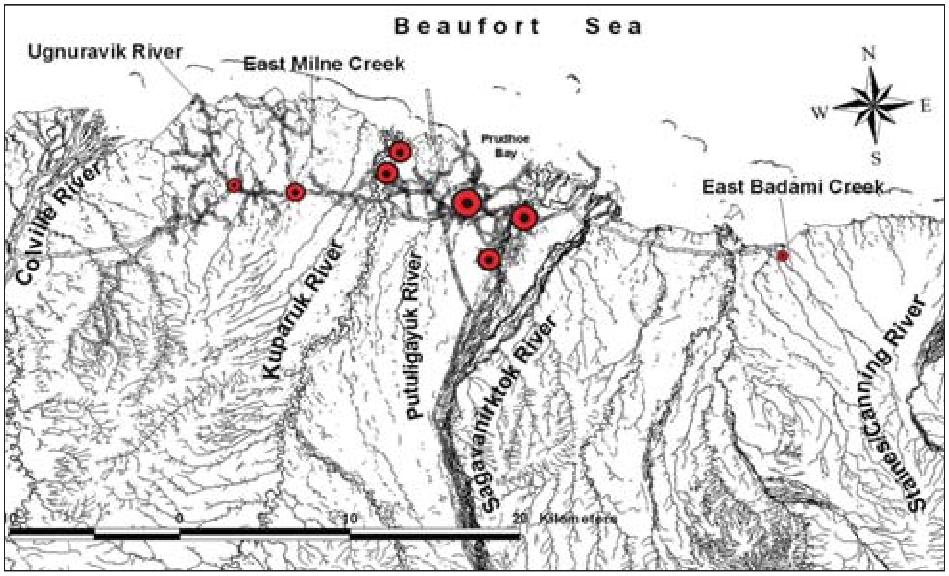
One gravel pit in the Kuparuk River field took more than 20 years for fish to find it. "Broad whitefish now use the pit as winter habitat, and to a lesser extent, other species of whitefish use it also," Morris said.

In all, eight gravel mines have been

see **GRAVEL** *page 40*

continued from page 39

GRAVEL



ADF&G/ALASKA DNR

Locator map of gravel mine sites that have been converted into fish and waterfowl habitat.

rehabilitated and connected to stream channels on the North Slope. Of the larger older sites, Morris said a majority have been rehabilitated for fish habitat.

He said some of the larger sites that are not feasible for fish will be reclaimed eventually for waterfowl habitat. State regulators plan to build islands within them for waterfowl nesting areas far enough from shore to deter predators such as Arctic foxes.

DNR biologists also figured out that getting the oil field contractors to contour the sides of a mine to create shallow shelves on the sides of the pit after gravel mining ends at a site improves the quality of the resulting fish habitat.

Ideally, the pits-turned-fish-ponds range from 25-30 feet up to 60 feet deep and in total area from 15-20 acres to well over 100 acres.

"The big thing for fish is deepwater habitat," Morris said. "In the Arctic, freezing limits over-wintering habitat. There is very limited liquid water on the slope in winter."

More sources of water

The gravel mines-turned-ponds also provide the industry with water in summer for remote camps and for keeping down dust on the roads. In winter, they help greatly with ice road and ice pad construction.

"It's a win-win for the environment," Morris said.

ADF&G/ALASKA DNR

A broad whitefish caught by state biologists in fish habitat created from a gravel mine on the North Slope.

The ponds are able to provide ample water for industry uses because of the low density of fish populations on the slope.

"When spring breakup comes, ponds and lakes on the North Slope fill almost instantaneously, so water removed during the winter for ice road and pad construction is hardly missed," Morris said.

Having the rehabilitated gravel mines allows even more fresh water to be stored over the summer, he added.

Today, rehabilitation happens concurrently with the gravel mining. The approach was successful when gravel was mined to build both the Northstar and Badami fields, officials say.

"The Northstar gravel pit near the Lower Kuparuk River was designed to mesh with the river so you wouldn't know it was there, and that's actually the case," Morris said.

Less gravel mining needed

Meanwhile, a trend nationwide toward minimizing industry's impact on the environment has brought other changes to gravel use on the North Slope. In 30 years, the industry has succeeded in reducing the amount of tundra its operations affect by more than two-thirds.

"With drilling pads now about 20 percent of the size they were in the 1970s and directional drilling enabling industry to produce more oil from fewer pads, less gravel is needed," Streever said.

BP spokesman Daren Beaudo said the next evolution in oil field design will require even less gravel. The new 120 million-barrel offshore Liberty field, for example, is being developed from an existing satellite development pad at the Endicott field "that is being augmented with a little more gravel."

"We're eliminating need for a new separate production facility, albeit a small one like at Northstar," Beaudo said. "We'll also be able to eliminate a subsea pipeline and drill ostensibly from onshore at a distance of eight miles."

Streever said BP also won't need a gravel road. "Prior to going to extended reach drilling at Liberty, the project would have required a gravel road," he said.

The operators are also picking up gravel.

"We have a program where we go out to old abandoned drill pads, pick up the gravel and rehabilitate the sites by doing things like planting native Arctic grasses," Streever said.

If the reclaimed gravel is contaminated, the operator follows regulatory guidelines to dispose of it. But if the gravel is clean, the company uses it in a new location.

So far, BP has reclaimed gravel from old exploration sites and three airstrips west of the Kuparuk River.

"We've also picked up parts of production pads and a man camp," Streever said. "In a couple of cases, we've also picked up gravel berms around the old reserve pits that we had for mud and cuttings in the 1970s.

"In a way, what we're doing with the gravel mines is an extension of this idea that you minimize your footprint and where you can't minimize your footprint, you look for ways to restore the area once you're done," he added. ◆

A 30-year partnership that's only just begun.

On June 20, 1977, oil began flowing down the Trans Alaska Pipeline. Since then, over 15 billion barrels have made the 800-mile journey south. It's an accomplishment made possible only because Alaska and the industry have worked together. On this historic anniversary, we want to say "thank you" to Alaskans.

As we look back and celebrate 30 years of accomplishment, we look forward with optimism to a future that is just as bright.

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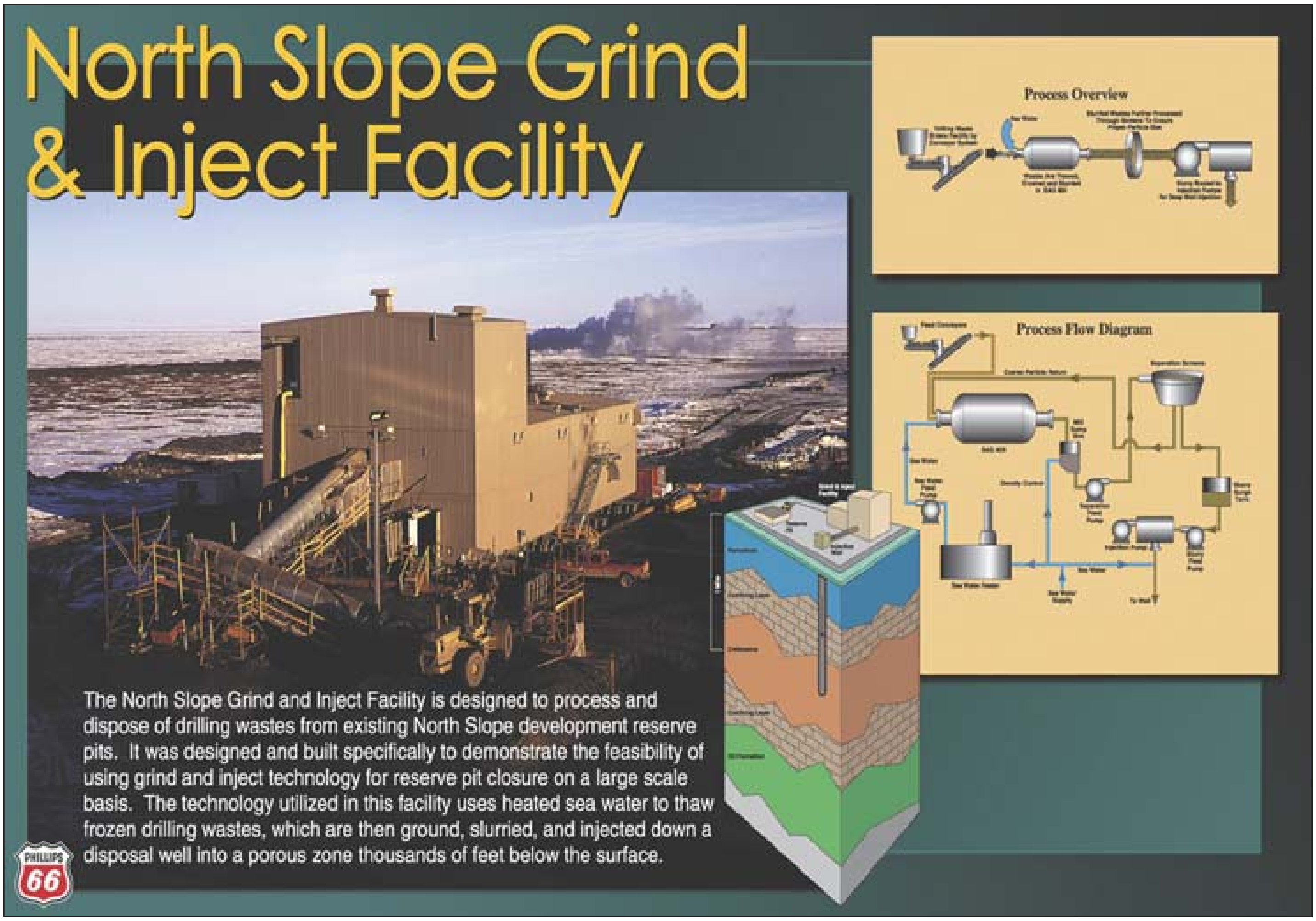


COURTESY OF BP EXPLORATION (ALASKA) INC.

The drilling waste dilemma

Hardrock mining technology adapted for modern grind-and-inject disposal

By ROSE RAGSDALE

When oil and gas explorers converged on the North Slope in the 1950s and 1960s, they brought industry practices from the Lower 48. These customs included constructing berm-enclosed pits beside new wells for disposal of discarded rock, mud and other solids that came out of the ground during the drilling process.

By the 1980s, these "reserve" pits not only had become eyesores dotting the tundra, they also could melt underlying permafrost and threaten to leak.

The Alaska Department of Environmental Conservation began to regulate disposal of drilling wastes and to issue permits for use of reserve pits.

It's not that drilling waste is a major hazard per se. Oil and gas drilling in Alaska is actually minuscule, compared with such activity in some other states. Only about 5,000 oil and gas wells have been drilled at 605 sites in Alaska. Compare that with more than 220,000 wells in Louisiana and 500,000-plus active wells in Texas, according to DEC.

Alaska laws, in fact, still allow operators to build reserve pits for drilling waste. But a single reserve pit can cover several acres, marring the landscape in a way that many people find objectionable. State regulations also require companies to monitor water quality near reserve pits for a number of years, and DEC holds operators responsible for pollution at the sites indefinitely.

Thus, ARCO Alaska Inc., a subsidiary of Atlantic Richfield Inc., was ready to talk when an environmental group sued the company in the late 1980s over the use of reserve pits on the North Slope.

ARCO decided to clean up its reserve pits, thereby paving the way for a new approach to drilling waste disposal.

Underground disposal solution

The idea of underground disposal of drilling solids surfaced. But how could operators get chunks of rock and other solids efficiently below ground?

Down-hole disposal of drilling waste, after all, wasn't a new idea. A few operators, in fact, were injecting water produced from oil and gas drilling as early as 1940. They started by disposing of produced liquids in depleted wells. But when petroleum production increased in adjacent wells, operators quickly recognized the benefits of this practice. The prospect of increased oil recovery encouraged them to favor disposing of produced water down hole, and by 1985, operators nationwide were injecting produced water into wells nine out of 10 times.

Injecting solids down hole on the North Slope, however, was another matter. After some trial and error, including a pilot project in 1988, ARCO drilling engineers realized they could solve the problem economically, with a little help from hardrock mining technology.

"We bought a ball mill and took drill cuttings, which are mostly rock, and crushed them to slurry them with water," recalled Jim Weeks, then a top manager for ARCO Alaska on the North Slope. "It was an old mining technology applied in a different way."

It wasn't long before the reserve pits became yesterday's news.

"The whole concept of reserve pits next to the wells went away," Bob Blankenberg, solid waste program director for DEC, said in June. "Solid waste disposal evolved from putting it in the reserve pits to taking it to a central landfill to applying grind-and-inject technology, which is used today."

North Slope operators soon began cleaning out their in-field reserve pits. They took mud and cuttings to a large-scale grind and injection plant near well Drill Site 4-19 in the Eastern Operating Area of the giant Prudhoe Bay oil field. DS4-19 was a disposal well, drilled and completed as a produced water injection well in September 1989.

By 1994, refined grind-and-inject technology had enabled both Prudhoe Bay operators, BP Exploration (Alaska) Inc. and ARCO to achieve "zero discharge" of drilling wastes, eliminating the need for reserve pits.

ARCO put its grind-and-inject plant into operation and slurry injection began at DS4-19 on March 31, 1995. By 2000, some 1.2 million cubic yards of solid material — mostly cuttings — had been pumped down hole on the slope. That amount in gravel would build a 3-feet-thick-by-27-feet-wide road about 75 miles, or from Anchorage to Willow.

COURTESY ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION

Reserve pits on production pads like this one built in 1978 were an integral part of drilling waste management practices on the North Slope until the 1980s.

Changing an industry

Today, most oilfield waste — drilling mud, drill cuttings, and produced brine water — generated on the North Slope is injected down hole. Produced brine water has never been a problem, but drilling mud and drill cuttings require special handling.

"Grind-and-inject technology changed the way we manage muds and cuttings," ARCO's Harry Engel told participants in a technologies conference in 2000. "G&I is a prime example of utilizing technology to improve an environmental management system. This permanent and environmentally sound disposal method isolates wastes, eliminates subsequent disposal and greatly reduces the surface space required for drilling operations," Engel said.

The elimination of reserve pits onshore has decreased habitat destruction and eliminated the possibility of reserve pit overflow as a potential source of tundra and surface water contamination. Offshore, the probable benefits are

see **DRILLING WASTE** *page 44*

continued from page 43

DRILLING WASTE

not easy to specifically define, but directionally, the potential for contamination of nearshore waters has been eliminated, according to engineers at the Alaska Oil and Gas Conservation Commission.

What is grind & inject?

When a well is spudded, a drilling mud is constructed by mixing a bentonite clay with water to produce a viscous, thixotropic solution that is capable of performing several functions essential to drilling the well, including mud the well bore, overbalance the formation pressure and remove cuttings from the well bore.

As the formation is drilled, rock material is ground up, some into large particles and some pulverized and suspended in the mud system. The process raises the viscosity to a point where the mud is not easily pumped. As the rock-laden mud circulates to the surface, it passes over 80-mesh shaker screens to remove coarse material. To maintain the mud at a pumpable viscosity, demanders, desilters, and centrifuges can be used to remove finer particles. In addition, the mud is diluted, or "watered back" to reduce its viscosity. This increases the volume of mud and some of it must be removed.

COURTESY ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION

North Slope operators agreed to clean up and rehabilitate reserve pits where they once deposited drilling waste. With the help of industry and state biologists, this reserve pit is well on its way to being reclaimed by the tundra.

Drill cuttings, or the solid material that results from drilling wells, are recovered at the surface through the use of the shakers, demanders, desilters, and centrifuges. This material is run through a ball mill to grind it until it is fine enough to be pumped into the formation without plugging the openings.

Best of available options

Thanks to grind-and-inject technology and the underground disposal of the resulting slurry in wells ranging from 2,000 to 9,000 feet deep, the operators have been able to clean up nearly all of the reserve pits on the North Slope. Some 513 of 605 reserve pits statewide have been cleaned out, while another 17 — mostly on the North Slope — are expected to be closed within the next year, according to DEC.

Another 57, mostly North Slope sites, are slated for future corrective action, and all inactive reserve pits owned by BP, ConocoPhillips Alaska Inc. and ExxonMobil Production Co. are currently expected to be closed by 2014, Blankenberg said.

Grind-and-inject technology and underground disposal also are used for drilling waste from recent exploration and development activities.

Thor Cutler, environmental scientist for the U.S. Environmental Protection Agency's Region 10, said widespread use of this preferred alternative, especially at newer slope fields like Alpine and Badami, has eliminated the need to transport waste material across the tundra, which further reduces the industry's footprint on the surface.

"It provides the opportunity for handling the material in a better way," Cutler said.

Figures compiled by AOGCC show that down-hole disposal of drilling waste may be the most cost-competitive alternative. Of viable options available, grind-and-inject disposal is certainly the most attractive, costing about $100 per cubic yard and offering the prospect of being a permanent solution. Other options include below-ground encapsulation, which also costs about $100 a cubic yard; and shipment to the Lower 48 at an estimated cost of $600 to $1,000 per barrel. Neither of these options can offer a guarantee of being permanent solutions, AOGCC said.

Though down-hole disposal is a "very expensive alternative" in that underground injection wells cost several million dollars to drill and require substantial sums for ongoing operation, Cutler said the technology, in the long run, has improved the net outcome and may lead to net savings.

"Not only is well spacing in newer fields such as Northstar and Alpine much smaller than in the past, we've seen significant reduction in the footprint of drilling pads, and permanent roads and river crossings are no longer needed for land transport of waste being hauled to a central site for disposal," he added.

North Slope fields, in fact, have shrunk to one-fifth of their former size during the past 30 years, due in part to the elimination of reserve pits and the advent of grind and inject technology. ◆

With DRA pipeline less of a drag

Chemical additive enables Alyeska Pipeline Service Co. to achieve huge cost savings

By ROSE RAGSDALE

ALYESKA PIPELINE SERVICE CO.

A worker dips a hand into a batch of drag reducing agent, or DRA. The chemical additive has proven to be an important boon to operators of the trans-Alaska oil pipeline.

Over three decades, Alyeska Pipeline Service Co. has operated the trans-Alaska oil pipeline with the assistance of numerous technologies. None, perhaps, is better known than a clever innovation cooked up in the chemical laboratories of Atlantic Richfield Co. called drag reducing agent, or DRA.

A long-chained hydrocarbon polymer, DRA has the consistency of a gooey, clinging gel resembling rubber cement. Technically, DRA is a poly-alpha-olefin, or non-saturated carbon with very large, long-chain molecules composed of hydrogen and carbon atoms.

ALYESKA PIPELINE SERVICE CO.

Mike Malvick is operations engineering supervisor at Alyeska Pipeline Service Co.

It proved to be a particularly important development for the pipeline, which was built to handle 1.5 million barrels per day of crude, according Jim Weeks, a senior ARCO manager in Alaska in the 1980s.

In the late 1980s when oil flow through the pipeline climbed to a rate of more than 2 million bpd, Weeks said injections of DRA made the higher throughput possible without additional construction.

"It gave TAPS a 30 percent increase in capacity without adding pipes or pumps or anything else," Weeks said in a recent interview.

But the story of Alyeska's love affair with DRA dates back to 1979, two years after startup.

DRA was first injected into the pipeline on July 1, 1979.

The pipeline was initially designed to move 2 million bpd of oil, using 12 pump stations. Each pump station could accommodate four mainline pumps, with three operating and one spare. Each of the pumps was to be driven by a 14,500-horsepower gas turbine.

The pump stations were designed to be built in phases. Phase 1 included building pump stations 1, 3, 4, 8 and 10, with two pumps each, which allowed for pumping 600,000 bpd of crude.

Phase 2 added pump stations 6, 9 and 12, with three pumps each and installed a 3rd pump at pump stations 1, 3, 4, 8 and 10, as throughput climbed to 1.2 million bpd.

Phase 3 was intended to add a fourth pump at pump stations 1, 3, 4, 6, 8, 9, 10 and 12, and to bring on line pump stations 2, 5, 7 and 11, with four pumps each to accommodate a boost in oil flow to 2 million bpd.

Before Phase 3 could be implemented, testing of DRA proved it to be a viable alternative to mechanical horsepower in the trans-Alaska oil pipeline system. As a result, Phase 3 never happened. Instead, pump stations 2 and 7 were built with just two pumps each, and the company shelved plans for building pump stations 5 and 11.

That fourth (spare) pump was never installed at any of the pump stations, but the stations' gas turbines were modified to produce more power, up to the equivalent of 18,000 horses.

Even without the extra pumps and pump stations originally envisioned, DRA enabled the pipeline to handle peak oil flow of 2.15 million bpd. Maximum capacity without DRA was slightly more than 1.4 million bpd, according to Mike Malvick, operations engineering supervisor.

"DRA use, when injected at strategic locations, allowed 28 pumps to pump 2.1 million bpd of oil and eliminated the need for eight additional operating pumps and gas turbines," he said.

"I'd say a rough estimate of the cost savings in facility construction from DRA would be approximately $300 million, in 1977 dollars," Malvick said. "In today's dollars, that would be in excess of $1 billion."

Operators master DRA

Despite its efficacy, DRA required a significant learning curve at Alyeska. Engineers and technicians conducted an ongoing series of tests through the years to assess the substance's range of capabilities.

Malvick said the original gel-like consistency, which had an active ingredient that required it to be dissolved in kerosene or diesel, was very difficult to use. Handling it was akin to manipulating an extremely sticky batch of melting mozzarella cheese.

"If you dipped up a handful of DRA, it would come away with a strand still attached to the batch that would get thinner and thinner but would never break," Malvick said. "If you spilled it, the clean-up tools of choice were a shovel and a long pair of shears."

This feature made DRA ideal for

see **DRAG** *page 46*

continued from page 45

DRAG

smoothing away turbulence as crude and natural gas liquids rushed through the pipe.

One problem with DRA was it would lose its desirable properties once it passed through a pump station, Weeks said.

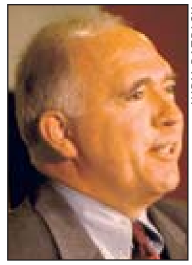
Thus, batches of the agent had to be injected in the pipeline at regular intervals to keep the oil flowing smoothly.

But exactly how does DRA work?

Malvick says the turbulent flow of crude in the pipeline chews up energy, and DRA acts like a spring or shock absorber, reducing turbulence and thus, the energy needed to move the oil to Valdez.

One factor in Alyeska's willingness to continue using DRA was its lack of lasting effects on Alaska North Slope petroleum liquids flowing through the pipeline.

"We've not seen quality degradation in the crude oil," Malvick said. "DRA is also injected into some pipelines for refined products in the Lower 48 with no detrimental impact."

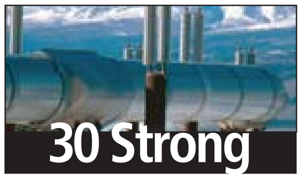


JUDY PATRICK

JIM WEEKS

Another key development was the success DRA manufacturers had in converting the substance into slurry products that can be more easily transported, injected and cleaned up than the original gel.

"The slurries appeared in the late 1990s, and they've taken the market by storm. So they don't make the gel anymore," Malvick said.



Could we save money by keeping equipment at a remote exploration site on the North Slope all summer? Oil companies can cut their costs by using ***special insulation****, without damaging the tundra.* *Turn to page 66 to learn more.*

New use for DRA

Alyeska used DRA to aid crude throughput in the 1980s and 1990s, but in 1995, the company drafted the substance into a different service.

"We started using it for horsepower management. We took the same concept and went in a different direction," Malvick said.

As North Slope petroleum production declined, Alyeska found that using DRA was more economical than running existing pump stations. The discovery led to shutdowns of Pump Station 8 in 1995, Pump Station 10 in 1996, Pump Station 6 in 1997 and Pump Station 12 in 2003 or 2004, Malvick said.

Today, Alyeska is still using DRA, though now it figures prominently in the company's strategic reconfiguration process, which called for electrifying the pipeline's remaining pump stations. Injection of DRA is allowing Alyeska to shut down or scale back power usage at pump stations 7 and 9.

"Depending on the cost of electricity, we may choose to inject DRA rather than run our pumps so hard and save on electricity consumption," Malvick said.

The decision, like earlier moves to use DRA, hinges on a simple equation.

"When DRA is cheaper than fuel plus station maintenance plus personnel, then we shut down the pump station and inject DRA," he said. ◆

Seeking systems for all seasons

After 30 years of upgrades, Alyeska brings telecommunications, computer systems to peak

By ROSE RAGSDALE

ALYESKA PIPELINE SERVICE CO.

Alyeska plans to move its operations control center, shown here, to Anchorage by early next year.

Advances in telecommunications and information technology have brought numerous improvements to the computer system that controls the trans-Alaska oil pipeline and the network that facilitates and reinforces its safe operation.

Moving at a slower but perhaps, surer pace than others in the industry, the 800-mile pipeline's computer systems are finally coming into their own, demonstrating capabilities pipeline operator Alyeska Pipeline Service Co. could only dream about 30 years ago.

"Originally, when the pipeline was being constructed, there really wasn't any communications infrastructure," said Mike Joynor, vice president of oil movements at Alyeska.

Mike Joynor is vice president of oil movements at Alyeska Pipeline Service Co.

Joynor leads a team of controllers and programmers who have marched the pipeline through three decades of changes. The pipeline's owners hired AT&T to build a dual microwave system for telecommunications in the early 1970s. Erected along the pipeline's right of way from Pump Station 1 to Valdez, it was an analog system based on serial communications.

"Back then, it was modern for the technology of the day," Joynor said.

Nearly 25 years later in the late 1990s, Alyeska took another telecommunications company up on an offer to build a fiber optics system along the pipeline right of way and connect it with a sub-sea fiber cable then under construction from the Seattle area through Prince William Sound to Valdez and Anchorage.

"We moved to the fiber system in 2002, but we kept the analog microwave system as part of our voice communications radio system, or mobile communications system," Joynor said.

Since then, Alyeska has worked with AT&T and GCI Inc. to fast forward its telecommunication infrastructure.

"AT&T went in and upgraded their entire analog microwave system to digital technology, making it fully redundant. With the two digital microwave systems and the fiber optic system, we now have a communication infrastructure that are independent of each other," Joynor said.

The upgrades have given the pipeline ground-based and microwave-based telecommunications systems and enabled Alyeska to develop primary, secondary and tertiary communication links. Alyeska now has analog and digital microwave, fiber optic and digital satellite telecommunications available.

The three different levels of communications circuitry to the pump stations means that if any one system fails, Alyeska will retain its ability to see what is happening on the pipeline. In addition, the satellite link has proven to be very useful maintaining communications at high elevations such as Atigun Pass.

"Very seldom does anyone get in a position to have the best of all the telecommunications worlds," Joynor said. "It gives us our 99.995 percent up time, which is the availability required by regulators for the pipeline. Outside of the military, that's significantly higher than any other place you can find."

Upgrades enhance control

In 30 years, Alyeska has undertaken three full upgrades of the computer system that originally controlled the pipeline. After startup with a Xerox-based system in 1977, Alyeska switched to a faster mainframe system in 1985 and moved again 20 years later to the new-generation User Configurable Open System marketed by Kansas-based Control Systems International.

The first two supervisory control and data acquisition systems were essentially mainframe computers that relied on serial, or point-to-point communications, but the one installed in 2005 is a network-based distributed system.

SCADA is an industry recognized acronym meaning "Supervisory Control And Data Acquisition system."

Before the latest update, all of the SCADA system's logic that controlled and protected the pipeline resided in the mainframe. This made the pipeline susceptible to power outages, said Paul Liddell, a computer systems engineer and supervisor of Alyeska's SCADA system.

If the pipeline lost power, the controller working in our operations control center, or OCC, couldn't take steps necessary to ensure a safe shutdown, Liddell said.

With the new distributed system, Alyeska has pushed the logic out as close

see **SYSTEMS** *page 48*

continued from page 47

SYSTEMS

to the field as possible, "such that if we lose communications, the pipeline can still safe itself out. (The system) can monitor for adverse conditions, and it can monitor for loss of communications with the OCC and can bring the pipeline down safely," Liddell said.

The new system also allows Alyeska computer analysts to troubleshoot and monitor it.

"We can actually go into the programming logic that controls processes out in the pump stations and see what's going on," said Liddell.

The technology is similar to that used in the aircraft industry for diagnostic analysis of airplane engines while they are still flying in the sky.

Liddell said telecommunications is used to access the system and once inside, analysts use the computer system's distributive nature "to peer around and see what's going on."

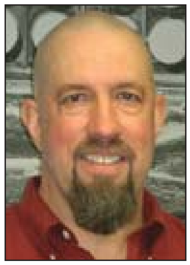
Though installation of the SCADA system is essentially complete, Alyeska programmers are up to their elbows in additional upgrades and reorganization designed to make the pipeline's operation even safer and more efficient. This includes moving the OCC to Anchorage.

SIPPS started up this year

The multiyear, multimillion-dollar process is called strategic reconfiguration.

Part of this picture was startup earlier this year of a new PLC-based Safety Integrity Pressure Protection System, or SIPPS, that Alyeska launched to provide additional safeguards for running the pipeline.

Since February when the SIPPS station came on line, systems analysts have focused on fine-tuning it to essentially watch pipeline operations for mistakes and mishaps.



Paul Liddell is a computer systems engineer and supervisor of the SCADA system at Alyeska Pipeline Service Co.

Liddell said SIPPS is a primary example of how the company has pushed the protective logic capabilities of the new computer system out into the field. Each pump station will have a SIPPS node when the work is completed, hopefully by 2009, and the nodes will be able to communicate with each other and exchange information continuously.

SIPPS will also monitor communications with other nodes on the same network and its own communications with the OCC, and take the appropriate action if a problem occurs in those areas, Liddell said.

Suppose a valve closes without receiving a command from the human controller at the OCC. SIPPS will respond by automatically shutting down pump stations upstream from the closed valve, Liddell said.

If SIPPS loses communications with the OCC or with other SIPPS nodes, it also will automatically shut down the pipeline.

"SIPPS is programmed to react if certain predetermined situations occur. It's not artificial intelligence. AI implies a certain level of learning. We'd like to get to that point, but we're not there yet," Liddell said.

At the OCC, meanwhile, Alyeska is also examining each and every alarm that comes in to the controller and deciding whether the alarms need to be presented to the controller, Liddell said. "Obviously with one person sitting there trying to control the pipeline, being hit with more than 1,000 alarms in a work shift is a bit much to handle."

Analysts are scrutinizing each alarm to determine its source, function, required response and whether it is even necessary. A new type of software developed by PAS of Seabrook, Texas, is helping with the automatic alarm analysis. The software intercepts all the alarms coming in and the operator's actions going out. Then it suggests ways to make the process more efficient.

The plan to move the OCC to the Government Hill offices of AT&T in Anchorage is moving apace. Joynor said the new facility should be finished by year's end and the OCC relocated in 2008.

"This is another area where technology advances have helped us," Liddell said. "With the old point-to-point communications with a centralized mainframe, trying to coordinate this move would have been very difficult.

"With the new SCADA system, all we have to do is establish another point of control in Anchorage and we can run the pipeline in parallel or from one control point at a time," he explained. "It really makes the transition over to Anchorage much, much easier."

Off-the-shelf technology

Alyeska made a conscious decision to

purchase off-the-shelf technology for the latest SCADA system and with its latest telecommunications upgrades and services.

"With the second generation SCADA system, we owned all the source code to it," Liddell said. "When you buy UCOS, it's essentially a toolbox. You can build yourself a house with that toolbox. "Before 2005, we had to build everything from scratch. It took a very high skill set to maintain, and quite honestly, a lot of us are getting a little long in the tooth and looking toward retirement." (UCOS, an acronym for user configurable open system, is a complete control system solution. In layman terms UCOS is a set of software tools that allows a user to build a SCADA system that 'out of the box' can communicate using a large number of standard process control protocols – i.e. messages — over a wide variety of communication infrastructure, such as Ethernet, point-to-point, etc.)

Alyeska no longer needs to hire engineers who are specialists in programming to run the new system. "Our people can use the toolbox to configure the changes that they need," Liddell said.

One reason Alyeska made the switch to off-the-shelf computer technology was that back in the '70s the hottest things in computers were languages like FORTRAN and COBOL, etc.

"Most everybody who really understood those computer programs are in their 60s and 70s today," Joynor said. "It's about using computer software that is industry standard. You can bring in support personnel to keep your in-house people trained. But the farther you depart from commercial- or industrial-grade technology that's available, the more you are building a system that requires specialists. You may have only one or two specialists, and if anything happens, you may have a gap in your ability to support your systems. That's why we try to stay with commercial or industrially available technology."

Alyeska's leak detection program also got a boost from advancements in personal computing technology.

The complexities of hydraulic modeling of pipelines leads to some very difficult equations, and Alyeska engineers used to submit a problem to the mainframe computer and wait all day to get an answer.

With the newest PCs, the engineers can solve equations within minutes, Liddell said. "So our leak detection system is now based on PC technology."

But these are not your standard PCs, Joynor cautioned. "They have a significant number of coprocessors in them, and they cost $10,000 to $15,000 each," he said.

New capabilities, versatility

What does all this technological muscle bring to Alyeska?

Flexibility and reliability, mostly.

"Once the OCC is in Anchorage, we'll have routing through Glennallen to Fairbanks that connects us to the system that way and we will have routing that comes from Valdez to Anchorage through our alternate control center in the Palmer area," Joynor said. "So if we had disruptions, say a fiber problem in Prince William Sound, we're connected in Anchorage going north over the mountains and we can intercept and restore communications.

"We always make sure we have at least two and maybe three or four routes. Having three communications routes will be our standard when we're done," he said. "The underlying goal is for TAPS' SCADA system to have the highest reliability that we can achieve with current technology. We never can be 100 percent, but we can be close." ◆

ALYESKA PIPELINE SERVICE CO.

A versatile fast-water booming tool, the BoomVane can be used to both recover and deflect spills in fast-moving rivers and streams. Alyeska Pipeline Service Co. has added the completely self-trimming and versatile technology to its oil spill response inventory.

Better mousetraps for inland spills

Alyeska Pipeline Service Co. scored big with recent advances in emergency preparedness

By ROSE RAGSDALE

Alyeska Pipeline Service Co., operator of the trans-Alaska oil pipeline, has assembled a diverse collection of tools to aid in its ongoing efforts to improve its emergency response capabilities.

Employees are essentially charged with seeking out better mousetraps. Not only do they troll the Internet and industry publications, but several employees attend major emergency response conferences, such as the International Oil Spill Conference, every year.

"When we find a new application, we often purchase a model and try it," said Wes Willson, manager of Alyeska's emergency preparedness and compliance department.

Willson's people also have taken to interacting more with SERVS, the marine side of emergency response at the company.

"We are training together and sharing ideas," he said. "In past years, we'd hear people saying a technology would work for marine applications or for the pipeline only. These days, we are seeing a lot more people taking these ideas and being very innovative."

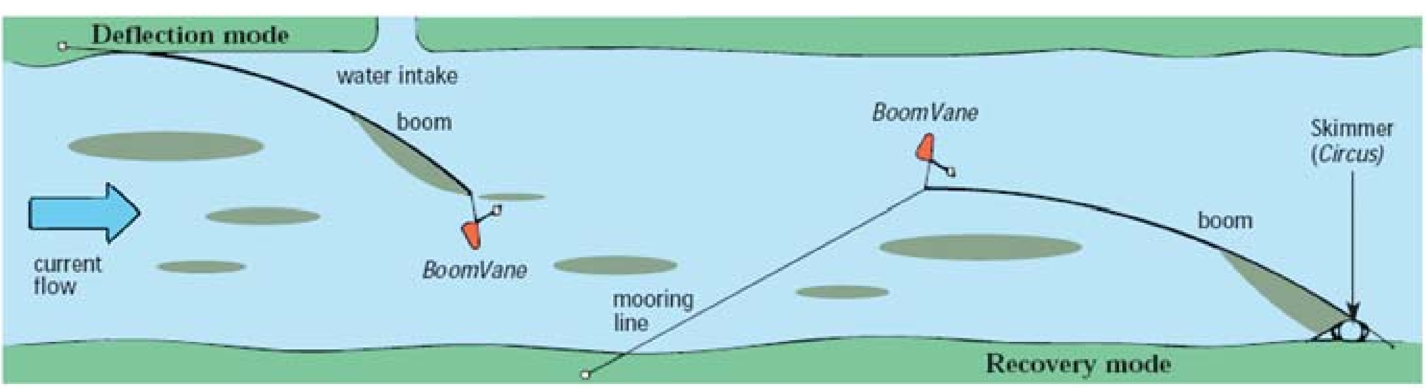
Part of the impetus for this initiative is the company's need to fulfill the requirements of numerous regulations that govern every aspect of the pipeline system's operation.

"We have a four-volume set of state requirements, so a lot of time and effort is put into compliance," Willson said.

Device helps deploying boom

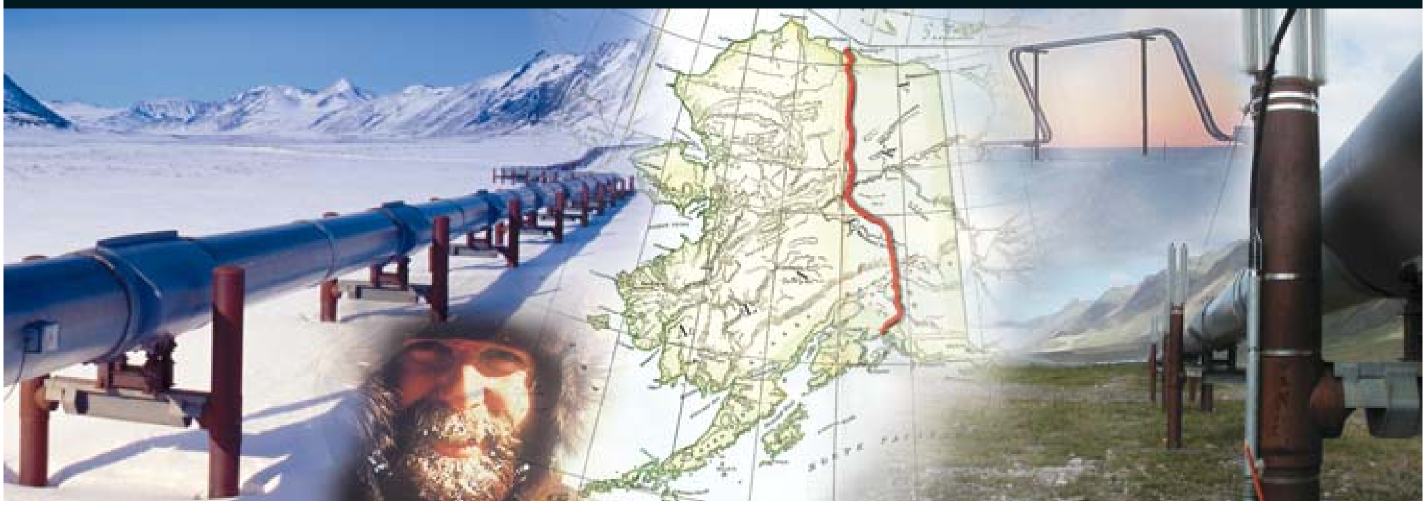
Sometimes Alyeska employees strike gold with this buy-and-try approach.

see **INLAND SPILLS** *page 52*



ALYESKA PIPELINE SERVICE CO.

Taking Experience to Extremes . . .



Alaska is an environment of extremes—designing, building, and maintaining infrastructure here takes skill, talent, and experience. Over 60 years ago, Baker's company founder, Michael Baker Jr., recognized both the potential for developing business and the importance of developing infrastructure in Alaska. Our first office in Alaska opened in 1942 in support of the growing U.S. military interests in the region. Since then, Baker has played a key role in the planning, design, construction, operations, maintenance, and renewal of some of Alaska's most renowned infrastructure projects, including a number of groundbreaking projects on the North Slope and the Trans-Alaska Pipeline System. Between 1969 and startup of TAPS in 1977, Baker personnel performed nearly 3.2 million manhours of engineering design and field work for civil, structural, and transportation related infrastructure for the project, including mile-by-mile pipeline design, north of the Yukon River. We continue to provide consulting expertise to this day.

Baker, long recognized as a world-class provider of cold regions pipeline expertise, also possesses strong hydrology/hydraulics, telecommunications, transportation, environmental, geotechnical, geospatial information sciences, and core civil engineering skills. We consistently apply innovative techniques and technologies to address arctic conditions, such as the award-winning Colville River Pipeline HDD Crossing—the first on the North Slope.

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continued from page 50

INLAND SPILLS

That was the case with the "BoomVane," a device that dramatically improved the company's response procedures on fast-moving inland rivers and streams during the past six or seven years, Willson said.

"It does so many things for us. We can deploy our boom now without a boat. If we are limited whenever we are at a remote site, we can fly a crew in and they can start deploying boom before you can get a boat there," he said.

One of the biggest challenges facing Alyeska's emergency response crews is getting a good anchor position for deploying boom in a rapid river current.

"There is a lot of stress and weight when that current is hitting against a long stretch of boom," he said. "The most challenging thing is having enough weight and anchor to hold the boom in place. The way the BoomVane is designed, you can anchor on land. You don't have to do it in the middle of a river. So it offers advantages in deploying boom in faster currents, but also in holding the boom in faster currents."

How does the BoomVane work? Imagine a kite, but instead of flying it in the air, you would put it in a river. It flies up the river. It has a float attached and it pulls a boom behind it. Alyeska can deploy boom to collect oil or other substances spilled in rushing water using the device.

The BoomVane is lightweight and portable. Designed in Sweden by ORC, it was originally developed for use in the ocean.

"What they were attempting to do was a typical marine application in open water with boom using two boats moving side-by-side, working in parallel with each towing part of the same set of boom in a U-shaped configuration," Willson said. "The BoomVane can eliminate that second boat.

ALYESKA PIPELINE SERVICE CO.

Two workers can deploy this 100-foot, 68-pound water dam in five to 10 minutes to do the work of a sandbag dam that would take at least two hours to erect with at least three times the manpower. Alyeska Pipeline Service Co. purchased the technology from a French manufacturer called Megasecur.

You have to be skilled to do it, but if you put the BoomVane out in the ocean and you anchor it properly to one boat and to the boom, it will take the place of a second boat."

He said the BoomVane will swim alongside the one boat, deploying boom in the same U-shaped pattern.

The technology caught the eye of Alyeska employees who work for the company's tanker escort service.

"They were using it to a certain extent. We happened to be working with them and we wondered how it would work on a river current. We borrowed one of the BoomVanes and put it on the Yukon River. We were pretty impressed with it," Willson said.

But one problem that Willson's crews had with the device was its size. Too large at 6 feet tall to work in shallower stretches of a river, the BoomVane needed a redesign for the pipeline.

"We worked with the company's engineers to make an inland river BoomVane and to get the design down to the smallest size that they believed would still work. So our BoomVanes are about 2 1/2 to 3 feet tall. We still need some water for them to work, but they are clearly able to go into much shallower waters than the original models," he said.

Better, quieter small boats

Other technologies with recent advances that have gotten the nod at Alyeska include air and jet boats.

"The big problem until recently with air boats was that they were designed for use in the Florida Everglades and the Louisiana marshes and not for the fast-moving rivers of Alaska," Willson said.

Another problem with air boats is the loud noise they make in operation.

"One of the new things to come out is a counter-rotating prop. Instead of one propeller, they now have two and they rotate in opposite directions. It provides a lot greater power for a smaller engine and lighter weight. Plus, it's also much easier on the ears of the operator and passersby," he explained.

Recently, Alyeska began working with several Alaska vendors who now routinely custom build air boats for the company. These vessels have more safety features, and their hulls are designed for use on Alaska rivers and streams.

Another big advance in technology in Alaska was the development of the "tunnel hull" in the jet boat industry.

"Originally, there was just one design, but now there is an extreme shallow-water design," Willson said.

The new tunnel-hull jet boats have brought versatility to Alyeska's small boat fleet.

Before, a huge difference in where air boats and jet boats could go in the water made it difficult for the company to manage its fleet efficiently.

"A jet boat couldn't compete at all with an air boat," Willson said. "But what we are finding with these tunnel hulls is they are not quite as good as an air boat, but they are pretty close. When we do our operations in some of these environments, it has allowed us to interchange crews and interchange equipment much more easily than before."

Today, Alyeska maintains a fleet of 12-14 air boats and 10 tunnel-hull jet boats. As the company purchases new equipment, it has replaced older models at a rate of four or five a year. At that rate, Willson estimated the company's entire small boat fleet will be newer models in two more years.

Sandbags no more

Another nifty technology tucked away in Alyeska's emergency response inventory is one originally used as a flooding protection device. Called a "water dam," the products are manufactured by several companies. Alyeska chose to purchase models made by a French

ALYESKA PIPELINE SERVICE CO.

An extreme shallow jet boat in Alyeska Pipeline Service Co.'s inland emergency response fleet.

company called Megasecur that come in various lengths and heights. Lightweight polyurethane rolls with a flap, two sides and a middle point, water dams function like instant sandbags.

A common technique in containing an oil spill is to block a culvert or build a temporary dam using sandbags, according to Willson.

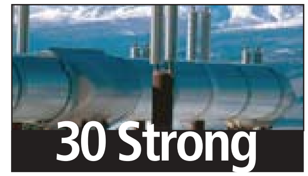
But constructing a dam of sandbags takes a lot of labor and can take several hours, depending how many people are working to built it so it can hold and pull water in a way that allows oil to be collected at the location, he explained.

By contrast, two workers can pull a 50-foot water dam across an area to be blocked and effectively dam up a river in five minutes.

"It's one of the neatest things we've found," Willson said. "We're learning how to use it. We've found that in some situations where the water is moving too rapidly or a stream is not straight enough, we don't have to dam a whole river, we can just deploy the water dam straight into river and it creates a small eddy at that location. It slows down the river and the water pools up noticeably. Then we have a much better location to actually be effective collecting oil."

The water dam is especially effective in braided rivers where oil coming downstream can be diverted into a dry channel where it can more easily be collected.

"A lot of times before, that would have required shovels or maybe even heavy equipment," Willson said. "We've trained on them so that, assuming it is a shallow river, like the Sag River, we are able to direct the flow pretty precisely and pretty quickly to where we want it to go." ◆



Can we move a massive drilling rig across remote stretches of the North Slope to drill an exploration well without damaging the tundra? We can, by using ***ice roads and ice pads****. To learn more, see page 63.*

ALYESKA PIPELINE SERVICE CO.

Alyeska Pipeline Service Co. teamed with Fairbanks firms, Mustard Engineering and Holaday-Parks metal shop to design and build the HC 320 Hydraulic Clamp after the Milepost 400 bullet hole incident in 2001. Once applied to the trans-Alaska oil pipeline as a temporary patch, the clamp can be left in place. This allows Alyeska to deploy multiple clamps, if needed.

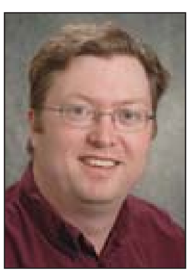
A tale of two leaks

Emergency response quicker, more effective in 23 years between oil spills at Alyeska

By ROSE RAGSDALE

In 30 years, Alyeska Pipeline Service Co. has only had to respond to oil spill emergencies caused by acts of sabotage against the trans-Alaska oil pipeline.

The first incident occurred in the Steele Creek area less than 25 miles north of Fairbanks on Feb. 15, 1978, just eight months after pipeline startup. Vandals planted explosives that blew a hole in the line, causing some 16,000 barrels of crude to spill before workers were able to stop the oil flow and make repairs.



Wes Willson, emergency preparedness and compliance manager at Alyeska Pipeline Service Co.

The second incident occurred 23 years later on Oct. 4, 2001, when an intoxicated man fired a rifle at close range, ripping a bullet hole in the pipeline near Milepost 400, about 75 miles north of Fairbanks. More than 4,500 barrels of oil spewed out of the pipeline, and of that some 3,000 barrels were recovered and re-injected.

Alyeska's emergency response to the two incidents, more than two decades apart, offers compelling evidence that technology has improved the company's capabilities and performance to respond to spills and other sudden events.

Effective communications help

One key factor in how technology has changed emergency response at Alyeska is the company's success in using an increasingly popular system, said Wes Willson, emergency preparedness and compliance manager at Alyeska.

Early on but not before the incident in 1978, Alyeska adopted the "incident command and control system" used by firefighters in battling blazes that flare up every summer in wilderness areas of the West. Over the years, the company has found ICCS to be very effective in dealing with emergencies. A key advantage: The system can expand and contract, as needed, during in an emergency.

Consider: The ICCS is so effective that Congress passed legislation after Hurricane Katrina, requiring all federal agencies and departments to adopt the system in responding to emergencies.

"The oil industry and Alaska agencies are actually leading the charge on this, helping the federal agencies with it," Willson said.

Advances in telecommunications also helped Alyeska greatly in handling the two emergencies.

"During the Steele Creek incident, we had no cell phones. Information had to be relayed by land. We had no fiber optic telecommunications link with the pipeline. As a result, more decisions and more actions were left with the local group of responders," Willson said.

"Where they struggled was when they needed additional resources, whether it was manpower or equipment," he said. "Getting that information back to the central hub and bringing in the additional resources were definitely challenges."

By comparison, Alyeska had good communications infrastructure available during the Milepost 400 incident.

"But even then, it was not as good as what we currently have," Willson observed.

By 2001, Alyeska was able to employ the ICCS and better telecommunications links to get some 300 people on site within 24 hours at Milepost 400 along with a massive amount of pre-staged equipment ready to be deployed.

"We had the ability to respond a lot faster," Willson recalled.

TEAM clamp used in 2001

Technological changes also influenced how the company repaired the leaks.

"The technology for how we dealt with the Steele Creek incident was a sleeve. That's a standard practice that we still continue to use at Alyeska. If we have concerns about a dent or corrosion or wall thickness, we will add a sleeve over the spot to effectively fix it," Willson said.

But one handicap at Steele Creek was that workers had to wait for the crude spewing out of the pipeline under high pressure to subside before they could cover the hole with the sleeve and weld it into place.

During the 2001 incident, Alyeska called on a nifty innovation it had added to its emergency response arsenal a few years earlier. Called a "TEAM clamp," the device was installed on top of the leaking oil, Willson said.

Inspired by off-the-shelf technology used on smaller pipelines, the TEAM clamp was redesigned for the trans-Alaska oil pipeline's 48-inch girth.

"Before the TEAM clamp was invented, no one had even tried to have that application for such a large-diameter pipeline," Willson said. "We've had mixed success with it, so we've planned to use it as a temporary patch that allows Alyeska to restart the pipeline and make future repairs. We have better technology that we've developed recently."

'Pump-around skid'

Back at Milepost 400, Alyeska still had to reduce the pressure of the oil leaking out significantly to apply the TEAM clamp.

To do that, technicians brought in "pump-around skids," basically large pumps that extract oil from one side of a valve and return it to the pipeline on the other side of a valve. These devices helped the company to quickly lower the internal pressure in the leaking section of pipe and apply the TEAM clamp.

see **LEAK RESPONSE** *page 56*

ALYESKA PIPELINE SERVICE CO.

This 50-foot expandable trailer is equipped with computer workstations, laptops, satellite phones, landline telephones and a dispatch center with air and ground radios as well as different repeaters. At a cost of $500,000 to $700,000, it was created to provide Alyeska Pipeline Service Co. with the best on-scene communications support possible in case of an emergency.

ALYESKA PIPELINE SERVICE CO.

The MCP has eight workstations with computers, laptops, satellite phones, regular telephones and a dispatch center with air and ground radios as well as different repeaters.

continued from page 55

LEAK RESPONSE

Originally called "gel-block skids," Alyeska purchased the technology in the early 1990s because it was one of few tools available on the market for aggressively sealing a valve, especially a check valve like those used on the pipeline.

A gel-block skid comes in handy when a leak occurs in a pipeline and a check valve designed to hold back additional oil from flooding the affected section of pipe won't close completely upstream from the leak.

"We get what we call a 'leak by' or 'leak through'," Willson said. "In the worse case situation, you would have a spill. We designed the pipeline so we could have valves to minimize the potential for a spill. But if a valve isn't working properly, you potentially could have an additional volume of oil leak out."

The gel-block skid can inject a 200-foot-long plug of diesel gel into the pipeline and seal it so additional oil cannot seep through to a section with a leak.

"At Milepost 400 because of the way that section of the pipeline is designed and the way we injected the gel both upstream and downstream around the valve, we stumbled upon the idea of using the device to pump the oil around (the leaking section)," Willson said. "That's why we now call it the 'pump-around skid.'"

Since 2001, Alyeska has changed the design to increase the pumping rate of the device and purchased additional units. The company now uses them as contingency equipment and for valve maintenance, draindowns and shutdowns.

Hydraulic clamp best yet

The company also set out to develop more efficient technology for dealing with such spills.

"We conducted a review with our stakeholders' input from a procedural, safety and equipment standpoint," Willson said.

After significant investment during the past five years, Alyeska has developed a new device and trained personnel to use it.

"The piece of technology we're proudest of is the HC320 Hydraulic Clamp," Willson said. "And what's so neat about this clamp is it was designed and built here locally."

That's right. Mustard

Engineering and Holaday-Parks Inc. metal fabrication shop of Fairbanks worked in partnership with Alyeska spill response experts to develop the device.

The HC320 clamp can quickly seal off a pipeline leak, and depending on the pressure in the affected pipe, actually serve as a temporary repair so Alyeska, under the right conditions, could restart the pipeline, Willson said.

The concept for the clamp was based on large excavators used in the logging industry. Those machines have an arm attached that is used to pick up huge logs.

"It has an articulated arm that you can move 360 degrees so you can really manipulate it," said Willson. "We asked why couldn't we take that same principle and instead of a tool to grab something, make a tool to fit on the end of the arm and clamp around something."

It took two years to create the prototype, test it and put it to work. The resulting HC320 is smaller, more lightweight and maneuverable than the TEAM clamp. It can be used to quickly apply a clamp to a section of pipe, lock it in place and move away from the pipeline.

"It's probably our No. 1 choice of how we would deal with that type of incident," Willson said.

Mobile communications a hit

Another lesson that Alyeska learned from the Milepost 400 incident was that the company would benefit significantly from having a self-sufficient communications system on site.

"We had communications but it took a while to set up and we had to tie into the available fiber optic line that goes through the pipeline," Willson said.

In response, Alyeska designed at a cost of $500,000 to $700,000 a "Mobile Command Post," that is, a 50-foot expandable trailer equipped and dedicated to providing on-scene command and support for emergency personnel at an incident.

The MCP has eight workstations with computers, laptops, satellite phones, regular telephones and a dispatch center with air and ground radios as well as different repeaters.

Since the MCP was rolled out, Willson said it has made a measurable difference. Communications problems, previously a constant challenge, rarely crop up now that it is in use.

"The incident field task force is talking to the MCP and the MCP is presenting that (information) back to Anchorage or Fairbanks emergency operations centers. It has worked outstandingly," he said.

One reason for the MCP's success is its superior telecommunications, including satellite uplinks that enable workers to upload and download pictures and large amounts of data quickly.

"We can display a map drawn in the field through video-teleconference and download it onto a Web site," Willson said. "All of a sudden, everyone in the room is using the same information the folks in the field have to make decisions about what resources need to be applied to the situation. It looks like something out of military movies"

Versatility key to success

The success of the MCP, which is typically hitched to a semi-tractor trailer to travel to the scene of an incident, is due in part to the versatility of its telecommunications system.

"Our preference is to tie into the fiber optic line along the pipeline. That gives us 100 percent full capability," Willson said. "It's like (being on scene while) sitting in our office in Fairbanks or Anchorage."

The MCP also can tie into the communications system at a Pump Station.

"It gives us the capability, but depending on the location of the incident, we may not be as close to the scene as we would like," Willson said.

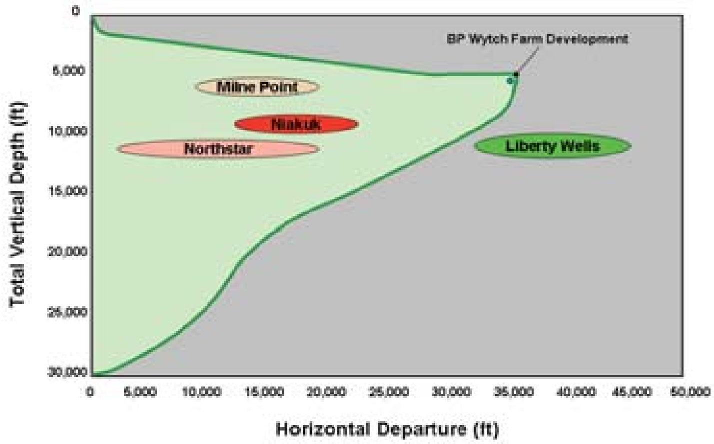
That's when a third method comes in handy. The MCP has satellite dishes on its roof and can work from a satellite feed. Instead of using regular phones, the staff simply switches over to the satellite phones.

"We can upload and download data, but the satellite is a little slower," Willson said. "So we have to be a little more deliberate in sharing data and making sure we prioritize it appropriately. But if the fiber was out, this unit could still go where it needs to and function."

Another reason for the MCP's success is the core staff of 25 trained professionals who go with it when it rolls. They come from the computer systems, environment, safety, operations and resources departments at Alyeska and train regularly for the emergency response work.

"Clearly the biggest benefit is when these trained people go hand in hand with the Mobile Command Post," Willson said. ◆

Industry Drilling Envelope



Juneau

BP EXPLORATION (ALASKA)

Wells with horizontal departures of 6 to 8 miles would reach from the Douglas Bridge to the Juneau airport.

Proposed ultra extended reach wells at BP's Liberty field in the Beaufort Sea will break new ground in extreme directional drilling.

UERD for offshore development

Ultra extended reach drilling enables Liberty offshore development without gravel island

By ALAN BAILEY

Directional drilling of wells that deviate far from the vertical has proved a key technology in accessing much of the North Slope's vast oil reserves. But drilling to horizontal departures of tens of thousands of feet takes you into the world of ultra extended-reach drilling, a technology that could, for example, allow some Arctic offshore oil fields to be developed from onshore or nearshore locations.

BP has successfully used extended reach drilling to develop its Wytch Farm oil field on the south coast of England, where the oilfield facilities lie onshore but a major part of the oil reservoir lies under scenic Poole Bay — wells with horizontal departures of 25,000 feet and more tap oil from the undersea reservoir without the need for any offshore infrastructure.

Drill from Endicott

The company hopes to repeat its Wytch Farm success at the Liberty field, about 5.5 miles offshore under the Beaufort Sea. Liberty development plans envisage a 20-acre expansion to an existing satellite gravel island at the neighboring Endicott field, to accommodate the Liberty drilling rig and wellheads. Production will go through the Endicott facilities and pipeline.

But Liberty drilling will likely achieve world records for extended reach drilling, with horizontal departures from the wellheads of up to 44,000 feet or more.

"Drilling studies support departures of 34,000 to 44,000 feet," BP has said. "Departures beyond 44,000 feet have not been studied."

Turning or pulling the drill string in these exceptionally long well bores will require a massive drilling rig. And, having established that there is no existing rig powerful enough for the job, BP is commissioning the construction of a purpose-built rig — construction is slated to start in 2008 with completion planned for the third quarter of 2009.

"We're looking at a 2010 timeframe … for actual drilling (after) going through permitting, rig design, engineering," Gary Christman, BP's director of Alaska drilling and wells, told Petroleum News.

The new rig for Liberty will be the largest land rig ever built in the world, and the exceptional length of the wells will require a raft of state-of-the-art technologies such as rotary steerable drilling.

"It will take all of this technology that we've developed and exploited in Prudhoe Bay and extend it to a new realm," Christman said.

Ingenuity

Manipulating the drill strings down the extended reach well bores will require some ingenuity. For example, the need to use progressively smaller diameter casing as a well penetrates further through the rock will likely drive the need to use tubing that the drillers can expand downhole to the well bore diameter.

And at these depths even the weight of pipe used to convey the bit downhole is a challenge for the rig to handle. To lighten the load, aluminum drill pipe may be used instead of traditional steel drill pipe, Christman said.

"We'll be doing some field trials with aluminum pipe in Prudhoe Bay," Christman said. BP also wants to establish a way of re-entering the Liberty wells, to enable the use of sidetrack wells that avoid the need to drill more of the highly expensive extended reach wells than necessary.

And BP plans to test some of the techniques that it hopes to use at Liberty as part of an extended reach drilling program in the company's Beaufort Sea Northstar field — the Northstar extended reach drilling will enable the company to increase the oil recovery at that field, Christman said. BP started work on its Northstar extended reach wells in the winter of 2006-07 but the company has not yet completed any of the wells.

"The intention is that this winter we will finish those Northstar wells, and knowledge from those wells will be supporting our efforts to be successful in Liberty," Christman said.

But in venturing into as-yet untried extended reach distances at Liberty BP expects the unexpected.

"The key to us is going to be reacting to problems that we don't anticipate," Christman said. ◆

Airtight seal skins inspire rolligons

Traditional Alaska Native knowledge yields secret of technology to California inventor

By ROSE RAGSDALE

To explore for and develop petroleum resources on Alaska's North Slope, engineers had to build an infrastructure that would disrupt the region's permafrost as little as possible.

Part of the answer for travel across the fragile tundra is the technology underlying the transportation innovation commonly referred to as rolligons.

But the premise for rolligon technology dates back to the first men to visit the Arctic.

The rolligon's inventor, William Albee got his inspiration while visiting Alaska on a fishing trip in 1950.

Albee observed a group of Alaska Natives preparing to remove a heavy wooden boat from the Arctic waters. He wondered how the small, heavily clad men would transport the boat up the muddy bank. The Natives produced and inflated several airtight seal skins and rolled the boat onto them, out of the water and up the bank.

Thus was born the concept of the Rolligon low pressure "air bag." Albee returned to Monterey, Calif., and began to develop the first low-pressure, off-road tire. He also formed the Albee Rolligon Co. to produce vehicles equipped with the low pressure tires.

The first tires were smooth and driven by a top roller, another Albee Rolligon innovation. They measured 30 inches in diameter and 40 inches wide. Albee Rolligon obtained patents on both the wide, low-pressure tire and the top roller drive.

Rolligon changes hands

But Albee was unable to develop his concept into a successful business. He sold the assets of his company to John G. Holland Sr. in 1960. Holland moved the business to Houston, Texas, where he owned and operated a highway-heavy construction company. He incorporated his new assets under the name of Rolligon Corp. and his two companies shared an office, warehouse, and yard.

Rolligon Corp. built several top roller vehicles; however, it was apparent that while the top roller vehicles operated well on sand and level, vegetated terrain, they did not perform well on muddy or wet, inclined surfaces.

Rolligon then vulcanized lugs on a 40-inch-by-50-inch smooth tire, and designed a 4x4 vehicle with axles directly driving the tire from the center. The vehicle was fitted with a pivot and steering was accomplished by articulating the frame. This 4x4 became the model 4450 Marsh Skeeter. It was lightweight, amphibious, and highly mobile and exhibited a ground-bearing pressure of less than 2 pounds per square inch.

With the success of the 4450 came requests for bigger payload capacity vehicles. So Rolligon then developed a 6x6 vehicle, Rolligon Model 6650, along with a larger 54-inch-by-68-inch tire.

In the late 1960s, Rolligon entered a joint venture with the Bechtel Corp. of San Francisco to manufacture several 12x12 vehicles for use in the new oil fields on the North Slope. The vehicles

JUDY PATRICK

Above, current global positioning technology has made a big difference in the ability of rolligon operators to navigate in remote areas of the Alaska Arctic

ALASKA DEPARTMENT OF NATURAL RESOURCES

Crowley Alaska recorded this startling image of a rolligon driving over the body of a researcher during tests of these unusual vehicles on the North Slope in 1970 and 1971.

were designed with the 54-inch-by-68-inch smooth tires designed to exert low pressure on surfaces, specifically around 3 psi. They had top roller drives rather than direct drives and 8x8 tractors with four-wheel-powered trailers. Their large, low-pressure rubber "air bag" tires enabled them to essentially float across unpacked snow, summer tundra, sand and marshland. The tires help distribute the weight of the vehicle and its payload over a large area, thus minimizing terrain impact.

Though they exert higher surface pressure than hovercrafts, rolligons still exert relatively low pressure, low enough for the U.S. Department of Energy to call them an "ultra-low impact vehicle." Early rolligons carried a maximum payload of 30 tons and traveled at maximum speeds of about 20 mph, making them ideal for carrying small drill rigs and drilling platforms.

Crowley acts

Six of the vehicles were delivered to Alaska in 1968. Another 12 were built in 1974 and the newest ones were built in 1980, according to Don Tunks, Crowley All-Terrain Corp.'s manager of operations and maintenance in 2002.

Crowley Maritime Corp., CATCO's parent organization, purchased the North Slope transportation venture in 1975 and still operates the original vehicles on the slope today, providing oil field services.

JUDY PATRICK

Close-up of part of a drilling rig chained down for transport across the tundra

Rolligon Corp. continues to manufacture tires for the vehicles.

The name Rolligon actually applies to a much smaller vehicle used for seismic work and refers specifically to the tires on the vehicles. Even though CATCO's machines are commonly called Rolligons, technically CATCO cannot use that name.

"We call them units or vehicles," explained Tunks, who came to the North Slope more than 30 years ago.

"I came here in '74," Tunks says. "There wasn't much here; a couple of ATCO units for the airport terminal. There were very few people, and I don't remember any women. The road went from East Dock to the Kuparuk River and stopped. On the other side it went to Service City, but it didn't cross the river."

Referred to by some as the "Neanderthals of the North Slope," CATCO's camps are vintage 1970s.

Crowley dubbed its specialized vehicles CATCOs. The company's 29 units are the only ones like them in the world. They operate virtually the same as they did when they first arrived on the North Slope, with two exceptions: The units have been equipped with cell phones and GPS navigational aids.

see **ROLLIGONS** *page 62*

continued from page 61

ROLLIGONS

JUDY PATRICK

Unloading part of a drilling rig and a forklift onto a ramp made of ice and snow at a remote location

Before the advent of rolligons, early operators on the North Slope used Cat trains to move supplies and equipment across the tundra. The practice was discontinued because of the detrimental effect the vehicles had on the tundra.

In 30 years, Crowley has developed a unique system for transporting cargos and personnel to remote roadless areas that has little if any effect on fragile tundra.

Peak Oilfield Services also operates the same type of vehicle on the North Slope today, but its vehicles are called Tundra Cats and Rimpulls.

"From the marine side, we call them 'land barges' because of their large 16-foot platform" said Craig Tornga, former Alaska manager for Crowley.

These "land barges" are used to build ice roads; transport drill rigs, fuel and supplies; and even construct ice pads in extreme locations and conditions.

GPS technology aid work of rolligons

More recently, global positioning technology has made a world of difference in the ability of rolligon operators to navigate in remote areas of the Alaska Arctic, according to Michael O'Shea, director of business development for Crowley.

"It's our company policy that the units and their operators travel in pairs for safety reasons, which reflects the company's ongoing focus on safety," O'Shea said.

Crowley transports more than 2 million gallons of fuel a year across the tundra by rolligon, and the company hasn't had a lost time accident in years, he said.

Crowley recently embarked on a $3 million refurbishment program for 10 of its oldest rolligons in a 20-unit fleet on the North Slope.

The units are getting new engines, transmissions and rear ends as well as frame modifications. The changes will result in a 33 percent cost savings in fuel consumption, reduced emissions and higher speeds under certain conditions, O'Shea said.

"These units are the only ones of their kind in the world that work day to day," he said.

Crowley's rolligon fleet contains four RD105 tractor-trailers capable of transporting 45,000-ton payloads; six RD 85s, which are 16-foot-wide units with power trailers capable of hauling 35,000 tons; seven RD 85 pup units with small trailers, also able to handle 35,000-ton payloads; and three RD 85 trucks with 17.5-ton capacities.

Permitted to operate on the tundra anytime after July 15, Crowley's rolligons are used predominantly during the winter season, O'Shea added.

A return to track vehicles

During the past few years, some North Slope contractors have taken to using tracked equipment for transporting goods and equipment across the tundra. But the tracked vehicles of today use a track made of rubber instead of steel.

Still, the tracked vehicles have a much greater impact on the tundra than rolligons, with a higher likelihood of tundra damage, according to Peak officials.

Also, others are using vehicles with the large tires, but instead of a smooth tread and a roller drive, these have a direct drive and tires with a chevron tread pattern.

This type of tire also has a greater impact on the tundra.

"When the vehicle gets stuck, the wheels start to spin, which damages the tundra," said a Peak official who asked not to identified. "We feel this increased use of non-rolligon-type vehicles will continue to cause damage to the tundra.

"This lack of environmental consciousness and short-sightedness in continuing to use these vehicles is going to risk the future of remote exploration," he added. ◆


JUDY PATRICK

Buiding an ice road by applying water from a water truck

A vanishing footprint

Use of ice-based infrastructure minimizes impact of winter exploration activity

By ROSE RAGSDALE

Ice roads, winter byways that disappear with breakup in spring, are efficient and indispensable aids to oil and gas exploration on the North Slope. These ribbons of frozen water have paved the way for explorers to venture into remote areas of the Arctic since the 1950s when the Royal Canadian Mounted Police first fashioned crude roadways out of snow.

In Alaska, ice roads have successfully served remote locations in the Arctic, even during winters characterized by minus 70 degree Fahrenheit temperatures, 20-foot snowdrifts and limited daylight.

Early road construction in the 1920s featured bulldozing the tundra, but the practice proved disastrous. After just one season, such a route was impassable when the permafrost thawed.

Pioneer explorers turned to gravel to insulate the permafrost and stabilize roadbeds, airstrips, and drilling pads, but soon found that gravel mining and construction are expensive and environmentally harsh.

Oil and gas explorers quickly realized that ice roads could get the job done without leaving behind harsh reminders of their passage, and they cost a fraction of their gravel counterparts.

As construction of the trans-Alaska oil pipeline drew to a close in the 1970s, winter exploration roads made of snow and ice gained popularity on the North Slope.

Ice roads enabled explorers to use the same equipment to conduct exploration development programs that they used on gravel year-round, while minimizing the impact of their presence in the Arctic environment.

Rough riding on early roads

But in the 30 years since the late 1970s, ice road and ice pad construction technology has come a long way. Thanks to the growing expertise of operators and contractors, ice road construction evolved from simply packing snow into crude pathways across the tundra to mixing ice, water and snow into surprisingly durable thoroughfares that can withstand the heaviest loads all winter long.

Early ice road builders just packed snow and basically drove on it.

The "ice" road was very rough, built with caterpillars and trucks, according to James Trantham, a project manager for ARCO Alaska Inc.

"Basically any time a truck went over it, you had to go back and roll over it again, because it just kind of 'squooshed' the snow up," Trantham told participants in an oil and gas technologies conference in 2000.

"So it was really high maintenance and probably not as safe a road as we have today," he added

The original North Slope ice road crews consisted of a couple of bed trucks with "suck-on" water tanks (tanks that had water pumps combined with the tank, that could be used for filling the tanks with water), a loader or grader and a dozer, according to contractors at Peak Oilfield Services Inc.

"The technique was to take snow on the road route, smooth it down with either a dozer, or a loader with a drag or a grader and then to put water on it. This produced a road that a rig could be moved across, but were not necessarily very wide or smooth. The average crew was between 14 and 16 people, half on days and half on nights," they said.

The soils of the North Slope have a

see **ICE ROADS** *page 64*

continued from page 63

ICE ROADS

permafrost layer that is frozen from a depth of about 1,600 feet up to maybe a foot below the surface. The top portion of the permafrost is called the active layer, and it thaws in the summer and refreezes in the winter. When snow is dumped on top of the active layer, heat is trapped in the top half-foot or so below the tundra.

"So by packing the snow, you remove the air and actually promote the freezing. We do that from a rolligon, and then in time the trucks come down the middle of the road and squirt water out to the sides and start moving around on the ice road," Trantham said.

Regulators set guidelines

"In the 1970s, it was pretty evident to everyone that the slope was a very sensitive area, and there were plenty of examples of tundra damage throughout the slope," said Leon Lynch, a specialist with the Alaska Department of Natural Resources Division of Mining Land and Water.

DNR responded by passing regulations giving the slope a special land use designation. As a result, activities such as off road travel that were generally allowed on other state lands require a permit on the North Slope.

Among stipulations of the permits:

• Ice roads and ice pads must be built so that they are thick enough to protect the vegetative mat;

• Vehicles must be operated so that there will be no damage to the vegetative mat;

• All rehabilitation must satisfy the DNR commissioner; and

• DNR or another applicable land manager must determine what travel openings and closures should be based on snow cover and frost depth.

JUDY PATRICK

Making ice chips for building ice roads

In the 1970s and 1980s, ice road builders started adding more water, especially close to the drill pads because there was so much traffic around the pads.

Later, they began to add more water to the roads, and use graders and snow blowers to maintain the ice roads.

"In the mid-80s, we actually started adding ice chips using a machine with a big pump that threw water up into the air where it turned into snow or ice chips (in the subzero temperatures of the 24-hour Arctic nights) and deposited on the road or pad where we would pack it down," Trantham said. "After awhile we started actually mining ice chips from lakes to use in ice road construction."

At the same time, the first insulated pads were built at the Leffingwell where insulation and boards were placed on the tundra to support the rig, he recalled. Later, the insulated foam was moved over to the KIC No. 1 well within the Arctic National Wildlife Refuge, he said.

The addition of delineators in the 1980s to mark the sides of ice roads also lessened the environmental impact of exploration on the tundra. Delineators allow exploration and construction crews to continue working in all but the very worst visibility, and they help to keep traffic on the ice roads.

Regulation drives ingenuity

As regulations governing the construction of ice roads and ice pads became more stringent, operators and contractors have responded, using technology to extend the length of the drilling season and to minimize damage to the tundra.

Regulators monitor the condition of the tundra closely and over the years have shortened drilling seasons as warmer weather has shortened North Slope winters.

The standard that regulators use for opening the tundra is 12 inches of frost and six inches of snow. Opening dates in general allowed for a six-month winter drilling season, but in the last decade, warmer temperatures have shortened the exploration season to about three and a half months.

Explorers responded with proposals for pre-packing trails and developing a graduated system of season opening. With such a system, instead of waiting for 12 inches of frost, lighter weight vehicles with lower ground pressure could actually operate on six or eight inches of frost. That became important for loaders and smaller vehicles used in ice road construction.

Working with regulators, operators and contractors refined this system until much of ice road construction occurs prior to the general tundra opening. This means that the sooner the industry gets to work safely, without damage to the tundra, the sooner they can complete their projects, and get off the tundra in spring, before breakup becomes a concern, DNR officials say.

Ice-based technology proves its mettle

"The construction and use of ice roads by the petroleum industry provided access into environmentally sensitive areas without permanent impact from gravel road construction," said Scott Guyer, a researcher with the Bureau of Land Management in Anchorage.

Based on a study of ice roads and ice pads construction, including work done in 2001 and 2002 for the Puviaq exploration well, in the northeastern corner of the National Petroleum Reserve-Alaska, BLM concluded in 2003 that "ice roads and pads that support drilling operations, if built with care, can have no long-term effects to the fragile tundra environment," according to Guyer.

Today, ice road construction is similar to gravel road construction in many ways, only it is done with snow or ice. Dozers and drags pulled behind loaders are no longer used because they damage the tundra. Graders and loaders combined with on- and off-road water trucks and haul trucks are used to build the roads. Both water and snow are hauled from lakes to where roads are being constructed. Average crews number 24 to 32 people, depending on the scale of the project, again with half on days and half on nights.

To get an early start, operators and contractors use rolligons — large vehicles with large, smooth, low pressure tires that have a roller drive rather than a direct drive — which regulators have approved for travel on the tundra in both summer and winter. The rolligons are used to pack down the snow and place a layer of water on top of the tundra.

Technology spurs more improvements

On remote projects, where ice roads cannot link explorers with the gravel road system, all of the ice road equipment as well as drill rigs and support equipment must be hauled to the drill site. Originally Cat trains were used, but the practice was discontinued in the 1970s because of their detrimental effect on the tundra. Rolligons or track vehicles with balloon-like rubber tracks are now used to haul most loads across the tundra.

Early researchers would test the delicate touch of the rolligons by lying down on the tundra and allowing operators to drive the huge vehicles over their bodies.

Recently, rolligon crews have demonstrated even greater environmental awareness by carefully monitoring their activities on the tundra and taking steps to remove all signs of their passage, according to Sharmon Stambaugh, wastewater program manager for the Alaska Department of Environmental Conservation.

Peak, for example, has focused on rigorous vehicle maintenance to prevent spills of hydraulic fluids and other substances on the tundra. ◆

JUDY PATRICK

Ice road maintenance in NPR-A

Insulated ice pads extend season

Innovation minimizes environmental impact, shrinks exploration footprint, cuts costs

By ROSE RAGSDALE

Regulations designed to protect the fragile Arctic tundra and shorter winters have given Alaska North Slope operators both economic and environmental impetus to develop clever ways to extend their drilling seasons.

One such innovation is insulating drilling pads to prevent them from thawing during the short Arctic summers. This technology succeeded in extending exploratory drilling seasons as much as 50 percent, and earned recognition from the U.S. Department of Energy as one of the Alaska oil and gas industry's best practices.

Currently, Arctic drilling seasons are restricted to 135-170 days, at best lasting from late November until mid-May. Operators not only must quickly build temporary ice roads to drilling sites, they also are required to construct ice pads, often as large as an acre. Drilling rigs and the remote camps that support them rest on these pads.

Drilling crews confine their activities to these islands of ice all winter and are careful to not stray onto the tundra beyond them. By mid-May, all traces of the rigs, camps and equipment must be removed to non-sensitive areas.

In the 1970s, regulations on the North Slope were less strict and the first ice roads invariably ended at a drill rig resting on a gravel pad. In very remote locations, a gravel airstrip also might be nearby.

COURTESY BP EXPLORATION (ALASKA)

BP Exploration (Alaska) used foam-core panels to insulate a drilling pad at Yukon Gold south of the Point Thomson unit. The 400-foot-by-300-foot-by-6-inch ice pad, pictured here while it was under construction, was built in the spring of 1993, covered in plastic sheeting and topped with 600 foam-core panels.

The approach resulted in a potential loss of eight to 10 acres of tundra habitat, and should the drilling program end with a dry hole, state regulators said operators could show no economic benefit from the lost habitat.

Shift to ice pads in 1980s

Operators switched to drilling pads made of ice in the 1980s, recognizing them as less costly and environmentally intrusive than their gravel predecessors. Still, by the 1990s, conventional ice pads were no longer meeting the needs of operators because they melted in spring and had to be rebuilt the following winter.

Adding prefabricated insulation to ice pad construction made ice pads last for multiple seasons. It enabled operators to build ice pads before a winter drilling season started, and preserve the site through the summer thaw for re-use the following winter.

More importantly, the technique gave the companies up to a two-month head start on conventional technology. Insulated ice pads, in effect, extended the available drilling season to 205 days and effective well operations to 160 days. This enabled drillers to complete at least one exploratory well, and sometimes two penetrations in a single season, operators say.

What's the allure of single-season completions?

Completing a multimillion-dollar

exploratory well in one season cuts mobilization costs considerably, not to mention reduces related environmental effects. It also shortens the time between initial investment and return on that investment, and gets valuable subsurface data to exploration teams sooner than otherwise would be possible. Such speedy feedback enhances planning, operators say.

DOE cites BP ice pad success

When a BP Exploration (Alaska) Inc. engineering feasibility study indicated that constructing an insulated ice pad in March 1993 at Yukon Gold No. 1 on the North Slope would significantly extend the winter drilling season, BP built a 390-by-280-foot ice pad covered with nearly 600 wind-resistant insulating panels. Summer visits confirmed that the ice beneath the panels remained sufficiently frozen. When the panels were disassembled in October 1993, they had not bonded to the resting surface, or scattered, and nearly 90 percent were in excellent condition and reusable.

BP began drilling in mid-November, two months ahead of conventional Arctic practice. With such an early start, Yukon Gold No. 1 was completed and the company had time to begin drilling at nearby Sourdough No. 2, where the insulated panels were placed under the drilling rig to give BP the option of leaving the rig on location over the summer and avoiding remobilization if the well wasn't completed before season's end. This proved to be unnecessary since the Sourdough well also was completed during the same season.

Overall, BP netted a cost savings of more than $2.3 million from the two single-season well completions, according to DOE. In addition, the tundra endured significantly less impact than would have been the case had BP's crews been required to move seasonal equipment back and forth between two or more drilling seasons.

DOE also reported that subsequent site monitoring showed no long-term environmental impacts from use of the insulated ice pads. ◆

Petroleum News March 2002 reprint

Petroleum news

Following is abbreviated text from an article that appeared in the March 24, 2002, issue of Petroleum News by Kristen Nelson

Phillips Alaska is planning winter exploration drilling next year on some of the farthest west leases in the National Petroleum Reserve-Alaska. The company has applied to build a 1.5 acre insulated ice pad in order to keep a drilling rig in the area over the summer.

The Puviag insulated pad, according to the U.S. Army Corps of Engineers, would be west of Teshekpuk Lake approximately 67 miles southeast of Barrow in section 35 township 16N range 10W, Umiat Meridian. The Corps said no drilling operations are planned for this site. The rig would be moved to a "nearby winter exploratory drilling site" after tundra travel is approved for the 2002-2003 winter season.

This prospect is some 45 miles west-northwest of the Trailblazer prospect BP drilled last year, and, other than development drilling at the Barrow gas field, will be the farthest west North Slope drilling in several decades. …

Phillips will mobilize a crew … and construction equipment by rolligon or other all-terrain vehicles to the site for pad construction, the corps said. The drilling rig will be moved to the site by rolligon after the pad is built but before the close of tundra travel this spring and then moved to a nearby winter exploratory drilling site after winter tundra travel reopens in late 2002 or early 2003.

The corps said the insulated ice pad would be approximately 245 feet by 265 feet by six inches thick. Construction is expected to begin in March. The ice pad will be covered with standard … 4 to 6-inch thick, 25 psi expanded polystyrene foam insulation. The panels weigh about 700 pounds each.

The polystyrene panels will be sandwiched between 8-foot by 24-foot sheets of 7/16-inch thick oriented strand board. Reinforced polyethylene film will be laid under the panels to prevent them from bonding to the ice pad to ensure easy pick-up.

Exposed panel surfaces will be covered with a white, opaque surface fabric that is designed to minimize thermal gain, minimize rainwater infiltration to the ice surface and minimize thermal erosion of the ice pad.

Standard rig mats will be placed on the insulated panels with the drilling rig sitting on the mats. Ice berms may be constructed to divert spring runoff from the pad. The berms will be about 3 feet high, roughly trapezoidal in cross-section with an 8-foot wide base and a 4-foot wide top.

Rope anchors will be used to resist wind uplift forces on the panels not protected by the rig and the site will be monitored every two to three weeks over the summer to collect data from 10 or more thermistor sensors monitoring ice-surface temperatures and to provide side maintenance. …

ALYESKA PIPELINE SERVICE CO.

Dave Hackney, program engineer in charge of pigging at Alyeska Pipeline Service Co.

Pipeline pigs dig the dirty work

Instruments used by Alyeska to monitor, maintain 30-year-old infrastructure have improved

By ROSE RAGSDALE

Perhaps the most talked about and least understood technologies in the transportation sector of the oil industry are in-line inspection devices known as "pigs."

These oinkers, like their namesakes, are built to thrive in messes. But unlike the barnyard animals, oil industry pigs are lean, industrious machines designed to wallow inside operating pipelines, where operators cannot.

Industry pigs, an acronym for pipeline inspection gauges and sometimes as big as automobiles, are periodically inserted into pipelines by operators to perform numerous and increasingly sophisticated tasks. There are two basic types, mechanical and instrument.

Mechanical pigs do everything from sweep trash out of a pipeline to scrape waxy buildup off its walls.

ALYESKA PIPELINE SERVICE CO.

This pig has hard plastic discs for aggressive cleaning. Alyeska Pipeline Service Co. technicians run them through sections of the 800-mile trans-Alaska oil pipeline as needed.

These are the most frequently used pigs on the 800-mile trans-Alaska oil pipeline. Alyeska Pipeline Service Co., the pipeline's operator, once sent cleaning pigs through the pipeline about once a month. But as Alaska North Slope crude flow has declined in the pipeline to about 800,000 barrels per day, operators are cleaning out the line as often as every week.

"From a pig's eye-view, the pipeline is really two pipelines," said Dave Hackney, program engineer in charge of pigging at Alyeska.

The section from Pump Station 1 to Pump Station 4 is typically cleaned by a pig every two weeks, but the longer section from Pump Station 4 to Valdez is quite a bit cooler. "So we run a pig on that section every week," Hackney said.

Instrument pigs, or so-called "smart" pigs, have high-tech circuitry that enables them to record images of the pipe using ultrasonic and magnetic sensors. Operators check these images for signs of corrosion, stress and bending in pipe walls.

First pigs down line in 1978

But the story of pigs in Alaska's oil

industry begins and ends at Alyeska Pipeline Service Co.

The company sent its first corrosion pig and caliper pig through the pipeline to look for dents in 1978, less than a year after the pipeline's startup.

"Neither (of the pigs) was very sophisticated, but they got better as time went on," said Hackney.

Among the company's early experiences was the time it sent a curvature, or deformation, pig through the pipeline in 1979 and it got stuck at check valve 29. Alyeska ended up opening the check valve, removing the pig and installing a stopple and bypass at the location.

Alyeska engineers had been advised by expert consultants that the pipeline would have little trouble with corrosion. Still, the company chose to commit substantial time and resources to developing better instrument pigs to make doubly sure.

In time, it became clear that the pigs were returning data to the company that left huge gaps in information. Alyeska began working with NKK, a Japanese vendor, to develop an ultrasonic transduction, or UT, pig that could produce more reliable data.

A UT pig sends sound waves through the pipe and compares the speed of their propagation with what would be expected in a pipe of proper thickness.

"NKK used Alyeska as a test bed for a better ultrasonic pig and when they were successful, we paid them for the data," Hackney said.

Alyeska also worked with a Canadian company, International Pipeline Engineering Ltd., to develop a magnetic flux leakage, or MFL, pig.

An MFL pig uses magnets to saturate the pipe walls with magnetic lines of force or flux, and if the lines are disturbed and leak out, the pig can sense the leakage and deduce how much metal has been lost from the pipe's walls.

ALYESKA PIPELINE SERVICE CO.

This paraffin cup scraper pig is used to clean wax buildup from the walls inside the trans-Alaska oil pipeline. It is one of three types of cleaning pigs used on the trans-Alaska oil pipeline and the one Alyeska Pipeline Service Co. uses most often.

"We did all this at a time when we thought we wouldn't have a problem with corrosion," Hackney said.

The new instrument pigs took their first maiden trip down the pipeline in 1987 and encountered significant signs of external corrosion on the buried pipe near the Chandalar River.

"The first anomaly we dug up had enough corrosion that we had to put a sleeve on it," Hackney said. "We thought we wouldn't have a problem with corrosion, but our world changed when the pigs told us otherwise."

Alyeska ended up putting so many sleeves on pipe in the Atigun Pass area in the late 1980s and 1990 that the company decided in 1991 to dig up and replace nine miles of pipe on the north side of the pass.

Meanwhile, concern arose in the early 1980s about the pipeline moving, Hackney recalled.

A deformation pig, which detects dents and bends in the pipe, began to return disturbing data.

"One of the company's greatest successes with this instrument happened when it detected wrinkling of pipe under the Dietrich River near Milepost 200 in 1985," Hackney said. "We did a reroute in February when it was 68 degrees below zero Fahrenheit. It was a success story because we intervened before oil got out of the pipe."

Pigs grow smarter

The pipeline was settling as it melted ice and permafrost below buried sections. This was another phenomenon that Alyeska engineers needed to carefully watch, so they urged instrument pig manu-

see **PIPELINE PIGS** *page 70*

ALYESKA PIPELINE SERVICE CO.

Alyeska Pipeline Service Co. technicians generally run this device in rotation with a disc pig prior to sending a smart pig down the pipeline.

continued from page 69

PIPELINE PIGS

facturers to develop an even smarter device called a "Geo" pig.

"The Geo pig has the brains of a guidance missile," Hackney said. "It gives its position in three-dimensional space every 2 inches."

Using data from different Geo pig runs, Alyeska engineers can plot the position of the pipeline within millimeters on a computer and determine conclusively if the line has moved and if that movement poses a threat to the pipeline's integrity.

"The pipeline moved quite a bit as it settled, but it's settled in now and moves less and less," Hackney said. "Most of the buried pipe is now a foot (deeper) than where we put it, but now the pipeline hardly moves at all."

Over the years, pig vendors have made more technological advances.

For example, Alyeska is now using second-generation ultrasonic pigs, instruments that operate 512 transducers, with each recording 625 readings a second, Hackney said. An onboard computer stores all the data and keeps track of where readings are taken. This helps operators pinpoint places quickly where the pipe wall is thinner.

By comparison, the ultrasound instrument in the doctor's office uses a single transducer to register and record images of the human body.

Alyeska also encouraged vendors to make improvements in the magnetic pigs.

"They've done a pretty good job keeping up with technology," said Hackney. "As a result, we have a pretty good idea of what the inside of the pipe looks like."

He likened Alyeska's new pigs to race cars. "Pigs come in different sizes, shapes and configurations, and other companies buy the taxicab models," he said.

Most of the pipeline's corrosion has stemmed from external forces such as water over the years. At 30, Hackney said the line is still relatively young by industry standards.

"Age is less important than maintenance and the characteristics of the contents of the pipeline," he explained. "For example, the guys who manufacture our magnetic pigs run a pipeline in northern Canada that has to be replaced every two years."

Hackney said that pipeline transports a highly corrosive product.

Smaller models coming

More advances in pig technology also may be under way.

Hackney said an instrument that can detect cracks in the pipeline, ostensibly called a "crack" pig is currently being developed, but Alyeska does not anticipate having a big need for it.

"We have really good steel, and our pipe isn't prone to

ALYESKA PIPELINE SERVICE CO.

Alyeska Pipeline Service Co. sent this instrumentation — or "smart" pig — down the trans-Alaska oil pipeline earlier this year from Pump Station 4 to Valdez. Here engineer Dave Hackney joins another worker in examining the pig.

cracking," he said. "We have no evidence that we are susceptible to cracks. But we look for it every time we dig up the pipe."

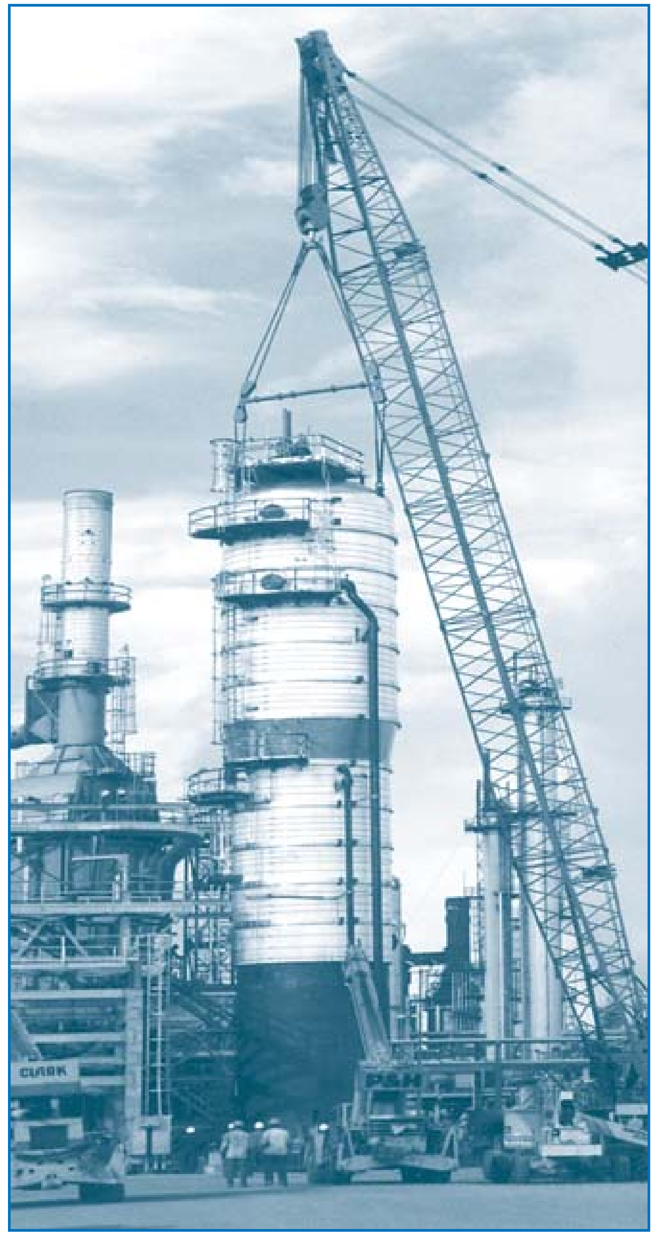
The last time Alyeska took a look? In June, said Hackney.

Despite their increasing sophistication, smart pigs do have limitations. Current models can be too big to navigate many pipes. To remedy this, the industry envisions smaller, svelter robots that move under their own power and go wherever an operator directs them, no matter the direction of the flow of oil (or natural gas in gas pipelines). These robots will require much lighter sensors, and researchers are looking at a number of techniques.

J. Bruce Nestleroth and Richard J. Davis, of Battelle, based in Columbus, Ohio, describe one sensing method in an article published on Aug. 30 in the journal Nondestructive Testing and Evaluation International. They use a device that moves through a pipeline while rotating pairs of permanent magnets around a central axis, stirring up powerful "eddy currents" in the surrounding metal. Variations in these currents can paint a detailed picture of the pipeline's walls. ◆

—Petroleum News staff writer Alan Bailey contributed to this article.

*Is there a way to drill out through the side of an existing well bore? You bet. Use **coiled tubing with a mud-motor-powered drill bit** to break out. Learn more on page 24.*



ALYESKA PIPELINE SERVICE CO.

A prevention and response tug maneuvers to assist the Overseas Chicago in getting under way after taking on a load of crude at the Valdez Marine Terminal, while an enhanced tractor tug waits in the background.

Prevention fuels best practices hunt

SERVS, terminal benefit from Alyeska's commitment to doing it right, best technology

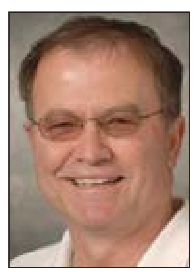
By ROSE RAGSDALE

Unquestionably, the watershed event in the evolution of oil spill prevention and response technologies used by Alyeska Pipeline Service Co. was the Exxon Valdez oil spill.

In a little over 11 1/2 years, oil tankers had taken on loads of Alaska North Slope crude and transported them to market without incident nearly 9,000 times.

But on March 24, 1989, all that changed when the Exxon Valdez ran aground on Bligh Reef. An inexperienced crewman, maneuvering to avoid huge chunks of ice that had calved into the Sound from Columbia Glacier, managed to rip a hole in the bottom of the single-hull tanker.

The resulting oil spill disaster grabbed headlines around the world and brought years of outrage and recriminations. But a significant outcome of the entire episode was an aggressive move by Alyeska, in cooperation with the U.S. Coast Guard, the State of Alaska and others, to ensure that nothing like the Exxon Valdez spill could ever happen again.



ALYESKA PIPELINE SERVICE CO.

Greg Jones, Valdez vice president, Alyeska Pipeline Service Co.

Part of that response was the creation of the Ship Escort Response Vessels System or SERVS, as it is commonly known. Established July 10, 1989, SERVS soon acquired a fleet of tugboats and escort ships and set up a schedule for the vessels to escort oil-laden tankers through Prince William Sound into the Gulf of Alaska.

Their mission: Help steer the oil tankers out of harm's way and provide initial oil spill response in an emergency.

"Some of the boats could do docking, and some were equipped more for towing operations and used for escorting the tankers through the sound," said Greg Jones, senior vice president of operations at Alyeska. "We had another class of vessel that pretty much had a bunch of pollution response equipment on board and did provide a lot of value as a tug."

Crowley's tugs world-class

Alyeska hired Crowley Maritime Corp in 1995 as its long-term marine contractor to provide tugs, barges, and qualified personnel for SERVS. The goal was to comply with federal and state regulations imposed as a reaction to the Exxon Valdez spill, according to Chairman, President and CEO Thomas B. Crowley Jr.

But an objective assessment of SERVS revealed the system's inefficiencies and

see **SERVS** *page 74*

continued from page 72

SERVS

that it lacked the prevention focus that Alyeska adopted as its top priority, Jones said.

To improve SERVS capabilities, Alyeska and Crowley designed and built two classes of new tugboats with an emphasis on prevention and with input from state, federal and industry experts as well as local citizens on the Prince William Sound's Regional Citizens' Advisory Council.

Alyeska rarely departs from its traditional approach of purchasing off-the-shelf tec hnology but in this instance, the company opted to build the tugs from scratch. In developing the final designs for the tugs, the company spent $2 million on a risk assessment study in which the State of Alaska, the marine shippers and the council collaborated.

"We wanted to build the system based on science and good engineering practices and not just on people's hunches," Jones said.

"We have developed and built vessels to meet the "Best Available Technology" requirement of the State of Alaska and Alyeska, both of which are committed to making Prince William Sound safe for oil transportation," Crowley told Time Magazine in 2001.

Crowley has supplied SERVS with three prevention-response tugs or PRTs and two enhanced tractor tugs. The PRTs can generate a certified bollard pull of 305,000 pounds and a free running speed in excess of 16 knots. They also are equipped with firefighting cannons and emergency response and oil spill recovery equipment. The enhanced tractor tugs are the most powerful cycloidal propulsion tugs ever built, capable of moving 360-degrees in either direction, a bollard pull of 208,000 pounds and a vessel speed of 14.5 knots.


DAVID PREDEGER, ALYESKA PIPELINE SERVICE CO.

The Nanuq, one of two enhanced tractor tugs operated by Alyeska Pipeline Service Co., is tethered to the stern of the oil tanker American Progress as it heads for the open ocean beyond Prince William Sound. Alyeska's new emergency prevention priority requires tug operator Crowley Marine Alaska to keep a line attached to oil tankers under way through the Sound.

"The specially designed tractor tugs are amazing," said Jones. "They have a deep skag or keel that enables them to turn sideways in the water without capsizing. This creates a tremendous drag, or braking force to stop a tanker."

If a conventional tug tried the maneuver, Jones said, the forces involved would flip the vessel over.

PRTs can turn 360 degrees

Jones said the PRTs have "z" drives and rotating dual thrusters on their sterns. "Think of them as having conventional propellers but ones that can turn on their axis 360 degrees," he said. "Those tugs are more capable as towing vessels in open water because they have the brute strength to come alongside a tanker and take it into tow, if necessary."

All five tugs have 10,000 horsepower engines, and together, they cost $75 million. They also are equipped with state-of-the-art water cannons to combat a possible fire on a tanker or at the Valdez Marine Terminal.

"There is nothing like them in the world," Jones said. "My understanding is we have more firefighting capability in Prince William Sound than they have on the entire (Lower 48) West Coast."

In addition to the extraordinary tugs, SERVS maintains several conventional tugs, a supply boat, and an oil spill response vessel as well as six large barges, four of them manned, and an assortment of skimmers and small barges for response readiness, all of which is based on the latest and best technology available, officials say.

Jones said the U.S. Coast Guard also operates a vessel traffic service where it monitors all vessels in the sound and joined Alyeska, the state, marine shippers and others in installing ice detection radar that tracks movement of ice coming from Columbia Glacier that would pose a hazard to oil tankers.

If a chunk of ice drifts too close, the Coast Guard informs the affected tanker of its location. "It's just one more piece of data that can be transmitted to the captain of a tanker to help the vessel make a safe transit," Jones said.

Alyeska's focus on prevention and the updated technology got a real life test in 2001 when the Chevron Mississippi oil tanker traveling through the Valdez Narrows avoided a collision with a fishing vessel that strayed into its path.

"These tugs stopped the tanker very abruptly, and nothing else happened," Jones said. ◆


ALYESKA PIPELINE SERVICE CO.

Alyeska workers lower a piece of metal called a "sleeve" into place, where it will be welded to a section of the trans-Alaska oil pipeline where corrosion or something else has compromised the pipe wall.

Corrosion battle began on Day 1

Ongoing campaign slows aging in trans-Alaska oil pipeline, yields technology dividends

By ROSE RAGSDALE

In the beginning, it was an occasional skirmish. Thirty years later, Alyeska Pipeline Service Co. is embroiled in a full-scale war on corrosion and destructive forces attacking the trans-Alaska oil pipeline.

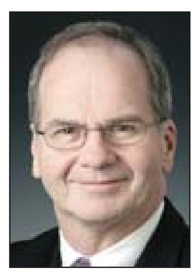
Alyeska President and CEO Kevin Hostler boasted in June that the pipeline is in pretty good shape after 30 years of operation.

But like any well-toned mechanism, the pipeline system pays a considerable price for its attractive condition.

A corrosion-related oil spill has never occurred in the trans-Alaska oil pipeline system, Hostler said. And, since dry oil passes through the pipeline, internal corrosion isn't as much of an ongoing concern as external corrosion.

Alyeska addresses corrosion control, monitoring and prevention with the best technologies the industry has to offer, many of which the company helped develop.

From the beginning, the company has committed to aggressive inspection and monitoring designed to detect the tiniest changes possible in the 800-mile mainline from Prudhoe Bay to Valdez and in the ancillary pipelines, storage tanks, valves, pumps and other equipment in the system.


Kevin Hostler is president and CEO of Alyeska Pipeline Service Co.

"Alyeska was one of the more aggressive users of in-line inspection tools from Day 1, so that when changes occurred in the pipeline we were on top of them," said engineering advisor Elden Johnson, who was there at the beginning after helping to design and develop the pipeline in the mid-1970s.

In-line inspection tools, or pigs as they are commonly called, have become one of Alyeska's most important inspection technologies.

"Thirty years ago the pigs were pretty rudimentary. We were lucky if they detected a 50 percent wall loss," Johnson said. "Now they can detect as little as a 10 percent wall loss."

Alyeska's leadership also encouraged others in the oil industry to use inspection pigs, Johnson said.

Focus on external corrosion

Alyeska's corrosion program began in the late 1980s and resulted in the replacement of about nine miles of corroded pipeline in the Atigun floodplain in the early 1990s. The Atigun pipeline replacement triggered an ongoing "pig and dig" program, Hostler said.

"If you look at our history over the past 30 years, as we do our inline surveillance and our inline pigging runs … what we've always seen and continue to look for is the

see CORROSION page 76

continued from page 75

CORROSION

impact of external corrosion, primarily as a result of water getting underneath the insulation," Hostler said.

The company requires pipeline repair or replacement in any area where surveillance discovers a corrosion anomaly impacting more than 40 percent of the pipeline wall, he said.

That standard applies to the whole length of the pipeline, despite the fact that only about one-third of the pipeline lies in "high-consequence" areas where the U.S. Department of Transportation would mandate that 40 percent limit, Hostler said. In less critical areas DOT mandates repair or replacement when corrosion anomalies impact 80 percent of the pipeline wall thickness, he said.

Alyeska also uses cathodic protection to help prevent corrosion, especially on buried sections of the pipeline, which span close to 380 miles. However, the pipeline's location relatively close to one of the earth's magnetic poles created special challenges. Telluric currents, the forces that cause the Northern Lights, interfere with the cathodic protection.

With the help of the Geophysical Institute of the University of Alaska Fairbanks, Alyeska developed a method to measure and compensate for telluric currents.

Elden Johnson is an engineering advisor who has worked for Alyeska Pipeline Service Co. for three decades and before on construction of the trans-Alaska oil pipeline.

Alyeska buried about 800 steel coupons along the 380 miles of buried pipe. Corrosion engineers can observe differences before and after the cathodic protection current running through the pipeline and the coupons are switched on and off.

It's an important part of controlling corrosion along buried sections of the pipeline. The coupons yield reliable information about the condition of corrosion protection in the pipeline, Alyeska officials say. Alyeska also buried zinc ribbons next to the pipeline to act as "sacrificial anodes" to inhibit corrosion. In Atigun Pass where nine miles of pipe has been replaced, four magnesium ribbon anodes are used instead of zinc.

The pipeline and zinc anodes pick up the telluric currents and the anodes act like grounding rods to safely return the currents back to the earth, reducing the risk of corrosion damage.

Technology developer role

"We didn't invent these devices, but the development of them and turning them into common usage in the industry happened at TAPS," Johnson said.

If Alyeska found that telluric currents were causing interference at a location, engineers would beef up the cathodic protection by using impressed current to fill in the gaps or painting a half-inch-wide zinc ribbon onto the pipeline if the metal's protective coating is damaged, Johnson said.

Over the years, certain places along the pipeline have experienced significant corrosion, that is, wall loss in the metal of 20 percent or more. Typically, additional corrosion protection is added to the spot, but in some instances, the company covers the affected pipe with a section of new metal called a "sleeve."

"In an extreme case, we can place the sleeve around the pipe and coat it. Then it's good as new," Johnson said.

Sleeves are also used to repair cracks and holes caused by pipe movement and in at least two cases, sabotage.

Alyeska also regularly checks for corrosion the old-fashioned way.

"We have a dig program every year. This year we've dug up the pipeline six times," said Dave Hackney, program engineer in charge of pigging at Alyeska.

In three decades, Alyeska has dug up buried sections of the pipeline 1,000 times, typically 20 feet at a time, according to Hackney.

Looking inside the pipe

Internally, corrosion has not been a significant problem for the main pipeline. Sales quality crude and natural gas liquids have very little water or other corrosive materials in them, and they flow through the pipeline as such high velocities that little water has a chance to settle out of the petroleum.

The pump stations and the Valdez Marine Terminal are a different story.

"We can't pig those lines and some are low-flow or 'dead legs' where the oil just sits in there," Johnson said.

Transportation crude contains up to 0.35 percent water, "so you can get a little water layer at the bottom of the pipe," Johnson said.

Alyeska uses coupons to check for corrosion in the low-flow and dead leg lines at least once every six months, he said.

Another method, remote field eddy current, or RFEC, testing, uses a coil of wire carrying low-frequency alternating current to induce eddy currents. Such coils can be made quite narrow, and can thus be used to inspect "unpiggable" pipes from inside.

The U.S. Department of Transportation is funding projects to test this idea in natural gas pipelines. Another concern, especially on the North Slope since the Prudhoe Bay oil spills in 2006, is the possibility of bacteria speeding corrosion, Johnson said.

Alyeska adds corrosion inhibitor to the pipeline system to prevent the little bugs from thriving in water that may be present in the smaller lines.

At the terminal in Valdez, the company has encountered another set of corrosion problems. Pipes inside the treatment system for the highly corrosive ballast water coming off the oil tankers have leaked.

"We learned early on that corrosion took place at joints. In the early 1980s, we had to recoat the ballast water pipeline on the insides," Johnson said.

Another problem area has been the huge crude storage tanks at the terminal, where water settles to the bottom of the tanks and causes corrosion over time.

Alyeska has placed anodes inside and outside the tanks with cathodic protection and inspected them every 10-20 years, depending on the observed corrosion rates, Johnson said.

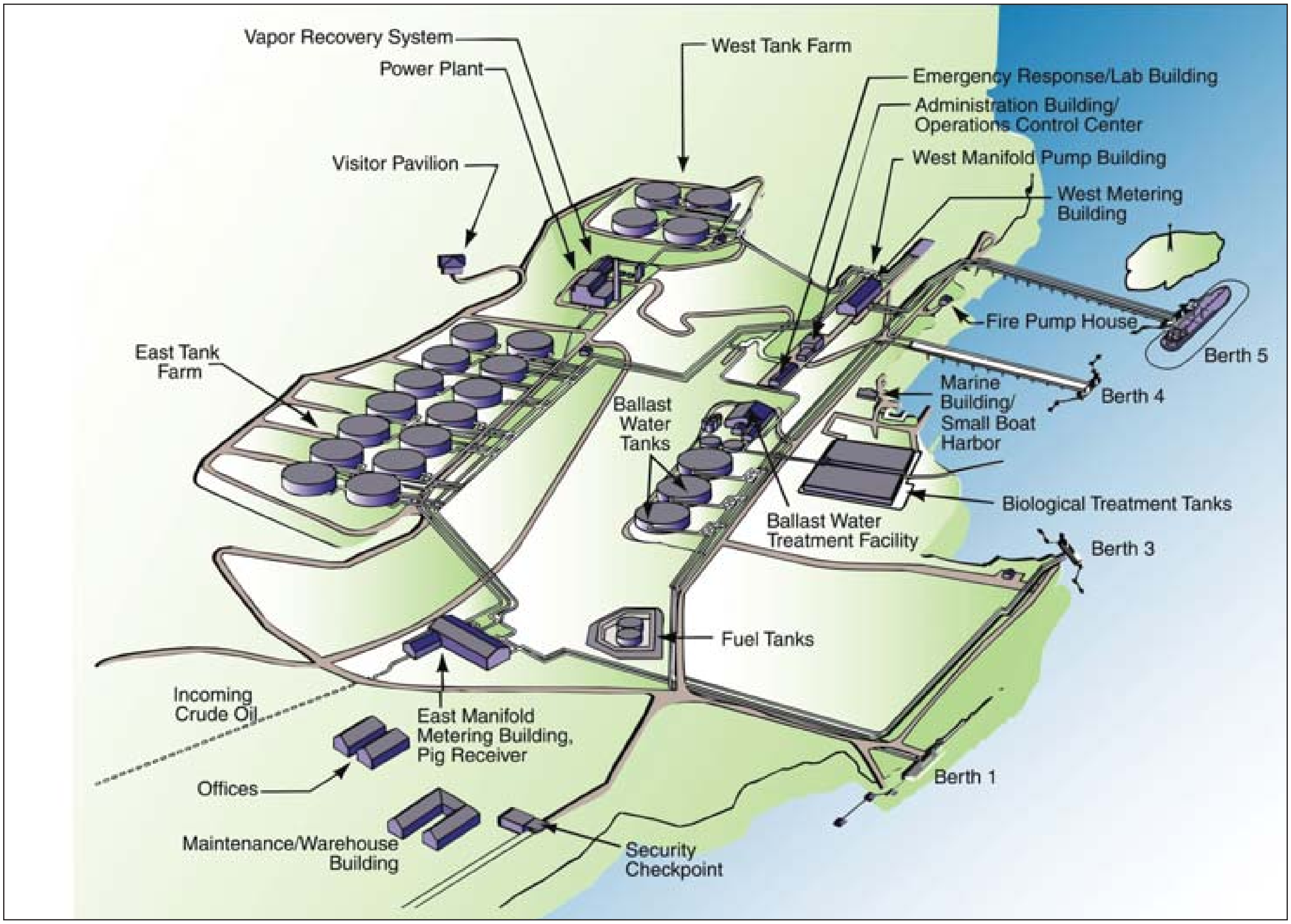
One technique the company has used and improved over the years to combat tank corrosion is a Magnetic Flux Leakage, or MFL, detector, a machine that resembles a huge lawn mower. The MFL, which a technician drives over the bottom of the tank, actually casts a magnetic field over the tank floor.

A difference in the thickness of the metal floor will register on the MFL as a disturbance in the magnetic field. This tells the technician that corrosion may be present.

"We can judge the change in the signal to determine how thick the floor is and where we need to replace a section of it," Johnson said.

Alyeska does worry that the aging infrastructure issues that have surfaced on the North Slope might also apply to the pipeline's pump stations, said Hostler. So, the company is running a continuous monitoring program in the pump stations, using inline investigation tools. An analysis of monitoring data collected since the summer of 2006 has indicated that the infrastructure in pump stations 1 to 4 is in good condition, he said. ◆

—Petroleum News staff writer Alan Bailey contributed to this article.



ALYESKA PIPELINE SERVICE CO.

The Valdez Marine Terminal of the trans-Alaska oil pipeline system has undergone several upgrades designed to eliminate uncontrolled vapor emissions during oil tanker loading and ballast water treatment.

VMT gets vapor control technology

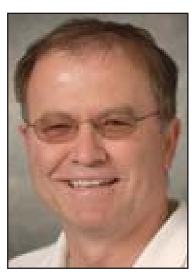
Air quality improves after Alyeska installs vapor control system at Valdez terminal

By ROSE RAGSDALE

The biggest advance in technology at the Valdez Marine Terminal was installation of a vapor control system at the oil loading berths in 1998, according to Alyeska Pipeline Service Co. officials.

Before Alyeska installed its vapor control system, an estimated 45,000 tons of crude oil fumes escaped annually from oil tankers in the Port of Valdez into the air as a result of loading operations. That made the Valdez terminal one of the largest emitters of such fumes in North America, and responsible for nearly half of all such emissions nationwide, according to the Prince William Sound Regional Citizens Advisory Council.

The problem was one of basic chemistry. During storage, light hydrocarbons previously dissolved in the crude tend to vaporize. These gases can collect in empty spaces either below a tank roof or onboard an empty oil tanker.



ALYESKA PIPELINE SERVICE CO.

Greg Jones, senior vice president of operations at Alyeska Pipeline Service Co.

Most often methane, other gases such as propane, butane, ethane, nitrogen, and carbon dioxide may be present in the mixture. The vapors also can contain potentially hazardous substances such as the BTEX compounds (benzene, toluene, ethylbenzene and xylene).

The vapor control system reduced emissions of these vapors from the tankers while they load. It uses vapor compressors and special vapor recovery arms to collect the gases that accumulate in empty spaces of shipboard oil tanks during the tanker-loading process. The vapors must be kept in an oxygen-deficient atmosphere because they become explosive when mixed with oxygen. The vapors are stored onshore and then burned to generate power, which is used to operate the terminal.

The RCAC lobbied aggressively for Alyeska to install vapor controls and the difference the system made in the atmosphere in and near the terminal was immediate and dramatic.

"Our people and the people on board the tankers had to wear respirators in the vicinity of the loading and generally a substantial amount of emissions was going into the atmosphere," said Greg Jones, senior vice president of operations at Alyeska Pipeline Service Co.

"This was a big event. It reduced total emissions from the terminal by 90 percent," he said. "And our employees like it because they don't have to wear respirators anymore."

Solutions for ballast water

Another big project currently under way at the terminal is designed to control vapors escaping from the ballast water treatment system. Ballast water is kept in three huge 430,000-gallon tanks that also have vents to allow vapors to escape into the atmosphere.

Alyeska is tying the three ballast water tanks into its vapor control system. The move will reduce remaining emissions from the terminal by 60 percent, Jones said.

"Closed systems are the way of the future," said Alyeska spokesman Mike Heatwole.

The company will spread blanket gas inside the tanks to keep the contents inert and prevent an explosive atmosphere from developing. The work is due for completion by year's end.

"This is a big deal. The terminal will be much more environmentally friendly," Jones said.

Meanwhile, the ballast water treatment system is undergoing a modernizing process after three years of study and design review. Built to handle the ballast of virtually nonstop oil loading when 77 tankers would pony up to the berths regularly to take on up to 2.15 million barrels of crude per day, the system now routinely accommodates 18 tankers loading oil at a rate of 750,000 bpd.

Technology tests

The ballast water treatment system is based on having microbes that eat the oil in the water.

"It's hard to keep the bugs alive when you don't have ballast water coming in," Jones said. "It's becoming obsolete, so we're making changes."

One tank will be removed from the system, and Alyeska is considering installing an inert gas flotation system in the other two tanks to remove potentially harmful emissions. A pilot project is under way to test off-the-shelf technology considered some of the best in the world.

Jones said the changes should be complete by 2009.

Alyeska, meanwhile, is also working to improve boom performance to contain oil better at the terminal. When heavy winds undermine the performance of boom placed around the tankers while they are loading crude at the terminal's berths, the company has been forced to shut down the loading until the winds subside.

Now, Alyeska is conducting a search for better boom technology.

"We're working on R&D and some other companies are looking at it," Jones said. "Within the next year, we'll probably try out some things on a pilot basis and see if they work." ◆

BP EXPLORATION (ALASKA) INC.

Operators at Prudhoe Bay launched oil production with relatively modest waterflood and gas injection capabilities. This compressor plant was a part of the original development.

Engineering ingenuity pays off

EOR techniques developed over three decades succeed beyond developers' wildest dreams

By ROSE RAGSDALE

Getting more oil out of the ground is a technical challenge that teams of engineers tackled from Day 1 on the North Slope.

More than 30 years later, the brainstorming that produced and perfected a series of remarkable techniques goes on.

But the story of enhanced oil recovery on the slope is a tale not only of creativity but also of converting big problems into bigger solutions.

In the early days of production at the giant Prudhoe Bay field, enhanced oil recovery was a relatively routine exercise. With an estimated 23 billion barrels of crude in place, the gleeful owner companies were awash in oil. Starting with what in hindsight seems a modest field development plan — 500 wells with 160-acre spacing — to produce 9.6 billion barrels of oil, they crafted a strategy that relied on conventional EOR technology used in oil fields since the 1940s.

Crude production would be helped along with supplementary water injection to keep up pressure in the reservoir. The Prudhoe Bay owners built a seawater treatment plant to help supply water for the process and added produced water and gas liquids from the depths of the reservoir as volumes became available.

BP EXPLORATION (ALASKA) INC.

Engineers like Gordon Pospisil wrestle daily with the question of how to produce more crude from Prudhoe Bay and other North Slope oil fields.

But advances in EOR technology and a suddenly plentiful resource enabled engineers to boost crude recovery dramatically. Today, Prudhoe Bay's owner companies have drilled more than 1,300 wells, and plan hundreds more.

"At that time, it was envisioned that we would have a gas pipeline built within five years to ship North Slope gas to market," said Gordon Pospisil, technology manager for BP Exploration (Alaska) Inc., Prudhoe Bay's current operator.

"When the world did not provide an opportunity to sell gas off the North Slope, it changed our world quite a bit," he said.

So much natural gas

Suddenly, Prudhoe Bay engineers found themselves coping with ever increasing quantities of natural gas coming out of the ground with the oil and no place to put it.

They began to pump substantial quantities of gas back into the reservoir along with the water, and soon built a series of gas handling facilities — GH1, GH2 and GH3 — completed in the late 1980s and early 1990s.

As more Arctic fields were discovered and developed, operators also jumped at the chance to boost production from these smaller reservoirs with injections of plentiful gas from Prudhoe. Point McIntyre, Milne

see **OIL RECOVERY** *page 82*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continued from page 80

OIL RECOVERY

BP EXPLORATION (ALASKA) INC.

As engineers developed more efficient technologies for boosting crude output at Prudhoe Bay using the field's abundant gas reserves, the owners commissioned construction of a series of huge gas-handling plants like this one built in the 1990s.

Point, Endicott and Kuparuk are all fields that drew on the gas riches at Prudhoe Bay to enhance oil recovery.

Along with the multimillion-dollar projects that made this possible, field owners invested in a huge central gas facility to cool gas to temperatures as low as minus 40 degrees Fahrenheit. The unit processes more than 8 billion cubic feet of gas daily, enough to meet all of the natural gas demand of London or Tokyo.

NGLs make a difference

The CGF also allows operators to separate out heavier gas components as natural gas liquids, while the remainder of the gas is injected back into the reservoir.

The process, which works best in colder temperatures, not only allows the owners to boost field production; it also contributes output in NGLs of about 50,000 barrels per day.

"If we hadn't had the Central Gas Facility, the NGLs would still be a part of the gas reserves on the North Slope," observed Pospisil.

Over the years, the small increments of NGLs have added up, said BP spokesman Daren Beaudo.

"Nobody's been sitting on that gas, or warehousing it. It's been working mightily for us," he said.

Total NGLs output over 20 years at Prudhoe Bay? More than 500 million barrels.

A real EOR winner

Engineering teams, meanwhile, set to work perfecting another known technology for use on the North Slope. Taking other portions of the gas stream, they blended heavier components with processed methane gas to create miscible injectant, or MI, a special solution designed for sweeping oil from underground reservoirs.

"Think in terms of salad dressing," said Pospisil. "If you just inject water, the water and the oil have a sharp interfacial tension, and the water tends to bypass the oil. If you inject gas, miscible gas in particular, the solution helps to sweep residual oil out more efficiently to the producers."

Working closely, reservoir, production and drilling engineers came up with the concept through trial and error of drilling fishhook-shaped wells around oil-producing wells in a certain pattern.

"We would inject that fishhook-shaped well with a 'bulb' of MI, and we would get a response from the nearby production well. We would see these cycles of increased oil production, so we kept on injecting bulbs of MI along the entire length of the well," Pospisil recalled. "This dramatically increased the amount of oil we could get out."

A bulb is a quantity of miscible injectant that forms a bubble within the reservoir. As it expands, the bubble pushes oil toward production wells.

The Central Gas Facility at Prudhoe Bay can handle gas at a rate of 9 billion cubic feet a day, enough supply to meet the needs of consumers in London or Tokyo.

Making a good idea great

But Prudhoe Bay engineers didn't stop there. They continued to experiment and soon took the MI process a step further. They created something they call miscible injectant sidetrack, or MIST.

MIST is a system of wells drilled between injector and producer wells in a pattern that further boosts crude output from a field.

By 1996, North Slope engineering teams were ready to launch an aggressive third phase of EOR at Prudhoe Bay and other North Slope fields using MIST. It involved integrating the drilling of production and injection wells to improve oil recovery. At Prudhoe, they started at the central core of the field and moved toward the western part of the field to Northwest Eileen and continued until the system encompassed Prudhoe Bay satellite fields, Aurora, Borealis and Polaris.

"In each one of those satellites (small fields with 40 million to 200 million barrels of crude in place) in the early days, it would have been difficult to justify doing an MI process. But they are part of the Greater Prudhoe Bay complex, so we were able to use MI," Pospisil said. "We're also doing that in the Point McIntyre reservoir."

The producers also are in the early stages of using MI in developing shallower viscous and heavy oil deposits at Orion and Polaris in the Schrader Bluff interval of the western Prudhoe Bay area.

Innovations keep coming

In each new application, the engineers and geologists monitor the process and continue to develop new ideas for improvements.

"We have periodic meetings around each field to brainstorm ideas for pushing EOR to the technical limits," Pospisil said. "Then we pick through these ideas for the gems as opposed to the clunkers."

A review of Society of Petroleum Engineer archives turned up more than 300 technical papers written on EOR ideas for Prudhoe Bay, according to Pospisil.

From this continuous brainstorming, three more promising EOR ideas have emerged recently.

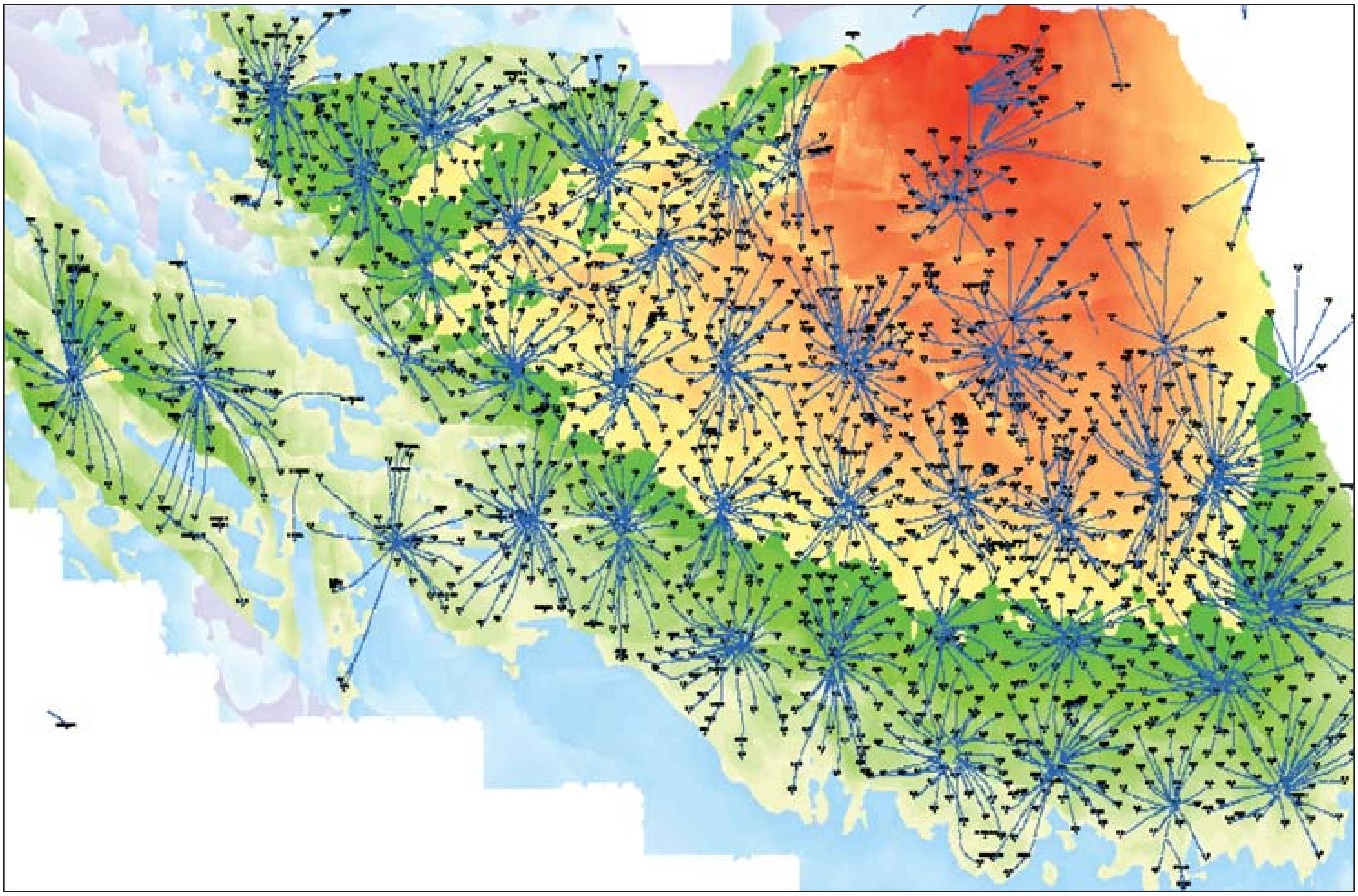
The first is "Bright Water," a system of injecting a polymer down hole that reduces the viscosity of oil and causes water pouring into the reservoir to avoid areas with high permeability and go where the remaining oil is located.

"We hope to implement Bright Water on a wide scale if we can demonstrate further success in some of the trials. We're still investigating it as part of (BP's) worldwide technology effort," Pospisil said.

Another new EOR possibility is low salinity, or Lo Sal, waterflooding. In trials currently under way at Endicott, BP engineers are injecting into the reservoir water that has less salt than that typically used to boost oil production.

"In waterflooding at Prudhoe Bay, we initially used seawater, and then produced water," Pospisil said. "But we

see **OIL RECOVERY** *page 84*



BP EXPLORATION (ALASKA) INC.

Operators at Prudhoe Bay have drilled more than 1,300 wells and plan to drill hundreds more in their quest to recover as much oil as possible from the mature field.

continued from page 83

OIL RECOVERY

found that with low salinity water, we're more effective in moving oil off the water."The situation is analogous to washing dishes in seawater or very hard water, he said. Removing grease from the dishes is much harder to do than it would be in soft water or H2O with less salt.

"Using low salinity water, we've seen significant increases in crude recovery, more than 20 percent increases in tests," Pospisil said.

BP is currently testing the use of reverse osmosis to remove salt from seawater and researching the feasibility of building a large-scale water injection plant on the North Slope. The company also has secured a rare patent for the Lo Sal technology. Typically, BP works with vendors who patent new technologies.

"It's a potentially groundbreaking technology that BP is spearheading in Alaska for worldwide application," said John Denis, BP's resource manager for North Slope fields other than Prudhoe Bay.

"The company is trying to prove the technology at Endicott and Milne Point" for use in existing fields like Prudhoe Bay and in new fields under development such as BP's Liberty prospect, Denis said.

"Liberty will come on stream about the time that the Lo Sal technology is fully mature," he added.

If the tests are successful, North Slope producers also plan to put Lo Sal technology to work at Prudhoe Bay and the satellite fields.

"Within Prudhoe Bay, we've recovered 11.5 billion barrels of crude, or about half of the 23 billion barrels in place. That leaves a very large target remaining," Pospisil said.

Win-win EOR with CO2?

Prudhoe Bay's owner companies are also investigating the use of carbon dioxide as an EOR agent. Trillions of cubic feet of gas reserves in the field have a CO2 content of about 12 percent. CO2 is considered a greenhouse gas that is harmful to the environment.

Currently, the CO2 is produced along with gas and reinjected into the reservoir where some of it is permanently trapped.

When Alaska succeeds in building a gas pipeline system to market North Slope reserves, the producers will need to separate and dispose of the potentially harmful CO_2. Or they can come up with a way to reuse it, said Pospisil.

Of the estimated 33 trillion cubic feet of gas reserves at Prudhoe Bay, some 4 trillion cubic feet is CO_2. The field would produce about 400 million cubic feet per day of CO_2 once gas sales begin, he said.

"We could re-inject it, but a better option would be to direct it to other fields where it could be a part of viscous or heavy oil recovery," Beaudo said.

CO_2, however, presents a considerable challenge; it is highly corrosive, Pospisil added.

Doing it right

Charles Thomas, Ph.D., of Science Applications International Corp., speaking at a 2002 University of Alaska Fairbanks energy workshop, praised EOR efforts on the North Slope.

"Prudhoe Bay got into gas and water injection — it started very early (in the field's life), which was the right thing to do," he said. "As technology came along, it was either applied or developed at Prudhoe Bay, where it was all put together in a very intelligent way."

Thomas said EOR enabled producers to boost recovery estimates of crude from Prudhoe Bay from about 9 billion barrels at the start of Prudhoe Bay's development to 10.2 billion in 1986, and to more than 14 billion barrels today.

Miscible injectant projects at Kuparuk also have helped to increase production at that field, which is the second-largest in North America and also contains heavy oil, he said.

Exploring newer frontiers

Continued slope research is focused on the heavy oil, Thomas said.

"Outside of finding new fields, we're looking at enhanced oil recovery in heavy oils, which is a major target of about 25 (billion) to 30 billion barrels of oil," Pospisil said.

Recovering 3 billion to 5 billion barrels of this crude would be quite a prize, the owners say.

Biotechnology and nanotechnology offer new promise for the future, according to Tony Meggs, BP group vice president for technology. On the biotech side, researchers want to produce a microorganism that will gobble up all residual oil in the reservoir and return it to the surface. Nanotechnology also could produce new EOR materials, he said.

Continuing the flow of crude through the trans-Alaska oil pipeline is crucial to Alaska's oil industry. Thanks to advances in EOR technology, the producers stand a good chance of keeping the oil flowing for many years to come and doing it without significantly increasing its footprint in the Arctic. ◆

BP EXPLORATION (ALASKA) INC.

A compact development, the Northstar development gets a lot done in relatively tight quarters. The five-acre complex has produced more than 115 million barrels of crude for BP Exploration (Alaska) Inc. in six years and is still going strong.

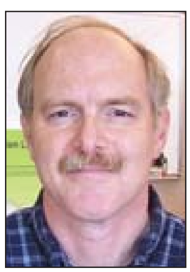
Meeting Northstar's challenges

Technology helps island development succeed in sensitive environment with leak detection, smart wells

By ROSE RAGSDALE

In developing the 200 million-barrel Northstar field some six miles offshore in the icy Beaufort Sea, BP Exploration (Alaska) Inc. placed a tall order with its engineering teams: Find a way to overcome the remote location and harsh Arctic Ocean environment and to wedge traditionally larger infrastructure into the tight quarters of a five-acre development island.

"Developing the field presented a whole series of technical issues and logistical challenges," said John Denis, resource manager for BP's North Slope fields other than Prudhoe Bay. "When you're on an island like that, you quickly get concerned about space and size because you're in very tight quarters. Things like well spacing and systems to control wells become very important."



John Garing, BP's production team leader at Northstar, marvels at the availability of well and reservoir performance data thanks to fiber-optic sensors installed in so-called "smart wells" in the oil field.

Also, "you couldn't have 24/7 access," Denis said. "You can't just drive up to the field."

Innovators at BP took on these challenges and nearly a decade and 115 million barrels of crude production later, the company considers the field a triumph.

Northstar hit its milestone of 100 million barrels of oil production in mid-2006, nine months ahead of schedule. The field came on stream Oct. 31, 2001.

Still, victory came with successful application of several unusual technologies.

"Northstar was the first true island in the Arctic for oil development," Denis said.

The five-acre pad erected on Seal Island was so far from shore it wasn't possible to connect to land with a causeway like BP did when it built the Endicott island complex just offshore in the 1980s.

BP EXPLORATION (ALASKA) INC.

The LEOS leak detection system is a key technology at Northstar, the first true island oil field development in the Arctic. BP Exploration (Alaska) Inc. engineers buried the LEOS with oil and gas pipelines beneath the Beaufort Sea that connect the island production and processing facility with the pipeline system onshore.

Buried, but safe pipelines?

"So we were faced with having to connect the island back to the mainland with a pipeline," Denis said.

Building a buried pipeline under the ocean to transport crude from the island to shore was a considerable challenge, but further complicating matters was the fact that the pipeline route lay hidden from view beneath the Arctic icepack most of the year.

"So very quickly, we had all the issues associated with that," Denis said.

How could BP bury a pipeline offshore in an area covered with ice three-quarters of the year? How could the company protect such a line from the scouring action of Arctic ice? How could it ensure that the pipeline could be monitored in such an environmentally sensitive part of the world, while providing reliable leak protection and assurances to governments, agencies, Alaska Natives and the company itself?

JUDY PATRICK

Burying the subsea pipelines that connect the offshore Northstar oil field development with land was a massive undertaking that challenged the ingenuity of BP Exploration (Alaska) Inc. engineers.

With all these questions looming, BP's engineers went in search of answers.

"We went looking for the best technology that would work," said BP spokesman Steve Rinehart. "We needed some different tools, the best ones we could find to make this work."

Much of the Northstar pipeline plan soon fell into place, but the technology that provided the critical compo-

see **NORTHSTAR** *page 88*

continued from page 87

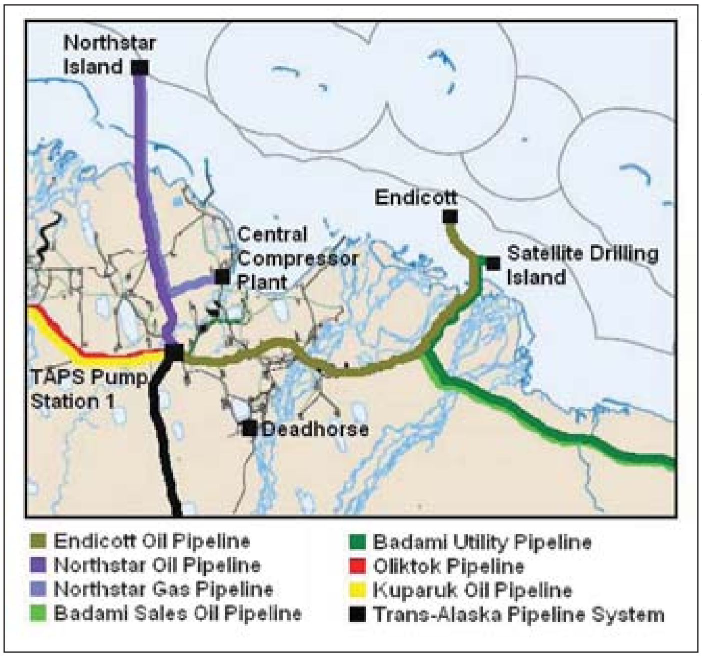
NORTHSTAR

nent was the "LEOS" leak detection system developed by Siemens Germany, Denis said.

Given that Northstar was a remote field, environmental groups, Alaska Natives, whalers and others were very concerned that BP could ensure there would be no offshore leaks or spills from pipelines, he said.

Northstar is a very pressure-sensitive reservoir. Keeping the field's pressure as high as possible is key to its operation. BP realized that shipping gas to the island from Prudhoe Bay and injecting it down hole, along with water and gas produced on the island, would be a smart move. So another subsea pipeline was needed to carry natural gas to the island for an enhanced oil recovery program, Denis explained.

Add LEOS, and BP suddenly had three pipelines to bury instead of one.



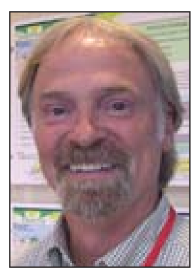
BP EXPLORATION (ALASKA) INC.

Seal Island, also known as Northstar Island, was constructed in the winter of 2000-01. BP has engaged in two pipeline right-of-way lease agreements with the State of Alaska for Northstar, an export oil pipeline and a gas pipeline that goes to the island.

"The LEOS is an oxygen-filled pipe that is designed to be adjacent to the oil and gas pipelines," Denis said. "Should a leak develop (in the oil or gas lines), those hydrocarbon fluids will seep a gas signature into the LEOS pipe. Every day, the oxygen is sucked out of that pipe and funneled across a gas chromatograph on the island. They have a little marker signal they put in onshore and when that marker signal hits, they know they have pulled all of the oxygen from the pipe."

LEOS is designed to detect leaks as small as one barrel per day and to pinpoint the location to within a few feet.

"If there were a leak, you would see a hydrocarbon or other type of signature come across the gas chromatograph, and you can actually estimate its location by the time it registered relative to the start and end of that sweep," Denis said.



John Denis is resource manager for BP Exploration (Alaska) Inc.'s non-Prudhoe Bay operations.

In tests, the system successfully detected a simulated leak of one liter six miles away from Northstar Island.

"Think about it. We've bundled these pipelines and sealed them all up together as a group, and it's kind of like a giant straw running down the middle of them," said BP spokesman Steve Rinehart.

"That straw is permeable, so if anything is leaking out of the oil or gas lines, those hydrocarbons will permeate the straw. As we monitor what's in the straw, we can tell if there are any leaks along the pipe," said Denis.

It was the first time in Alaska that LEOS was used, and it was fairly new technology at the time, he said.

BP is now using a variation of LEOS in a new transit line the company is building to replace corroded sections of pipeline in the Prudhoe Bay field. The company added it to three miles of the transit line built this winter to Pump Station 1.

"We're going to do a trial of the LEOS on that three-mile section. It holds out the opportunity to detect a very, very small leak," Rinehart said.

Intelligent wells pass test

Northstar also claims the distinction of being the first North Slope field to use "smart wells."

This innovation enabled engineers to install sensors down hole that collect data and track well and reservoir performance continuously.

"We knew we had to be able to respond very quickly to changes. And that wasn't really being done in the industry," Denis said.

"From a pressure point of view, we had done some work on locating technologies," said John Garing, BP's production team leader at Northstar. "We identified that we would be the first on the North Slope to go after fiber-optic sensors and put them down hole just above the reservoir in each well to measure pressure and temperature continuously and wire it back into our control plant, with the data available all the way down here in Anchorage."

Previously, operators had to physically open the well bore and put tools down hole every time they wished to collect the data.

The idea was to obtain continuous data so engineers could get pressure readings as needed. In addition, "it minimized the number of times that crews had to enter the well bore with wire-line or e-line to gather equivalent data," he said.

"There were cost savings and the advantage of not having to have the equipment operating on the wells as often, plus the opportunity to have all that data," Garing said.

Though Northstar's use of the fiber-optic technology wasn't a global first, it was fairly early in the evolution of smart wells, he added.

BP EXPLORATION (ALASKA) INC.

Aerial view of the Northstar shore crossing landfall at Point Storkersen, the point where the pipelines transition between buried sub-sea and supported above-ground. The visible module houses an RTU valve.

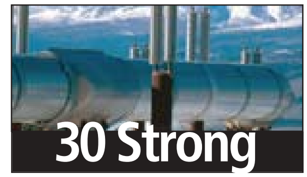
Rig system made for walking

Another innovation at Northstar was a custom-built moving system that allows a drilling rig to walk up and down the row of wells on the island. The rig-moving system called the Columbia Moving System is a set of hydraulically driven pads that can pick up the drill rig and move it forward like a big foot.

"It can walk its way with different components of the rig, a few inches at a time, in either direction along the well row. It's very effective with our limited spacing, going up and down the well row," Garing said.

"It may be a few years before its time," said Rinehart, "but it's like the Star Wars walker."

Though BP may be considering building one like it for use elsewhere, Garing said no other drilling rig in Alaska currently uses such a system.



How can you steer an oil well drilling bit from the surface? You ***send pressure pulses through the drilling mud*** *to communicate with control equipment at the bottom of the drill string.* *See page 24.*

Overall, BP has taken technological lessons learned at Northstar and used them to develop and enhance its operations at other fields around the world.

A team of engineers working to develop the new 120 million-barrel Liberty field, for example, is currently spending time at Northstar, studying the performance of that field's wells.

Adds Denis: "Northstar is a huge success. BP saw all the challenges up front and met them." ◆

JUDY PATRICK

The Doyon-Akita Arctic Wolf rig was specially designed for Arctic exploration and can be broken down into truckable loads.

Exploration rigs more mobile

By ALAN BAILEY

For many years large, powerful and heavy drilling rigs had been the norm for exploration drilling on Alaska's North Slope. With deep drilling targets in the traditional reservoir rocks associated with the original North Slope oil fields, exploration drillers had tended to use rigs that are equally suitable for oilfield development or exploration.

But a shortening winter drilling season, an interest in prospects some distance from the central North Slope infrastructure and a need to make Alaska exploration more cost effective have been driving a trend toward the use of lighter-weight, purpose-built exploration rigs.

Doyon-Akita rigs

Pioneer Natural Resources broke with tradition when in 2005 it commissioned a joint venture between Doyon Drilling and Akita Drilling to build a rig, the Arctic Fox, based on a design that had already been proven for exploration in the Canadian Arctic.

"It is a fit-for-purpose rig, designed to drill exploration on the North Slope of Alaska," Pioneer's President Ken Sheffield told Petroleum News.

The rig's design included a 400,000-pound-rated double mast, rather than the triple mast of a typical Alaska rig. The rig was designed to drill to 10,000 to 12,000 feet, considered an adequate depth for near-vertical exploration wells targeting the type of prospect that companies like Pioneer were pursuing.

The rig's modular design would enable it to be relatively easily broken down into sections that would load onto a conventional truck for transportation. And that would all translate into an ability to move the rig quickly between drill sites, to enable the drilling of more wells in a single exploration season.

"We're hopeful that we'll be able to move this rig in three or four days from location to location," Sheffield said.

And Pioneer drilled three wells with the new rig in the winter of 2005-06.

In 2006 Akita completed a second purpose-built Alaska exploration rig, the Arctic Wolf, for operation by the Doyon-Akita joint venture. And FEX, Talisman Energy's Alaska subsidiary, successfully drilled three exploration wells with that rig in the northwestern part of the National Petroleum Reserve-Alaska in the winter of 2006-07.

Nabors rigs

The trend towards lighter weight rigs continued in 2007. In February of that year, Mark Hanley, Anadarko's top official in Alaska, told Petroleum News that the company and its Brooks Range Foothills partners, BG Group and Petro-Canada, had ordered a lightweight drilling rig, Nabors Rig 105, from Nabors Alaska Drilling, "for a multi-year drilling program with extensions options" in the Brooks Range Foothills. Rig 105, which is being built in Alberta, is a "mobile rig, not a wheeled rig, so it can be broken down and transported on rolligons," Hanley said.

Then in March 2007 Nabors announced that it was building a high-tech lightweight rig, Nabors Rig 106, at the request of Chevron. Chevron plans to use that rig in a multi-year drilling program in the company's White Hills exploration acreage, southwest of Prudhoe Bay and south of the Kuparuk field. Rig 106 should see service for Chevron on the Kenai Peninsula before moving to the North Slope.

Nabors Rig 105 for Anadarko and Nabors Rig 106 for Chevron will be the first "purpose-built AC rigs for the North Slope," Dave Hebert, Nabors' general manager for Alaska, told Petroleum News. An AC rig uses alternating electrical current for power, as distinct from the direct current of a traditional rig. ◆

The quest for happy caribou

After 30 years of study, much learned about Central Arctic herd as industry continues to accommodate

By ROSE RAGSDALE

Both government and industry scientists acknowledge that the question of caribou in the oil fields of the Arctic is a very complex topic.

"It has been a challenge for us to try and study it and to make sense out of what that data has told us," said Mike Joyce, a retired biologist who worked for ARCO Alaska Inc. and its successor, Phillips Alaska Inc.

Over 30 years of constant study, of trying to figure out how oil companies on the North Slope are interacting with the caribou, and how they respond to mitigation, the oil industry and government agencies have worked to find better ways coexist with the caribou and other wildlife species.

In the Kuparuk River oil field, for example, when the oil companies first realized in the early 1970s that there was a caribou herd called the Central Arctic herd in the vicinity, scientists established the first population estimate of the herd at about 3,000 animals.

In three decades, regular censuses show the herd has grown to exceed 31,000 animals.

At the same time, industry plopped a 40-pad oil field down in the middle of the area where the Central Arctic caribou herd lives and calves, bringing to the area about 160 miles of roads, and hundreds of vehicles running back and forth in all directions at all times of the day.

The oil industry's challenge has been to figure out how to understand what influence its presence is having on the caribou, their migration patterns and their very strong traditional use of the area. The herd, meanwhile, has continued to grow rapidly, and its traditional use patterns have had a high degree of annual variability, scientists say.

"When we start to think that maybe we are beginning to understand something that is going on, then the CAH loves to throw us a little curve and makes it a little puzzle, so that maybe the traditional use isn't quite what we understood it to be. So it's been a very difficult topic. It has created lots of debate," Joyce told participants at a technology conference, "Established Oil & Gas Practices and Technologies on Alaska's North Slope," sponsored by the U.S. Department of Energy in April 2000.

Still, much has been learned about the herd over the past 30 years, and industry has adapted its operations to accommodate the caribou's needs.

JUDY PATRICK

Lone caribou, Kuparuk Operations Center, North Slope.

With the help of government and industry scientists, including independent consultants such as Alaska Biological Research in Fairbanks, significant gains have been made in understanding the species and its habitat.

The oil industry's goal has been to have "happy caribou" — to allow the Central Arctic herd do what it wants to do, completely undisturbed, according to Joyce.

An image of "happy caribou" bedded down in the oil fields, with steel oilfield infrastructure in the background has been immortalized during the past decade in national debate over allowing oil and gas development in other areas of the North Slope currently off limits.

Spacing roads and pipelines

One of the first issues that North Slope operators had to resolve was putting pipe and roads and traffic in the middle of the caribou herd's movement patterns.

They tackled the gargantuan task of accumulating data on the herd's movements to determine what the patterns are.

Imagine young grad students sitting in towers across the North Slope and tracking the actual movements of every individual caribou.

This rather low-tech undertaking resulted in a complex distribution map, a spaghetti diagram that showed movement patterns and how the caribou interacted with roads and pipelines when they encountered them.

"You'd like to see nice straight lines that run across it, but we don't have straight lines — we have a whole mass of confusion," Joyce said in 2000. "In the early days, the late '70s to the early '80s, pipelines were right on the ground, gravel roads were right next to the pipelines, and the caribou had no visual window to see if there was free range on the other side of that limit."

As a result, the caribou did a lot of wandering and their distribution patterns reflected their confusion.

But industry researchers studied the problem and found that it wasn't the gravel or the roads that caused problems.

Rather, it was the combination of low pipelines adjacent to the gravel roads, and as animals approached this obstacle, their line of sight was blocked.

The industry responded by building what amounted to sidewalks for the caribou over the pipelines — gravel ramps called "caribou ramps."

"We built and studied several different designs in the late '70s, early '80s, and what we often found was that caribou would use the ramps sometimes, but they would not travel along the linear feature to search for a ramp. And often, they would cross right next to the ramps, without actually using the ramp," Joyce recalled.

But the animals did use the ramps to some degree, so scientists concluded that the ramps could be beneficial in key areas, especially if researchers could figure out what preferred crossing locations might be.

They also learned that the caribou did not use the ramps in selective-search fashion.

Researchers also studied the pipelines. In the early days, the pipe was built right on the tundra surface. Welders hated to get down on their knees, and they hated to build scaffolding. Instead, they wanted to work at belt-high or chest-high levels, which often meant that the bottom of the pipe was too low for a caribou to walk under.

"We started looking at putting pipe up at a level of five feet high in the early 1980s, and found that the caribou had good passage success under that taller platform," Joyce said.

So a new standard was born — a minimum of five feet from the ground to the bottom of the pipe. For linear features, pipelines in particular, from the early or mid-70s to the early to mid-80s, industry began to keep the pipe up off the tundra, and also to separate the pipe from the road. Instead of putting the pipeline right next to the road, the companies spaced them some distance apart.

Joyce said this practice evolved from a crude understanding and use of ice roads in the early days as a development technique. Instead of having a gravel pad for construction of the pipelines, the industry began to build pipelines from ice roads, thereby providing the distance needed to help the caribou get through.

No traffic jams for caribou

The next focus was traffic. Pipes were okay, using the right design and orientation. The gravel road itself was not a problem.

"It became clear to us that traffic was the prime stress in causing caribou to give up an attempt to cross a pipeline or a road. There were lots of trucks around, so traffic became the focus, and we studied traffic. We can't control traffic. But if we provide caribou with plenty of space, they can get under the pipeline, check out the traffic, wait for the traffic if they need to, and then pass," Joyce said.

The oil company soon realized that traffic management during caribou season would be necessary.

Other issues that greatly concerned the oil companies were how to allow the caribou unimpeded movement as they pursued their seasonal activities, and how to ensure that they maintained a healthy population and net production. Calving has to occur at a spot that is beneficial to the herd, with minimal predators, good forage and low snow cover. So the animals use traditional patterns for calving. However, those patterns have changed over time.

From the 1980s through the 1990s, a shift in caribou calving occurred in the Kuparuk area. The bulk of calving now occurs to the south and west of the oil field. Some calving still occurs in the Milne Point and Kuparuk fields, but over a 20-year period, most of the calving has shifted further south, according to researchers.

Why? And even more important, said Joyce, "What does it mean?"

Today, researchers still don't know the answers to these questions.

Joyce said all kinds of variables influence caribou behavior from year to year — weather, snow and predators — all of which can cause stress within an area like Kuparuk.

But further study will help researchers get a feeling for whether the shift reflects a real problem, he said.

"Remember, our goal is healthy caribou populations — happy caribou," he observed.

Joyce also said the number of calves being dropped every year per 100 cows, from the late 1970s through 1999, showed a lot of between-year variability. But when researchers compared what was happening in the Central Arctic herd with other herds and other species, they found a fair amount of commonality in terms of down years, he said.

Herd growth unimpeded

The other component of "are the caribou happy and healthy?" depends on how the population is doing.

In 1972, when it was first recognized that the Central Arctic herd was a discrete group, there were only about 3,000 animals in the herd, Joyce said.

see **CARIBOU** *page 94*

continued from page 93

CARIBOU

Over 30 years, the herd has grown ten-fold, with numbers currently exceeding 30,000 animals.

This growth pattern included a rather significant decline in the mid-90s that researchers still do not understand.

"We do know that there were a couple of hard winters at that point. We also know by looking at ungulates across the North Slope, that other caribou herds showed declines at about the same time. So this may have been weather-induced from those harsh winters. It is not clear," Joyce said.

"Which brings me to maybe the most important lesson I'd like to share with you," he told the technology conference in 2000. "For a disciplined wildlife scientist trying to figure out what the results are in terms of cause and effect, a couple of years of data doesn't help you answer those questions. We've been studying this caribou herd for over 25 years, and we still have questions about what is happening with this herd."

Joyce said it has taken a cooperative program working with government agencies, the North Slope Borough and village community residents, as well as some very powerful consultants with a lot of experience to try to gain the beginnings of an understanding.

Researchers agree that the discipline needs constant attention and surveillance and monitoring. The Central Arctic caribou herd is the perfect example of how important a continuous record of monitoring has been and will be for future oil development on the North Slope, Joyce said.

Fields provide insect relief

Population numbers, however, can help explain what the calving distribution shift means.

In 2000, Joyce said he believed the herd's population was healthy, and that oil-field stress had caused no serious population-level disturbance at that point.

"We've talked about the fact that we also have learned behavior, habituation going on. For example, caribou need to go to the coastal plain for insect relief. They are harassed early by insects, and it's very important to move to avoid this. A learned behavior that we have seen over time is that our gravel fill provides secondary insect relief benefit to them," he said.

"You see a lot of caribou in the oil fields standing on the gravel pads with their noses down in the gravel to protect them from the insects' harassment early in the season. They have learned that there are fewer insects up on this gravel fill. It simulates coastal beach areas or gravel bars that they normally use for insect relief. So there is a learned behavior going on," Joyce said. "Remember that the herd was growing in the mid-1980s, so there are four or five generations or more of caribou that have grown up with Kuparuk. They've grown up with pads and pipelines and traffic, and there is a learned behavior and an adaptation, and I think there is some influence in what we currently see in terms of cause and effect on the caribou populations."

Monitoring the caribou over 30 years with the help of computer technology has enabled the oil companies to adapt their operations to successfully coexist with the Central Arctic herd.

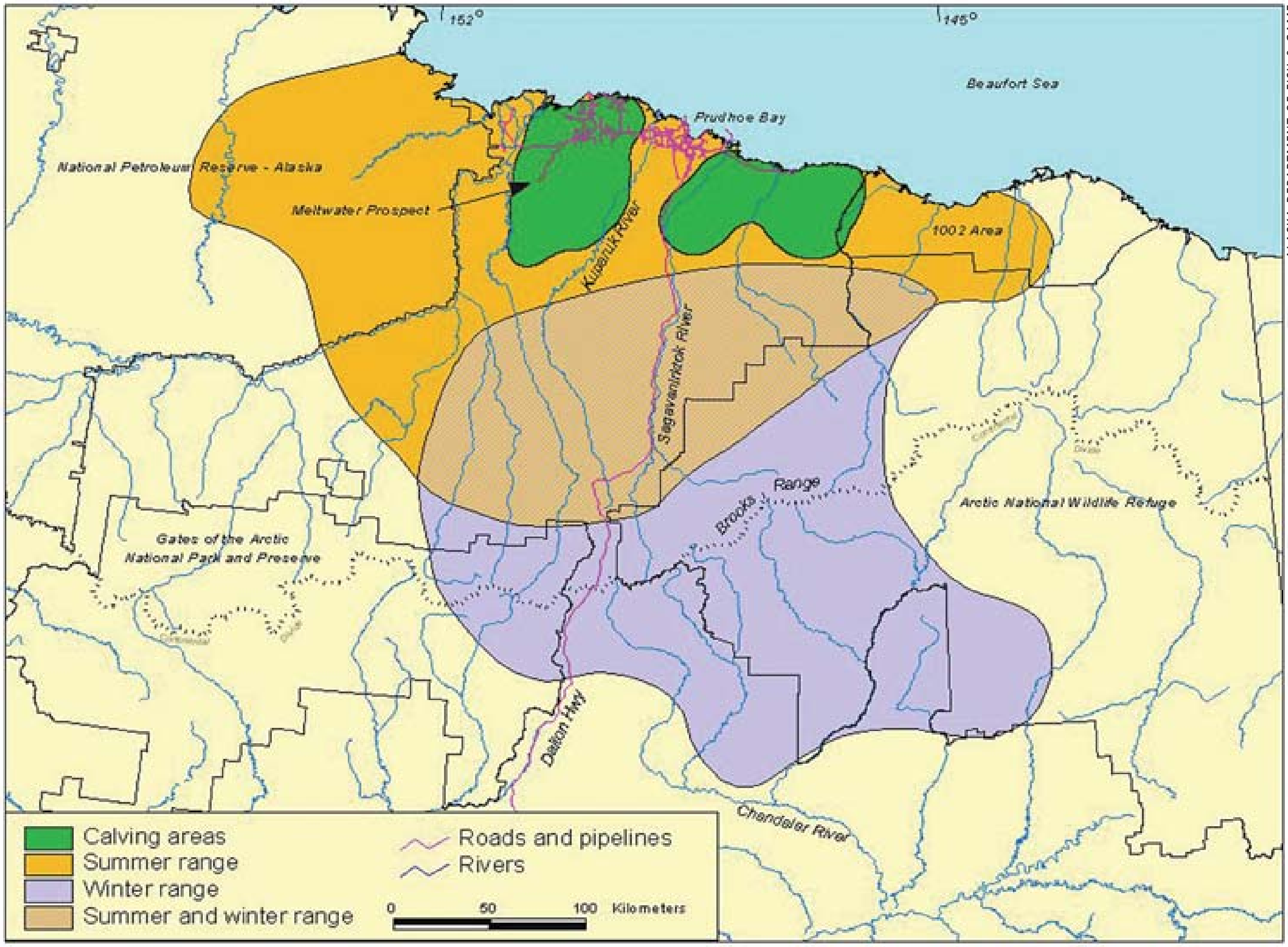
Among the lessons the operators have learned: Keep pipe up off the tundra; try to minimize number and location of roads and try to not place them perpendicular to caribou movement patterns — try to go parallel as much as possible; and keep traffic down and control it during calving season. Ramps can be beneficial in key locations, but probably more important is giving the caribou space between pipes and roads.

Government has important role

Because the Alaska Department of Fish and Game is ultimately accountable to the public for the welfare of the Central Arctic herd, the agency scrutinizes any influences on the herd's sustained viability, and makes appropriate recommendations to land management agencies and to policy makers, according to ADF&G researcher Dick Shideler.

"One of the things we feel we really need is thorough predevelopment studies — but only recently have we had really good before and after data," Shideler told the technology conference participants in 2000.

"But the bottom line for caribou calving is that the response of the caribou to the roads and facilities really does complicate what our mitigation options are for future oil fields. If they are so very reactive, it is essentially unrealistic to expect that an oil



ALASKA DEPARTMENT OF FISH & GAME

field the size of Kuparuk or Prudhoe Bay would shut down all traffic during calving, and in fact this might not be effective anyway. So we have to look at other options."

Fortunately, the physical size of oil fields has shrunk about 80 percent since Prudhoe Bay and Kuparuk were built.

As for the shift in proportional caribou habitat use, Shideler said there has always has been some calving occurring in the hills south of Kuparuk, up through an area known as the Itkillik Hills.

"I can remember doing calving surveys with Ray Cameron in the mid-80s during heavy snow years on the coast, and we had a little more calving down in the southern parts of the field, south of Kuparuk. So some of the observed shift is probably related to snow conditions down on the coast," he said. "We do not feel that the caribou can't physically get to the calving area. There is no impediment to ewes crossing the pipeline and roads, but it really has more to do with their behavioral response."

Shideler said no oil development other than the tiny Badami site has occurred on the east side of the Sag River, so that area can be used as a semi-control of what has been happening on the west side of the river where the shift in calving has occurred.

"We have to remember that some caribou herds, like the Beverly herd for example, will go through major shifts in calving area almost annually. On the other hand, herds like the Western Arctic herd haven't significantly changed its calving area in recent years, although its population has grown from 65,000 to almost a half a million animals in the past 25 to 30 years. The Teshekpuk herd hasn't changed much either," he told conference participants.

"From a biologist's standpoint, trying to integrate all of this conflicting information is difficult. The bottom line is we may never know why some of these trends occur," he added.

More study needed

Still, the question of what the shift in calving areas means remains unanswered for the Central Arctic caribou herd.

Hoping to find answers, ConocoPhillips Alaska Inc. and the Bureau of Land

see **CARIBOU** *page 96*

continued from page 95

CARIBOU

Management provided major funding for a five-year study of cows and newborn calves in the Central Arctic herd from 2001 to 2006. The National Park Service, U.S. Fish and Wildlife Service and state agencies also provided support.

Biologists Steve Arthur and Patricia Del Vecchio sought to identify and measure the mechanisms through which oil field development might affect the Central Arctic herd, such as by reducing body condition, reproductive success or calf survival.

In an interim research technical report, "Effects of Oil Field Development on Calf Production and Survival in the Central Arctic herd," published in March 2006, Arthur and Del Vecchio compare what happened to calves that were born in the two different calving areas, the mostly undeveloped area east of Prudhoe Bay and the area west of Prudhoe Bay that has seen increasing development since the late 1980s. In the western area, calving has shifted south since development began, though the researchers point out that it remains unclear if the shift resulted from development, increased herd size or other factors.

Arthur and Del Vecchio found that newborns from the western area on average weighed a little less and were slightly smaller than those from the eastern area, and that the differences persisted through at least the first nine months of life.

They concluded that the differences in size and mass of calves may be largely influenced by the quality of habitat and forage available to caribou cows during the calving period.

"Thus, displacement of caribou cows from preferred calving habitats may reduce fitness and survival of calves," they wrote.

JUDY PATRICK

A caribou cow and calf at Kuparuk

Technology advances could help

One of the most interesting differences in this extensive study from ones conducted in the 1980s is the sophistication of the technology used today by the researchers.

Caribou cows were captured and fitted with collars containing satellite-linked GPS receivers programmed to determine their locations every five hours from May to October and every two days between November and April. Also newborn calves were captured and fitted with the radio collars every June. Location data was stored in the collars and relayed via uplink with the Argos satellite system once a week in winter and daily in summer.

Techniques used to analyze the GPS data collected in the study have not kept up with the ability to gather the data, so researchers focused on developing new techniques for better analysis.

They hope to look more closely at where caribou move and what habitat they use in relation to oil field infrastructure, they say.

Dave Yokel, wildlife biologist with the Bureau of Land Management, has said he's looking forward to that sort of analysis. "We hope we can use the results to mitigate any impacts on the Teshekpuk (caribou) herd from development in the NPR-A (National Petroleum Reserve-Alaska)," he told an ADF&G spokeswoman. "To do that, the BLM needs to know more about the impacts on caribou of movement through infrastructure."

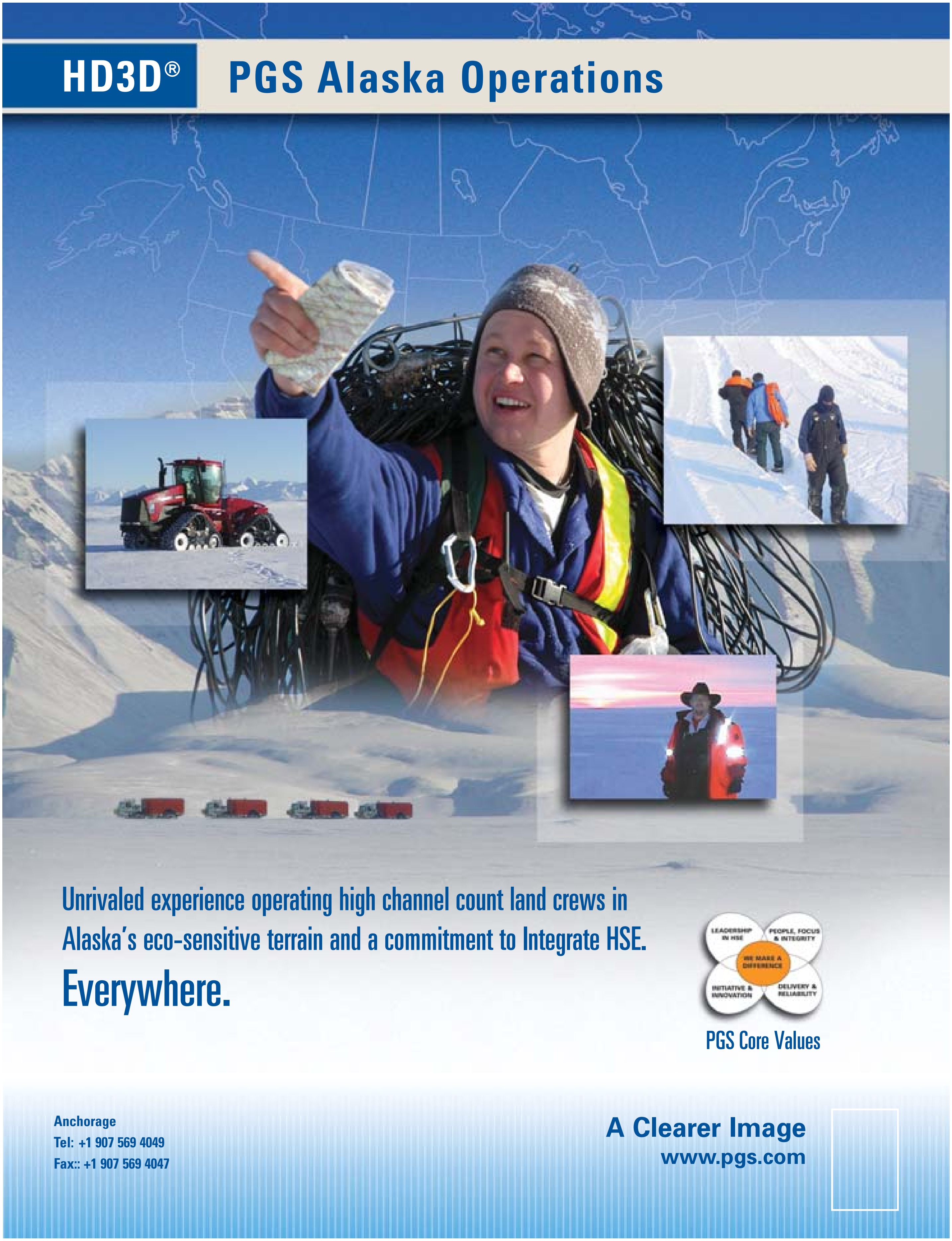
Meanwhile, a 2002 photo census of the Central Arctic herd, the latest available, shows the herd's growth trend continues. The Alaska Department of Fish and Game's Division of Wildlife Conservation counted 31,857 caribou from photographs of the Central Arctic Caribou herd taken July 16, 2002. Groups and number of caribou were in the following locations: Katakturuk Point (115), Katakturuk Point (4,526), Canning River mouth (567), Shaviovik Delta (13, 461), East channel Sagavanirktok River (1,962), Putuligayuk River (1,437), Sakonowyak River (3,299), Beechy Point (3,499) and Kaverarak Point (2,991).

"We located groups by radio-tracking collared caribou from a small fixed-wing Piper PA-18 aircraft and took photos of the groups using a 9-inch aerial mapping camera mounted in the belly of a DeHavilland Beaver aircraft, according to ADF&G researchers.

The CAH increased from 26,128 caribou in 2000 to an estimated minimum of 31, 857 caribou in 2002, reflecting an annual growth rate of approximately 8.5 percent.

"Parturition rates, late June calf-to-cow ratios, and fall calf-to-cow ratios were good in 2000 and 2001 and mortality rates also were low. Thus, it was not surprising that the CAH increased," the ADF&G said.

Though state biologists planned to count the herd every two or three years, they said no new census has been possible in recent years due to smoke from wildfires and cloudy weather. ◆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