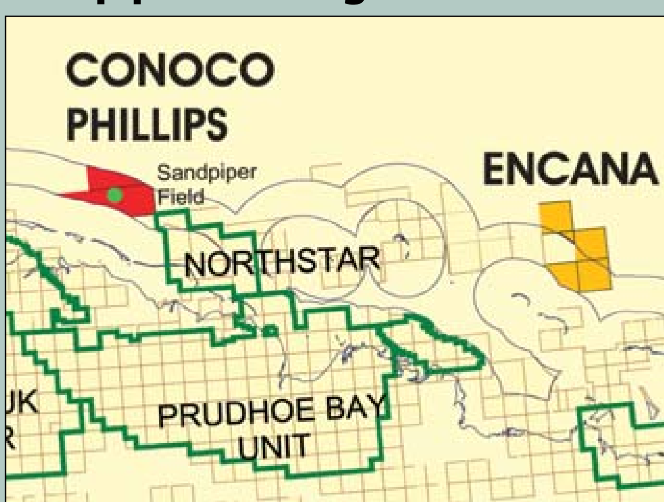
Petroleum news

Vol. 8, No. 39 • www.PetroleumNews.com — North America's source for oil and gas news — Week of September 28, 2003 • $1

page 11 North America E&P takes huge capital spending hit

Sandpiper field big draw at sale



See map of the results of the Sept. 24 MMS Beaufort oil and gas lease sale on page 13 and information on the Sandpiper prospect on page 14 of this issue.

Anadarko buys ChevronTexaco's 30% interest in NPR-A leases

On Sept. 23, Anadarko Petroleum's spokesman in Alaska confirmed rumors that the Houston-based independent had purchased ChevronTexaco's lease interests in the National Petroleum Reserve-Alaska.

"We acquired all of Chevron's 30 percent interest in the (33) leases it had in NPR-A," Mark Hanley told Petroleum News. "Chevron's interest is being transferred to Anadarko and should be recorded in the next few days."

The 33 leases, which are in the Northeast NPR-A, were originally owned by a partnership of BP Exploration (Alaska) (50 percent), ChevronTexaco (30 percent) and ConocoPhillips Alaska (20 percent).

In a deal driven by Anadarko, it and NPR-A partner

see **ANADARKO** page 21

Draft energy bill includes offshore inventory requirement

Republican leaders have added a provision to the draft energy bill requiring an inventory of oil and gas reserves in U.S. coastal waters, drawing strong criticism from several lawmakers who worry it's a maneuver to eventually lift the drilling ban in effect in most coastal areas.

Sen. Pete Domenici, R-N.M., chairman of the energy talks, argued the inventory is needed to get accurate numbers of how much oil and gas is available. He dismissed fears the inventory study would lead to actual exploration and drilling.

However, an industry advisory group, the National Petroleum Council, recommends in a new report an end to the freeze on natural gas drilling in selected areas by 2005.

Rep. Lois Capps, D-Calif., who is not part of the House-Senate conference committee, said the decision to include the inventory

see **BILL** page 20

BREAKING NEWS

3 Alaska issues three exploration licenses in the Susitna basin north of Anchorage; two to Forest Oil, one to Clearflame

7 Canadian companies digging in against mergers with the few U.S. firms still interested in assets across the border

15 Kyoto still troubles Imperial; other companies and new player Fort MacKay First Nation unveil new oil sands projects

BEAUFORT SEA, ALASKA

MMS sale draws $10M

ConocoPhillips picks up Sandpiper leases, EnCana goes for large block off NPR-A

By KRISTEN NELSON

Petroleum News Editor-in-Chief

Three companies bid more than $10 million at the U.S. Minerals Management Service's Sept. 24 Beaufort Sea sale, with a known field in the central Beaufort and a wildcat area north of the National Petroleum Reserve-Alaska attracting the most attention. (See map on page 13.)

There were 37 bids on 34 tracts, 15 in Zone "A" and 22 in Zone "B" with total high bids of $8,903, 538, MMS Alaska Regional Director John Goll said in summing the sale results, with $10,175,949 exposed.

ConocoPhillips Alaska took three tracts for $4 million, bidding $2,151,600 on one tract, the highest single bid in the sale, and $1,201,600 and $646,800 on two other tracts. Armstrong Alaska, a subsidiary of Denver-based Armstrong Resources, which bid $2.6 million in the sale and took seven tracts for $1.4 million, also bid on these three tracts.

MMS Director Johnnie Burton said after the sale that she was very pleased with the results: "We're showing a couple of large companies that are still big players and we're seeing an independent" active, which hasn't happened a lot in that area.

EnCana was the second highest bidder, at

see **SALE** page 13

NORTHWEST TERRITORIES

Mackenzie needs hard numbers

Exploration spotlight intensifies along Canada's natural gas pipeline route

By GARY PARK

Petroleum News Calgary Correspondent

The Mackenzie Gas Project is entering a new phase, with the pressure on potential shippers to start attaching numbers to the gas volumes they anticipate delivering to the C$4 billion pipeline.

Imperial Oil, which spearheads the venture, has asked for signed "precedent agreements" by mid-December with shippers so that it can give substance to its regulatory filings with the National Energy Board in 2004.

Hart Searle, a spokesman for Imperial, told Petroleum News that the proponents now need further confirmation of the numbers

see **MACKENZIE** page 21

Fueling optimism is a forecast by Peters & Co. analyst Brian Prokop that key U.S. independents — Anadarko, Apache, Burlington and Devon — will hike their Canadian capital spending in 2004 by as much as 20 percent, pushing the combined total above C$2 billion as they employ about 200 rigs to accelerate their hunt for natural gas.

GULF OF MEXICO

Operators consider hub for gas-prone Eastern Gulf

PETROLEUM NEWS

The Eastern Gulf of Mexico, although still in its exploration infancy, seems to contain far more gas than oil, based on early drilling results that also show gas discoveries thus far are not large enough to justify stand-alone deepwater developments.

That predicament has led big independents Anadarko Petroleum and Kerr-McGee, as well as other, undisclosed operators in the region to discuss the possibility of forming a hub or central production facility to process dry gas from a host of discoveries, including Anadarko's Jubilee and Atlas fields and Kerr-McGee's Merganser and Vortex fields.

The idea is not without precedent. Over the past

see **HUB** page 23

Disappointments mount for Devon Energy

Big independent Devon Energy, already stressed by mounting well expenses at its troublesome Yorktown prospect, has come up short at Tuscany East and Shiner Deep, two other deepwater prospects the company operates in the Gulf of Mexico.

Tuscany East, with pre-drill reserve estimates ranging up to 240 million barrels of oil equivalent, turned out to be a duster, Devon partner EOG Resources disclosed at

see **DEVON** page 24

● WASHINGTON, D.C.

Alaska counting votes for ANWR

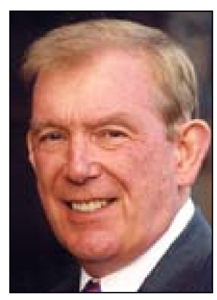
State hopeful but still short on winning congressional approval for drilling in refuge

By LARRY PERSILY

Petroleum News Juneau Correspondent

Alaska's chief lobbyist in Washington, D.C., says he feels a little like a Chicago Cubs or Boston Red Sox fan, hoping this will be the year the team wins it all. The Cubs haven't won a World Series since 1908 and the Red Sox since 1918, but regardless whether this is their year John Katz of Alaska's D.C. office hopes this is the state's year to finally win congressional approval for oil and gas drilling in the Arctic National Wildlife Refuge.

"There isn't that much new to say to members of Congress on the issue," said Katz, director of Alaska Gov. Frank Murkowski's Washington office. "The issue has been debated for so long."



FORREST CRANE

"It's unpredictable, especially when you consider the energy bill as a whole is not finalized and the fact that its most contentious issues are still to be decided, mainly electricity," —Roger Herrera of Arctic Power.

It might be settled in Alaska's favor this fall. House-Senate conferees working on a national energy bill have included ANWR language in their draft bill, though opponents say they have enough votes to force drilling supporters to drop the provision.

The question of allowing drilling in the coastal area goes back to at least 1959, when Alaska Sen. Ted Stevens worked in the Interior Department. Then Congress got involved during work on the Alaska Native Claims Settlement Act, which was adopted in 1971, and while debating the Alaska National Interest Lands Conservation Act, which became law in 1980.

Murkowski took office as a senator after the November 1980 election, and spent the next 22 years pushing for congressional approval to open the coastal plain for drilling.

Over the past decade the Alaska Legislature has given $6.5 million to Arctic Power, an industry-backed lobbying group, to help with the fight. The Legislature appropriated almost $2 million of that money this past session.

Governor writes former colleagues

And though no longer a member of the Senate, the governor is personally lobbying his former colleagues, Katz said, including recently sending a letter to all 65 members of the House-Senate conference committee working to put together a compromise energy bill.

John Manly, the governor's press secretary in Juneau, said the administration is hopeful, but realistic, of the chances for winning a vote on ANWR.

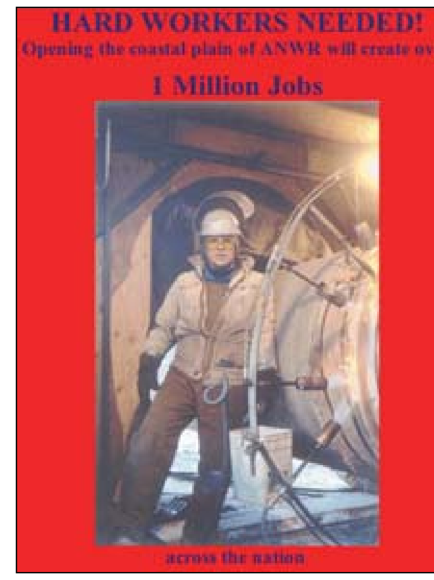
Although it takes just 50 senators to approve a measure — assuming Vice President Dick Cheney would cast his vote in favor of opening ANWR if the chamber were to deadlock 50-50 — it takes 60 senators to block a filibuster. A collection of 43 senators has gone on record as opposing any version of an energy bill that opens ANWR to drilling, which might leave Alaska at least three votes short of stopping a filibuster in the 100-member chamber.

Katz said the state's lobbying tactic is to talk with senators, suggesting that even if they oppose drilling in ANWR they should look over the entire energy bill and maybe they'll find enough other provisions to like. The bill includes so many other issues, such as provisions in support of nuclear energy, coal, oil and ethane production, and efforts to fix the nation's electrical distribution problems, that Katz said he hopes at least 60 senators will find something good for their own constituents to convince them to back the measure.

Lobbyists assist state's effort

The state has two high-powered lobbying firms under contract to help with the ANWR push. "They enable us to expand our advocacy into the nooks and crannies of Congress on a daily basis," Katz said.

One of the firms is The Lundquist Group, led by Andrew Lundquist, formerly a director of President Bush's White House National Energy Policy Development Group, chief of staff for then-Sen. Murkowski and senior legislative assistant for Sen. Ted Stevens. He is a University of Alaska graduate and currently serves on the board of directors of Evergreen Resources, the Denver-based company that is looking to develop large coalbed methane gas wells in the Matanuska Valley north of Anchorage.



Arctic Power, an industry-backed lobbying group, has put together a numbers of ads (such as the one above) in what could be the final push for opening the 1002 area of the Arctic National Wildlife Refuge.

The other lobbying firm under contract to help the state is Wexler & Walker Public Policy Associates. Katz explained this firm covers both sides of the political aisle. Anne Wexler worked for President Jimmy Carter and was a senior adviser to President Bill Clinton's transition team in 1994. The other principal of the firm, Bob Walker, served 20 years as a Republican congressman from Pennsylvania.

The state also is getting help from some labor unions, especially the Teamsters, Katz said, in addition to coordinating its lobbying work with Arctic Power.

Roger Herrera of Arctic Power said the battle is in the Senate, not the House where members have twice in the past two years passed legislation to open ANWR to drilling. "The Senate could do all sorts of things … crumble … come off the wall and threaten sort of a revolt," Herrera said. "It's unpredictable, especially when you consider the energy bill as a whole is not finalized and the fact that its most contentious issues are still to be decided, mainly electricity."

Senate likely to vote after Oct. 13

Herrera and others watching the conference committee say the members could fin-

see **VOTES** *page 4*

SUSITNA BASIN, ALASKA

Alaska issues three exploration licenses

The Alaska Department of Natural Resources said Sept. 25 that it intends to issue three exploration licenses in the Susitna basin north of Anchorage, two to Forest Oil and one to Clearflame Resources.

Forest's license No. 1 is for 386,206.63 acres and its license No. 2 is for 471,474.23 acres. The Clearflame license, No. 3, is for 478,584.25 acres. The department's Division of Oil and Gas said all the license areas are west of the Parks Highway, and include only lands for which the state owns the mineral estate. Communities in the area include Trapper Creek, Talkeetna, Willow and Skwentna.

The companies will pay licensing fees of $1 per acre.

There is no rental fee for exploration licenses and no up-front payment to the state, as is the case with conventional oil and gas leasing. Instead, money goes into exploration and licenses are granted based on the state's approval of work commitments by the licensees.

Forest's work commitments are $2,520,000 for license No. 1 and $3 million for license No. 2, each of which has a primary term of seven years. Forest has the option to extend the primary term for up to three years, the state said, with the submittal of an additional $5 million work commitment.

Clearflame's work commitment for its license is $2.5 million. That license also has a primary term of seven years. The state said that some of the acreage included in the Clearflame application lies in existing shallow natural gas leases, and if a shallow natural gas lease expires during the term of the license, that acreage may be included in the license.

Once the required work commitment has been completed, the licensees may convert all or a portion of each license area into oil and gas leases, with a rental of $3 per acre per year. Conversion leases from the Forest licenses will have a primary term of five years; those from the Clearwater license will have a primary term of seven years.

The division has issued final findings and decisions for the licenses.

ANCHORAGE, ALASKA

Alaska Mental Health Trust lease sale brings in $178,000

The Alaska Mental Health Trust sold seven leases at its Cook Inlet oil and gas lease sale in Anchorage Sept. 25. Two companies, Aurora Gas and Marathon Oil, picked up some 24,000 acres, paying a total of $178,190.46

Aurora Gas took one lease on the west side of the inlet northwest of Tyonek at $12.80 an acre, paying $40,077.06 for the tract of some 3,100 acres.

All of the tracts which Marathon took were on the Kenai Peninsula side, east and northeast of Soldotna. The company's bids ranged from $5 an acre to $10.47 an acre, averaging $6.64 an acre. Marathon bid $138,113.40 for some 20,808 acres.

This is the third Cook Inlet oil and gas lease sale the trust has held, said Mike Franger, Trust Land Office senior resource manager. With the new tracts on the Kenai Peninsula offered in this sale, all Cook Inlet acreage leasable for oil and gas is now available, he said. Franger said the office has already done title work for the tracts and leases should be issued within about 30 days. Duration of the leases is five years.

Including results from this sale, he said, the trust has leased some 100,000 acres over the last three years, out of less than 250,000 leasable acres in the Cook Inlet area.

—KRISTEN NELSON, Petroleum News editor-in-chief

Issue Index

Petroleum news

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HOUSTON, TEXAS

EOG looking at 25% growth through 2006

Natural gas producer EOG Resources said Sept. 23 that at year-end 2006 it expects to have boosted daily production to 1.405 billion cubic feet of equivalent from 2003 levels of about 1.120 billion cubic feet of equivalent, a 25 percent increase.

The Houston-based independent said it expects to increase annual production 6.5 percent in 2004, 10 percent in 2005 and 7 percent in 2006. In North America alone, EOG is looking for a 6.5 percent production increase in 2004, a 5 percent increase in 2005 and a 3 percent increase in 2006.

However, most of the anticipated increase would come from EOG's Trinidad operations, which should rise to nearly 300 million cubic feet per day from a current 150 million cubic feet per day, the company said. About 50 million cubic feet per day of incremental production is expected from the U.K. North Sea.

In Trinidad, EOG said it plans to drill up to eight wells over the next nine months, compared to its traditional two wells over the same period. EOG said the supply-demand equation has swung in favor of demand, largely because of planned LNG and chemical plants in the area.

IRVING, TEXAS

Magnum Hunter forms coalbed methane venture with CDX in New Mexico's San Juan basin

Magnum Hunter Resources has formed its second joint venture arrangement this month with a move to explore a huge number of acres in the San Juan basin of New Mexico for coalbed methane. The exploration area, which could cover as much as 6 million acres, will be drilled with CDX, a Dallas-based private company, Magnum Hunter said in late September.

Earlier in September, the Irving, Texas-based Magnum Hunter announced a joint venture with a Japanese company to explore offshore in the Gulf of Mexico's outer continental shelf.

Magnum Hunter executives said the company and affiliates have exercised options on about 554,000 acres in northwestern New Mexico. And they're in the process of exercising option rights on an additional 922,000 acres that covers area in the west-central part of the state, including the county that surrounds Albuquerque.

CDX, which formally includes CDX and CDX Frontier, both limited liability companies, will contribute 14,000 mineral acres and will perform all the drilling operations with its own rig fleet. CDX specializes in coalbed methane drilling.

Magnum Hunter will manage production.

The exploration will be concentrated in the upper and lower Menefee coals of the Mesaverde group, the company said.

Drilling began in early September for an initial 25-well program to provide stratigraphic and core testing.

Wells will be drilled to depths of up to 3,500 feet in the first phase, which is expected to cost approximately $3 million and end no later than February of next year.

Plans call for an additional $3 million investment for 25 more wells to be finished by next July, and then a $5 million third phase.

Production probably won't begin until 2005, the company said.

—**ALLEN BAKER,** Petroleum News contributing writer

continued from page 2

VOTES

ish their negotiations and present a bill to the House and Senate before Congress adjourns for its Columbus Day recess Oct. 3. And although some say it's possible the House might even vote on the package before the break, most expect the Senate will wait until it returns to work the week of Oct. 13.

One reason for the delay is negotiators are looking for ways to reduce the price tag that has climbed into the billions of dollars for all of the energy production incentives in the bill. Estimates put the total cost at as much as $20 billion, far more than the president has said he is willing to support.

Like Katz, Herrera figures maybe there will be enough other provisions in the bill to win out over opponents to ANWR drilling.

Leaders want an energy bill

But Sen. Pete Domenici, chairman of the conference committee, has acknowledged he doesn't see enough votes yet to block a filibuster. Congressional leaders say winning passage of the energy bill is too important to let it die over ANWR, and the Alaska provision will be dropped from the bill if drilling supporters cannot show they have enough votes to win.

The New Mexico Republican is a strong supporter of opening ANWR to exploration, and including ANWR in the committee's work draft was intended as a signal of his support, according to his staff. "The best way to know if you have 60 votes is to put it out there in draft discussion and start bargaining," said Marnie Funk, Domenici's spokeswoman.

In an effort to win support, the ANWR language would limit to 2,000 acres the amount of land that could be developed with gravel pads, airstrips, production facilities or other structures. And in an effort to retain more of the hopeful oil and gas revenue for the federal treasury, the draft language also would share federal leasing and royalty revenues 50-50 with the state, instead of giving the state 90 percent as provided in existing law.

It also would limit legal challenges to the legislation. ●

● WASILLA, ALASKA

Evergreen more than quadruples holdings

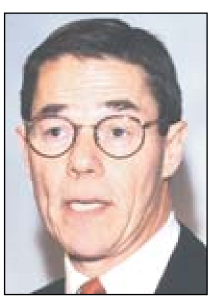
CEO Mark Sexton said Colorado coalbed methane producer remains committed to south-central Alaska development

By KAY CASHMAN

Petroleum News Publisher & Managing Editor

Evergreen Resources announced Sept. 22 that it has acquired an additional 230,000 acres of "prospective unconventional gas properties" in the Matanuska-Susitna area, bringing the Denver-based independent's total leased acreage in Southcentral Alaska from approximately 70,000 acres to more than 300,000 acres.

Evergreen said in a press release that the new properties — state shallow gas leases — were acquired through "several separate transactions." One of the largest transactions was with Ted Williams of South Dakota, John Kelso, Evergreen's director of investor relations, told Petroleum News.



JUDY PATRICK

Just before Evergreen Resources acquired leases in Alaska in May 2001, former Gov. Tony Knowles (pictured above) presented the company with the prestigious chairman's stewardship award from the Interstate Oil and Gas Compact Commission, an organization of governors of producing states of which Knowles was chairman. Evergreen received the award for its produced-water handling program in the Raton basin of southern Colorado — i.e. for its stewardship of the land and its water resources.

Ownership increases in Pioneer unit

A portion of the new acreage is included in the company's Pioneer unit 35 miles north of Anchorage, in which Evergreen now has the mineral rights to approximately 75,000 acres, up from 58,000 acres less than two months ago.

The majority of the new acreage is adjacent to the Pioneer unit on the northwest, extending about 25 miles up the Susitna River Valley.

Evergreen drilled eight coalbed methane wells in the Pioneer unit in late 2002 and is testing five of them. The company said it plans to drill five stratigraphic test wells on various parts of its acreage "to obtain additional petrophysical data, including information on coal quality and gas content."

JUDY PATRICK

"The expansion of our leased acreage base demonstrates our commitment to making shallow gas production a reality in south-central Alaska." —Evergreen Resources President and CEO Mark S. Sexton

Based on the results of those test wells, Evergreen said it "will determine potential locations in 2004 for additional stratigraphic test wells or multi-well pilots."

Despite problems, Evergreen committed to Alaska

Since Evergreen applied for shallow gas leases in Alaska in August 2000, the company has been "encouraged" by the "enthusiastic" response it has received from state and local officials, company spokesman Jack Ekstrom told Petroleum News Sept. 23.

The administration of Alaska's former governor, Tony Knowles, often flaunted the fact the Knowles administration had brought Evergreen to the state. They also touted the independent's environmental record in Colorado, a state with tough environmental regulations rivaling Alaska's.

In fact, just before Evergreen acquired leases in, and took over operatorship of, the Pioneer unit in May 2001, Knowles presented the company with the prestigious chairman's stewardship award from the Interstate Oil and Gas Compact Commission, an organization of oil and gas producing state governors of which Knowles was chairman.

Evergreen received the award for its produced-water handling program in the Raton basin of southern Colorado — i.e. for its stewardship of the land and its water resources.

Starting this past summer, however, the

see **EVERGREEN** page 6

Evergreen engineers shallow gas lease settlement in south-central Alaska

In the process of consolidating its acreage position in the Matanuska and Susitna valleys north of Anchorage, Evergreen Resources intervened in and brought to settlement a lease dispute which began some five years ago, allowing the state of Alaska to award the remaining shallow gas leases from February 2000 applications.

Pirtle Bates, natural resources manager with the Alaska Department of Natural Resources' Division of Oil and Gas, told Petroleum News Sept. 22 that the remaining 30 leases from the state's initial February 2000 shallow gas lease offering were awarded after a judge signed off Sept. 15 on a voluntary withdrawal of the appeal. The leases are in the Matanuska-Susitna area, Bates said, with the bulk of the acreage in the Willow area and the remainder around Palmer and Sutton.

The settlement was reached after Evergreen Resources intervened and worked out an agreement with Ted Williams of Spearfish, S.D., and Kenneth Schlenker and William Fulton of Billings, Mont. The men had appealed decisions made in 1998 and 1999 by the Division of Oil and Gas when the state was establishing its shallow gas leasing program. After the appeals were denied by the department the men appealed in Superior Court.

Williams, Schlenker and Fulton were awarded 12 leases, which by terms of the settlement they will assign to Evergreen Resources. Bates said the state held 30

see **SETTLEMENT** page 6

ANCHORAGE, ALASKA

Forest selects former ARCO executive senior vice president for Alaska

Forest Oil has named Leonard Gurule senior vice president in Alaska. Gurule will be responsible for directing all Forest Oil's activities in Alaska, the company said Sept. 24, including exploration, production, drilling and engineering. He will report to Craig Clark, Forest's president and chief executive officer.

Gurule most recently was chairman of the board and CEO of Virginia Indonesia Co. He previously spent 19 years with ARCO. His last position there was as executive vice president operations for ARCO Indonesia.

Gurule also worked for ARCO in Alaska, managing ARCO's Prudhoe Bay operations and construction activities, engineering support for ARCO's Alaska exploration activities and petroleum engineering support for ARCO's Kuparuk field. Gurule has a bachelor of science degree in engineering from the University of New Mexico.

ALASKA

Potential Alaska, federal oil gas lease sales

Agency	Sale and Area	Proposed Date
MMS	Sale 186 Beaufort Sea	Sept. 24, 2003
MHT	Cook Inlet	Sept. 25, 2003
DNR	North Slope Areawide	Oct. 29, 2003
DNR	Beaufort Sea Areawide	Oct. 29, 2003
MMS	Sale 191 Cook Inlet	2004
DNR	Cook Inlet Areawide	May 2004
DNR	Foothills Areawide	May 2004
BLM	NE NPR-A	June 17, 2004
BLM	NW NPR-A	June 17, 2004
DNR	North Slope Areawide	October 2004
DNR	Beaufort Sea Areawide	October 2004
MMS	Sale 195 Beaufort Sea	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

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.

JUNEAU, ALASKA

Alaskans to Receive Oil Wealth Dividend

The Alaska Permanent Fund dividend is $1,107.56, several hundred dollars less than last year, Gov. Frank Murkowski said Sept. 24.

Eligible Alaskans will receive $443.20 less than they did from last year's dividend of $1,540.76. The amount of the 2002 dividend was announced at the annual meeting of the Permanent Fund Corp., which manages the $25 billion investment fund created from oil riches.

Dividends are calculated based on a five-year average of permanent fund investment income derived from bonds, stock dividends and sales and other investments.

Murkowski also announced he's backing a new way to calculate the amount of money available to legislators each year from permanent fund.

Murkowski said he's supporting the "percent of market value" plan advocated by the fund's Board of Trustees.

"This provision would balance the good years against the bad and virtually guarantee that even in poor earning years dividends could still be paid, preventing a future Legislature from spending too much of the earnings," Murkowski said.

Currently, the Legislature can spend only revenues derived from the fund's investments, which historically they have spent only to pay dividends. Past Legislatures returned the rest of the income to the fund, Murkowski said, and if they had not, the fund would be a third-smaller.

A proposed "percent of market value" plan would let lawmakers spend up to 5 percent of the fund's total value averaged over the previous five years. Such a change would require voter approval.

Earlier this year, any dividend at all was in doubt because of a long losing streak on Wall Street. But in the months before the fiscal year ended June 30, the stock market rallied and the oil wealth savings account earned enough to pay a dividend.

The fund ultimately finished the year with a gain of about 4.5 percent on investments, said spokeswoman Laura Achee.

Murkowski also announced a new member of the fund board: Former state Rep. Bill Hudson, a Republican from Juneau.

The permanent fund was created by voters in 1976 as an investment account for royalties after oil was discovered on the North Slope. The first dividend paid in 1982 was $1,000. The highest dividend ever paid was $1,963.86 in 2000.

Department of Revenue Commissioner Bill Corbus said an estimated 598,813 Alaskans will receive a dividend, up from 589,300 last year.

A total of $663.2 million will be disbursed for dividends, Corbus said.

Direct deposit of dividends is scheduled for Oct. 8. Checks by mail will be sent starting Oct. 16, Corbus said. Mailing is expected to take two weeks, Corbus said.

— THE ASSOCIATED PRESS

Alaska officials head to Raton basin

Four state of Alaska officials left Sept. 22 for a three-day tour of shallow gas operations in Colorado and Wyoming, an Alaska Division of Oil and Gas official told Petroleum News.

Department of Natural Resources Commissioner Tom Irwin, Division of Oil and Gas Director Mark Myers, Alaska Oil and Gas Conservation Commission Commissioner Randy Ruedrich and Pat Galvin, who heads up permitting within the Division of Oil and Gas, were to spend their first day touring Evergreen Resources' operations in the Raton basin in southern Colorado.

From there they were to meet with U.S. Bureau of Land Management personnel, who issue permits in the basin, and with officials from AOGCC's counterpart in the region.

The Alaska officials were also to meet with a Wyoming environmental group which opposes coalbed methane development and has been instrumental in bringing those concerns to the citizens of Southcentral Alaska.

On Oct. 13 the state of Alaska will host a public informational meeting in Wasilla at the Middle School gym at 6:30 p.m. Irwin, Myers, Ruedrich and Galvin will be at that meeting to share what they learned from their trip.

—KAY CASHMAN, Petroleum News publisher & managing editor

continued from page 5

EVERGREEN

company has come under fire from a group of citizens in the Mat-Su area concerned about possible depletion or pollution of their drinking water wells as a result of coalbed methane development by Evergreen — a concern that has not been widely voiced at public meetings regarding Evergreen's plans until recently.

Despite the surge of recent controversy, which Ekstrom said took the company by surprise, Evergreen remains committed to its Alaska coalbed methane program.

On Sept. 22, Evergreen President and CEO Mark Sexton said, "The expansion of our leased acreage base demonstrates our commitment to making shallow gas production a reality in south-central Alaska." ●

continued from page 5

SETTLEMENT

leases because of overlap between the additional 18 leases and leases applied for by the men.

Statute passed in 1996

The Alaska Legislature created the state's shallow gas leasing program in 1996, providing for leasing on a first-come, first-served basis, rather than the competitive leasing the state uses for conventional oil and gas leases, and authorizing the commissioner of Natural Resources to adopt regulations to implement the program.

Williams, Schlenker and Fulton submitted letters and deposits for shallow natural gas leases in October 1998, before the state opened lands for noncompetitive shallow gas leasing or provided public notice. The division initially accepted the letters as applications for shallow gas leases and said it would hold them until shallow natural gas lease forms were developed. But in 1999 the division told the men it had determined that, under state regulations, it could not accept applications or deposits until the Natural Resources commissioner had opened land for leasing and provided public notice. The letters and deposits were returned.

In January 2000, the division published a notice that shallow gas lease applications would be accepted Feb. 29 on a first-come, first served basis, with priorities among overlapping applications determined by a public drawing. Williams, Schlenker and Fulton submitted applications for the Feb. 29 opening covering the same acreage they had applied for in their 1998 letters, and obtained rights to some of the acreage, but not all. They appealed the acreage they did not obtain.

Agreement provides for overriding royalty interests

The agreement approved by the court is a voluntary withdrawal of the appeal by Williams, Schlenker and Fulton against the state and Evergreen Resources, which had intervened in the case.

Williams, Schlenker and Fulton agreed to convey their interests in the leases to Evergreen in exchange for a 2 percent overriding royalty interest.

In exchange for non-objection by the state of Alaska to the motion to dismiss the appeal, the state will receive partial payment of the attorney fees it would have received had it prevailed, up to $8,000, to be paid 50 percent by Evergreen and 50 percent by Williams, Schlenker and Fulton.

Williams, Schlenker and Fulton also agreed not to pursue any interests competing with Evergreen within six miles of the exterior boundaries of the leases for a year after the expiration of any of the leases in exchange for a one-time lump sum payment of $75,000.

—KRISTEN NELSON, Petroleum News editor-in-chief

finance&economy

HOUSTON, TEXAS

Anadarko still mum on possible sale of company

Anadarko Petroleum, with speculation heating up over a possible sale of the big Houston independent, had an assertive "no comment" on the persistent rumor as recently as Sept. 17 at the RBC Capital Markets energy conference in Houston, Texas.

"We wouldn't want to comment on that. We won't comment on rumors," Richard Sharples, Anadarko's vice-president of marketing and planning, told analysts at the conference.

Anadarko appears to be dressing up the company for a possible sale. It recently moved into an uncharacteristic cost-cutting mode, laying off a hefty 15 percent of its workforce and closing two offices in Texas. Sharples cautioned analysts that with Anadarko's new focus on lowering overhead, capital discipline and improving finding and development costs, "if you bet against us, you lose."

Sharples reiterated Anadarko's plans to lower its already "comfortable debt load" of 43 percent of capitalization to 38 percent. He said the company would even have "a little dry powder" left over to do an acquisition. He also said the company would continue to reduce costs.

Apache says big acquisition possible by year-end

Exploration and production independent Apache Corp. says it should have more than $1 billion in discretionary cash by the end of the year and that a chunk of it would be available for a large acquisition, possibly by year-end.

"We are constantly looking for good things to buy," Steve Farris, Apache's chief executive officer, said Sept. 16 at the RBC Capital Markets energy conference in Houston, Texas.

However, Farris indicated that Apache probably would not use all of its cash reserves on a single deal, primarily because that would stretch the company's balance sheet. Earlier this year Apache coughed up $1.3 billion to acquire BP properties in the North Sea and on the Gulf of Mexico's continental shelf.

Farris said that if Apache were to do another large deal this year, it likely would be in the range of $400-to $500 million. He said Apache would be most interested in buying properties in areas where the company already does business, adding that it would be unlikely for Apache to seek out a new core area through an acquisition.

MICHIGAN

Shell sells assets to Merit

The Houston Chronicle reported in late September that Shell Exploration & Production had sold all of its oil and natural gas wells, plus related facilities, in Michigan to Dallas-based Merit Energy for $445 million. The Houston daily said the sale involved approximately 500 wells that are producing 3,650 barrels of oil per day and 53.7 million cubic feet of natural gas, as well as 36 central producing areas, two gas processing plants and associated pipelines.

● CANADA

Companies digging in on the Canadian front

Some U.S. invaders shed oil and gas assets, others plan for long haul

By GARY PARK

Petroleum News Calgary Correspondent

As fast as it happened, the American invasion of Canada's oil patch has slowed and in some cases gone into reverse. But it's far from a full-scale retreat.

Faced with shrinking exploration prospects in the Western Canada Sedimentary Basin, the second largest producing basin in North America, some of the U.S.-based companies that feasted on Canadian assets in the 1998-2002 period have now embarked on consolidations and divestitures of non-core holdings.

With commodity prices remaining relatively high and acquisition prices following suit, it would stand to reason that "more companies that made major purchases in the past will review their assets with the intention of selling," said Frank Sayer, president of Calgary-based Sayer Securities.

To that end, he suggested merger and acquisition activity could pick up in the second half of 2003.

In the first half of 2003, Sayer logged deals worth a mere C$5 billion — less than one-fifth the value in the first half of 2001 and scarcely a blip alongside the C$140 billion racked up in the five years from 1997.

Of the transactions to the end of June this year, U.S. buyers accounted for a mere C$200 million, or 4 percent of the market, compared with C$16 billion, or 61 percent, in the first half of 2001 and C$3.9 billion or 24 percent in 2000.

The continued strength of oil and natural gas prices is complicating deal-making, as prospective sellers hold out for prices that match the current value of their reserves and buyers insist on something based on longer-term averages.

So far this year, the scales have tipped in favor of sellers, with Sayer estimating the median acquisition price for the first six months at C$8.94 per barrel of

see DIGGING page 8

● VIENNA, AUSTRIA

OPEC members vote to cut output by nearly 4%

Cartel says decision is a pre-emptive effort to keep crude oil prices from plunging when demand slackens early next year

By BRUCE STANLEY

AP Business Writer

Despite earlier signals from OPEC that it would hold oil output steady, fears of a possible oversupply of crude persuaded its members instead to lower their output ceiling by 900,000 barrels a day.

The Organization of Petroleum Exporting Countries defied expectations and decided Sept. 24 to cut its target to 24.5 million barrels starting in November. The 3.5 percent cut caused crude futures to surge more than $1 a barrel and drew a harsh response from the energy watchdog for major oil importing countries.

However, OPEC defended its decision as a pre-emptive effort to keep prices from plunging when demand slackens early next year, and some analysts said the cut would have little impact on the prices consumers pay for heating oil and gasoline.

OPEC reached the agreement at its Vienna headquarters in a meeting that included Iraq for the first time since the toppling of Saddam Hussein. Iraq is a founding member of OPEC, which pumps about a third of the world's crude.

Claude Mandil, head of the Paris-based

see OPEC page 8

continued from page 7

DIGGING

oil equivalent, up 18 percent from the C$7.60 recorded in the same period of 2002.

Leading the U.S. retreat so far this year is Marathon Oil, which unloaded its Western Canadian interests to Husky for about C$820 million, with Husky spinning off about C$448 million worth to EOG Resources.

In addition, National Fuel Gas is selling the southeast Saskatchewan assets of its Seneca Resources subsidiary; Vintage Petroleums has had production troubles in the Northwest Territories without giving any indication it wants to bail out; and Calpine sold its northern British Columbia holdings to Pengrowth Energy Trust.

Some companies selling, others in Canada "for the long haul"

That list could grow significantly before year's end if ConocoPhillips finds a buyer for a large package in Alberta, Anadarko disposes of Canadian assets yielding 391 million cubic feet of gas per day and 17,000 barrels per day of crude and condensate as part of a speculated takeover of its Houston-based parent and ChevronTexaco settles on which properties it will unload in Canada where it produced 76,500 bpd of oil and natural gas liquids and 182 million cubic feet of gas per day last year.

But others, in the words of Devon Canada president and Chief Executive Officer John Richels, are in Canada "for the long haul," viewing their holdings north of the 49th parallel as an important part of an integrated North American gas market. Other U.S. independents such as Burlington Resources, Apache and Wiser Oil are ramping up their activities, giving every sign that they intend to stay. The Canadian Association of Petroleum Producers has calculated that foreign-owned companies control just over 50 percent of the industry, partly reflecting their expanding role in the East Coast offshore and Alberta oil sands.

Canadian units of Burlington, Devon, Apache and Anadarko contribute 15 to 40 percent of the parent companies overall production — reflecting their efforts in recent years to lock up prized natural gas resources beyond their home base.

The M&A spree was so intense that the number of large Canadian-controlled companies tumbled to six from 47 in 1997, with U.S. companies involved in 21 acquisitions or mergers. ●

continued from page 7

OPEC

International Energy Agency, expressed disappointment at the decision, which came ahead of the busy winter heating oil season in the northern hemisphere.

The IEA is the energy watchdog for the Organization for Economic Cooperation and Development, a group of the world's richest industrialized nations.

"Given the continued weakness in the world economy, OPEC's strategy to maintain prices at persistently high levels can't contribute to a sustained recovery and return to global economic growth," Mandil said in a statement.

White House spokesman Scott McClellan, with President Bush in New York, would not comment directly on OPEC's decision but said the economy depends on stable oil supplies and prices.

More cuts could follow

At current output levels, OPEC predicts that the daily supply of crude will outstrip demand by 2.5 million barrels by next April. Iranian Oil Minister Bijan Namdar Zanganeh called the cut a possible "first step" and did not rule out an additional reduction later in the year.

"It is better that we start before we witness a very bad situation in the market," he told reporters before the group's oil ministers met in private to approve the cut.

OPEC also wants independent, non-OPEC producers such as Russia to take "concrete measures" to restrain their own output, Ibrahim said, although the cartel is not making its cut conditional on their cooperation as it did in December 2001.

A 14 percent slide in crude prices this month and expectations of a buildup in oil inventories compounded OPEC's fears of a further softening of the market.

Iraq oil a factor

Iraq's gradual return to the market was another factor. Zanganeh noted that a cut of 900,000 barrels would return OPEC's output target to what it was until April, when the war in Iraq removed that country temporarily from the market.

In a symbol of the growing acceptance of Iraq's U.S.-backed leadership, the newly installed Iraqi oil minister, Ibrahim Bahr al-Uloum, took his place between counterparts from Kuwait and Iran at the U-shaped table in the OPEC Secretariat.

Iraq did not seek a production quota of its own. It only produces about 1.8 million barrels of oil a day — 700,000 barrels less than on the eve of the war in that country. It exports some 900,000 barrels a day, al-Uloum said in a separate news conference.

Benchmark still $22 to $28 per barrel

OPEC wants to keep the price of its benchmark blend of crudes stable within a targeted range of $22 to $28 a barrel. The benchmark price stood at $25.14 on Sept. 22, the most recent day for which OPEC calculated it.

Crude oil futures soared on reports about OPEC's planned decision. Contracts of U.S. light, sweet crude for November delivery rose $1.11 to settle at $28.24 a barrel on the New York Mercantile Exchange. November contracts of North Sea Brent crude rose $1.15 to settle at $26.67 a barrel on the International Petroleum Exchange in London.

Norwegian adviser predicts additional OPEC cuts

Tor Kartevold, a special adviser on the oil market for Norway's state-owned company Statoil, argued that OPEC's cut would have little impact on consumers. It was obvious that the market would weaken in the fourth quarter unless OPEC acted soon to scale back supplies, he said.

"I think they will have to cut further, possibly later this year," Kartevold said.

Other analysts noted that prices for heating oil prices were more sensitive to a sudden cold snap than to OPEC production cuts.

The group plans to meet again Dec. 4 to reassess market conditions. ●

● WASHINGTON, D.C.

Gas pipeline, NPR-A in energy bill

Draft legislation contains items designed to accelerate leasing in petroleum reserve

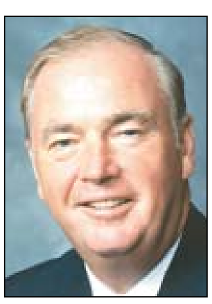
By LARRY PERSILY

Petroleum News Juneau Correspondent

While continuing with its nonstop lobbying to open the Arctic National Wildlife Refuge to oil and gas exploration, the state of Alaska isn't downplaying the natural gas pipeline and several other issues in the energy bill before a House-Senate conference committee.

ANWR and the controversial natural gas commodity price-support provision are called Tier I items, meaning they are not being handled by staff and are under the sole purview of House and Senate members themselves, said John Katz, director of Alaska's Washington, D.C., office.

And it's the Tier I items, which include possible fixes to the nation's electrical distribution problems, that the committee is holding for last. Members hope to finish drafting the energy bill before they leave town Oct. 3 for a 10-day Columbus Day holiday break.



Alaska Gov. Frank Murkowski

The state has done well to convince a majority of committee members to include in the legislation a multibillion-dollar federal loan guarantee, accelerated depreciation for tax savings and other financial incentives for a North Slope natural gas project, Katz said. That leaves only the issue of whether Congress is willing to pledge federal funds to help gas producers if commodity prices slip below $1.35 per thousand cubic feet at the wellhead.

The intent of the package is to ease the financial risk on North Slope producers looking to build a $20 billion pipeline project for moving North Slope gas into Canada and to the North America distribution grid.

Opposition continues from Lower 48 producers that fear a price drop if a load of Alaska gas flows into the market; from Canadian producers and government officials who complain of unfair subsidies; and from fiscal purists in Congress who do not believe the federal treasury should support commodity prices for private companies.

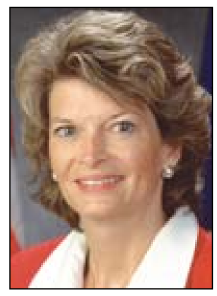
In addition to ANWR and the gasline provisions, the draft energy bill also includes:

Incentives for NPR-A

Several items in the bill are intended to accelerate leasing within the National Petroleum Reserve-Alaska. One provision would allow the Secretary of the Interior to reduce royalties for existing and future leases as an incentive to encourage investment and production in the area, said U.S. Sen. Lisa Murkowski, R-Alaska.

Because the state would share NPR-A lease revenues 50-50 with the federal government, any royalty reduction incentives would cut into state revenues, too.

Alaska Gov. Frank Murkowski has said he supports the provision.



U.S. Sen. Lisa Murkowski, R-Alaska

Although oil has been discovered in NPR-A and more exploration is planned, no oil or gas is being produced from any of the leases.

Another provision in the bill— which is still a work in progress until presented to the full conference committee for adoption — would allow the Interior secretary to extend leases in NPR-A in 10-year increments to encourage companies to move ahead with development of marginal fields.

Other provisions would allow leaseholders to form operating agreements to jointly run fields, and language calling on the federal government to consult with the state and Alaska Native corporations about oil and gas leases in areas where the corporations may also have other mineral interests.

One provision would allow the Secretary of the Interior to reduce royalties for existing and future NPR-A leases as an incentive to encourage investment and production, said U.S. Sen. Lisa Murkowski, R-Alaska.

Loan for Healy coal plant

The bill also includes a $125 million federal loan to rebuild a long-dormant electrical generating plant at Healy, south of Fairbanks. The Healy Clean Coal Project, owned by the Alaska Industrial Development and Export Authority, has never produced electricity since construction was completed in 1999.

The likely buyer of power from the plant, Golden Valley Electric Association in Fairbanks, claims the plant does not meet its performance specifications and needs a major retrofit to operate under more conventional coal-burning technology. The state development authority disputes that claim, but acknowledges some work is needed to get the plant on line.

The plant cost almost $250 million, with almost half of the money coming from the federal treasury. The Legislature kicked in $25 million in state funds, and AIDEA sold $85 million in bonds — a debt that is pays down each year from its other income and reserves.

Sen. Murkowski said she requested the $125 million loan as necessary to bring the plant into operation. ●

● ANCHORAGE, ALASKA

Gas authority wants in on energy bill

Board wants federal legislation to require state of Alaska-producer partnership

By LARRY PERSILY

Petroleum News Juneau Correspondent

The Alaska Natural Gas Development Authority believes the best way to build its project for moving North Slope gas to market would be to share billions of dollars of construction and operating costs with the producers that want to build their own line for carrying gas to mid-America.

The authority figures it's a natural for the two projects to share the costs of the gas treatment plant needed at Prudhoe Bay and the pipeline as far as Delta Junction, southeast of Fairbanks, where the producers' line would turn to Canada and the authority's line would head south to Valdez.

And just to make sure the state doesn't lose out on the cost-sharing opportunity between the two projects, the gas authority's board of directors has sent a letter to Alaska's congressional delegation asking that the federal energy bill include a requirement for such a partnership.

FORREST CRANE

"I think it is a great idea to at least ask for it." —board member Scott Heyworth

"If we're willing to pay our share, we get it. No b.s.," said Harold Heinze, the authority's chief executive officer.

The board would like to see the governor and Alaska's congressional delegation push to add the provision to the energy bill currently before a House-Senate conference committee. Time is extremely tight, however, as congressional conferees hope to finish work on the bill by Oct. 3.

"I think we need to raise the flag with the administration," Heinze said of the authority's letter to Gov. Frank Murkowski, with a copy to the congressional delegation. "We need frankly to make sure … there is at least the opportunity for the state to invest … at least to get our gas as far as Delta."

The seven-member board agreed unanimously at its Sept. 22 meeting in Anchorage to have Heinze draft and send the letter. "The easiest protection is for the state to at least be granted the right to become an investor in the project," Heinze said.

The gas authority may see it as a reasonable request, but North Slope producers see it as a problem.

"ConocoPhillips is opposed to placing any mandates or additional requirements on a project, since it can raise costs and slow or preclude the project from becoming viable," said company spokeswoman Dawn Patience in Anchorage.

"In particular," Patience said, "we are concerned with any mandates that could impact the scoring ... for the proposed legislation, and therefore reduce the probability of the legislation being passed."

Congress "scores," or estimates, the possible financial cost of each piece of tax-related legislation. The draft energy bill contains several financial incentives and a federal loan guarantee to encourage private investment in the $20 billion Alaska gas project. The score, or price tag, for the bill could increase if congressional staffers believe the state's own LNG project carries more risk than the stand-alone, producer-owned pipeline to mid-America covered by the legislation.

"The LNG project will have a different risk profile and different costs, which could change the scoring," Patience said. "We do not see Alaska LNG as a viable alternative."

BP Exploration (Alaska) also would oppose such a partnership provision in the energy bill. "Mandates are unhelpful for moving a project forward," said BP gas spokesman Dave MacDowell in Anchorage.

State gas authority board members Sept. 22 discussed their belief that the state could simply pay the producers the amount needed to make the gas treatment plant and pipeline large enough to accommodate the combined gas flow of both projects.

"I think it is a great idea to at least ask for it," said board member Scott Heyworth.

How much the state would pay for ownership and/or use of the gas treatment plant and pipeline would be subject to negotiation, Heinze said. "I would expect to pay something less than if I were doing it alone," he said, declining to specify if that meant paying only the additional cost of building a larger plant and pipeline or the average cost of the facility's handling capacity.

"I would expect to work out some commercial arrangement," he said.

The state authority wants to build a project that would move 2 billion cubic feet of gas per day from the North Slope to Valdez, where it would be liquefied and shipped aboard LNG tankers to West Coast and/or Far East markets. The producers prefer their project, which would carry 4.5 bcf per day by pipeline to Alberta, where it would feed into the North America gas grid.

If both projects were built, the combined flow of 6.5 bcf per day would drain the North Slope's proven gas reserves of 35 trillion cubic feet in less than 15 years — far short of the life expectancy of the pipelines and other investments. The gas authority believes there is much more gas on the slope, with state projections ranging as high as 100 tcf, though additional exploration and billions of dollars in investment would be needed to prove the reserves.

If the state fails to convince Congress to include the partnership provision in the energy bill, it could try to add the language to the project contract envisioned in the state's Stranded Gas Development Act. That law allows the producers and the state to negotiate a long-term contract for payments in lieu of state and municipal taxes on a natural gas project, and Deputy Revenue Commissioner Steve Porter told the gas authority those negotiations would be a more appropriate venue to raise the partnership issue than in the energy bill.

Heinze explained after the meeting that unless the governor were willing to walk away from the bargaining table during the contract negotiations, there would be no way to force the producers to accept the state as a partner unless it were required in federal law. ●

exploration&production

WORLDWIDE

North America takes oil and gas industry capital spending hit

A dramatic shift in global exploration spending is taking place as the industry shifted from upstream North America to less expensive plays in Asia, the Pacific, Africa and the Middle East, according to a report by the firms of John S. Herold and Harrison Lovegrove.

The study of 200 oil and gas companies showed capital investment in these new "frontiers" made double-digit increases from 2000 to 2002, while the United States slumped by 20 percent and Canada by 10 percent.

"Capital is increasingly being directed to regions that have significant growth opportunities and higher profit margins" regardless of whether those regions have higher perceived economic or political risks, said Arthur Smith, chairman of John S. Herold.

Finding and development costs in North America soared to $11.85 per barrel of oil equivalent in 2002 from $4.76 in 1999, while costs averaged $3.31 in the Asia-Pacific and $3.33 in Africa and the Middle East.

Reserve growth overall has been a mere 2.6 percent a year since 1998, with gas additions outpacing crude oil, which the study said indicated the world's petroleum base can support growth in production but at a slower pace.

Reserve replacement has shifted in recent years from exploration

see **SPENDING** *page 12*

NORTH AMERICA

Canada drags down North America rig count

The Canadian rotary rig count took it on the chin again during the week ending Sept. 19, dropping by 40 rigs for a net loss of 69 rigs for a three consecutive week period.

With a loss of three rigs in the United States, the North American weekly count fell by 43 to 1,430, still up by 314 rigs compared to the same period last year, according to rig monitor Baker Hughes.

And even though Canada's rig count fell by 40 to 338, it also was up by 74 rigs versus the same weekly period last year.

In the United States, the weekly rig count stood at 1,092, up 240 rigs compared to the same week a year earlier. Land rigs totaled 964 and accounted for the loss of all three rigs in the U.S. offshore and inland water rigs remained unchanged at 110.

Of the total number of rotary rigs operating in North America, 936 were used to drill gas wells and 152 to drill oil wells. Four were used for miscellaneous purposes. Of the total, rigs drilled 716 vertical wells, 285 directional wells and 91 horizontal wells.

Among the leading producing state in the United States, New Mexico's rig count fell by five to 67. Texas was down by three to 469 rigs. And Oklahoma fell by one to 139 rigs. Wyoming's rig count increased by two to 66 rigs. California was up by two to 24 rigs. And Alaska increased by one to eight rigs.

● GULF OF MEXICO

Forest Oil jumps on Unocal Gulf properties

Acquisition gives Denver independent 273,000 net acres, 128 offshore blocks

PETROLEUM NEWS

Forest Oil, after spending big bucks on exploring and developing a seriously under performing Redoubt Shoal oil field in Alaska's Cook Inlet, has wasted no time embarking on a new strategy of playing it safer when it comes to building reserves and production.

The Denver-based independent has turned to more familiar territory in the Gulf of Mexico, agreeing to pay about $260 million for Unocal "legacy" assets that give Forest an immediate 150 billion cubic feet of gas equivalent reserves and 80 million cubic feet per day of additional production.

Forest Oil CEO Craig Clark

"This acquisition plays to our strength in the Gulf region and makes us a stronger competitor in the Gulf of Mexico and onshore Gulf Coast," Craig Clark, Forest's chief executive officer, said Sept. 22.

That makes four Lower 48 acquisitions totaling $311.3 million for Forest since May, providing the company with additional combined reserves of 200.1 bcf of gas equivalent and 96 million cubic feet per day of production. The Unocal deal, expected to close at the end of October, would boost Forest's daily production by 20 percent to nearly 400 million cubic feet of gas equivalent.

Forest clearly changed direction in late July after long-time chief executive officer Robert Boswell resigned and Clark took the helm. In the same second-quarter conference call that Clark expressed disappointment with Redoubt's performance, he unveiled a new company strategy that included decreasing Forest's exposure to frontier ventures to 5 to 10 percent of capital employed, versus the company's traditional 20 percent.

In the August call, Clark said that since Redoubt had come on stream in late December 2002 the field was producing about 4,000 barrels of oil per day, roughly half of the 7,000 to 8,000 barrels per day that had been expected. The company had

see **FOREST** *page 12*

Want to know more?

If you'd like to read more about Forest Oil's Redoubt Shoal field in Alaska's Cook Inlet, go to Petroleum News' archives on its web site and search for these articles, which represent most, but not all, of the articles about Redoubt Shoal published in Petroleum News since June 2001.

Web site: www.PetroleumNews.com

2003

- **Sept. 14** New Forest Oil head promises change
- **Aug. 17** Forest Oil will put less capital into frontier exploration
- **Aug. 10** Forest disappointed in Redoubt; Cosmopolitan gets extended test
- **June 15** Redoubt production impacted by water
- **May 25** Setting litigation limits
- **May 18** Kustatan fully operational
- **Feb. 23** Forest Oil posts quarterly profit as productions volumes drop
- **Jan. 26** Creative thinking

2002

- **Dec. 29** Money, time, an assist from the Legislature were all required to bring Redoubt Shoal online
- **Dec. 29** Forest may explore deeper horizons at Redoubt Shoal
- **Dec. 22** Forest announces beginning of production at Redoubt Shoal
- **Aug. 11** Forest Oil reports Redoubt No. 5 well drilling in Hemlock
- **July 28** Redoubt Shoal No. 2 certified capable of production
- **June 23** Oil Patch Insider
- **June 2** Forest Oil focuses on growth in Cook Inlet oil production
- **May 12** Court rules against state on Redoubt
- **April 14** Forest drills to new depths
- **March 10** Court decision stalls Redoubt
- **Jan. 27** How much oil can be recovered at Redoubt Shoal?
- **Jan. 20** Forest Oil pipe has arrived; company's permits being reviewed

2001

- **Nov. 4** Forest Oil pleased with results of third Redoubt unit well
- **Oct. 14** Forest Oil expands Osprey platform, plans to lay pipeline in spring
- **June 25** Redoubt reserves set at more than 50 million barrels

continued from page 11

SPENDING

to proved acquisitions.

Martin Lovegrove, managing director of Harrison Lovegrove, said that given the maturing of the worldwide oil industry, it is now assumed that to achieve growth companies "are going to have to do more acquisition than exploration."

Global mergers and acquisitions dropped by one-third last year, but the industry still led all sectors, accounting for 15 percent or $170.2 billion of the total M&A value.

—**GARY PARK,** Petroleum News Calgary correspondent

continued from page 11

FOREST

hoped Redoubt eventually would produce about 15,000 barrels per day, a goal that now appears unachievable without better well performance. Clark also said the company likely would have to reduce current booked reserves of about 60 million barrels.

Unocal assets proven

In regard to the Unocal deal, Forest stuck closely to its current strategy of acquiring proven assets in and around properties the company already operates. The transaction specifically would give Forest 273,000 net acres in 128 blocks offshore and in three fields onshore south Louisiana. The onshore component represents about 42 percent of reserves and 24 percent of current production, Forest said.

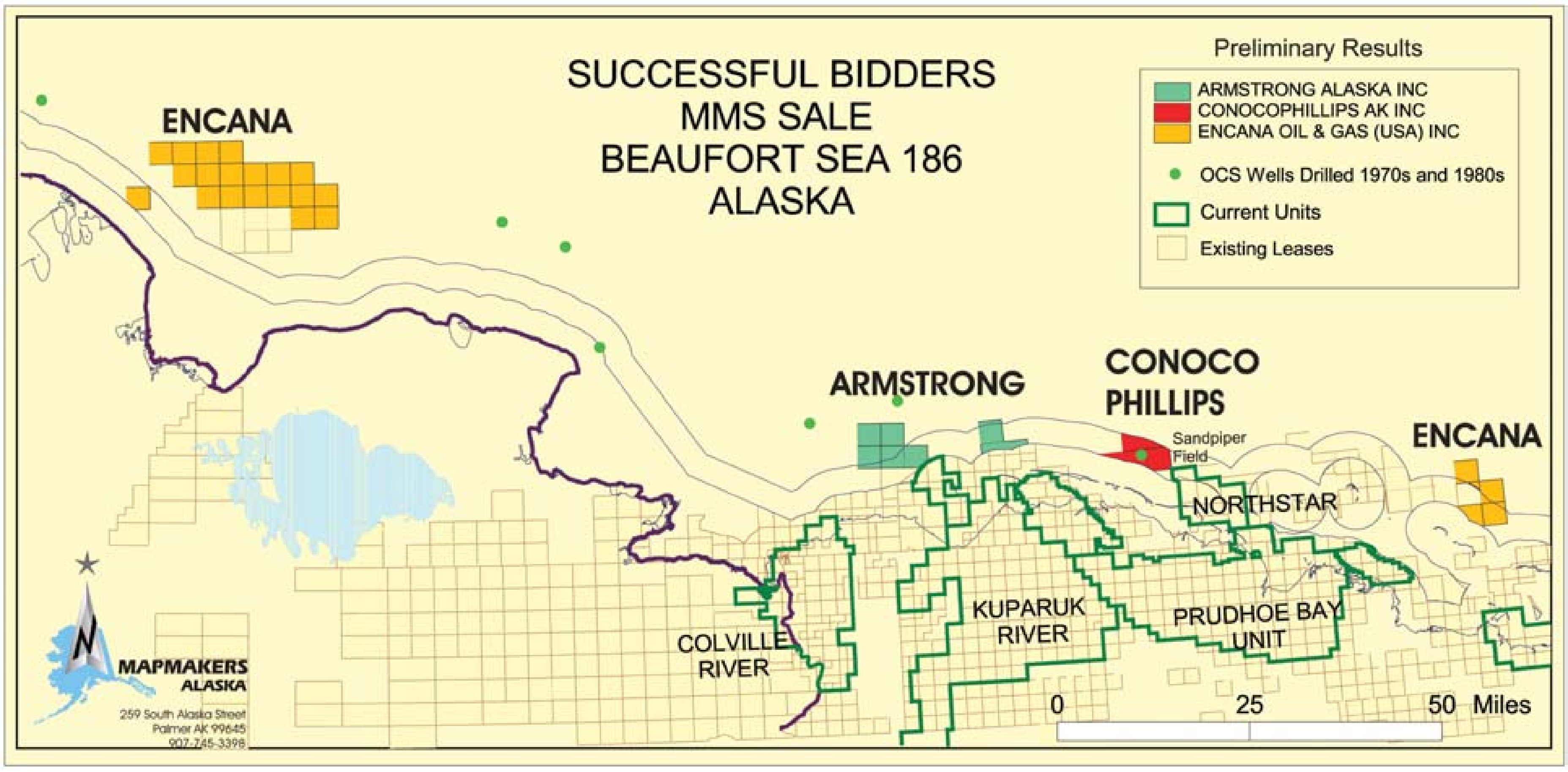
Forest said it would operate 70 percent of the assets. The deal also would place Forest among the top six operators on the Gulf's continental shelf in terms of acreage and production.

The company said it would pay for the properties through a combination of cash, debt and equity.

The Unocal assets should generate about $100 million in annual cash flow, Forest said, adding that it would spend about $60 million on the properties over the next two years.

Under terms of the deal, Unocal would have the right to farm into deep-shelf prospects on 41 of the 128 acquired blocks.

If Unocal proposes to drill a prospect greater than 14,000 feet, Forest said it could elect to either participate for an interest equal to Unocal or receive an overriding royalty interest. ●



continued from page 1

SALE

$3,550,158, 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 Petroleum leases.

ConocoPhillips paid the highest average price per acre, $265.70 for approximately 15,055 acres; Armstrong averaged $36.01 an acre for some 37,600 acres; and EnCana averaged $27.51 an acre for some 129,100 acres.

MMS Director Johnnie Burton said after the sale that she was very pleased with the results.

"We're showing a couple of large companies that are still big players and we're seeing an independent" active, which hasn't happened a lot in that area. Burton also said MMS was "pleased to see that EnCana is really stepping out and going into a wildcat area."

Some tracts near existing exploration

Sale 186 is the first MMS Beaufort Sea outer continental shelf lease sale since 1998.

The "A" area bids — closer to shore and to existing infrastructure — included five leases taken by Armstrong Alaska northwest of the company's existing acreage position in the Ooguruk unit, where Pioneer was operator for the partnership last winter on three exploration wells on state oil and gas leases acquired by Armstrong. Armstrong also took two leases adjacent to blocks of offshore state leases north of the Kuparuk River and Milne Point units.

ConocoPhillips took three "A" leases for $4 million — the leases on which Armstrong also bid — in the area of the old Sandpiper wells, northwest of the Northstar unit.

MMS Director Johnnie Burton said MMS was "pleased to see that EnCana is really stepping out and going into a wildcat area."

EnCana took two "A" and three "B" leases offshore on the east side between Badami and Endicott.

EnCana was the only bidder for "B" leases, those farther offshore and farther from infrastructure, bidding on 22 tracts, the three on the east side and the majority in the block north of NPR-A. There are six existing ConocoPhillips-Anadarko leases in this area, Goll told Petroleum News after the sale, "so it appears that people think there's something there." But there are no wells in the immediate area. It's in a hole between exploration wells, he said, and MMS will be very interested to see results of seismic exploration in the area.

Armstrong playing off last year's success

Ed Kerr, Denver-based vice president of land and business development for Armstrong, told Petroleum News that some of Armstrong's bids were for tracts "playing off of our success of last year, drilling in the state waters in the Ooguruk unit." Other tracts the company won, he said, offset the Milne Point unit.

The tracts where Armstrong bid against ConocoPhillips are in the Sandpiper area, Kerr said. "And they had a bigger bid, of course, a bigger wallet," and took those tracts.

But, he said: "The things we wanted most, we got, and we're very excited about it." The company is looking forward to doing a lot more in the Beaufort, he said, and still has a lot of work to do with acreage it already owns.

ConocoPhillips looking for gas

Rick Mott, ConocoPhillips Alaska's vice president of exploration and land, told Petroleum News the company was pleased to win the blocks it bid on. "We thought there would be competition on the blocks and obviously there was. It was an area where there had been drilling historically and gas and oil had been found there, but predominately gas. And this kind of fits with our strategy to be a major gas producer on the North Slope."

The ConocoPhillips tracts are about 11 miles offshore, he said, and about eight or nine miles from Northstar.

This is the area of the former Sandpiper unit. There have been two wells drilled on the feature, Mott said.

EnCana evaluating Alaska portfolio

EnCana spokesman Alan Boras told Petroleum News Sept. 25 that the 24 tracts the company took, some 120,000 acres for approximately $3.5 million, includes about 100,000 acres on the western Beaufort and about 20,000 acres

see **SALE** *page 14*

continued from page 13

SALE

approximately 20 miles northeast of Prudhoe Bay.

Prior to this sale, he said, EnCana had 675,000 net acres in Alaska, about 390,000 in the Foothills, about 230,000 on state land on the North Slope, and about 57,000 acres in NPR-A.

Asked what the company had planned for its newly acquired acreage, Boras said EnCana would evaluate existing seismic data and do exploration evaluation with that existing data, as well as looking at whether the company might acquire additional seismic in the future. "It's very early days," he said, but the company will evaluate the prospects on its new leases and plan work in due course.

He said EnCana was pleased with its acquisitions at the sale. It adds to the company's portfolio of Alaska exploration acreage, he said, and the company continues to evaluate that portfolio.

No wells are planned in Alaska this winter, he said, although the company does plan to drill a well this winter in the Mackenzie Delta. ●

Sandpiper prospect a big draw

The old Sandpiper prospect, where two wells were drilled in the mid-1980s, was the biggest dollar draw at the Sept. 24 Minerals Management Service Beaufort Sea lease sale, attracting winning bids of $4 million from ConocoPhillips Alaska, as well as $1.27 million from Armstrong Alaska, in the sale's only competitive bidding.

Shell Western Exploration and Production drilled the Sandpiper No. 1 nine miles northeast of Seal Island (where BP Exploration (Alaska) developed Northstar in the late 1990s), spudding the well in 1985 and completing work in 1986. Shell tested the 12,575-foot well from below 11,910 feet at 500 to 2,500 barrels of 40-52 degree API oil and up to 18.5 million cubic feet per day from two different Sadlerochit formation intervals. Shell had a 31.5 percent interest in the well. Its partners were Amoco Production (31.5 percent), Murphy Oil USA (20 percent), Petrofina Delaware (10 percent) and Koch Industries (7 percent).

Shell spud the second well, Sandpiper No. 2, but Amoco later took over as operator. That well was drilled to 14,983 feet, sidetracked three times due to downhole problems, and plugged and abandoned in July 1986.

Both wells were drilled from Sandpiper gravel island in 49 feet of water, and MMS lists both wells as producible. Former leases at the prospects expired in April 2001. The Alaska Department of Revenue said in 2001 that it considered Sandpiper a prospective source of oil production, and estimated production at 12,000 barrels per day by 2008.

BP was the operator until 1999; its partner Murphy Exploration and Production then took over as operator. Murphy told MMS that the most economic development plan would be "to construct a gravel island on Loan Shoal with minimum process facilities." Crude oil would then be piped to BP's Northstar facility for processing. Murphy estimated that Sandpiper would have peak daily production rates of 8,000 barrels of oil and 50 million standard cubic feet of gas and a field life of 24 years. Total recoverable liquid reserves were estimated in the 47 million barrel range.

There was a unit at Sandpiper until 2001.

Want to know more?

If you'd like to read more about Minerals Management Service's Beaufort Sea lease sale 186 and the Sandpiper prospect go to Petroleum News' web site and search for the following articles, published in Petroleum News in the last few years:

Web site: www.PetroleumNews.com/

2003

- **Aug. 24** MMS issues Beaufort sale notice
- **Aug. 3** A second look
- **Aug. 3** Details on Oct. 29 lease sales issued
- **May 11** Total drops slope leases to focus on NPR-A
- **July 27** MMS slashes bid, rental amounts for sale 186
- **June 29** Kuvlum, other discoveries may be key to successful lease sale
- **March 30** Minerals Management Service asks for nominations for Norton Sound….
- **March 2** Selling the Beaufort
- **Feb. 23** MMS issues final EIS for Beaufort Sea planning area
- **Feb. 23** Production incentives offered in upcoming MMS Beaufort Sea sale

2002

- **Dec. 22** Five bucks a barrel
- **Sept. 29** MMS director sees potential in Alaska outer continental shelf
- **July 21** MMS schedules hearings on Beaufort Sea multiple sale draft EIS
- **July 7** Norton approves MMS five-year OCS oil and gas lease program
- **June 23** Minerals Management releases draft EIS for proposed Beaufort Sea lease sales
- **June 9** TotalFinaElf not new to Alaska
- **April 21** Revenue's spring forecast shows prices up, offshore production delayed
- **Feb. 3** MMS to prepare multi-sale EIS for Beaufort Sea sale

2001

- **Dec. 23** ANS oil production to stay slightly above 1 million barrels a day through 2010
- **Nov. 4** MMS issues proposed 2002-2007 OCS leasing program, DEIS
- **Sept. 30** MMS to use single EIS for Beaufort Sea, possibly Cook Inlet sales
- **Sept. 23** MMS to use multiple sale process for Alaska's Beaufort Sea

1999

- **Oct. 28** BP Exploration (Alaska) affirms commitment to Alaska buy, build, hire
- **Aug. 28** BP's Beaufort Sea field developments moving forward

● ALBERTA

Kyoto treaty still troubles Imperial

Other companies unveil wave of new oil sands projects

By GARY PARK

Petroleum News Calgary Correspondent

Imperial Oil, Canada's petroleum powerhouse, does not yet believe that Prime Minister Jean Chretien's soothing assurances remove the risk to oil sands development posed by the Kyoto climate-change treaty.

Chretien sent a letter to the industry in July pledging that oil sands developers will carry no more than their share of Kyoto's costs, but Imperial Senior Vice President Paul Smith told reporters at a Toronto investment conference Sept. 18 that the promise is "just a letter."

Canada Prime Minister Jean Chretien sent a letter to the industry in July pledging that oil sands developers will carry no more than their share of Kyoto's costs, but Imperial Senior Vice President Paul Smith told reporters at a Toronto investment conference Sept. 18 that the promise is "just a letter."

Imperial would be more at ease with a signed "commercial agreement" to give it a clear understanding of the risks involved in projects whose life span will extend far beyond the initial 2008-2012 phase for implementing Kyoto.

He noted that Imperial is moving ahead with plans for its Kearl Lake project in northeastern Alberta — a possible C$7 billion, two-phase investment that could come on stream by 2010, ultimately produce 200,000 barrels per day and have an operating life of 70 years.

The project involves drilling this winter, followed by regulatory applications once there is a better fix on the commercial and engineering implications.

Other projects gaining speed

Meanwhile, a host of other ventures, big and small, are gaining speed, based partly on confidence that the Kyoto clouds are dispersing.

• Canadian Natural Resources is counting on regulatory approval before year's end that will allow it to make a final decision by mid-2004 on its possible C$8.5 billion Horizon project. Company President John Langille said at the Toronto conference that he sees no major unanswered questions standing in the way of the venture that is targeted to produce 232,000 bpd by 2012.

• Devon Energy generated excitement by confirming it is moving ahead with its C$550 million Jackfish project, signaling an oil sands debut by a major U.S. independent. If all goes according to plan, Jackfish will come on stream in 2007 and reach peak production of 35,000 bpd in 2008, tapping into recoverable reserves estimated at 300 million barrels.

• Privately owned junior Deer Creek Energy announced plans to go public in 2004 to raise C$100 million to finance a major expansion of its bitumen production. Reinforcing the trend towards smaller undertakings and the growing use of steam-assisted gravity drainage technology, Deer Creek plans to start at 600 bpd in the second quarter of 2004, grow to 10,000 bpd in 2007 and reach final output of 30,000 bpd in 2009. The company figures Kyoto will add no more than 15 cents per barrel to its operating costs.

• Climbing aboard the oil sands bandwagon, the Fort MacKay First Nation, with 530 members and land 45 miles north of the "oil sands capital" of Fort McMurray, said it hopes to join the giants such as Syncrude Canada, Suncor Energy and Shell Canada. Assuming members ratify a land-claim settlement in an Oct. 23-24 vote, Fort MacKay will have control of 23,000 acres, including an oil sands lease. Although plans are in the early stages, the first nation is close to hiring an engineering firm to develop size and cost estimates.

• In another new wrinkle, Petrobank Energy and Resources has applied for regulatory approval of a pilot project to test a technology known as gravity fireflood — which involves injecting air into the bitumen deposit, igniting a fire and thinning the viscous bitumen, with results that are similar to those achieved in a refinery. ●

ODESSA, TEXAS

Oxy, region's biggest crude oil producer, to stay active in Permian basin

The largest crude-oil producer in the Permian basin said it will remain active in the region, a reassurance that was welcomed by local oil industry officials.

Oxy Permian will continue to reinvest funds into its Permian assets and maintain production of those facilities, president and general manager Tom Menges said Sept. 18.

"That's our biggest push, and it's been very successful, but it gets harder each day as oil wells decline and costs go up, so we have to continue to work that," Menges said.

The announcement was greeted by local industry officials, who have seen other major producers leave the area in recent years.

"It's so refreshing, especially after Marathon leaving, to see someone committed to the Basin like Oxy is," said independent oil producer Jim Henry.

Marathon Oil said this summer it would slash its Midland staff and move management of its Permian basin interests to Houston.

Henry, president of Midland-based Henry Petroleum Corp., said it was encouraging to see that Oxy is doing well "and making a good return on their investments."

Menges said Oxy plans to spend $100 million to $200 million next year to drill 200 to 250 new wells and to maintain steady production levels from the assets it acquired in the 2000 purchase of Altura Energy. The company will further develop proven reserves of 1 billion barrels of oil, he told about 130 members of the Permian basin Petroleum Association. In the Permian basin, Oxy operates so-called legacy assets — large oil fields discovered many years ago that still have reserve capacity.

"Some would say they are old and tired, but they have tremendous oil in place," Billy Bledsoe, an Oxy reservoir management team leader in Midland, told the Odessa American.

Menges told the petroleum association that Oxy plans to start at least one major project using so-called enhanced recovery — such as flooding a well with carbon dioxide to force out oil. Possible locations include near Hobbs, N.M., in western Andrews County or near Levelland, he said.

—THE ASSOCIATED PRESS

CANADA

Gas drillers continue blistering pace in Canada

New natural gas well permits are being issued at a record pace and land sales in Western Canada point to a lively fall and winter drilling season. To the end of August, regulators authorized 11,006 gas wells, many of which will not be spudded until next year, while gas completions for the eight months tallied 7,500, which should put the industry on track for 12,000 this year and next.

Calgary-based investment dealer FirstEnergy Capital has reinforced that optimism by raising its 2003 forecast for oil and gas wells to 20,068 from 18,462, with gas targets accounting for at least 60 percent. For the January-August period, Alberta logged 5,742 gas wells, Saskatchewan 1,306, British Columbia 434, Northern Canada 5 and Eastern Canada 39. The breakdown included 2,114 exploration holes.

In Western Canada, gas wells soared to 72 percent of August's total completions of 1,254.

—**GARY PARK,** Petroleum News Calgary correspondent

NEWFOUNDLAND

Newfoundland explores CNG for offshore natural gas

The Newfoundland government is weighing four options for using compressed natural gas to exploit gas resources in its iceberg-studded, storm-buffeted offshore.

A joint study with the Canadian government, completed by David Engineering and Associates, evaluated four proprietary compressed natural gas technologies as alternatives to pipelines and liquefied natural gas for stranded offshore gas.

Newfoundland Energy Minister Walter Noel said that based on the findings his government will explore all technologies to ensure development of its gas "sooner rather than later."

The study explored compressed natural gas systems proposed by EnerSea Transport, Williams Energy, TransOcean Gas and TransCanada.

Noel said the study found "all systems were well developed to be used on the Grand Banks (offshore Newfoundland) and worldwide."

He said Davis Engineering recommended that the proponents should establish a CNG Centre of Excellence to undertake more detailed studies. Compressed natural gas has been promoted as a technological answer for companies with offshore gas discoveries that lack the reserves to justify the costs of building an undersea and onshore pipeline infrastructure.

Faced with a downturn in its offshore oil sector, Newfoundland is turning its attention to its untapped gas prospects.

Estimates by the National Energy Board suggest there could be 45 trillion cubic feet, although the current total sales volume is calculated at only 5.34 tcf, which some experts have projected is at least 2.4 tcf short of the economic threshold needed to produce 1 billion cubic feet per day over 15 years. Noel's predecessor, Lloyd Matthews, called earlier this year for the industry to develop his province's gas by 2007, a target that many deem to be at least five years too soon.

—**GARY PARK,** Petroleum News Calgary correspondent

● BRITISH COLUMBIA

EnCana takes stranglehold on northeastern B.C. play

British Columbia deep basin could hold gas riches that dwarf anything else in Canada; independent invests C$500 million on land, drilling licenses

By GARY PARK

Petroleum News Calgary Correspondent

EnCana is now the pivotal natural gas player in northeastern British Columbia, taking a stranglehold on 500,000 net acres and possible long-life recoverable reserves of 4 trillion cubic feet.

EnCana COO Randy Eresman

Armed with data from 25 wells and faced with stiffening competition, the Canadian independent rolled the dice Sept. 17, spending C$369 million on land and drilling licenses in the Cutbank Ridge of the Deep basin play that straddles the British Columbia-Alberta border.

That raises its total investment in Cutbank over the past 18 months to about C$500 million, which it proposes to follow with 100 to 200 wells per year into the tight gas formation.

After quietly compiling about 150,000 acres by operating through land brokers, EnCana took the plunge earlier this month when it locked up another 350,000 acres.

Chief Operating Officer Randy Eresman said the company's extensive seismic surveys, geological analysis and exploratory drilling have enabled it to identify a "promising resource play" in Deep basin.

"We have successfully demonstrated that our application of technology and large repeatable drilling programs can drive down development costs in these resource plays to achieve attractive financial returns," he said.

Lehman Brothers analysts Thomas Driscoll and Philip Skolnick said technological innovations have indicated that single sections of Cutbank contain an average 6 billion cubic feet each of recov-

see **ENCANA** page 17

● ANCHORAGE, ALASKA

Kenai Borough wants gas line

Borough tells state authority it's a better location for line than Valdez

By LARRY PERSILY

Petroleum News Juneau Correspondent

The Kenai Peninsula Borough believes a pipeline carrying North Slope gas to tidewater for export as liquefied natural gas makes more economic sense in its neighborhood than in Valdez.

Based on that belief, the borough says it would support asking the Alaska Legislature to change the law that limits the Alaska Natural Gas Development Authority to only looking at building the pipeline terminus at Valdez.

The Kenai Peninsula has an LNG plant and export terminal and an underutilized fertilizer plant that could use additional supplies of gas, said Bill Popp, oil and gas liaison for the borough. Cook Inlet could run short of gas for the two industrial users, home heating and power generating needs in 10 years, Popp told the state gas authority board at its Sept. 22 meeting in Anchorage.

"If these people want a pipeline, why don't they go out and build one," said state gas authority board member John Kelsey of Valdez.

He also noted that the Southcentral pipeline grid already serves almost 400,000 of the state's 635,000 residents, and a line to the Kenai Peninsula could feed North Slope gas into that system.

Borough suggests change in law

Popp told board members they have the ability to

see **KENAI** page 17

continued from page 16

ENCANA

erable reserves.

First-year decline rate 50-60 percent

Full-cycle finding and development costs are calculated at C$1.50 per thousand cubic feet, with per well costs estimated at C$4 million each, including drilling, completion, production tie-ins to sales pipelines and facilities costs.

The average first-year output per well is forecast at 1 million to 2 million cubic feet per day, with a first-year decline rate per well of 50-60 percent, settling down to 15 percent a year after that.

Deep basin could hold gas riches that dwarf anything else available in Canada. The consulting firm of Petrel Robertson delivered a report to the British Columbia Energy Ministry earlier this year that rated the resource potential at 185 tcf to 525 tcf for the British Columbia side of the basin alone.

Cutbank is 30 miles southwest of Dawson Creek and viewed by EnCana as comparable to its Greater Sierra play in northeastern British Columbia and its Mamm Creek field in the U.S. Rocky Mountain region, where its accumulated experience is expected to help keep costs in check, despite

Deep basin could hold gas riches that dwarf anything else available in Canada. … (potentially) 185 tcf to 525 tcf for the British Columbia side of the basin alone.

Canada's limited exposure to tight gas reservoirs.

EnCana Chief Executive Officer Gwyn Morgan told the Financial Post that his company was determined to seize control of Cutbank because it needed a large land base to deploy a drilling program that could drive down costs.

Greater Sierra, with reserves projected at 5 tcf, is currently pumping about 220 million cubic feet per day and forecast to reach 450 million cubic feet per day in 2005 as EnCana accelerates a drilling program that included 70 wells this summer.

To reinforce the confidence in Greater Sierra, the National Energy Board approved a new C$55 million pipeline earlier this month that has design capacity of 418 million cubic feet per day and is scheduled for start-up in April 2003.

There is street talk that Burlington Resources Canada could be a partner with EnCana, but no confirmation. El Paso Oil & Gas Canada, Anadarko Canada and Apache Canada are also active in the region. ●

continued from page 16

KENAI

suggest a change in state law if the economics show there is a better project than building at Valdez.

"We think it flies in the face of reason not to be looking at this issue," he said in an interview the day after the board meeting.

The statute adopted by voters when they passed the citizens initiative last fall says the state gas authority shall prepare a project development plan by the summer of 2004 for a pipeline from the North Slope and an LNG export terminal in Prince William Sound. Supporters of the initiative have always talked of Valdez as the sound's only feasible building site, where the LNG plant would share the community with the terminus of the trans-Alaska oil pipeline.

Scott Heyworth, sponsor of the initiative and a member of the state gas authority board, was not receptive to the Kenai Peninsula Borough's suggestion of trying to change the law. He said past studies by longtime LNG proponent Yukon Pacific Corp. and others have pointed to environmental challenges to running a pipeline to the Kenai Peninsula.

Change could cause delay

Heyworth also challenged the economics of building the line to the Kenai, and said any change in routing at this point could delay the project.

Popp responded that a pipeline to the Kenai could follow much of the existing rights of way used by the Alaska Railroad, utility lines and highway routes, and defended his belief that the economics are better to the Kenai Peninsula than Valdez.

In all likelihood, Popp said, any pipeline to tidewater for LNG export will not be stand-alone project but rather will be a spur line from a main pipeline running from the slope into Canada and on to the North America gas supply grid. As such, he said, it makes sense to route the spur to serve a majority of the state's population. "We have a gas supply problem in Cook Inlet," he said, adding that the line could solve that problem for decades to come.

Southcentral natural gas consumers and industries currently use more than 530 million cubic feet of gas per day, with about two-thirds of the volume going to fertilizer production and LNG export. The gas authority is looking at a line that would carry 2 billion cubic feet of gas, which would require major expansion of the peninsula's existing LNG and fertilizer export operations to use up that much new supply.

Kelsey also opposes change

Board member John Kelsey of Valdez joined Heyworth in opposing any move to join with the Kenai Borough to amend state law for a new pipeline terminus site. "If these people want a pipeline, why don't they go out and build one," he said. "I say more power to them. Let them go."

Board Chairman Andy Warwick of Fairbanks put an end to the discussion when he told the board, "I don't think we need to debate the issue at this time."

Popp said the day after the meeting it would be premature to speculate whether the borough would seek legislative action to change the law without support from the gas authority. ●

● ANCHORAGE, ALASKA

Gas board says no to special session

Says legislative session not needed to pursue LNG deal with Sempra

By LARRY PERSILY
Petroleum News Juneau Correspondent

Members of the Alaska Natural Gas Development Authority board of directors voted unanimously that a special legislative session is not needed to deal with the authority's request for $2.5 million to study the costs and feasibility of building a liquefied natural gas export project.

Instead, the authority said it would work with the governor and legislators to find whatever sources of money might be available to complete as much of the work as possible before the Legislature convenes in January.

The authority had asked for the money at the end of August, saying it was running out of time to gather information and prepare cost estimates in its rush to win a contract to supply LNG for Sempra Energy's proposed receiving terminal in Mexico, just south of the California border. Board members said they needed a decision on the funding request in September, or the state risked losing out to other potential suppliers that also are courting Sempra.

The vote to drop the push for full and immediate funding came at the authority's Sept. 22 board meeting in Anchorage, 72 hours after the entire seven-member board met in private with Alaska Gov. Frank Murkowski.

"I think we can find ways to get the money without a special session," Harold Heinze, the authority's chief executive officer, told board members after the meeting with the governor.

State agencies may help with work

The first step will be to meet with administration officials to review the authority's work list, to determine "if there is some way to fit this in with existing state resources," Heinze said. Then, if state agencies cannot help pay for the work or help actually do the work, he said, the authority would turn next to the Legislature with the same request.

Alaska Senate President Gene Therriault, participating in the authority's Sept. 22 meeting by phone, said the Legislature might be able to help by loaning staff to the authority or possibly transferring legislative funds to the agency and then repaying itself when lawmakers return to session in January.

The North Pole Republican specifically asked the gas authority board at its meeting to announce whether it believed a special session was necessary.

Board member David Cuddy of Anchorage supported backing away from a special session, which would have meant bringing all 60 House and Senate members together for public hearings and floor votes on the gas authority's funding request and a possible Sempra contract.

"Personally, I think it's premature to need a special session," Cuddy said.

The gas authority itself never specifically asked for a special session, though Heinze did mention it as a possibility at the board's August meeting. The actual call for a special session came from legislative Democrats, who sent a letter to Republican leaders Sept. 15 asking for a poll of members on the call. A two-thirds majority in each chamber is required to call a special session, and it's expected the Democratic request will fall far short of the votes needed in the GOP-dominated Legislature.

The gas authority's decision not to support a special session will further weaken the Democrats' call.

Authority could borrow money

The authority believes it could obtain financing for its studies if it can't get enough money from the administration or the Legislature. Board Chairman Andy Warwick, in a Sept. 18 letter to Therriault, said, "If we have the demonstrated political will, we can borrow the funds."

The new authority's budget for its first year of operations is $150,000, and Heinze has told board members the money is quickly running out.

Board member Scott Heyworth told his colleagues perhaps the authority could borrow money from the Alaska Industrial Development and Export Authority or Alaska Housing Finance Corp. to carry the budget until lawmakers can approve additional funding in January.

The entire board met with the governor four days after his chief of staff sent them a six-page letter, listing the governor's detailed questions about the rush to strike a deal with Sempra, the authority's financing options, cost estimates, contract terms, gas supply and several other items. "I think he felt as they left the meeting … reassured they would do their due diligence and come back with a more realistic proposal," said John Manly, Murkowski's press secretary.

"It wasn't an official meeting of the board," Manly said. "They chatted about the Sempra proposal."

see **NO** *page 18*

● ANCHORAGE, ALASKA

Alaska ready to talk with gas line cities

Municipal advisory group to start work in advance of stranded gas application

By LARRY PERSILY

Petroleum News Juneau Correspondent

While the state continues to wait for the major North Slope producers to submit a project application under the Stranded Gas Development Act, it figures there's no sense in waiting any longer to start talking with the municipalities that would be affected by a natural gas project.

The Stranded Gas Act requires the Department of Revenue to set up a municipal advisory group of the cities and boroughs that would see economic or social effects from a pipeline running through their communities. The department will start talking with those communities in the next couple of weeks, said Steve Porter, deputy commissioner at Revenue.

The department's earlier plan was to wait for a project application before starting talks with municipalities, Porter said. But that was when the state expected an application this summer. With time running short to review an eventual application, work through issues with the municipalities, negotiate a contract with the producers and still present the package to the public and Legislature by next session, he said, the decision was made to set up the municipal advisory group in advance of receiving a project application.

Contract would replace all taxes

Alaska's Stranded Gas Development Act, adopted in 1998 and amended this past session without a dissenting vote in either the House or the Senate, authorizes the administration to negotiate with natural gas project developers for contractual payments in lieu of taxes. The intent is that the contractual payments would provide a greater measure of fiscal certainty to project developers and investors than the existing collection of state and municipal property taxes, local sales taxes, state corporate income and production taxes.

The statute requires a municipal advisory group — comprised of one representative from each affected community — to help ensure that the contract provides cities and boroughs with a reasonable share of the gas line project payments.

Municipalities, however, have been concerned that the state contract for payments in lieu of taxes could leave them short of funds needed to handle the social and economic impacts of such a large project. The communities also have been worried that they lack a vote or a veto on terms of the contract, and will need to trust the state to protect their local interests.

The statute requires the Department of Revenue to work with a municipal advisory group — comprised of one representative selected by each affected community — to help ensure that the project contract provides cities and boroughs with a "fair and reasonable share of the payments."

Advisory group to start this fall

Porter said he expects the department will work with the municipalities this fall to set up the advisory group.

"The main focus for the municipalities will be to try to work with them to identify impacts from the proposed project," Porter said. Their financial needs over the life of the project — especially during construction, when the strain of work crews on communities would be greatest — will be a key part of the discussion, he said.

Although the statute requires the commissioner of Revenue to set up the municipal advisory group after receiving a project application, there is nothing in the law that prevents formation of the group in advance of an application.

Porter said the administration still plans to submit a contract to the Legislature for approval next session. The Stranded Gas Act directs the administration to negotiate the contract, then seek public comment before submitting the document to the Legislature for an up or down vote. Lawmakers may not amend the contract.

Legislators have asked that they not get the contract toward the end of the session, when they are short on time for complex issues. Porter said the delivery date to lawmakers will be a function of how soon the state receives a project application. The Department of Revenue is the lead agency on the state's negotiating team, assisted by the departments of Law and Natural Resources.

Producers working together

As they continue working together on an application, the major North Slope producers have asked the state questions about what it needs to see in the application, Porter said. The administration is also doing its homework, preparing for the application, he said. That includes running economic models and analysis, looking at some of the issues it expects will be on the negotiating table.

Company officials were reluctant to predict a date or even an approximate timeframe for an application, although all three producers said the timing of the application is not related in any way to energy bill negotiations under way in Congress. The state and North Slope producers are pushing for federal tax incentives to help ease the financial risk of building a $20 billion natural gas pipeline from Alaska to the North America pipeline grid in Alberta.

FORREST CRANE

Steve Porter, deputy commissioner of Revenue

"The timing of an energy bill does not affect the timing of ExxonMobil's work with BP and ConocoPhillips to develop a joint application," said ExxonMobil spokesman Bob Davis from Houston.

BP natural gas spokesman Dave MacDowell added, "A good application is our primary objective." He said BP is working with the other producers and the state to ensure that the eventual application meets everyone's information needs.

"We have no specific timeline for submittal," he said. ●

continued from page 17

NO

Meeting likely violated state law

Official or not, the meeting likely violated the state's public meetings law, says an attorney who has handled media law cases in Alaska for 25 years.

"It seems pretty clear, like hit-you-over-the-head obvious," said Anchorage attorney John MacKay. "If it's a meeting, the law requires that reasonable notice be given." It doesn't matter if the board did not take action, what they talked about or who they met with, MacKay said.

"If they're talking about the business of the agency, it's a meeting," he said. There is no exemption from the open meetings law for the gas authority.

The board at its Sept. 22 meeting directed Heinze to prepare a response to the chief of staff's letter, answering as many questions as quickly as possible. The authority's work list to prepare for a possible deal with Sempra includes requests for the following consultant contracts:

- VECO Corp., of Anchorage; almost $440,000 to study pipeline and compressor station costs.
- ASRC Energy Services, of Anchorage; $981,000 to study costs for the gas liquefaction plant at Valdez.
- Peratrovich, Nottingham & Drage, of Anchorage; almost $500,000 to study Valdez marine terminal costs.
- Northern Economics, of Anchorage; $151,000 to study in-state gas uses and economic benefits of the $12 billion project to move North Slope gas to Valdez for export.
- Wood Mackenzie, a global energy consulting firm; $120,000 for market analysis to determine how Alaska LNG might compare to competitors' costs.
- And $150,000 for legal opinions and $200,000 for authority staff and administrative costs.

Work to start soon

Heinze presented the board with detailed proposals from the companies, explaining the contracts could proceed quickly after the authority obtains funding. "I would like to get on with that work as soon as we can."

One of the questions raised in the chief of staff's letter to the authority was why it was in such a hurry to get the money, considering it would have to wait to award any contracts while it moved through the state's procurement process and solicited competitive proposals for the work.

"I would recommend to the board sole-sourcing some of this work," Heinze said after the Sept. 22 meeting. "The board has the authority to conduct its business."

The statute establishing the board, however, does not include an exemption from the state procurement code, meaning any effort to award a contract without competitive bid would require justification and advance approval from the state contracting office and the Department of Revenue.

Project decision next year

The authority's work schedule calls for negotiating an agreement with Sempra before the end of the year, assuming Sempra will wait that long. Assuming the state can sign a tentative supply deal with Sempra, Heinze told the board, the authority would need to decide whether to proceed with the project by July 1, 2004.

Although Sempra officials say Alaska is still in the running for the contract, Indonesia's oil and gas industry regulator announced several weeks ago it had signed a memorandum of understanding with Sempra to start supplying between 800 million cubic feet and 1.3 billion cubic feet a day of LNG to the company's Baja Peninsula terminal in 2007.

That volume would fill most if not all of Sempra's proposed 1 bcf a day West Coast terminal, leaving little room for Alaska gas.

Industry skeptics have speculated that Sempra is just using Alaska in an effort to negotiate a better price with Indonesia or other supplier. ●

FAIRBANKS, ALASKA

Teryl hits gold at West Ridge

On Sept. 18 Teryl Resources reported a gold mineralized zone outlined by soil and rock samples taken on its West Ridge exploration property, neighboring the True North mine located about 20 miles north of Fairbanks, Alaska.

Anomalous gold in rocks and soil has been detected in an area measuring 400 meters northeast-southwest by 200 meters northwest-southeast, according to the company's press release. The prospect has been named Old Glory.

Results reported by Teryl's geological consultant, Avalon Development of Fairbanks, indicate soil values in this grid range up to 1,155 parts per billion gold, equal to 1.16 grams of gold per ton of rock.

Rock samples collected from old prospect pits and trenches within the soil grid assayed up to 10 grams or one-third ounce per ton gold.

Teryl plans to continue expansion of the soil auger grid at Old Glory, followed by backhoe trenching of the main Old Glory anomaly in preparation for drilling in 2003. Also, ground-based geophysical surveys are planned to help better define drill targets.

—**PATRICIA JONES,** Petroleum News contributing writer

DELTA JUNCTION, ALASKA

Final EIS for Pogo released

State and federal agencies released Sept. 19 a final Environmental Impact Statement for the proposed $250 million Pogo gold mine located about 40 miles northeast of Delta Junction, Alaska.

Final permits have yet to be issued by the Alaska Department of Natural Resources, U.S. Army Corps of Engineers and the U.S. Environmental Protection Agency. The go-ahead for development may follow a 30-day appeal period mandated by EPA.

"I can't say that we're going to permit. All I can say is that I can't really see anything that would trip it up at this point," said Ed Fogels, DNR's project manager.

A review of the mine's impact on Alaska's wetlands opened last Friday, with the comment period open until Oct. 20.

Construction of the mine would result in the permanent loss of about 140 acres of wetlands, said Victor Ross, Army Corps of Engineers project manager.

The owners of the mine proposed payments of $500 per acre lost toward a conservation fund of the corps' choice to help offset the wetlands loss.

Permitting agencies have reviewed and evaluated development plans for the underground gold mine first submitted in August 2000 by joint venture partners on the project, Teck Cominco Ltd. and Sumitomo Metal Mining Co.

Teck-Pogo's Alaska Regional Manager Karl Hanneman told Petroleum News Sept. 24 that he's hopeful the company can begin construction in January 2004.

Final company approval is needed to start spending the $250

see **POGO** *page 20*

● K E T C H I K A N , A L A S K A

Platinum play progresses

Freegold's Union Bay property receives additional funding from major partner for more work this fall; new mineralized zone and claims staked

By PATRICIA JONES

Petroleum News Contributing Writer

Prospecting for platinum in Southeast Alaska seems to be paying off for Freegold Ventures, as geologists are starting additional work this month on a mineralized area discovered during the summer exploration program at Union Bay.

PATRICIA JONES

CURT FREEMAN

Freegold, a Vancouver, British Columbia-based junior exploration company, signed a joint venture agreement earlier this year on the company's Union Bay property with Lonmin PLC, the world's third largest underground platinum group metals producer.

Lonmin funded this summer's exploration program, spending $815,000 for mapping, drilling and sampling at Union Bay, located about 35 miles northwest of Ketchikan, Alaska.

Freegold's President Harry Barr said Lonmin opted to pay for additional work this fall, approving $120,000 more for further prospecting a mineralized zone discovered this summer.

"Typically the big companies don't add to budgets unless they think something is going on," Barr told Petroleum News Sept. 17. "I'm very pleased the company added to the budget. Usually it doesn't happen very often."

The additional money gives geologists another 30 to 40 days on the property, Barr said. That information, combined with drill data and other geological information gathered this summer, will be compiled into a report that should be released to the joint venture partners in about 60 days, he said.

New mineralized area discovered

The recently discovered mineralized area, dubbed the Continental Zone, is some six miles

see **PLATINUM** *page 20*

● A L A S K A

Contracts signed to ship coal to Korea once again

Usibelli Coal Mine says it is working to extend contract, increase amounts shipped

THE ASSOCIATED PRESS

Alaska coal sailed on freighters to South Korea again in September after shippers and a Healy coal producer completed details of a contract.

The agreement followed months of negotiations to restore an 18-year business relationship.

The agreement between Usibelli Coal Mine, the Alaska Railroad and Hyundai Merchant Marine will allow 400,000 tons of coal to be sold annually to Seoul, said Pat Flynn, railroad spokesman.

The shipments, cut off last September after Alaska lost ground to low-cost Pacific Rim producers, resumed the week of Sept. 22 and will last for a minimum of two years. Two trainloads of coal each week will move from Healy in Interior Alaska to tidewater at Seward on Alaska's Southcentral coast.

"We're already focused on extending the contracts and the amounts of the shipments," said Bill Bittner, an Anchorage attorney representing Hyundai.

The deal hinges on the state-owned railroad purchasing a mothballed coal-loading terminal in Seward, co-owned by a state agency and Hyundai, with a $9.6 million congressional appropriation, earmarked by U.S. Sen. Ted Stevens, R-Alaska. Now that Usibelli and Hyundai have come to terms on the coal purchase price, the railroad is moving ahead to buy the terminal, appraised at $8 million, Flynn said.

The Alaska Industrial Development and Export Authority will receive $5.5 million for its 49 percent ownership of the terminal, said Lynn Kenney, authority development specialist. Hyundai will get $2.5

see **COAL** *page 20*

continued from page 19

PLATINUM

west of where this summer's exploration work was focused, Barr said. The Continental Zone provides a seventh mineralized target on the Union Bay claim block. "It looks very significant, in terms of surface samples," Barr said. "The Continental is totally a different geological setting" than the other six known mineralized areas at Union Bay.

This summer, crews drilled three holes at the North Zone, according to a Freegold press release. Between eight to 15 diamond core drill holes were punched this summer, Barr said, and about 10,000 feet of samples were taken from four to five known mineralized areas. Notable about samples taken from Union Bay — the deposit is "pure platinum," Barr said. "That's unusual in North America, where there is usually a lot of palladium … 60 to 70 percent palladium, with the rest platinum."

Platinum prices have hovered near the $700 per ounce mark this summer, while palladium recently has sold for less than $200 per ounce. Both are industrial-useful metals.

Exploration crews also increased the size of the Union Bay claim block this summer, Barr said.

A July 14 press release from Freegold said an additional 396 claims were staked in the project area, increasing the size of the existing project by 100 percent. Last spring, Union Bay was described as 6,000 acres in size.

Barr said that the company has funded four rounds of claim staking since the initial block was staked late in 2000. "The size of the property has tripled since the initial staking," Barr said.

"With a land mass this size, a $1 million budget allows you only to do so much, so we are in the very early stages with this," he said.

Lonmin's commitment to keep its interest in the property requires $1 million in annual exploration spending in 2004 through 2006, and $750,000 each year after. Lonmin can earn a 70 percent interest in Union Bay by delivering a full feasibility study, which would outline economic options for platinum production. ●

continued from page 19

POGO

million estimated for Pogo construction, an underground mine expected to employ about 300 full-time people working to produce 375,000 ounces of gold a year.

"The timing of that…depends on when the actual permits come through," Hanneman said.

Some requests for proposals have recently gone out, Hanneman said, for early components needed at Pogo. Those include camp construction, potable water treatment and domestic waste treatment systems needed to house a construction workforce that could peak at 500 workers.

"We're starting to talk with folks…to get some scope of work out there to be thinking about," Hanneman said.

Pogo is located in the upper Goodpaster River Valley, currently accessible only by air. Teck-Pogo proposed building a 50-mile all-season industrial road to the project, restricting public access during the mine's operation. Public testimony supported that plan.

—**PATRICIA JONES,** Petroleum News contributing writer

continued from page 19

COAL

million, Bittner said.

The remaining $1.6 million of the federal appropriation will be used to upgrade the terminal's loader so that larger ships can pull up to the dock and take on coal.

"The good news for Alaska is that we'll maintain Seward as an export location for Alaska minerals," said John Binkley, railroad chairman.

Coal to Korea for nearly two decades

South Korea bought Usibelli coal for nearly two decades. Every year, coal mine executives hashed out the terms of a one-year contract with their counterparts at Hyundai, a global shipping and logistics company, which sold the coal to a Korea utility. The railroad moved as much as 3.5 million tons a year but more commonly transported around 2 million, Flynn said.

The relationship worked until last year, when the Koreans decided to turn to other coal suppliers, including Indonesia, that could provide a cheaper product.

The demise of the contract almost immediately kicked off intense efforts to restore the shipments. The economies of Seward and Healy, and Alaska's ability to ship minerals, such as coal and gravel, depended on it, local and state officials said.

Terminal buyout will retire Hyundai's debt

Stevens, chairman of the Senate Appropriations Committee, got Congress to approve the terminal buyout money, intended to retire Hyundai's debt on the plant and encourage the South Korean company to continue purchasing the coal.

The new contract is smaller than prior ones: It involves only 400,000 tons of coal a year. Flynn described it as a "placeholder" contract, meaning it's meant to keep Alaska's foot in the door as it pursues a longer-term, bigger-volume deal. At least it's for 24 months, as opposed to earlier ones that lasted only a year, Bittner said.

"We've doubled that," he said.

Bittner, who is Stevens' brother-in-law and South Korea's honorary consul in Alaska, said he's optimistic that Usibelli and the railroad will find ways to further reduce costs to keep Alaska coal competitive. Usibelli will hire six workers as a result of the contract resumption, said Steve Denton, vice president of business development. The company had laid off 30 employees after the contract ended.

At the Seward coal plant, some 12 jobs will be saved.

The deal will be completed after the Federal Railroad Administration agrees to release the $9.6 million grant. The railroad expects that soon, Flynn said. ●

continued from page 1

BILL

was "an outrage" because the provision was removed from energy bills that passed the House and was not in the Senate version of the bill that went to the conference committee several weeks ago.

Provision added in private

The provision was inserted into the committee's draft bill by Domenici and Louisiana Rep. Billy Tauzin, who is leading the House Republican delegation on the committee. Domenici and Tauzin are drafting the conference committee bill behind closed doors, later releasing the provisions to the public. The leaders hope to finish writing the bill by Oct. 3.

The GOP leaders released news of the offshore inventory provision Sept. 23.

It didn't take long for the protests to start. The next day a bipartisan group of senators including Olympia J. Snowe, R-Maine, and Elizabeth Dole, R-N.C., wrote Tauzin demanding that the inventory provision be deleted from the energy legislation.

More than 100 lawmakers recently signed a letter urging conferees not to include the inventory language in the bill. Democrats, who have been complaining about being left out of the energy bill negotiations, strongly oppose the inventory.

Closed-door sessions unpopular

But Republicans also are starting to grumble about the closed-door sessions.

Rep. Sherwood L. Boehlert, R-N.Y., Science Committee chairman and a member of the House negotiating team on the energy bill, told the Washington Post his staff was not actively participating in drafting the provisions on items that fall under his panel's jurisdiction.

"We're being told we have to accept on faith what they're going to produce, but I always say, 'Trust but verify,'" Boehlert told the Post. He said he plans to meet with Tauzin to "tell him I'm hoping for more give-and-take."

Democrats say utility, gas and oil lobbyists are writing key parts of the bill. Republicans have told Democratic aides, for example, that there will be a major rewrite of existing laws covering underground gasoline storage tanks. Gasoline retailers and the American Petroleum Institute have been heavily lobbying on the issue, according to the Washington Post.

Provisions aim to boost development

To spur oil and gas development, the most recent provisions of the Republican version of the draft energy bill would:

• Provide royalty payment relief for natural gas taken from very deep areas of the western and central Gulf of Mexico.

• Streamline the permitting process to allow for quicker development of natural gas in the Rocky Mountain area. The provisions are intended to improve access to federal lands by requiring the Interior Department to ensure improved permitting and enforcement of oil and gas leases, and to identify federal impediments to production.

— THE ASSOCIATED PRESS AND PETROLEUM NEWS

continued from page 1

MACKENZIE

offered during a non-binding open season last year "so that we can really nail down the pipeline configuration."

But, emphasizing a desire to maintain flexibility and "keep the doors open," he said final firm-service agreements will not be required until regulatory approvals have been obtained — which the agencies have indicated could be about 2006.

For now, the three anchor fields on the Mackenzie Delta — Taglu, Niglintgak and Parsons Lake — are seen as contributing 800 million to 1 billion cubic feet per day.

The preliminary information package released in June calls for a 30-inch diameter line from Inuvik, Northwest Territories, to northern Alberta with capacity for 1.2 billion cubic feet per day that could be expanded to 1.9 bcf per day with additional compression.

Even to reach the 1.2 bcf level by projected start-up in 2009 increases the pressure on all shippers to put a harder edge on their projected numbers and build on the modest reserves available outside the 5.8 trillion cubic feet controlled by Imperial and its partners in the Mackenzie Delta Producers Group — ConocoPhillips Canada, Shell Canada and ExxonMobil Canada.

As negotiations move ahead on pipeline size and capacity, they are being accompanied by stirrings on the Northwest Territories drilling front and what is in store for the next five winters.

"We know a lot of activity is under way or planned," said Searle.

Ramp up in exploration expected

It is expected the deal signed earlier this year with the Aboriginal Pipeline Group, which lays the foundation for one-third aboriginal ownership of the pipeline, will ramp up exploration, although those programs are still mostly under wraps.

There was a mild setback this month when Devon Canada Chief Executive Officer John Richels said his company will not drill on the Delta in the coming winter after participating in five wells over the past two seasons.

Christopher Bergquist, a geologist with Devon Canada, said purpose-built Arctic rigs have cut drilling time by 30 percent, while consistent and integrated 3-D data is becoming a valuable tool.

Despite the Tuk M-18 discovery of 200-300 billion cubic feet with Petro-Canada and despite being the largest Delta landholder at 1.8 million gross acres, Devon prefers to wait for the pipeline to move closer to reality before resuming onshore exploration, he said.

However, North America's largest oil and gas independent will not be idle in Canada's Arctic.

Richels said September 18 that Devon is trying to line up partners to revive drilling in the Beaufort Sea for the first time since the 1980s.

If it succeeds in talks with several multinationals, Devon hopes to drill as many as four wells, starting in the 2005-06 winter, he said. Any discoveries could see Beaufort gas fed into the Mackenzie pipeline by 2012.

Armed with three-dimensional seismic covering about 460 square miles and attracted by the Beaufort's shallow waters, which are only about 40 feet deep as much as 60 miles offshore, the company is eager to take on the gamble of drilling wells at a cost of about C$50 million each.

But Richels, indicating that deals could be announced in the next few months, said Devon would limit itself to 25 percent to 50 percent interest in such high-impact, high-risk plays.

Official view of Beaufort optimistic

Estimates by Canada's National Energy Board lend weight to the optimistic view of the Beaufort, with reserve projections of 54 tcf, compared with 17 tcf on the delta.

Exploration in the 1970s and 1980s, heavily supported by Canadian government incentives, yielded several significant discovery licenses, with a total of 39 gas fields accounting for 8.8 tcf of marketable gas.

Industry consultant Robert Meneley told geologists and geophysicists at a June meeting that future discoveries are "unlikely to be larger than the large simple early discoveries that have already been made. It will take a lot of smaller wins to add up to significant volumes."

However, other technological advances in the hiatus since Beaufort drilling was suspended could enhance the region's prospects.

Christopher Bergquist, a geologist with Devon Canada, said purpose-built Arctic rigs have cut drilling time by 30 percent, while consistent and integrated 3-D data is becoming a valuable tool.

Fueling optimism is a forecast by Peters & Co. analyst Brian Prokop that key U.S. independents — Anadarko Petroleum, Apache, Burlington Resources and Devon Energy — will hike their Canadian capital spending in 2004 by as much as 20 percent, pushing the combined total above C$2 billion as they employ about 200 rigs to accelerate their hunt for natural gas.

"This is still the best gas market in the world," Apache Canada president Floyd Price told a Peters & Co. investment conference September 17.

Active winter planned onshore

For the onshore plays, there are preliminary indications of an active winter:

• On the delta, EnCana has a Nabors rig being barged to Tuktoyaktuk and Chevron Canada Resources has signaled its intention to build on the success of last winter's North Langley K-30 well, drilled in partnership with BP Canada Energy and Burlington Resources Canada. Chevron, which is mobilizing equipment to be barged to a base camp, is targeting the Ellice Island well site about 45 miles northwest of Inuvik. Chevron and BP plan to spend C$20 million conducting three-dimensional seismic this winter. EnCana is leading a partnership with ConocoPhillips Canada and Anadarko Canada to drill a well on Richards Island and extend the knowledge gained from drilling in the 1970s.

• At Colville Hills, in the north-central Northwest Territories, partners Paramount Resources and Apache Canada aim to follow up on successful drilling last winter by re-entering two wells on a 40,000 acre prospect to assess the untested zones and drill additional wells to delineate the find. The Nogha C-49 well was reported to have encountered multiple zones of gas-bearing sandstone reservoir, while Nogha M-17 was cased and completed as a successful gas producer. Price said now that Imperial is trying to firm up volumes he anticipates a "fair amount of drilling this winter and next," saying his firm could drill as many as seven wells in the Colville area. But Imperial has made it clear that it will not build any pipeline laterals from fields such as Colville.

• Canadian Natural Resources drilled two dry holes at Colville Lake last winter and said it has no intention of spudding any further wells this winter.

• In the Sahtu region, EnCana is gearing up to drill near Tulita, while Northrock Resources is endeavoring to strike deals on road access and aboriginal business opportunities so that it can proceed with a two-well, C$15-million program.

• A full agenda is shaping up for the Fort Liard area of the lower Northwest Territories, with Anadarko Canada — pending a resolution of the parent company's future — planning to drill a number of wells after filing four significant discovery licenses from nine exploratory wells last winter. Anadarko also hopes to build a pipeline to tie-in the four significant discovery licenses. BP has licensed some wells for re-entry in the Pointed Mountain area and Canadian Forest Oil is close to completing a 15,000-foot well just north of the Northwest Territories-British Columbia border. ●

continued from page 1

ANADARKO

ConocoPhillips acquired BP's 50 percent interest in the 33 leases earlier this year.

Hanley would not comment on whether or not ConocoPhillips will exercise its partnership option on the 30 percent interest Anadarko purchased from Chevron.

Although neither Anadarko nor ConocoPhillips has commented publicly on the exact terms of their agreement in NPR-A, ConocoPhillips told Petroleum News this past summer that all leases owned by the companies in NPR-A are jointly owned. Lease records show either a 78/22 split in favor of ConocoPhillips, which is the split ConocoPhillips opted for in the BP portion of the 33 leases, or a 60/40 split — in favor of ConocoPhillips — which are the percentages the two companies hold in the Puviaq leases west of Teshekpuk Lake.

Trailblazer wells plugged and abandoned

The 33 leases acquired from BP and Chevron include the Trailblazer prospect northwest of the village of Nuiqsut where BP, in partnership with ChevronTexaco and ConocoPhillips, drilled two oil exploration wells in the first part of 2001, the G-1 Trailblazer and the H-1 Trailblazer.

A federal Bureau of Land Management official told Petroleum News Sept. 24 that the H-1 Trailblazer well has been "plugged and permanently abandoned, and the wellhead totally removed."

However, the BLM official said the Christmas tree was left at G-1 Trailblazer "in case the operator wanted to go back in. But they've since decided not to and are waiting" for the right ground and weather "conditions to go back out there and remove the valves and pipes."

Both wells have been "plugged and permanently abandoned according to state and federal standards," the official said.

Out in a blaze

The 2001 Trailblazer wells were the last wildcat wells BP drilled in Alaska.

In January 2001, two months before BP spud the wells, BP Exploration (Alaska) President Richard Campbell said in a guest editorial in Petroleum News that BP had launched its "most aggressive exploration program in a decade" on Alaska's North Slope, planning to spend more than $800 million that year on capital projects and exploration. Campbell said the company would drill six exploration wells, three of which were slated for its Trailblazer prospect in NPR-A.

BP's 2001 Trailblazer program had a price tag of approximately $30 million and involved building a 70-mile ice road to the first ice drilling pad, 50 miles of which was across sea ice and 20 miles onshore across tundra. Two additional ice drilling pads, plus 10 miles of supporting ice roads, were planned for the second and third wells, the last of which did not get drilled.

Before the end of that year, BP would announce a halt to all frontier exploration in Alaska, including drilling in NPR-A. The company, however, has remained committed to infield exploration and development, as well as to finding a way to market the North Slope's stranded natural gas.

—**KAY CASHMAN,** Petroleum News publisher and managing editor

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

Jim Gilbert, president

Udelhoven Oilfield System Services Inc.

Now in its 33rd year, Udelhoven specializes in mechanical and electrical contracting and in providing technical project management, functional check-outs and inspection expertise. Alaska operations are in Anchorage, Nikiski and Prudhoe Bay to better serve the company's public and private clients. In addition to Anchorage South High School, the firm is working on four bush schools.

President Jim Gilbert worked his way up from an entry-level maintenance position to learning instrumentation. Since transferring to Alaska in 1977 he worked at Prudhoe Bay for 16 years; his last 10 have been with Udelhoven. Jim enjoys working on his Kenai River camp, boating and 4-wheeling. He recently experienced the loss of two long-time coworkers; "enjoy life today," he says, "there's no guarantee for tomorrow."

FORREST CRANE

John Rine, employment specialist

Alaska's People

Matching rural Alaska clients with employment opportunities throughout the state has been the company's main objective. CIRI, Cook Inlet Tribal Council and Peak Oilfield Service Co. started the operation five and a half years ago to promote Native hire and training. Educating rural Alaskans about the types of apprenticeship and intern programs available is a first step to future alliances.

John Rine's broad Alaska construction background, during 40 years as a laborer, operator and H.D. master mechanic, helps him identify the right person to fill specific jobs in general construction, oil and gas, and mining. John thrives on the progress of young people making successful transitions into the workforce. Most weekends John and his wife head for their cabin, with three dogs in tow.

continued from page 1

HUB

few years, BP and others in the northern deepwater sector of the Eastern Gulf were able to tie together three relatively small fields — King's Peak, Aconcagua and Camden Hills — into a vibrant project that today feeds about 500,000-million cubic feet of gas into the Canyon Express pipeline system. None of the fields by itself was considered to be commercial.

However, discoveries in the southern portion of the Eastern Gulf promise to be more challenging to develop employing the hub concept. For one, the fields are spread across a much broader area than Canyon Express. Moreover, the fields are located beneath ultra-deep waters ranging up 9,000 feet or greater, where extreme pressures on subsea pipelines and equipment can be menacing.

Still, operators believe a hub project in the south would be doable, largely because developing dry gas in smaller, remote fields apparently would be far less expensive than for oil. “We are confident these will be developed,” Richard Sharples, Anadarko's vice president of marketing and planning, said of the company's Jubilee and Atlas discoveries.

Anadarko has proposed hub development

Anadarko recently proposed a hub development encompassing a giant circle stretching all the way from the giant Thunder Horse field in Mississippi Canyon on the west to Lloyd Ridge in the Eastern Gulf lease sale area. In addition to Jubilee, Atlas, Merganser and Vortex, prospects not yet drilled by Anadarko, Kerr-McGee and other operators presumably could be included in a master hub development.

Murphy, either alone or together with ChevronTexaco, holds a substantial acreage position with attractive prospects within the great circle and relatively close to Anadarko and Kerr-McGee discoveries. First on Murphy's list is South Dachshund, located on a pair of Lloyd Ridge blocks just inside the East Gulf sale area.

South Dachshund, owned 50-50 with ChevronTexaco, holds an estimated 400 to 500 billion cubic feet of gas reserves, John Higgins, Murphy's U.S. exploration and production manager, told analysts at the recent RBC Capital Markets energy conference in Houston, Texas. He said drilling could begin in the 2004 second quarter.

“We are hot to trot on this prospect,” Higgins said. “In the southern area, we're trying to couple up enough reserves for another gas development.”

Other Murphy prospects that fall within the great circle include North Dachshund, Bull Dog, Great Dane and perhaps Perro, which actually is located on the northeast boundary of the circle and next door to Anadarko's high-profile Spiderman prospect.

In fact, Anadarko now believes Spiderman could hold enough reserves to serve as its own hub, if drilling proves up reserves of more than 100-million barrels of oil equivalent, Anadarko officials disclosed at the energy conference. “Spiderman has the potential to be a major hub location,” Anadarko's Sharples said.

Anadarko is hoping to spud a first exploration well at Spiderman in the 2003 fourth quarter, once a joint operating agreement is reached with Dominion Resources and Spinnaker Exploration, which own an adjoining block that includes a portion of the prospect they call Amazon. It likely would be a 50-50 deal with some type of split operatorship, the company indicated. ●

continued from page 1

DEVON

Sept. 23 analysts' meeting in Houston, Texas.

"Unfortunately, it is a dry hole," said Loren Leiker, EOG's executive vice president of exploration and development. EOG holds a 37.5 percent interest in the prospect.

Devon, through its acquisition of Ocean Energy, has a 62.5 percent stake in Tuscany East and operates the prospect, located in 6,700 feet of water on DeSoto Canyon blocks 180 and 224. Dry hole costs initially were pegged at $26 million, although a spokesman for Devon said the tab likely would be less.

> *Dry hole costs initially were pegged at $26 million, although a spokesman for Devon said the tab likely would be less.*

Kerr-McGee, a Devon partner at the Shiner Deep prospect at Garden Banks Block 700, said during a Sept. 24 conference call an initial exploration well operated by Devon is probably not commercial.

Rich Buterbaugh, Kerr-McGee's vice president of investor relations, said that while the well encountered 60 feet of primarily oil pay, "we're unsure whether there are sufficient quantities for a commercial development."

Despite the uncertainty over Shiner Deep, Kerr-McGee said it has decided to take a $20-million dry hole charge in the 2003 third quarter, adding that the well has been temporarily abandoned.

Shiner Deep, situated in 4,480 feet of water, came with a pre-drill mean reserve estimate of 115-million barrels of oil equivalent, with well costs estimated at around $36 million. Kerr-McGee, Devon, Anadarko Petroleum and Dominion Resources each hold a 25 percent working interest in the prospect.

Drilling resumed at Yorktown

Meanwhile, exploration drilling has resumed at the Devon-operated Yorktown prospect after weeks of disruption caused by strong ocean currents, partner Kerr-McGee said, adding that the currents have subsided in the area.

Spud nearly a year ago on Mississippi Canyon Block 886, Yorktown well expenses are now projected at roughly $80 million, ranking it among the most expensive wells ever drilled in the Gulf of Mexico. Although Kerr-McGee and Devon are 50-50 partners in Yorktown, Devon's share of well costs will be substantially higher, about $57 million.

Located in 2,100 feet of water, Yorktown is currently at 23,400 feet and headed to 25,000 feet, Kerr-McGee said. Pre-drill reserve estimates ranged from 175 to 450-million barrels of oil equivalent.

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