Petroleum news

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North America's source for oil and gas news

Week of June 27, 2004 • $1

page 5 BP Statistical Review: 41 years of oil reserves, 67 years of gas

Pelican Hill back at work

BRUCE WEBB, ALASKA DIVISION OF OIL AND GAS

This photo was taken about two weeks ago at the Iliamna No. 1 well site, on the west side of Cook Inlet.

Independent upgrading equipment at Iliamna well site

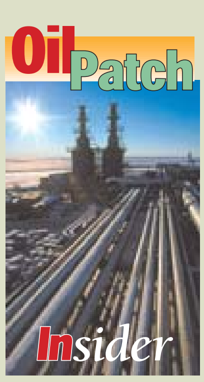
Pelican Hill Oil and Gas spud its first well in Alaska on Nov. 4, the Iliamna No. 1, on the west side of Cook Inlet. Its target natural gas, the company used a Water Resources International rig, the Ideco H-35 KD, which Pelican Hill President Al Gross had brought in from Hawaii last summer. The rig had mainly been used to drill water wells.

The San Clemente, Calif.-based independent ran into a number of equipment problems and was unable to finish drilling the well this past winter, temporarily capping it in early December after drilling approximately 3,500 feet of a target depth of 5,500 feet.

"There is a 200 foot cement plug in the well bore to prevent any unexpected problems while the site was unmanned," Bruce Webb, natural resource officer for the Alaska Division of Oil and Gas, told Petroleum News in mid-June. Webb had just come from the Iliamna drill site. "Pelican is in the process of rebuilding a

see **PELICAN HILL** *page 22*

Last call for offshore ANWR well



AS THIS EDITION OF PETROLEUM NEWS is headed to press the state contractor in charge of forming a consortium to drill a stratigraphic test well offshore the Arctic National Wildlife Refuge is preparing to e-mail a ballot to all oil companies that expressed interest in participating in the project.

"It's a check-the-box deal. You either check you will participate or you will not participate in the Beaufort Sea strat well," John Lewis, vice president of operations for ASRC Energy Services E&P Technology, told Petroleum News in a June 23 interview.

For those companies that indicate they will participate, there

see **INSIDER** *page 2*

BREAKING NEWS

NORTH SLOPE, ALASKA

Work under way

Alpine facilities expansion in progress; field will be down for four weeks in July

By KRISTEN NELSON

Petroleum News Editor-in-Chief

Onsite work began in March for facilities expansion at the Alpine field on the west side of Alaska's North Slope.

The work, approved in two phases, will increase produced water handling and allow Alpine to produce 140,000 barrels per day of oil, up from its current capacity of 100,000-105,000 bpd.

JUDY PATRICK

John Whitehead, ConocoPhillips Alaska

There are two separate projects at the Colville River unit, Alpine capacity expansion phase 1 or "ACX1" and Alpine capacity expansion phase 2, "ACX2."

Alpine field operator ConocoPhillips has to do a shutdown for each phase of the work, one this summer and one next summer.

Once ACX2 was approved earlier this year, John Whitehead, ConocoPhillips Alaska's vice president for the western North Slope, told Petroleum News June 17, "we identified … the ability to actually complete a lot of the modules and be able to do the tie-in work in '04, to minimize the shutdown that we're going to have to do in '05."

Whitehead said the shutdown this summer is planned to begin in mid-July and to last four weeks.

Tweaking has already been done

ConocoPhillips Alaska (78 percent) and Anadarko Petroleum (22 percent) are partners in the Alpine field, which ConocoPhillips operates. When development was announced, production was planned for 70,000

see **ALPINE** *page 20*

NORTH AMERICA

Like bringing coal to Newcastle

LNG receiving terminal proposed for Kitimat, B.C., where only eight years ago the proposal was to build an LNG export terminal, shipping to Asia

By DON WHITELEY

Petroleum News Contributing Writer

Occasionally, a sea change occurs in global markets that alters the dynamics of a particular business forever. A growing body of evidence suggests that North America's supply-dominated natural gas business is about to go through just such a process.

The announcement last month that Calgary-based Galveston Energy hopes to build a liquefied natural gas facility at Kitimat brings British Columbia solidly into this unfolding environment. Galveston wants to import LNG, not export it, and its proposal is one of about 35 similar projects in various stages of development throughout North America.

Only eight years ago, Kitimat was looking at a similar type of project — but the gas was going to move in the other direction, from British Columbia and Alberta to markets in Asia. In a variation of the old British joke about bringing

see **LNG** *page 20*

GULF OF MEXICO

Kerr-McGee hikes reserves for three Gulf deepwater areas

Neptune upgrade largest, at 40%, based on development drilling, satellite fields

By RAY TYSON

Petroleum News Houston Correspondent

Exploration and production independent Kerr-McGee has increased oil and gas reserve estimates significantly for its producing Neptune, Nansen and Boomvang field complexes in the deepwater Gulf of Mexico.

All three deepwater areas also have exceeded company expectations in terms of field performance, Kerr-McGee said in a June 23 conference call. The company attributed that partly to operational efficiencies gained through offshore truss

see **KERR-MCGEE** *page 16*

COURTESY OF KERR-MCGEE

Production from the Neptune spar is currently averaging 11,000 barrels of oil per day and 50 million cubic feet of natural gas per day.

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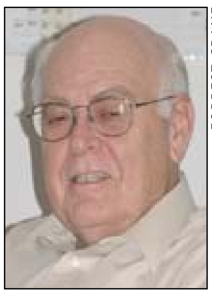
INSIDER

are two more boxes asking them to select where they want the well drilled — either an eastern location, off Angun Point, 30 some miles southeast of Kaktovik, or a western site off Anderson Point in Camden Bay area, 20-plus miles southwest of Kaktovik. (The locations are on opposite sides of the Marsh Creek anticline.)

The results of the ballot "will determine whether DNR goes forward with the project or not," Lewis said, referring to the Alaska Department of Natural Resources Division of Oil and Gas, the state agency in charge of the test well program for Alaska Gov. Frank Murkowski.


FORREST CRANE
JIM COWAN

Ballots must be returned to Lewis via e-mail by July 2.

In mid-May the division extended ASRC Energy Services' contract to plan and promote the project from May 31 to June 30.

According to division geologist Jim Cowan, the deadline was extended because an April announcement that ASRC Energy Services E&P Technology "was also awarded a contract to initiate the permitting — and has done so — apparently did, as we hoped, stimulate additional interest" from large oil companies."

Cowan, who is in charge of the project for the division, said the agency thought those companies "should be allowed a little additional time to evaluate the data in the areas" proposed for the test well.

He cautioned that "time is running short for those wishing to participate as original participants, however. It's highly unlikely that additional extensions will be made if the well is to be drilled this coming winter," as planned.

In evaluating options for the test well, Lewis said three scenarios have been identified: one, barge all equipment to location during the summer; construct the ice pad in shallow state water; two, fly all equipment in during winter season, construct the ice runway and ice pad in shallow state water, using a "Herc'able rig" and equipment; and, three, mobilize offshore rig (SDC) during the summer; drill at a location in 25-80 feet of state water.

Each scenario has it own strengths and hurdles, Lewis said.

The first two options require, to some degree, access to navigable waters within the 1002 area of ANWR. Option three would not require any access to the refuge.

Option one and three would require mobilization of equipment during the summer navigation season while option two would not commence operation until well into the winter season.

Lewis said his firm and the state had decided option three was the best alternative, largely because the first two options "require access to the navigable waters of the 1002 area and as such would require 18 months to two years to obtain necessary permits."

The permitting process "appears to be proceeding and all required permits will be available for mobilization efforts that could start in late July 2004 if necessary," he said.

Lewis can be reached at 907 339-6256 or via email at john.lewis@asrcenergy.com.

CAPP renovating Calgary office

THE CANADIAN ASSOCIATION of Petroleum Producers is renovating its Calgary office space.

Work started June 18 and is expected to be completed by the end of August.

The association's staff has temporarily moved to floors 26 and 27 in the same office tower at 350 7th Ave. S.W.

World Bank to shift investment focus to gas from oil

THE WORLD BANK, CRITICIZED by environmentalists for backing controversial oil pipelines, plans to shift more of its investment focus to natural gas projects.

According to recent wire reports, the bank will increase spending on gas projects over the next three to five years from the current 10 percent to 30-50 percent of all its equity investments, loans and guarantees for the oil and gas sector. Through its private sector investment arm the World Bank has a lending budget of approximately $1.5 billion for upstream, midstream and downstream projects around the world.

Canadian to lead UN investigation of oil for food program

A CANADIAN WILL LEAD a United Nations investigation into its controversial oil for food program in Iraq, according to a report in the Globe & Mail. There are allegations that former Iraqi dictator Saddam Hussein, and others, skimmed more than $10 billion from the program while it was in operation.

Reid Morden, 63, ran the Canadian Security Intelligence Service from 1987 to 1991, and was also Canada's deputy foreign minister in the mid-1990s.

"I think it's potentially important for the UN to either learn some lessons or to have the names of a number of people cleared — one of the two," Morden told The Globe. U.S. officials believe Hussein pocketed $5.7 billion smuggling oil into neighboring countries, and another $4.4 billion extracting illicit surcharges and kickbacks on otherwise legitimate contracts.

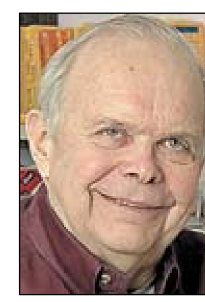
Established to ease the effects of sanctions on Iraq imposed after the 1991 Persian Gulf War, the oil for food program was a $67 billion boondoggle that saw very little in the way of food or aid delivered to Iraqi citizens.The probe into the allegations of corruption and fraud in the $67 billion program was ordered by the Security Council after the Iraqi Oil Ministry released documents in January listing more than 200 individuals and agencies that allegedly received kickbacks under the program.

The director of the UN's Office of Iraq Programs and a company tied to the son of Secretary General Kofi Annan both show up on a list of suspects. Both have denied any wrongdoing.

Dave Shafer takes Gil Mull's position with state

LATE LAST YEAR VETERAN geologist Charles G. (Gil) Mull retired from the Alaska Division of Oil and Gas. With his vast knowledge of Alaska geology, Mull had become something of an institution since he first arrived in the state in 1961, part of the team that discovered the giant Prudhoe Bay oil field.

Mull and his wife Yvonne are now living in Santa Fe, N.M., where he is doing Alaska-related geological consulting.


ALAN BAILEY
GIL MULL

Dave Shafer has taken Mull's position with the division in Anchorage. Shafer brings to the position 23 years of experience as a petroleum geologist, in development planning, operations and exploration, as well as a strong background in horizontal well planning. He has interpretative and operational experience with clastic and carbonate reservoirs in California, the Gulf of Mexico, Texas, Alaska, Trinidad, Venezuela, Argentina, Brazil, Peru and Algeria. And experience in well logging, project management and databases.

Like Mull, he's a good writer and communicator, with an eye for the larger picture and creative solutions. And, like Mull, you can expect work-related e-mails from him seven days a week, at all hours.

Shafer began working for the division in January where his job scope has included leading the investigations of the petroleum potential of Alaska's sedimentary basins; planning and implementing the 2004 North Slope field studies in collaboration with the Alaska Division of Geological and Geophysical Surveys and the University of Alaska Fairbanks; implementing investigations of the Alaska Peninsula lease sale area; and consolidating all of the prior North Slope studies into summary posters.

Editor's note: This week's column was compiled by Kay Cashman and Don Whiteley. Insider tips should be emailed to publisher@PetroleumNews.com.

BRITISH COLUMBIA

Canadian producers urge lifting offshore British Columbia drilling moratorium

It's time to lift the moratorium on oil and gas drilling on Canada's west coast, the Canadian Association of Petroleum Producers said at an engineering conference in Vancouver June 21.

"We believe the moratorium is a public policy decision and we are looking for jurisdictional consistency across Canada," association spokesman Rob Carss told a Vancouver conference on offshore mechanical and Arctic engineering. "Why should British Columbia be penalized and have a moratorium when the same activity is ongoing on the other coast of this country?" Despite its unique ecology and rugged coastline, British Columbia's coast has no operational challenges that have not been successfully dealt with by the oil and gas industry in other parts of the world.

"It's a heavily regulated industry that incorporates the best practices from around the world," he said. "There is never a situation of zero risk, but we can lower the risk to as low as is reasonably practical." Estimates of resource potential off the British Columbia coast vary widely, and are controversial. Natural gas resource potential is put as high as 25 trillion cubic feet, and oil potential is as high a 9 billion barrels.

The moratorium has been in place for nearly three decades, and lifting it is a highly-charged debate in British Columbia. Opponents warn of serious environmental risks, while proponents point to the economic benefits of developing a resource that is worth $110 billion by some estimates. Further complicating the issue are unresolved First Nations claims to title in the Queen Charlotte Islands and the surrounding waters.

Tsimshian Nation representative Theresa Ryan told the conference that First Nations' people will insist on high standards for environmental protection, health and

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North America's source for oil and gas news

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● JUNEAU, ALASKA

Is Alaska one of the nation's most polluted states? You be the judge

By ERNESTA BALLARD

For Petroleum News

The Environmental Protection Agency will soon report that over 500 million pounds of toxic chemicals are being released to the environment. Alarmists will say that Alaska is one of, if not THE most, polluted places to live. Before you decide to pack up and move elsewhere, please take a closer look at EPA's data and decide for yourself if Alaska is truly at risk.

Every June the federal EPA issues a "Toxics Release Inventory", a list of the estimated weight of toxic chemicals that have been "released" to the nation's air, land and water. The report compares the total weight in each state, and then ranks the states from highest to lowest. This year's report will list Alaska as having the greatest weight of toxic "releases" in the nation

You may want to consider how EPA defines a "release", how a person or the environment is exposed to a "release", and ultimately, the risk from the "release". EPA's definition of "release" does not distinguish between permitted "routine releases" and uncontrolled "accidental releases". Most of Alaska's "releases" are "routine" discharges or contained disposals that are regulated under State and federal laws to ensure no harm to human health or the environment.

expertVIEW

Ernesta Ballard

EPA's report does not explain that before a "routine release" is allowed, a permit application must be made available for public comment and reviewed to determine appropriate protective controls. The permit spells out how pollution will be controlled and the requirements for regular monitoring. Inspections by State and federal agencies ensure compliance with the permit requirements.

Last year's federal data for Alaska show that of the 522 million pounds of "released" toxic chemicals, 99 percent is from Alaska's five largest mines. Virtually all of these "releases" were in the form of mining waste rock. Waste rock contains minute quantities of reportable substances, such as lead and zinc, naturally occurring minerals that remain in the rock after it is mined. The Red Dog zinc and lead mine in Northwest Alaska is the largest zinc mine in the world and has the largest volume of waste rock. All of Alaska's mining waste rock piles have been studied, engineered, and permitted by state and federal agencies to protect public health and the environment.

Before 1998, EPA did not consider waste rock a "toxic release". Then, Alaska was ranked 46th. In 1998, EPA decided to include waste rock in the national reporting requirements. Overnight Alaska jumped from 46th to 4th in the nation for toxic "releases." This leap is due to a change in federal reporting requirements, not a change in what was being released, how "releases" are regulated or overall risk.

EPA admits that their toxic release inventory doesn't explain the associated risk to public health and the environment. To determine the risk you must have site-specific information, know the material's toxicity, its persistence in the environment, and the amount and duration of human or environmental exposure. Fortunately, all of this information is taken into account during the permitting process. Activities that pose unacceptable impacts are not permitted.

It is critical that people receive accurate information about materials discharged and disposed of in the environment and how those "releases" are controlled by state and federal permits. The Alaska Department of Environmental Conservation's Guide to EPA's Toxics Release Inventory will be available online June 24 at www.state.ak.us/dec/TRI/.

Alaska's environment is clean, healthy, and productive. We have strong environmental laws that agencies enforce to control pollution using protective standards that ensure releases are well managed and regulated. Take a hard look at the data in the federal report, ask questions, and decide for yourself. I'm confident you'll find that there isn't a safer place to live than in Alaska. ●

Editor's note: Ernesta Ballard is commissioner of the Alaska Department of Environmental Conservation.

MONTANA

Rocky Mountain drilling proposal brings flood of correspondence

Government officials studying possible petroleum drilling along the Rocky Mountain Front northwest of Great Falls, Mont., are awash in letters and e-mails from people who commented. Close to 50,000 pieces of communication, on paper and electronic, have been received, said Lynn Ricci of the federal Bureau of Land Management in Lewistown, Mont. She leads an interagency team of more than 40 people that is reviewing public comment and expects to release, in February, an environmental impact statement on Rocky Mountain Front drilling. Some of the pieces of correspondence are duplicates with different signatures, but Ricci said June 21 that she was struck by the extent to which people "took time to lay out issues and concerns involving the proposal." Only a handful of the comments were on postcards, she said.

It will be at least a month before the content is summarized in a report.

Ricci declined to say whether the comments tend to favor or oppose drilling.

"I hesitate to even go there," she said. "We're not taking a vote here."

StarTech Energy Corp. of Calgary, Alberta, owns oil and gas leases in the Blackleaf area of the Front and wants to develop them. The leases predate the 1997 suspension of leasing in the area. Some writers said they were concerned about pollution, wildlife protection, the spread of noxious weeds and petroleum development's effect on scenery. Others said it is important to tap energy resources along the Front.

"It's definitely a project with national interest and beyond," Ricci said, noting the correspondence originated from coast to coast and also came from some other countries. In May the BLM held a series of Montana meetings to gather public comment. Letters and e-mails continued to arrive after the comment deadline. Ricci said those are read and considered, but do not become part of the formal record.

—THE ASSOCIATED PRESS

● INTERNATIONAL

BP changes basis for worldwide reserves

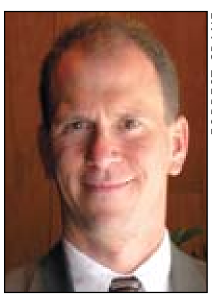
With 41 years of known crude reserves, 67 years of natural gas, company says world not running out of energy

By KRISTEN NELSON

Petroleum News Editor-in-Chief

BP's annual Statistical Review of World Energy is out, and in addition to highlighting major events in energy in 2003, the company has focused on the current interest in reserves, and has revised its numbers in an effort to make the data more timely and accurate.

The bottom line, BP economist Mark Finley told an Anchorage press briefing June 22, is that the world is not running out of either oil or natural gas. In 1980 the reserve-to-production ration for oil was 29 years, and in the company's 2003 numbers it is 41 years he said: "The current proved resource base of the world is sufficient to meet current production levels for 41 years."



FORREST CRANE

Mark Finley, BP economist

Finley said that in the 23 years BP has been tracking crude oil reserves, "the reserves have grown, even though the world has produced 80 percent of what at the time we knew as proved reserves for the whole world in 1980." And while 80 percent of proved crude oil reserves known in 1980 have been produced, "proved reserves have actually risen by 70 percent since then."

BP's new numbers for oil reserves are 1.15 trillion barrels, some 10 percent higher than the number reported in 2002.

For natural gas, reserves have doubled since 1980, and the reserve-to-production ratio is 67 years, with gas numbers up 13 percent from BP's numbers last year.

Numbers as reported by countries

The proved reserves BP is now reporting are "what countries report as proved reserves … those quantities of oil and gas that can be recovered in current economic conditions and current technologies." These numbers, Finley said, are neither estimates "of the ultimately recoverable resource" nor do the numbers necessarily conform to corporate reporting standards required by the U.S. Securities and Exchange Commission or other agencies worldwide.

And BP hasn't tried to second guess the official government data, he said, "but what we do is work very hard at making sure that we have the most current and up-to-date statistics possible."

BP revised its oil and gas reserves numbers, he said, because reserves have been so much in the news.

"Some people are arguing that the world is running short. Some people are arguing that world production is about to peak. And in fact, some people are arguing that the reason why oil prices are high is because we are facing, currently, a shortage of world oil resources," Finley said.

In revising its oil and gas reserves data, part of what BP did was to "rely more on our own internal process for generating" the data. "When we produce the statistical review we send data surveys to governments all over the world, and we ask

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MORATORIUM

safety.

"The Tsimshian Nation will take zero tolerance for negative impacts, whether it's environmental or social," she said.

Even with the moratorium lifted, no drilling would likely take place before 2010, and assuming oil or gas reserves are found in commercial quantities, production would be unlikely before 2020.

—DON WHITELEY, Petroleum News contributing writer

NEW ORLEANS, LA.

Gulf of Mexico Lease Sale 190 draws an official $364,024,583 in high bids

The U.S. Minerals Management Service, following an extensive two-phase bid evaluation that resulted in the rejection of several offers, says last March's Central Gulf of Mexico Lease Sale 190 brought a final $364,024,583 into the government's coffers.

Of the 557 tracts receiving bids, MMS said it rejected 14 high bids totaling $4,537,449 as insufficient for fair market value. In addition, one high bid at $201,450 was deemed unacceptable by MMS because it was below the required minimum bid amount stated in the Final Notice of Sale. MMS accepted the high bids on 542 tracts.

The highest bid accepted on a tract was $35,290,892 by Amerada Hess for Green Canyon block 468. The second and third highest bids accepted were for $31,088,000 by the bidding team of Unocal, Anadarko Petroleum, Nexen Petroleum, BHP Billiton Petroleum on Green Canyon blocks 512, and $8,213,415 by EnCana on Walker Ridge block 969.

"This sale indicates the continued strong interest of major and independent oil and gas companies in the Gulf," MMS said, adding that sale results indicated a continuing interest in shallow-water areas, with 61 percent of the tracts receiving bids in less than 200 meters of water.

Money collected from the sale is distributed to the general fund of the U.S. Treasury, shared with the affected States, and set aside for special uses that benefit all 50 states.

—RAY TYSON, Petroleum News Houston correspondent

NEWS IN BRIEF

Petrobras expands presence in Gulf

With U.S. demand for natural gas on the rise, Petrobras is expanding its presence in the U.S. Gulf of Mexico, picking up 56 shallow water exploration blocks in the Treasure Bay project from Newfield Exploration.

The Brazilian oil company's executive manager for international operations told Dow Jones Newswires June 22 that Petrobras hopes to start drilling test wells next year. Under the letter of intent Petrobras has to drill one exploration well and has the option to drill a second to earn an interest in all of Newfield's Treasure Bay leases.

Project operator, BHP Billiton, has a 44 percent stake in Treasure Bay; Newfield, a 26 percent stake.

Court lifts injunction on Yukos assets

A Moscow court lifted an injunction June 23 that would have prevented tax authorities from seizing oil giant Yukos' assets to pay for $3.4 billion in back taxes, news agencies reported.

The decision by the Moscow Arbitration Court does not clear the way for collection of the money, which the Tax Ministry has claimed, saying Yukos garnered it through the improper use of onshore tax havens.The ruling does, however, move forward one leg of the complex legal actions against Yukos.

Yukos, which sought the injunction to prevent the assets' seizure, says any tax schemes it used were legal and paying that amount in back taxes would bankrupt the company.

SPR draws possible if Saudi oil disrupted

The head of the Paris-based International Energy Agency told Dow Jones Newswires June 18 that his organization would call on its members to release their emergency crude reserves if there is a disruption in Saudi Arabia's oil supplies due to Islamic militant attacks.

Claude Mandil said that the energy watchdog's board, which met earlier that day, had agreed for the IEA's oil stocks to be used in such a situation.

● NORTHWEST ALASKA

Red Dog: Release ranking misleading

Alaska's largest mine and world's largest zinc source says EPA report misleading because naturally occurring metals contained in waste rock and tailings counted as toxic releases

By PATRICIA LILES
Mining News Editor

Alaska's largest mine and the world's single largest source of zinc counters its national top ranking by the Environmental Protection Agency for toxic releases, saying that naturally occurring minerals contained in mine tailings are included in the count at the Red Dog mine.

Located in the remote northwestern region of Alaska, Red Dog produced 579,300 tonnes of zinc and 124,300 tonnes of lead concentrate in 2003, milling more than 3 million tonnes of ore to extract those valuable metals.

Remaining mineralization which is of a low grade and not economically recoverable is classified as waste rock, which must be moved to access the higher grades of ore. In addition, some trace amounts of metals remain in Red Dog tailings, which are stored under strict monitoring from environmental agencies.

Even though that mineralization remains locked up in its host rock, the metals must be counted in Red Dog's annual report to EPA for its Toxic Release Inventory. Red Dog's volume of lead and zinc mineralization puts the mine at the top of the nation's Toxic Release Inventory.

Federal regulations don't distinguish

"Federal regulations do not distinguish between natural materials locked away in rock which is safely stored on the plant site from hazardous releases of man-made chemicals from an industrial plant which is released into the environment," Rob Scott, general manager at Red Dog, said in a June 23 press release.

"As a result, the TRI numbers paint an inaccurate and misleading picture of what actually happens at one of the most regulated mines in the world."

Red Dog, 90 miles north of Kotzebue and about 55 miles from its shipping port on the Chukchi Sea, is on land owned by NANA, the Native regional corporation in the northwestern part of Alaska. Teck Cominco leases land from NANA and operates the mine and mill, and markets the mineral concentrates.

The state-owned Alaska Industrial Development and Export Authority owns the mine's transportation system, which consists of a road system, the port and storage facilities. ●

Editor's note: For more detailed information, look for a report in the July issue of North of 60 Mining News, a monthly special publication of Petroleum News.

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BP

them, what is happening with production, consumption, by fuel? And this year we asked in our survey: what are your reserves?"

In the past, Finley said, BP "had tended to rely on external consultants for more of the data — and we decided this year, with all of the focus on reserves, we would try to do it and see if we could add more value by doing more ourselves" by going "right to the source of government ourselves with our annual survey."

BP also focused, he said, on trying to get as much up-to-date, timely data as possible, given that "these reserves are announced annually, and if they aren't announced in time to meet our production deadline, we can't get them."

Definitions were also revised. (See sidebar on Alberta oil sands.)

The focus, Finley said, was on getting "more timely, accurate, reliable, consistent data."

Prices at 20-year highs

Why are oil prices sitting at 20-year highs? Overall worldwide energy consumption grew by 2.9 percent, "actually a bit faster than the world economy grew" and faster than the 10-year average. Prices were driven by "rebounding economic growth," Finley said, but also by war in a major oil producing country and some major supply disruptions.

While oil prices hit a 20-year high, he said it is important to remember that in real terms those prices are only about half of what they were in the early 1980s. For natural gas it is another story: prices there are at record high levels.

Oil prices have been driven by "a lot of one-time effects," Finley said, including "the war in Iraq, disruptions in Venezuela and Nigeria, but also rebounding economic growth and because of that, rebounding oil consumption, in China especially, but really all over the world, including here in the United States."

With higher consumption, there was also higher production, but OPEC production cuts in 2001 and 2002 left inventories "at very low levels, and that left room for OPEC to increase production last year while still maintaining inventories basically at the bottom end of the normal historical range." And, Finley said, "low inventories correlate historically very closely with high prices."

Investment drives production

There are long lead times to bring oil supplies on stream, Finley said, "And I think some of the sluggishness that we're seeing in non-OPEC production these days is as a result of investment decisions from the late 1990s when oil prices were very weak."

But significant growth in non-OPEC production is expected in the next few years, "because investment spending has increased significantly, and in fact, industry wide it's at record levels right now."

Consumption is the other side of the picture, and while right now robust economic growth is overwhelming high prices, U.S. gasoline consumption has started to drop in the last few weeks due to high prices, and high natural gas prices have already driven down U.S. natural gas consumption, which dropped by 5 percent in 2003 — by 7 percent in the industrial sector and by 13 percent in the power generation sector, even though the amount of electricity generated didn't change much.

Fuel switching is the story here, Finley said, with a switch from natural gas to coal. There is also a switch from natural gas to residual fuel oils, and even some switch from natural gas to diesel when natural gas prices top diesel prices.

China and Russia: consumption and production 'twins'

China's booming economy is a real energy consumer, with consumption of all energy sources up 14 percent in 2003 from 2002, Finley said, with double-digit increases in consumption of oil, gas, coal and nuclear power. China's energy pro-

see **BP** *page 22*

Oil sands added to oil reserves

This year BP has added a portion of Alberta's oil sands to its oil reserves numbers.

The change came, BP economist Mark Finley said June 22, as part of a revision of the company's reserves data. The data is being collected differently, and some of the definitions BP uses have also been changed.

"In the case of Canada," Finley said, "we had historically had a footnote in the table that said we only do conventional oil resources: we didn't include the oil sands."

But, he said, production from Alberta's oil sands is now approaching a million barrels a day. "It didn't make sense to pretend that that oil doesn't exist."

The challenge then became how much of the oil sands to include.

The Alberta government talks about 174 to 175 billion barrels of "established reserve," he said.

BP chose to use a second data series from the Alberta government, one called "an established reserve under active development."

Or, as Finley described it to the Alaska State Chamber of Commerce: the data set that describes "where people are putting money on the table to turn a resource into a reserve."

That amount is about 11 billion barrels, and that is what BP "chose as best matching up with the standard of what we're trying to collect in the statistical review, which is a proved reserve, rather than a recoverable resource."

finance&economy

CALGARY, ALBERTA

Petro-Canada plans share buy back

Flush with cash from soaring oil and gas prices, Petro-Canada hopes to buy back up to 21-million common shares at a cost of about $1.23 billion. The move follows hard on the heels of nearly $2 billion worth of acquisitions made in the last month by the Canadian oil company. "The share buyback will enable the company to optimize its financial structure and is consistent with the company's strategy of creating value for shareholders," the Calgary-based oil and gas company said in a statement. Canada's federal government still owns about 19 percent of the former Crown corporation, but has indicated it would like to sell the stake within the next 12 months. The 21 million shares to be bought back represent about 10 percent of the public float.

Within the last six weeks, Petro-Canada announced a $719 million takeover of Denver-based Prima Energy Corp, and a $1.15-billion purchase of a 29.9 percent interest in the North Sea's Buzzard oil field.

—**DON WHITELEY,** Petroleum News contributing writer

HOUSTON, TEXAS

Offshore rig economics jump 2.1 percent in May

GlobalSantaFe's worldwide SCORE, or Summary of Current Offshore Rig Economics, for May came in at 43.1, a 2.1 percent increase from the previous month, a 13.7 percent increase from the same monthly period a year earlier, and a 65.6 percent improvement from five years ago. The SCORE compares the profitability of current mobile offshore drilling rig day rates to the profitability of day rates at the 1980-1981 peak of the offshore drilling cycle. In the 1980-1981 period, when SCORE averaged 100 percent, new contract day rates equaled the sum of daily cash operating costs plus about $700 per day per million dollars invested.

Despite the continuing loss of rigs in the U.S. Gulf of Mexico, the region scored a 39.9 rating in May, up 6.6 percent from April, up 35 percent from May of last year, and up 78 percent from five years ago. However, the North Sea continued to struggle with rig economics. The region scored 37.9 in May, down 6 percent from April, down 2.9 percent compared to the same period a year earlier, but up 51.5 percent versus five years ago.

Offshore West Africa scored a 50 in May, a 3 percent increase from April, a 3.3 percent improvement vs. the year-ago period, and up 37.8 percent from five years ago.

Worldwide, the economics for both jackup rigs and semi-submersibles improved month-over-month and year-over-year, as well as from five years ago, according GlobalSantaFe's calculations.

Jackups scored 53.2 in May, up 2.3 percent from April, up 23.8 percent from May of last year, and up 112.7 percent from five years ago. Semi-submersibles scored 33.4, an increase of 3.5 percent from April, an increase of 1.1 percent from a year earlier, and an increase of 23.6 percent compared to five years ago.

—**RAY TYSON,** Petroleum News Houston correspondent

● ALBERTA

Syncrude consortium trying to keep a lid on gas prices

Natural gas consumption of nearly 150 million cubic feet a day accounts for 20 percent of oil sands plant's operating budget

By DON WHITELEY
Petroleum News Contributing Writer

Having just added C$2.1 billion to the capital cost of its Athabasca oil sands expansion project, the Syncrude consortium is now hoping to keep a lid on natural gas prices.

In a conference call with analysts on June 21, Syncrude CEO Charles Ruigrok said the C$7.8 billion price tag for the massive project would likely hold within 5 percent either way. But that comes after bumping it by $2.1 billion just last March. Syncrude arranged the conference call to discuss the results of its 2003 sustainability report.

Of concern to the consortium now is the rising price of natural gas, which has driven up operating costs at the existing operation as well as threatening to do the same for the expansion.

Gas consumption at Syncrude is nearly 150 million cubic feet per day, representing 20 percent of the plant's operating budget. In 2003 it cost the consortium C$350 million. Gas prices have increased dramatically since 2002, rising by nearly 70 percent.

Overall energy costs at Syncrude in 2003 averaged nearly $4.50 per barrel of production, up 24 percent over 2002.

Natural gas can be extracted from bitumen

Syncrude Chief Operating Officer Jim Carter told the analysts' conference that technology allows

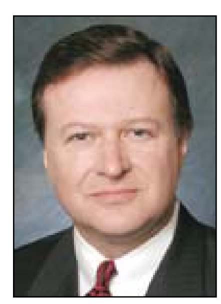
see **SYNCRUDE** page 8

● IRVING, TEXAS

Magnum Hunter vastly expands New Mexico position

$243M deal with EnCana gives company nearly 100 bcf proved gas equivalent reserves on acreage near its own Morrow-Atoka-Strawn drilling program

By RAY TYSON
Petroleum News Houston Correspondent



GARY EVANS

Magnum Hunter Resources, among the fastest growing exploration and production independents in the United States, was forced to wait three long years for the opportunity to meaningfully expand its oil and gas position in southeastern New Mexico.

The company sat it out while the properties, situated largely in New Mexico's Lea and Eddy counties, passed from one owner to another. But patience finally paid off for the Irving, Texas-based company.

In a $243 million deal announced June 21, Magnum Hunter said it agreed to purchase nearly 100 billion cubic feet of proved gas equivalent reserves and other assets from Tom Brown, a recent acquisition and subsidiary of big Canadian independent EnCana Corp.

"Our management team has been chasing this group of assets for over three years," said Gary Evans, Magnum Hunter's chief executive officer. "While these assets have gone through a number of different owners during this period, minimum development on the properties has occurred."

Properties in area Magnum Hunter is drilling

Moreover, the properties are in the vicinity of

see **MAGNUM** page 8

ALASKA

Potential Alaska, federal oil gas lease sales

Agency	Sale and Area	Proposed Date
DNR	North Slope Areawide	October 2004
DNR	Beaufort Sea Areawide	October 2004
MMS	Sale 195 Beaufort Sea	March 2005
DNR	Cook Inlet Areawide	May 2005
DNR	Foothills Areawide	May 2005
BLM	NE NPR-A	June 2005
DNR	North Slope Areawide	October 2005
DNR	Beaufort Sea Areawide	October 2005
DNR	Alaska Peninsula Areawide	October 2005
MMS	Sale 199 Cook Inlet	2006
MMS	Sale 202 Beaufort Sea	2007
MMS	Chukchi Sea/Hope Basin	interest based
MMS	Norton Basin	interest based

** Selected tracts in northwest NPR-A, including some northeast area tracts along border of northeast and northwest areas.*

Agency key: BLM, U.S. Department of the Interior's Bureau of Land Management, manages leasing in the National Petroleum Reserve-Alaska; DNR, Alaska Department of Natural Resources, Division of Oil and Gas, manages state oil and gas lease sales onshore and in state waters; MHT, Alaska Mental Health Trust Land Office, manages sales on trust lands; MMS, U.S. Department of the Interior's Minerals Management Service, Alaska region outer continental shelf office, manages sales in federal waters offshore Alaska.

DALLAS, TEXAS

ENSCO delays redeployment of two jackup rigs from Gulf to Middle East

Offshore drilling contractor ENSCO International said June 18 the scheduled redeployment of the ENSCO 93 and 95 jackup rigs from the U.S. Gulf of Mexico to the Middle East has been delayed.

The delay, which will cost ENSCO an additional $3 million to $4 million in the 2004 second quarter, resulted from an inability to meet the contractual loading date for the transport vessel due to a delay in completion of a drilling contract for the ENSCO 93 and other operational considerations, the company said.

The rigs were scheduled for upgrades in a Middle East shipyard upon arrival, and were not subject to drilling contract commitments, the company said, adding that ENSCO intends to proceed with rig relocations as soon as alternative transportation can be secured. To mitigate the delay in availability for work in the Middle East, the company said it would complete some of the upgrades prior to departure.

—**RAY TYSON,** Petroleum News Houston correspondent

SAN ANTONIO, TEXAS

Pioneer Drilling turns corner on profit, sees better days ahead for land fleet

For the first time in eight consecutive quarters, contract driller Pioneer Drilling has something to cheer about.

Pioneer, which maintains a fleet of 36 land rigs that operate in Texas and Louisiana, reported a profit of $409,000 or 2 cents per share for its fiscal fourth quarter ending March 31. That compared to a loss of $1.9 million or 11 cents per share for the year-ago quarter. Revenues for the fiscal fourth quarter of 2004 were $33.4 million, compared to revenues of $25.1 million in the fourth quarter of 2003.

"We are pleased that operating income was sufficient to have generated our first net earnings in eight quarters," Stacy Locke, Pioneer's chief executive officer, said June 23. Locke said demand for its rigs continued to improve, which allowed the company to gradually increase day rates and profitability on turnkey contracts.

"With continued strong commodity prices, particularly natural gas prices, we see no reason why the current trends will not continue," he added.

Pioneer reported 2,496 revenue days during the fourth quarter of fiscal 2004 compared to 1,808 days for the fourth quarter of fiscal 2003. Average rig utilization for the fourth quarter was 91 percent, up from 84 percent in the same period last year, the company said. During the company's last fiscal year, Pioneer increased its rig fleet by 46 percent, from 24 to 35 drilling rigs, in four separate acquisitions, two of which allowed Pioneer to expand geographically. Pioneer's rigs drill in depth ranges between 8,000 and 18,000 feet.

"Over the last several years we have maintained a focus on growth and intend to continue to look for strategic and financially attractive growth opportunities," Locke said.

—**RAY TYSON,** Petroleum News Houston correspondent

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MAGNUM

Magnum Hunter's current Morrow-Atoka-Strawn drilling program, an area representing the company's most active and successful onshore area of focus in recent years.

With the combination of recent farm-ins from major companies plus the properties being acquired in Tom Brown property acquisition, Magnum Hunter would become one of the largest producers and mineral acreage owners in southeastern New Mexico.

Since the program's inception in 1999, the company has participated in 66 successful wells out of 68 attempts. It also has maintained a two-rig drilling program for the past 26 months on company operated properties, in addition to participating in new wells operated by other companies active in this region.

Of the proved reserves acquired from Tom Brown, 77 percent are natural gas, according to DeGolyer and MacNaughton, an independent reservoir engineering firm. The deal includes 45 proved undeveloped locations.

Additional 50-70 drilling locations in Morrow formation

However, Magnum Hunter said its geologists and engineers have identified an additional 50 to 70 drilling locations in the Morrow formation alone that could be developed into proven reserves. Magnum Hunter's internal reserve estimates provide for 50 billion cubic feet of proved, probable and possible reserves from additional wells, the company said.

Magnum Hunter said it based its reserve projections on similar results achieved from the company's earlier Burlington Resources Permian basin acquisition in 1997 and the Mallon Resources property acquisition completed in 2001. The company said it achieved a low finding and development cost in this core geographic area of $1.02 per thousand cubic feet of gas equivalent.

In addition to the 458 producing oil and gas wells provided in the transaction, Magnum Hunter said it also would acquire about 44,000 net acres of undeveloped leasehold mineral interests. About $26 million of the $243 million purchase price was allocated to the undeveloped mineral acreage position, the company added.

The properties to be acquired currently produce about 18 million cubic feet of gas per day and 870 barrels of liquids per day, or about 23 million cubic feet of gas equivalent per day, representing a hefty 72 percent increase to Magnum Hunter's existing 32 million cubic feet of equivalent per day of production from its existing properties in southeastern New Mexico.

Deal would more than double well count in SE New Mexico

Additionally, it represents an increase of about 11 percent of the company's current total net daily production. The acquisition would more than double Magnum Hunter's well count and mineral acreage position in southeast New Mexico, the company said.

Magnum Hunter said the deal is expected to close on or before July 30, with an effective date of May 1.

Magnum Hunter said it intends to finance the acquisition through the issuance of 15 million shares of common stock plus borrowings under its credit facility. The company expects a debt-to-capitalization ratio of between 51 and 54 percent after completing financing of the acquisition.

Lehman Brothers and Deutsche Bank Securities will serve as joint book-running managers for the common share offering. ●

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SYNCRUDE

the extraction of natural gas from the bitumen, assuming a relatively high price for natural gas. High prices for natural gas threaten a Syncrude commitment to the consortium's partners to lower production costs by 15 percent.

Natural gas for oil sands extraction has been a controversial topic in the last year or so, as Alberta has ordered gas wells shut in to ensure maximum oil production from the oil sands.

One of the biggest engineering projects in the world, the Syncrude expansion is making good progress, according to Ruigrok. "The upgrader expansion project will be close to 50 per cent complete at the end of June and we expect it to be about 70 per cent complete at the end of the year," he told the conference.

The existing operation shipped 253,000 barrels of oil per day in its last quarter — the best first quarter production performance on record. The gain reversed a 7.8 per cent decline in 2002 to a total of 212,000 barrels per day, amid unscheduled production interruptions and downtime for maintenance.

Production from Syncrude equaled 9 percent of the crude oil produced in Canada in 2003. The 2004 target is 86 million barrels, or 235,000 barrels per day. The consortium hopes to achieve the gains through improvements in operating reliability and more efficient maintenance turnarounds.

2004 capital spend will approach $3 billion

Capital spending for 2004 will approach $3 billion with $2 billion for the upgrader expansion project at Fort McMurray. The construction workforce currently stands at 5,500 — matching the 4,000 permanent employees and 1,500 contract workers at Syncrude's current operations.

"All of the large prefabricated modules that were fabricated in the Edmonton area are now in Fort McMurray, and we've got about 100 of the 945 or so left to install," Ruigrok said in the conference call. "The focus then will really be on tidying up the piping work, instrument and electrical work to complete the project." Ruigrok told the conference call that a proposed $1.8 billion railway between Edmonton and Fort McMurray may not be necessary. "The jury's still out on the railway," the Syncrude CEO said. The idea for a railway was put forward by Alberta Premier Ralph Klein as a means of improving the shipment of industrial goods between the two communities. But road transportation appears to be sufficient to get the job done.

When the project is completed in 2006, Syncrude production will increase to 350,000 barrels per day of higher-quality Syncrude sweet premium blend. Syncrude is a joint venture of Canadian Oil Sands, Imperial Oil, Petro-Canada, Nexen, Mocal Energy and Murphy Oil. ●

UNITED STATES

U.S. refineries at capacity as gasoline demand rises

The United States is reaching a "golden age" of refining, with no new refineries built in nearly three decades as demand for gasoline continues to rise, the president and CEO of Marathon Oil Corp. said June 17.

Clarence Cazalot told oil and gas executives at a conference in Houston that oil companies are making "staying-in-business" investments in existing refineries to meet environmental specifications.

"We believe at Marathon that we are reaching a golden age of U.S. refining," he said. "The fact of the matter is, there's not been a new refinery built in the United States since 1976. And that refinery was our refinery in Louisiana."

High oil and gas prices "have certainly improved everyone's balance sheets," Cazalot said, prompting oil companies to pay down debt.

Unwillingness to build new refineries

But industry leaders don't think oil and gas prices will remain at their current high levels in the long term, hindering willingness to shell out billions to build new refineries.

Luis Marin, president and CEO of Citgo Petroleum Corp., noted at the same conference that U.S. refineries are at capacity without a cushion for refining outages or disruptions in supply.

"I don't think we have space for any of those problems," Marin said.

According to the National Petrochemical and Refiners Association, refinery capacity is now about 16.8 million barrels a day, compared with 18.6 million barrels a day more than 20 years ago.

Legislation prompts refinery construction

On June 17 House Republicans pushed through energy legislation that supporters say will prompt construction of refineries. The legislation, which Democrats say has no chance of Senate approval, would make the Energy Department a key agency regarding refinery permits in areas where a refinery has closed or that have high unemployment. The legislation also would streamline the permitting process, requiring decisions on permits within six months of applications.

Some Democrats argued that the Energy Department's role as proposed would usurp the Environmental Protection Agency and state officials' enforcement of clean air standards.

Cazalot also said oil companies need new breakthroughs in technology for various aspects of the business — from refining to exploration and production.

But most oil companies have cut back on such research, he said. The industry itself "never saw solid returns on our own grassroots research," so companies "got lazy" and relied on the service industry to create new technologies.

Cazalot said he'd like to see more cooperation in developing technology, and "then we go out and beat each other's brains out" in terms of how efficiently it is deployed.

—KRISTEN HAYS, Associated Press business writer

● COOK INLET, ALASKA

Old pipelines an issue in moving Cook Inlet gas

RCA rules Agrium has presented no evidence that Cook Inlet Gas Gathering System, built before Alaska Pipeline Act enacted, is used as common carrier

By KRISTEN NELSON

Petroleum News Editor-in-Chief

Access to natural gas pipelines in and around Cook Inlet can be an issue in moving new sources of natural gas to market, and a ruling by the Regulatory Commission of Alaska illustrates why: some pipelines predate the effective date of the Alaska's pipeline and right-of-way statutes.

In April the commission dismissed petitions by Agrium U.S. against Beluga Pipe Line Co. and Marathon Oil; Agrium has requested reconsideration.

The Marathon-operated Beluga Pipe Line is regulated by the commission as a public utility. It moves gas north along the west side of Cook Inlet from an interconnection with the Marathon-operated Cook Inlet Gas Gathering System near Granite Point to the Beluga power plant and to Enstar's pipeline to Anchorage.

Agrium's complaint against Beluga requested the commission to require the pipeline to "provide bi-directional service under the Alaska Public Utilities Regulatory Act" or as an alternative under the Alaska Pipeline Act, which the commission said "would require commingling of two separate gas streams flowing in opposite directions," because Agrium wants to move gas south, through the pipeline and gas in that line is moving north.

But bi-directional flow through Beluga would only be of value to Agrium if it prevailed in its second complaint, which asked the commission to require Marathon to provide — under the Alaska Pipeline Act — transportation services through the Cook Inlet Gas Gathering System. That pipeline system, separate from Beluga, runs north from Trading Bay to Granite Point, where it crosses under Cook Inlet to the east forelands near Nikiski on the Kenai Peninsula side.

But the Cook Inlet Gas Gathering System is a pri-

see PIPELINES page 10

● HONOLULU, HAWAII

Hawaii governor to decide on gasoline price cap law

Price controls passed in 2002 scheduled to take effect July 1 would be modified by legislation passed earlier this year, delayed to 2005

THE ASSOCIATED PRESS

With less than two weeks to go before gasoline price controls passed in 2002 take effect, Hawaii Gov. Linda Lingle is still deciding what she will do with a bill passed this year that would modify the controls and delay their start until September 2005, a member of her cabinet said.

"This is being fully and actively considered," said Ted Liu, director of the Hawaii Department of Business, Economic Development and Tourism.

Price controls passed two years ago and scheduled to take effect July 1 allow the state of Hawaii to set a maximum price for regular unleaded gasoline sold at wholesale and retail levels. The price cap would be based on an average of prices in West Coast markets.

Lawmakers this year changed the formula, tying it instead to a national average of spot prices and applying it to all grades of gasoline, but only at the wholesale level. The proposal also delays the price controls 15 months.

Governor has options

Lingle, who doesn't support the price cap, has three options.

She could veto the new bill and allow the 2002

see HAWAII page 10

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PIPELINES

vate, not a common carrier pipeline, and is not regulated under the act.

The commission said that through its two complaints, "Agrium hopes to facilitate movement of gas from the west side of Cook Inlet to the Agrium plant" on the Kenai Peninsula, requesting "bi-directional service" on the Beluga pipeline in one filing and in the other filing, seeking "to gain access to the CIGGS Pipeline that conveys gas from the west side of Cook Inlet to the east side of Cook Inlet. Agrium envisions its future gas supplies traveling south through the Beluga Pipeline, then east through the CIGGS Pipeline, and across Cook Inlet to the Agrium plant."

Common carriage an issue

Marathon has argued, the commission said, that the Cook Inlet Gas Gathering System is a private carrier not subject to the Alaska Pipeline Act because it "is not, and never has been, operated as a common carrier and does not provide transportation for hire." The commission said Agrium argued that the commission "has the authority to regulate a pipeline regardless of the manner in which the 'transportation for hire' is commercially structured based on the substance and not the form of the commercial transactions." Marathon told the commission that it does not receive natural gas from any third party on the Cook Inlet Gas Gathering System, and said the line "is not used by Unocal and Marathon to provide third-party transportation for hire."

The commission said the pipeline is under its jurisdiction "if it transports gas for hire and as a common carrier. To meet its burden justifying good cause for us to begin an investigation, Agrium must provide to us specific information that would support such a finding." The commission said it did not find facts in Agrium's complaint that the Cook Inlet Gas Gathering System is operating as a common carrier pipeline.

"A complainant is responsible for bringing us sufficient information from which we can make a reasoned judgment that an investigation is warranted. Agrium did not make the necessary factual allegations. Instead, it requested, in effect, that we elicit those facts, if they exist. We decline to do so. We find nothing in Agrium's complaint that would justify the cost of the requested investigation to the public and the parties against which the complaint has been brought."

The commission ruled "that good cause does not exist to investigate the formal complaints filed" by Agrium against Beluga Pipe Line Co. and Marathon Oil and dismissed those complaints, "without prejudice, due to lack of good cause."

As to Agrium's second complaint, the commission said that since Agrium cannot use bi-directional service on the Beluga Pipeline without access to the Cook Inlet Gas Gathering System, that complaint is dismissed without prejudice. "If, in the future, bi-directional service could be in the public interest, we may consider this issue based on the facts presented at this time."

Pipeline in existence before Alaska Pipeline Act

In a concurring statement, Commissioner Kate Giard said the underlying issue here is "the regulatory status of pipeline infrastructure existing before the Alaska Pipeline Act." The Alaska Pipeline Act became effective Jan. 1, 1974, and certificates of public convenience and necessity for pipelines in existence before that date were to be issued without hearings or proceedings. The Alaska Right-of-Way Act requires common carriage as a condition of pipeline leases, Giard said, but the state leases for the Cook Inlet Gas Gathering System were signed before that act was effective and contain no common carriage requirement. The definition of pipeline in the Alaska Pipeline Act, she said, includes "used by a pipeline carrier for transportation, for hire and as a common carrier."

Giard said private pipelines constructed before the Jan. 1, 1974, effective date of the Alaska Pipeline Act "are not even considered 'pipelines' under this definition and have no responsibilities under the statute. CIGGS is one such pipeline." ●

EDSON, ALBERTA

Talisman breaks ground on innovative co-generation plant at its Edson facility

Talisman Energy has begun construction of a 10-megawatt co-generation power plant at its Edson natural gas processing facility, the Calgary-based company said June 21. The C$21 million plant will be the first co-generation facility at a sour gas processing plant in Alberta and the first retrofit of an existing gas plant to co-generation.

"This is an excellent project that improves the cost competitiveness of the Edson gas plant and meets our investment hurdle rates," said Jim Buckee, Talisman's president and chief executive officer.

Capital spending by Talisman in the Edson area this year is projected to be about $249 million with plans to spend about $45 million on infrastructure and participate in drilling 103 wells.

COURTESY OF TALISMAN

Talisman Energy has begun construction of a 10-megawatt co-generation power plant at its Edson natural gas processing facility, the Calgary-based company said June 21.

The company said in a press release that the new co-gen facility will replace older equipment with cleaner, more efficient technology. In addition to reducing the amount of natural gas needed to operate the processing plant by about 12 percent, or 700 thousand cubic feet daily, the new co-generation power plant will produce about two megawatts of electricity more than is required to operate the gas plant, which is enough electrical power to serve about 1,000 homes. Under the Voluntary Challenge and Registry program, Talisman has committed to reduce carbon dioxide emissions. The co-gen project will result in the reduction of direct carbon dioxide emissions by 22,000 tonnes a year and a further indirect reduction of 82,000 tonnes annually, the company said.

Construction of the project, which will employ about 100 people, began after Talisman received approval for the facility from the Alberta Energy and Utilities Board and Alberta Environment.

Construction is expected to be completed by the end of 2004.

The Edson facility, which now processes about 200 mmcf of gas daily, is the largest gas plant operated by Talisman in Canada. It is connected to about 500 kilometers of pipelines within the company's 100 percent owned Central Foothills Gas Gathering System, Columbia Minehead Gas Gathering System and other midstream pipeline assets ranging from 75-100 percent ownership that support exploration and development in both the Edson and Foothills areas.

—PETROLEUM NEWS

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HAWAII

law to take effect as scheduled. Opponents say that could lead to higher prices when the cost of gasoline in West Coast markets goes above Hawaii's average, which has happened in the past.

But the 2002 law also contains a provision that the governor can suspend the price cap if it is determined to cause economic hardship.

Lingle also could sign the new bill and delay implementation of the price cap, although her signature could be viewed as supporting price controls.

Her third option is to let the new bill become law without her signature.

Because of various legislative deadlines, if Lingle decides to let the law pass unsigned it wouldn't take effect until July 13, meaning the 2002 price cap would take effect, but only for 13 days.

Under that scenario, it's unlikely price caps would be implemented or enforced because no money was provided by the Hawaii Legislature to the Public Utilities Commission and Liu's department, which would oversee the law.

An antibusiness issue

Liu said price caps, even if only in place for two weeks, would add to the state's reputation of being antibusiness.

"I think it would be a bad signal, even if it's for a short period of time, it's going to run that risk," Liu said.

Magazines such as Forbes that rank the business climate of states "all talk about this price cap because that's an example of over-regulation of the business climate," he said.

If price caps become a reality next month, but aren't enforced, they are unlikely to have an impact, said Sen. Ron Menor, chairman of the Senate Consumer Protection Committee.

"As a practical matter, I don't think it should be problem," said Menor, D-Mililani, an architect of both price caps. "We're just looking forward to the legislation we passed this last session to take effect because I think it will lead to good results for consumers."

The average price for regular unleaded gasoline in Honolulu was $2.25 a gallon June 20, according to AAA. The average was $2.38 a gallon in Hilo on the Big Island and $2.65 a gallon in Wailuku on Maui.

The national average was $1.96 a gallon, AAA said. ●

● ANCHORAGE, ALASKA

Industry leaders: Alaska could cripple the goose

Because of the high cost of doing business in Alaska, the state could jeopardize its supply of golden eggs if it turns to the oil industry to solve its fiscal gap, reducing competitiveness of Alaska projects that would benefit state

By KRISTEN NELSON
Petroleum News Editor-in-Chief

How do you cheerlead the potential for continued — and even expanded — oil and gas development in Alaska while at the same time trying to persuade the state not to increase taxes, crippling the goose that has been laying golden eggs for all these years?

Petroleum news InDepth

That was the task tackled by executives of Alaska's oil and gas companies at the 10th annual Alaska Oil and Gas Association-Anchorage Chamber of Commerce luncheon June 14 in Anchorage.

The approach they took was to temper predictions of what the oil industry in the state could look like in 2014 — they had been asked to make predictions, and to include what might seem farfetched — with admonitions about the high cost of oil and gas exploration and development in Alaska, and the competition their investment proposals face from projects around the world. The Alaska Oil and Gas Association provided summaries of a study ranking total government take, cost per barrel and profitability of oil and gas in Alaska compared with other oil provinces — a 2002 study by consulting firm Wood Mackenzie which found Alaska has higher than average total taxes and royalties and the highest total oil and gas costs, putting it almost at the bottom in terms of profitability.

There were a number of references to the state's fiscal gap, the spread between income and expenditures, and concern that the state might increase taxation on the oil and gas sector, reducing the competitiveness of Alaska projects.

Oil and gas executives were joined by a top official of the U.S. Department of the Interior and by Alaska Gov. Frank Murkowski, who has called a special session of the Alaska Legislature beginning June 22 to tackle the fiscal gap.

The federal perspective

Assistant Secretary of the Interior Rebecca Watson offered a federal perspective, noting the importance of energy in the United States economy: with only about 5 percent of the worlds' population, "we use that energy we consume to create 25 percent of the world's GDP," she said.

Watson, responsible for both the Bureau of Land Management and the Minerals Management Service, said: "As I look into my crystal ball for 2014, I see us building on the successful sale we had in the National Petroleum Reserve-Alaska," and predicted continued lease sales and production from NPR-A Alpine satellites. On the Minerals Management Side, in the outer continental shelf, Watson predicted: "Northstar entering its second decade of production, Liberty oil flowing down the pipeline," as well as continued exploration and other discoveries moving toward production.


JUDY PATRICK
Assistant Secretary of the Interior Rebecca Watson

> *…in the outer continental shelf, Assistant Secretary of the Interior Rebecca Watson predicted: "Northstar entering its second decade of production, Liberty oil flowing down the pipeline," as well as continued exploration and other discoveries moving toward production.*

As for gas, Watson said she sees "Interior looking far into the future for methane hydrates, so that these gas resources can be added to the gas flowing" through a gas pipeline, "a pipeline that Interior helped to permit."

She said that, like President Bush, the Department of the Interior believes "that energy production and environmental protection are not competing priorities. We think they're dual aspects of a single purpose — and that is to live well and wisely upon the earth."

So along with increasing oil and gas development in Alaska, she said the future she sees includes "birds continuing to nest, caribou herds migrating freely and the North Slope residents continuing to hunt successfully."

Governor wants state to look at equity position in gas pipeline

Alaska Gov. Frank Murkowski said he expects to see a gas pipeline in operation by 2014, expects it will follow the Alaska Highway and connect with the North American gas pipeline grid in Alberta. He said he thinks the potential is "very strong" for spur lines to Valdez and Southcentral, supporting consumers and industrial users.

As for financing, the governor said he thinks "that you will see the state participating in the gas pipeline as an equity owner" of up to 12.5 percent, equal to the

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state royalty on gas. "It could dramatically increase revenues for the state and I think it's worth taking a serious look — and my administration's in the process of doing just that."

JUDY PATRICK

Alaska Gov. Frank Murkowski

On the oil side, the governor said, companies producing in the state "need to reinvest more of their profits in the state."

Once the gas pipeline is in operation, the governor said he expects "a significant southward and westward migration on the North Slope over the next decade as explorers reach further inland in search of additional gas."

On the oil side, Alaska Gov. Frank Murkowski said, companies producing in the state "need to reinvest more of their profits in the state."

He predicted "a major discovery on the Alaska Peninsula," which he noted is ice-free, and also predicted "a major discovery offshore of ANWR, which will require the Department of Interior to drill ANWR to prove from whose reserves" the oil is being pumped.

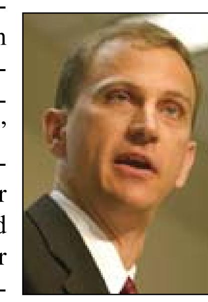
"I also predict major discoveries in NPR-A, and then we'll be looking at boosting the oil flow through Taps, instead of merely holding it steady."

"Farfetched" possibility for much more exploration drilling

Ken Sheffield, president of Pioneer Natural Resources Alaska, a large independent which has been working in Alaska for less than two years, said possibilities for the future include "continued step-out exploration" on the central North Slope, which "offers attractive reserve target sizes for independent companies."

On the far-fetched side of the agenda, Ken Sheffield, president of Pioneer Natural Resources Alaska said that if "operators achieve a significant capital cost reduction," if "we have a period of sustained higher oil prices" and Alaska "initiates additional tax and royalty incentives" to spur development, "you could see greatly increased exploration activity, and an influx of independent operators."

Exploration in the gas-prone Foothills "awaits a pipeline to carry the gas to market," he said. "The lightly explored NPR-A offers larger exploration targets than the mature east-central area," but "significant discoveries" require facilities construction. The outer continental shelf and Bristol Bay offer exploration opportunity, but have "huge commercial challenges," Sheffield said.



JUDY PATRICK

Ken Sheffield, president of Pioneer Natural Resources Alaska

He predicted "modest step-out exploration with increasing participation from the independent companies" on the central North Slope, "paced westward expansion with infrastructure" in NPR-A, low activity for the OCS and frontier basins — while the future of the Arctic National Wildlife Refuge is "in the hands of politicians. … The resulting impact of this best-bet forecast is that exploration discoveries over the next 10 years will likely only moderate the overall North Slope production decline."

Sheffield stressed the tough nature of the exploration business, with very long

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cycle times from land acquisition through discovery and appraisal to production, and said those long cycle times and huge investment and business risks mean that "most companies shy away from exploration altogether and focus on investments exclusively — on property acquisitions and development."

On the far-fetched side of the agenda, Sheffield said that if "operators achieve a significant capital cost reduction," if "we have a period of sustained higher oil prices" and Alaska "initiates additional tax and royalty incentives" to spur development, "you could see greatly increased exploration activity, and an influx of independent operators."

Exploration wells in the state, currently some 10 to 15 a year, could increase "up to 40 or 50 wells a year."

But, Sheffield said, "lowering the cost of doing business and providing appropriate exploration incentives are critical to this scenario," because higher oil prices will positively affect investment opportunities worldwide, not just in Alaska.

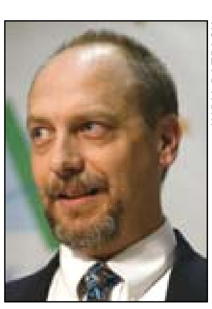
"In this high-exploration scenario, over time, new discoveries not only arrest Alaska's oil production decline, but result in an overall production growth."

Is it farfetched? Sheffield said his exploration manager told him it's a realistic goal, "if all the players commit to make it happen."

Cook Inlet needs step change

John Barnes, Alaska asset team manager for Marathon Oil, said Marathon "signed its first lease agreement on the Kenai Peninsula" in 1954, "so now in 2004 we're proudly celebrating 50 years in Alaska."

The search in the 1950s was for oil, and it was found in the Cook Inlet basin, with production peaking at 227,000 barrels a day in 1970. But oil production in the inlet is now about a 10th of that peak, he said, and the focus is on the search for more natural gas, a resource discovered during the search for oil, and discovered in such quantities that it fueled both heating and electric use and created two new industries — the fertilizer plant and the liquefied natural gas plant. But there is now only some 10 years of supply left.


JUDY PATRICK

John Barnes, Alaska asset team manager for Marathon Oil

"The Cook Inlet needs a step change in natural gas exploration and development activity," Barnes said. The state and industry have responded to the need for more natural gas, but a bump in the road occurred with pipelines, he said: Marathon and Unocal are still waiting for a tariff on the Kenai Kachemak Pipeline, although that line went into operation in September, and the regulatory portion of the pipeline cost may "approach 20 to 25 percent of the project cost" of $25 million.

Companies need some certainties to make investments, he said, and while companies understand subsurface risk, accept commodity price risk and work to control project risk, Barnes said he believes "regulatory and tax uncertainties" are now "the most notable risk companies face in Alaska."

As for the future, Barnes said: "If sufficient exploration occurs, and sufficient success is achieved, enough gas may be found to meet local utility and industrial demands." A higher price for natural gas will be required to attract capital for that drilling, he said.

"The Cook Inlet needs a step change in natural gas exploration and development activity," John Barnes, Alaska asset team manager for Marathon Oil said. The state and industry have responded to the need for more natural gas, but a bump in the road occurred with pipelines, he said: Marathon and Unocal are still waiting for a tariff on the Kenai Kachemak Pipeline, although that line went into operation in September, and the regulatory portion of the pipeline cost may "approach 20 to 25 percent of the project cost" of $25 million.

But if there is "less exploration" or "insufficient success … this creates the distressing scenario" where only one of the industrial plants may stay in operation — or worst case, both may be forced to close.

Viscous could triple

Steve Marshall, president of BP Exploration (Alaska), talked about the success BP has had with viscous oil at Milne Point and Orion. Horizontal dual-lateral wells are now used to produce viscous oil, he said, and whereas early vertical wells did well to produce 200 barrels per day, the company now has 10 wells that have each been producing "in excess of 1,000 barrels a day for more than a year."


JUDY PATRICK

Steve Marshall, president of BP Exploration (Alaska)

And in addition to dual-laterals, the company now has tri-lateral wells and at Orion, a Prudhoe Bay satellite, "the latest well there was a quad-lateral, with four wells going off it" and "26,000 feet of reservoir contact — five miles in one well." Compare that, Marshall said, to 400 feet of reservoir contact in a viscous well in the 1990s.

As for the future, the industry today is producing 50,000 bpd of viscous oil from the North Slope. "We see potential for that to triple by 2014, or maybe more." But that production level will require an investment of some $10 billion, he warned.

As for technology, Marshall said BP is looking at ways to increase well productivity by reducing the viscosity. "We're looking at miscible injectants, detergents if you will, to flush the oil out — even bacteria; looking at heat, perhaps from deeper water sources that we'd need to produce; maybe CO2, with major gas sales."

It's difficult to predict technology changes, such as those that have occurred over the past 10 years, but Marshall said, "one thing hasn't changed and it's not going to change: and that's that capital flows to the investments with the greatest returns."

And "Alaska has some of the highest costs in the industry," he said.

Marshall offered two examples: BP Exploration (Alaska)'s drilling efficiency, the time it takes to drill, is almost at the top for BP, but so are the costs to drill those wells. Viscous has an additional problem, he said: you have to look at productivity in relation to cost. The lifetime production of a viscous well is some 5-6 million barrels, compared to 35-40 million barrels for a well in the deepwater Gulf of Mexico fields.

BP will continue to work the technology challenges, Marshall said, and future successes in that area will impact what North Slope activity is like in 10 years. But costs will continue to be an issue, as will public policy. And future activity, he said, doesn't depend only on technology, it "depends just as much on decisions being made today in Juneau."

Marshall, who has been president of the Alaska Oil and Gas Association for the past year, said in closing that the companies who spoke agree Alaska has a world-class resource, but "it takes well in excess of a billion dollars a year — maybe it's closer to 2 billion" just to keep the existing operations running.

What the oil and gas companies operating in Alaska want to know, Steve Marshall, president of BP Exploration (Alaska), said, is: "Can we go back to our boards, wherever they are — in London, Houston, Calgary, Dallas — and say with confidence, that this is a good place to invest? The oil and gas is there, we just need to find a way to get it out."

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Will Alaska go to the well again?

Kevin Meyers, president and chief executive officer of ConocoPhillips Alaska, said the potential of a gas pipeline is what is most exciting to Alaskans. He compared it to oil: The 4.5 billion cubic feet a day of natural gas coming off the North Slope will be the equivalent of 700,000 barrels per day of oil.

In addition to being a big project, "it also will open up a whole new business for us here in Alaska," the business of looking for natural gas in addition to looking for oil.


JUDY PATRICK

Kevin Meyers, president and CEO, ConocoPhillips Alaska

But the financial commitment remains huge, he said, with the tariff estimated to cost shippers about $10 million a day. And with an estimated cost of $20 billion to take gas to the Midwest, investors have to be comfortable that the price of natural gas will remain high enough to help pay back that investment, Meyers said. "And it's not just 10 years: it's 20-30-40 years from now that the prices have to be good enough to help pay back … that $20 billion investment."

In addition to paying back investors, the natural gas price has to be high enough "to yield a wellhead price that is high enough to encourage new exploration, new development and the production of gas on the North Slope…"

The federal enabling legislation is also key, he said, because "investors need confidence that the regulatory and permitting process in the U.S. will not hinder or even kill a project once a decision has been made to move forward."

Just the permitting for the gas line, Meyers said, is expected to cost between half a billion and a billion dollars.

The federal fiscal legislation that ConocoPhillips wants "can help increase investors' confidence in the project," he said, because gas prices have to be high enough for decades to pay back that investment.

And then there is state fiscal certainty: "The investors also need to know the rules by which the state will take its royalty and taxes. And more importantly, investors need to know the state won't change those rules after they have invested billions of dollars."

Hence the Alaska Stranded Gas Development Act, under which the producers are negotiating "a fiscal contract that will provide certainty and clarity for the gas pipeline project."

The producers are also looking for ways to reduce the capital cost.

But there's also Alaska's fiscal gap. If "Alaska chooses to address the fiscal gap by going back, once again, to the well — excuse the pun — the oil and gas industry, the industry that already provides almost 90 percent of the state's general revenues, then it puts future oil and gas investments here at risk," Meyers said.

Will the industry leave the state? "No, that's not going to happen," he said. But if oil and gas taxes are raised, "it will mean less investment, fewer jobs, less production, a poorer economy — and in the long run, less revenues for the state." ●

ALBERTA

Value Creation to drill 50-60 wells on oil sands leases

Calgary-based Value Creation Inc. said June 17 it will conduct a 50 to 60 well drilling program next winter on 16 oil sands leases covering nearly 72,000 hectares in the Athabasca oil sands area.

The private company, which is developing a proprietary bitumen upgrader, said in a press release that the drilling is the initial phase of a $30 million to $50 million evaluation program to be conducted on its properties.

"It is consistent with our long-term strategy to develop our oil sands resources using our own proprietary technologies," said Dr. Columba Yeung, founder and chairman of Value Creation.

The 2004-05 program will focus on two leases southwest of Fort McMurray, and one lease northwest of Fort McMurray.

Value Creation estimates that crude bitumen in place totals 26 billion barrels. Some areas may be suitable for in situ operations such as steam assisted gravity drainage.

Value Creation subsidiary BA Energy Inc. has submitted an application to the Alberta Energy and Utilities Board for approval of its 226,000 barrel per day Heartland upgrader planned for Strathcona Country. Subject to regulatory approval, the first phase of the Heartland upgrader could be completed in late 2006.

—DON WHITELEY, Petroleum News contributing writer

NORTH AMERICA

Canada drops 77 drilling rigs, United States down by 16

The total number of rotary drilling rigs operating in North America during the week ending June 18 fell by a combined 93 rigs to 1,367 compared to the prior week, according to rig monitor Baker Hughes. Canada's rig count took the largest hit, decreasing by 77 rigs compared to the previous week and was down by 141 rigs versus the same period last year.

The total number of rigs operating in the United States during the recent week stood at 1,171, down 16 rigs from the previous week and down 104 compared to the year-ago period. Land rigs alone decreased by 15 to 1,005 from the prior week, while offshore rigs dropped by two to 96. Inland waters gained one rig for a total of 20 rigs. Of the total number of rigs operating in the United States during the recent week, 1,006 were drilling for natural gas and 163 for oil, while two were being used for miscellaneous purposes. Of the total, 722 were vertical wells, 316 directional wells and 133 horizontal wells.

Among the leading producing states in the United States, Texas suffered the biggest loss of drilling rigs in the recent week, falling by 11 for a total of 490 rigs. Louisiana's rig count was down by six to 165 rigs. New Mexico lost three rigs for a total of 68, while Oklahoma lost three rigs for a total of 167. California's rig count was down by two to 23. Alaska was unchanged at seven rigs, according to Baker Hughes.

—RAY TYSON, Petroleum News Houston correspondent

● NORTH SLOPE, ALASKA

Recent ANS exploration activity will impact facility sharing landscape

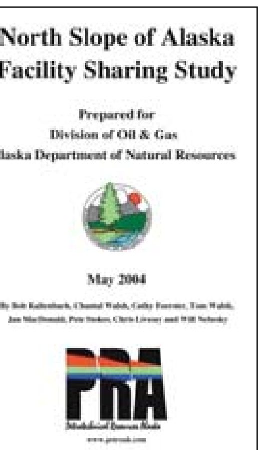
By KAY CASHMAN

Petroleum News Publisher & Managing Editor

The first major wave of new explorationists to Alaska's North Slope in recent years was led by Anadarko Petroleum in the early 1990s, followed by EnCana's predecessor Alberta Energy in 2000. Both companies initially signed on as partners with the North Slope facility owners and experienced slope operators, BP Exploration (Alaska), ConocoPhillips Alaska and ExxonMobil.

1 2 SERIES

According to the North Slope of Alaska Facility Sharing Study, released June 15 by the Alaska Division of Oil and Gas, seven exploration wells, including sidetracks, were drilled in 2001 on the North Slope (see map on page 23). Five of those wells were drilled by the predecessor to ConocoPhillips and two were dilled by BP — the last two wildcats BP would spud in the state.


North Slope of Alaska Facility Sharing Study

Prepared for
Division of Oil & Gas
Alaska Department of Natural Resources

May 2004

In the winter of 2002, 12 exploration wells were drilled on the North Slope, one operated by BP on the edges of the Prudhoe Bay unit, 10 by ConocoPhillips, and one by independent Anadarko, its first stint as a slope operator. By this time Anadarko had become one of the largest leaseholders (including ASRC options) on the North Slope.

Second wave of new explorationists

In 2003 a second wave of new explorationists drilled wells on Alaska's North Slope, including home-grown independent Winstar, headed by former ARCO Alaska executive Jim Weeks, and Irving, Texas-based independent Pioneer Natural Resources.

AVCG added to its lease position last year with acquisitions east and south of the Colville River unit, north of Prudhoe Bay and west of the Kuparuk River unit. "They are considering stand-alone processing options at this time, which would limit the facility impact to common carrier pipelines," the study said.

Pioneer had bought into a North Slope prospect put together by independent Armstrong Oil and Gas. Bill Armstrong, who heads up the Denver-based company, had the foresight to bring into his group experienced North Slope explorers, including Stu Gustafson, former head of Exxon's exploration department in Alaska.

Nine exploration well were drilled on the North Slope in 2003, six by independents and three by a major. The wells included a hot ice well by Anadarko that tested its new Arctic drilling platform, EnCana's first operated well in Alaska at the offshore McCovey prospect, three by Pioneer in partnership with Armstrong at the Northwest Kuparuk prospect (now called Oooguruk), a Winstar well drilled for the tiny independent by ConocoPhillips, and three wells drilled by ConocoPhillips.

This past winter seven exploration wells were drilled on the North Slope, including three in the National Petroleum Reserve-Alaska by ConocoPhillips in partnership with Anadarko, one by newcomer Total in partnership with independent Talisman Energy (Fortuna) in NPR-A, and two by new player Kerr-McGee, a Oklahoma-based independent which acquired majority interest in Armstrong's Nikaitchuq prospect northwest of Milne Point.

In the winter of 2005, independents Armstrong, Pioneer and Kerr-McGee are expected to drill as many as five exploration wells on the North Slope. Anadarko is expected to drill its Jacobs Ladder prospect south of the Badami unit in either 2005 or 2006, depending on whether or not it can find a partner for the project.

see EXPLORATION page 22

GULF OF MEXICO

Current Deepwater Activity

Operator	Area/ Block	OCS Lease	Rig Name	Prospect Name	Water Depth (ft)
BP Exploration & Production Inc.	WR 724	G17011	OCEAN CONFIDENCE	Das Bump	7,591
Shell Offshore Inc.	MC 657	G08496	R&B FALCON NAUTILUS	Coulomb	7,565
Union Oil Company of California	WR 678	G21245	DISCOVERER SPIRIT	Saint Malo	7,038
Chevron U.S.A. Inc.	WR 759	G17016	TSF DISCOVERER DEEP SEAS	Jack	6,965
BP Exploration & Production Inc.	GC 743	G15606	TSF DEEPWATER HORIZON	Atlantis(GC)	6,829
BP Exploration & Production Inc.	MC 778	G09868	TSF DISCOVERER ENTERPRISE	Thunder Horse South	6,040
Dominion Exploration & Production, Inc.	MC 734	G21778	TRANSOCEAN CAJUN EXPRESS	Thunderhawk	5,724
Dominion Exploration & Production, Inc.	MC 773	G19996	PRIDE 1503	Devil's Tower	5,610
Marathon Oil Company	AT 488	G18617	NOBLE AMOS RUNNER	Kansas 2	4,725
Mariner Energy, Inc.	VK 962	G15444	DIAMOND OCEAN AMERICA	Swordfish	4,677
Spinnaker Exploration Company, L.L.C.	MC 124	G24049	GLOMAR JACK RYAN	Zorin	4,479
BHP Billiton Petroleum (GOM) Inc.	GC 653	G20084	GLOMAR C. R. LUIGS	Shenzi	4,340
Anadarko Petroleum Corporation	GC 608	G18402	NABORS POOL 140	Genghis Khan	4,287
Chevron U.S.A. Inc.	GC 640	G20082	FALCON DEEPWATER MILLENNIU	Tahiti	4,017
Anadarko Petroleum Corporation	GC 518	G21801	NOBLE PAUL ROMANO	K2 North	3,993
Eni Petroleum Co. Inc.	GC 562	G11075	GLOMAR CELTIC SEA	K2	3,933
Kerr-McGee Oil & Gas Corporation	EB 688	G09191	DIAMOND OCEAN STAR	Boomvang (East)	3,786
Shell Offshore Inc.	GC 248	G15565	NOBLE MAX SMITH	Glider	3,440
Shell Offshore Inc.	GB 516	G11528	NOBLE JIM THOMPSON	Serrano	3,392
Eni Petroleum Co. Inc.	GC 254	G08010	DIAMOND OCEAN VALIANT	Allegheny	3,225
Shell Offshore Inc.	VK 956	G06896	H&P 205	Ram-Powell	3,214
Kerr-McGee Oil & Gas Corporation	GB 668	G17408	NABORS MODS RIG 150	Gunnison	3,152
Nexen Petroleum U.S.A. Inc.	GC 243	G20051	NOBLE HOMER FERRINGTON	Aspen	3,050
TOTAL E&P USA, INC.	MC 243	G19931	SUNDOWNER XVI	Matterhorn	2,816
Chevron U.S.A. Inc.	GC 205	G05909	NABORS 85 (MAYRONNE 162)	Genesis	2,590
Walter Oil & Gas Corporation	MC 583	G16624	DIAMOND OCEAN LEXINGTON	Killer Bee	2,487
Murphy Exploration & Production Company -	MC 582	G16614	MODS 141	Medusa	2,214
LLOG Exploration & Production Company	GB 378	G24488	DIAMOND OCEAN SARATOGA	GB 378	2,044
Kerr-McGee Oil & Gas Corporation	GB 244	G15860	TRANSOCEAN MARIANAS	Basal Peak	1,946
Chevron U.S.A. Inc.	VK 786	G10944	ENSCO 25	Petronius	1,754
El Paso Production GOM Inc.	EW 1003	G13091	SUNDOWNER XI	Prince	1,490
BP Exploration & Production Inc.	MC 109	G05825	H&P 203	Amberjack	1,030

Total Deep Water Prospects with Drilling/WO Activity 32

New Deepwater Activity

Operator	Area/ Block	OCS Lease	Prospect Name	Water Depth (ft)
Mariner Energy, Inc.	VK 962	G15444	Swordfish	4,677

Falcon satellites Tomahawk, Raptor begin producing in deepwater Gulf

Dallas-based independent Pioneer Natural Resources said its Tomahawk and Raptor satellite fields, subsea tiebacks to the company's Falcon complex in the deepwater Gulf of Mexico, came on-stream June 16.

Pioneer holds a 100 percent working interest and operates four fields in the so-called Falcon Corridor, which currently produce about 350 million cubic feet of natural gas and 1,000 barrels of condensate per day.

Tomahawk, on East Breaks block 623, and Raptor, on East Breaks block 668, are 1.4 miles and 5.5 miles, respectively, from the Falcon subsea manifold in water depths ranging from 3,600 to 3,700 feet. The wells produce into a dual flowline system connecting the Falcon manifold to the Falcon Nest processing platform 32 miles to the north on the Gulf of Mexico shelf. Falcon Nest is owned and operated by GulfTerra Energy Partners.

With Tomahawk and Raptor, Pioneer established a new record for deepwater Gulf of Mexico operations completing development of the fields in 10 months.

The Falcon field began production in March 2003.

The Harrier field began production in February 2004.

"We expect similar results with Tomahawk and Raptor and look forward to testing additional prospects with subsea tie-back potential in our exploration program planned for the second half of this year," said Scott Sheffield, Pioneer's chief executive officer.

—**RAY TYSON,** Petroleum News Houston correspondent

continued from page 1

KERR-MCGEE

and spar platform technologies pioneered by Kerr-McGee in the U.S. Gulf.

The most notable reserve upgrade came at Neptune at Viosca Knoll, where the company said it now expects to produce more than 85 million barrels of oil equivalent during the life of the project, up about 40 percent from initial projections of 60 million barrels of proven and probable reserves, when the project was sanctioned in 1994.

The decision to increase recoverable reserves at Neptune was based on results from the first two phases of development drilling, the addition of wells on Viosca Knoll block 825, production performance and, most recently, satellite fields on Viosca Knoll block 869, Kerr- McGee said.

Production began at Neptune in 1997

Neptune came on stream in March 1997 from the world's first production spar on Viosca Knoll block 826 in 1,050 feet of water. Its field and satellites have now produced a total of 46 million barrels of oil and 65 billion cubic feet of natural gas, totaling 56 million barrels of oil equivalent.

Production from the Neptune spar is currently averaging 11,000 barrels of oil per day and 50 million cubic feet of natural gas per day. Production is derived from 11 dry tree wells on the spar and four subsea wells.

"We also continue to have satellite development opportunities around the field," said Rick Buterbaugh, Kerr-McGee's head of investor relations.

The company plans to spud the Viosca Knoll 869 No. 2 well, another potential subsea development well, to the Neptune spar in this year's third quarter, he added.

Nansen sanctioned in June 2000

The Nansen field project at East Breaks was sanctioned in June 2000 on a gross proven reserve base of 55 million barrels of oil equivalent, plus a probable resource base of about 120 million barrels of oil equivalent.

Buterbaugh said that following development drilling, the addition of its Navajo satellites and better than anticipated production performance, the company is now expecting to produce more than 200 million barrels of oil equivalent of gross proven and probable reserves from the area.

Nansen came on line in January 2002 and is the world's first truss spar, on East Breaks block 602 in 3,700 feet of water. Kerr- McGee operates the field and the Nansen area with a 50 percent working interest.

The Nansen field and its Navajo satellites have now produced 22 million barrels of oil and 135 billion cubic feet of natural gas, totaling 45 million barrels of equivalent, the company said. Production through the spar is averaging about 30,000 barrels of oil per day and about 165 million cubic feet of natural gas per day.

Nansen production is derived from nine dry tree wells on the spar and six subsea wells, of which three produce the Nansen field and three produce the Navajo satellites.

Upcoming activities in the Nansen field include planned recompletions of several of the dry tree wells and one of the Navajo subsea wells.

"Additional satellite drilling is under evaluation as far as capacity and field operations allow," Buterbaugh said.

Boomvang production began in June 2002

Kerr-McGee said it now expects its Boomvang field at East Breaks to produce nearly 80 million barrels of oil equivalent, up from original proven and probable reserve estimates of about 70 million barrels of equivalent.

COURTESY OF KERR-MCGEE

Kerr-McGee said it now expects its Boomvang field at East Breaks to produce nearly 80 million barrels of oil equivalent, up from original proven and probable reserve estimates of about 70 million barrels of equivalent.

Boomvang began producing in June of 2002 from a truss spar on East Breaks block 643 in 3,650 feet of water. The truss spar produces the North Boomvang field with five dry tree wells, the East Boomvang field with three subsea wells and the West Boomvang field with one subsea well. Kerr-McGee operates the area and holds a 30 percent interest in most of the wells.

The Boomvang area has produced more than 18 million barrels of oil and more than 100 billion cubic feet of natural gas, totaling about 35 million barrels of oil equivalent since inception. The current production rate is about 30,000 barrels of oil per day and 98 million cubic feet per day of natural gas.

However, Boomvang has not been without its troubles. Recently the East Breaks block 688 No. 8 subsea well experienced a failure of a subsea safety valve, the company said, adding that the well would remain shut in to comply with its own environmental policy until the valve can be repaired, which is expected in early July.

Gas production from the failed well is expected to be restored at 35 million cubic feet per day when the valve is repaired, Kerr-McGee said.

Reservoir performance on a well by well basis at Boomvang has met expectations except for the West Boomvang area where early water breakthrough on the East Breaks 642 No. 1 well and 686 No. 2 well has occurred, Kerr-McGee said.

The 642 No. 1 well was sidetracked updip and the well's production has been re-established at 20 million cubic feet of gas per day, the company said, adding that remedial work on the 686 No. 2 well "is not justified at this time."

Future plans for the Boomvang area include a recompletion of one of the East Boomvang wells, subsea tiebacks of two additional satellite wells in East Breaks blocks 598 and 599 north of the platform during the third quarter, as well as the evaluation of further satellite opportunities in the 2004-2005 timeframe, as space and capacity become available, the company said. ●

natural gas

FREEPORT, TEXAS

FERC grants LNG permit

Cheniere Energy said June 21 that the Federal Energy Regulatory Commission has authorized development of the proposed liquefied natural gas receiving terminal on Quintana Island near Freeport, Texas.

Cheniere owns a 30 percent limited partnership interest in Freeport LNG Development which will construct and operate the terminal.

Freeport LNG filed an application with FERC in March for authorization to construct and operate the 1.5 billion cubic feet per day facility under the Natural Gas Act.

The Dow Chemical Co. and ConocoPhillips are contracted with Freeport LNG for all of the facility's capacity.

Charif Souki, chairman and chief executive officer of Houston-based Cheniere, said the company is "confident that this first success will be followed by a similar experience for the applications we filed with FERC" in December for LNG receiving terminals at Sabine Pass, La., and Corpus Christi, Texas.

"We believe enough infrastructure can be built to allow LNG to account for 25 percent of domestic natural gas consumption by the end of the decade," Souki said.

—PETROLEUM NEWS

CLARK, WYO.

Gas companies turn attention back to Clark area in Wyoming

Exploration for oil occurred in Park County, Wyoming's Elk and Oregon basins many years ago, but companies only found natural gas and moved on.

That gas now is drawing them back to this tiny community just south of the Montana line.

Two oil and gas development projects are in the works, a 20-mile gas pipeline and a 47-square-mile seismic survey. Both are proposed by Windsor Wyoming on private, state and federal land.

The pipeline would link Windsor's existing gas wells in Clark to Elk Basin, where storage tanks are planned near the county landfill.

"Basically we're just digging up the ground, putting in the pipe and covering it back up again," said Rick Kirkenslager, contractor for Windsor Energy Group. "It will probably be the greenest spot out there in Clark."

The company has already received permission from at least seven landowners but has not yet won blessings from the BLM, Park County or all the property owners.

An application is on file at the Cody Field Office of the U.S. Bureau of Land Management, but it is still incomplete, said Becky Heick, an assistant field manager for BLM.

County commissioners say they support the idea in principle but have not yet received an application for the right of way permit and easement, County Landfill Manager Dave Hoffert said.

Some property owners, such as Brad and Cindy Cicci, might not be sold on the idea at all. The Clark residents have proposed an alternative route that avoids their land.

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● COOK INLET, ALASKA

State gets mixed reviews on proposed royalty gas sale

Views of producers of natural gas, and utilities and other industrial users range from expressions of concern to outright rejection

By **KRISTEN NELSON**

Petroleum News Editor-in-Chief

Tyonek platform

Part 1 of this story, in the June 20 issue of Petroleum News, contained an overview of the state of Alaska's request for expressions of interest in a royalty in kind sale of its Cook Inlet natural gas, and includes a summary of responses from Agrium, the Kenai Peninsula Borough, Forest Oil and Fairbanks Natural Gas.

1 2 SERIES

Those views were favorable to a sale — or at least to the Alaska Department of Natural Resources Division of Oil and Gas proceeding with a best interest finding for the proposed sale.

The views of Cook Inlet natural gas producers, the other industrial user in the inlet, the Nikiski liquefied natural gas plant, and utilities, are basically opposed to the sale idea, and most told the state that they feel such a sale would not be in the state's best interest.

ConocoPhillips a seller, buyer and consumer

ConocoPhillips Alaska said it "is a seller, buyer and direct consumer of natural gas in the Cook Inlet market," and told the state it does not believe a royalty in kind sale of Cook Inlet natural gas would be in the state's best interests.

ConocoPhillips produces natural gas at the Beluga field on the west side, and at the Tyonek platform in the North Cook Inlet field.

The company said it "understands that one focus for the state's evaluation of an RIK gas sale at this time is a noncompetitive sale for industrial feed gas purposes, including, potentially, a noncompetitive sale to Agrium, the owner of an export fertilizer manufacturing plant in Kenai."

ConocoPhillips said a royalty in kind sale of Cook Inlet gas "cannot avoid adverse impacts on other operations and utilities that depend on the use of royalty gas taken in value by the state.

"An RIK sale would simply shift the current tightness in the Cook Inlet gas market from parties whose current gas-short situations result from their own business decisions, to other parties who would be put into the same gas-short situations as a direct result of the state's RIK sale."

ConocoPhillips said it also believes the price in a non-competitive sale would be lower than what the state currently receives, so there would be a revenue loss to the state.

The ConocoPhillips-Marathon LNG plant could be adversely impacted, ConocoPhillips said, because if the state's royalty gas from the North Cook Inlet unit — which now goes to the LNG plant — was sold elsewhere, ConocoPhillips would need to find other sources of gas for the LNG plant.

At the Beluga River unit, sale of royalty in kind gas would "have a negative impact upon utilities as well as industrial operations," the company said, noting that on cold days the Beluga River unit is producing at maximum volumes to both industrial and gas and electric utilities. "At the very least, directing (Beluga River unit) gas away from the utilities decreases the ultimate amount of gas available to supply the utility contracts over the long term," the company said.

Marathon questions transportation availability

Marathon Oil told the state it does not believe the state should hold a Cook Inlet royalty gas sale, noting that a significant portion of the state's royalty gas is now sold under long term contracts, many of which

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● EQUATORIAL GUINEA

Marathon, GEPetrol a step closer on LNG project

PETROLEUM NEWS

Marathon Oil Corp., the government of Equatorial Guinea and Compania Nacional de Petroleos de Guinea Equatorial, "GEPetrol," the national oil company of Equatorial Guinea, have finalized the necessary agreements for the companies' Equatorial Guinea liquefied natural gas project.

The companies said this is "the final investment decision" for the project, expected to be completed and shipping its first cargoes of LNG in late 2007, and called it "a record-setting pace from project inception to first delivery of LNG."

Clarence Cazalot Jr., president and CEO of Marathon, said the project "is an excellent investment opportunity that will yield attractive rates of return enabling both Marathon and Equatorial Guinea to create sustainable value growth."

The companies said the project "will be one of the lowest cost LNG operations in the Atlantic basis with an all-in LNG operating, capital and feedstock cost of approximately $1 (per million Btu) at the loading flange of the LNG plant."

Marathon is funding 75 percent of the project, GEPetrol the remaining 25 percent, although the companies said both "have received expressions of interest from a number of companies about acquiring an equity interest in the LNG project."

The project will purchase natural gas from Alba field participants Marathon (63 percent), Noble Energy and GEPetrol under a long-term gas supply agreement, the companies said, and 3.4 million metric tons per year of LNG will be sold to BG Gas Marketing Ltd., a subsidiary of BG Group, under a 17-year purchase and sale agreement which begins in late 2007.

The companies said BG Gas Marketing will be purchasing free on board, F.O.B., at Bioko Island, Equatorial Guinea, with pricing linked principally to the Henry Hub index, and will target the Lake Charles, La., LNG import terminal as its primary destination.

The companies said "the agreement provides destination flexibility of the LNG," so that BG Gas Marketing can "take advantage of prevailing market conditions at other import destinations around the world."

Bechtel is the primary engineering, procurement and construction contractor. Construction costs are estimated at approximately $1 billion or approximately $260 per metric ton of installed capacity.

Preliminary construction work on the plant began in December 2003, and work is progressing on schedule with site preparation, accommodation, equipment mobilization and ordering of major plant components.

The plant will use the Phillips Optimized Cascade Process.

The contracted off-take rate is 3.4 million metric tons per year for 17 years, but "the plant is expected to have the ability to operate at higher rates and for a longer period," the companies said.

The Alba field holds estimated remaining gross risked recoverable resource of 4.4 trillion cubic feet of gas, and the companies said approximately 3 tcf of that is expected to be produced through the LNG plant under the contract with BG. ●

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REVIEWS

serve the interests of Alaska consumers for generation of electricity and natural gas for home use, and that the state "currently enjoys the financial benefit of higher market value pricing for its share of natural gas production."

Diversion of some or all of this natural gas to a preferred consumer would amount to a state subsidy, Marathon said, "which over the long term would distort markets and hinder future industrial developments. Subsidizing an uneconomic plant would shift the economic burden to all other local consumers," the company said, and "would not create any new gas supplies."

Agrium's gas supply is at risk, Marathon said, because it requires a low price because of competition in a world fertilizer market. For many years the "gas oversupply" in Cook Inlet "allowed Agrium and its predecessor to compete successfully in the world market. More recently, however, the natural gas market has tightened significantly, putting economic pressure on Agrium."

Marathon also said it believes there would be transportation problems.

"Aggregating and redirecting royalty gas from each of 25-odd fields and various pipelines in the Cook Inlet to Agrium's plant would be a complex undertaking," the company said, and argued that neither Agrium nor the state "presently have the resources to identify, measure and transport these volumes on a daily basis."

Unocal concerned about impacts on 'fragile' Cook Inlet gas market

Unocal Alaska told the state that, while it "is not opposed in principle" to a Cook Inlet royalty gas sale, it is "very concerned about the impact such a sale or sales will have on the already fragile Cook Inlet gas market."

The company said it expects that, if the state decides to go ahead and accept bids for Cook Inlet royalty gas, it would "structure the bid process in such way as to not increase our costs as operators or further complicate or create an unworkable delivery system in Cook Inlet."

Unocal said that until "exploration creates a more secure supply of deliverable gas in Cook Inlet," royalty in kind sales "will be fraught with complications and unintended consequences." Unocal said it believes a sale of the state's royalty gas "may only result in shifting the gas short fall from one consumer to another."

In addition to the shortage of supply, Unocal said the "seasonal nature of deliveries, demand profiles, complicated field balancing, exchange arrangements, royalty settlement agreements and fragile interplay of the gas consumers in Cook Inlet" could lead to "a multitude of untended consequences."

The company said the needs of industrial and utility consumers "are dramatically different," and argued that "an increase in gas sale pricing," which has "stimulated the desired response of increased exploration and higher valuation for the state," demonstrate the "supply and demand marketplace is working."

Utilities opposed

Chugach Electric Association told the state that it is currently purchasing 23.5 billion cubic feet a year of Cook Inlet natural gas and has long-term contracts for some 184 bcf, contracts which it expects will meet its needs through 2010.

Chugach said its Beluga River contract provides that if royalty gas is taken in kind, the volumes it receives would be reduced, and said it is concerned that if the state sells its royalty gas in kind, such a sale "could reduce volumes of gas available under Chugach's existing contracts and cause Chugach to have to purchase higher priced gas."

Chugach said that because it has contracts in place, it is not in a position to purchase royalty gas, but could be harmed by such a sale, and recommended that the state not sell its royalty in kind gas unless Chugach "can be assured it will not reduce the volumes available under our contracts with the Beluga producers."

Enstar Natural Gas told the state it is purchasing some 27 bcf annually, and has about 200 bcf committed under long-term contracts, contracts which will meet its needs through 2007, so does not have any immediate "need or ability" to purchase royalty in kind gas.

However, Enstar said, any sale of the state's royalty gas "will reduce the amount of gas available for the use of residential and industrial gas customers, including the Anchorage electrical utilities." Because discoveries have not kept pace with gas use, the company said, if the state sells its royalty gas "in order to increase current gas use without adding new discoveries" there will be "shortages and price increases for all Southcentral Alaska consumers."

Enstar said it explored a royalty in kind purchase in the mid-1990s, but decided it was not in its best interest, or the state's, to pursue a royalty in kind purchase.

"Instead, Enstar believed then, as it does now, that it is preferable for buyers of significant volumes of gas to be proactive in encouraging exploration for new sources of gas."

This is what it has done, Enstar said, by contracting with Unocal to meet its long-term needs, which Unocal agreed to do by exploring for gas, and committing that gas to Enstar.

"This contract has resulted in significant drilling and other economic activity and new gas reserves at prices that benefit the consumers and the state," Enstar said. "This 'free market' solution benefits all gas consumers, as it induces new exploration and brings new gas to market, extending the supply of gas in the region."

Municipal Light & Power told the state that its one-third interest in the Beluga River field will meet its gas requirements for electrical generation of some 10.5 bcf a year and does not expect to purchase additional gas until 2010.

But if the state takes its royalty gas in kind, the utility said, "this will accelerate the time at which ML&P will need to purchase gas."

The utility said gas sold to utilities has historically "yielded higher values than for other uses," and said it believes it is in the best interest "of all concerned" that supplies to utilities are "not impaired." ●

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WYOMING

"The more we look at the pipeline, the more we don't want it to come across our property," Cindy Cicci said. "We would just as soon they keep it on public property or county roads so they wouldn't have to deal with us at all."

Windsor Wyoming has asked to complete a seismic survey west of Clark this fall. About 70 shot holes would be loaded with a 10-pound explosive charge and detonated to provide a map of the minerals underground.

The bulk of the project kicked off June 8 with the release of a scoping statement.

—THE ASSOCIATED PRESS

● MEXICO

Mexico's president taps new energy chief

Elizondo facing tough mission: Opening energy to foreign firms

By DEBRA BEACHY

Petroleum News Contributing Writer

Mexico's new Energy Minister Fernando Elizondo is facing an impossible mission that no one else has accomplished: getting Congress to change Mexico's Constitution to allow more foreign investment in energy, an analyst says.

Elizondo, formerly finance director of the northern border state of Nuevo Leon, was chosen by Mexican President Vicente Fox Quesada June 1 to replace Felipe Calderon. The flamboyant, outgoing former energy minister resigned from the post after Fox publicly rebuked him for unveiling presidential ambitions.

Energy Minister Fernando Elizondo

"I don't think Elizondo will be able to do anything to move Fox's energy reforms forward. I don't think anything will happen until Mexico's next president is elected," said Michele Foss, director of the Energy Institute at the University of Houston. Fox's term ends in 2006.

"Why did Fox choose Elizondo?" she added. "He is not well known."

Calderon, a former president of Fox's National Action Party, had a strong, extensive political network that included influential members of the opposition Institutional Revolutionary Party and the leftist Revolutionary Democratic Party, as well as his own National Action Party.

"If Calderon couldn't get anything done, how can he?" Foss remarked. Calderon held the position less than a year, having been appointed energy minister in September of 2003.

Elizondo, a former corporate lawyer, built his career in the northern industrial city of Monterrey, providing legal counsel for large Monterrey-based corporations, such as steelmaker Alfa S.A. He had been working with Fox on tax reforms aimed at changing the country's tax code.

Elizondo Fox's third energy minister

Elizondo is Mexico's third energy minister under Fox. His political experience includes serving as interim governor of the state of Nuevo Leon and as its finance minister. He has been described as unassuming and quiet.

The new appointment is unlikely to affect Mexico's oil policy, Foss said. The state-run oil monopoly Pemex has said it aims to raise crude oil exports to 1.95 million barrels a day by the fourth quarter from the current 1.86 million barrels a day to help ease high crude prices and supply concerns.

It remains to be seen whether Elizondo will pursue the plans announced shortly before Calderon's resignation to lay off more than 3,000 non-unionized Pemex workers. Calderon had said the layoffs were part of his plan to slim down Pemex, which has nearly 140,000 employees. More than 90,000 of the Pemex employees are union members, and the union strongly opposes opening up Mexico's energy sector to foreign investment.

The proposed administrative overhaul of Pemex would merge Strategic Planning, Safety and Environmental Protection, and Competitiveness and Innovation into other areas. In the first quarter of this year, Pemex reported a 10 percent increase in administrative costs, which contributed to the company's 993 million peso ($86 million) net loss for the period, compared with a 4.71 billion peso ($409 million) profit in the same 2003 period. Mexico's government-owned oil monopoly also pays taxes and royalties to the government that equal about 60 percent of its revenues.

Calderon had proposed improving corporate governance

In addition, Calderon had proposed the creation of a special audit committee, aimed at improving corporate governance. Calderon had said it was needed because Pemex, as an issuer of bonds on international markets, was supposed to have an independent audit committee, which is required to guarantee accurate financial information for bondholders.

Mexico's president, a former Coca-Cola executive and state governor, has pushed hard to open up Mexico's energy sector to foreign investors. Under his administration, foreign companies have won contracts to build power plants, and to supply natural gas to power plants. His administration also has allowed foreign companies to compete for contracts to drill for natural gas in Mexico's rich Burgos basin. But his energy initiatives that would allow foreign companies any share in production have faced stiff opposition from political opponents, and have ended up deadlocked in debate.

Political opponents also have ripped the so-called multiple service contracts that allow foreign companies to drill in the Burgos basin as unconstitutional because Mexico's constitution prohibits any foreign participation in energy. Although Mexico's Congress hasn't declared the so-called multiple service contracts to drill for gas unconstitutional, it also hasn't said they are constitutional. It has sidestepped the entire issue by saying it doesn't have the jurisdiction to decide the matter. ●

● NORWAY

Norwegian oil workers strike escalates supply fears

THE ASSOCIATED PRESS

Plans to escalate an offshore oil field strike raised fears that flows from the world's third-biggest oil exporter could dry up as global demand is holding prices high. An industry executive described the conflict as "completely deadlocked."

A Norwegian union announced Jan. 23 that it would step up a five-day-old strike early Monday, Jan. 28, which would cut Norway's daily production by 715,000 barrels and disrupt natural gas supplies to Britain.

Only Saudi Arabia and Russia export more oil than the Nordic country, which has a daily production of three million barrels.

Employers said they were contemplating their options, which many fear could include a lockout that would virtually halt Norwegian production.

However, the Norwegian government has traditionally been quick to order an end to oil-field strikes when oil exports crucial to the economy are threatened.

Crude prices slipped despite news of the worsening labor conflict. Traders said that was partly because many buyers had adopted a wait and see attitude before committing themselves to such expensive oil.

On Jan 21, Iraq, another important oil source, resumed exports after repairs to a pipeline sabotaged by insurgents, helping to cool off prices.

The August contract for light sweet crude was off 60 cents at $37.65 US a barrel in afternoon trading in New York. Brent crude oil for August delivery fell 58 cents to settle at $35.03 per barrel in London.

In a dispute largely over pensions and job security, the Federation of Norwegian Oil Workers and its smaller ally Lederene ordered a strike by 207 workers on Friday, June 18. That has reduced Norwegian oil production by about 375,000 barrels per day. Another 16 workers were ordered to shut down a platform late on Jan. 23, bringing the total loss in production to 455,000 barrels per day, about 15 percent of Norway's output. The union also said that roughly 100 more members would strike June 28, cutting oil production by another 260,000 barrels per day.

It said the expanded strike would target the Heimdal field, operated by Norsk Hydro ASA, and the production ship Norne, operated by Statoil ASA. The strike has already hit fields operated by Statoil, ConocoPhilips and ExxonMobil.

"The strike situation on the Norwegian continental shelf is extremely serious, it is completely deadlocked, and we are evaluating the situation continuously," said Per Terje Vold, managing director of the Norwegian Oil Industry Association, said.

Earlier in the day, Tom Gedero, a spokesman for the association, said a lockout was being considered. The association later played down that threat, however.

"At present, we have no plans for a lockout," Ola Morten Aanestad, another spokesman, said by telephone.

He also said the total impact on production by Monday could be greater than the 715,000 barrels per day now estimated if it also disrupts smaller satellite fields linked to platforms idled by the conflict.

Terje Nustad, leader of the federation of unions, said they wanted to escalate the strike enough to make oil companies feel the economic sting, but not enough for the government to order binding arbitration, which would end the conflict. ●

VENEZUELA

Venezuelan state oil company to invest $37B by 2009 to boost production

Venezuela's state oil company plans to invest $37 billion by 2009 to improve production capacity by 32 percent, one of the corporation's directors said June 22.

Nelson Martinez said Petroleos de Venezuela SA, also known as PDVSA, would increase production capacity from 3.8 million barrels per day to 5 million barrels per day under the investment plan.

"In this context, Venezuela is and will be one of the most important international oil suppliers," Martinez told the state-run Venpres news agency.

Martinez said Venezuela, a top supplier to the United States and the world's No. 5 oil exporter, is currently producing 3.1 million barrels of oil per day.

Venezuela is still recovering from a general strike last year that temporarily paralyzed oil production, costing the nation an estimated $7.5 billion.

President Hugo Chavez fired half of PDVSA's work force for joining the strike, saying he would cut bureaucracy and improve efficiency.

Critics say the dismissals cost PDVSA critical manpower and expertise. Many new employees and technicians in the field lack experience and training, they argue.

Former PDVSA executives claim the government has exaggerated production figures, arguing that Venezuela's total production is roughly 2.8 million barrel per day.

—THE ASSOCIATED PRESS

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LNG

coal to Newcastle (home of the UK's coal mines), North America will now see growing levels of gas imports.

It will be a decade or more before the implications of this trend are fully felt, but Canada, and particularly British Columbia, will not escape the effects of this change. In the last year, LNG imports in the United States doubled. LNG is expected to comprise about 20 percent of the North American market by the year 2020. It will surpass Canada's current 15 percent share of the U.S. market by 2015. While only a handful of those 35 projects now on the drawing board will likely proceed, the trend is obvious.

U.S. gas shortfall equals entire supply for Japan

At the Offshore Oil Technology Conference in Houston, Marathon Oil's Steve Lowden told delegates that the projected U.S. gas supply shortfall equals the entire supply for Japan, currently the world's largest importer of LNG. According to the Oil & Gas Journal, the world's five major oil companies have committed to spending $50 billion over the next five years to move LNG.

Ultimately, LNG will drive prices in the North American domestic market, and that could impact British Columbia's natural gas producers and provincial gas royalties. Coincidentally, that 20 percent LNG market share is predicted to take hold just about when the first production from the province's offshore wells might be getting started.

The North American natural gas market has been a contained unit, virtually impervious to global energy trends. While natural gas prices were tied to global oil prices (much to the chagrin of domestic producers in the 1990s) there was never any worry about serious competition from offshore supplies.

But a combination of rising prices and falling North American supply have rekindled interest in LNG. Driving that interest is the fact that while natural gas is now in short supply in North America, global gas reserves are estimated at a mind-boggling 4,500 trillion cubic feet (British Columbia has a potential of 50 tcf in conventional gas). Most of that gas currently has nowhere to go.

And adding to the impetus is a significant reduction in LNG costs. The cost of building just the natural gas liquefaction plant has declined by 60 percent since 1989.

"The cost of moving gas has dropped by half," says Tom Dawson, Galveston's marketing vice president. "Everything from building ships, to liquefying the gas, to regasifying it. Technology has really made a huge impact."

El Paso regasifying onboard ship

Case in point: El Paso Natural Gas is currently building a new import terminal in the Gulf of Mexico that uses a patented Energy Bridge system. The LNG is regasified on the ship and pumped through an offshore dock into a pipeline, eliminating the need for a conventional land-based terminal.

According to Dawson, it costs $30 million to convert an LNG ship to use this system, as opposed to $200 million to construct an onshore regasification plant. In another technological development, a utility in Atlanta, Ga., just completed a successful test on regasifying the LNG by using sea water in a new heat exchanger to warm it up (LNG is stored at minus 260 degrees Fahrenheit.)

"We're looking at another 25 percent cost reduction over the next 10 years," Dawson says. "Technology has really gotten a hold of the LNG market." As a result of all this, LNG prices at North American ports are expected to range from US$2.50 per thousand cubic feet to about $3.50.

LNG as competition for unconventional gas?

And that raises the prospect that LNG could provide price competition for domestic producers, particularly those now trying to develop high-cost unconventional natural gas in places like EnCana's Greater Sierra play, or the Cutbank Ridge play near Tumbler Ridge.

Greg Stringham, executive vice president with the Canadian Association of Petroleum producers, is not concerned.

"We think we will need all of it," he said. "We'll need LNG, northern gas, tight gas, Alaska gas, and coalbed methane. We still think we can compete with LNG through about a 50 to 90 cent cost advantage."

Stringham concedes that technology could bring the LNG cost lower, "but technology works for all of it — technology could also lower costs for coalbed methane."

Regardless, LNG has arrived on the scene, introducing the biggest change in the North American gas market in decades. It has the potential, in the longer term, to turn natural gas into a global commodity on the same scale as crude oil.

Given the enormous gas supplies in remote locations all over the world, that can't help but provide growing competition in North America. ●

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ALPINE

barrels per day.

But further study of the reservoir and the decision to go with horizontal wells, waterflood and enhanced oil recovery changed that initial capacity to 80,000 bpd, Whitehead said.

After the field came on production in November 2000, "they ramped up to the 80,000 barrels a day and then as … they drilled more wells they recognized that they had well capacity to go above the 80,000 barrels a day."

The tweaking that was done then was "a real team effort" between operations, engineering and drilling, he said, "to take advantage of that opportunity."

Sometimes production bottlenecks involved learning how to operate at a little higher rate, sometimes it was something like replacing a valve with a little bigger valve — and for the reservoir engineers, it was a matter of working on "how do we manage this reservoir correctly at a higher rate," he said.

This work began in 2001, Whitehead said, and over about a year's time the de-bottlenecking kicked up the Alpine production rate to 100,000 to 105,000 bpd.

In addition to de-bottlenecking, ConocoPhillips did an Alpine capacity expansion "junior" project on the reservoir management side. ACX Jr., completed in the summer of 2002, upgraded transfer pumps at Kuparuk, where Alpine buys its seawater for injection.

"And that upgrade allowed us to ship about 10,000 barrels a day more water to Alpine so that we could use that to basically replace the oil that we were taking out of the ground," Whitehead said.

ACX1 primarily directed at produced water

ACX1, approved last year, will increase oil throughput at Alpine by about 5,000 bpd with "some of those final tweaks to the plant for that higher rate …," Whitehead said, "but the real thing that we did with ACX1 was to increase our produced water handling capacity."

The plant was designed to process 10,000 bpd of produced water — water mixed in with the crude oil when it comes out of the ground — which needs to be separated and re-injected. Since 95,000 bpd of seawater are also being injected, "at some point you start producing that water back and you want to re-inject" it, Whitehead said. So ACX1 increases produced water handling capacity to 100,000 bpd.

ConocoPhillips knew that produced water handling capacity would have to be increased over the life of the field, he said, but that expansion was moved forward "because we were producing our oil with our accelerated rate, it just drove us to have to do it a little sooner."

The engineering is complete for ACX1, Whitehead said, and the modules were fabricated in Anchorage and trucked out to Alpine over the ice road last winter.

Implementation overlaps

ACX1 and ACX2, each about $60 million, were approved separately, and implementation was going to be done separately, with a shutdown planned this summer for ACX1, followed by "a fairly long shutdown" next summer for ACX2. But after ACX2 was approved early this year, Whitehead said, planners identified that a lot of the modules for both ACX1 and ACX2 could be completed and the tie-in work done this summer, shortening the shutdown that will be required next summer.

The projects remain separate, he said, "except when it comes to doing the construction piece."

ASRC Energy Services and VECO are the prime contractors, and Whitehead said they "did a really fantastic job for us as far as identifying opportunities and just working closely with us to take advantage of that opportunity that we identified."

ACX2 will be completed in '05

It wasn't possible to complete ACX2 this summer because some equipment couldn't be moved ahead fast enough to get it to the slope for ice road delivery this year, so parts of ACX2 will come up on the ice road this winter and be installed next summer.

But accelerating modules and piping for ACX2 make next summer's shutdown shorter than it would have been, Whitehead said.

ACX2 is designed to increase oil capacity to 140,000 barrels a day, although Whitehead said that with normal operational ups and downs Alpine probably won't see an annual average of 140,000 bpd. Seawater injection will be increased to a little more than 130,000 bpd to compensate for increased oil production.

And ACX2 includes a small increase in gas handling capacity: "Right now we can produce about 160 million (cubic feet) a day and we'll go to about 180 million," Whitehead said. That gas is re-injected, he said, both as miscible injectant for enhanced oil recovery and as pressure support in the reservoir.

Full rates from the ACX2 work are expected in the third quarter of '05.

Maintenance also during shutdown

ConocoPhillips is also taking advantage of the shutdown to do maintenance that can only be done when equipment is down. Alpine is a one-train facility, Whitehead said, which means there is one primary generator, one primary compressor. There is a short maintenance shutdown once a year for inspection of critical equipment, and once every four or five years there is a longer shutdown so that the machinery can be inspected in more detail and planned parts change out done.

"We'll be doing all that operational work during this shutdown, too, so that's adding more people, more complication to the shutdown and just more coordination," he said.

The maintenance people have to coordinate with the construction people to make sure they stay out of each others way, and also to share equipment.

And because wells will be shut in during the shutdown, that gives engineers an opportunity to check bottomhole pressures, "so from a reservoir standpoint it helps them get a better understanding and helps them better manage the reservoir."

Pre-shutdown work under way

Planning for the shutdown began in January, Whitehead said, and included outside experts in shutdown planning, as well as a peer review within ConocoPhillips.

The main ACX work requiring a shutdown is work inside the vessels.

"We have to shut the vessels down, deinventory them, safe them out" before people can go in to do the necessary work to increase throughput capacity.

Then there is the new piping, which again requires that we "depressure and deinventory lines, safe them out, before we can make tie-ins."

There will be backup power generation while the main generator is down, and seawater injection will be started back up before the plant comes back up, Whitehead said, even though no oil will be produced during shutdown.

Prior to shutdown work under way now

Eight million pounds of modules, equipment and piping for both projects were moved to Alpine on the ice road which was completed in January, Whitehead said, and the ramp up for the work began in early March.

Part of the planning process was to identify work that could be done prior to the shutdown, including setting modules on pilings and putting piping in place in pipe racks, ready to be tied in during the shutdown. Work started with about 50 people at Alpine in March. "We have about 250 right now on construction and another 50 doing kind of that additional O&M work, and then our normal 100-plus people up there."

Because there is no road to Alpine, scheduling workers around the number of people the camp can hold — about 500 — has been part of the challenge for shutdown planning, he said.

And development drilling at Alpine, expected to be completed at the end of this year or early next year, was also part of the planning, Whitehead said.

Because there isn't a lot of room on the main pad, Colville Delta 1, the drilling rig — which drilled two wells at the main pad this spring — had to be moved over to the second drill site, Colville Delta 2, to make room.

Whitehead said that once this summer's work is done, over about a week's time Alpine production will get back to where it was, and "then on top of that I think we'll pretty quickly get up to the 5,000 incremental barrels that we get with ACX1."

The final ramp up, to 140,000 bpd, won't take place until next year, when ACX2 construction is complete. ●

Companies involved in North America's oil and gas industry

All of the companies listed above advertise on a regular basis with Petroleum News

Petroleum news

Business Spotlight

By PAULA EASLEY

FORREST CRANE

Richard Faulkner, president

STEELFAB

STEELFAB is Alaska's largest steel fabricator and service center. It provides pressure vessels, tanks, modules, bridges, major buildings, special design items, and raw steel products to the state's major industries. STEELFAB's topnotch workforce of fabricators, engineers and detailers guarantees that customers get quality, on-schedule products.

When Richard and Janet Faulkner bought STEELFAB in 1988, they embarked on an intensive, multi-million dollar capital improvement plan. Today STEELFAB's indoor work space is 80,000 square feet on 10 acres of land. Modern, labor-saving equipment, such as an auto I-beam welder and a plasma-powered, computer-guided cutter, guarantee fast deliveries. Richard is a longtime supporter of the Alliance and the Resource Development Council's industry advocacy activities. He and Janet have one son, Heath, and a baby granddaughter.

FORREST CRANE

Kelly L. Gifford, office manager

PRISM Training Center

PRISM, an affiliate of AAI Engineering Support Inc., is a full-service fire, safety, and emergency response training facility located in Kenai, Alaska. The company opened its doors in October 1988 and has since provided a range of courses designed to meet the needs of rural and urban clients in both the public and private sectors.

Kelly Gifford joined PRISM in February 1998 after spending 13 years with the Kenai Borough School District. A favorite part of her job is working with individuals throughout Alaska. Kelly and her husband Dennis have two married daughters, two grandchildren, and two single daughters. Boys interested in Amanda or Madison are strongly encouraged to complete Kelly's "application for permission to date my daughter."

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EXPLORATION

According the North Slope facility sharing study, which was conducted for the state by Petrotechnical Resources of Alaska, recent North Slope exploration activities that "will potentially impact the facility sharing landscape" include Pioneer/Armstrong's' Oooguruk unit evaluation, Kerr-McGee/Armstrong's Nikaitchuq 2004 exploration drilling, ConocoPhillips' 2004 NPR-A drilling, and 2004 lease acquisition by Pioneer, Kansas-based independent AVCG, and UltraStar exploration, a sister company to Winstar.

Pioneer and Armstrong "have announced a discovery in the Nuiqsit Fm., and are evaluating options for development," the study noted. Development "could impact the Kuparuk facilities and or its pipeline."

Kerr-McGee and Armstrong "have announced a discovery in the Sag River Fm." Development could impact the Milne Point facilities, the Mile pipeline and Kuparuk pipeline, the study said.

ConocoPhillips discoveries west of the Colville River unit will impact the Alpine facilities and pipeline, as well as the Kuparuk pipeline.

North Slope Pipeline Capacities and Projected Field Production

MBPD	Badami	Endicott	Milne Pt.	Alpine	Kuparuk	NorthStar	TAPS
Year	Pipeline	Pipeline	Pipeline	Pipeline	Pipeline	Pipeline	Pipeline
Current Capacity	35	100	65	100	400	65	1400
2003	0	29	51	98	361	62	994
2004	0	30	52	99	359	68	997
2005	0	29	53	98	364	60	982
2006	0	27	57	103	376	50	968
2007	0	25	58	117	390	40	954
2008	0	24	59	117	379	32	923
2009	0	22	59	104	367	27	878
2010	35	56	59	86	338	20	852
2011	50	70	58	71	322	17	824
2012	48	66	57	60	300	15	775
2013	38	55	56	51	290	12	734
2014	31	47	56	44	273	10	691
2015	27	42	55	38	267	9	663

(a) Badami includes projected Liberty throughput
(b) Endicott includes Badami and Liberty throughput
(c) Kuparuk includes Alpine and Milne Pt. throughput

Pioneer acquired tracts in the 2003 North Slope and Beaufort Sea state areawide lease sales in the Hemi Springs area, as well as north of Prudhoe Bay, east of Northstar and west of Kuparuk. "Successful exploration programs associated with these lease acquisitions could impact numerous production facilities," the study noted.

AVCG added to its lease position last year with acquisitions east and south of the Colville River unit, north of Prudhoe Bay and west of the Kuparuk River unit. "They are considering stand-alone processing options at this time, which would limit the facility impact to common carrier pipelines," the study said.

In 2003 UltraStar, headed by Jim Weeks, added new leases to its portfolio around Badami and north of Prudhoe Bay. Successful drilling of its prospects could impact Badami, Point McIntyre/Lisburne and/or the Prudhoe Bay facilities.

Armstrong, EnCana, ConocoPhillips

In addition to this activity, continued prospect development and technological breakthroughs to lower North Slope environmental impacts and costs by Armstrong could also have an impact. (See Petroleum News archives at www.PetroleumNews.com)

Another potential player among the non-facility owners is EnCana. Although the Calgary independent is not drilling in Alaska this next winter, it views the state as one of its key international exploration provinces.

EnCana was the second highest bidder (ConocoPhillips was the first) at the U.S. Minerals Management Service's Sept. 24 Beaufort Sea sale, taking all 24 tracts on which it bid, including a block of 19 tracts north of NPR-A in the Smith Bay area, adjacent to six existing ConocoPhillips-Anadarko leases.

EnCana was the only bidder for "B" leases, those farther offshore and farther from infrastructure in what MMS referred to as the wildcat area, bidding on 22 tracts, the three on the east side and the majority in the block north of NPR-A.

ConocoPhillips continues to be a major North Slope explorer. The company, which partners with several majors and independents in Alaska, has drilled or participated in 43 exploration wells and acquired more than a million acres of exploration acreage in Alaska in the last six years.

"A critical constraint will be available processing and pipeline capacity to the west and north of the Kuparuk River unit," the study said. "Alpine satellites, NPR-A, and the Oooguruk and Nikaitchuq discoveries will all place significant pressure on the Kuparuk and Alpine pipelines. However, with enough new production potential realized, additional pipeline capacity may be justified," the study said. ●

CORRECTION

The first story about the North Slope Facility Sharing Study that appeared in the June 20 edition of Petroleum News said that majors such as BP and ExxonMobil are focused on oil and gas provinces outside Alaska where they have the potential of finding 1 billion barrel-plus oil discoveries, "something geologists say is no longer likely in the areas of Alaska that are open to oil and gas drilling." Wrong! While it is true that most geologists believe it is more likely to find a 10-500 million barrel discovery on the North Slope than a 1 billion barrel discovery, there are areas of Alaska open to drilling that likely carry 1 billion barrel-plus fields, the main two being the Chukchi and Beaufort seas.

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BP

duction — primarily coal for domestic use — also rose, "but oil consumption outpaced oil production in China and as a result imports surged by a third." Finley said he believes the surge in Chinese oil imports is one of the factors behind recent price increases, since China is increasingly playing a role in international markets, and "in the future will become an importer of liquefied natural gas as well."

Russia's economy is also growing, but the energy relationship is different there, Finley said: "in Russia higher energy production is pushing the economy higher," and while Russia had increases in both oil and gas production, "really it's been an oil story." Production "collapsed when the Soviet Union unraveled, but 1998 was the low point and since then Russian production has risen by 2.5 million barrels a day of oil."

That amount, Finley said, is enough to "meet half of all of the growth in worldwide consumption over that interval, and, in fact, Russian oil production growth has been faster than Chinese oil consumption growth." ●

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PELICAN HILL

good portion of their mechanical components … pumps, generators and engines. They have also purchased several new pieces of equipment."

Once the drilling operations resume, expected to be in mid-summer, "they will drill out the cement plug and run cased hole logs. This will include a pulse neutron over the previously unlogged interval of the well to evaluate for gas potential. They will also run a cement bond log to ensure the cement is in place properly between the outside of the casing and the ground," Webb said.

"If the logs prove to be sufficient, and they get the necessary permits from AOGCC and the DEC, they plan on injecting the used drilling mud into a non-producing zone from this well," he said.

The cuttings from the well will be washed and used for fill by a local private property owner, Webb said.

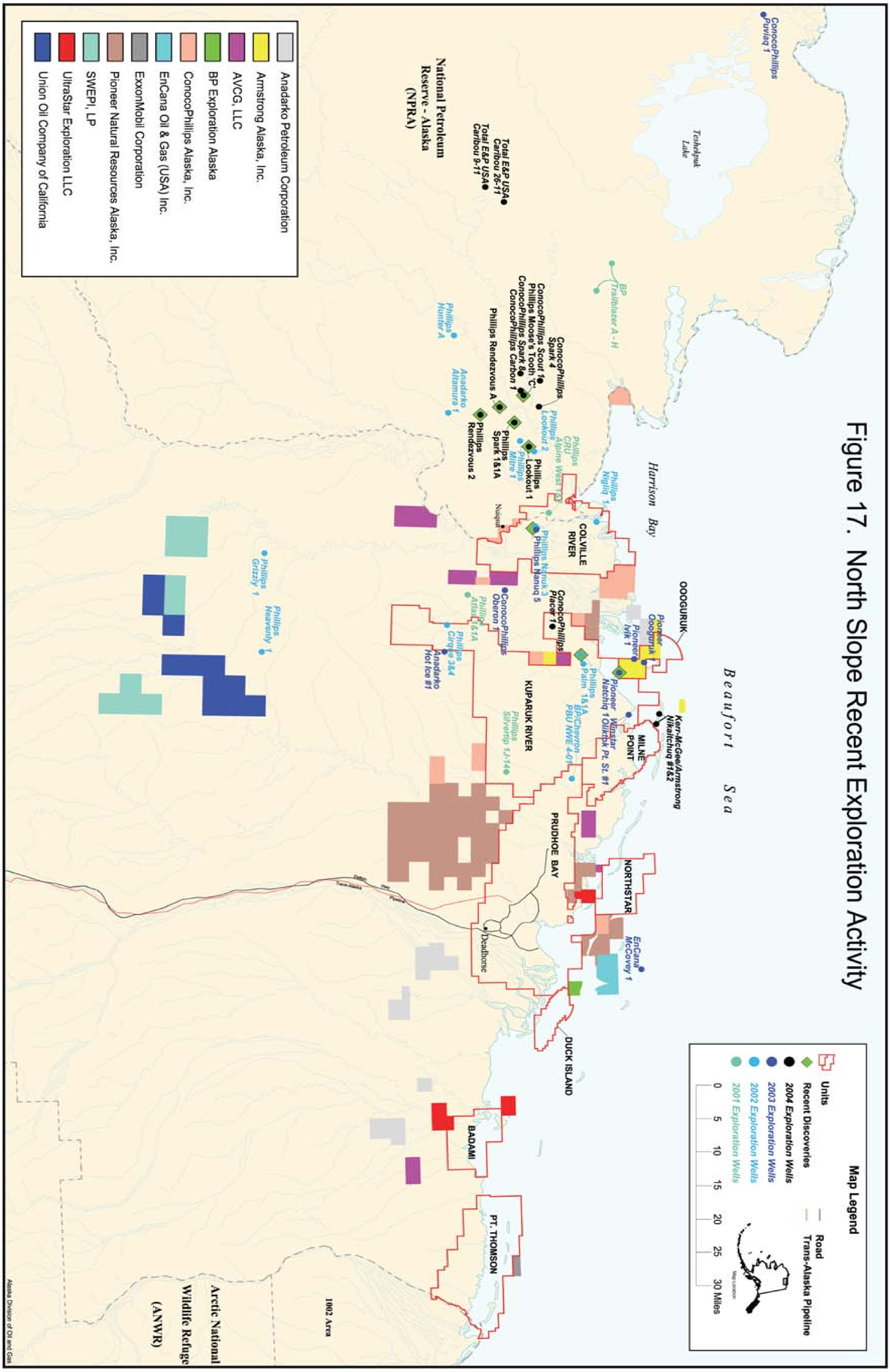
Iliamna No. 1 is a vertical hole in section 31, township 9 north, range 14 west, Seward Meridian. It is on state oil and gas lease ADL 0388133, onshore at Trading Bay, north of the Trading Bay production facility.

Access to the exploration sites is by existing roads and temporary roads constructed with an interlocking mat system which will be removed once the work is complete.

Pelican Hill received a permit for a second well, the Iliamna No. 2, on Oct. 30. That well is also a vertical hole. It is in section 29-T9N-R14W, SM, also on state oil and gas lease ADL 0388133.

Webb said the company plans to drill the second well upon completion of the first.

—PETROLEUM NEWS



Note for 2004 the above map shows exploration wells in NPR-A that were not drilled in 2004. Seven exploration wells were drilled this past winter on the North Slope, four of which were in NPR-A – three by ConocoPhillips and one by Total. ConocoPhillips also drilled Placer No. 1 this past winter and Kerr-McGee drilled two exploration wells at its Nikaitchuq prospect.