Petroleum news

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Week of February 29, 2004 • $1

page 11 Evergreen waits on results from Alaska core holes

Remedial well work on slope

JUDY PATRICK

Schlumberger's Slickline unit at Prudhoe Bay on Alaska's North Slope.

Chesapeake says gas properties becoming more difficult to find

"We have seen acquisition costs go up ... and we think acquisition costs will go up." —Aubrey McClendon, CEO, Chesapeake Energy

Natural gas producer Chesapeake Energy, which has readily used acquisitions to help boost reserves and production to record levels, said competition for good properties in the United States is intense while quality reserves are becoming more difficult to find as high commodity prices make them more expensive to buy.

"We have seen acquisition costs go up ... and we think acquisition costs will go up," Aubrey McClendon, Chesapeake's chief executive officer, told industry analysts in a Feb. 24 conference call on 2003 fourth-quarter earnings.

In addition to production gains from acquisitions, the Oklahoma-based independent — now the leading natural gas producer in the U.S Midcontinent — also had remarkable success through the drill bit last year. Overall, 2003 production rocketed 48 percent from the

see **CHESAPEAKE** page 23

Total demobs rig in NPR-A; Chretien takes the stand in Calgary court

Oil Patch Insider

IT WAS A DAY MANY ALBERTANS have dreamed about for years.

Jean Chretien in court in Calgary, the city that has refused to elect a single Member of Parliament from Chretien's Liberal party since 1968.

But it wasn't the kind of appearance that posed a threat to the freedom of a man who has been out of politics for less than three months.

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BREAKING NEWS

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ALASKA

Alaska on the brink

Myers says 2004 pivotal year for state's oil and gas industry, economy

By KRISTEN NELSON

Petroleum News Editor-in-Chief

Mark Myers, director of the Alaska Division of Oil and Gas, believes that in five or 10 years Alaskans will look back on 2004 as a pivotal year for the state's oil and gas industry — and for its economy.

"The administration's goal of bridging the future into resource development to provide for the basic needs of public service is a do-able thing. I think you'll see the seeds have been planted to do just that," Myers told an audience at the annual Pacific Rim Construction Oil Mining Expo & Conference, Feb. 19 in Anchorage.

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JUDY PATRICK

Chris Cheatwood, executive vice president for worldwide exploration for Dallas, Texas-based Pioneer Natural Resources and Bill Armstrong, president of Denver, Colo.-based Armstrong Oil and Gas, represent two independents that have started working the North Slope recently.

HOUSTON, TEXAS

Dynamic Duo kicks up fuss

Plains rejects then accepts new offer; Raymond, Flores at center of storm

By RAY TYSON

Petroleum News Houston Correspondent

The Dynamic Duo of John Raymond and James Flores has been hard at work these past months, leading the charge on the friendly takeover of one publicly traded company and kicking up a storm with investors over the attempted takeover of another one. In fact, Raymond and Flores wear so many hats it's tough keeping track of their exploits.

Raymond, the son of ExxonMobil Chairman Lee Raymond, serves as president and chief operating officer of independent producer Plains Exploration & Production Co. and president and chief executive officer of Plains Resources, while at the same time sitting on the board of Plains All American Pipeline.

In an apparent effort to appease shareholders, Plains Resources specifically mentioned in its press release announcing the deal that Raymond and Flores, as players in the Vulcan Group, could participate in the transaction but could not receive $16.75 for each of their shares of Plains Resources, as could other shareholders of the company.

Flores is chairman and chief executive officer of Plains E&P and chairman of Plains Resources. For these services, Flores reportedly earns separate paychecks totaling nearly $2 million a year. Raymond is listed as earning $1.18 million a year

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NORTHWEST TERRITORIES

Trying Imperial's patience

CEO troubled by possible delay in Mackenzie gas line hearings

By GARY PARK

Petroleum News Calgary Correspondent

Imperial Oil's patience is starting to wear thin as a slow-moving bureaucracy threatens to stretch the regulatory handling of the Mackenzie Valley gas pipeline by six months.

In a blunt criticism of the environmental process, Imperial Chief Executive Officer Tim Hearn said he is "concerned right now about the pace of things," warning that delays in the pipeline phase could spill over to other aspects of the C$5 billion project.

He told reporters in Toronto Feb. 19 that the

Imperial Chief Executive Officer Tim Hearn

Mackenzie Valley Environmental Impact Review Board says it "wants to have hearings to decide if they want to have hearings and the federal environmental minister and all the producers have said, 'We agree, we need hearings.'

"I'm not sure why we need hearings to determine why we're having hearings, which will add ostensibly another six months to the process."

The Mackenzie Gas Project proponents expect to submit regulatory applications this year to set in motion a coordinated regulatory

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INSIDER

He was merely testifying in a drawn-out lawsuit by the Samson Cree Nation, near Edmonton, which has accused the Canadian government of mismanaging its oil and natural gas revenues to the tune of about C$1.4 billion.

JEAN CHRETIEN

Initially he balked at acting as a witness in the case because he is an honorary chief of the Samson Cree, but the federal court ordered him to testify once he stepped down as prime minister, making him the first former prime minister to testify at such a hearing.

Samson attorney Jim O'Reilly said the government mishandled the royalties over 60 years and prevented the band from collecting better rates of interest.

Chretien was the minister of Indian Affairs and Northern Development from 1968 to 1974 as well as being minister of justice and finance at other times.

He told the court Feb. 23 that as minister in charge of Native issues he had wanted to abolish his own department, tear up the Indian Act and give full self-government to the reservations.

But he said the Indian leaders did not want to "lose the special link that they had with the federal government," even though they wanted to manage their own money.

The case has already involved 295 days of hearings at a cost of millions of dollars to the Samson Cree and taxpayers. Federal attorney Alan McLeod estimated it could stretch through another four years.

The flag flap has folded in Nova Scotia, allowing Marathon Canada to set a May spud date for a deepwater well on the Scotia Slope. The winner, Transocean's Deepwater Pathfinder rig

Total demobs rig at Caribou prospect

TOTAL AND ITS PARTNER FORTUNA ENERGY Inc., a subsidiary of Calgary-based Talisman Energy, are demobing the drilling rig at their Caribou prospect in the National Petroleum Reserve-Alaska. The Caribou 26-11 #1, drilled by Nabors Alaska 14E, is in the vicinity of the old Inigok test well.

"They do not plan to drill another well this winter," U.S. Bureau of Land Management spokeswoman Jody Weil told PN Feb. 23.

When asked if Total drilled a sidetrack, Weil said, "There was some discussion about a second well ... or sidetrack ... this year, but they told us this morning that they (were not going to) … drill a second well because they were not budgeted with Houston to drill another well this year."

Jack Bergeron, Alaska manager for Total E&P U.S.A., confirmed Weil's statement. "We only planned to drill one well this year as per our exploration plan. … After the well data is analyzed at our corporate headquarters in Houston the next steps in our exploration plan will be finalized."

Bergeron said Caribou 26-11 #1, a tight hole, was "spud on Jan. 29 and drilled to its planned TD."

Nova Scotia well has investors in a flap

THERE'S A GROWING BUZZ that Canadian Superior Energy and El Paso Oil and Gas Canada may be the answer to Nova Scotia's faltering hopes.

With the partnership nearing completion of a deepwater exploration well, Canadian Superior shares took flight Feb. 23, rising 25 percent to C$4 in heavy trading of 4 million shares, eight times the average daily volume.

That closely followed some troubling news from the Mariner I-85 well, where drilling was suspended for four days in mid-February to correct an obstruction in the well bore.

Mile Coolen, the company's director of East Coast operations, said the "potentially serious situation was addressed swiftly in a safe and efficient manner" and drilling resumed Feb. 16.

He said the minimum target depth of about 18,500 feet should be reached at the end of February, followed by an assessment of the results in March.

The C$30 million well is one of the few current prospects of a badly needed breakthrough for a region that is now littered with drilling failures and reserve write-downs and the prospect of 23 exploration licenses expiring this year.

The investor edginess over Mariner has been reflected in the past week, with Canadian Superior shares dropping 10 percent on Feb. 18 before the Feb. 23 rebound.

Headed by industry maverick and eternal optimist Greg Noval, the Calgary-based company, which holds interests in 1.3 million acres in the region, has predicted a possible find of 1.2 trillion cubic feet from the Mariner well and a total of 2.5 tcf of reserves from three major structures.

If those goals are achieved, the play will have almost double the reserves of the nearby Sable field, which has been hit by a succession of downgrades since coming on stream in 1999.

El Paso is paying two-thirds of the tab for Mariner to gain a 50 percent stake in the exploration block, which is now its main Canadian interest after its decision to sell its Western Canadian oil and gas assets to BG Group for C$455 million.

Marathon emerges victorious in flag dispute

The flag flap has folded in Nova Scotia, allowing Marathon Canada to set a May spud date for a deepwater well on the Scotia Slope.

What was seen as a threat to the single deepwater exploratory well scheduled for offshore Nova Scotia this year — and an even more damaging blow to the region as a whole — has been averted by a Canadian Transportation Agency ruling that Marathon and its partners can use their first choice of a rig.

The federal agency rebuffed attempts by Norwegian-based Ocean Rig to gain an edge over Transocean's Deepwater Pathfinder rig by arguing that its Eirik Raude rig should get the contract because its crew consisted primarily of Canadians and a Halifax shipyard refitted the semi-submersible at a cost of C$250 million.

It also asked the agency to reflag the Eirik Raude as a Canadian vessel, in which case the Ocean Rig would have been required to pay Canadian taxes because of federal rules giving preference to domestically flagged vessels.

Marathon countered that the Eirik Raude was unsuited to its job and would need C$10 million in modifications.

Three arbitrators appointed by the transportation agency concluded that "there is no Canadian ship or non-duty-paid ship suitable and available to provide the service or perform the activity described in the application."

Marathon said it was happy to be able to move forward with the well, a follow-up to the 2002 Annapolis G-24 discovery it made with EnCana, Norsk Hydro and Murphy Oil. Marathon, as 30 percent operator, has estimated the block could hold 5 trillion to 15 trillion cubic feet of reserves.

Equally satisfied is the Offshore/Onshore Technologies Association of Nova Scotia, which made a plea to the agency to decide the matter before a late March deadline, warning that delay could see Marathon scrap its plans.

Ocean Rig has declined to say whether it will appeal the ruling.

Offshore snoring becomes hot issue

SNORING HAS BECOME A HOT POLITICAL ISSUE in Norway after offshore oil workers complained of roommates keeping them awake at night.

On some offshore oil platforms, workers have to share accommodations. So if one of them snores, the other can get dangerously deprived of sleep.

The problem made national news Feb. 25, after a member of parliament wrote to Labor Minister Victor Norman, demanding that something be done to help the sleep-deprived workers.

Karin Andersen, of the Socialist Left party, said she asked the minister to explain by March 1 how he planned to meet the demand for undisturbed sleep.

"It seems the problem is increasing," she was quoted as saying by the Haugesunds Avis newspaper.

Platform workers generally spend two-week shifts offshore, meaning they have no escape from roommates' nightly noises for the period.

Geir Heddeland, union leader on the Ekofisk oil field off southern Norway, said the problem affects about 700 of the 1,050 workers on that field alone.

"It goes beyond just snoring," he said by telephone. Roommates, often in bunk beds, can wake each other up simply by getting in and out of bed, he added.

"These are industrial workplaces at sea," Heddeland said. "If people get too tired, they can make a misstep, which can be dangerous."

Kenai Peninsula Borough website ready for visitors

The Kenai Peninsula Borough's new website, www.cookinletoilandgas.org, is ready for visitors.

Bill Popp, the Southcentral Alaska borough's oil and gas liaison, said the website is an excellent tool for researching issues involving the Cook Inlet's oil and gas industry.

Any "comments, information, PowerPoint presentations, pictures or graphics" that visitors would like posted to the site should be sent by email (bpopp@borough.kenai.ak.us) or snail mail to Popp at the Kenai Peninsula Borough, 43335 Kalifornsky Beach Road, Suite 16, Soldotna, AK 99669.

Editor's note: Gary Park, Kay Cashman and The Associated Press contributed to this report.

HOUSTON, TEXAS

ConocoPhillips' 106% production increase from Australia, Canada, Norway

ConocoPhillips added 650 million barrels of oil equivalent to its proved reserves during 2003, as the company replaced 106 percent of its production. Factoring out sales and acquisitions, company geologists brought in 133 percent of the oil and gas pumped from ConocoPhillips fields during the year.

Major increases in reserves came from Australia, Canada and Norway, executives said. Total reserve base at the end of the year was 7.8 billion barrels of oil equivalent, plus 0.3 billion barrels of Canadian syncrude, which is excluded under U.S. accounting rules.

The Houston-based company now has reserves representing 12.6 years of production at current rates. For comparison, ExxonMobil has 22.0 billion barrels of proved reserves, representing 14 years of production. ExxonMobil's reserve replacement also was similar to the ConocoPhillips number, at 105 percent of production.

ConocoPhillips reported its finding and development costs for the year came to $5.35 per barrel. Putting together the five-year record of predecessor companies Conoco and Phillips, average replacement was 210 percent of production at an average finding and development cost of $5.12 per barrel.

For 2004, executives say ConocoPhillips is moving toward development of the

see **CONOCOPHILLIPS** *page 4*

GULF OF MEXICO/ALASKA

Gulf's Dawson Deep prospect turns up 160 feet of pay for Kerr-McGee

The Dawson Deep exploration well on Garden Banks Block 625 in the Gulf of Mexico encountered 160 feet of net hydrocarbon pay, operator Kerr-McGee disclosed in a Feb. 25 conference call with industry analysts.

Moreover, a sidetrack currently being drilled off the main well bore should provide "meaningful insight into other satellite opportunities that we have surrounding the Gunnison facility," said Rick Buterbaugh, the company's head of investor relations.

> *… a sidetrack currently being drilled off the main well bore should provide "meaningful insight into other satellite opportunities that we have surrounding the Gunnison facility."*
>
> **—Rick Buterbaugh, Kerr-McGee**

The nearby Gunnison field, recently brought on line, is currently producing daily about 3,600 barrels of oil and 125 million cubic feet of natural gas, with peak daily rates of 30,000 barrels of oil and 180 million cubic feet of gas expected by year-end when field development is completed.

The Dawson Creek well was drilled to a total depth of 24,450 feet, including about 3,000 feet of water, Buterbaugh said, adding that the sidetrack is planned to reach a total depth of nearly 26,000 feet with results expected in two or three weeks.

Kerr-McGee, an exploration and production independent, operates Dawson Deep with a 25 percent interest. It also operates Gunnison with a 50 percent working interest.

Buterbaugh assured analysts in the conference call that Kerr-McGee's Red Hawk project in the deepwater Gulf is on schedule for startup about mid-year. He said the company also does not expect any delays with its Constitution project in the deepwater Gulf, largely because the company adopted the same "proven design" used at Gunnison and employed the same contractors for the project's major components.

"First production is expected late in the second quarter of 2006," Buterbaugh said. Kerr-McGee holds a 100 percent stake in Constitution and a 50 interest in Red Hawk.

Company hopes to do an Alaska appraisal well this season

On Alaska's North Slope, where Kerr-McGee is a new player, exploration drilling began mid-February at the company's Northwest Milne prospect – referred to by Buterbaugh as the "Milne Point extension well." He said it should take two to three weeks to complete.

"We hope to do an appraisal well prior to the end of the drilling season in March,"

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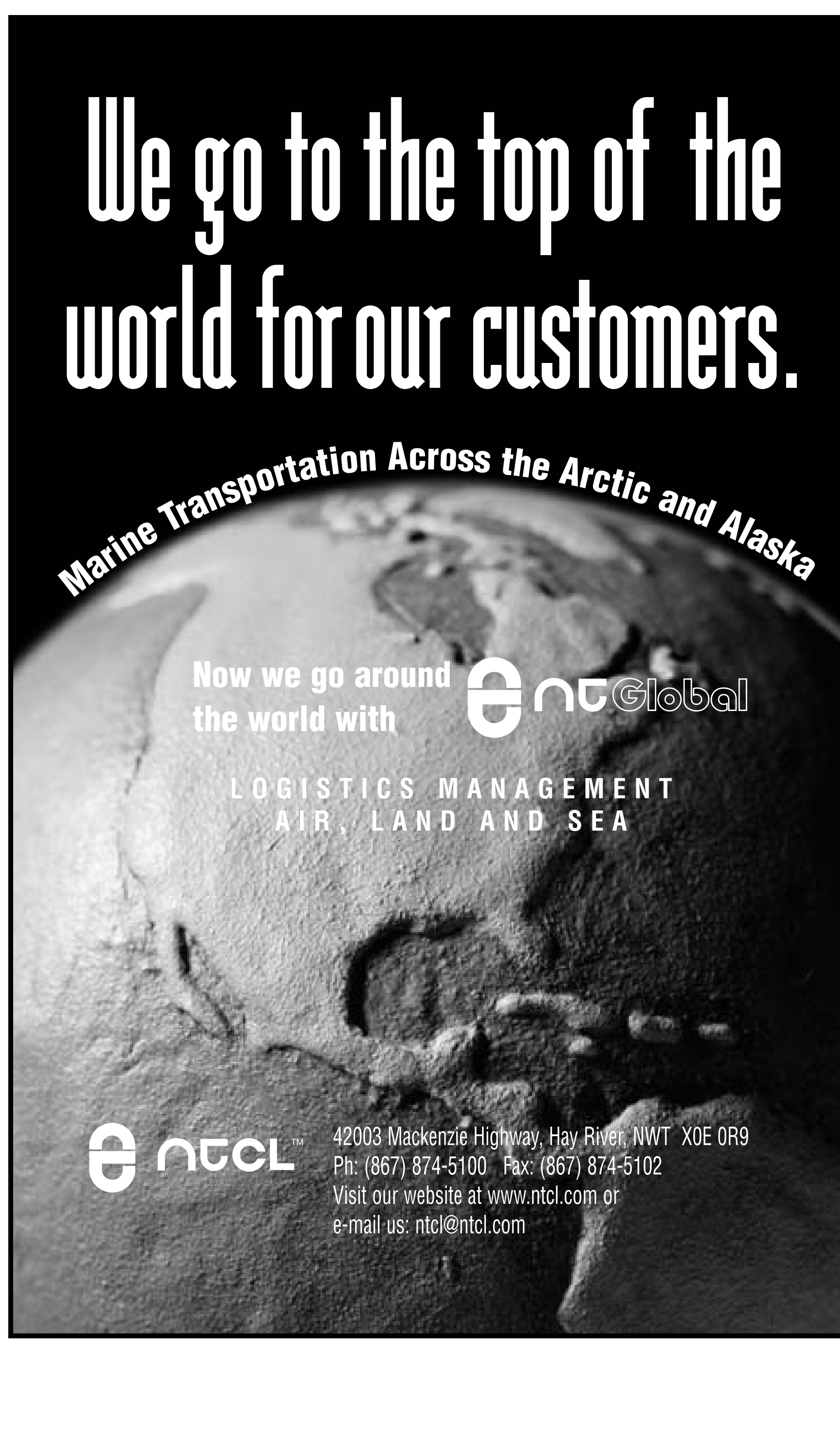

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KERR-MCGEE

Buterbaugh added.

Meanwhile, Oklahoma-based Kerr-McGee said it is holding to earlier production guidance of 257,500-274,000 barrels of oil equivalent per day during the 2004 first quarter and an average 260,000 barrels of equivalent per day for the year. First-quarter projections break down to 132,000-140,000 barrels per day of oil and 750-805 million cubic feet of natural gas, with 85 percent of the volume coming from the United States, the company said.

Buterbaugh noted that since the beginning of the year, benchmark NYMEX oil prices for West Texas Intermediate have averaged $34.25 per barrel and North Sea Brent $30.40 per barrel, up $3 for WTI and $1.25 for Brent when compared to 2003 fourth-quarter averages. Kerr-McGee has hedged about 75 percent of its projected first quarter U.S. oil production at $29.03 per barrel WTI and 75 percent of its Brent at $26.76 per barrel.

Since the start of the year, NYMEX gas prices have averaged $5.85 per thousand cubic feet, up about 45 cents versus last quarter averages. Kerr-McGee has hedged 25 percent of its projected U.S. gas volumes in the first quarter at $5.33 per thousand cubic feet. "The remaining sales will likely fluctuate with the appropriate index prices," Buterbaugh said.

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

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CONOCOPHILLIPS

giant Kashagan field in Kazakhstan, comparable in size to Prudhoe Bay with estimates of 13 billion barrels of recoverable oil. The company's plan for development of that field received government approval Feb. 25. Initial production target is 75,000 barrels daily, starting in 2008, with the field eventually expected to yield up to 1.2 million barrels a day. ConocoPhillips has just over 10 percent of that field, which is expected to cost $29 billion to develop.

The company also expects authorization of major projects in Alaska, China and the United Kingdom this year.

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

● NORTH AMERICA

TransCanada pounces on weakened U.S. natural gas pipelines

Firm stands to open direct link to California if deal goes through

By GARY PARK

Petroleum News Calgary Correspondent

TransCanada has carved itself a direct link to the huge California natural gas market by negotiating a US$1.7 billion purchase of U.S. pipelines with combined capacity of 3.6 billion cubic feet per day. If the transaction with a unit of troubled PG&E Corp. is concluded, Canada's largest gas carrier will lock up a 1,350 mile link from the British Columbia-Idaho border to the Oregon-California line, opening the door to California. A spokeswoman for TransCanada described California as a "high demand market."

The deal, including US$500 million of assumed debt, would see TransCanada acquire Gas Transmission Northwest, a Bethesda, Md.-based gas pipeline company, formerly known as Pacific Gas Transmission.

The system can move 2.1 billion cubic feet per day to California and 1 billion cubic feet to the U.S. Pacific Northwest.

Gas Transmission Northwest is a subsidiary of National Energy & Gas Transmission, which in turn is a unit of PG&E, one of the largest U.S. energy utilities that has been unloading assets since last July to pay down debt after filing for Chapter 11 bankruptcy protection along with several sister companies.

With a stable of coveted pipelines on the market, there is a long list of prospective buyers, including Nebraska-based billionaire Warren Buffet. The deal for Gas Transmission Northwest needs U.S. bankruptcy court approval, which TransCanada expects within 75 days.

National Energy & Gas Transmission is obliged to wait for better offers, which TransCanada would have the right to match. If another bid is accepted, the Calgary-based company is entitled to a break fee and reimbursement of expenses.

Robert Hastings, an analyst with Raymond James, told the Globe and Mail that TransCanada has a good chance of wrapping up the deal, given that the break fee involved would make it difficult for a rival to trump the offer.

Other analysts said TransCanada has learned from its past mistakes when it bought operations that were geographically and strategically distant from its core.

In addition to the pipeline business, National Energy & Gas Transmission has more than 7,300 megawatts of generation including a mix of natural gas, coal/oil, hydroelectric, waste coal and wind power at many plants across the United States.

The package also positions TransCanada to acquire the 80-mile North Baja pipeline, which has capacity for 500 million cubic feet per day from Arizona to the Mexico-California border. That sale is subject to a right of first refusal by another firm.

Since the collapse of several major U.S. pipeline firms, TransCanada has been biding its time, weighing the available options.

The Canadian firm said its acquisition war chest includes C$1.35 billion and US$650 million of debt and/or equity issuance capacity remaining under its Canadian and U.S. shelf prospectuses.

However, it may consider selling some assets within its existing portfolio to finance the Gas Transmission Northwest purchase.

With 24,900 miles of gas pipelines, TransCanada has a market capitalization of C$12.9 billion. It posted sales last year of C$5.3 billion.

The company also owns, controls or is building 4,700 megawatts of power and is a key player in proposed pipelines from the North Slope and Canada's Mackenzie Delta. ●

NORTH AMERICA

U.S. pipeline backs oil sands outlook

California-based Pacific Energy Partners has issued a strong endorsement of Alberta's oil sands future by acquiring one Alberta pipeline system and setting itself up to buy a second. If the deals announced Feb. 24 go through, Pacific Energy will be able to offer an integrated connection from Edmonton to the PADD IV Rocky Mountain refineries that it currently serves.

It will pay C$156 million for BP Canada's 800-mile Rangeland system, including an 85,000 barrel-per-day trunk line from southern Alberta to the U.S. border at Montana. A letter of intent has been signed with Imperial Oil to acquire the 138-mile Mid Alberta pipeline that feeds 50,000 bpd into the Rangeland system.

From the U.S.-Canada border, Pacific Energy operates its Western Corridor System through Montana to Guernsey, Wyo., with refineries in both states.

It roughly parallels the route of the Terasen-owned Express Pipeline from Hardisty, in central Alberta, to Casper, Wyo., where it feeds into Terasen's Platte pipeline to the Wood River, Ill., refining region. Express, which has struggled over the years to fill its 172,000 bpd capacity, is now in such heavy demand that Terasen has accelerated plans to boost volumes to 280,000 bpd by April 2005.

Pacific Energy President and Chief Executive Officer Irv Toole said the Alberta pipelines are part of the partnership's regional development plans in the Rocky Mountains and set up a "unique and strategic opportunity" to take advantage of the expected surge on Alberta's synthetic crude production.

The partnership said "supplies of synthetic crude production, blends derived from synthetic crude oil and displaced conventional Canadian crude oil are increasing as a result of the on-going expansion of oil sands processing in northern Alberta."

It said the potential reserves of 175 billion barrels in the oil sands are important to Rocky Mountain refineries as production in that region is declining and new supplies are needed to meet a rising demand for refined products.

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

● WASHINGTON, D.C.

Alaska gas price support in energy bill

But controversial pipeline measure not expected to survive in energy bill

By LARRY PERSILY

Petroleum News Government Affairs Editor

Not only is the energy bill still alive but at least for a few weeks so is the Alaska natural gas line commodity-risk provision, or price-support guarantee, back in play in the legislation waiting for a vote in the U.S. Senate.

The latest Senate Energy Committee version of the bill includes last year's provision for using federal tax credits to guarantee North Slope producers that if the wellhead value of their natural gas ever drops below $1.35 per thousand cubic feet the federal treasury will chip in penny for penny up to a maximum support of 52 cents per mcf.

The price support would remain at 52 cents, even if the wellhead value drops below 83 cents per mcf.

> *"We are realistic there was previously opposition."*
> **—Chuck Kleeschulte, spokesman for Sen. Lisa Murkowski, R-Alaska.**

The provision, key to taking the $20 billion plunge to building a North Slope natural gas pipeline, according to two of the three major producers, was dropped from the energy bill last fall in a House-Senate conference committee. The House passed the compromise bill but it stalled in the Senate before the Thanksgiving break and has sat there ever since, waiting to gather enough votes for passage.

Senate leaders Feb. 10 released a revised version of the bill, hoping to win more votes than the stripped-down bill will lose. They dropped billions of dollars in tax incentives for energy companies and, perhaps more importantly, the controversial liability waiver for manufacturers of the octane-enhancing gasoline additive methyl tertiary butyl ether, or MTBE.

MTBE liability waiver still a problem

But House leaders have always insisted that the final bill include the waiver to protect MTBE manufacturers in their home states, putting a high hurdle in front of efforts to find a compromise acceptable to both chambers.

"The bad news is a lot of the dynamics around the energy bill have not changed," said John Katz, director of Alaska's Washington, D.C., office. "The supporters of the (MTBE) waiver in the House have shown no sign of changing their position."

Another political reality that has not changed is the opposition of the president and the House leadership to the Alaska gas line commodity-risk provision, Katz said.

Lower 48 gas producers, including those in the president's home state of Texas, have lobbied against the price support for Alaska gas, as have Canadian producers and fiscal conservatives in Congress who don't believe the federal government should take the risk. The legislation does not include a payback provision at high prices, although a 2002 proposal for a different price support mechanism included a payback clause.

"We are realistic there was previously opposition," said Chuck Kleeschulte, spokesman for Sen. Lisa Murkowski, R-Alaska.

No press release on gas line provision

Aware of the strong opposition and the low probability the provision will stay in the final energy bill, the senator's office did not even issue a press release announcing the Energy Committee version includes the price support language.

Kleeschulte explained that the Energy Committee, in its effort to craft a new version of the bill acceptable to enough senators to win passage, simply took the tax provisions of last year's committee bill and rolled them into the new package.

Senators could be voting on the bill sometime in March. Senator Majority Leader Bill Frist, R-Tenn., has calendared the bill for Senate action, meaning all it will take is a simple motion to bring it to the floor when Republican leaders think they have enough votes for passage.

Senate bill includes other gas line incentives

Regardless of the controversy over price supports, there is no vocal opposition to the energy bill's other provisions to encourage construction of the Alaska gas line project. The Senate Energy Committee version includes the same tax credits, accelerated depreciation, federal loan guarantee and expedited permitting as the House-Senate conference committee bill that failed to pass the full Senate.

The trimmed-down Senate committee bill includes $14 billion of tax incentives and direct appropriations to help promote domestic energy production and conservation, although the total is more than the $8 billion the president said he wanted. The House-Senate conference committee version is closer to $30 billion. ●

CANADA

Income trust negotiates C$175 million takeover of Birchill

Shiningbank Energy Income Fund has fattened its portfolio by entering an agreement to take over privately held Birchill Resources for C$175 million.

If the transaction closes next month, the income trust will gain production of 4,600 barrels of oil equivalent per day, approximately 65 percent of it natural gas, with reserves of 2.55 million barrels of oil, 52.3 billion cubic feet of gas and 2.73 million barrels of natural gas liquids. The estimated combined reserves of 13.99 million boe are 21 percent lower than the 17.6 million boe calculated by Birchill's independent engineers.

With 71 percent proven, the reserves have an estimated reserve life index of 8.3 years and will cost C$38,000 per flowing boe.

In addition, Shiningbank will acquire significant development drilling opportunities and 72,300 net acres of undeveloped land in Alberta and Saskatchewan.

—GARY PARK, Petroleum News Calgary correspondent

Vintage Petroleum punished by Canadian reserve write-down

Vintage Petroleum has joined the lengthening list of companies to make a hefty reduction in their Canadian reserves, blaming the write-down for its net loss for 2003 of US$241 million.

The negative Canadian revisions for the Tulsa, Okla.-based company, were 26.3 million barrels of oil equivalent.

It exited 2003 with 3.5 million barrels of oil and 66.7 billion cubic feet of gas, compared with proved reserves a year earlier of 18.5 million barrels and 183 billion cubic feet.

Vintage Chief Operating Officer Bill Abernathy said the company was "disappointed to have to report results such as these, but we felt compelled to do so given the state of our analysis of our fields."

The company said a critical review of all remaining future activities included in its Canadian proved reserve base was performed to revise or re-validate each of them.

Vintage has shrunk its Canadian E&P budget for 2004 to $22 million from last year's $38 million.

Canadian oil output declined to 1.25 million barrels in 2003 from 1.83 million in 2002 and gas production was down to 19.15 billion cubic feet from 29.95 billion in 2002.

Vintage made its entry into Canada in 2001 by acquiring Genesis Exploration for C$740 million, paying C$39,000 per barrel of production. Another reserve decrease was reported by Calpine Natural Gas Trust, a subsidiary of Calpine Corporation, which exited 2003 with proved holdings of 15 million boe, a drop of 14 percent from mid-2003.

But the gas trust expects production to average 6,600-7,200 boe per day in 2004, compared with 5,441 boe per day in the 78 days after it began operations last fall. That target includes gas properties acquired for C$40.5 million in the Peace River Arch area of northwestern Alberta.

The trust has budgeted C$10 million for its current properties this year, including C$7 million for drilling and completions.

—GARY PARK, Petroleum News Calgary correspondent

NEW YORK

U.S. crude price nears highest level since 1990 Gulf War

The monthly average price of West Texas Intermediate crude oil rose 24 cents for March delivery, to $34.37-34.39 per barrel, making it the second highest since the early 1980s according to a Feb. 25 report from Platts, the energy information division of McGraw-Hill. "Not only was the price for March delivery the highest since the first Gulf War (averaged $36.50 per barrel), but the market closed the month particularly strong," said John Kingston, global director of oil at Platts.

At this point, there are few signs on the horizon of a pending decline in prices, Kingston said, noting OPEC is readying a cut in production, demand in the United States remains extremely strong and inventories continue to drop.

"There also have been loading problems in Iraq, as well as a slowing in the rate of production growth there, so hopes that a recovering Iraqi industry would soften high prices for consumers are not coming to pass," he said.

● CANADA

British big on Canada

El Paso purchase 'right in the sweet spot' of BG Group strategy, says CEO; confident Western Canada basin can support drilling for 'many years'

By GARY PARK

Petroleum News Calgary Correspondent

The shifting fortunes of major international players in Canada were reflected in the Feb. 16 deal by British-based BG Group to pay C$455 million for the Western Canadian assets of El Paso.

Formerly British Gas, BG, with interests in 20 countries, has returned to Canada after a decade-long hiatus, certain that the Western Canada sedimentary basin has plenty of potential to meet the U.S. appetite for natural gas.

> *"Gas flows across the border. The North American gas market is one and the same to me."* —Martin Houston, BG

The acquisition is a key piece in BG's strategy to invest in the North American gas market as it returns to exploration and production on the continent.

In 1994, it sold a 53 percent stake in Calgary-based Bow Valley Energy to Talisman Energy, which paid C$1.8 billion for all of Bow Valley.

That deal came a year after the C$1.2 billion sale by British Gas of Consumers Gas, Canada's largest gas distribution unit, to Enbridge.

British Gas privatized in 1998

Those divestitures flowed from the 1998 privatization of British Gas, which was forced at the time to reduce debt and strengthen its British holdings.

In 1997, the company was divided into two entities — BG and Centrica, which bought Enbridge's retail energy services business for C$1 billion two years ago.

Over the past couple of years, BG has signed contracts to accept foreign shipments of liquefied natural gas at U.S. terminals by acquiring a large LNG facility in Louisiana, spent US$127 million to buy capacity and contracts at the Elba Island terminal in Georgia and plans to open a terminal in Rhode Island by 2005.

Martin Houston, president of BG's North American division, said gas demand is surging across North America at a time production is shrinking, so BG is eager to dig out other buying opportunities in Canada.

"Gas flows across the border," he said. "The North American gas market is one and the same to me."

He said the El Paso properties, covering 725 square miles in Alberta and British Columbia, of which 90 percent is undeveloped, are "right in the sweet spot of our group strategy. We bought (El Paso Oil and Gas Canada) for its upside and its growth potential."

The purchase price includes 132 billion cubic feet of gas equivalent in proved reserves, about 84 percent of them natural gas, with production of 80 million cubic feet per day of gas and 1,100 barrels per day of oil by the end of 2003. Since then the gas volumes have grown to 90 million cubic feet.

The package also includes valuable seismic surveys and tax pools that would allow BG to reduce future taxes.

see BRITISH page 7

● WASHINGTON, D.C.

Big energy companies had a bad year in 2002

Slim refining margins cut income sharply, U.S. Energy Information Administration report shows

By ALLEN BAKER

Petroleum News Contributing Writer

In the roller-coaster world of the oil industry, 2002 was not a good year. For the 28 biggest U.S. oil companies, net income was $20.6 billion, a decline of 45 percent from their $37.7 billion in earnings for 2001. It was also just 39 percent of the $53.2 billion those companies earned in 2000, the industry's peak year.

The new report from the Energy Information Administration gives a comprehensive look at what went wrong for oil firms in 2002, before the turnaround in the industry last year.

With stable and higher prices in 2003, profits rebounded to the extent that ExxonMobil alone made $21.5 billion — more than all 23 companies made the year before, when the oil giant still collected more than half of the profits for the entire group.

Supply and demand

The 2002 compilation is a reminder of what a relatively small change in worldwide energy supplies can do to prices and profitability.

"The primary explanation for the steep decline in net income was the excess supply of petroleum (crude oil and refined products) at the beginning of 2002 that squeezed refining margins … for most of 2002," the report says.

"Beginning-of-year petroleum inventories in 2002 (excluding government stockpiles) among the industrialized nations of the Organization for Economic Cooperation and Development were near a 5-year maximum," the report notes. In the United States, stocks of motor gasoline, distillate fuel and crude oil were at the top of their ranges. Natural gas in working storage in the United States opened the year at the highest level since 1990."

All that took a while to work out of the system, and downstream operations bore the brunt.

Refining and marketing income plummeted in 2002, with the 23 companies showing a loss of about a third of a billion dollars that year from downstream operations, compared with a profit of $12.8 billion the year before. That accounted for two-thirds of the decline in net income for the companies that year.

Natural gas glut

There was also a glut of natural gas in the first half of 2002, the report notes. That seems like ancient history now, with tight supplies in North America and increasing imports of liquefied natural

see COMPANIES page 7

● CANADA

Terasen puts damper on trust conversion talk

Company examining various options to monetize assets; trust would generate cash for pipeline expansion plans

By GARY PARK

Petroleum News Calgary Correspondent

Vancouver-based Terasen has doused rumors that it is about to spin off a large stake of its natural gas distribution unit into an income trust.

Canada's third largest pipeline company is in no hurry to place some of the assets from a unit worth about C$1.7 billion into a trust, said Chief Executive Officer John Reid.

The partial conversion has been the subject of intense speculation, which, Reid said, "gave an unfortunately strong weighting to the likelihood of us doing in the near term an income trust relative to the utility assets."

He told a conference call that Terasen management is examining various options to "monetize existing assets," but it is a "large stretch" to suggest a trust deal is imminent.

A month ago Reid said creating a trust would be do-able "if the need arises," while Treasurer David Bryson said a trust was among "a number of fairly significant investment opportunities we are pursuing."

A trust would generate cash for the parent company's aggressive expansion plans, which include a decision to proceed with a two-phase expansion of its Trans Mountain pipeline from Alberta to the Pacific Coast, adding 280,000 barrels per day to capacity, and a possible C$1 billion crude oil pipeline from Fort McMurray, the heart of Alberta's oil sands region, to the company's Edmonton hub.

Terasen is working on plans to give oil sands producers greater access to Washington state and California refineries as well as Far East markets.

Depending on negotiations with oil sands producers, there could be a three-stage construction totaling 640,000 bpd and costing C$2.1 billion.

Fierce rivalry between Terasen and Enbridge

It's all part of a fierce rivalry between Terasen and Enbridge to become the dominant shipper of oil sands production.

Terasen posted earnings in 2003 before non-recurring items of C$136.1 million, compared with C$105.8 million in 2002, while Enbridge's earnings for last year were C$667.2 million, up from C$576.5 million.

Credit Suisse First Boston analyst Dominique Barker recently described Terasen as the "most focused pipeline company in Canada," forecasting a jump in net income from its pipeline operations to C$92 million by 2007 from C$29 million in 2002.

Deliveries on the Trans Mountain Canadian mainline averaged 216,100 bpd in 2003 compared with 201,200 bpd in 2002, while its U.S. mainline rose to 54,600 bpd from 47,800 bpd.

Reid also announced that Terasen will build an LNG gas storage plant on Vancouver Island by 2007 at a cost of up to C$180 million in support of the gas-fired generation strategy of BC Hydro.

If the 1 billion cubic foot plant proceeds it will replace the controversial C$180 million Georgia Strait Crossing gas pipeline that has National Energy Board approval, but has been heatedly opposed by several environmental groups.●

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COMPANIES

gas expected to supply significant amounts of U.S. demand going forward.

But gas prices slumped to $2.35 per thousand cubic feet in January of 2002, down 66 percent from the wellhead price the previous January. For the year as a whole, gas yields averaged $3.07 per thousand cubic feet, a decline of 23 percent from the 2001 average. There went $4 billion in upstream profit for the companies.

On the oil side, revenues declined slightly as volumes slid 4 percent while the average U.S. wellhead price rose 2 percent. Lifting costs changed little in 2002, with a small decline in the United States offset by a small increase in foreign operations.

The demise of Enron didn't help 2002 numbers either. The companies' take from energy trading, electric power, and so on moved from a positive $2 billion to a loss of $1.5 billion as Williams, ChevronTexaco and other companies were caught in the Enron fallout.

Less investment

Capital spending by the 28 companies on the Energy Department list slid to $98 billion in 2002, from $110 billion in 2001. That was a decline of 9 percent overall from 2001's record figure.

But the difference wasn't across the board. Canadian spending slid 37 percent that year and onshore U.S. investment dropped 17 percent, though that category still remained the largest. The Gulf of Mexico remained a favorite target, so offshore spending stayed about even with 2001.

Outside the United States, instability in Venezuela apparently put a dent in spending in South America, as exploration and development spending in that category dropped 43 percent. But the companies added 22 percent to their investment in the Asian Pacific region, and spending in the North Sea drove the European figure up nearly a billion dollars, or 19 percent.

Big piece of economy

While the 28 companies studied by the Energy Department represent just a small fraction of the industry, they carry a big share of the load. Those 23 companies accounted for 49 percent of U.S. liquids production, 45 percent of natural gas extraction, and 84 percent of U.S. refining capacity.

Their operating revenues, even in 2002, amounted to $699 billion, or 10 percent of the total revenue for the Fortune 500 largest U.S. corporations.

The group ranges from giants such as ExxonMobil and ConocoPhillips to smaller firms such as XTO Energy and Tesoro Petroleum.

The full report can be found at www.eia.doe.gov/emeu/perfpro/ ●

PITTSBURGH, PA.

Discoveries prompt Union Drilling to order two new rigs for its fleet

Union Drilling, the nation's largest privately held natural gas drilling contractor, has ordered two new rigs for its Appalachian fleet, the company said Feb. 23.

The company said the order was prompted by a series of significant discoveries resulting from horizontal drilling in the Trenton Black River formation in New York and northern Pennsylvania. "This has generated increased demand for rigs with greater capability," Union added.

Union, which currently has several rigs in the area capable of drilling distances in excess of two miles, said it ordered a National Oilwell Model 900 portable rig with 441,000 pounds of hoisting capacity and a GEFCO 185,000 pound capacity rig for operations in the southern Appalachian basin.

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

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BRITISH

BG sees many drilling opportunities

What BG paid was close to the net asset value of C$430 million that Tristone Capital placed on the package, but was seen by some analysts as a premium price.

For all the talk of declining prospects in the Western Canada basin, Houston said the El Paso land gives BG "enough opportunities to support a drilling campaign for many years.

"The very large position of undeveloped oil and gas acreage provides significant opportunities for exploration and development.

"We've spent two years looking at Canada and we've waited very patiently and been very prudent about making our first move," he said.

Canada might also offer long-term LNG opportunities, although that's a distant prospect, he said. ●

ALASKA

BLM issues finding of no significant impact for Alyeska's reconfiguration plan

The U.S. Bureau of Land Management has issued a finding of no significant impacts and a decision record approving Alyeska Pipeline Service Co.'s proposed strategic reconfiguration.

Jerry Brossia, BLM's Office of Pipeline Monitoring authorized officer, said in the Jan. 30 decision, "Based on an analysis of the environmental impacts contained in the attached environmental assessment, I have determined that impacts to the human environment are not expected to be significant and an environmental impact statement is not required…"

Brossia said there would be short-term impacts from the reconfiguration, which includes installation of new equipment and facilities (including replacement of the turbine-driven mainline pumps with electric-driven mainline pumps), new on-site electric power generation facilities and greater automation through upgrades to electrical and control systems. The reconfiguration also includes implementation of a regional center concept for maintenance and oil spill response.

"Impacts associated with the installation and modification of equipment on the existing pump stations would be predominantly negative, but short-term and local," Brossia said. But the long-term impacts, from the new equipment "would reduce overall environmental impacts of continued operation," he said.

"Air emissions would be reduced, leading to air quality improvements. A reduction in requirements for liquid turbine fuel delivered by truck would likely reduce risk of spills associated with such delivery and would reduce traffic volumes of heavy-duty commercial vehicles." The reconfiguration proposed by the trans-Alaska pipeline owners would "allow the flexibility to adapt to changes" in pipeline throughput, BLM said in its environmental assessment, to respond to "throughput decline, technological improvements, and optimization of support infrastructure and resource utilization."

Alyeska has already received conditional approval for amendments to its oil discharge prevention and contingency plan from BLM and the Alaska Department of Environmental Conservation. Both approvals require the company to update its 2001 screening risk analysis, perform a crude oil fate and transport study and provide a management of change plan to address the transition before it implements any plans.

Alyeska spokesman Mike Heatwole told Petroleum News in early January that the company submitted the strategic reconfiguration plan to the pipeline owners for review and decision at the end of 2003, and hopes for a decision by the end of the first quarter. Heatwole said a strategic reconfiguration proposal for the Valdez Marine Terminal is about a year behind where Alyeska is with the pipeline, and the company will be taking a look at ideas generated for changes at the terminal in the first two quarters of the year.

—**KRISTEN NELSON,** Petroleum News editor-in-chief

● DENVER, COLORADO

Tom Brown looking to unload drilling company

By RAY TYSON

Petroleum News Houston Correspondent

Denver-based independent Tom Brown, which saw its 2003 fourth-quarter profit jump nearly 250 percent versus the same period a year earlier, said it wants to get out of the drilling business and focus entirely on exploration and production.

Tom Brown said Feb. 19 that it has retained investment bank Petrie Parkman to advise the company on the sale of its wholly owned subsidiary Sauer Drilling, which Tom Brown bought in 1998 to maintain a drilling program on the Wind River Indian Reservation in Wyoming.

"The business has been performing very well," said Jim Lightner, Tom Brown's chief executive officer. "However, owning drilling rigs is not the core business of Tom Brown."

Based in Casper, Wyo., Sauer operates nine drilling rigs with average depth ratings of 5,000 to 16,000 feet and drawworks ratings from 500 to 1,500 horsepower. Sauer had five rigs when Tom Brown bought the company.

Today, only two of the 20 Tom Brown-operated rigs are company owned.

"Our manpower and capital resources are better focused on growing our reserves and production than on running a drilling company," Lightner said, adding that Tom Brown is confident it would be able to contract with Sauer or other contractors to meet its drilling needs.

Fourth-quarter profits soar

On the strength of increased production and strong commodity prices, Tom Brown's 2003 fourth-quarter profit soared to $25.5 million or 54 cents per share, compared to $7.4 million or 18 cents per share in the year-ago period.

The company attributed the earnings surge specifically to acquisitions, development drilling and exploration. "This resulted in record production, earnings, discretionary cash flow and reserve additions," Lightner said.

Helping the company's cause in the 2003 fourth quarter was last June's acquisition of independent Matador Petroleum, which boosted Tom Brown's reserves and production. Compared to the 2002 fourth quarter, Tom Brown posted a 37 percent increase in average daily production to 309.2 million cubic feet of gas equivalent.

Separately, Tom Brown reported year-end 2003 proved reserves of 1.137 trillion cubic feet of gas equivalent, a 52 percent increase over year-end 2002 reserves of 750 billion cubic feet of equivalent. The company said it replaced 521 percent of its production last year.

The company's discretionary cash flow in the final quarter of 2003 was $82.1 million, an increase of 90 percent from the $43.1 million in the corresponding period of 2002. Tom Brown's results for the recent quarter did include a pre-tax $7.8 million charge for the impairment of value on oil and gas properties at the company's James Lime play in East Texas. ●

HOUSTON, TEXAS

Southwestern Energy planning 2004 boost in exploration spending

Southwestern Energy Co. is increasing its capital investment program to $203.5 million this year, up from $180.2 million in 2003. The bulk of the investment — $194 million — will go into the E&P segment.

The 2004 program includes 180 wells and is weighted heavily toward development drilling, according to executives in the Houston-based company. East Texas will get $111 million in drilling money and the Arkoma basin more than $44 million.

Southwestern had profits of $48.9 million for the year, and predicts 2004 earnings will be in the range of $69 million to $72 million. That estimate is based on New York pricing of $5 per thousand cubic feet of gas and $26 for a barrel of oil.

"We plan to accelerate development of our Overton field in East Texas by drilling 70 wells" this year, says Harold M. Korell, president of Southwestern Energy. "We also plan to drill over 80 wells and perform 95 workovers in the Arkoma basin."

Southwestern produced the equivalent of 41.2 billion cubic feet of gas last year, up just a bit from 40.1 bcfe in 2002. It predicts a bigger gain in 2004, in the range of 47.5 to 50 bcfe.

The company added 145 billion cubic feet of equivalent to its reserves in 2003, bringing that total to 503 bcfe. The company replaced 351 percent of 2003 production at a finding and development cost of $1.18 per thousand cubic feet of gas equivalent.

Southwestern had profits of $48.9 million for the year, and predicts 2004 earnings will be in the range of $69 million to $72 million. That estimate is based on New York pricing of $5 per thousand cubic feet of gas and $26 for a barrel of oil.

Southwestern ranked 69 in the Petroleum News' Top 70 report for North American E&P spending and was number 52 in U.S. expenditures in 2002, when its capital spending totaled $85 million.

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

HOUSTON, TEXAS

Hybrid Auction to offer 980 U.S. oil and gas properties

The next so-called Hybrid Auction, in which participants can bid on U.S. oil and gas properties from the floor or via the Internet, is scheduled for March 10 at the Sheraton North Hotel in Houston, Texas, according to The Oil & Gas Asset Clearinghouse, the auction's sponsor.

Some 980 properties combined into 143 lots will be offered. The properties are in Arkansas, Kansas, Louisiana, Mississippi, Montana, New Mexico, North Dakota, Oklahoma, Texas and Wyoming. Sellers include major ExxonMobil and independents Range Resources, Britnic Oil & Gas, Premier Energy, Raven Resources, Ward Petroleum and Tulsa Energy Partners.

Properties for the auction can be previewed online through Data Room Explorer on the Clearinghouse website, www.ogclearinghouse.com. Prospective bidders can search for properties based on specific criteria and view all supporting information such as property data sheets, production reports and lease operating statements.

Data rooms, including complete files for most of the notable properties, will be open through March 5. An appointment can be scheduled by calling Clearinghouse at 281-873-4600. A pre-sale conference will be held from 8 a.m. to 5 p.m. March 9 at the Sheraton, and all seller files will be available for review.

—RAY TYSON, Petroleum News Houston correspondent

FORT WORTH, TEXAS

City looking to lease land for gas exploration and development

The city of Fort Worth is looking to cash in on its subsurface wealth — a piece of Barnett Shale, an unconventional East Texas play containing trillions of cubic feet of potential natural gas reserves.

Doug Rademaker, director of the city's engineering department, told the Star-Telegram last month, "Our goal is to have our first gas well this summer, and by late summer, we could be producing."

The city council has hired Bank One to manage the site selection, leasing and contracting process. Revenues generated from leasing and production would go into the city's general fund, which pays for services such as police and fire protection and code enforcement. Bank One will receive a percentage of those revenues as payment for its services. Currently, Bank One is reviewing Fort Worth's potential gas properties. Those that have generated the most interest from E&P companies to date include tracts near the Alliance Airport, Meacham Airport, the Village Creek Wastewater Treatment Plant, the Fort Worth Nature Center and Buck Sansom Park, the Star-Telegram reported.

Dot Kent, interim public information officer for Fort Worth, told Petroleum News Feb. 26 that the next step will be to finalize site selection, which she said "won't be quick. Bank One has to look at a number of issues including environmental and neighborhood concerns, making sure we are doing everything correctly" and the site selections have to be approved by the city council.

"After that, the sites will go out for competitive bids," Kent said.

● ALASKA

Bill aims to finalize Alaska land transfer

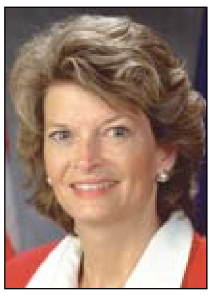
Sen. Murkowski pushing bill that would speed land transfer of 89 million acres from federal government to state, Native corporations

By PATRICIA JONES

Petroleum News Contributing Writer

Alaska's senators in Washington, D.C., have proposed legislation designed to speed up the process of transferring from the federal government lands due to the state of Alaska, to Alaska Native corporations and for individual Native allotments.

Senate Bill 1466 lays out procedures for the Bureau of Land Management to complete surveying and final title transfer of 89 million acres of land in Alaska. Of that, roughly 60 million acres will go to the state of Alaska, part of its 104-million acre entitlement allowed under statehood.



"Under current law and procedures we are at least 20 years from seeing these conveyances complete. And some estimates are that it might take 85 years or even another 300 years to complete the conveyances." — Sen. Lisa Murkowski, during a Feb. 12 hearing on the bill, heard by a subcommittee of the Senate Energy and Natural Resources Committee

The remaining 29 million acres will go to Alaska Native corporations, the remaining land due of the total 44 million acres given under the 1971 Alaska Native Claims Settlement Act.

Competing claims to lands, many selected for mineral potential, has slowed the process. Sorting out those conflicts and then completing final survey work has been part of the holdup.

"Under current law and procedures we are at least 20 years from seeing these conveyances complete. And some estimates are that it might take 85 years or even another 300 years to complete the conveyances," said Sen. Lisa Murkowski, during a Feb. 12 hearing on the bill, heard by a subcommittee of the Senate Energy and Natural Resources Committee.

Murkowski and Alaska's senior senator, Ted Stevens, proposed the legislation that includes technical changes to resolve problems in the land transfer process, an attempt to complete the state's land selections before Alaska's 50th anniversary of statehood in 2009.

"The federal government now has management jurisdiction over about 63 percent of the state. It is long past time to transfer these public lands from Federal to state and private ownership," Murkowski said during the hearing.

Some clarifications on the bill are being considered and a final vote within the subcommittee of Public Lands and Forests is expected mid-spring, according to Chuck Kleeschulte, a Murkowski staff assistant.

see TRANSFER page 10

Kaktovik land claims still outstanding

Among the myriad of technical changes designed to resolve some land transfer issues in Alaska, Sen. Lisa Murkowski's proposed land conveyance acceleration act would settle a long-standing specific issue involving the Kaktovik Inupiat Corp.

The Alaska Native corporation would gain clear title to the last of the 2,000 acres of land it is entitled to under the Alaska Native Claims Settlement Act and under a 1983 land trade in the coastal plain of the Arctic National Wildlife Refuge.

Murkowski noted twice in a press release that the bill would not permit oil development on the Native inholding inside the "1002" area of ANWR unless Congress approves oil development on the coastal plain.

Initially, the senator's staffers said no surface development on those Native lands would be allowed. Additional inquiries produced a different scenario for surface use.

"They would be able to use the land for any purpose, excluding oil and gas exploration," Chuck Kleeschulte, a Murkowski staffer, told Petroleum News Feb. 24.

That seemed to surprise leaders of Kaktovik Inupiat Corp., a Native corporation headquartered in the village of Kaktovik on Alaska's north coast.

see KAKTOVIK page 10

TEXAS/ISRAEL

Noble launches Israeli production

Houston-based independent Noble Energy has begun its first natural gas deliveries to Israel Electric Corp., the company said Feb. 23. The gas is being supplied from Noble's Mari-B field, off Israel's coast, to Israel Electric for use in its electric power plants throughout the country.

Noble said Israel Electric converted its first steam boiler to natural gas resulting in the sales of about 35 million cubic feet per day.

Noble said Israel Electric converted its first steam boiler to natural gas resulting in the sales of about 35 million cubic feet per day. This year the utility plans to convert three more boilers and a turbine to natural gas. That will result in ultimate gross production of 170 million cubic feet, 70 million cubic feet net to Noble under an 11-year take-or-pay contract with Israel Electric to supply 636 billion cubic feet of gas.

Noble is project operator with a 47.059 percent working interest. Avner Oil Exploration Limited Partnerships holds a 23 percent stake. Delek Drilling Limited Partnership holds a 25.5 percent share, followed by Delek Investments and Properties with a 4.441 percent interest. Deliveries to Israel Electric began Feb. 17.

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

● CANADA/KAZAKHSTAN

No let up in legal battles for PetroKazakhstan

By GARY PARK

Petroleum News Calgary Correspondent

PetroKazakhstan's adventures and misadventures in the former Soviet republic of Kazakhstan continued unabated.

The latest blow occurred Feb. 17 in a legal tussle with Kazakhstan's anti-monopoly agency, which claimed the Calgary-based company received US$91 million in "unjustified revenues" from its 11 oil fields, refinery and pipeline.

In two earlier scraps, the Kazakh agency tried to collect $6.3 million in October, which was reduced to $1 million by a court, and $31 million in November, which was thrown out by the court.

The initial charges involved allegations that farmers were overcharged for diesel fuel during the fall harvest season. The later claim spread to gasoline and other refined products.

In the latest appearance, a court in the Kazakh capital of Astana upheld the competition agency's claim that PetroKaz distributors made excessive profits.

That ruling, too, will be appealed, said PetroKaz Vice President of Investor Relations Ihor Wasylkiw.

"These allegations are unfounded and there's no legal basis to them," he said.

"We continue to operate under the laws of the land and we will continue to have dialogue with the politicians, but the courts will take their course."

He said PetroKaz petroleum prices are consistent with world prices, with imports from Russia and with gasoline produced by Kazakhstan's two other refineries.

PetroKaz said in a statement that what it charges for gasoline at its branded service stations are "generally the lowest in every city where they are present."

The company's stock fell 2.5 percent on word of the on-going legal wrangle, having earlier made a gain following the appointment of former Canadian Prime Minister Jean Chretien as special advisor to PetroKaz. But, despite Chretien's reputed international negotiating skills, PetroKaz is uncertain what, if any role he will play.

"We will use any and all resources at our disposal," Wasylkiw told the Globe and Mail.

Wilf Gobert, an analyst with Peters & Co., told reporters that any suggestion PetroKaz has overcharged by $91 million is "ludicrous," accusing the Kazakh bureaucrats of taking a heavy-handed approach to scare PetroKaz into submission.

He applauded PetroKaz for its refusal to be bullied, saying the alternative would be unrelenting harassment. ●

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KAKTOVIK

"We're wondering where we can select from," said Adam Lyn, the corporation's manager. "If we select in ANWR, what good is it?"

The corporation has 90,000 acres of land on the coastal plain, stretching south into the Brooks Range, said Eve Ahlers, Kaktovik Inupiat chairwoman. Restrictions on using its Native land have made it difficult for the corporation.

"We're struggling to survive. We have to wheel and deal just to keep the corporation going," she said. "They restrict us on what we can do with the land."

Both Lyn and Ahlers were surprised to hear that the corporation would be allowed surface development of the 2,000 acres of ANWR lands. "That's the first I've heard of it," Ahlers said. "We'll have to do a little more checking."

For the record, Ahlers approves of oil and gas development. "First and foremost, we're hoping for ANWR to be opened. That's our priority," she said.

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

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TRANSFER

Additional funding

To aid in the land conveyance work, Murkowski sought an additional $15 million for fiscal year 2004. Of that, $9.5 million was approved, giving federal agencies a total of $46.5 million to fund land conveyance issues.

Most of that money goes to the Bureau of Land Management, Kleeschulte said, primarily to complete cadastral surveys of selected lands. Some of the money contributes to agency overhead expenses in Alaska.

"They really need $52.5 million over the next five years to complete the survey work," he said.

Federal funding for Alaska's land conveyance issues has been about $37 million annually for "a number of years," he added.

Environmental groups' concern

One potential land transfer addressed by environmental groups testifying during the hearing is really a "non-issue," Kleeschulte said.

That involves the final selection and transfer of 2,000 acres of land to the Kaktovik Inupiat Corp., due under the Alaska Native Claims Settlement Act and under a 1983 land trade in the coastal plain of the Arctic National Wildlife Refuge.

While the bill would complete the complex land trade, it would not permit oil development on the inholding inside the 1002 area of ANWR unless Congress approves oil development from the coastal plain.

Other types of surface development by the Native corporation would be allowed, Kleeschulte said.

Testimony during the hearing from environmental groups centered around concern that the land transfer might somehow open the area to oil development, he added.

Mining industry support

Also complicating the process are some mineral rich lands that were withdrawn in past years by federal orders, which have now expired, said Steve Borell, executive director of the Alaska Miners Association, an industry group that supports the bill.

"All across Alaska there are lingering withdrawals of various types," he wrote in testimony submitted to the subcommittee. "The amount of land covered by the lingering withdrawals has been estimated to be possibly several millions of acres. What is known is that some of the lands … have high potential for minerals and have been selected by the state of Alaska and/or Native corporations."

He requested that the bill include provisions to deal with those lingering withdrawals, where the original intent has been satisfied but the land has not become available for state or Native selection.

"First, the existing Public Land Orders must be 'revoked' and then the lands must be specifically 'opened' to appropriation under the public land laws," Borell wrote. "Furthermore, these lingering withdrawals must be removed at the earliest possible date so the state can evaluate and compare these lands with its other selections to ensure that the highest value lands are conveyed to the state. This is especially true given the restrictive time limitation required for final prioritization."

Both the Alaska state Legislature and the BLM Alaska Resource Advisory Council have passed resolutions calling for removal of the lingering land withdrawals, he added.

"In the nearly 23 years since passage of ANILCA (the Alaska National Interest Lands Conservation Act), this is the first time there has been an opportunity to address the issue of these obsolete/lingering withdrawals. Without addressing these withdrawals, S.1466 is of only marginal value," he wrote. ●

WYOMING

BLM allows more exploratory drilling north of Baggs

More exploratory drilling for natural gas is being allowed along the Atlantic Rim north of Baggs, Wyo.

Warren Exploration and Production, Double Eagle Petroleum Co. and Anadarko Exploration and Production are proposing to drill 24 wells to see if the area holds commercially viable amounts of gas.

Two injection wells are also planned to dispose of water that must be pumped off coal seams to draw off the gas. Other water might be used for livestock watering.

Sixteen wells will be drilled on Bureau of Land Management land. The other eight are proposed for private land to develop privately owned gas. Kurt Kotter, manager of the BLM Rawlins Field Office, concluded that the drilling would cause no significant environmental harm. The wells would be drilled over about a year.

The project is one of nine groups of wells to be developed to produce data for a massive environmental study the BLM is developing on potential gas drilling.

—THE ASSOCIATED PRESS

WESTERN NORTH SLOPE

State of Alaska begins Alpine satellite project review

The Alaska Department of Natural Resources' Office of Project Management said Feb. 23 that it has begun its review of ConocoPhillips Alaska's Alpine satellite development project. Comments are due March 23.

The Bureau of Land Management said Feb. 25 that it is extending the comment period on the Alpine satellite development plan draft environmental impact statement by a week. That comment period now ends March 8.

—PETROLEUM NEWS

NORTH AMERICA

Weekly rig count falls by nine

The number of rotary rigs operating in North America dropped by nine to 1,688 rigs during the week ending Feb. 20, rig monitor Baker Hughes reported.

Canada lost a dozen rigs to end the week with 574 rigs, still up by 16 compared to the same period a year earlier.

The United States gained three rigs to end the week with a net 1,114 rigs compared to the previous week, and the count was up by 186 versus the year-ago period. The land rig count slipped by one to total 994 rigs, while the offshore increased by three to 100 rigs. Inland waters picked up one rig for a total of 19.

Of the total number of rigs operating in the United States, 954

see **RIG COUNT** page 12

● CANADA

Oil sands a 'sound' bet

Drive Canada to new crude oil production high in '03 and are poised to grow even more because of expected 50% rise in global demand by 2020

By **GARY PARK**

Petroleum News Calgary Correspondent

Canadian crude oil production grew by 5.5 percent in 2003, bolstering an investment dealer's view that the Alberta oil sands are the place to invest.

Statistics Canada, a federal government agency, reported Feb. 23 that the year-over-year oil output climbed to 2.49 million barrels per day from 2.36 million bpd in 2002.

Propelling the increase was a 6.1 percent rise in Alberta's crude bitumen volumes to 600 million barrels, or 1.64 million bpd, and a 16.4 percent jump in offshore Newfoundland production to 121.4 million barrels, or 332,595 bpd.

The balance came from British Columbia, Saskatchewan, Manitoba and the Northwest Territories.

"With continued strong demand from the U.S., Canadian crude oil exports grew 5.5 percent over 2002," with exports accounting for 62.1 percent of Canada's total crude oil and equivalent production.

But natural gas experienced a sharp setback because of problems finding new reserves, despite robust commodity prices that averaged US$5.49 per million British thermal units, more than double the long-term norm.

Output dropped 3.8 percent to 16.04 billion cubic feet per day, the first drop since 1986, and exports to the United States nose dived 5.6 percent to 9.83 billion cubic feet per day, StatsCan reported.

Canada also posted a 3.1 percent increase in oil imports to Eastern Canadian refineries, with Norway, the United Kingdom and Algeria accounting for 64 percent.

December oil up, gas down

StatsCan said December production of crude oil and equivalent averaged 2.62 million bpd, up 7.3 per-

see **OIL SANDS** page 12

● MATANUSKA-SUSITNA BOROUGH, ALASKA

Evergreen waits on results from Alaska core holes

By **KRISTEN NELSON**

Petroleum News Editor-in-Chief

Alaska was a topic of some interest at the Evergreen Resources fourth-quarter conference call Feb. 19.

The Denver, Colo.-based independent has a substantial coalbed methane development in the Raton basin, and is testing to determine if coalbed methane can be developed commercially on its Alaska acreage.

Evergreen had a $7 million capital budget for Alaska in 2003, but has budgeted only $2.3 million for Alaska in 2004, $1.5 million in the first quarter, $700,000 in the second quarter, $100,000 in the third quarter and zero in the fourth quarter.

The company is drilling five core holes to evaluate coalbed methane potential on its Alaska acreage, 300,000 acres in the Matanuska-Susitna Borough north of Anchorage.

JUDY PATRICK

Mark Sexton, president and CEO, Evergreen Resources

Evergreen said in its Feb. 18 fourth-quarter results statement that it is drilling the five stratigraphic cores on its Alaska acreage "to obtain additional petrophysical data, including information on coal quality and gas content." Based on results, the company said, it "will determine potential locations for additional core holes or multi-well pilots."

"In Alaska, we've reduced the cost of the five stratigraphic wells we plan to drill in 2004 … to about $2.3 million," Kevin Collins, the company's chief financial officer, told the conference call.

Mark Sexton, Evergreen's president and chief

see **EVERGREEN** page 12

continued from page 11

EVERGREEN

executive officer, said that "given our inability to acquire the data we want in Alaska and Kansas, we've simply decided to scale back the operations until we have the data necessary to go forward as bullishly as we had originally projected."

Sexton said that in Alaska the company has "had requests from the administration, the regulators and the legislators, to go slowly while they work out the new rules in Alaska and we've agreed to accommodate them and we're going out and getting the geologic data that's necessary for us to be more aggressive about where we want to drill in the future on the 300,000 acres approximately that we have under lease in Alaska."

He said Evergreen had to set surface casing first at the core holes, through the glacial till zone, to assure regulators and residents that there would be no contamination of local water well or water supplies.

Drilling the core holes is "going slow," he said, with about a half of the first hole completed by Feb. 19.

"But once we have those five cores, we will evaluate them … get the geophysical and petrophysical data analyzed, and figure out where" the company will drill next, Sexton said, adding that he expects to know something by the end of the year.

He said Evergreen is using an experienced drilling contractor in Alaska to drill the core holes. But, he said, if the company goes "into full development mode, given how slow things are going, we'll probably have to purpose build equipment … specially designed for Alaska's geology." ●

● CANADA

Going green in Canada

Suncor, Husky reinforce leading roles in ethanol production; plants will produce combined 330 million liters a year

By GARY PARK

Petroleum News Calgary Correspondent

Two of Canada's leading developers of bitumen and heavy oil are also leading the way into a greener future.

Suncor Energy and Husky Energy have stepped up their ethanol programs — Suncor with plans for a C$120 million plant at Sarnia, Ontario, and Husky with a C$90 million-$95 million plant near its heavy oil upgrader at Lloydminster, Saskatchewan.

Suncor will receive C$22 million in federal money for its plant, which is expected to produce 200 million liters a year to be blended into gasoline sold through its Ontario retail stations by about mid-2006.

Already, Sunoco-branded gasolines contain 9.8 percent ethanol, making the company Canada's largest user and marketer of ethanol.

Husky, the smallest of Canada's integrated oil companies, plans Western Canada's largest ethanol facility that will come on stream by late 2005 and produce 130 million liters a year.

"Husky Energy is committed to continually improving fuel quality and expanding its operations to meet consumer demand," President and Chief Executive Officer John Lau told a news conference.

Saskatchewan Premier Lorne Calvert welcomed the investment as a "major step towards our goal of growing the economy and in a 'green' and sustainable way."

He said the facility will provide a new outlet for Saskatchewan grain farmers, who have been struggling to survive in recent years amid droughts and slumping prices.

Ethanol blending reduces carbon monoxide emissions

Ethanol is produced from grain, corn or wood waste. When added to gasoline it promotes fuel combustion, raises octane levels and prevents fuel line freezing.

The use of the ethanol-blended fuel also reduces carbon monoxide emissions, by as much as 30 percent in Suncor's estimation, and thus net emissions of greenhouse gases.

Suncor is also working on a technology to slash its use of natural gas in converting Alberta's raw bitumen into synthetic crude.

Chief Executive Officer Rick George told an investors' conference in Toronto he hopes to make an announcement within 12 to 18 months on the use of clean-burning coke as well as turning coke into natural gas — two techniques aimed at finding ways to utilize what is described as a dirty fossil fuel, high in sulfur and with a lower energy content than natural gas, without harming the environment.

The coke is a byproduct of the upgrading process in which Suncor extracts carbon from bitumen to create lighter synthetic crude.

In the final quarter of 2003, it cost Suncor C$11.05 to produce a barrel of synthetic oil, of which C$1.60 covered the cost of natural gas. ●

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RIG COUNT

were drilling for natural gas and 155 for oil, while five were being used for miscellaneous purposes. Of the total, 730 were drilling vertical wells, 289 directional wells and 95 horizontal wells.

Among the leading producing states in the United States, Oklahoma gained two rigs for a total of 145, and Alaska picked up two rigs for a total of 12. New Mexico's rig count increased by one to 62, and Wyoming's rose by one to 64 rigs. Texas lost three rigs to total 482, while Louisiana's count fell by three to 165 rigs. California was unchanged at 20 rigs.

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

continued from page 11

OIL SANDS

cent from a year earlier, while marketable gas production decreased 2.2 percent.

The oil sands trend prompted a report from investment dealer Raymond James entitled "Invest in the Oil Sands — High Oil Prices are Here to Stay!"

The Calgary-based authors, John Mawdsley, Jenny Mikhareva and Craig Espey, predicted that prices will hover around US$30 per barrel this year and $32 next year, making the Alberta oil sands a "very sound investment" as the days of huge oilfields and cheap production start to wind down around the globe.

The study said about 60 percent of the world's 93 oil-producing countries have already hit their peak production, notably the United States, where output has dropped to 5.8 million bpd from 9.6 million bpd in 1970.

"It is important to note that the list of countries that are on an irreversible decline will only grow over time; the likelihood of discovering large new pools in established basins is very low," the authors said.

But the study forecasts global demand for crude will grow by 50 percent to 112 million bpd by 2020, or an average 950,000 bpd every year.

No exploration gamble with oil sands

For that reason, Raymond James rates the oil sands as an excellent investment opportunity because there is no exploration gamble, there is a long reserve life and the Alberta government's royalty regime is attractive.

Calgary-based Peters & Co. echoed the Raymond James oil price forecast by raising its target for 2004 to $30 from $27. If the prediction is accurate it will be just the third year on record that the $30 threshold has been surpassed.

But not everyone is clambering on the oil sands bandwagon.

Credit Suisse First Boston issued a recent report entitled "Oil Sands — Not Saudi Arabia," cautioning investors against a high oil sands exposure.

It described those ready to pour billions of dollars into the oil sands over the next decade as suffering from "capital amnesia" for ignoring the recent history of capital cost overruns and production hiccups.

Credit Suisse said it does not believe that 2004 will be the year when "oil sands are finally revealed to be the solution to North America's growing hydrocarbon deficit." ●

● FORT WORTH, TEXAS

XTO takes a bite out of Barnett Shale

By RAY TYSON

Petroleum News Houston Correspondent

It was just a matter of time before fast-growing XTO Energy made a move on the Barnett Shale, an unconventional East Texas play containing trillions of cubic feet of potential natural gas reserves. Barnett also happens to be situated in the company's own back yard near Dallas-Fort Worth.

"Our technical teams have been assessing the long-term viability of the Barnett Shale for the past two years," Steffen Palko, XTO's president and vice chairman, acknowledged Feb. 23. "The areal extent of the shale should allow XTO to build a compelling growth program."

The deal-minded independent wasted little time resuming its acquisition game, just as the company recently promised when announcing its capital spending plans for 2004. Not yet two months into the new year, XTO already had shelled out some $450 million for U.S. oil and gas properties and plans to spend at least another $200 million before year-end.

XTO's latest investments: $80 million for additional properties in the Arkoma basin, a major core area for the gas-weighted company, plus $120 million for a ticket into the prolific Barnett Shale, a play currently dominated by big U.S. independent Devon Energy. XTO did not identify the sellers.

Oklahoma's Devon, which built its huge 545,000-acre Barnett Shale position on the back of its merger with Mitchell Energy, has estimated the Barnett could hold as much as 120 trillion cubic feet of gas reserves, 20 trillion cubic feet of which the company believes may be recovered.

Horizontal drilling economic

The tight nature of shale reservoirs, including the Barnett, has been challenging to producers, in particular the need for wide-scale hydraulic fracturing to create artificial permeability so gas can flow freely. Horizontal drilling has slowly emerged as an economic way of capturing more gas per well.

XTO's 11,000-acre piece of the Barnett includes estimated reserves of 97.6 billion cubic feet of natural gas equivalent, 42 percent of which is proved developed, the company said. The properties currently produce just 15 million cubic feet of equivalent per day, but XTO made it clear that it's in the market for more acreage.

"With years of production data and well assessment, we are now confident in the feasibility of the play," said Bob Simpson, XTO's chief executive officer. "In typical XTO fashion, we have acquired producing properties in the core area of development and plan to expand our position."

"Given the conclusions, our development teams are enthusiastic and committed," added Palko. "Our expertise in horizontal drilling and water-fracturing techniques will find perfect application in developing the Barnett Shale."

XTO said it also expanded it presence in the Arkoma basin of Oklahoma and Arkansas with the purchase of 56.3 billion cubic feet of gas equivalent reserves, 70 percent of which are proved developed. The properties currently produce about 10 million cubic feet of equivalent per day, the company added.

Because of its latest transactions, XTO has increased the company's projected natural gas production for 2004 over 2003 from 16-18 percent to 18-20 percent. "We remain focused on securing more strategic properties through acquisition efforts this year," Simpson said of XTO's overall plan.

Of the roughly 154 billion cubic feet equivalent reserves acquired by XTO in its latest deals, 99 percent is natural gas and 52 percent proved developed. The company said it would allocate $20 million in additional development funds to the new properties, bringing 2004 development expenditures to $520 million.

XTO said it will operate more than 88 percent of the value of the producing properties when the latest transactions close on or before April 15. Financing will be provided through a combination of credit and cash flow from operations, the company said. ●

SAN ANTONIO, TEXAS

The Exploration Co. hits on seven horizontal gas wells at Georgetown

The Exploration Co., a small independent producer based in San Antonio, Texas, said it has recorded seven successful Georgetown horizontal wells in a row, attributing the success to an improved seismic processing technique that better predicts the location of the formation's faults and fractures.

"We have demonstrated that our Georgetown success is repeatable at widely varied locations across the 300,000-acre portion of our lease block containing the play," James Sigmon, the company's chief executive officer, said Feb. 19. He added that the new seismic technique has identified several hundred potential drilling locations.

The Exploration Co. reported year-end 2003 proved reserves of 28.4 billion cubic feet of gas equivalent, a 21 percent increase from 23.5 billion cubic feet at year-end 2002.

The Exploration Co. reported year-end 2003 proved reserves of 28.4 billion cubic feet of gas equivalent, a 21 percent increase from 23.5 billion cubic feet at year-end 2002. "Virtually all" of the increase came via the drill bit, the company said. Fifty-five percent of the company's proved reserves are classified as natural gas and 45 percent oil.

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

● NORTH SLOPE, ALASKA

From experimentation to manufacturing

ConocoPhillips using new technologies, narrowing in on robust well design to produce West Sak heavy oil

By KRISTEN NELSON
Petroleum News Editor-in-Chief

Heavy oil has been "the forgotten big resource in Alaska," but after more than two decades of trying to get it right, North Slope producers are "narrowing in on a very robust design" for producing heavy oil, says ConocoPhillips Alaska's Greg Leveille.

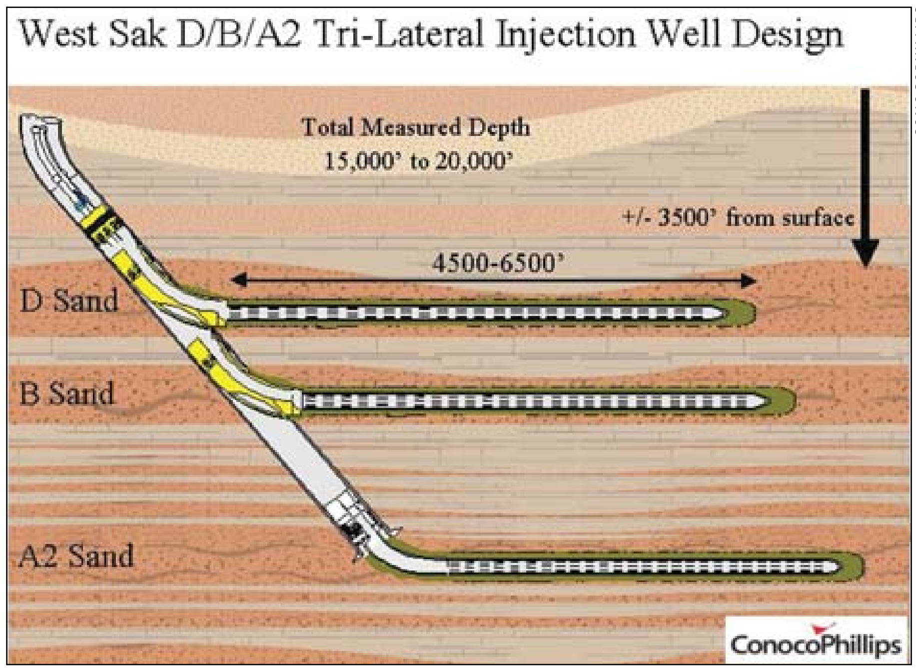
The 25 billion barrel heavy oil resource was discovered in the 1960s and 1970s, Leveille, manager of ConocoPhillips Alaska's North Slope Greater Kuparuk satellites, said Feb. 19 at the annual Pacific Rim Construction Oil Mining Expo & Conference in Anchorage. Heavy oil on the North Slope includes the ConocoPhillips-operated West Sak accumulation at Kuparuk and the BP Exploration (Alaska)-operated Orion and Polaris accumulations at Prudhoe Bay and the Schrader Bluff accumulation at Milne Point.

The reason this heavy oil hasn't been produced is because it doesn't flow easily.

Think of the light oil accumulations as water, Leveille said: you can pour it easily and it flows readily into well bores, with production rates of 5,000 to 10,000 barrels a day.

The best heavy oil, at about 19 degrees American Petroleum Institute gravity, has "about the consistency of cold molasses," he said, while heavier oil, at about 10 degrees API, is more like "warm peanut butter. And that's what we're trying to get out of the ground on the North Slope today."

Because the flow rates for heavy oil are so low, "it's been an economically very, very challenging opportunity to develop," he said.



CONOCOPHILLIPS

First efforts in the 1980s

Efforts to develop heavy oil began in the 1980s, with vertical wells and a "fracture stimulation technique to try to get the oil to move into those wells at a higher rate." Although the companies were using the best science and technology available at the time, they only achieved production rates of a few hundred barrels per day, and with the cost of drilling the wells and fracture stimulating them, "that effort was not economic," Leveille said.

Efforts were made again in the 1990s, but the results were the same: it just wasn't economic.

But in 2000, "we started to employ some different technologies" to drill long lateral wells through producing zones. By drilling hundreds and then thousands of feet "of production lateral, we open up more of the rock to the well bore and that allows the oil to flow" from the reservoir more easily, he said.

In the 2000-2002 time frame, sand-exclusion screens were combined with medium-length laterals and the company got a "marginally economic result," Leveille said. The sand-exclusion screens were an effort to control the formation, because in addition to being slow flowing, heavy oil occurs in formations that are not well consolidated — when oil flows, it brings solids with it.

2003 a transition year

2003 was "a big transition year for us," Leveille said. "We took our moderate-length wells and we turned them into extremely long ones." ConocoPhillips began drilling longer lateral sections through the reservoir, "we opened up all that reservoir rock … (and) for every foot of reservoir rock you open up you get that much more oil."

Sand-exclusion screens were also replaced with a less expensive slotted liner, a "lower-cost type completion, " he said.

With these changes, developing heavy oil became an economic proposition.

As part of its 2003 drilling, ConocoPhillips "set an Alaska record for 11,812 feet of section within the reservoir

see WEST SAK page 17

NORTH SLOPE, ALASKA

Northstar field back on line

BP Exploration (Alaska)'s Northstar field came back on line about 11 a.m. Feb. 22, after going down Feb. 8 when a low-pressure gas compressor motor failed.

BP spokesman Daren Beaudo said Feb. 23 that the field was initially operating at reduced rates of about 40,000 to 45,000 barrels per day "as the wells and facilities warm up after the two-week shutdown." He said it would take Northstar "a few days to reach maximum rates as the plant, pipelines and oil are extremely cold and we need to go slow until everything stabilizes." Replacement equipment was on hand for the motor, Beaudo told Petroleum News Feb. 9, but "because of the compact nature of the island it's a bit like performing surgery." Complex heavy lifts were required to replace the equipment, he said, "and it is critical to do the appropriate planning and execution in order to do the work safely the first time." Beaudo said the replacement work was done safely, with no recordable injuries, even though weather conditions were severe, "often –40 to –50 degrees and blizzard conditions."

Beaudo said the replacement work was done safely, with no recordable injuries, even though weather conditions were severe, "often –40 to –50 degrees and blizzard conditions."

Northstar was designed to produce at 72,000 bpd, and "set a recent single-day record" of 84,931 bpd Jan. 26.

—PETROLEUM NEWS

natural gas

TORONTO, CANADA

Admiral Bay Resources acquires 90% stake in Kansas gas project

Toronto-based Admiral Bay Resources said Feb. 23 that its U.S. subsidiary has taken a 90 percent working interest in the Swordfish gas project located in Chautauqua County, Kan.

The project, situated on 35,000 contiguous acres, was acquired from M & S Methane Development LLC of Denver, Colo., and lies in the heart of the prolific Cherokee Basin and on the edge of the growing coalbed methane development in southeastern Kansas and northeastern Kansas, Admiral Bay said.

There are two shut-in wells on the property capable of producing 200 thousand cubic feet of gas per day, and the wells will be reactivated shortly, the company said, adding Admiral Bay plans to begin developing the acreage as both a conventional oil and gas and unconventional shale and coal gas project. The company said it intends to drill up to five additional wells before the end of June.

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

CALIFORNIA

Ivanhoe farms into gas prospect

Ivanhoe Energy Inc. has an exploration and development deal to farm into acreage in the Sacramento gas basin in northern California. The agreement with Nahabedian Exploration Group LLC was announced Feb. 18.

Ivanhoe is buying an interest in four wells drilled by Nahabedian at its Knights Landing project on a 14,000-acre block in Sutter and Yolo counties, northwest of Sacramento. Ivanhoe, based in Bakersfield, Calif., will build pipelines to the four wells and drill up to 20 added wells for $3.8 million. Its interest will be 50 percent after costs are recovered.

The four wells drilled so far have shown a constricted flow rate of more than 2 million cubic feet daily. Ivanhoe is planning 10 development wells offsetting the four current producers. Ten exploration wells will also be drilled in the block in a program to start in April and run through November.

The wells are expected to cost about $200,000 each, targeting the Starkey Sand formation at depths of 2,000 to 3,500 feet.

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

HOUSTON, TEXAS

Freeport LNG signs deal

Cheniere Energy said Feb. 26 that Freeport LNG Development signed a 20-year terminal use agreement with Dow Chemical for up to 500 million cubic feet per day of throughput capacity at Freeport LNG's proposed liquefied natural gas receiving terminal on Quintana Island, near Freeport, Texas. Cheniere holds a 30 percent limited partnership interest in the development.

Dow has made a firm commitment to take 250 mmcf per day, but has until Aug. 31 to exercise its option on the remaining 250 mmcf.

see **FREEPORT** *page 17*

● NORTH AMERICA

Research group gives upbeat outlook for Canadian gas

Cambridge Energy Research Associates confident northeastern British Columbia will contribute to production turnaround by 2010

By GARY PARK

Petroleum News Calgary Correspondent

Northeastern British Columbia's lively natural gas play holds out hope of reversing the downward spiral in Canadian exports to the United States, Cambridge Energy Research Associates predicts.

In a continental gas supply forecast to 2010, the firm predicted that shrinking output from the Western Canada sedimentary basin will come to an end, given the British Columbia potential of EnCana's plans for Greater Sierra and Cutbank Ridge and Talisman Energy's deep Monkman prospect.

Despite the decline of about 500 million cubic feet per day from British Columbia's once prolific Ladyfern field, which has dropped Canadian output to 16.5 billion cubic feet per day from 17 billion in 2001, Cambridge Energy forecasts 2010 volumes will grow by slightly more than 2 billion cubic feet per day.

It expects Canada's coalbed methane output could grow to 500 million cubic feet per day over the next six years and might even exceed that level.

North American demand surge to 71 bcf by 2010

Cambridge Energy is counting on combined U.S. and Canadian gas demand surging to 71 billion cubic feet per day by 2010 from 62 billion this year, with about 70 percent of that demand growth coming from gas-fired power generation.

The power sector is being driven by investments of US$190 billion over recent years to boost capaci-

see **OUTLOOK** *page 16*

● WORLDWIDE

LNG safety draws attention

Receiving terminals 'very different animals' from Algeria liquefaction plant damaged in blast

By LARRY PERSILY

Petroleum News Government Affairs Editor

While the federal Energy Department expands its study of liquefied natural gas tanker and terminal safety issues, critics of LNG sites near urban areas continue to push for more assurances their communities will be safe from explosion and fire.

The federal study, ordered by Assistant Energy Secretary Mike Smith, will look at the safety risks of a large LNG spill in the water. The department has not given a date for completion of the study, which is an expansion of an earlier report attacked by critics as inadequate and allegedly misused to support permitting of new LNG terminals.

Of the almost 10 sites proposed for the U.S. West Coast and Mexico's Baja Peninsula, Jensen expects just two terminals will be built this decade. And of the more than 20 sites proposed for the U.S. Gulf and East coasts, most industry observers look for just three or four to start operating this decade.

And the Federal Energy Regulatory Commission also is studying LNG spills on water to develop a model for calculating vapor and fire hazards. The report is due in March.

Adding to the safety focus on the nation's rush to build LNG import terminals, a bond rating agency warned of possible higher insurance costs and increased public scrutiny of the industry following a deadly Jan. 19 explosion at an Algeria liquefaction plant that killed 30 people.

Although U.S. natural gas users are looking forward to new supplies from whichever of the more

see **SAFETY** *page 16*

● NORTH AMERICA

Exxon develops new LNG storage tank

Company says modular storage system can save months in construction

By LARRY PERSILY

Petroleum News Government Affairs Editor

ExxonMobil believes its new modular system for liquefied natural gas storage tanks could trim up to a year from construction schedules.

The key to the patented construction system is a rectangular, self-standing storage tank of nickel (9 percent) and steel, "standardized, scalable and pre-engineered for a broad range of design conditions," according to a statement from ExxonMobil Upstream Research Co.

"The technology employs modern shipyard fabrication practices," the company said. "It is modular because of a repeated structural module between the two tank ends that permits a variable length and thus the variable capacity of the tank."

The research company recently licensed the patented technology to U.K.-based Skanska Whessoe, which operates worldwide to design and build LNG storage tanks and terminals.

"(The) design allows it to be constructed off-site, in parallel to the on-site construction of the reinforced, prestressed concrete outer tank," the ExxonMobil statement reported. Both the inner nickel-steel tank and the outer concrete tank are independently capable of containing the stored LNG.

Tanks could hold 200,000 cubic meters of LNG

Contractors could build one of the modular tanks to hold as much as 200,000 cubic meters of LNG, with the company reporting that a standardized version of its storage system to hold 100,000 cubic meters would measure 44 feet wide by 33 feet high by 100 feet long.

The first use of the new technology could come at an LNG receiving terminal ExxonMobil plans for offshore in Italy's northern Adriatic Sea, near Venice.

The terminal, scheduled to open as soon as 2007 to regasify and send out about 800 million cubic feet of gas a day, is a partnership of ExxonMobil (45 percent), Italy's Edison (10 percent) and Qatar Petroleum (45 percent), which will supply most of the natural gas for the facility 10 miles off the Italian coast in 95 feet of water.

Exxon/Qatar in LNG partnership

ExxonMobil said the new storage tanks are among the technological advancements under way for its joint venture projects with Qatar Petroleum, including plans for the world's largest liquefaction trains that would each produce more than 1 billion cubic feet of gas per day from the Middle East nation's giant North field.

Development of the modular tank construction technology started in 1997 at Mobil, and continued after Exxon took over its smaller rival.

"Storage system construction is often on critical path for an LNG receiving terminal," Exxon said. "Parallel construction of the inner and outer tanks can reduce construction time by up to 12 months, with associated cost savings," as opposed to building the two tank structures in succession at the job site. ●

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OUTLOOK

ty by 190,000 megawatts.

North American industrial demand for gas is expected to grow again towards the end of the decade, when the advent of LNG supplies should ease the supply-demand balance, while residential and commercial customers will need only an extra 1 billion cubic feet per day.

For the United States, CERA predicts production declines from the Gulf Coast and Midcontinent, although the Rocky Mountains should increase, especially in the Powder River basin coal seam.

The latest Canadian export numbers show a total for the first 11 months of last year of 3.11 trillion cubic feet, down 9.3 percent from 3.43 tcf in the same period of 2002.

The National Energy Board reported that exports in November alone dropped by 15.6 percent to 269.7 billion cubic feet, while revenues for the month slumped by 21.1 percent to C$1.55 billion.

But the 11-month revenues were C$22.86 billion, up from C$16.05 billion in the same period of 2002, reflecting a jump in average prices to C$6.77 per gigajoule from C$4.34 in 2002. ●

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SAFETY

than 30 proposed LNG receiving terminals eventually are built, the Algeria explosion provided opponents of LNG expansion with a visible reminder of the risks in handling natural gas.

Algeria blast started in boiler

The Algeria blast, however, did not start in the liquefaction equipment but in an ordinary steam boiler separate from the gas processing equipment, according to initial industry reports. The steam boiler explosion set off the liquefaction trains.

But a more recent report carried by Reuters quoted the Algerian Energy minister as saying he was told by insurance experts that gas may have leaked from a cracked pipe and exploded. The Los Angeles Times reported, however, that only small amounts of LNG were stored in the area of the explosion.

Working from the initial accident reports in an effort to reassure nervous residents of proposed LNG sites, industry officials have explained that regasification plants don't include steam boilers.

"There will be a small percentage of people who overreact to the news," said Deborah Resley, a 23-year veteran of the natural gas industry in Texas, England and Trinidad.

Liquefaction and regasification "are very different animals," said Resley, a Houston-based LNG consultant. Liquefaction is a massive refrigerator, chilling natural gas to minus 260 degrees Fahrenheit and turning it into a liquid for shipment aboard insulated tankers at 1/600th its volume as a gas. Regasification terminals allow the LNG to warm up, restoring the methane to its gaseous state.

"Basically, what a regas terminal does is take lumpy deliveries and smooth it out for the pipeline system," Resley explained of handling a tanker delivery of perhaps 150,000 cubic meters of LNG and turning it into more than 5 billion cubic feet of natural gas.

Ratings service warns of higher insurance rates

Fitch Ratings, one of the three major international investment rating agencies, reported the week after the Algeria blast that insurance rates on LNG plants could increase in the near term, with rates easing back after all the facts are known and insurers regain full confidence in the industry.

Regardless of people's concerns, the domestic market still needs new gas supplies. "The fundamentals in the gas market in this country are not going to go away," Resley said.

"I hope the companies that are developing these regas terminals are taking on a massive explanation exercise," she said. "The whole business of marketing gas is about information. … The more informed people are, the better armed they are to understand the risks."

People also need to remember the nation needs new gas supplies, said Ralph Alexander, BP's chief executive for gas, power and renewable energy. "I think the greater risk for the U.S. is to reject LNG as a supply," Alexander said in an interview published in Natural Gas Week.

Still, the perception that LNG presents safety hazards is going to be a continuing problem for companies looking to build new terminals to serve domestic needs, said Jim Jensen, a Massachusetts-based LNG consultant with 30 years experience in the industry. "The perceptions and the reality are often very different."

Public education important

Jensen, like Resley, said educating the public will be important, adding that much of the "scare stuff going on right now" probably is not realistic.

Meanwhile, ExxonMobil confirmed it has scaled back its work to develop a new LNG receiving port near Mobile, Ala., in part because of community opposition. Alabama's Republican governor was vocal in his opposition to the site, calling for an "in-depth, individualized, independent study" before federal regulators consider issuing a permit for the project.

Gov. Bob Riley said the study should look at "the most credible worst-case scenario" for a potential LNG accident at the site in Mobile Bay.

Jensen said he believes residents' concerns, strengthened by the Algeria explosion, will push more than just the ExxonMobil project to the back of the line or out of the game entirely among proposed LNG sites. But that's OK, he said. There are more proposed projects than the nation needs. "There's a lot of deadwood that's got to be cut out anyway."

Not all projects will be built

Of the almost 10 sites proposed for the U.S. West Coast and Mexico's Baja Peninsula, Jensen expects just two terminals will be built this decade. And of the more than 20 sites proposed for the U.S. Gulf and East coasts, most industry observers look for just three or four to start operating this decade.

And, as the industry works to reassure potential LNG neighbors of the safety of the facilities, it points out there have been just two fatal LNG accidents worldwide in the past 60 years. An improperly designed storage tank in Cleveland collapsed in 1944 and killed 128 people in the resulting fire, according to a September 2003 report by the Congressional Research Service.

The Cleveland tank was built with a low-nickel content steel alloy that turned brittle when exposed to the extreme cold of LNG storage. New storage tank technology has prevented a repeat of the Cleveland accident.

No matter that technology has improved over the past 60 years, many residents of coastal communities get nervous about the risk of terrorist attacks, which was covered in last year's Congressional Research Service report.

"The LNG industry has a long history of safe operations and has taken steps to secure its assets against terrorist attacks," the report said. "Recent studies have also shown that the potential hazard to the public of an LNG attack, while significant, is not as serious as is popularly believed." ●

● JUNEAU, ALASKA

Alaska gas reserves tax on the table

Legislator says tax is good way to force North Slope gas line construction

By LARRY PERSILY
Petroleum News Government Affairs Editor

None of Anchorage Rep. Eric Croft's 39 colleagues have stepped forward to co-sponsor his bill to impose a state property tax on North Slope natural gas reserves.

Croft for the third time in five years has introduced legislation to put a gas reserves tax on the books. And although this latest effort is just as likely to fail as the first two, the legislator believes the tax is needed to push leaseholders into moving the gas to market.

The leaseholders, principally ConocoPhillips, ExxonMobil and BP Exploration (Alaska), could avoid the annual property tax, at 2 cents per thousand cubic feet, if they either build a pipeline to carry the gas to market or sell the gas to another project developer.

"This is a tax that is never meant to be collected," Croft said in announcing his bill Feb. 16. "This measure is intended to produce a pipeline."

Croft is one of the loudest critics in the Legislature of the producers' caution in committing to a $20 billion gas pipeline from the North Slope to mid-America markets. He also is a strong supporter of the separate effort to build a state-owned line to Valdez and a liquefied natural gas terminal to compete in the LNG export market.

Legislative approval not likely

Regardless that few Alaskans would argue with the goal of getting a gas line built — and royalty and tax revenues into the state treasury — the tax-it-into-existence tactic is not likely to win legislative approval.

The bill's first committee of referral is House Oil and Gas, where the chairman has never supported a reserves tax. Other legislative leaders and the North Slope producers are on record opposing such a tax to force development of a gas pipeline, arguing that the threat doesn't help in any way to lower the multibillion-dollar risk of the largest private construction project in the nation's history.

Under the four-term Democrat's proposal, House Bill 482 would impose the tax on all proven North Slope gas reserves except those needed for reinjection into a reservoir for enhanced oil recovery operations. The Department of Revenue would estimate the amount of proven reserves subject to the tax each year, with leaseholders given the opportunity to appeal the assessment.

If all of the 35 trillion cubic feet of gas reserves on the slope were considered taxable, Croft's legislation would hold over the heads of leaseholders an annual property tax bill of $700 million.

Surrendering leases would stop the tax

The first tax payments would be due in 2008 unless the companies agree by Dec. 31, 2007, to sell gas on a 20-year contract at not less than $1 per mcf at the wellhead. Gas deliveries would have to begin by Dec. 31, 2011. The escape clause would apply if the producers built the line and sold the gas on their own, or if another company built the line and the producers sold gas for the project.

Another option under Croft's bill to avoid the tax would be for the producers to surrender their leases back to the state by Dec. 31, 2007, although the legislator acknowledged that could present problems if a company is producing oil but not gas from the lease.

"I would like to flesh out how you return a gas lease while producing oil," he said, adding he expects to continue working on the bill and likely will offer a revised version later in the session.

One other section of the bill states that any Alaska voter could go to court after Jan. 1, 2008, to require that the Department of Revenue commissioner enforce the gas reserves tax. ●

Want to know more?

If you'd like to read more about a gas reserves tax, go to Petroleum News' Web site archives. These are a few of the articles published over the last two years in which a gas reserves tax was either featured or mentioned.

Web site: www.PetroleumNews.com

2004
● **Jan. 25** Alaska legislators want action on gas pipeline

2003
● **Nov. 2** Gas reserves tax unlikely from legislators
● **Oct. 5** Alaska LNG backers propose reserves tax

2002
● **March 17** Today's gas price no reason to postpone pipeline
● **March 17** Condon: No to gas reserves tax
● **Feb. 24** Gasline commercial now; time to get tough with producers

continued from page 14

WEST SAK

in a multilateral well," opening more than two miles of reservoir to the well bore.

And production went from those few hundred barrels a day from vertical wells in the 1980s and 1990s, past production figures approaching a thousand barrels a day in 2000-2002, to numbers approaching 1,600 barrels a day in 2003. "What we're doing with these wells is cutting the overall development cost and increasing the rate — which of course is good for the economics," he said.

Heavy oil still only accounts for a small percentage of North Slope production, but the volume is growing. In mid-2003, Leveille said, the three North Slope heavy oil accumulations, in total, produced 30,000 to 35,000 barrels per day.

Tri-lateral West Sak wells planned

The plan in 2004 is to open even more reservoir to the well bore: tri-lateral wells are planned for West Sak in 2004, "which are going to have not two, but three laterals, and we're going to have total distances which are in the three to four mile range instead of the 11,800-foot range. So we're stretching these laterals longer and by doing that we're hoping to increase the productivity of the wells."

Heavy oil still only accounts for a small percentage of North Slope production, but the volume is growing. In mid-2003, Leveille said, the three North Slope heavy oil accumulations, in total, produced 30,000 to 35,000 barrels per day.

"Today it's about 40,000 barrels of heavy oil being produced on the slope. And we expect that rate to grow significantly by year-end: we'll certainly be above 50,000 barrels a day total production," he said.

Number of heavy oil wells expected to grow

The trick with heavy oil, Leveille said, is to drill a lot of wells and "get up that learning curve very, very quickly," and one way ConocoPhillips is doing that is by sharing information from its other heavy oil operations in Canada, Venezuela and China. The company is "involved with projects around the globe which have oil in place of over 100 billion barrels" of heavy oil, and has drilled hundreds of wells in the Orinoco heavy oil belt in Venezuela "that look very, very much like the wells we're drilling here in Alaska." The company is sending drilling engineers from Alaska to Venezuela to share what's been learned in Alaska and pick up tips from those drilling in Venezuela.

From experimentation to manufacturing

What ConocoPhillips wants to do, Leveille said, "is to go from what I would call the experimentation phase — where we've been for the last several years in Alaska — to what I would describe as a manufacturing process."

What's an experimentation phase? "For the last several years … we've been drilling a lot of different types of wells. We've been testing lateral lengths; do we use slotted liners or screens to keep control of the formation?"

The company has tried "a lot of different variables."

In 2004, "we're narrowing in on a very robust design," he said. "What we want to do now is to essentially start implementing that design time after time after time. Because that's the way you get your costs down in this business, is by finding the best way to do something and then doing it over and over and over again."

What's next?

ConocoPhillips drilled eight heavy oil wells in 2003, "far more than we've drilled in the past," Leveille said. The goal for 2004, he said, is to get approval for a much bigger program, including a number of projects. If those projects are approved, "we're looking at drilling over 50 wells here in the next several years.

"But we're going to try to transition here from this experimentation phase into a manufacturing phase … If you can do things over and over and over again, the costs tend to go down."

Wells get drilled faster: West Sak is now at about 10 days per 10,000 feet, and the goal is to improve that in 2004, he said.

"By improving that efficiency, learning how to do things, we're certainly able to access these resources in a much more economic manner." ●

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FREEPORT

Jody Sumrall, Dow business manager for LNG and Texas Gas, said Dow is the "first industrial energy user in the U.S. to commit to LNG terminal capacity on a long term basis." The LNG will be used, in part, for Dow's petrochemical facilities on the Texas Gulf Coast.

According to Michael Smith, chief executive of Freeport LNG, the deal with Dow marks an important milestone for the proposed terminal. Assuming Dow exercises its "option to take the full 500 mmcf per day, and with our previously announced transaction with ConocoPhillips, we believe that the entire first phase of our facility is now sold out. We expect final approval from the Federal Energy Regulatory Commission in the next couple of months, which will keep us on target to begin construction in mid-2004. LNG deliveries would begin in mid-2007."

Cheniere, a Houston-based Gulf of Mexico E&P company, is also developing LNG receiving terminals in Sabine Pass, La., and Corpus Christi, Texas.

● JUNEAU, ALASKA

Alaska shallow gas leasing would change

Opponents say bill to end over-the-counter program doesn't go far enough; AOGA supports concept of bill

By LARRY PERSILY

Petroleum News Government Affairs Editor

The Senate Resources Committee listened as several Matanuska Valley and Homer area residents testified that legislation to end Alaska's over-the-counter shallow gas leasing program doesn't go far enough to solve the problem. They want the Alaska Legislature to do something about the 273,000 acres already leased out.

"You've got to make it retroactive," said Jeff Arndt, coalbed methane coordinator for Friends of Mat-Su, a citizens group formed in opposition to state shallow gas leases in their area.

"This one still does not cover the problems we have right now," said Roberta Highland of Homer, another area with residents mobilized against last year's state leases.


SEN. SCOTT OGAN

The committee heard public testimony Feb. 23 on a new version of Senate Bill 312, sponsored by Committee Chair Scott Ogan, which would end the controversial leasing program that is by Ogan's own admission short on public notice and long on conflicts. In its place, explorers would need to go through the competitive-bid process of the state's exploration licensing or areawide leasing programs.

Best-interest finding would be required

Exploration licensing and areawide leasing include well-defined procedures for notifying residents and allowing public comment on lease applications, Ogan said, and also require the Alaska Department of Natural Resources to issue a best-interest finding after reviewing potential effects of oil and gas exploration and drilling activity on fish and wildlife habitat and communities.

The change would not affect any shallow gas existing leases or lease applications filed before Jan. 1, 2004.

The state's shallow gas leasing program "is applicant driven," with explorers picking the lands they want to lease, Ogan said in explaining why he proposed the committee substitute for Senate Bill 312 to end the program. It was intended for rural areas that need small, local sources of natural gas, not for the urban areas of last year's leases around Homer and the Matanuska Valley. "The program had some unintended consequences," he said.

This year's bill recognizes the need to make a change, particularly by going to a stronger public notice requirement, Ogan said. "No one should be caught off-guard."

More action on bill in March

The committee heard more than an hour of testimony and held the bill for further discussion, expected in early March.

Dropping the over-the-counter leases, Ogan said, "will bring a better, upfront public process." Critics of Alaska's 8-year-old shallow gas expedited leasing program said its lack of competitive bidding and public notice requirements led to last year's uproar in Homer and the Matanuska Valley as residents learned the state had leased the subsurface rights beneath their property.

Alaska law retains the subsurface rights for the state, although many homeowners were not aware of the law.

Jeanne Walker of Homer testified at Senate Resources that neither the real estate agent nor the title company were aware at closing in July 2003 that the state had leased out the rights beneath the home she and her husband had just purchased. She asked that the committee consider amending the bill to require that the state notify all property owners affected by existing leases.

"Unfortunately, this realization in Senate Bill 312 comes too late," said Michelle Church, a former director of Friends of Mat-Su.

Not all of the testimony was negative.

Some testimony supports bill

Ken Boyd, representing the lands committee of the Alaska Oil and Gas Association, said the industry group supports the concept of the bill.

And Carroll Martin of Soldotna spoke in general support of shallow gas drilling. "Twenty years from now, everybody will be thanking Scott Ogan."

The committee chair also explained the bill has some pluses for the industry, including the option for longer lease terms than are allowed under existing shallow gas leases and greater flexibility in looking for unconventional gas reserves at all depths.

None of the committee members addressed the public comments that favored retroactive changes in existing shallow gas leases. ●

● JUNEAU, ALASKA

House committee takes different angle

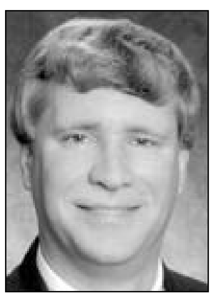
Bill would amend but not abolish Alaska's shallow gas leasing

By LARRY PERSILY

Petroleum News Government Affairs Editor

While the Senate Resources Committee works on legislation to end Alaska's controversial shallow gas leasing program, the House Oil and Gas Committee is more interested in changing but not abolishing the program.

The House committee on Feb. 24 released its latest version of legislation — House Bill 395 — to deal with residents' fears of damaged water wells and noise, and concerns with property-line setbacks and public notice of coalbed methane drilling in their communities.



REP. VIC KOHRING

But the committee substitute does not include a key provision of the original bill, which would have repealed last year's legislation allowing the Department of Natural Resources to override municipal land-use rules if they hinder shallow gas development and the department finds an "overriding interest" for the state-imposed waiver.

The repeal provision was not expected to survive in the Oil and Gas version of the bill, as Committee Chair Rep. Vic Kohring said three weeks ago he did not want to roll back Alaska's progress in attracting coalbed methane exploration.

The committee substitute for HB 395 does include much more stringent public notice requirements for new leases, including letters to every resident in affected areas.

Bill would impose new tax

And the bill would impose a new tax on shallow gas production at 1 cent per thousand cubic feet to fill up a $250,000 water well restoration fund. Residents could apply to draw on the fund to repair or replace wells damaged by gas drilling. The original version of the bill set the tax at 1 cent per 20,000 cubic feet.

At the new tax rate, for example, the account could reach its cap in about 18 months if coalbed methane production totaled 50 million cubic feet per day, about 10 percent of the production from Alaska's Cook Inlet fields. The tax would switch on and off as needed to keep the account at $250,000.

> *"This bill is a step in the right direction."*
> **—Robert Archibald of Homer**

No shallow gas production is under way in Alaska, though companies hold leases to 273,000 acres for exploration.

The committee's version combined Kohring's own measure, HB 420, with another coalbed methane measure, HB 395, which was introduced last month by four lawmakers whose districts include the leasing areas. The public notice requirements came from HB395, with the water well restoration fund from HB 420.

The requirement for heavy public notice of shallow gas leasing — much more than is required under existing law — addresses one of the major complaints of Matanuska Valley and Homer residents who say they were caught unaware by last year's leases. The existing over-the-counter program for shallow gas leases allows developers to choose the areas they want and does not require any sort of best-interest finding by the state as is used in other leasing programs.

Committee holds bill for more work

The committee took public comment on the new version of the 12-page bill, which was not distributed until the start of the meeting. Kohring said he plans to hold the bill for further work.

Even if the bill moves out of Oil and Gas, it still has three more committee assignments before reaching the full House for a vote and would then face Senate committee hearings — a lot of work in the 10 weeks before the Legislature's adjournment deadline.

Kohring's committee members clearly were not ready to move the bill Feb. 24, and toward the end of the meeting the chairman announced he was calling a brief at ease so that lawmakers could meet in the hall, in private, to discuss timing of the legislation. Republican Reps. Jim Holm of Fairbanks and Cheryll Heinze and Norm Rokeberg of Anchorage got up from the table and joined Kohring in the hallway outside the committee room, with Democrat Reps. Harry Crawford of Anchorage and Beth Kerttula of Juneau declining to participate in what they said was a violation of Alaska's open meeting law.

The four Republican members quickly returned to the room and the committee resumed taking public testimony on the bill.

Water well tests would be required

Among the changes in the bill from its original proposals is the requirement that the leaseholders, not the property owners, would be responsible for testing a property owner's water well before drilling begins to establish a water-quality baseline. Property owners would refer to that test if they needed to file a claim against the well restoration fund.

"This bill is a step in the right direction," said Robert Archibald of Homer, though he would like to see the measure amended to require that leaseholders hire independent contractors to test the wells instead of doing the work themselves.

The bill also would require developers to take steps to lessen noise from their operations and allow the state to impose "appropriate setbacks" for compressors near property lines. The measure also addresses operator bonding and land restoration requirements. ●

JUNEAU, ALASKA

Alaska Senate passes three minor oil and gas bills, two aiding Bristol Bay sale

Without objection, the Alaska Senate has passed three of the governor's oil and gas bills aimed at moving ahead with plans for a 2005 Bristol Bay lease sale and also expediting pre-application work for oil and gas pipeline right-of-way applicants.

The Senate voted Feb. 25 to pass and send to the House for its consideration:

• Senate Bill 264, to authorize the Department of Natural Resources to negotiate reimbursement agreements with pipeline right-of-way applicants. The intent is that by paying the department for pre-application reviews, applicants could avoid delays in the state's final review of permit applications.

The bill extends a program already in place.

• Senate Bill 266, to close certain lands in the Bristol Bay region to oil and gas exploration licensing and shallow gas leasing to hold back the acreage for the administration's planned, large-scale competitive lease sale in the area.

• Senate Bill 265, to allow the Department of Natural Resources to get started a year earlier on preparing a report to lawmakers on proposed oil and gas lease sales.

The measure would amend requirements for the state's five-year oil and gas leasing program to allow adding potential competitive sales to the schedule each year instead of only every other year. The practical effect is that the bill would allow the department to start work sooner on potential Bristol Bay leases.

The three bills are among more than 40 oil and gas measures introduced this year and left over from last year, and still alive in the final 10 weeks of the legislative session that is scheduled to end May 12.

—**LARRY PERSILY,** Petroleum News Juneau correspondent

Alaska governor blasts suit against northwest NPR-A leasing decision

Alaska Gov. Frank Murkowski said Feb. 18 that he wants the state of Alaska to intervene in a lawsuit filed in U.S. District Court in Alaska Feb. 16 by Earthjustice against the U.S. Department of the Interior's recent decision to offer large portions of the northwest National Petroleum Reserve-Alaska for oil and gas leasing.

GOV. FRANK MURKOWSKI

"Alaska has a great deal at stake at NPR-A, in terms of royalties, as well as jobs and the economic activity associated with oil exploration and development," Murkowski said. "The state clearly has an interest in making sure NPR-A leases are kept on the Department of the Interior's schedule.

"Once again, we find the 'lock-up Alaska' attitude of the environmental organizations has resulted in a legal challenge to the public process," Murkowski said. "I'm sure they would like nothing more than to be able to delay indefinitely any reasonable use of the National Petroleum Reserve. The fact is that it is a petroleum reserve. It should be used for the purpose for which it was aside in 1923. Reducing America's dependence on foreign oil is a laudable objective of the Bush administration, but it is not compatible with the agenda of the environmentalists."

● WASHINGTON, D.C.

Analysts see small savings from energy bill

Report from U.S. government agency says legislation will have little effect on production, consumption or price

By **LARRY PERSILY**
Petroleum News Government Affairs Editor

federal analysis of key provisions of the energy bill stalled in Congress says the combination of tax credits, royalty relief, energy efficiency initiatives and fuel standards will have only a small effect on the nation's total energy production, consumption and prices over the next 20 years.

"On a fuel-specific basis, changes to production, consumption, imports and prices are negligible," said the report, prepared by the U.S. Energy Information Administration at the request of Sen. John Sununu, R-N.H.

The report measured the probable effects of the legislation against the department's latest projection of energy production and consumption. It determined domestic energy consumption would remain "virtually identical" through 2020 with or without the bill, with a 0.3 percent drop in consumption after 2020.

Toward the goal of reducing the nation's dependence on foreign energy imports, the bill would result in only a 1 percent drop in foreign oil imports by 2025, the Energy Department report said. Provisions in the bill would produce a 1 percent increase in domestic natural gas production by 2025.

The study included a note of caution: "The projections … used in this report are not statements of what will happen but of what might happen."

Report looks at wide range of issues

The report considered the bill's tax credits and other financial incentives for a wide range of production and consumption issues, including the Alaska North Slope natural gas pipeline, offshore royalty relief, unconventional natural gas production, motor vehicle fuel standards and increased use of ethanol in blended gasoline, nuclear plants, coal technology, initiatives for residential and commercial energy efficiencies and alternative-fuel vehicles.

The agency did not analyze unfunded provisions in the bill — authorization for the work but no money to do the job — or any of the provisions that authorize a target for energy savings but fail to set the target.

Although the House passed the bill by an easy margin, supporters in the Senate have been unable to find enough votes to block further debate and bring the bill to the floor for a vote. Senate Republican leadership the second week of February released a stripped-down version of the bill in the hope that a less expensive package could win passage, though it's not expected to reach the floor for a vote until the first week of March at the earliest.

Bill's price tag, effectiveness questioned

Sununu, a fiscal conservative, is one of several Senate Republicans who voted to block passage of the bill last November, citing its bulging multibillion-dollar price tag, its questionable effectiveness, and its provision to release from product liability claims the manufacturers of the gasoline additive MTBE, methyl tertiary butyl ether. Sununu's state was the first to sue the octane-enhancer manufacturers, seeking cleanup costs and damages for pollution of underground water supplies.

The Energy Department reviewed the version of the bill that passed the House — not the proposed substitute waiting for Senate action. The Feb. 19 report included the following conclusions:

• The federal loan guarantee, accelerated depreciation and tax credits for construction of an Alaska North Slope natural gas project to serve Lower 48 markets would reduce the line's tariff by about 15 cents per thousand cubic feet of gas. The lower cost and financial incentives, the report said, would prompt an earlier decision to build the line, advancing by one year the start-up date for the first gas flow, to 2017 instead of 2018.

• Despite the bill's royalty relief provisions for shallow-water, deep wells in the Gulf of Mexico, lower natural gas prices would slow development of the expensive wells.

• Weatherization funding and tax credits for existing homes, solar, wind and fuel-cell energy "are not large enough to measurably affect" energy consumption.

• Natural gas wellhead prices in 2015 would be a just dime less with the energy bill, but unchanged by 2025.

• Electricity prices would be a tenth of a cent lower with the energy bill in 2015 and 2025.

Bill would help Alaska gas line

In reviewing the bill's provisions for the Alaska gas line project, the report said the tax credit for the $2-billion-plus gas conditioning plant needed on the North Slope would reduce costs by 5 cents per thousand cubic feet. Adding that to the savings from the presumed lower interest rate the borrowers would receive with the federal loan guarantee for the project, the report calculated, the gas tariff would be about 15 cents less per mcf than if the energy bill does not pass.

The accelerated depreciation provision for the pipeline itself would improve the owner's cash flow but would not "appreciably alter the tariff," the report said.

Other projections in the report include:

• Imports of liquefied natural gas would remain unchanged from current projections without the energy bill, as domestic production will fall far short of demand — even with increased unconventional gas production and the Alaska gas pipeline. LNG imports are expected to increase more than 20-fold from 2002 levels, up to almost 13 billion cubic feet per day in 2025 with or without the bill, the report said.

• Regardless whether the energy bill passes, Lower 48 onshore conventional gas production would drop 10 percent by 2025, and Lower 48 onshore unconventional gas production would jump more than 50 percent by 2025, to more than 25 bcf per day. Offshore production would increase just a few percentage points from 2002 to 2025, regardless of the bill. ●

Companies involved in North America's oil and gas industry

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Petroleum news

Business Spotlight

By PAULA EASLEY

FORREST CRANE

Christina Wallace, director of sales

Evergreen Helicopters of Alaska

Merrill Field in Anchorage is where Evergreen first lifted off in February 1961. Cold Bay, Nome, Kotzebue, Deadhorse, Drift River and Fairbanks have since been added to its Alaska service locations. The Alaska fleet supports petroleum exploration and production, firefighting, forestry, search and rescue, cargo transport, and utility construction and transmission.

Well-grounded in supply chain management, Christina Wallace spent 11 years finding air charter transportation solutions for global automotive assembly plants; she most recently worked on developing Evergreen's Boeing 747 super tanker aircraft. Christina has been with Evergreen three years and is active in Anchorage Air Cargo Association, RDC, the Alliance and PCA. She and hubby Wayne have two great dogs, Loki and Riley, who have chosen not to run the Iditarod.

FORREST CRANE

John Parrott, Alaska general manager

Totem Ocean Trailer Express

Long-time transporter between Alaska and the mainland, TOTE provides fast, reliable connectivity to road and rail infrastructure at both ends. The firm recently introduced two 820-foot diesel electric roll-on, roll-off cargo ships especially designed for the Alaska trade. Upgraded terminals, equipment and software provide customers the latest in intermodal systems and technology.

John Parrott, licensed Merchant Marine master and former Sea Star Stevedoring manager, has held his current title since mid-2002. Despite a heavy work schedule, he enjoys participating in community volunteer activities. He and wife Lynne, an accomplished sailor and fly-fisher, have two preschoolers and another on the way. The family thrives on water-related sports, and both boys skate, ski and clean fish. John's favorite quote: "Time makes more converts than reason."

continued from page 1

PLAINS

in his role at Plains Resources, but it was unclear just what he makes as a top executive at Plains E&P and as a board member of Plains All American Pipeline.

Plains E&P spun off in 2002

In late 2002, Plains E&P was spun off Plains Resources into a separately traded company. Like its sister, Plains Resources is an independent energy company engaged in the acquisition, development and exploitation of oil and natural gas. The company also holds an ownership position in Plains All American Pipeline, which has interests in U.S. midstream activities, gathering, transportation, terminalling and storage of oil.

Raymond and Flores have a common thread dating back to at least Ocean Energy, a large exploration and production independent that ultimately was taken over by an even larger independent, Oklahoma's Devon Energy. Flores began his career in 1982 as chairman and chief executive officer of Flores & Rucks, which later was renamed Ocean Energy, a company that established a strong position in the Gulf of Mexico. Raymond was Ocean's vice president of corporate development from April 1998 to January 2000.

In recent months, Raymond and Flores have been squarely at the center of merger activity that included Plains E&P's friendly takeover of fellow independent Nuevo Energy, announced Feb. 12, in a stock deal valued at $945 million. Industry analysts seemed to have welcomed that transaction, in part because of cost savings and the close proximity of Plains-Nuevo exploration and production acreage. Both companies maintain strong positions both onshore and offshore California, as well as in Louisiana.

Plains Resources' deal has ruffled feathers

It's the other deal involving Plains Resources that ruffled the feathers of investors and put both management and the board in an embarrassing position, with a lot of explaining still to do.

Raymond, Flores and another key player in the proposed takeover of Plains Resources, Microsoft co-founder and billionaire Paul Allen, teamed up in a tumultuous effort to buy the outstanding stock of Plains Resources last November for the sum of $14.25 per share and then transform Plains into a private company. Their first attempt failed after a special committee appointed by the board reviewed the proposal with the help of outside advisors and rejected it with little explanation. The committee said only that the offer "was inadequate and not in the best interests of Plains Resources' shareholders."

Internet chat rooms had come alive with investors furious with the initial proposal if, for no other reason, the share value of Plains Resources had exceeded the offer during the period of the committee review.

Meanwhile, a revised offer of $16.75 per share was presented to the special committee and that seemingly clinched the deal. Plains Resources announced Feb 19 that "after careful consideration" it had entered into "a definitive cash merger agreement" with the Vulcan Group, an affiliate of Vulcan Capital, the investment arm of Allen's Vulcan Inc.

In an apparent effort to appease shareholders, Plains Resources specifically mentioned in its press release announcing the deal that Raymond and Flores, as players in the Vulcan Group, could participate in the transaction but could not receive $16.75 for each of their shares of Plains Resources, as could other shareholders of the company.

Investors still uncomfortable, even at $16.75 per share

Still, investors were uncomfortable with the deal. For one, the board failed to mention that while it was open to proposals from other potential buyers, it actually had received one from a group led by Pershing Square L.P and Leucadia National Corp. Pershing is a recently formed investment partnership managed by William Ackman, a formal principal in the now-defunct hedge fund Gotham Partners.

That revelation led to yet another press release, issued just days after the merger agreement with Vulcan was announced, in which Plains Resources acknowledged Pershing as a suitor. However, Plains said it rejected Pershing's offer because of the "highly conditional nature of the proposal."

Pershing offered $3 per share in cash plus new securities with an uncertain trading value to be issued by Plains Resources itself. Complexities of the proposal, including unknown tax consequences, also weighed into the board's decision, Plains said. Ultimately, shareholders will have to approve the deal with Vulcan.

Microsoft's Allen and his deep pockets have no doubt added intrigue to the Plains deal with Vulcan. Over the years, Allen's holdings have included stakes in DreamWorks SKG, Ticketmaster, Starwave, c/net, and others. One reporter characterized Allen as an "everywhere man" torn between his Microsoft duties and his personal ambitions as an investor. ●

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IMPERIAL

review by 37 agencies in 2004 and 2005.

Delays beyond that period would stall the start of the construction phase, scheduled to last three to four years, and the prospects for deliveries to start late this decade rather than the most optimistic target of 2008.

Pipeline needed before gas reserves development

Until the pipeline is built, development of gas reserves in the Northwest Territories is an economic risk that few companies are prepared to take on.

Hearn insisted that speeding up approvals will not compromise environmental concerns.

"We can get the job done right from everybody's point of view.

"But we can do it more efficiently and I challenge all of us to push for those kinds of solutions," he said.

The growing worry for Imperial is that a delayed Mackenzie pipeline could clash with multi-billion dollar pipelines by Enbridge and Terasen from the Alberta oil sands, setting up fierce competition for labor and materials.

Deh Cho still a threat

Outside of the existing regulatory structure, the Deh Cho First Nations continue to pose a threat.

They are still waiting for a response from the Canadian government to their proposal that the current process be dismantled and replaced by what they claim would be streamlined environmental and regulatory hearings. Without a positive response, the Deh Cho, whose lands cover the lower 40 percent of the pipeline route, have threatened to take their case to the Federal Court of Appeal, claiming that they have not been properly consulted.

A legal spokesman for the Deh Cho said the first nations want an assurance within a month that their arguments are being treated seriously.

In a Feb. 17 presentation, George Bezaire, Imperial's director of corporate planning and communications, said the Mackenzie partnership with ExxonMobil Canada, ConocoPhillips and Shell Canada, plus the Aboriginal Pipeline Group, has already held more than 500 meetings with parties involved in the scheme to ship Arctic gas to southern markets.

Imperial looking at two buried pipelines

He said Imperial is aiming for two buried pipelines down the Mackenzie Valley — a gas line that would connect with existing infrastructure in northern Alberta and a natural gas liquids pipeline from the Mackenzie Delta to Norman Wells.

As well, he said Imperial and sister company ExxonMobil are moving ahead with possible joint development of their oil sands leases in northeastern Alberta.

Bezaire and Hearn both indicated that results from winter drilling of 200 core wells has been encouraging in delineating the resource potential of Imperial's Kearl Lake lease.

"We expect that this is a very large, high quality resource that will be capable of supporting a project of 200,000 barrels per day or even larger," Bezaire said.

A regulatory filing is expected by 2005, with production starting at 100,000 bpd.

Imperial's Cold Lake heavy oil scheme produced 129,000 bpd in 2003 and further expansions could raise that to 180,000 bpd by adding 350 million barrels of proved reserves. The development drilling program for this year includes more than 300 wells. ●

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BRINK

The upside for oil and gas in Alaska is that the state is the "premier area" of North America for oil and gas, with 22 percent of U.S. reserves, he said, but on the downside, the state is far from markets, and the state's traditional explorers — the majors, most recently the North Slope producers — are investing elsewhere in the world, looking for the next Prudhoe Bay.

And the next Prudhoe Bay, he said, isn't likely to be found in Alaska. Alaska's remaining oil is likely to be found in smaller fields and finding those fields will require more exploration wells.

Statewide, exploration drilling has been "a little over historical averages" in recent years, but a lot of that drilling has been gas exploration in Cook Inlet, not oil exploration on the North Slope, Myers said. The exploration incentive passed by the Alaska Legislature in 2003 that provides a substantial tax credit, up to 40 percent, for exploration drilling and seismic exploration at a distance from infrastructure, a 20 percent credit closer in, is one of the things the administration has done to try to jump-start exploration, he said.

Independents exploring now

While North Slope producer ConocoPhillips Alaska and its partners will account for much of this winter's North Slope drilling — up to three wells in the National Petroleum Reserve-Alaska and a well on the western edge of the Kuparuk River unit — international major Total is also drilling in NPR-A and independent Kerr-McGee and its partner Armstrong Resources are drilling northwest of Milne Point in the shallow waters of the Beaufort Sea.

Last winter independent Pioneer Resources, another Armstrong partner, also drilled in the Beaufort.

"The ability to attract new exploration capital to the state is extremely important," Myers said, as the majors move "a lot of their capital offshore to international areas where they see these large Prudhoe Bay-type potential projects."

That, he said, has created a vacuum in Alaska. "And one of the goals the administration has is to fill that vacuum."

The independents are filling the vacuum — both acquiring acreage and drilling wells.

"In the past," Myers said, "the independents would typically come up and they would buy leases and they would stop… They couldn't monetize them and move to the next stage" with exploration.

Myers said having new companies exploring in the state is a plus: "we are starting to get the new capital investment."

But the key to economic success for the state, he said, will be for independents to take successful exploration and turn it into development.

Bristol Bay-Alaska Peninsula expected to attract independents

Myers said he expects to see independents come in when the state offers oil and gas leases in the Bristol Bay and Alaska Peninsula area in 2005.

The area was last explored in the mid-1980s, but state leases expired and the federal offshore area was put under moratorium because of concerns over the high-value fishing industry. With a slump in that industry, a concern for the local economy and a need for a local energy source, people in the Bristol Bay area came to the administration last year to ask for oil and gas leasing.

There are oil seeps in the area, Myers said, and while the basin is "very under explored," the oil seeps prove the basin has generated oil — and gas bubbles in the oil seeps show it has also generated gas. The oil is coming from source rocks related to those that are producing oil in Cook Inlet, he said, the gas is coming from shallow coals — also similar to Cook Inlet.

The thicker area of the Bristol Bay sedimentary basin is more than 20,000 feet thick, "which is the first good sign. The second good sign is in the upper portion of the section we have very good quality reservoir rocks."

Myers said there are positive answers to basic questions about a basin: Is there known generated oil and gas? Is there good quality reservoir rock? Are there geologic structures? Could they entrap significant quantities of oil and gas?

And other than the seeps, there is evidence of oil and gas from 26 wells drilled in the area prior to 1985.

Some of the wells were drilled very early, starting in 1903, so the technology doesn't begin to compare with what is available today. In spite of that, those wells had "significant oil and gas shows. So with modern technology, modern seismic, modern wells, we would expect substantial oil and gas."

Geologic data being provided

Myers said the state believes oil potential in the Bristol Bay-Alaska Peninsula is "in the hundreds of millions of barrels — potentially large enough for a commercial development — and the gas is in the multiple tcfs (trillions of cubic feet), enough, potentially for an LNG project."

And this geology is at tidewater. "No 800-mile pipeline is required," he said.

Myers said the state is "putting together full data packages" including geologic maps, seismic data and well data, in digital format on compact disks and "providing that to the industry at no cost."

"We expect the target audience to be the large substantial independent companies," he said. "This is the right sized basin for them to explore and develop."

And the advantage those independents have is that they can move quickly.

On the North Slope, Myers said, independents have drilled prospects within two years of acquiring them.

And even in the offshore environment, "probably the hardest area to permit," independents have gotten permits in as little as 91 days.

While Bristol Bay-Alaska Peninsula gas would be at tidewater, North Slope natural gas requires a pipeline.

Will a pipeline be built?

"We at DNR (the Alaska Department of Natural Resources) believe the project can be done economically… There are currently ongoing negotiations with both the major producers and MidAmerican," Myers said.

"So now for the first time instead of begging for someone, we have competition in the market to see who builds this system."

And conventional natural gas at Prudhoe Bay and Point Thomson isn't the only source of natural gas in Alaska.

On the North Slope there are also gas hydrates, "gas in frozen condition," and coalbed methane.

Farther south, the Foothills are believed to be gas-prone, Myers said.

And then there are the Interior basins, most drilled for oil in the 1970s and 1980s. "The geology did not look favorable for oil in most of them. It does look very favorable for gas."

Interior gas and a North Slope pipeline

The state has issued an exploration license for the Interior Nenana basin near Fairbanks, and Andex, the company with the license, "has identified 26 different large structures and leads: very favorable geology," Myers said.

Natural gas is now trucked into the area from Anchorage, so gas from Nenana has a local market, he said.

But what if there is a gas pipeline built from the North Slope? Would that preclude Nenana gas development?

Myers said it would not.

For example, he said, if a natural gas pipeline coming off the North Slope included gas liquids, "you could strip out the liquids for a petrochemical industry in Fairbanks, replace the gas — the voidage loss to the pipeline — with gas from the Nenana basin, and basically … the liquids would ride free on the pipeline. So there's commercial opportunities in addition to local gas needs." ●

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CHESAPEAKE

previous year to 268 billion cubic feet of gas equivalent. Of the 87 billion cubic feet of increase year-over-year, the company said 36 billion cubic feet was attained through "organic" growth or drilling and 51 bcf through acquisitions.

That put the Chesapeake's organic growth rate at 20 percent compared to the prior year, well above the company's initial projected growth rate of five percent and placing the company in the top three among mid-to large size independents.

Record production in the fourth quarter translated into a healthy profit of $62.4 or 25 cents per diluted share on revenues of $456.7 million, compared to 2002 fourth-quarter net income of $23.7 million or 13 cents per share on revenues of $258.4 million. Excluding charges, the firm's net income in the fourth quarter would have been $94.9 million or 37 cents per share.

Despite the difficulty in finding good properties at the right price, Chesapeake said it has managed to stay ahead of the acquisition game through its own five-year "rolling inventory" of prospects. "We are prospect rich in a prospect poor industry," Marcus Rowland, Chesapeake's chief financial officer, told analysts.

Chesapeake further strengthened its U.S. position late last year with three separate deals totaling $510 million, including $420 million it paid for independent Concho Resources. In those transactions alone, the company picked up reserves of 320 bcf of gas equivalent and daily production of 70 million cubic feet of equivalent.

In June Chesapeake shareholders gave their approval to another acquisition, the $118 million takeover of Canaan Energy. In that transaction, Chesapeake gained reserves of about 100 bcf of equivalent. In 2000, Chesapeake took out Gothic Energy in a cash-and-stock buy valued at $345 million.

Chesapeake began 2003 with estimated proved reserves of 2.205 trillion cubic feet of gas equivalent and ended the year with record reserves of 3.169 tcf, an increase of 964 bcf of equivalent or 44 percent. Taking into account production of 268 bcf of equivalent, reserve replacement during the year was 1.232 tcf, or an astonishing 459 percent, at an enviable finding and acquisition cost of $1.36 per thousand cubic feet.

While production in the first quarter is expected to come in at the lower end of Chesapeake's projected 78-79 bcf of equivalent, it would still be a 37 percent increase over the same quarter last year. The company's 2004 production is expected to surpass last year by 21 percent.

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

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