Petroleum news

page 4 Remaking Anadarko Petroleum: Hackett announces new strategy

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Nova Scotia basin pushed to brink

COURTESY TRANSOCEAN

Three exploration failures since last summer spread disappointment through industry, government circles; but Nova Scotia offshore still in infancy, with only 200 wells drilled. See story on page 9.

Alberta to shut in hundreds of natural gas wells, says agency

The Alberta Energy and Utilities Board has confirmed a decision to shut in hundreds of natural gas wells to benefit oil sands production, and reaction from gas producers has been predictably negative.

"This decision gives the appearance of a disregard for a resource which took decades and billions of dollars validly invested by Albertans to develop," said Sue Rose, president and chief operating officer of Paramount Energy Trust.

In a press release, Paramount estimates that 16 percent of the trust's production, or 15 million cubic feet per day, will now be shut in. This is in addition to 4.5 million cubic feet per day shut in last September.

"In today's market this gas production remains of significant

see **ALBERTA** *page 2*

Chevron looks at undersea line to move Hebron oil to Hibernia

In an attempt to revive the mothballed Hebron offshore oil project, Chevron Canada Resources Ltd. is looking at a $1 billion undersea pipeline to get the heavy oil to Hibernia for production and shipment to onshore refineries.

A report in the Toronto Globe and Mail outlines this "tieback" proposal as being possibly the lowest-cost option of four options to produce the heavy oil deposits, lying 350 kilometers southeast of St. John's, Newfoundland. The field is only 35 kilometers from the Hibernia production platform.

"We would drill subsea wells, trench 35 kilometers to Hibernia and lay the flow lines in that trench back to Hibernia," Hebron project manager Mark MacLeod said in an

see **CHEVRON** *page 2*

● NORTH SLOPE, ALASKA

Arc of plenty

With discoveries in adjacent units, Armstrong applies for Tuvaaq unit

By KRISTEN NELSON

Petroleum News Editor-in-Chief

ED KERR

It may not be the National Petroleum Reserve-Alaska or the Arctic National Wildlife Refuge, but it is currently the hottest little exploration trend on Alaska's North Slope.

Over the last several years Denver-based Armstrong Oil and Gas has assembled 46,000 acres of state oil and gas leases in the shallow waters of Harrison Bay, arcing across the top of the Kuparuk River and Milne Point units.

Armstrong brought in two large independents, Pioneer Natural Resources and Kerr-McGee Oil and Gas, as majority partners and operators of exploration units on either end of the acreage.

Armstrong first brought in Pioneer at Oooguruk, the unit on the most westerly of the acreage. The companies drilled three wells in the winter of 2002-03 and announced an oil discovery. Armstrong then brought in Kerr-McGee as operator of the Nikaitchuq unit on the eastern side of the arc. Kerr-McGee and Armstrong drilled two wells last winter, and also announced an oil discovery.

The Alaska Department of Natural Resources Division of Oil and Gas approved the exploration unit at Oooguruk (Pioneer 70 percent, Armstrong 30 percent) last July and the exploration unit at

see **PLENTY** *page 18*

● ONSHORE UNITED STATES

Noble Energy: Hundreds of new wells possible in West

Drilling planned in shallow, biogenic gas plays of Colorado, Montana

By RAY TYSON

Petroleum News Houston Correspondent

Noble Energy says it could end up drilling hundreds of new development wells in the U.S. Rockies over the next few years.

The Houston-based independent appears to be particularly bullish on the Niobrara trend of northeastern Colorado and the Bowdoin area of northern Montana. Both are shallow, biogenic gas plays located in producing fields.

However, initial drilling results from the deeper interval of the 27,000-acre Iron Horse gas play in Wyoming's Wind River basin are less encouraging. Noble said it went into Iron Horse's deep zone expecting "a basin-centered gas accumulation" similar to the prolific Jonah discovery.

Last year the company drilled a 15,600-foot exploration test well at Iron Horse, initially testing a prospective section between 7,600 and 15,600 feet.

"I can say rates have been disappointing. It's tighter (sand) than we expected," Ted Price, Noble's

see **WELLS** *page 16*

● NORTH AMERICA

Lessons for Alaska across border?

Producers were key to 1990s' project for moving Western Canada gas

By LARRY PERSILY

Petroleum News Government Affairs Editor

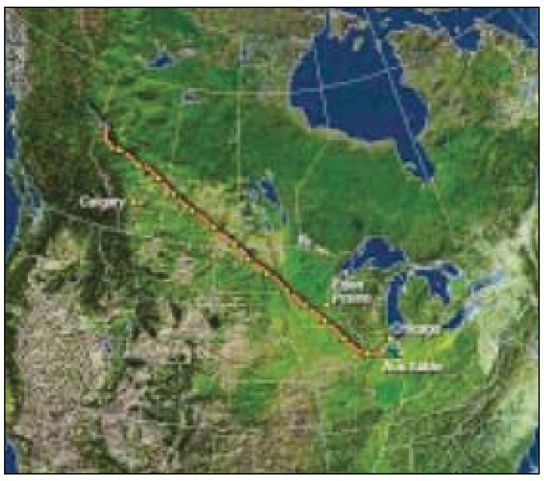
There could be a history lesson across the border for supporters of the proposed Alaska North Slope gas line project.

Almost a decade ago, 22 Western Canada natural gas producers and marketing companies got together to find a competitive alternative for moving their gas to Midwest consumers.

Although producers don't usually build gas lines, they took on the Alliance Pipeline project.

The partners put up hundreds of millions of dollars in cash, borrowed a couple billion dollars by signing firm ship-or-pay commitments, and put together the deal for the line, stretching almost 1,900 miles from

see **ALLIANCE** *page 18*



The Alliance pipeline stretches almost 1,900 miles from eastern British Columbia to just southwest of Chicago.

● RUSSIA

U.S. energy envoy: Sakhalin move discourages investment

PETROLEUM NEWS

In a recent official visit to Moscow, U.S. Deputy Energy Secretary Kyle McSlarrow reiterated the U.S. government's concern over Russia's de-facto annulment of a 1993 tender awarding an ExxonMobil-led consortium a license to an offshore Sakhalin oil field.

"In the absence of some compelling reason, which I have yet to hear, that original tender ought to be honored to allow the project to go forward," McSlarrow said, adding that he didn't know whether annulment was final.

"The danger is that a contrary decision would have a chilling effect on the willingness of other investors to do business here in Russia," McSlarrow said in a June 9 briefing of company and government officials.

In January, Russia said it wouldn't issue a license for the development of the Sakhalin-3 oil project to the consortium which also includes U.S.-based ChevronTexaco and Russian state-owned oil major OAO Rosneft. The group has already invested $600 million in Sakhalin-3.

But the license was never issued due to the lack of a legal framework for production-sharing agreements and Russia has since passed laws to make those agreements unfeasible. It is "clearly a bump in the road" toward closer cooperation on energy issues between the U.S. and Russia, McSlarrow said.

Russia urged to pursue LNG

McSlarrow also urged Russia to develop its potential for producing liquefied natural gas and become a bigger player in the gas export market at a time when demand in America is growing but production isn't.

With proven gas reserves of 700 trillion cubic feet, Russia "ought to be a major player when it comes to LNG," McSlarrow said.

He offered U.S. assistance to "allow U.S. companies that have the greatest experience in the world in building the entire LNG value chain... to partner with Russian companies in ways that allow us to share technology, and share exploration and production."

—The Associated Press contributed to this story

continued from page 1

CHEVRON

interview with the Globe and Mail..

Chevron shelved the Hebron project more than two years ago because the high costs associated with producing and shipping the heavy oil outweighed the benefits. But with global oil prices now around $40 per barrel, and expected to stay north of $30 for the foreseeable future, the numbers have improved.

The pipeline option is estimated to be about one-third the cost of a concrete production platform at Hebron. The other two options involve a floating production, storage and offloading vessel; and drilling equipment at the wellhead in conjunction with a production vessel.

Working against the pipeline option is the fact that it would require far fewer employees, and governments in Eastern Canada look at job creation as the most important component of any large-scale energy developments.

The Hebron oil discovery comprises three fields — Hebron, West Ben Nevis and Ben Nevis — which contain an estimated 400 million to 600 million barrels of heavy oil.

As the operator of Hebron, Chevron has Petro-Canada, Exxon Mobil Corp. and Norway's Norsk Hydro ASA as partners. The four are also among the seven partners in the $5.8 billion Hibernia concrete platform, which is currently underutilized.

—DON WHITELEY, Petroleum News contributing writer

continued from page 1

ALBERTA

value to gas producers and Albertans through royalties, continued investment, employment and other tertiary benefits relative to any lost value from reduced incremental bitumen recovery which might ultimately be placed at risk by its production, " Rose said. "The tenacity of the AEUB in pursuing its intended course of action on this matter and its lack of consideration for the technical input from industry over the past twelve months threatens to jeopardize Alberta's role in North American natural gas markets."

The panel's original decision in January was upheld by a review panel after public hearings in which Alberta gas producers argued vehemently against the action. The energy board has ordered the shut-in, effective July 1, 2004, of Wabiskaw-McMurray natural gas production in Northeast Alberta totaling about 123 million cubic feet per day, almost 1 percent of Alberta's 2003 daily average natural gas production.

Panel ruled in favor of bitumen production

The three-member review panel ruled that conserving 25.5 billion barrels of bitumen — a type of heavy oil — is more important than allowing the gas wells to resume production. The energy content of the oil is significantly greater than the gas.

"These are the latest steps in a fair and balanced process to protect the bitumen for current and future generations of Albertans," Alberta Energy and Utilities Board Chairman Neil McCrank said at a news conference June 8 in Calgary.

The decision is based on technical problems with bitumen production. High pressure levels in the reservoirs are essential to maximize bitumen production. If associated gas is produced first, the reservoir pressures drop low enough to affect bitumen recovery.

According to the energy board panel, 835 gas wells are in contact with bitumen, and 330 of those wells can't produce gas from any other zone.

Paramount says in its release that it is "hopeful" that discussions with the Alberta provincial government will produce "a comprehensive financial solution." An interim financial assistance package already is in place.

Paramount plans to appeal the energy board decision "on the basis of a lack of due process and natural justice." The producer says the interim hearing concluded in April did not consider recent technological advancements and new evidence with respect to the technical issues.

The bitumen reserves identified by the review panel are equal to 70 years of production, based on output of 352 million barrels of bitumen last year in Alberta.

—DON WHITELEY, Petroleum News contributing writer

DENVER, COLO.

Evergreen Resources taps Randall & Dewey to sell Kansas CBM assets

Coalbed methane producer Evergreen Resources has hired divestiture advisor Randall & Dewey to shop its Kansas assets, a condition of its previously announced $2.1 billion merger with Pioneer Natural Resources.

Under terms of the merger agreement, Evergreen shareholders would receive an additional 35 cents per share, equal to about $15 million in cash, or the proceeds from the sale of the company's Kansas assets to a third party, whichever is greater.

Evergreen thus far has drilled or acquired 60 wells in the Forest City basin in eastern Kansas. The company holds a 100 percent working interest in 766,000 acres contained in two contiguous development areas, and has spent about $45 million on the project to date.

Evergreen said Randall & Dewey will conduct the data room process, which opened June 9 in Denver. Companies interested in reviewing the data may contact the firm at 281-774-2000. Bids are due June 28, unless regulatory review of the merger allows for more time, Evergreen said.

Closing on the sale of Evergreen's Kansas properties is anticipated by early August. However, the closing must occur before the closing date of the merger, which is expected this September or October. And the deal is still subject to the approval of the shareholders of both Evergreen and Pioneer.

Upon closing, Evergreen would become a subsidiary of Pioneer, with Evergreen shareholders receiving new shares of Pioneer, valued at $39 per share, plus an extra 35 cents per share should the Kansas assets not sell.

The addition of Evergreen's overall reserves, essentially all North American natural gas, would increase Pioneer's proved reserves by about one-third. Evergreen's year-end 2003 proved reserves of about 1.495 trillion cubic feet of natural gas equivalent are located primarily in Colorado's Raton basin.

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

Issue Index

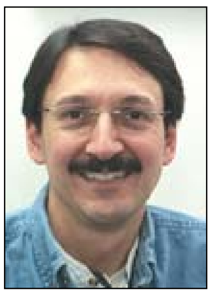
ALASKA

Alaska lawmakers begin hearings on proposed North Slope gas pipeline

Alaska legislators will look mostly at tariff issues in the first in a summer series of committee hearings on the proposed North Slope natural gas pipeline project. The opening hearings are set for June 16-17 in Anchorage.

The intent is for lawmakers to learn as much as they can about gas line tariffs, taxes, economics and market issues in anticipation of eventually receiving and voting on a fiscal contract negotiated between state officials and gas line project developers.

"It really is the beginning of a process, a series of meetings to get a lot of information on the table," said Senate President Gene Therriault, vice chairman of the Legislative Budget and Audit Committee, which is holding the hearings with the Senate Resources Committee.


PATRICIA LILES

The hearings are to ensure "we are schooled up and able to evaluate what the administration hands us." —Alaska Senate President Gene Therriault

The meetings are to ensure "we are schooled up and able to evaluate what the administration hands us," said Therriault, a North Pole Republican.

The administration of Gov. Frank Murkowski is negotiating under Alaska's Stranded Gas Development Act with the three major North Slope producers — ExxonMobil Production Co., ConocoPhillips Alaska Inc. and BP Exploration (Alaska) Inc.— for a long-term fiscal contract setting out payments in lieu of state and federal taxes should the companies go ahead with the gas line.

The administration also is negotiating with Canadian pipeline companies TransCanada Corp. and Enbridge Inc. for their own Stranded Gas Act contracts, should either or both companies take a role in the project.

State law requires legislative review

State law requires legislative approval of any contract before it can take effect. Murkowski has said he hopes to complete a draft contract before the end of this year.

"The Legislature is not an integral part of that," Therriault said of the administration's negotiations. The hearings will better prepare lawmakers for their consideration of the contracts, he said.

"It's education for legislators and to get the word out to the public so that the public realizes it's more than just a buy-a-new-car kind of contract," said Rep. Ralph

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● HOUSTON, TEXAS

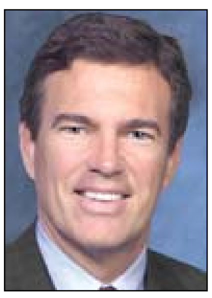
The remaking of Anadarko Petroleum

By RAY TYSON

Petroleum News Houston Correspondent

Anadarko Petroleum, which last year saw its chief executive officer resign over the company's sagging stock price, has made sweeping changes in the way it conducts business, including plans to sell more than $2.5 billion of high-cost oil and gas properties and to repurchase up to $2 billion of company stock.

The move would reduce Anadarko's reserve base by 15 percent and its production by a hefty 25 percent, but also is expected to create a stronger foundation on which to grow the company.


JAMES HACKETT

From the reduced asset base, Anadarko raised its projected annual production growth rate to a range of 5 to 9 percent from previous guidance of 3 to 7 percent.

Moreover, at mid-cycle oil and gas prices, Anadarko expects to generate $1.5 billion of unallocated cash flow over the next five years, which is expected to provide "some crucial flexibility" to deliver on its new goals.

"The end result is a company positioned to deliver stronger, highly visible growth and improved cash margins through 2009 and beyond, along with a substantially improved balance sheet," James Hackett, Anadarko's chief executive officer, said in a June 9 conference call with reporters.

Hackett said 2005 is expected to be above the high end of the new production range due to major development projects that begin this year and next. Moreover, he added, portfolio improvements are expected to lead to cash flow growth at a rate faster than production.

Sales proceeds targeted to debt reduction, stock repurchases

Anadarko intends to use the expected $2.5 billion in proceeds from property sales to reduce debt and to repurchase stock, he said. He said the board of directors has authorized the buy back of up to $2 billion of Anadarko common stock, which at roughly $50 per share still remains well below its 2000 peak of $76 per share.

Anadarko actually began restructuring itself last year several months after then CEO John Seitz resigned under pressure from a board of directors seriously concerned about the company's performance and lagging stock price. The company laid off about 10 percent of its workforce in an effort to save an annual $100 million, set out to reduce debt by $300 million, and closed two offices in Texas.

Anadarko's new strategy largely entails using profits from proven "foundation assets" onshore U.S. and Canada to fuel "growth platforms" in the Gulf of Mexico, Algeria and Qatar.

"Production from our foundation assets is expected to provide enough cash to help fund both recurring corporate capital needs and the growth platforms," Hackett said.

The majority of asset sales are expected to close by year-end, with the rest to be divested by the end of the first quarter of 2005. Properties identified for sale are estimated to include between 325 and 350 million barrels of oil equivalent of proved reserves and between 115,000 and 125,000 barrels per day of equivalent per day of production.

Most of the properties to be sold are located in the shallow-waters of the Gulf of Mexico, Western Canadian Sedimentary Basin and the Midcontinent region of the United States.

Conventional continental shelf properties to go on block

In the Gulf of Mexico, Anadarko said it intends to sell all of its "conventional" properties on the continental shelf, or those reserves and production located in the shallow, heavily exploited pay zones of the shelf. He said the company will now concentrate investment in more promising areas, specifically deepwater Gulf and deeper geological gas plays on the shelf.

Other U.S. properties targeted for sale include the majority of Anadarko's interest in oil recovery fields in central Oklahoma, fields in the Hugoton basin of southwest Kansas and Oklahoma, West Panhandle fields in Texas, properties in Wyoming's Overthrust region and in southeastern Colorado, various fields in the Permian Basin of New Mexico and Texas, as well as other unspecified onshore assets.

In Canada, Anadarko plans to sell fields in southern and central Alberta, northeast British Columbia and southeast Saskatchewan. Internationally, the company has targeted Oman and other "miscellaneous" properties.

"From a strategic perspective, the divestitures will enhance our ability to perform in the future," Hackett said. "By removing properties that are difficult for Anadarko to grow and retaining those we can grow efficiently and that have more upside potential, we expect to be able to provide near-term growth and profitability while also generating enough cash flow to fund long-term growth."

Focus on managing costs

He said Anadarko is specifically focused on managing costs, with renewed efforts to lower lease operating expenses per barrel of oil equivalent produced and to improve overall general and administrative expenses.

"Since the beginning of the year, we've been conducting a thorough review of the entire company to determine the best path forward," he added. "Our review highlighted the fact that, despite the good quality of our assets, there were factors at work making it difficult to grow the company and maintain strong capital efficiency."

Anadarko is not changing what the company does, but rather where and how resources are allocated, he said, adding that Anadarko's new strategy "envisions steady financing" of capital projects regardless of oil and gas price volatility.

"We are retaining our commitment to exploration and development, especially in the areas of high-potential exploration and unconventional resource identification and commercialization," he said. "We will strengthen our focus in those areas. However, we are changing which properties we choose to work, and how we're going to manage them."

Hackett said selling properties is not an effort by Anadarko to raise capital or to reduce debt, noting that the company already is generating significant free cash flow at current commodity prices.

"The best time to fix your roof is when the sun is shining, and it's shining on our industry right now, with recent property sales going at record prices," he said.

Anadarko said it hired Deutsche Bank to serve as its lead advisor to coordinate the overall asset divestiture program. Randall & Dewey was tapped to market the U.S. properties, while Waterous & Co. and Kobayashi Partners Ltd. will be handling the Canadian assets. In addition, Waterous will market international assets and Oil and Gas Journal Exchange will market southeastern Colorado.

Anadarko said it plans to repurchase stock depending on market conditions, but hopes to purchase a majority of the authorized $2 billion in shares within the next 12 months.●

Anadarko on track with Alaska plans

Mark Hanley, Anadarko Petroleum's top executive in Alaska, told Petroleum News June 10 that the company is "not divesting" any of its oil and gas properties in the state.

"Anadarko is focusing on areas where we think we can win. … We're still investing here," Hanley said, noting that Anadarko had participated in the June 2 lease sale for the National Petroleum Reserve-Alaska.

"In Alaska we have three areas where we are working," including what he refers to as "Alpine and west, the ConocoPhillips-operated Alpine field, its satellites and a good chunk of NPR-A."

The company is also operator of several oil prospects on Alaska's North Slope, including Jacob's Ladder.

"We're looking for partners for Jacob's Ladder (see Petroleum News' online archives). If we can get a partner by July 1 … we should be able to drill there next winter," Hanley said.

The third area Anadarko is involved in on the North Slope is the natural gas-prone Brooks Range Foothills.

"We've shot seismic there but our gas strategy is on hold until … there is progress on a gas pipeline and we get some idea of what access options we have," he said.

—KAY CASHMAN, Petroleum News publisher & managing editor

● WASHINGTON, D.C.

Federal energy bill issues delayed

Alaska natural gas pipeline provisions caught up in House, Senate corporate tax dispute

By LARRY PERSILY

Petroleum News Government Affairs Editor

The U.S. House version of corporate tax legislation will not include Alaska gas line tax incentives and other federal energy bill tax breaks adopted by the Senate last month, likely pushing the entire package into a conference committee later this summer or fall.

The House Ways and Means Committee chair deleted all of the energy bill provisions from the legislation in a move to hold down the bill's price tag, said John Katz, director of the state of Alaska's Washington, D.C., office.

The Senate version of the bill, adopted 92-5 on May 11, included provisions for accelerated depreciation for the proposed North Slope natural gas pipeline and tax credits for the project's gas treatment plant on the slope. Proponents of the project say they need the tax savings to reduce the gas line's financial risk.

Alaska's gas line provisions are not the problem holding up final passage, Katz said.

The tangled dispute between House and Senate members covers a long list of partisan election year fights, budget deficit debates and special-interest provisions that have stymied congressional passage of a comprehensive energy bill for more than a year and now threaten timely passage of the corporate tax bill.

"We're just caught up in it," Katz said.

The corporate tax bill is intended to settle a trade dispute with the European Union over a U.S. export tax break for corporations. The measure would eliminate the break but protect U.S. businesses from higher taxes by dropping the overall corporate tax rate 10 percent.

Bill also allows clergy to endorse political candidates

The 398-page House version also includes billions of dollars for tobacco farmer buyouts to attract Southern votes and a controversial provision to allow clergy members to engage in political activity, including endorsing candidates, without jeopardizing their church's tax-exempt status as long as they state they are not acting on behalf of their religious organization.

The $18 billion estimated cost of the Senate's energy tax breaks and incentives "was more than he wanted to absorb," Katz said of House Ways and Means Chair Bill Thomas. The California Republican's version of the corporate tax bill, unveiled the first week of June, already carries a net cost to the U.S. treasury of $34 billion over the next decade, according to reports in the Wall Street Journal.

And those non-energy tax breaks are drawing a fair amount of criticism in the news media. "The House would leave out the energy provisions but add tax breaks for bourbon distillers," Washington Post business columnist Steven Pearlstein said June 9. Senators had added the Alaska gas line and other energy bill provisions to the tax bill in hopes of catching a ride to passage and then to the White House for signature into law. The energy bill itself has been stuck in the Senate since House members passed it last fall but senators couldn't agree on a version acceptable to themselves and House Republican leaders.

House, Senate disagree over liability waiver

Still the single biggest difference between House and Senate members is the House-backed product liability waiver for manufacturers of the gasoline additive methyl tertiary butyl ether, or MTBE. Enough senators oppose the liability waiver to block passage of the energy bill.

"Nothing's changed in the Senate," Katz said.

The House had been scheduled to consider the tax and energy bills the week of June 7, but the death of former President Ronald Reagan pushed the calendar back a week, said Chuck Kleeschulte, spokesman for Republican Sen. Lisa Murkowski, the Alaska delegation's energy bill leader.

House Ways and Means is expected to consider its chairman's new version of the tax bill the week of June 14, with action by the full chamber perhaps the next week, Kleeschulte said. "I expect the House to pass their version," he said, leading to a conference committee when the Senate rejects the energy-free House version. The full House also intends the week of June 14 to take up last year's version of the energy bill — the version senators blocked in November. That bill, too, could go back to a conference committee this summer or fall. It will include the MTBE liability waiver, Kleeschulte said, and the Alaska gas line provisions missing from the Senate tax bill — the federal loan guarantee covering up to 80 percent of construction borrowing and provisions to speed up permitting and any judicial review.

Congress running out of time

Time, however, is getting tight for lawmakers, Katz said. Congress is scheduled to break June 26 for the July 4 recess, and will return to work after the holiday only until members leave town for their political parties' conventions in late July and August. Then there are the November elections to contend with, too.

"Anything is conceivable at this point," Katz said. ●

DALLAS, TEXAS

Pioneer takes stake in West Africa blocks

Exploration and production independent Pioneer Natural Resources has agreed to acquire from ROC Oil a 20 percent interest in Blocks H15 and H16 offshore Equatorial Guinea, West Africa, the company said June 7.

Pioneer said it would meet ROC's obligation to pay 70 percent of the cost of the Bravo-1 exploration well which began drilling on June 6. Pioneer said it also would carry ROC's retained 15 percent interest through the drilling of a second well currently scheduled for 2005. Pioneer said it also has the right to assume the role of technical manager upon the completion of drilling on the Bravo-1 well provided it meets the criteria. The transaction is subject to normal industry terms and conditions including receipt of government approval, Pioneer said.

Other participants on the block are operator Atlas Group with a 45 percent interest and Sasol with a 20 percent interest.

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

continued from page 3

HEARINGS

Samuels, chairman of the Budget and Audit Committee.

It's especially important in an election year to take the politics out of the discussion and make sure everyone understands the complexity of tariffs and the potential multi-billion-dollar pipeline investment, the Anchorage Republican said.

The first round of public hearings is set for June 16-17 in Anchorage, at the Legislative Information Office. The meetings are scheduled to run from 8:30 a.m. to 5 p.m., June 16, and 8:30 a.m. to early afternoon, June 17.

"This one is heavy on tariffs," Therriault said. The agenda includes presentations on pipeline costs and tariffs, regulatory oversight, the effect of tariffs on future exploration, and the effect of tariffs on state royalty and tax revenues.

Presenters will include the state departments of Revenue and Natural Resources, the North Slope producers, Anadarko Petroleum Corp., TransCanada and Enbridge, the Regulatory Commission of Alaska, J.P. Morgan Chase & Co. and state gas line consultant Lukens Energy Group Inc.

Next hearings to include access, expansion

The next two hearings likely will cover the state's desire for access for new producers to feed their gas into the line and for Alaskans to draw out gas for local use, and expansion of the line to accommodate future production, among other issues, Therriault said. Other possible agenda items include "potential pitfalls" the state should look for in any fiscal contract for a gas line, and short-term vs. long-term project benefits to the state, he said.

The two committees are expected to meet two more times this summer, with the dates and agenda to be announced.

The membership of the Legislative Budget and Audit and Senate Resources Committee totals 16 lawmakers, one-quarter of the entire House and Senate. The Legislature's gas line consultant, former state Oil and Gas Division Deputy Director Bonnie Robson, is advising the committees on the meeting agendas and helping to line up presenters, Samuels said.

—**LARRY PERSILY,** Petroleum News government affairs editor

U.S. ROCKIES

Petro-Canada acquires Prima Energy

Following in EnCana Corp.'s footsteps, Petro-Canada has gained a foothold in the U.S. Rockies natural gas region with an acquisition (subject to shareholder approval) of Denver-based Prima Energy Corp.

The Canadian energy giant announced June 8 it would pay US$534 million (US$39.50 per share) for Prima, giving it access to significant production and land holdings in unconventional gas — both coalbed methane and low-permeability tight gas. Both company boards have recommended approval of the deal.

The acquisition is the third major move made by Petro-Canada in recent months, following closely behind purchase of a 30 percent interest in the North Sea's Buzzard field, and an operating deal for a natural gas project in Syria.

Petro-Canada President Ron Brenneman described the Prima deal as "an excellent fit with our long-term strategy to sustain and expand our core North American natural gas business. Prima has an extensive land position and strong capability in unconventional gas production, offering Petro-Canada an important new footprint and an entry into the fastest-growing segment of continental natural gas supply."

"We've been seeking opportunities to step out from our existing platform in Western Canadian gas and beyond opportunities in Arctic gas and liquefied natural gas from abroad," Petro-Canada Senior Vice President Kathleen Sendall said at a press conference. "Unconventional gas has been a focus from the start."

The Prima purchase also follows EnCana's move into the U.S. Rockies gas industry with its US$2.7-billion takeover of Tom Brown Inc. Brenneman said at the press conference that the Prima acquisition could well be a springboard to further acquisitions in the U.S. Rockies.

Prima's gas production is expected to double by 2007, from 55 million cubic feet per day at current production levels. Proved gas reserves at the end of 2003 were 152 billion cubic feet — 552 billion cubic feet with probable reserves added.

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

WASHINGTON, D.C.

ExxonMobil CEO: Energy use to grow 40 percent by 2020

LEE R. RAYMOND

The chief executive of Exxon Mobil Corp. says the United States must face its energy future realistically and reduce dependence on Middle East oil by developing sources in other parts of the world.

Lee R. Raymond said June 7 that Americans must allow more drilling off the shores of California and Florida, in Alaska and the Rocky Mountains.

Raymond, who leads the world's largest publicly traded oil company, also said that

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● HOUSTON, TEXAS

Marathon looking to sell Powder River CBM assets

Pennaco Energy, acquired in 2001, no longer a good fit; Marathon now focused on stranded gas worldwide, including West Africa LNG

By RAY TYSON

Petroleum News Houston Correspondent

Marathon Oil is taking offers for U.S. Rockies subsidiary Pennaco Energy, a little over three years after acquiring the independent coalbed methane producer in a deal valued at about $500 million.

When closing the transaction in March 2001, Marathon said Pennaco was "a great strategic fit" for the company and would provide "a significant new reserve base that we can develop and deliver quickly to the marketplace."

Marathon has altered its tune, saying June 8 it intends to solicit offers for Pennaco, which operates solely in the gas-rich Powder River Basin of northern Wyoming and southern Montana.

"Marathon's decision to market Pennaco and its assets is part of the company's ongoing efforts to actively manage its global asset portfolio to ensure alignment with its business strategy and to generate sustainable value growth," Marathon said in a written statement.

Translated that means the value of Pennaco no longer measures up to other opportunities, such as Marathon's desire to capture more of its stranded gas around the world, including West Africa where the company wants to construct a large liquefied natural gas plant to process gas from its Alba field.

"Assets need to be reviewed and stacked up against other opportunities," Marathon spokesman Paul Weeditz said of Pennaco." Hopefully, he added, "the value to them (potential buyers) is greater than it is to us."

Strong prices, recent sales in Rockies a factor

Moreover, strong natural gas prices and recent sales transactions in the Rocky Mountains "indicate

see **MARATHON** *page 7*

● BEIRUT, LEBANON

OPEC boosting output ceiling by 2 million barrels in July

Decision no guarantee of more oil on market, since cartel already producing 2.3 million barrels above limit; increase will come over two months

By BRUCE STANLEY

Associated Press Business Writer

OPEC's decision to raise its output ceiling by up to 11 percent over two months may help soothe a nervous market, but it doesn't oblige the group to pump a single barrel of additional oil.

The Organization of Petroleum Exporting Countries agreed June 3 to hike its production ceiling by 2 million barrels a day next month and an additional 500,000 barrels a day in August, if necessary, in a bid to rein in uncomfortably high prices for crude.

OPEC portrayed the two-stage increase as a strong signal of its resolve to ensure ample supplies for a growing world economy. Representatives of the group approved the decision during four hours of talks at a Beirut hotel.

Production already above current ceiling

However, OPEC acknowledges that it's already producing at least 2.3 million barrels above its current ceiling of 23.5 million barrels. Even if OPEC followed through with both stages of its planned hike in the target, OPEC President Purnomo Yusgiantoro implied that it would simply be legitimizing the cur-

see **OPEC** *page 7*

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MARATHON

that now is the appropriate time to solicit potential offers for these interests," Marathon said.

In a similar effort to high-grade its portfolio, Marathon last year sold its upstream assets in Western Canada to Husky Energy for about $588 million. The company said then the assets no longer represented "a strategic fit." That deal included booked reserves of about 69 million barrels of oil equivalent and average net production of about 21,000 barrels of oil equivalent per day. However, if Marathon does not receive a "compelling offer" for Pennaco, Marathon will keep the assets and "simply move on" with current development plans for the Powder River basin, Weeditz said.

"These are quality assets," he said.

Bidding to conclude in third quarter

Marathon said it plans to conclude the bidding process in the third quarter of this year. If an acceptable offer for Pennaco is received, Marathon said it would anticipate closing the transaction during the fourth quarter. Three years ago Denver-based Pennaco, founded in 1998, was among the largest leaseholders in the Powder River basin with more than 400,000 net acres and net production exceeding 50 million cubic feet of natural gas per day. Net proven reserves at the time were estimated at about 200 billion cubic feet, with more than 800 billion cubic feet of upside potential.

Marathon is currently the largest holder of coalbed methane acreage in the Powder River basin, with more than 650,000 net acres. Production from its operations averaged about 72 million cubic feet of natural gas per day during the first quarter of 2004.

At year-end 2003, Marathon's total resource base in the Powder River basin exceeded 2 trillion cubic feet of natural gas, of which 388 billion cubic feet were booked as proved reserves.

Pennaco only 10 percent of Marathon's U.S. gas production

Marathon noted that while it has a major presence in the Powder River basin, production from Pennaco represent only about 10 percent of its total U.S. natural gas production of around 732 million cubic feet per day, and about 3 percent of worldwide oil and gas production of about 365,000 barrels of oil equivalent per day.

The marketing and potential sale of Pennaco does not include any of Marathon's conventional oil and natural gas exploration and production operations in Wyoming and Montana, the company said. That represents 21,000 barrels of oil per day and 39.8 million cubic feet per day.

In 2001, Marathon acquired for cash all the outstanding common shares of Pennaco for $19 a share in a transaction valued at about $500 million, including $54 million in debt. Before the deal was approved, Marathon estimated the final acquisition and development costs of Pennaco's proven, plus probable reserve base would be around $4.50 per barrel of oil equivalent. ●

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OPEC

rent overproduction. Still, crude prices cooled after OPEC's announcement, easing 9.5 percent since hitting record highs earlier in the week. But industry analysts said the decision was unlikely to make gasoline any cheaper in the United States, where refinery constraints and rising demand during the peak summer driving season have pushed prices higher at the pump.

"Gasoline prices are still going to stay high," said Jamal Qureshi, of the Washington-based consultancy PFC Energy.

Saudis wanted increase at once

In his opening address at the meeting, Purnomo of Indonesia called on OPEC's members to do "as much as they can to help stabilize the oil market," but he refrained from an explicit request for them to provide additional barrels above what they're already producing.

Saudi Arabia, OPEC's most influential member, pushed to lift the ceiling by 2.5 million barrels all at once, and markets were expecting OPEC to approve the widely publicized Saudi plan. But OPEC member Iran insisted on a more gradual rise, to keep prices from falling too fast, and the Saudis compromised on the conditional two-step increase.

Claude Mandil, head of the Paris-based International Energy Agency, said OPEC's decision shows that producing countries recognize that production is important for calming oil markets. The IEA is the energy watchdog for oil importing nations.

"At the same time, we think the most important (thing) is not quotas, it's not targets," he said. "What is really important is real extra barrels."

Actual increase in supplies needed

Many analysts agreed, arguing that OPEC's focus on its production ceiling was diverting attention away from the market's need for an increase in actual crude supplies.

"Who cares about the quotas," said Adam Sieminski of Deutsche Bank in London. "The important thing is what the Saudis are doing with their volumes and what others are doing with production as well."

Under pressure from the United States and other major importers, Saudi Arabia has already boosted its actual output by 600,000 barrels a day, independently of OPEC. Saudi Arabia has the world's largest proven oil reserves and is the only OPEC member with capacity to pump significant amounts of fresh oil. The United Arab Emirates announced June 2 that it would raise production by more than 400,000 barrels a day, while Kuwait said it would increase output by 100,000 barrels.

Prices have escalated

Prices have escalated in recent weeks despite OPEC's efforts to meet market requirements, the group said in a communique. Geopolitical tensions, stronger than expected demand in China and the United States, and stricter U.S. specifications for gasoline have all contributed to higher prices, it said.

"Combined, these factors have led to unwarranted fear of a possible future shortage of crude oil, which has, in turn, resulted in increased speculation in the futures markets with substantial upward pressure on crude oil prices," OPEC said.

Contracts of light U.S. crude for July delivery shot up to $42.33 a barrel on June 1 — the highest settlement price in the contract's 21-year history on the New York Mercantile Exchange — following a terrorist attack in the Saudi oil hub of Khobar that killed 22 people, most of them foreign oil workers. The attack stunned markets, which were already jittery about stretched oil inventories and instability in the Middle East.

But prices fell about 6 percent on June 2, after Saudi Arabia claimed backing for its proposed hike in production limits, and they slipped again June 3 and early June 4. Contracts of U.S. light crude for July delivery were 63 cents lower at $38.65 a barrel in early June 4 trading on the New York Mercantile Exchange. In London, July contracts of Brent crude fell 33 cents to $36.07 on the International Petroleum Exchange.

Analysts predicted that the increase in OPEC's ceiling would have only a modest effect on crude prices in coming weeks.

Yasser Elguindi of Medley Global Advisors in New York said U.S. prices would stay "very strong" during the summer, averaging $35 a barrel. Disruptions in supplies — such as a strike in Nigeria, political chaos in Venezuela or another terror attack in the Gulf — could push prices still higher, he said. ●

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CEO

energy use will increase 40 percent by 2020, ensuring a rise in carbon dioxide emissions. Many climate scientists link emissions to global warming, but Raymond has always said more study is needed.

"This reality is one that many people recoil for accepting, but the United States and other industrial nations will continue to increase carbon emissions for some time, regardless of Kyoto," he said, referring to an international treaty to limit emissions by developed countries.

Raymond made the comments in a speech prepared for delivery June 7 to the Woodrow Wilson International Center for Scholars in Washington.

United States dependent on imports

The ExxonMobil CEO said the United States will, like most of the world, be petroleum importers, increasingly dependent on the Middle East because of the region's large oil and gas reserves, estimated at half the global supply.

"We do not have the resource base to be energy independent," he said of the United States. "Even if we are prepared to develop more petroleum supplies here, we will still be far, far short of our needs. And in doing so, we simply cannot avoid significant reliance on oil and gas from the Middle East because the world's supply pool is highly dependent upon the Middle East."

Raymond said the United States should give economic aid and trade liberalization to help unstable but oil-rich countries elsewhere in the world, including Africa, Russia and the Caspian Sea area.

Raymond said 80 percent of the world's energy in 2020 will still come from fossil fuels such as oil, coal and natural gas. He said alternate sources such as solar and wind power will be too costly.

Raymond skipped over policies to encourage more efficient use of energy, calling it "a discussion for another time."

ExxonMobil is based in Irving, Texas.

—THE ASSOCIATED PRESS

● NPR-A NORTHEAST

BLM proposes changes to NE NPR-A leasing plan

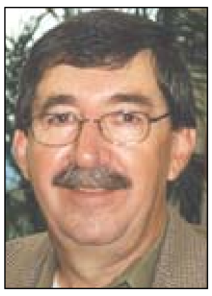
Preferred alternative would open more acres for leasing, change stipulations from prescriptive to performance-based

By KRISTEN NELSON
Petroleum News Editor-in-Chief

The area available for oil and gas leasing in the northeast planning area of the National Petroleum Reserve-Alaska would be expanded under a proposal announced June 8 by the Bureau of Land Management.

And, says the agency's Alaska head, by changing from 79 prescriptive stipulations to performance-based stipulations — and adding more consultation with North Slope residents — development which does take place will be done in ways which meet management objectives, such as protecting caribou migration.

The change to performance-based stipulations, BLM Alaska State Director Henry Bisson said at a June 8 press briefing, "gives us the flexibility to be more stringent if we need to or to work with industry to come up with alternative ways to meet those objectives, and so we've gone to a more performance-based approach."



BLM's preferred alternative would keep 213,000 acres of "the most sensitive goose molting habitat" unavailable for oil and gas leasing. … "That area … (was) set aside during the first Reagan administration," but was expanded in the mid-1990s to about 600,000 acres, BLM Alaska Director Henry Bisson said.

As an example, he said, there are three stipulations among the 79 in the 1998 Northeast NPR-A record of decision which deal with pipelines and caribou, and they all require the pipelines to be five feet from the ground.

But when BLM looked at the objective, he said, which is to permit caribou to migrate "without being impeded by petroleum production facilities — they need to get under the pipelines, they need to get around the area, and the subsistence users on the North Slope need to be able to do the same thing to go hunt caribou," the agency found that five feet is not high enough.

So the new management objective says that before permanent facilities are allowed to be constructed, BLM needs "to be assured that caribou can migrate through the area, and we said that the current standard is pipelines have to be seven feet — two feet higher than they currently are."

More high oil potential areas to be offered

At present, only 56 percent of areas with high potential for oil and gas are available for leasing in the northeast NPR-A. BLM's proposed alternative would allow leasing on 75 percent of areas with high potential for oil and gas, opening the area closest to the Barrow Arch to leasing.

"Virtually all of the oil that has been produced … on the North Slope, has come from within 25 miles of the Barrow Arch," Bisson said. And in the northwest NPR-A lease sale June 2, he noted, the bulk of the leases sold were within that 25-mile radius of the Barrow Arch.

Some 600 million barrels of oil are economically recoverable under acreage offered in the existing northeast plan at a $30 per barrel crude oil price, but 2.1 billion barrels would be economically recoverable under Alternative B, the agency's preferred alternative, Bisson said.

The existing plan for NPR-A northeast could result in 60,000 barrels of oil production per day, but under the preferred plan, "we estimate that there would be likely about 200,000 barrels of production per day," reducing the cost of imported oil by some $2 billion a year.

But, he said, "we also recognize the significance of the subsistence values and wildlife values that exist on the North Slope, and we're attempting to balance our plan to provide for oil and gas development while protecting those resources."

Protected area 213,000 acres

The agency's preferred alternative would keep 213,000 acres of "the most sensitive goose molting habitat" unavailable for oil and gas leasing. This area, Bisson said, is about nine townships north of Teshekpuk Lake.

"That area has actually been set aside from oil and gas leasing since the early '80s. During the first Reagan administration, that area was set aside as being too sensitive for oil and gas leasing activities to be conducted," he said, but was expanded in the mid-1990s to about 600,000 acres.

Some protections have been expanded in the proposed alternative.

"We are also proposing to expand no surface occupancy requirements to include all of the deepwater lakes south of Teshekpuk Lake, not just the ones that exist in the current plan… we have protected substantially more lakes than were protected by the existing plan," Bisson said, and no-surface occupancy restrictions along an additional river, the Tingmiaksiqvik, "which was not protected by the existing plan."

The Native community, he said, did not want BLM to change the buffers at Fish and Judy creeks, "and we are not," Bisson said. Consultation with the Native community under the existing plan is required "only for activities that occur at Fish Creek and Judy Creek, and we are going to require consultation for virtually all of the activities that we do in the planning area."

Bisson said this provision would be identical to what BLM is requiring in the northwest planning area.

"So we're going to be requiring more communication, more discussion with the folks on the North Slope before activities occur on the ground, including the whaling folks up there as well."

BLM's preferred alternative is "B". The proposal also includes a no action alternative, which would make no changes from the 1998 record of decision, and an alternative which would open the entire northeast NPR-A to leasing.

The amendment is available on the agency's web site at www.ak.blm.gov. ●

GULF OF MEXICO

Shell Gulf platform to be closed down longer than expected

Shell Oil Co.'s deepwater Mars platform in the Gulf of Mexico will be shut off to production longer than the two to three weeks originally anticipated, the company said June 7.

Shell closed production on May 22 after workers discovered a pipeline leak that released just over 3 gallons of crude oil into the water.

During an inspection, workers found that a natural gas line also showed signs of deterioration, thus forcing a longer delay in starting production, Shell said. The gas pipeline has not leaked, the company said.

Shell said it expected repairs to take several more weeks.

When operating, platform produces about 150,000 gallons of crude oil and 170 million cubic feet of natural gas per day.

The platform is about 130 miles southeast of New Orleans

—THE ASSOCIATED PRESS

NORTH AMERICA

Drilling rig count jumps by 60 to 1,424 in weekly survey

The number of rotary rigs operating in North America, spurred by the Canadian rig count, soared to 1,424 during the week ending June 4, according to rig monitor Baker Hughes.

That means there were 60 more rigs operating in North America compared to the previous week and 102 more versus the year-ago period.

Canada accounted for all of the increase, jumping by 61 rigs to end the recent week at 256 rigs. However, Canada's rig count was down by 12 compared to the same period last year.

The overall rig count was partly offset by a loss of one rig from the previous week in the United States, bringing the total there to 1,168 rigs for the recent week, still an increase of 114 rigs compared to the same period last year. Land rigs alone fell by five from the prior week to 1,054, while the inland waters picked up five rigs to end the recent week at 22. Offshore United States lost one rig for a total of 92 in the recent week.

Of the total number of rigs operating in the United States during the recent week, 1,008 were drilling for natural gas and 159 for oil, while one rig was being used for miscellaneous purposes. Of the total, 739 were drilling vertical wells, 305 directional wells, and 124 horizontal wells.

Among the leading producing states in the United States, Louisiana's rig count during the recent week jumped by nine to 169. Oklahoma's increased by five to 168. Wyoming's increased by 74. And California's increased by one to 22. The number of rigs operating in Texas fell by seven to 494 and slipped by one to total seven in Alaska. New Mexico was unchanged at 66 rigs.

—RAY TYSON, Petroleum News Houston correspondent

● NOVA SCOTIA OFFSHORE

COURTESY TRANSOCEAN

Transocean's rig Deepwater Pathfinder was contracted to drill the only Nova Scotia wildcat in 2004, the Crimson K-81 well.

Costs, dry holes push Nova Scotia basin to brink

Three exploration failures since last summer spread disappointment through industry, government circles; but offshore still in infancy, with only 200 wells drilled

By GARY PARK

Petroleum News Calgary Correspondent

It's a numbers game that keeps pushing Nova Scotia's hopes of turning its offshore into a significant natural gas-producing basin closer to the brink of a shutdown, despite the beckoning riches of the U.S. Northeast market.

Both the shallow and deepwater prospects are compiling a discouraging record, with 12 of the last 15 wells since 1998 abandoned at a cost of about C$750 million and three in the uncertain category, despite claims of gas strikes.

The latest exploration failure in May ranked as the costliest yet on Canada's offshore, with estimates ranging from C$100 million to C$120 million for the Weymouth A-45 drilled by EnCana (the 55 percent operator), Shell Canada 30 percent and Norway's Ocean Rig 15 percent.

Although the partners did not disclose the actual drilling costs beyond EnCana's price tag of about C$60 million, even at the low end of the cost scale it surpassed the C$90 million Onondaga B-84 well drilled two years ago by 100 percent-owner Shell Canada.

The other setbacks since last summer have included:

• Imperial Oil's decision to abandon its Balvenie B-79 deepwater well, drilled in partnership with Talisman Energy after reaching a depth of 15,600 feet or a targeted 18,450 feet. It failed to encounter hydrocarbons in commercial quantities.

• Canadian Superior Energy's abandonment of the Mariner I-85 well. Its partner El Paso refused to spend any more money participating in a well flow to test Canadian Superior's reports of a significant discovery.

Even the traditional optimists were hard pressed to find much encouragement in the Weymouth well.

Debora Walsh, the East Coast manager for the Canadian Association of Petroleum Producers, told the Globe and Mail that "it's difficult to put a positive spin on the abandonment of this well."

"Absolutely," said Nova Scotia Premier John Hamm when answering his own question: "Am I disappointed?"

Fewer than 200 wells drilled

But the province's Energy Minister Cecil Clarke

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NOVA SCOTIA

and several analysts kept trying to inject a dose of reality into the assessments.

Clarke said offshore Nova Scotia is in its infancy — an undeniable fact given that fewer than 200 wells have been drilled in the basin and only five in the deepwater, compared with more than 40,000 in the U.S. Gulf of Mexico.

The test now is whether the industry will meet its commitments to drill 16 wells — 11 deepwater, five shallow-water — between now and the end of 2006 when the bulk of C$1.6 billion in work commitments expire.

On top of the dry holes, confidence in the region took a jolt last August when ExxonMobil Canada, Shell Canada and Imperial Oil opened up a data room of exploration acreage parcels containing work commitments of C$277 million and significant discovery licenses to potential farm-in partners.

GULF OF MEXICO

Current Deepwater Activity

Operator	Area/ Block	OCS Lease	Rig Name	Prospect Name	Water Depth (ft)
Shell Offshore Inc.	MC 657	G08496	R&B FALCON NAUTILUS	Coulomb	7,565
Union Oil Company of California	WR 678	G21245	DISCOVERER SPIRIT	Saint Malo	7,036
Chevron U.S.A. Inc.	WR 759	G17016	TSF DISCOVERER DEEP SEAS	Jack	6,965
BP Exploration & Production Inc.	GC 743	G15606	TSF DEEPWATER HORIZON	Atlantis(GC)	6,829
BP Exploration & Production Inc.	MC 778	G09868	TSF DISCOVERER ENTERPRISE	Thunder Horse South	6,040
Dominion Exploration & Production, Inc.	MC 734	G21778	TRANSOCEAN CAJUN EXPRESS	Thunderhawk	5,724
Dominion Exploration & Production, Inc.	MC 773	G19996	PRIDE 1503	Devil's Tower	5,610
Marathon Oil Company	AT 488	G18617	NOBLE AMOS RUNNER	Kansas 2	4,725
Spinnaker Exploration Company, L.L.C.	MC 124	G24049	GLOMAR JACK RYAN	Zorin	4,479
BHP Billiton Petroleum (GOM) Inc.	GC 653	G20084	GLOMAR C. R. LUIGS	Shenzi	4,340
Anadarko Petroleum Corporation	GC 608	G18402	NABORS POOL 140	Genghis Khan	4,287
Chevron U.S.A. Inc.	GC 640	G20082	FALCON DEEPWATER MILLENNIU	Tahiti	4,017
Anadarko Petroleum Corporation	GC 518	G21801	NOBLE PAUL ROMANO	K2 North	3,993
Eni Petroleum Co. Inc.	GC 562	G11075	GLOMAR CELTIC SEA	K2	3,933
Newfield Exploration Company	MC 291	G25085	GLOMAR EXPLORER	Nelson	3,911
Shell Offshore Inc.	GC 248	G15565	NOBLE MAX SMITH	Glider	3,440
Shell Offshore Inc.	GB 516	G11528	NOBLE JIM THOMPSON	Serrano	3,392
Eni Petroleum Co. Inc.	GC 254	G08010	DIAMOND OCEAN VALIANT	Allegheny	3,225
Shell Offshore Inc.	VK 956	G06896	H&P 205	Ram-Powell	3,214
Kerr-McGee Oil & Gas Corporation	GB 668	G17408	NABORS MODS RIG 150	Gunnison	3,152
Nexen Petroleum U.S.A. Inc.	GC 243	G20051	NOBLE HOMER FERRINGTON	Aspen	3,050
Shell Offshore Inc.	MC 807	G07963	H&P 201	Mars	2,945
TOTAL E&P USA, INC.	MC 243	G19931	GLOMAR ARCTIC I	Matterhorn	2,847
TOTAL E&P USA, INC.	MC 243	G19931	SUNDOWNER XVI	Matterhorn	2,816
Chevron U.S.A. Inc.	GC 205	G05909	NABORS 85 (MAYRONNE 162)	Genesis	2,590
Walter Oil & Gas Corporation	MC 583	G16624	DIAMOND OCEAN LEXINGTON	Killer Bee	2,487
Murphy Exploration & Production Company -	MC 582	G16614	MODS 141	Medusa	2,214
LLOG Exploration & Production Company	GB 378	G24488	DIAMOND OCEAN SARATOGA	GB 378	2,044
Kerr-McGee Oil & Gas Corporation	GB 244	G15880	TRANSOCEAN MARIANAS	Basal Peak	1,946
Chevron U.S.A. Inc.	VK 786	G10944	ENSCO 25	Petronius	1,754
Westport Resources Corporation	MC 707	G25103	DIAMOND OCEAN CONCORD	Valley Forge	1,538
El Paso Production GOM Inc.	EW 1003	G13091	SUNDOWNER XI	Prince	1,490
BP Exploration & Production Inc.	MC 109	G05825	H&P 203	Amberjack	1,030
Total Deep Water Prospects with Drilling/WO Activity			33		

New Deepwater Activity

Chevron U.S.A. Inc.	GC 640	G20082	Tahiti	4,017
LLOG Exploration & Production Company	GB 378	G24488	GB 378	2,044

Study thinks resources are there

These cumulative developments put a cloud over the most recent study by the Canada-Nova Scotia Offshore Petroleum Board that estimated reserve potential of the deepwater at 15 to 41 trillion cubic feet and of the shallow-water at 18 tcf, based on interpretations of seismic results from about 20,000 square miles.

The study's authors likened the deepwater to the basins of the Gulf of Mexico, offshore Brazil and West Central Africa.

"We think the resources are there, but it's theoretical and we won't know until there are discoveries made through drilling," said offshore board chief executive officer Jim Dickey.

The study conceded that it is "very important to acknowledge that calculated upside potentials ... also have a downside possibility so any conclusions or expectations drawn from these (estimates) should be cautiously employed."

EnCana, Shell say they're not quitting

Regardless of the Weymouth failure, EnCana and Shell Canada insist they will take time to evaluate the results and have no intention of quitting the basin.

"We know this was an exploration prospect," said a spokeswoman for Shell Canada. "It has considerable risk because the deepwater is a high-risk, high-reward play."

The challenges is drilling in 5,200 feet of water to a depth of 21,400 feet were readily apparent when the well took 185 days, 65 days longer than expected, because of tough weather conditions and geological structures.

But EnCana spokesman Alan Boras insisted "we learned a lot" that will help shape the company's future strategy for the block and the basin.

There isn't much time to rue the misfortunes or ponder the next move.

Crimson K-81, in 6,200 feet of water and targeting a depth of 20,300 feet, is scheduled for early spudding by partners Marathon Oil 40 percent, EnCana 35 percent and Murphy Oil 25 percent to probe the same exploration license as the Annapolis G-24 wildcat discovery in 2002 that operator Marathon said could be part of a block holding 5 to 15 trillion cubic feet.

Results from Crimson could be crucial for Marathon which has two other exploration licenses in the deepwater — 100 percent of a work commitment of C$177 million and 50 percent of a second license with a work bonus bid of C$194 million, with both expiring by the end of 2006.

The Nova Scotia Department of Energy said last fall it was optimistic that drilling would exceed even the work commitments, predicting nine shallow-water and 18 deep-water wells over the next three years.

If it's right, the Conference Board of Canada projects that offshore activity could raise Nova Scotia's Gross Domestic Product by 72 percent through 2020.

Deep Panuke development uncertain

Hanging in the uncertainty category are two wells drilled in the shallow-water Deep Panuke reservoir, which EnCana originally targeted for production in 2006 at 400 million cubic feet per day before withdrawing the regulatory applications last year to explore a smaller production facility.

Of the two wells, Margaree F-70 (wholly owned by EnCana) flowed at 53 million cubic feet per day from a gas bearing pay zone of 70 meters and MarCoh D-41 (ExxonMobil 51 percent, EnCana 24.5 percent and Shell Canada 24.5 percent) reportedly struck 100 meters of gas-bearing zone, yielding enough information to determine that a flow test was not needed.

EnCana believes Margaree and MarCoh have improved the economic potential of the 935 billion cubic foot Deep Panuke field, but will not indicate whether the project is now commercially viable.

For now, EnCana, while looking for additional reserves, is also exploring "possible" synergies with partners in the producing Sable Offshore Energy Project, with the though of sharing infrastructure to improve the prospects for Deep Panuke.

Reserves have been dropped at Sable

The first and so far only producing field at Sable is grappling with its own woes, less than four years after coming on stream.

It commenced operations with estimated original sales gas reserves of 3.5 trillion cubic feet — a figure that has since plummeted in stages to 1.38 tcf, reducing the projected economic operating life to 10 years from 25 years.

Alex Dodds, president of ExxonMobil Canada, the operator with a 50.8 percent interest, said earlier this year that to maintain the facility and "make sure it's utilized for its design life ... we must continue to look for additional gas resources and develop what's already there."

The message to Clarke is plain: The Nova Scotia government cannot afford to see exploration wane.

To that end he has tried wooing potential explorers in Alberta and at the recent Offshore Technologies Conference in Houston.

The Canadian government also offered a helping hand in May by suspending duties for five years on foreign-owned offshore rigs, giving up about C$50 million in potential revenues.

In addition, Clarke said governments have pledged to answer industry calls for streamlining regulations and looking at tax changes.

But the clock is running. Harvey Doerr, president of Murphy Oil, said that if the Crimson well fails to deliver it could be the last deepwater well in some time, since there is no sign of any other company willing to step up to the plate. ●

● NENANA, ALASKA

Shooting seismic in Nenana this winter

Andex Resources contracts with PGS Onshore to complete $3 million seismic program in Nenana Basin during winter of 2004-2005

By PATRICIA LILES

Petroleum News Contributing Writer

Andex Resources LLC plans to spend $3 million this winter on a two-dimensional seismic program in the Nenana basin, a relatively unexplored area in Interior Alaska believed to have natural gas potential.

The Denver and Houston-based company holds an exploration license for nearly 500,000 acres of land in the Nenana basin. Andex has contracted PGS Onshore to complete the seismic work, scheduled to begin in December as soon as weather conditions allow, according to Larry Watt, PGS's Alaska manager.

"Start up depends on the weather — when we have enough snow cover and ice," Watt said. "We'll start everything after Dec. 1 and will be out of there by April 30."

The actual seismic recording work will take about 60 days, he said, once the front-end work is completed. A temporary camp to house workers will be set up by Taiga Ventures of Fairbanks, roughly 15 miles west of Nenana in the Minto Flats. Temporary ice roads will be constructed to the camp, providing four-wheel drive vehicle access. Constructing a snow/ice bridge across the Nenana River to access the Minto Flats area will be the first access hurdle.

Watt expects a crew of 35 to 40 people to work on the seismic project, which includes camp and catering employees. Talks about efforts to hire locally have already begun, a topic included in a public meeting held in Nenana on May 25.

"We had about 40 or 50 people there. There was a lot of interest and questions," Watt said. "A lot of the concerns involved local hire."

Slots that could be filled locally include drivers, mechanics, recording helpers and camp catering staff, he said.

About two months prior to start-up, PGS will take applications from local residents and conduct a two-day induction, providing safety, environmental and job training.

Spending details

PGS Onshore's client, Andex Resources, announced during the public meeting in Nenana their plans to spend $3 million on the seismic program this winter. That's in addition to spending about $3 million to acquire old seismic data shot in the 1960s and 1980s, and reprocessing that information, Watt said.

An Andex spokesman declined to comment for this article.

"They said they have already spent $3 million, and they will spend another $3 million this winter. To drill wells, they plan to spend $10 to $12 million in ensuing years," Watt said.

Andex has a work commitment with the state of Alaska, part of its exploration license issued in late 2002, according to Matt Rader, natural resource specialist in the Department of Natural Resources' Division of Oil and Gas.

Andex's license contains a seven-year term to convert to oil and gas leases, and contains a work commitment of $2,525,000, Rader said.

The division is taking comments on the seismic exploration program through June 11 and should issue the permit to PGS later in June, said Rader, who also attended the public meeting in Nenana.

"People at the meeting were interested in local employment opportunities, and how the work would be staged out of Nenana," he said. "There were not really any other concerns that came up at the meeting."

Exploration plans

PGS plans to collect approximately 200 line miles of 2-D seismic in the northeast/southwest trending basin. One initial reconnaissance line will stretch 40 miles, running nearly the entire length of the exploration area. A second line, parallel to that initial reconnaissance line, will cover about two-thirds of the distance, or about 25 miles.

Two small areas within the exploration license area will contain clusters of seismic lines, in a pattern "fairly concentrated," Watt said. The center of the exploration area is about 10 miles west of Nenana, Watt said. "They will be working northeast and southwest of that point," he said. "They will not go more than 25 miles from Nenana."

Andex's license is west of the Parks Highway, extending from Anderson north to approximately eight miles south of the village of Minto. There are also lands within the license area owned by Doyon Ltd., Seth de Ya-Ah Corp. (the Minto village corporation) and Toghottehle Corp. (the Nenana village corporation).

Andex and PGS met with the Native corporations in May, prior to the public meeting, Watt said.

Past work

According to the department's final best interest finding for the Nenana basin, issued in August, the area is relatively unexplored. The northern basin is undrilled, and no seismic data has been gathered there, despite gravity surveys showing it hosting the deepest portion of fill in the sedimentary basin.

"The sedimentary basin fill consists of as much as 16,000 feet or more of non-marine Quaternary and Tertiary sediments lying above a Jurassic metamorphic basement," the state report said. "The prospective sedimentary section, thought to be time-equivalent to the productive Kenai Group in the Cook Inlet, consists of sands, gravels, conglomerates, shales and coals ... structural, stratigraphic and combination traps are likely to occur throughout the basin." Two shallow exploration wells were drilled in the central and the southern portion of the study area, where some seismic data has been previously acquired.

"Except for minor amounts of gas associated with coal beds, no hydrocarbon shows were observed in the wells," the state said in its report. "Reports of oil seeps in the basin are unconfirmed."

Unocal drilled the 3,062-foot Nenana No. 1 just west of Andex's license area in 1962. ARCO drilled the 3,509-foot Totek Hills No. 1 south of the exploration license area in 1984.

"At that time, no one was looking for gas," Watt said. "Hopefully this will prove out to be good for the community and our client." ●

HOUSTON, TEXAS

Cabot's Little Horn Bayou prospect yields more gas pay

Independent producer Cabot Oil & Gas said June 7 it drilled a successful offset well to this year's previously announced natural gas discovery on its Little Horn Bayou prospect in Terrebonne Parish, La.

The CL&F 5-1 well was drilled to a depth of about 13,000 feet and encountered 64 feet of natural gas pay in the Hollywood sand, Cabot said.

Completion operations are under way with first production for both the initial CL&F 8-1 discovery and the offset expected by the end of the month at a stabilized rate of 20 to 30 million cubic feet equivalent per day, Cabot said.

Cabot holds a 75 percent working interest in both wells with partner Walter Oil & Gas.

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

NORTHERN CANADA

Mackenzie natural gas line regulators seek comment

Regulators charged with handling the Mackenzie Gas Project are seeking public comment on a draft agreement for an environmental impact review of the C$5 billion venture.

They have set a July 15 deadline for comments on two documents as the regulatory pace starts to quicken, in anticipation of formal applications in the second half of the year from the Mackenzie Delta Producers Group, comprising Imperial Oil, ConocoPhillips, Shell Canada, ExxonMobil Canada, owners of the three anchor gas fields on the Delta, and the Aboriginal Pipeline Group.

The draft terms were released June 3 by the Canadian Environmental Assessment Agency, the Mackenzie Valley Environmental Impact Review Board and the Inuvialuit Game Council.

The agreement spells out how the environmental assessment processes for the project may be harmonized with the creation of a joint review panel process that meets the requirements of both the Canadian Environmental Assessment Act and the Mackenzie Valley Resource Management Act.

It also ensures the joint review panel will include unique measures related to wildlife impact assessment as provided for in the final Inuvialuit land claim deal.

The draft established how the joint review panel would be formed, the scope of its review and the factors it would consider.

Deh Cho still involved in land claims

As well, there are guidelines for the preparation of an environmental impact statement for the Mackenzie project. That statement would serve as the basis for the joint review panel's review and

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● NORTH AMERICA

Long-term natural gas price forecast at $4.25

Canadian investment bank prediction close to U.S. energy department forecast through 2025

By LARRY PERSILY
Petroleum News Government Affairs Editor

Long-term natural gas prices continue to show strength, with a Canadian-based investment bank looking at $4.25 per thousand cubic feet as the likely average for North American supplies between 2007 and 2025.

That's pretty close to the $4.40 forecast (2002 dollars) by the U.S. Department of Energy for domestic wellhead prices in 2025.

And both numbers are in line with what RBC Capital Markets' oil and gas investment analysts see as the breakeven point at $4.50 per mcf for marginal gas drilling in North America.

All of which are higher than the estimated cost for delivering liquefied natural gas to U.S. ports, which could mean healthy profits for LNG suppliers. RBC analysts believe a delivered price of $3.50 per mcf is needed for LNG economics to work, said analyst Kurt Hallead of the Canadian corporate and investment bank's Austin, Texas, office.

But that doesn't mean LNG will sell for $3.50 in the United States, he said. The Department of Energy believes buyers will see little price difference between domestic and imported gas over the next 20 years.

LNG at $3.75 allows for small netback

RBC's forecast of at least $3.50 for new LNG projects is in the range of other estimates. U.S. buyers will need to pay about $3.75 for imported LNG in order to allow a return on project developer investments, Muse Stancil, a worldwide energy industry consulting firm headquartered near Dallas, told state of Alaska officials in April.

And R.W. Beck Inc., a nationwide engineering and

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● MEXICO

New LNG plant proposed for northern Mexico

By DEBRA BEACHY
Petroleum News Contributing Writer

Houston-based DKRW Energy has announced plans to build an LNG terminal in Mexico's northern state of Sonora.

In a May 25 press release, the company said it has signed an agreement with Sonora State to build the 1.3 billion cubic foot per day terminal at Puerto Libertad on the Gulf of California. Officials did not provide an estimate of how much the project would cost. Other LNG projects have been estimated to cost between $650 million and $1.7 billion.

"We have a great partner in the Sonora government and we think the Puerto Libertad site is the best in the western region of North America," said Thomas E. White, a DKRW principal, and managing partner of its newly formed subsidiary, Sonora Pacific LNG.

White, a former vice chairman of Enron Energy Services, was the U.S. Secretary of the Army until he resigned from the post, amid controversy over his role at Enron, in April of 2003. According to published reports, White left Enron with a $1 million severance payment.

Project would also serve Arizona, California markets

The project would include construction of pipelines to distribute gas throughout the state of Sonora, and to an interconnection with the El Paso

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● ALASKA

Muni gas line trio settles dispute

Municipal port authority agrees North Slope Borough can withdraw

By LARRY PERSILY

Petroleum News Government Affairs Editor

Looking to avoid a contentious breakup, the three municipalities that comprise the Alaska Gasline Port Authority have agreed to a plan for letting the North Slope Borough pull out of the effort to build a publicly owned Alaska natural gas pipeline.

"Both sides saw they could get what they wanted if they both took a step back," said David Harding of the North Slope Borough mayor's office.

The borough wants out and the port authority is looking for an orderly transition and also formal ratification by the entire membership of action taken at an early May meeting disputed by North Slope officials.

The full port authority met May 24 and settled enough of their differences, including directing their attorneys to draft the paperwork needed for the North Slope Borough to withdraw. "It was agreed that we do it as expeditiously as possible," said Dave Dengel, Valdez city manager and executive director of the port authority.

"The goal is, if we can, to reach that," though there is no timetable for formal action, Dengel said June 7.

"It's probably everybody's position that it got a little messy," Harding said.

Meanwhile, the authority's two remaining members — the Fairbanks North Star Borough and city of Valdez — are continuing to negotiate with San Jose-based Calpine Corp. as a potential buyer for Alaska natural gas.

The port authority wants to line up purchase deals with North Slope producers, negotiate contracts to sell the gas and obtain debt financing to build a $26 billion project that would take more than 6 billion cubic feet of gas a day from the slope. About half would go by pipe through Canada on its way to Lower 48 markets. Almost 2.7 bcf per day would move to Valdez, where it would be liquefied for shipment to Far East and U.S. West Coast markets.

Borough wanted out in March

The three municipalities joined together in 1999 to create the port authority but the North Slope Borough in March said it wanted out — citing a couple of reasons.

The borough had signed up as a partner in the effort by Berkshire Hathaway Inc.'s MidAmerican Energy Holdings Co. to put together an Alaska gas line deal, and borough officials said it would be a conflict to cooperate with partners on a privately owned project while also working on a publicly owned project to move the same gas to much the same market.

And although MidAmerican later dropped the project, the North Slope Borough still believed it needed to leave the port authority so it could protect its property tax revenues in fiscal negotiations between the state and North Slope producers.

The producers, who are working separately from the port authority to build a gas line, have been negotiating under Alaska's Stranded Gas Development Act since February for a long-term contract for payments in lieu of all state and municipal taxes on the proposed project. The contract would not include a firm commitment to build the line, but rather a structure for payments if the companies decide to go ahead with the project.

Alaska Department of Revenue estimates from 2002 show the borough could receive as much as $1.7 billion in property tax revenues over 35 years from a gas line project. Negotiating payments in lieu of that much tax revenue is more important than continuing as a member of the port authority, the borough said.

North Slope worries about property taxes

"The stranded gas negotiations have the potential for devastating effects on the North Slope Borough's taxing authority and we simply cannot have our time and attention diverted from this critical issue by continued participation in the Alaska Gasline Port Authority," said Borough Mayor George Ahmaogak Sr. in a May 19 letter to Fairbanks and Valdez officials.

"I want the borough's position to be clear and focused at all times. This will not happen as long as we are wearing several hats and taking multiple positions because of our involvement with the port authority," Ahmaogak said in an

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MEXICO

pipeline system east of Tucson to serve the Arizona and California markets.

Partners in the project include: Bechtel Corp. and CHI as project builders; Andrews Kurth LLP as legal counsel; and the El Paso Pipeline Co. for infrastructure and connects. Construction is scheduled to begin in 2005, with operation to begin in mid-2008, the company said.

The project will include a gas pipeline going through Sonora, and possibly the neighboring state of Sinaloa, as well as a 36-inch export pipeline through Nogales that will go to an interconnect with the El Paso Pipeline system east of Tucson. According to the company's estimate, 500 million cubic feet of gas per day would be consumed in Sonora, mainly by gas-fired power generators, and another 800 million cubic feet a day would be exported to the United States. The terminal would be supplied with liquefied natural gas from the Middle East, the Pacific and southern Asia, officials said.

"With our strong partnership with the state of Sonora firmly established and a world-class team in place it is time to begin discussions with potential gas suppliers, downstream gas off takers and federal government permit issuing agencies," White said. The projects are aimed at supplying the U.S. and Mexico's growing demand for natural gas. LNG is natural gas that is cooled until it turns into liquid, and then reheated at a regasification terminal until it converts again into gas.

Growing demand in Mexico

Growing demand for natural gas in Mexico has been met by importing gas from the United States. Demand is expected to grow by 8 percent a year through 2010, analysts say. The construction by Mexico of gas-fired power plants is expected to push up demand for natural gas.

However, opposition parties have said the plants, which would end up forming a part of the U.S. energy system, would pose a security threat to Mexico and unleash environmental hazards. Leaders of Mexico's two major opposition parties, the former ruling Institutional Revolutionary Party, or PRI, and the Party of the Democratic Revolution, or PRD, are focusing their opposition on ChevronTexaco's plan for a floating LNG regasification terminal next to the Coronado Islands.

The opposition leaders contend that if the receiving terminals are intended to serve the U.S. energy market, they should be in the United States.

Opposition has killed Baja California proposals

Opposition by political and environmental groups has killed a number of proposed LNG terminals in Baja California, including ConocoPhillips-El Paso's joint venture in Rosarito and most recently, Marathon Oil's regional energy center in Tijuana. The ChevronTexaco LNG proposal for the Coronado Islands and the Sempra Energy-Shell Oil joint venture at Costa Azul, both in Baja California, are the only two still on track for the Baja California region.

In March, Repsol YPF announced plans to build an LNG terminal in the Pacific port of Lazaro Cardenas. But that project also could be in doubt if plans to import Bolivian gas to Mexico don't go forward, Repsol officials have said.

On the Gulf Coast of Mexico, an LNG receiving terminal is planned for the port of Altamira. A Royal Dutch/Shell Group subsidiary has a contract to supply Mexico's government-owned power utility with 500 million cubic feet a day of natural gas from the plant planned for Altamira. The LNG plant at Altamira would be able to supply gas through pipelines to power plants in the states of Tamauplias, Veracruz and San Luis Potosi. ●

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MACKENZIE

evaluation of the potential environmental and socio-economic impacts.

The Canadian government announced on June 3 that it will provide C$113,516 to 16 participants to help them take part in the first phase of the environmental review.

It said that up to C$1.38 million will be made available for the second and third phases of the federal funding program.

Separately, a working group is exploring ways to bring the hold-out Deh Cho First Nations into the review panel, while the Deh Cho are still immersed in land claim negotiations with the Canadian government.

The Deh Cho, whose land covers the lower one-third of the Mackenzie pipeline route, have refused to join other Northwest Territories aboriginal communities in the Aboriginal Pipeline Group until their land claim is settled.

More details on the regulatory process are available on www.ceaa.acee.gc.ca.

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

● ALASKA

The deal of last resort

If LNG becomes a commodity, trading companies would make logistics work, says Alaska Gas Development Authority CEO Harold Heinze, making LNG a possibility for West Coast; within Alaska, to Pacific Northwest, authority looking at possibility of compressed gas

By KRISTEN NELSON

Petroleum News Editor-in-Chief

Jones Act tankers to move Alaska liquefied natural gas to markets touside the state would add to the cost of a project, but the way LNG is moved — not tankers — may solve that problem.

1 2 3 SERIES

Harold Heinze's estimates for the cost of liquefied natural gas tankers have drawn a lot of heat, Heinze, the Alaska Natural Gas Development Authority's chief executive officer, told Petroleum News in a May 3 interview.

But, he said, remember that you only have to use Jones Act tankers to go from Valdez to the West Coast. Tankers for trade to the Far East are no problem, shipyards are "cranking them out now, several dozen a year, (and) the fleet's up over 200 ships" — all foreign-flagged, there are no U.S.-flagged LNG tankers. The price has been coming down, partly because of technology and partly because more people are building tankers, and Heinze said he doesn't think a foreign tanker would cost much more than $150 million.

FORREST CRANE

Harold Heinze, Alaska Natural Gas Development Authority CEO

U.S.-built tankers could cost three times that much — the shipyards can't even quote a price, he said, because they haven't built any. But the Jones Act only requires that the hull and propulsion be built in the United States, Heinze said, and "a good bit of the cost is also the cryogenic containers," so theoretically you could build a Jones Act hull and propulsion unit in the United States which you would take to Korea to have the cryogenic units installed. That, he said, might bring the cost down to $300 million.

Moving a commodity

But there's another angle, Heinze said.

"We may also be in a tremendous evolution in how gas moves."

If LNG starts to become a commodity, "if people become smart at moving it, trading it," Alaska LNG — which is molecularly identical to any other LNG — could be sold to the West Coast, but the LNG which physically arrives on the West Coast to fill that contract could be from elsewhere, Sakhalin perhaps. And the Alaska LNG which is sold to the West Coast physically goes to fill a contract in the Far East.

"I pay the other guy to sail the longer route and make

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FORECAST

management consulting firm, puts the price at $3.75 per mcf for LNG delivered to Southern California (including regasification charges). That price assumes a wellhead netback of at least 50 cents per mcf, according to the company's recent presentation based on information it compiled from Marathon Oil Corp., BP PLC, Sempra Energy and federal officials.

With declining production from mature North America gas fields, LNG and new wells will need to fill the supply and demand gap. And that's where marginal gas drilling will play an increasing role. RBC said the $4.50 breakeven point for new, marginal production is much higher than a few years ago.

"You're going to have to drill deeper wells to get it," Hallead said June 7.Natural gas prices are expected to hold significantly above $4.50 this summer, with $6.11 per mcf for July delivery the June 8 quoted price on the New York Mercantile Exchange. RBC sees the price averaging $5.75 this year and $5.35 in 2005. Demand destruction and new LNG terminals are expected to further reduce the price to an average $4.25 as of 2007, RBC said.

High prices forecast through 2005

Those short-term estimates are similar to other investment adviser forecasts compiled by the Department of Energy for a May 18 conference presentation: "Future Trends in the Natural Gas Market." The forecasts are for Henry Hub prices (with the date the forecast was issued).

- Lehman Brothers; May 11; $5.25 in 2004 and $4.75 in 2005.
- Raymond James Financial; March 22; $5.92 and $6.
- Merrill Lynch & Co.; April 20; $5.25 and $4.75.
- And global oil and gas consultant Cambridge Energy Research Associates; April 16; $5.48 and $6.02.

The Energy Information Administration at the Department of Energy on May 11 issued its prediction for an average price this year at $5.79 per mcf and $6.07 in 2005.

All of the prices are around three times the 1986-1999 average U.S. natural gas spot price of $1.81 per mcf, as reported by the Department of Energy. ●

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DISPUTE

opinion column in the May 14 edition of the Arctic Sounder newspaper.

The port authority, which is exempt from property taxes, has proposed setting up its own system of payments to municipalities.

The mayor also said the borough had grown distrustful of the other port authority members. "Behind the scenes, they have attempted to stall or block any action that would formalize our withdrawal," he said in his newspaper column.

The North Slope Borough also accused the other port authority board members of accepting a deal with Calpine at a meeting that lacked a legal quorum. "They have even taken board action to approve these agreements when no board member from the North Slope Borough was present, which is a violation of their own bylaws. This is not honorable," Ahmaogak said in the newspaper column.

Port authority disputes allegation

Dengel disputed that the meeting without the North Slope Borough violated the bylaws, citing case law. The non-Alaska court rulings, Dengel said, state that a quorum is not required if a member's sole purpose in staying away from the meeting was to disrupt the organization.

Ahmaogak said in his newspaper column and letter that Fairbanks and Valdez were stalling in accepting the North Slope Borough decision to withdraw.

Fairbanks North Star Borough Jim Whitaker told KUAC-FM in Fairbanks in mid-May there was no intentional delay in acting on the North Slope's decision, and that the port authority was only moving cautiously to ensure that the borough's departure was not harmful to the authority.

"It must be accomplished without any damage to the port authority project," Whitaker said June 7.

The state law that allowed the municipalities to establish the port authority does not set out a specific procedure for one member to withdraw, and attorneys for all three members are working on a solution, Harding said.

In exchange for getting out of the port authority, Harding said the North Slope Borough agreed May 24 to validate the authority's agreement with Calpine. Officials from the company attended the port authority meeting by teleconference.

Port authority pursues Calpine

The port authority's agreement with Calpine is a key step in trying to put together a sales contract for the California energy company to buy Alaska gas, delivered by LNG tanker or pipeline — or both.

But the company faces its own financial problems. Its stock closed at $3.77 a share on June 7, far off its $60 high in 2001 and down a further 20 percent from just six weeks ago. Its $17.8 billion debt exceeds its shareholder equity by an almost 4-to-1 margin. "We have substantial indebtedness that we may be unable to service and that restricts our activities," it acknowledged in its 2003 annual report.

Calpine burns almost 2 bcf per day of gas at its electrical generating plants, with more than three-quarters of the supply coming from short- and long-term contracts. The company runs 85 power plants in the United States and Canada.

The port authority has about $60,000 left of the original seed money from Valdez, Fairbanks and the North Slope, and will need more money to finish putting together contracts and financing for the gas line project, Dengel said.

"We are working a deal … there should be an infusion of cash in the next month or so to help pay some of those costs." He would not say where the money might come from, other than to emphasize it would not come from the municipalities.

North Slope concerned about liabilities

Ahmaogak, however, said in his letter to Fairbanks and Valdez officials that he was concerned about the port authority's efforts to obtain the needed funding from Calpine and take on financial obligations with other parties.

"The North Slope Borough will in no way be responsible for any commitments from the port authority," Harding said.

Dengel confirmed the port authority owes "contingent liabilities" to law firm O'Melveny & Myers, construction company Bechtel Corp. and financial consultant Taylor-DeJongh for planning work on the project, but he said the money would be paid only if the gas line goes forward. ●

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HEINZE

the delivery (to the West Coast), I pay for all that, and I'm still money ahead… So at some point I just don't build the Jones Act ship… I use the world fleet."

That would require a world in which LNG is a commodity.

"LNG is not a commodity yet," Heinze said, "but I see it going there.

Would the world fleet be big enough? Well, in 10 years, as larger LNG tankers are built, there will be a surplus of smaller ships, he said. There will be some 200 of these older — but well maintained — LNG tankers available.

The aggregators

"And if it's a commodity that has implications in terms of transportation costs, pricing, other strategies. It also has tremendous implications in terms of people wanting to be involved."

For the highway route, all the major oil companies involved are players in the Lower 48, in Canada and in Alaska, and have indicated they will be big players in LNG coming into the United States.

These big players, he said, "are positioned in four major parts of the thing. The only thing they don't do is consume a lot of gas."

In the LNG world, he said, there will be the five mega-majors and British Gas — BG, "and then probably room for one or two major Japanese trading company types as aggregators, people who buy lots of little supplies and meet lots of little demands. … that's what trading companies do.

"And that's why Mitsubishi is interesting, because if anybody is going to play, they're going to play that role."

Trading companies make the logistics work

The trading companies, as aggregators, have "got a little piece of a lot of things — supply — and they've got a part of lots of markets. And they make the logistics work."

That's why, Heinze said, he doesn't get excited about the tankers.

If LNG becomes a commodity on the world market, "Mitsubishi will make it work. My only negotiation with them is how much I'm going to pay them to make it work. They will make it work at the lowest cost, and I will pay them a fee on top of that. And that's the only negotiation, is how big's the fee."

Mitsubishi would place the LNG in the market in Japan and would own or lease LNG tankers.

They would do the logistics. They already have, Heinze said, "the ability to exchange cargoes, meet contract volumes. I just become a supply point for them. I don't worry about where my gas is going: I don't care."

And the tradition of the trading companies, he said, is to invest in the project.

"Traditionally, in the LNG business, people — especially people like Mitsubishi — try to go as far upstream as they can. They start in the market and go all the way back. They'd like to be in the pipeline. … They want the return on investment as well as the transaction fee."

Costs, business structure

Heinze said that he has used the producers' pipeline cost estimates, and also their estimates — scaled to size for a smaller project — for the gas treatment plant.

The cost estimates Heinze has for the development authority LNG project total out at $10.5 billion, including a 2 billion cubic foot a day treatment plant on the North Slope ($1 billion); 800 miles of 36-inch pipeline ($3.5 billion); a two-train liquefaction plant ($3 billion); tankers ($2.25 billion), "a proxy for what I would actually contract for," Heinze said; and the spur pipeline to Cook Inlet, a natural gas liquids plant, and regasification facilities on the West Coast ($750 million).

The development authority hasn't yet decided on a business structure, Heinze said. Is it a holding company, a nonprofit, a utility? Different business structures "imply different things in terms of debt and equity and borrowing rates and security and good faith and credit of the state," he said.

But he has prepared a comparison of what he calls "notional cost of service" per million Btu comparing commercial terms (30 percent equity at 12 percent return and 70 percent debt at 8 percent) and a utility-type structure (20 percent equity at 12 percent return and 80 percent debt at 5 percent), comparing the development authority's LNG proposal and the highway project.

These costs of service, he said, do not include wellhead value of natural gas.

If the development authority built a project on commercial terms, its LNG project would have a cost of service of $2.51 per million Btu, compared to $2.27 per million Btu for the highway project.

Built on utility terms, the authority's project would have a cost of service of $1.94 per million Btu, compared to $1.79 per million Btu for the highway project.

Throughput for the LNG project would be 2 billion cubic feet per day, compared to 4.5 bcf for the highway project. Total capital costs are $10.5 billion for the LNG project, $19 billion for the highway project.

Heinze said this notional cost of service is not a tariff, but "a way of trying to describe, in one number, the relative economics" of a project. Then you add the wellhead value, and "that tells you something about what you have to get in the market for it to work."

If you add a dollar for the wellhead value, he said, that's $3.51 for the authority's project. "What that says is, you can satisfy those basic economic conditions — debt, equity, return on equity — if I get $3.51 in the market."

And right now the market is more than $5.

Qatar will set price floor

"Well, nobody expects it to be five bucks forever. People use three and a half as a good testing point because that's the number that people describe Qatar delivering LNG to the United States," Heinze said.

"And at 900 trillion cubic feet, they are the 8,000-pound gorilla of this thing. What they can do starts to affect what everybody does."

What Qatar has done, he said, is make deals with the major oil companies to sell at the wellhead and the companies make all the investment and incur all of the risk downstream of the wellhead, and also make all the profit.

And even if the mega-majors can deliver at $3.50, that doesn't necessarily mean they will.

"I don't think there's going to be a 'gaspec' but I think the mega-majors will play a role that looks more like OPEC" in the gas business, Heinze said, just to provide some supply-demand price discipline.

And LNG out of Qatar will set the price floor because of the large supply there. "It can go below that, but it can't stay below that for a long time, because the guy with the big supply rules the day."

And the high end? That will be set by alternatives to gas, and if you look at the $5 price today, he said, "there aren't a lot of people switching to oil or coal. They're still using gas, even though it's a lot more than

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WELLS

U.S. onshore manager, said in a late May meeting with industry analysts. "We've been spending a lot of time on the deeper zones, trying to understand them."

But he said there remains several thousand feet of untested section to be analyzed, although he said it was doubtful individual wells could produce 10 billion cubic feet of gas during their lifetime.

Company still testing, looking at seismic

"We have a lot of stuff still to test in this well, and there is a lot of potential on this block," Price asserted. "This is still a block that could contain the potential for hundreds of wells."

Price noted that since drilling the well, Noble has acquired 109 square miles of 3-D seismic covering Iron Horse and that information on both the deep and shallower zones is currently being evaluated.

Noble already has seen "interesting things" in the data as the company works its way up the test well, Price said. "We're trying to hone it down to some drilling opportunities for later this year, he added.

Price also said drilling activity offsetting Noble's block has been "very positive and we're obviously interested in that." Still, Noble is resisting "the urge to hurry up" drilling at Iron Horse, he said.

"We had a little stumble in that portion of the block in the deep, and that's basically all we have tested in that entire prospect," Price said. "It takes time to do it the right way."

To improve performance at Niobrara, small pumping units are being installed on shallow gas wells primarily to lift water off the pay zone, which allows more gas to flow.

Niobrara and Bowdoin also hold potential

Like the Iron Horse in Wyoming, Colorado's Niobrara trend and Montana's Bowdoin area each hold the potential for hundreds of development wells, Noble said.

The company planned to drill 25 wells this year in the Niobrara, including two separate five-well pilot projects to determine whether it would be economic to drill wells on 40-acre spacing. The field, which already houses some 350 wells, was developed on 80-acre spacing.

Noble said it completed one of the infill pilot projects at Niobrara and plans to drill the second later this year. The field currently produces about 2,200 barrels of oil equivalent per day net to Noble.

"The early results we have seen are positive and, if that pans out, we're looking in the neighborhood of 200-plus development locations that could be drilled as quickly as we choose to drill them," Price said.

Niobrara geologically complex

Although a large production area, Niobrara is geologically complex requiring structural closure to establish production, he said.

"There currently is a lot of discussion on whether this can be economic on 40-acre type spacing," he said. "I don't want to get too excited because we don't have all the data in. The fear when you infill is that you drill a well that is clearly depleted. And that pretty much lets the wind out of your sails for the upside."

To improve performance at Niobrara, small pumping units are being installed on shallow gas wells primarily to lift water off the pay zone, which allows more gas to flow.

"This is not spectacular on a well-by-well basis but you multiply it by hundreds and it becomes very significant, very cost efficient," Price said.

Price said production aided by a recently installed pumping unit was increased to 400,000 cubic feet per day from 80,000 cubic feet per day. "That's the kind of success we've seen, so we're accelerating the program there," he added.

Noble plans 25 development wells at Bowdoin

Bowdoin, another shallow biogenic gas field, also has more than 200 locations for new development drilling to go along with some 800 already producing wells, all of which are operated by Noble with an average 66 percent working interest.

Noble planned to drill 25 development wells this year mainly on undrilled spacing units. "We do have a lot of undrilled locations in the field," Price said.

The field currently produces about 9.6 million cubic feet of gas equivalent per day net to Noble. "We're at the point where we are not only focused on it, but we're accelerating it and we're testing some new things as well," Price said.

Noble has found that one effective way to enhance production is simply to replace older tubing with small diameter coil tubing, which allows the well to lift more water and create better gas flow.

"That has been extremely successful," Price said. "We've done it on a couple hundred wells and we continue to do that. And we'll accelerate our efforts."

$85 million to onshore U.S.

Noble has allocated $85 million in 2004 capital expenditures to onshore United States, with two-thirds of the total going to the company's Gulf Coast operations and the rest mainly to exploration opportunities in the Midcontinent and Rockies. The cash will be used to pay for 95 wells.

Noble's proved onshore reserves at year-end 2003 stood at 67 million barrels of oil equivalent. Daily production during the 2004 first quarter averaged about 23,000 barrels of equivalent, or roughly a quarter of the company's total production.

Eighty-four percent of Noble's onshore proved reserves are classified as natural gas, while about 80 percent of the company's production consists of gas.

A year ago 80 percent of Noble's onshore capital budget went to exploration and only 20 percent to development and production. This year exploration accounts for only 60 percent of expenditures and development and production 40 percent. ●

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HEINZE

it was."

Authority's costs in range

At $2.51, looking at a range of projects around the world from $2.20 to $2.60, the authority's LNG notional cost number is at the high end, Heinze said, "but it's in the range."

What the authority is working on now is demonstrating that the project is feasible, "and that's what these numbers say — we're feasible.

"It doesn't say it's a good investment, it doesn't say it's the best investment. Those are issues that come down the road. But is there a project here that I can define that makes sense economically? And the answer is yes."

Heinze said he knows the project is feasible by looking at Sakhalin.

"And here's mega-major Shell doing a big arctic LNG project that involves the arctic environment, it involves a fairly good hunk of pipeline, ports …"

The Shell project costs $10 billion for 1.3 bcf a day; the authority is proposing to spend $10.5 billion for 2 bcf, he said.

"You don't have to be quick with numbers to figure out that I can't be any worse than they are.

"And Shell made the decision to proceed. They made the decision to proceed absent one single signed contract to sell their gas."

Producers have a portfolio

Heinze says he isn't arguing with the producers' decision that the highway route is right for them.

"My argument is, it's not necessarily right for us. We don't have a portfolio. We only have one thing going for us — North Slope gas. How I get that to market is my job. And if the highway dies, if the highway don't go, I've got to have some other things I'm willing to look at."

And, he said, "given the fact that they're not interested in LNG doesn't scare me, because they're barely interested in the highway project."

Heinze takes issue with the producers' contention that at $19 billion a highway project isn't economic.

With a notional cost of service of $2.27 per million Btu at the feasibility level, he said, "excuse me, this is an economic project. … The risks and rewards may not balance for your investment — I'm not questioning that decision — but at a feasibility level, there is an economic project …"

LNG to West Coast may be essential

And even if Alaska gas goes down the highway, most of that gas would go into the Midwest, Heinze said.

And California, 10 percent of the U.S. economy, is dependent on gas pipelines that would be difficult to expand in many areas.

Not to mention, he said, that power plants in Washington and Oregon are planted on top of a major gas pipeline headed south. "What happens if they suck it dry before it gets to California?" he asked.

The development authority believes there will be opportunities in the Columbia River area, the West Coast of Washington, even the Port of Long Beach.

"Because coming in at a specific spot where you can feed power plants makes sense," he said.

The Los Angeles area uses 2.5 bcf to 3 bcf a day of natural gas. "There is no way to expand or build a new pipeline into that area. The pipelines in that area are at maximum capacity…

"If you come into the Port of Long Beach you are a mile and a half from the major pipeline connection that feeds the LA area. We think logistical circumstances like that in the long run will dominate."

People went into Baja because projects could be done there, but there is only very limited ability to move natural gas back into the United States. LNG coming into Baja would take care of Northern Mexico and San Diego, maybe Las Vegas, Heinze said.

"So we believe truly that because of where the population is and the communities along the coast that sooner or later you've got to fess up to it that the only way you're going to have this great clean energy that you really like is to figure out this LNG deal."

Compressed natural gas

In addition to LNG, Heinze said the authority is also looking at compressed natural gas. LNG is cooled to minus 260 degrees and liquefied: 600 volumes of gas becomes one volume of liquid.

Compressed natural gas isn't chilled, he said, it's just put under pressure to about 2,500 pounds per square inch. The volume advantage is only about 100 to one, but it takes much cheaper equipment, Heinze said, just tanks instead of cryogenic tanks, just compressors instead of complicated plants, "and it turns out that for smaller volumes and shorter distances, compressed natural gas is attractive, compared to LNG.

"So for supplying around Alaska, we're very interested in compressed natural gas."

The advantage is great enough to go to the Pacific Northwest, he said, but probably not to Baja, and certainly not to Japan.

A compressed natural gas facility looks like a bunch of 36-inch pipe, Heinze said, and the pressure, 2,500 psi, is the same as that in a pipeline, so the risk elements are no different than a gas pipeline.

For smaller volumes of gas, in areas such as remote Gulf of Mexico fields, compressed natural gas is a transportation alternative to pipelines.

In Alaska, you could drag a barge with compressed natural gas in 36-inch pipe to a community and leave it there.

And 36-inch pipe only requires a rolling mill. Steel plate could come to Alaska on coal barges making the return trip.

We are the tail of commercializing North Slope natural gas, Heinze said, the second or third or fourth option.

But nothing is dead and buried — it's alive and in play, he said. ●

Companies involved in North America's oil and gas industry

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

Petroleum news

Business Spotlight

By PAULA EASLEY

COURTESY PHOTO

John Riggs, owner, general manager

Great Northern Engineering

Great Northern's headquarters are in Palmer, Alaska, with offices in Anchorage, Kenai and Deadhorse, Alaska. The firm provides civil, mechanical, electrical, structural and API 653 certified engineering services. It also provides consulting services in project design, preparation of project documents, bid assistance, project management, cost estimating and inspection services.

Owner John Riggs has been a mechanical engineer for 22 years and enjoys the tremendous diversity of problems requiring innovative engineering solutions. Away from work he flies, hunts, fishes and cherishes time spent with wife Cheryl, two grown daughters and three grandchildren. John is an Elks Lodge and NRA member, and he supports youth sports activities and academic scholarship programs.

FORREST CRANE

Brian M. Moore, district sales manager

Cooper Cameron

Cameron supplies gate valve, actuator, chokes and wellhead components to all oil industry sectors — from wells to refineries and all between. Cameron leads the industry in total vendor management (TVM) tailored to individual needs while supplying major brands of equipment, including Cameron, Ingram Cactus, WKM, Demco, McEvoy, Willis, Thornhill Craver and Foster.

Brian Moore began his oil industry career in 1975. He's worked for Cameron 26 years in the wellhead, gate valve and blowout preventer divisions. Before coming to Alaska nine months ago, he was an avid golfer; friends say he might even qualify for the Nome Bering Sea Ice Classic. Wife Verneisa and daughters Melissa and Abby moved north with dad; two grown children are mainland holdouts.

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ALLIANCE

eastern British Columbia to just southwest of Chicago.

When the 22 companies banded together to study the issue in 1995, Western Canada producers were earning much less for their gas than U.S. Gulf Coast producers because of insufficient pipe capacity for moving gas out of Alberta.

It took just a year to decide on a solution, and in 1996 17 of the original 22 set up the Alliance partnership and started the regulatory and financing work. Of those 17, a few were small natural gas marketing companies and the rest were producers, including some of the largest names in Western Canada: Alberta Energy Co. Ltd., Canadian Occidental Petroleum Ltd., Gulf Canada Resources Ltd., Unocal Corp., Petro-Canada and Chevron Canada Resources.

It was their money that built the line. "One hundred percent of the construction budget is financed through bank, bond or equity contributions backed by investment-grade corporate guarantees or cash," said a 2000 report by the Financial Times Energy Inc., an arm of the Financial Times of London.

Producers all drop out before start-up

But even before gas started flowing in December 2000, all of the producers had left the partnership, selling out to pipeline companies.

"It wasn't surprising once they got it built to sell off," said Ed Small, of CanAm Energy in Calgary.

The producers knew they were going to have to take all of the financial risk of building the line and pledging shipping commitments to cover the borrowing, so they figured they might as well take on the project, said Small, who started work in 1976 for major oil and gas companies in Calgary and switched in 1992 to his own consulting business.

It was a combination of pipeline companies not moving fast enough to add capacity for the producers, in addition to producers wanting an option to the region's major pipelines operated by TransCanada Corp. and Nova Gas Transmission Ltd., the Financial Times report said.

Early on, it looked like the pipeline companies would oppose the Alliance project. But to help ensure peace, the Alliance partners agreed not to oppose the 1998 merger of TransCanada and Nova in exchange for the companies withdrawing their regulatory opposition to Alliance.

Rather than waiting for the pipeline companies to build more capacity only after pipe constraints drove down the value of Western Canada's gas, the producers wanted to get ahead of the curve and match supply growth with demand growth, Small said.

Producers wanted to know tariff

The producers stayed in long enough to not only put together the financing and start construction, but to ensure they could live with the tariff structure, said Jim Pearson, senior coordinator for strategic analysis at Alliance Pipeline L.P. in Calgary.

"The tariff had been pretty well designed" by the time producers started to sell off their interest in the project, Pearson said. "They knew what they were going to be faced with."

And when the work was done, they were ready to turn it over to pipeline companies. "Producers are interested mostly in looking for gas and producing it. They'd rather put their money into drilling," Pearson said.

The project went so well that by the time Alliance filed its application with Canada's National Energy Board in 1997, it had firm shipping commitments for 98 percent of the line's capacity — even though the tariff required shippers to post a letter of credit or prepay for 12 months of estimated tariffs.

By 1998, with the pipe and compressors ordered and financing locked down, the 17 partners were down to just seven, of which only two were producers. A syndicate of 42 international banks agreed to finance up to $2.6 billion for the project, with a 70/30 debt-to-equity split.

The list of partners dropped to just two in late 2003, with Duke Energy Corp. selling its small share and Fort Chicago Energy Partners L.P. and Enbridge Inc. each holding 50 percent of the venture.

Line starts just 2 months behind schedule

The final price tag for construction was $3.1 billion (in 2000 U.S. dollars), a cost overrun of about 15 percent, according to a company spokesman. The line opened for service just two months past its scheduled completion date, about four and one-half years after the partners created the venture.

"The Alliance Pipeline project demonstrated that natural gas producers can effectively initiate pipeline projects, but that successful projects will be market driven," said the Financial Times report.

Although the producers that initiated the project are no longer participating in the partnership directly, "they advanced North America's transition to a more competitive natural gas market discipline," the report said.

"There are a lot of comparables" between the Alliance project and efforts to move North Slope gas to market, Small said, including the desire to move stranded gas, producer financing and the large risk. But there also is a difference, he said. In Canada, the producers expected they were going to have to take all of the new line's financial risk, while in Alaska the producers would like to share some of the risk that tariffs could eat up too much of the gas price at the market end of the line.

And the volume makes the risk much greater for the Alaska pipeline, Small said. The Alliance line was built for 1.325 billion cubic feet per day, while the North Slope producers are looking at building a 4.5 bcf line. The producers worry that so much gas could force a drop in North America gas prices, taking money out of their pockets and any other company with U.S. or Canadian production.

Oversupply fear quickly dissipated

Competitors of the Alliance pipeline warned of the same fear of oversupplying the market, testifying that netbacks would fall. Alliance management countered the effect would be minimal, maybe 10 cents per thousand cubic feet.

In fact, when the line started moving gas in December 2000, North America was in the middle of a wintertime price spike at about $6 per mcf at the wellhead, pushing prices to almost triple what they were when the Alliance partnership was created in 1996.

High demand and minimal compressor outages have helped keep the line running above its nameplate capacity. Its firm contract capacity is listed at 1.325 bcf per day, though it usually can handle much more gas. The line has carried as much as 1.8 bcf, and averaged 1.6 bcf per day in 2003 with all the compressors online, Pearson said.

The line has not expanded its capacity but has added additional receipt points — it's up to 42 feeder pipes, ranging from 4 inches to 24 inches. The Alliance starts in British Columbia, near the Alberta border, and then after loading up with British Columbia and Alberta gas moves nonstop toward Chicago, helped along the way by 14 compressor stations spaced 120 miles apart.

Tariff about $1 to Chicago

The so-called bullet line is a mix of 42-inch and 36-inch pipe, at a maximum pressure of 1,740 pounds per square inch, with several pipeline and customer delivery points in the Chicago area.

North Slope producers are advocating a 52-inch line, operating at 2,500 pounds per square inch.

Alliance's reserved capacity tariff runs $1.09 per mcf to Chicago, depending on the U.S.-Canadian exchange rate. But when the line is operating at peak efficiency and carrying between 1.5 bcf and 1.6 bcf, the rate drops to 94 cents per mcf, according to the company's published tariffs.

A single management operation runs the pipeline, though for corporate governance purposes there are separate U.S. and Canadian partnerships for the pipe in each country. ●

Partners built liquids plant near Chicago

The Alliance Pipeline project includes the Aux Sable Liquid Products L.P. facility at the end of the line, 50 miles southwest of Chicago. The $400 million plant was designed to extract up to 70,000 barrels a day of ethane, propane, butane and other liquids from the natural gas stream, shipping the products by pipe or rail to customers as far away as the U.S. Gulf Coast.

And although the liquids have to come out of the gas somewhere, the Aux Sable plant hasn't been a profit center since it opened in December 2000, said Ed Small of CanAm Energy, an oil and gas consultant in Calgary. "That side of the business has lost money ever since."

The push for the Alliance partners to get into the liquids business was similar to the incentive for building the gas line itself, Small said. Just as the producers wanted to get away from TransCanada Corp.'s dominance in moving gas out of Western Canada, they also wanted to break away from Amoco Canada Petroleum Co. Ltd.'s control of the region's liquids business. Amoco was not part of the producer-dominated partnership that created the Alliance venture in 1996.

To ensure that the liquids plant was built as part of the gas line project, partners in the pipe had to take an equal share in Aux Sable, Small said. The theory was that the producers could sell off the liquids in Chicago to help offset some of the gas line tariff. Just as with the gas line, the original partners eventually sold off their interest in Aux Sable, which is owned today by pipeline companies Enbridge Inc. and Fort Chicago Energy Partners L.P., at 42.7 percent each, and Williams Cos. at 14.6 percent.

And, as Small said, the plant doesn't make money stripping the liquids from the gas. Enbridge's share of the loss from Aux Sable was $6.9 million in 2003, $3.1 million in 2002 and $6.2 million in 2001, according to Enbridge annual reports.

Aux Sable is the largest facility of its kind in the United States, according to the company. It can handle up to 2.1 billion cubic feet of wet gas per day and is a significant propane supplier for the Midwest.

—LARRY PERSILY, Petroleum News government affairs editor

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PLENTY

Nikaitchuq (Kerr-McGee 70 percent, Armstrong 30 percent) at the end of April (see story on Nikaitchuq in this issue).

Armstrong has now applied for the Tuvaaq exploration unit on 14,560 acres between Oooguruk and Nikaitchuq, and in the application said it will be the operator at this third unit.

"We are not currently looking for partners," Ed Kerr, Armstrong's vice president of land and business development, told Petroleum News June 9.

Armstrong has acquired five leases at Tuvaaq from ConocoPhillips Alaska, and is in the process of acquiring the last two, also held by ConocoPhillips, so it will have 100 percent working interest ownership. ConocoPhillips holds a 4.25 percent overriding royalty on the five leases assigned to Armstrong. All of the leases have a 16.66667 percent state royalty and expire at the end of the year.

The seven leases, 14,561 acres, proposed for the Tuvaaq unit are immediately northeast of the Oooguruk unit, north of the Kuparuk River unit and southwest of the Nikaitchuq unit.

Armstrong has proposed a five-year exploration plan, with the first well, Tuvaaq No. 1, to be drilled this winter to test Triassic/Jurassic. A second well is proposed in 2006-7 to test Cretaceous/Jurassic and a third well in 2008-9 to test Triassic/Jurassic.

Armstrong told the state that prospective intervals to be tested in the exploration program "may include but are not limited to the Cretaceous Kuparuk sandstone, the Jurassic Nuiqsut sandstone, the Triassic Sag

see **PLENTY** *page 19*

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PLENTY

River sandstone, the Triassic Eileen sandstone and Triassic Ivishak sandstone."

Historic drilling in area

Early exploration, beginning in 1969, encountered pay in the Cretaceous Kuparuk A sandstones, minor oil shows in the Triassic Ivishak sandstone that tested wet, porous sands bleeding oil in the Triassic Eileen and oil-stained sands in the upper Triassic Ivishak, Armstrong said in its application.

In 1992 ARCO Alaska (now ConocoPhillips Alaska) drilled the Kalubik No. 1 which tested Kuparuk C sands at a rate of 1,220 barrels per day (25.5 degree API gravity oil) and Jurassic Nuiqsut and Nechelik sandstone (19.7 degree API gravity oil) — on nitrogen lift — at an average rate of 660 bpd.

In 1993 Exxon drilled the Thetis Island No. 1. That well had minor shows of hydrocarbon in Sag River sandstone and an additional pay zone in the Nuiqsut interval, which tested at rates as high as 650 bpd and had an average rate over the test of 120 bpd.

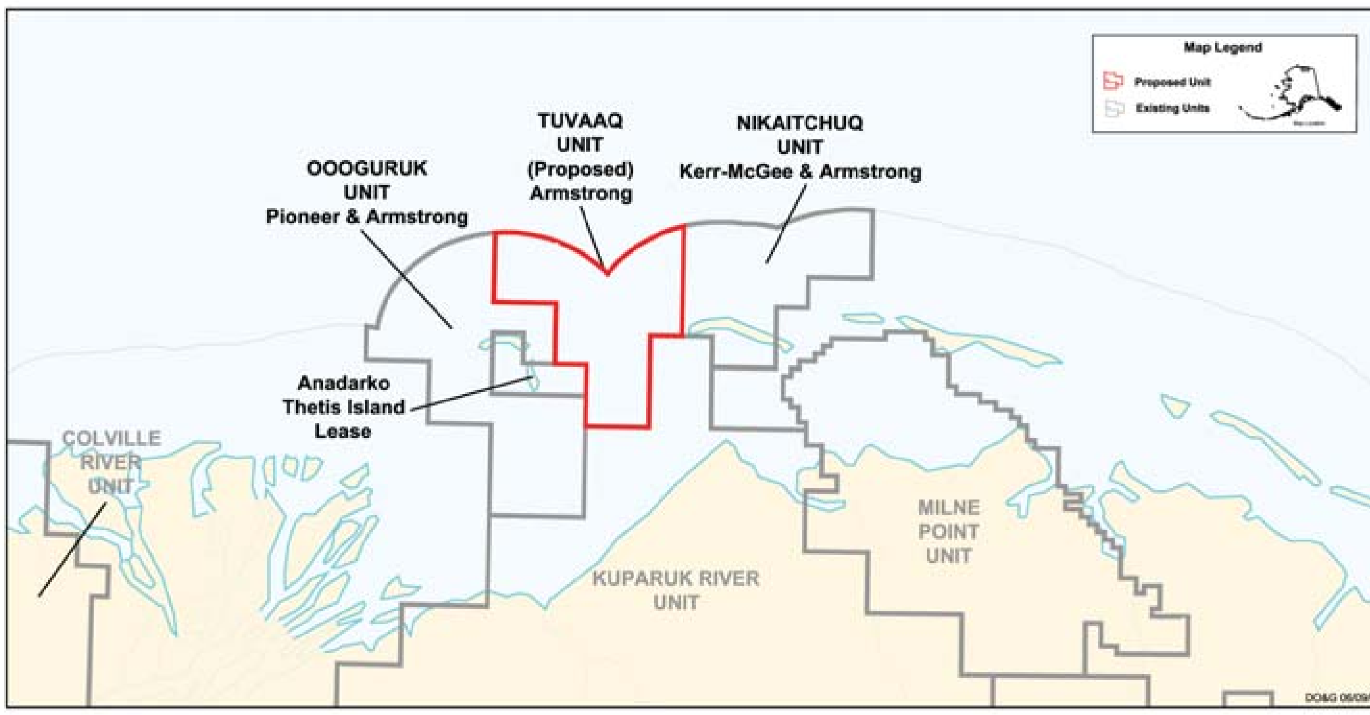
Both wells, Armstrong said, "encountered prospective sandstones with significant hydrocarbon shows in the Cretaceous Brookian section."

Pioneer and Kerr-McGee wells

The most recent drilling, in 2003 and 2004, was by Armstrong partners Pioneer Natural Resources and Kerr-McGee in what are now the exploration units on either side of Tuvaaq.

In 2003, Pioneer and Armstrong drilled three wildcats, the Ivik, the Natchiq and the Oooguruk, "directly to the southwest of the Tuvaaq unit, within the Oooguruk unit," Armstrong said in its application.

The Ivik "penetrated reservoir-quality sands within the Brookian and Jurassic intervals," Armstrong said. While the there were "impressive mud log hydrocarbon shows" in the Brookian, it yielded water on formation test. The Nuiqsut sandstone, an interval of more than 60 feet, had an initial potential rate of 1,300 barrels of oil per day after fracture stimulation. Armstrong said the Oooguruk was an offset well to the Ivik, and encountered more than 45 feet of sandstone pay in the Nuiqsut. The Oooguruk was not production tested, "but yielded hydrocarbons on wireline formation test." The Oooguruk also encountered 10 feet of porous Kuparuk C sandstone which was productive on wireline formation test, Armstrong said.



ALASKA DIVISION OF OIL & GAS

The Nikaitchuq No. 1 and No. 2 wells, drilled by Kerr-McGee and Armstrong last winter, "were drilled to the Triassic Ivishak sandstones" and the No. 1 "encountered productive Triassic Sag River sandstone" and was tested at a stabilized rate of 960 bpd of light 38 degree API gravity oil. That well also encountered Eileen/Ivishak sands with "significant hydrocarbon mud log shows."

Armstrong said the No. 2 well "successfully extended the known limits of the Sag River accumulation. … Engineering modeling work on the Sag River sand suggests the well could produce at rates as high as 2,500 bopd if drilled and completed laterally."

Drilling prospects

Armstrong told the state that in the Triassic Sag River/Eileen/Ivishak sandstones there are "two prospective structurally independent four-way closures" identified by an ocean bottom cable 3-D patch seismic survey acquired in 2000, and said it "was one of the first companies to integrate this data … with other recently acquired 3-D data in the area."

The company said the seismic data, in conjunction with recent exploration and development drilling, "established an overall prospective trend for Ivishak sand and a trend of improving Sag River/Eileen sand quality and thickness to the north/northwest over the West Milne structures and within our proposed Tuvaaq exploration unit."

Armstrong said the Jurassic Nuiqsut sandstone, a "secondary interval of prospective interest," is expected to have a "separate hydrocarbon system than previous penetrations to the southwest" and "hydrocarbon limits should be controlled by the stratigraphic sand limits within the Tuvaaq unit area" not by structural elevation.

"Sand presence, good reservoir quality and hydrocarbons tests within the Kuparuk interval in the Oooguruk and Kalubik wells directly to the southwest highlight" the Cretaceous Kuparuk sandstone as the third prospective interval at Tuvaaq, Armstrong told the state. The company said pressures collected at the Oooguruk well "define a separate hydrocarbon accumulation than the Kuparuk field" and it believes "that this sand is stratigraphically separated from the Kuparuk field accumulation and more similar to the structural hydrocarbon levels observed in the Mukluk and Phoenix Cretaceous Kuparuk intervals."

Drilling program

The Tuvaaq No. 1 well, in the upcoming 2005 winter, is planned for a true vertical depth of 9,150 feet and has a proposed surface location in section 25, township 14 north, range 8 east, Umiat Meridian, and a proposed bottom hole in section 15-T14N-R8E, UM.

Armstrong said that based on results from the first well, "geologic studies, engineering studies and seismic reprocessing are planned in 2006 leading to a second exploration well for the 2007 winter drilling season, or earlier."

The proposed second well would have a TVD of 9,600 feet, a surface in section 19-T14N-R8E, UM, and a proposed bottom hole in section 8-T14N-R8E, UM, would "test the prospectivity of the Cretaceous Kuparuk sand interval, Jurassic Nuiqsut sand continuity and limits of the Triassic Sag/Eileen/Ivishak accumulations" in the unit.

The third well, planned for the winter of 2009, or earlier, would "test the prospectivity of the Triassic Sag/Eileen/Ivishak intervals on the eastern structure," with a proposed surface in section 25-T14N-R8E, UM (the same proposed for the first well), a proposed bottom hole in section 11-T14N-R8E, UM, and a proposed TVD of 9,600 feet. ●

Alaska okays Kerr-McGee's Nikaitchuq unit

The state of Alaska has approved formation of the Nikaitchuq unit on the North Slope. The 12,968-acre unit, proposed by Armstrong Alaska, will be operated by Kerr-McGee Oil and Gas Corp.

Nikaitchuq is the most easterly of the three Harrison Bay exploration units assembled by Armstrong. It is in the near-shore waters of the Beaufort Sea, north of Oliktok Point at Spy Island, and north of the Kuparuk River and Milne Point units.

The Nikaitchuq No. 1, drilled by Nikaitchuq-operator Kerr-McGee this last winter season, tested 38 degree API crude oil at more than 960 barrels per day, the company said in April. The Nikaitchuq No. 2, drilled 9,000 feet southwest of the No. 1 well, "successfully extended the accumulation down dip," Kerr-McGee said.

There are eight state leases in the unit, five of which date from Beaufort Sea Sale 86, held in November 1997, with expiration dates of Dec. 31 this year. The state has a 16.66667 percent royalty in all of the leases. Kerr-McGee holds a 70 percent working interest in seven of the leases, Armstrong the remaining 30 percent. Armstrong holds 100 percent of the eighth lease, but has told the state it will also be assigning 70 percent of that lease to Kerr-McGee.

Armstrong filed for the unit on behalf of itself and Kerr-McGee, proposing a five-year unit plan of exploration with three exploration wells. Kerr-McGee drilled and tested the Nikaitchuq No. 1 this winter season and plans geologic studies and seismic reprocessing in 2005. Additional wells are planned for the 2006 and 2008 winter seasons, but the companies said they may be drilled earlier.

There are three prospects in the unit: the Cretaceous Brookian sandstone; the Jurassic Nuiqsut sandstone; and the Triassic Sag River sandstone.

The state said the first well, the Nikaitchuq No. 1, satisfies the first well required under the initial plan of exploration.

Failure to drill a second well or obtain approval of a revised plan of exploration by June 1, 2006, will result in the automatic termination of the unit effective that date; a third well — or approval of a revised plan — is required by June 1, 2008, or the unit will terminate.

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

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At issue — the majority of the plans may not be approved, rejected, or even reviewed by the USCG by the July 1 deadline.

How can CH2M HILL help?

CH2M HILL is a leader in providing port security for both public and private ports. We have experience developing Facility Security Plans and rewriting existing plans to conform with USCG regulations. Key to our success is our knowledge of port infrastructure and operations. And, to help you fund the implementation of your plan, the Department of Homeland Security (DHS) has made grants available. The next round of grants is scheduled for the summer of 2004.

CH2M HILL's experience in helping our maritime security clients includes:

- **Intercontinental Terminals Co., Houston, TX** – Design, procurement, and construction of all elements of Transportation Security Act appropriation including cameras, intrusion detection, credentials, access control, and lighting for more than 8 million barrels of storage in 181 tanks connected to the Texas Eastern Pipeline
- **Nova Chemicals, Virginia Beach, VA** – Nova's security plan was rejected by the USCG. CH2M HILL has been hired to help Nova revise and submit a plan that will be approved
- **Port of Palm Beach, Florida** – Security management, engineering, and construction management services including the development and implementation of security training, security procedures, cruise terminal security compliance, and serving as the Executive Director's representative to all federal, state, and local law enforcement and regulatory agencies
- **Port of Corpus Christi, Texas** – Risk assessment and implementation support for one of our most strategic ports, spanning a ship channel 8 miles in length and housing multiple petrochemical refineries that provide nearly one-third of our nation's military and commercial aviation fuel
- **U.S. Virgin Islands Port Authority** – Developed passenger vessel security plans for cruise ports at Crown Bay in St. Thomas and Fredrikstad Pier in St. Croix, identifying operational, planning, logistics, and training requirements for each of the three designated Maritime Security Levels in accordance with U.S. Coast Guard and International Maritime Organization (IMO) guidance documents

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