Petroleum news

Vol. 8, No. 28 • Anchorage, Alaska www.PetroleumNews.com Week of July 13, 2003 • $1

page 5 Alaska streamlines North Slope ice road approval

Ahead of schedule, under budget

JUDY PATRICK

Nabors Rig 7-ES has completed development drilling at Palm, a Kuparuk River unit satellite on Alaska's North Slope. Operator ConocoPhillips Alaska said the project came in under budget and ahead of schedule.

Palm production exceeds expectations

ConocoPhillips Alaska has completed development drilling at drill site 3S, the location of the Palm discovery on the western side of the North Slope's Kuparuk River unit.

"The total number of wells at the drill site is 17, including nine producers and eight MWAG injectors. The current oil production rate is approximately 29,000 barrels of oil per day, which exceeds pre-development expectations," company spokeswoman Dawn Patience told Petroleum News July 9.

"The project came in under budget and ahead of schedule," she said.

Expected to peak at 16,000 barrels per day in 2004, Patience said the Kuparuk satellite is currently producing approximately 29,000 bopd, exceeding pre-development expectations.

Development drilling began in early November and the field came on line Nov. 14, initially producing 2,350 bopd of 26 degree API gravity oil from one well.

Rick Mott, ConocoPhillips Alaska's vice president of exploration and land, said Nov. 21 that the Kuparuk accumulation at Palm is estimated to contain 35 million barrels of recoverable reserves.

The time from the spud of the discovery well to first production was 20 months.

—KAY CASHMAN, Petroleum News publisher & managing editor

BREAKING NEWS

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NORTH SLOPE, ALASKA

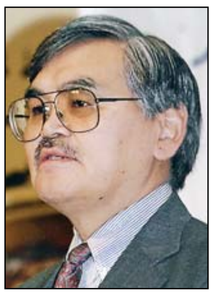
Made in Alaska

Native regional corporation aims to be independent North Slope producer

By KAY CASHMAN

Petroleum News Publisher & Managing Editor

Steve Marshall, president of BP in Alaska



Jacob Adams, Arctic Slope Regional Corp. president and CEO

Arctic Slope Regional Corp., a company representing the business interests of 9,000 Inupiat Eskimos, is expanding its scope to become an independent oil and gas producer in its own backyard — i.e. the petroleum-rich North Slope of Alaska.

As the "next step" in its evolution from oilfield service provider and land owner/manager, ASRC has entered into a "mentoring" agreement with major North Slope producer BP Exploration (Alaska), the state's largest investor and one of the biggest oil and gas companies in the world.

The agreement, signed March 20, "establishes a framework for sharing data and technical knowledge" between the two companies, including information on unit and near-unit oil and gas investment opportunities on the North Slope, ASRC and BP company executives told Petroleum News in early July.

Specific opportunities for ASRC to participate in exploration and development activities will be "subject to individual negotiation," the companies said.

No specific exploration or development deals have been cut yet, but Conrad Bagne, ASRC's chief administrative officer and in-house counsel, said the companies hope to "have something identified by

see **ASRC** *page 16*

VALDEZ, ALASKA

LNG market gets more competitive

As more sellers enter the market, Asian buyers are looking for better deals

By KRISTEN NELSON

Petroleum News Editor-in-Chief

1 2 SERIES

It's a different world than it used to be for sellers of liquefied natural gas. The terms for LNG sales to Asia — traditionally long-term inflexible contracts — are becoming more flexible as more sellers enter the market.

That was the message the June 28 Valdez LNG Summit heard from buyer Korea Gas and Tokyo Gas.

The summit, hosted by the City of Valdez and the Alaska Gasline Port Authority, also heard about the potential market for liquefied natural gas on the West Coast of North America (see part 1 of this story in the July 6 issue of Petroleum News), but the Asian market has been buying LNG from Alaska since 1969 when production started from the ConocoPhillips-Marathon Oil (then Phillips-Marathon) plant in Nikiski on the Kenai Peninsula. LNG has traditionally been sold to that market via long-term contracts with take-or-pay provisions and pricing tied to a basket of oil prices.

Korea Gas looking for more liberalized market

Hong-Shih Jean, vice president of the LNG purchase department at Korea Gas, told the summit that the company has seven long-term contracts and two mid-term contracts for LNG with six

see **LNG** *page 15*

GREENLAND

Chasing Arctic breakthrough

Greenland touts North Sea-size potential in preparing licensing round

By GARY PARK

Petroleum News Calgary Correspondent

Greenland, with reserves estimated to be comparable in size to those of the entire North Sea and seeking an economic alternative to its fishery, is trying again to push itself into the forefront of the Arctic hunt for oil.

Along with Denmark, under which it has limited home rule, Greenland said June 30 that its Bureau of Minerals and Petroleum will open a licensing round in 2004, offering an area offshore West Greenland between 62 and 69 degrees North longitude.

The process will start with an open letter of invitation, followed by a meeting in Copenhagen on April 1, 2004, and another in Houston.

The deadline for applications will be Oct. 1, 2004 and the bureau expects to grant licenses either next year or 2005.

The licenses areas include parts of Lady Franklin Basin, Kangaamiut Basin and Ridge, parts of Ikermiut Fault Zone/Sisimut and parts of the Atamnik and Fylla structural complexes.

Terms of the 10-year licenses will be based on existing license terms — awarded to Norway's Statoil and Phillips Petroleum in 1999 and

see **GREENLAND** *page 15*

● ANCHORAGE, ALASKA

LNG not cost competitive for ConocoPhillips

Company reviews sponsor group study for new Alaska Natural Gas Development Authority

By KRISTEN NELSON
Petroleum News Editor-in-Chief

Joe Marushack and Gary Endorf of ConocoPhillips Alaska struggled for most of the afternoon July 7 to convince members of the Alaska Natural Gas Development Authority board that liquefied natural gas is not economic for Alaska. They reviewed results of the 30-month, $14 million engineering effort by the Alaska North Slope LNG Sponsor Group (ConocoPhillips, BP Exploration (Alaska), Foothills Pipelines and Marubeni Corp.) completed in 2001 which concluded an Alaska North Slope LNG project was not cost competitive with other LNG projects.


JOE MARUSHACK

Endorf compared estimated costs of LNG service to Japan: projects on the Pacific Rim averaged less than a $2 per million Btu while Alaska LNG had a cost of service of $2.94 per million Btu. The costs were closer for delivery to the West Coast: Alaska LNG averaged $2.80 per million Btu, while Pacific Rim projects averaged less than $2.50 per million Btu.

The numbers for cost of service are estimated from external sources, Endorf said, and do not include upstream costs and the cost for re-gasification of the LNG. The cost of service numbers illustrate the burden of the 800-mile Alaska pipeline, he said, estimated to add 97 cents per million Btu.

The sponsor group did a significant amount of work to evaluate an LNG project, he said, "and at the end of the day it was concluded that the investment was just not cost competitive."

One issue the board raised was voiced by Dan Sullivan, who asked if the Alaska LNG project was not cost competitive because ConocoPhillips needed to meet a certain rate of return on the project.

"It's a good question. And that's truly not how it works," Marushack said. The company looks at the cost, and what it takes to be competitive. As for hurdle rates, those vary with the level of risk in a project, he said.

"In order to do a project," Marushack said, "you've got to be very cost competitive. If you're not amongst the most cost-competitive projects, you're not ultimately going to be the one that's able to get the deal done."

> *"In order to do a project, you've got to be very cost competitive. If you're not amongst the most cost-competitive projects, you're not ultimately going to be the one that's able to get the deal done."*
> **—Joe Marushack, ConocoPhillips Alaska**

Costs for LNG projects dropping

Another way to compare projects is by what it costs per million tons per annum, said Endorf. First there is a difference between expansion projects and greenfield or new projects. Projects with published costs ranged from $200 million per MTPA, cited for Malaysia III, an expansion project, to $330 million per MTPA for Qatar Ras Laffan, a grassroots project. These numbers compare with $610 million per MTPA for an Alaska LNG project at Nikiski and $730 million per MTPA for an Alaska LNG project at Anderson Bay, with the Alaska projects burdened by some $300 million per MTPA for the 800-mile pipeline.

Recently, he said, projects costs are dropping, with grassroots projects beginning to approach $200 million per MTPA. Endorf said expansion projects like Malaysia III, which cost $200 million per MTPA, "nowadays are going for more like $150 million (per MTPA)."

Board wants to verify

Board member John Kelsey asked if ConocoPhillips would provide the authority with copies of the study, and Marushack said it is owned by four companies, and the authority would have to negotiate with all four to buy it.

Board Chairman Andy Warwick told Marushack that various groups are telling the authority "that one project is more viable than the others," and asked how the board could analyze ConocoPhillips' results "without the underlying data?"

Jack Griffin, head of external affairs for ConocoPhillips Alaska's, said the company was not asking the authority to accept its numbers as correct, and was not trying to dissuade the state from going forward with the project.

"That's the state's decision. We're just trying to explain why we're not going forward with the project."

Harold Heinze, who did background work for the authority on a contract from the governor's office, told ConocoPhillips he thought "the authority may want to look at these numbers with a different perspective than you have." If the state looks at the project as building infrastructure, he said, it may be looking at a very different rate or return than the company.

Griffin said the Department of Revenue already had the ability to compare numbers, and Warwick asked if ConocoPhillips would be willing to "work with the Department of Revenue t help them back into your numbers?" Marushack said they would work with Revenue, "describe some of the numbers that we've got and help them to get a number."

Marushack said some of the market data could be pulled from publications, but "there's almost no substitute for actually negotiating deals on that one and that takes a staff of people. … (and) actually working the market.

"And you don't work the market in two or three meetings," he said. "You work the market over two or three years…" ●

NORTH SLOPE, ALASKA

Armstrong, ConocoPhillips, Anadarko win BP's exploration acreage bundles

Armstrong Resources, ConocoPhillips Alaska and Anadarko Petroleum were the companies that won North Slope exploration packages from BP Exploration (Alaska), BP spokesman Daren Beaudo told Petroleum News July 9.

Beaudo said June 25 that BP had sold three of the 12 North Slope exploration acreage bundles it put up for sale in January, but was unable to release the names of the three winners after bid closing May 6 because commercial arrangements had not been finalized. (See June 29 Petroleum News article.)

Armstrong won "close to 10,000 acres northwest of the Milne Point unit, adjacent to that unit," company President Bill Armstrong told Petroleum News July 10. He said his company "has plans for the area," which is "offshore in shallow water," but was not yet ready to discuss those plans.

Beaudo said Anadarko won a bundle in the Southeast Prudhoe area and ConocoPhillips won the Colville acreage. Additional information was not available as Petroleum News went to press.

The three packages represent nearly half the 405,000 acres BP had left for sale outside of its North Slope producing acreage. The 12 bundles were offered to 15 companies, including independents, "positioned to prospect the leases," BP said.

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

Issue Index

Message from the publisher

Petroleum News, formerly Petroleum News Alaska, is a weekly newspaper that covers the North American energy market with regional reporting preferences in the following order: Alaska, northern Canada, western Canada, Gulf of Mexico, continental United States, eastern Canada and Mexico. Between April 6 and Dec. 31, Petroleum News is adding more and more oil and gas news outside of its prime coverage areas of Alaska and northern Canada but will not reduce the amount of attention it gives to those primary areas. Input from readers is welcome. Please email your comments, suggestions and news tips to Kay Cashman at publisher@petroleumnews.com

Petroleum news

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Petroleum News and its supplement, Petroleum Directory, are owned by Petroleum Newspapers of Alaska LLC. The newspaper is published weekly. Several of the individuals listed above work for independent companies that contract services to Petroleum Newspapers of Alaska LLC or are freelance writers.

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Petroleum News (ISSN 1544-3612) Week of July 13, 2003
Vol. 8, No. 28
Published weekly. Address: 5441 Old Seward, #3, Anchorage, AK 99518
(Please mail ALL correspondence to:
P.O. Box 231651, Anchorage, AK 99523-1651)
Subscription prices in U.S. — $52.00 for 1 year, $96.00 for 2 years, $140.00 for 3 years. Canada / Mexico — $165.95 for 1 year, $323.95 for 2 years, $465.95 for 3 years.
Overseas (sent air mail) — $200.00 for 1 year, $380.00 for 2 years, $545.95 for 3 years.
"Periodicals postage paid at Anchorage, AK 99502-9986."
POSTMASTER: Send address changes to Petroleum News, P.O. Box 231651 • Anchorage, AK 99523-1651.
NOTICE: Prior to April 6, 2003, Petroleum News was formerly known as Petroleum News Alaska.

NORTH SLOPE, ALASKA

Winstar's North Slope well a duster; working on other slope prospects

In a written statement to Petroleum News titled, "We'll be back," Winstar Petroleum President Jim Weeks said Tuesday, July 8, that the independent's first well on Alaska's North Slope was a duster.


JIM WEEKS

"The Winstar Oliktok Point State No. 1 well reached total depth Sunday afternoon, with disappointing geological results. Winstar decided to plug and abandon the hole on Monday afternoon, and the Doyon Rig 141 was released," Weeks said.

The well was spud on June 26 by ConocoPhillips for Winstar from onshore drill site 3-R on the northern edge of the Kuparuk River unit to an offshore target that is part of Winstar's 1,280-acre lease. The lease was recently included in the Kuparuk unit, which is operated by ConocoPhillips.

"This is a huge disappointment to all the Winstar leaseholders and investors in this well," Weeks said. "We were all excited about the prospect of becoming the first Alaskan owned and based independent to produce oil from the North Slope, but we must now wait for another occasion to celebrate.

Looking near Point McIntyre, Liberty, Badami

"We are anxious and excited to see what prospects there are on our other acreage positions in the Point McIntyre, Liberty and Badami areas, and to bring those prospects to drillable status," he said.

Winstar and its sister company, UltraStar Exploration, have more than 21,000 other acres of state leases on the North Slope, plus an over-ride on a nearly 2,000 acre lease near Thetis Island that was recently assigned to Pioneer Resources and Armstrong Resources.

Weeks said Winstar has a license from BP Exploration (Alaska) to more 50 square miles of 3-D seismic data covering a substantial portion of Winstar's Liberty and Badami area leases, and last year awarded a contract to a subsidiary of Chroma Energy of Sugar Land, Texas, "to evaluate the seismic and work up prospects."

Well drilled safely, efficiently

In spite of the geological failure of Oliktok Point State No. 1, "the well was successful in that it was drilled safely and efficiently for the budgeted amount of money into the targeted formation with no environmental incidents," Weeks said. "We got to see what we wanted to see for the price we agreed to pay. I'd like to commend and pub-

see **WINSTAR** *page 4*

MEXICO

Precision-BJ Services expand Mexican contract in country's Burgo Basin

Mexico's burgeoning natural gas sector is turning into a lucrative opportunity for Precision Drilling, Canada's largest oilfield services company, and its joint owner, Houston-based BJ Services.

They received a contract extension of $339 million July 7 for at least 285 wells in Mexico's northern Burgo Basin, adding to an initial contract of $270 million.

Precision chief executive officer Hank Swartout said the extension will see his company increase its Mexican rig fleet to 10 from seven.

The two companies, operating under their joint venture PD Mexicana, finished 240 wells sooner than expected and continued to drill another 60 for the same contracted price.

That lowered the average well costs to $900,000 from an estimated $1.1 million and encouraged state-owned Pemex to extend the deal, which is expected to earn the partners about $1.2 million a well.

Precision Chief Financial Officer Dale Trembaly said about 36 percent of the contract value will flow to Precision, as the lead contractor, with the balance going to BJ and other third parties.

The Burgos basin, covering about 13,000 square miles, is one of Mexico's largest gas basins.

Precision, which drills about 40 percent of Canada's oil and gas wells, also has operations in the Middle East and South America, but Mexico has become its hottest international project for more than two years.

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

LONDON, ENGLAND

BP flags strong second-quarter results

British oil company BP PLC said July 2 it expects stronger second-quarter earnings, amid oil and natural gas prices that remain high despite a recent dip.

However, it also warned that the profit margin from its U.S. gas-trading activities would be "significantly lower" in the quarter because of a decline in market volatility.

In April, BP reported its highest-ever quarterly net profit — $4.27 billion, three times higher than its results the previous year.

The surge was due to stratospheric oil prices tied to the war in Iraq, coupled with supply disruptions in the key producing nations of Nigeria and Venezuela.

The surge was due to stratospheric oil prices tied to the war in Iraq, coupled with supply disruptions in the key producing nations of Nigeria and Venezuela.

At the same time, U.S. gas prices were also sky-high because an especially cold winter elevated demand at a time when gas storage levels hit a record low.

In February, BP Chief Executive John Browne said the company would be steering clear of setting specific production targets, opting instead for "indicative ranges," after it was forced to lower its outlook three times last autumn to 3 percent from 5.5 percent.

BP said refining margins in the second quarter will probably be lower than last quarter, though the retail environment is expected to improve, since falling oil prices have boosted demand despite the worldwide economic slowdown.

The decline in refining margins, particularly a 7 percent decline on the U.S. West Coast, led Merrill Lynch to cut its second-quarter net income forecast for BP by around $50 million to $2.88 billion.

However, this is still a 32 percent increase from the $2.18 billion net profit BP reported in the second quarter of last year.

BP is expected to report second-quarter financial results July 29.

—**THE ASSOCIATED PRESS**

● ANCHORAGE, ALASKA

New exploration plans under consideration

By KRISTEN NELSON

Petroleum News Editor-in-Chief

Cheryl Frasca, director of the Alaska governor's Office of Management and Budget, and Tom Irwin, commissioner of the Alaska Department of Natural Resources, told the Anchorage Chamber of Commerce July 7 that the governor wants the Constitutional Budget Reserve to be "used strategically" to meet the state's budget gap until state income can be increased from resource development, primarily oil.

Why primarily oil? Because, Frasca said, the infrastructure and the tax framework are in place.

With a cap of $400,000 a year to be drawn from the reserve, it took a combination of spending cuts and new revenues from the Legislature, and vetoes from the governor, to hold the line this year, Frasca said. The administration is trying to do business differently, she said, to look at every program the state delivers and ask: Should we do it? Can private industry do it? Is the program effective? And, is it worth the dollars being spent?

In addition to spending reductions this year, there will need to be more next year. "It doesn't look like it gets any easier," she said.

Incentive already working

The governor pushed for incentives for the oil and gas industry to help attract investment to Alaska, Frasca said. One of the incentives passed last session, that for exploration incentives, came about after it was brought to the governor's attention near the end of the session that Alaska ranked close to the bottom of oil provinces offering exploration incentives, and partially as a result of that, only three exploration wells were planned for the upcoming winter of 2003-04. The package the administration introduced and the Legislature passed offers severance tax relief for up to 40 percent of the cost of an exploration well or seismic survey.

"Since the tax incentive took effect on July 1st, it is our understanding that there are a number of new exploration activities being considered for Alaska," she said.

In the coming five years, Frasca said, increased revenues from resource development will come primarily from oil, since that is the major source of state revenues now. The governor has identified oil as a growth area because the tax structure is in place and a lot of the infrastructure is in place, she said.

Irwin said the state, like any business, has to work on the details. "And that's the approach we're really taking," he said. With the support of the governor, the Legislator and the commissioners, "we're looking at all the issues," he said.

It started with the incentive for exploration. "We don't see exploration like in Alberta — 2,500-plus exploration wells in 2002 — an incredible difference." The state needs to attack all of the issues behind that difference, he said. What can we learn from other places? What are they doing, he asked.

"Alaska's competing in a world market," he said, and companies "don't come because they love us … companies come here because they want to make a profit."

Those companies look at rate of return and economic analyses and cash flow, "and we've got to make a difference in Alaska to compete," he said. ●

ANCHORAGE, ALASKA

Authority hears from ConocoPhillips

The Alaska Natural Gas Development Authority held its second board meeting July 7, heard a presentation by ConocoPhillips (see story on page 2) on liquefied natural gas, West Coast receiving terminals and the Lower 48 gasline project, and agreed to meet telephonically July 14 to select a chief executive officer for the authority. Board members will also look at proposed bylines and take action on them at its next full meeting. A time for that meeting will be set after the board names a CEO.

The board also heard a work study plan developed by Harold Heinze under a contract with the governor's office. Heinze told board members that he thought important things for the board to do initially include organizing itself, practicing for bigger decisions and working parallel efforts on long-lead items.

Since the authority has an initial budget of $150,000, Heinze recommended focusing on only the most useful activities in support of a work plan or producer negotiation.

continued from page 3

WINSTAR

licly thank the Doyon rig team, the numerous oil field service contractors, and ConocoPhillips Alaska, who operated this well and allowed us to have this prospect evaluated."

He also acknowledged the other Kuparuk River unit owners, "BP, Unocal, ChevronTexaco and ExxonMobil, for their support of the access agreements to Kuparuk production facilities and drill site that enabled us to get the well drilled."

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

● NORTH SLOPE, ALASKA

State of Alaska streamlines ice road approval

Agency alters procedures for North Slope ice road construction; federal, private lands now included for exploration access review

By PATRICIA JONES

Petroleum News Contributing Writer

A minor change in procedures governing ice road construction for Alaska North Slope exploration projects will streamline and expedite the approval process for companies needing access to federal or private lands.

In a letter issued June 19, state project analyst Glenn Gray announced completion of a state review of minor changes that govern ice road construction to ensure consistency with the Alaska Coastal Management Program.

The main focus of the changes is to add federal and private lands to provisions that govern temporary ice road construction on state lands, he told Petroleum News July 8.

"Before, it was just state land," he said. "This is a streamlining (of review) for ice road construction for oil and gas exploration."

Benefits NPR-A, Colville exploration

Companies that will benefit from the changes include those working in the Colville River area on privately owned land and in the federally controlled National Petroleum Reserve-Alaska.

In past years, Gray said, such winter access work has been held up — sometimes for weeks at a time — due to the exclusion of federal and private land in ice road construction provisions under the Alaska Coastal Management Program.

Those delays in ice road construction occurred because the entire exploration project, including building the ice-based temporary roads, had to receive regulatory approval — also called General Concurrence — on those federal and private lands, Gray said.

Now, ice road construction is viewed as a separate, distinct phase of exploratory drilling on all lands on the North Slope and is considered initial work that can be conducted while final permitting for actual exploration drilling is still pending.

That expedited approval comes only if operators submit a plan for ice road construction to state permitting agencies that complies with regulations outlined in detail in the General Consistency Determination 34 and regulators determine that no individual review is required.

JUDY PATRICK

Ice road construction on the North Slope

Permits are still required for access and water use from the different agencies, Gray said.

Other changes

Gray's letter and attached ACMP final consistency determination also notified participants of three other minor changes in the regulations.

First, the name of the General Concurrence 34 rule, pertaining to ice road construction for exploration work, was changed to General Consistency Determination 34.

Second, the altered rules allow for temporary storage of materials on ice. That would include "any kind of material that would be brought to a drilling location or a staging area — pipe, equipment, construction material," Gray said.

Before this change, the general concurrence did not allow materials to be stockpiled on surface ice of lakes, ponds, rivers or on sea ice. GCD 34 lists three exceptions that allow such temporary storage. Those include the use of light plants and water pumps (including refueling), stockpiling materials on surface ice of lakes and ponds that do not contain fish, and storing materials on fish-bearing waters with consent from the Department of Natural Resources or the applicable land manager.

The third change allows for addition of the Bureau of Land Management right of way authorization to the list of permits involved with the General Consistency Determination.

Purpose of GCD 34

Establishing the general rules of GDC 34 for ice road construction actually speeds up the approval process for construction of the temporary access routes, Gray explained.

Without the General Consistency Determination to operate under, companies planning exploration would be required to submit their ice road construction plans for a more time-consuming individual review.

"They would have to come in much earlier … months earlier," Gray said.

Typically, companies are requested by the Department of Natural Resources to begin submitting their winter exploration work plans and permits in August and early September. "Many companies come in later than this," he said. "Without this (GCD 34) a problem with another aspect of the project wold hold up construction of ice roads."

The general rules for ice road construction allow that work to begin as soon as the department allows access on the frozen tundra. Companies can begin building their access roads to remote locations, while finalizing permits for the exploration drilling.

"In a year with a standard freeze, they can get through all their permitting by the time ice road construction is complete," Gray said.

An earlier freeze-up on the North Slope, somewhat unusual in recent years, could allow for that portion of the work to be completed in advance of final permitting work, he added. ●

NORTHWEST TERRITORIES

NWT lobbies for better revenue deal

The Canadian government stands to harvest almost C$22 billion in revenues from the planned Mackenzie Gas Project — unless it can be pressured to share those spoils with the Northwest Territories.

And the campaign for an equal distribution of those royalties and taxes — potentially one third to the Northwest Territories government, one third to aboriginal governments in the territories and one third to the federal government — has been intensified.

STEPHEN KAKFWI

In a letter to the leaders of Canada's 10 provincial governments and two other territories, Northwest Territories Premier Stephen Kakfwi has laid out the basis of revenue sharing.

"Under existing arrangements, the federal government has control over all natural resources in the NWT and collects all royalties generated by their development," he said.

What he wants is a transfer of powers to the Northwest Territories. "It's an issue of dignity; it's our resources; it's our land," Kakfwi said, describing the territories' objective as the negotiation of an agreement over the land and resources.

Kakfwi noted that within 10 years the territories — through its gas project and diamond mines — could become a net contributor to the Canadian economy, instead of a region dependent on federal hand outs.

So far, the Northwest Territories has gained the support of the four western provinces (British Columbia, Alberta, Saskatchewan and Manitoba) and its two neighboring territories (Yukon and Nunavut).

Kakfwi noted that within 10 years the territories — through its gas project and diamond mines — could become a net contributor to the Canadian economy, instead of a region dependent on federal hand outs.

The Northwest Territories government has calculated that the Canadian government could collect C$18.1 billion directly over three decades from the Mackenzie project, plus clawing back another C$3.6 billion from the territories under the existing revenue formula, leaving the territories with just C$900 million.

The diamond mines are forecast to inject C$7.5 billion into government treasuries, of which the Northwest Territories would collect a mere C$260 million.

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

ADVICE

Portfolio strategy update

Advanced electioneering economics, courtesy Bush administration

By **DAVID GOTTSTEIN**

PETROLEUM NEWS CONTRIBUTING COLUMNIST

Editor's note: David Gottstein is with Dynamic Research Group in Anchorage. This column was written in early July.

Advanced electioneering economics. That is a mouthful, but what I really mean is that the Bush administration has pulled out all the weapons in its arsenal to get the economy, and hopefully, the stock market, moving solidly in a positive direction before the next election.

Low interest rates, more tax cuts, massive federal deficits, and an export-oriented falling dollar, have all contributed to the general and growing perception that the combination of these powerful forces at play will propel the economy forward.

And Alan Greenspan, set for another term as head of the Federal Reserve, has learned to survive politically.

He will likely have a pro-Bush economics posture going into the election.

You have to say that the government is fully engaged in trying to improve the economy. And traditionally these moves have had a positive effect.

I have also observed that in the short and possibly intermediate term, stock prices follow the money, and money has been flowing into stocks.

Whether it is interest rates being so low, or because people are feeling more positive, we have seen an impressive run-up in stocks. One, I have to admit, I have been surprised at the strength and breadth of.

Is it working?

The proof will be in the second quarter earnings to be reported in July, and the continuum of weekly claims for unemployment and the monthly unemployment numbers.

If earnings come in well, and employment doesn't get any worse, then the market's rise will have been somewhat justified.

If you're to believe the bull market case.

Watch out otherwise.

Valuations

Byron Wien of Morgan Stanley said it well: "We are in a bull market cycle in a secular bear market."

This run may have some legs yet, and may go on for a while, but eventually the market will run out of hot air. Even with interest rates so low, trailing PE ratios north of 30 are once again near the stratosphere. Even if you normalize the earnings data, the PE ratio on stocks is close to 20, the upper band of what has often signaled extended fundamental valuations.

Current valuations are discounting almost everything good happening, and nothing in terms of negatives.

Until we see job growth, the risk of a struggling economy is present.

In spite of a full court press in talking the economy up by the administration, et al, we believe interest rates will begin to rise over time, and spoil the housing market boom, the only true growth area as of late, besides healthcare.

This will reverse the positive influence interest rates have had on PE ratios the market has enjoyed for almost 20 years.

It will take a very strong economy to deliver higher stock prices in that scenario.

ALBERTA

Alberta fund logs first loss in 27 years

Alberta's Heritage Savings Trust Fund, its equivalent of the Alaska Permanent Fund, took a heavy blow from stock market investments, reporting a net loss of C$894 million for fiscal 2002-03.

The fund value now stands at C$11.1 billion, compared with C$12.7 billion in 1986 and a peak C$12.9 billion in 2000, but, after factoring in inflation and purchasing power, the nest-egg is estimated to have declined by 40 percent over the past 17 years.

Revenue Minister Greg Melchin said the first loss in the fund's 27-year history was "disappointing," but he insisted it can "handle (the) volatility" of investments that are intended for 10- to 20-year cycles.

He said the loss will not harm Albertans at a time of significant budget surpluses for the government.

The fund was established in 1976 to building a financial cushion for future generations from an oil boom, but as commodity prices slumped in the 1980s capital infusion to the fund stopped.

In 1986, the fund would have covered 95 percent of the province's spending; in 2003 it will barely cover 50 percent.

Now, instead of being set aside for the long-term, the fund's returns are being used to cover today's expenses.

In addition, the fund has increasingly gambled by moving its assets into equities and away from safe interest-bearing bonds.

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

CANADA

Uranium mine resumes production

Cameco, the world's largest uranium producer, has resumed production at its northern Saskatchewan mine well ahead of schedule.

The company, which owns 70 percent of the McArthur River mine, was forced to shut operations April 7 following a cave-in and flood and did not expect to restart until late July or early August.

It expects operations at McArthur River and nearby Key Lake will produce up to 13 million pounds of uranium in 2003.

The area where the water entered the mine has been "filled with concrete and work is continuing to permanently seal it off by mid-August," Cameco said in a statement.

The shut down did not result in any layoffs, but is expected to trim Cameco's net earnings for the year by about C$8 million to C$10 million.

Diamond plays sparkle in northern Canada

The lure of diamonds is spreading through Canada's Arctic, with reports of new kimberlite finds in a lightly explored region of eastern Nunavut.

Cumberland Resources and Comaplex Minerals have completed drilling on their Meliadine East project on the Melville Peninsula with an announcement that they have intersected kimberlite on 11 of 12 geophysical targets.

Cumberland director Glen Dickson said the discoveries look like pipes, but cautioned that there are only one or two holes in the targets.

He said the size and dimension have yet to be established — probably within three months once the samples have been analyzed by the Saskatchewan Research Council.

Meantime, Shear Minerals and Northern Empire Minerals are spending C$2.5 million exploring the Churchill project, which is northeast of Meliadine and covers about 1,079 square miles. So far, kimberlite has been intersected in each of the first three targets drilled, giving a 50 percent boost to shares of Shear on the S&P-TSX Venture Exchange.

Placer Dome wins bid for Africa gold mining company

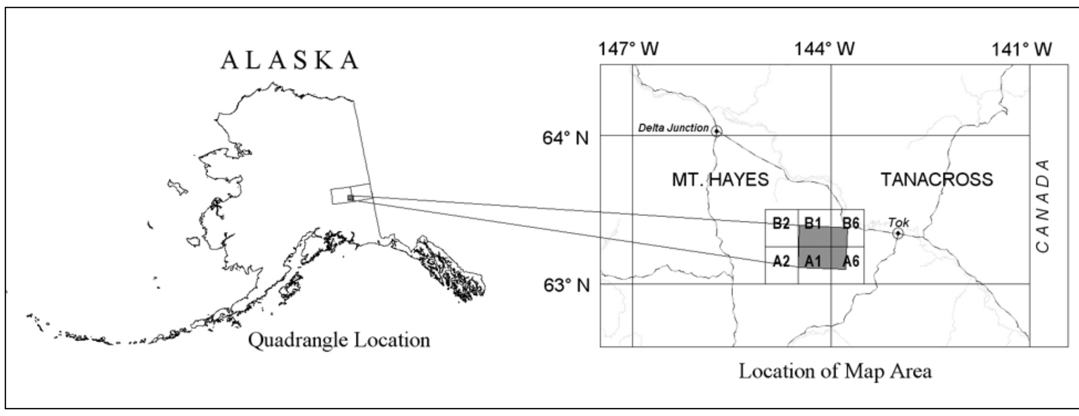
Vancouver-based Placer Dome recently beat out two rivals in a friendly $255 million takeover of Australia's East African Gold Mines, a deal that gives the firm access to "one of the fastest growing areas for gold exploration and investment," said Placer CEO Jay Taylor.

East African owns the North Mara open-pit gold mine in northern Tanzania that is expected to produce 220,000 ounces a year at cash costs of $200 an ounce and total costs of $252 an ounce.

Placer plans to spend $25 million upgrading a nearby mill and $3 million a year on exploration to boost annual output to 300,000 ounces for more than 10 years.

AngloGold and Gold Fields were competing bidders for East African, losing out to Placer's offer of $3.015 a share in cash.

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



● INTERIOR ALASKA

Industry sells valuable data

State of Alaska plans to release geological maps for 440 square miles of mineral prospects in Alaska Range, data compiled since 1976 by industry

By PATRICIA JONES

Petroleum News Contributing Writer

Later this summer the Alaska Division of Geological and Geophysical Surveys plans to release geological maps and related data covering the Delta Mineral Belt, a section of 440 square miles in the Alaska Range some 52 miles west of Tok, Alaska.

The data comes from industry-commissioned geological work in the mineralized area, started in 1976 and continuing through 2001 — research worth about $20 million, said Laurel Burns, mineral section chief at the division.

The division will release to the public one inch to the mile scale geological maps, along with an analysis of more than 800 rock samples gathered in the area. Information used in the state printing of the maps and reports came via Northern Associates, a Fairbanks-based geological consulting firm that has prospected the area for industry clients since 1994.

"For this area, the focus of (past) exploration has been for base metals," said Sam Dashevsky of Northern Associates. "The map identifies 66 mineral occurrences."

Most of those mineral occurrences are classified polymetallic, containing copper, gold and silver in addition to the base metals of lead and zinc, he said.

Dashevsky obtained permission from the current owner of the geological data, Grayd Resource Corp., to produce the information for state release.

The cost to the state was "pennies on the dollar," he said, although he declined to reveal the exact amount.

"It was pretty minimal — thousands of dollars, versus the millions of dollars the data represents," said division geologist Dave Szumigala. "It was a very low-cost way to acquire something that benefits us in the mineral community."

First state-industry information release

This is one of the first joint state-industry geological information releases of this kind, Burns said. Usually such detailed and expensive prospecting information gathered by a private company is kept secret.

"So many times each private company goes in and works an area and then leaves Alaska and they take their information with them," Burns said. "Unlike in Canada, where (the government) ends up with copies of their maps."

Annual work on mining claims in Canada requires proof, contained in geologic maps and reports that companies file with the government, Szumigala said. That information is held confidential for a certain period of time.

In the United States, companies conducting annual work necessary to hold mining claims are not required to include such proof of their work, he said, a surprise to some firms accustomed to working in Canada.

"To have more data would help in a lot of areas," Szumigala said. "There's a lot of good data out there from other private companies. We hope they see this and they might consider releasing some data in a similar manner."

Grayd hopes the information release sparks additional exploration in the area, and generates interest in prospects the company still holds, Dashevsky said.

"It will help people understand the geology and existence of deposits," he said. "It's a three-way

see **MAPS** page 8

● NOME, ALASKA

Digging in all the wrong places

Amerigold's Nome placer lease terminated, NovaGold looks at other options

By PATRICIA JONES
Petroleum News Contributing Writer

Amerigold, a gold placer mining operation working near Nome in western Alaska, recently lost its lease on virgin ground at Dry Creek after starting to dig on the wrong property last year.

NovaGold Resources owns patented Dry Creek ground on the outskirts of Nome; ground it leased to Amerigold in 2001. NovaGold terminated the placer operator's lease for Dry Creek and Bourbon Creek land this spring, Doug Nicholson, senior projects engineer at NovaGold told Petroleum News on July 8.

"They started operations last year," Nicholson said. "Nothing was done (on the property) this year."

That's because in 2002 Amerigold began stripping overburden — the first step in placer mining to get to loose gold — on the wrong piece of property.

The backhoe and bulldozer work was on the same Dry Creek drainage but on state land, about 1,800 feet from NovaGold's leased land, said Victor Ross, Nome area project manager for the U.S. Army Corps of Engineers.

Residents in the area notified the landowner, who initially issued a cease and desist order, Ross told Petroleum News on July 9.

"People in Nome are pretty astute," he said. "They operated only a short period of time — long enough to strip about seven acres of land, which doesn't take very long using heavy equipment."

The corps also issued a cease and desist order and required Amerigold to reclaim the area of disturbance, which the company did, he said: "They completed what we required and spent money and time to do so."

Reclamation work started last year and was completed this spring, Ross said.

Amerigold is also required to complete reclamation dirt work to satisfy the landowner, the Alaska Department of Natural Resources and the Alaska Department of Transportation and Public Facilities, Ross added. Transportation asked Amerigold to construct a stabilizing berm because the initial digging was close to a nearby road.

Representatives from Amerigold could not be reached by phone by press time.

The company still holds a 10-year mining lease on another NovaGold property in the Nome area, ground near the community's airport on the northwest side of town.

Nicholson said no operation is planned for that property this year, but added that the company "can certainly apply for permits."

Ross said he has received no other permit applications from Amerigold.

"I know they've spent a fair amount of money moving equipment to Nome, and they're not in production," he said. "They have a lease but no plan of operation, and a bunch of equipment sitting there in Nome."

Other placer development considered

The upper portion of Dry Creek has previously been mined, Nicholson said, and miners are currently working its headwaters. But the lower portion that NovaGold owns is virgin i.e. it has never been mined.

"If the ground is viable, we'll attempt to do something with it and see some value to our company," Nicholson said. "It is a placer resource and we hope to see it developed."

Like most typical lease agreements for placer mining, NovaGold received an advance payment and was scheduled to receive royalty payments from Amerigold based on gold produced from the ground.

NovaGold, a junior-sized exploration company with a number of hard rock gold projects — including the 28 million ounce Donlin Creek deposit in southwest Alaska — acquired the Nome area land in its 1999 purchase of the Alaska Gold Co.

Currently, NovaGold holds 14,000 acres of patented ground in and around Nome. In addition to leasing placer gold resources, NovaGold is developing the estimated 1 million ounce gold Rock Creek deposit about seven miles from Nome.

NovaGold also benefits from gravel sales on its Nome-area land, Nicholson said.

"With the pick-up in gold prices, we are looking at the placer ground," he said. "Potentially we could do something with the placer ground in conjunction with our gravel sales." ●

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MAPS

win-win deal for the state, Grayd and Northern Associates."

Long prospecting history

Data to be released to the public is based on the geologic mapping, lithochemistry, airborne geophysics and core drilling carried out by Northern Associates from 1994 to 1999 for two of the property's industry prospectors, Grayd and American Copper & Nickel Co.

"Grayd has a fantastic piece of research summarizing what they know from thousands of feet of drilling, geochemical work, airborne geophysical surveys and ground geophysical surveys," Burns said.

Grayd earned an ownership of part of the property in 1998 and subsequently inherited the data gathered since the first prospecting started on in 1976.

Resource Associates of Alaska, working on contract for Cook Inlet Regional Corp., first discovered the massive sulfide occurrences in the Delta Mineral Belt in 1976, Dashevsky said. Since then, numerous companies have explored the area, spending $18 million through 1999, according to Grayd.

A project summary on the division's web site said an inferred resource has been calculated for eight deposits contained within the Delta Mineral Belt. One of those calculated resources contains 19 million tons of mineralized rock, grading 0.6 percent copper, 2 percent lead, 4.6 percent zinc, 73 parts per million silver and 1.9 parts per million gold, Dashevsky said.

Other occurrences on Grayd's property contain "considerably higher grades" of mineralization, he added, but with less drilling work to date.

Recent work shows gold

Currently, Grayd is taking another look at those high-grade occurrences and testing some other exploration concepts, Dashevsky said, work of a casual nature not requiring exploration permits.

The company's last partner in the area, Placer Dome, financed $350,000 of exploration work in 2001, which included surface sampling, geophysics, hand trenching and drilling on a five-mile long mineralized trend called White Gold.

According to the 2001 Alaska Mineral Industry Report, higher-grade intersections drilled included 4.3 feet grading 0.36 ounces of gold per ton of rock, 57.4 feet grading 0.035 ounces and 42.6 feet grading 0.035 ounces. Twelve holes were drilled, spread over five miles, for a total of 5,720 feet. All holes contained anomalous gold intervals, according to the state report. Placer Dome canceled its option on the property after that exploration program. ●

HUNTINGTON, OHIO

Pipeline project on hold until permit violations corrected

Construction of a petroleum pipeline through southern Ohio will remain on hold until permit violations are corrected and a plan addressing future compliance is approved, the U.S. Army Corps of Engineers said July 7.

The corps halted construction on the Marathon Ashland Petroleum pipeline project on July 2 after inspections revealed violations at a section running through the Richland Furnace State Forest in northern Jackson County, Ohio.

Inspectors said workers dumped fill into waterways, failed to control erosion and sediment and worked outside the approved right of way.

Over the following weekend, the corps and Ohio River Pipeline LLC agreed on an interim plan to correct the violations, the agency said. Ohio River Pipeline, Marathon Ashland Petroleum subsidiary, holds the permit to build the 149-mile pipeline.

Under the interim plan, Ohio River Pipeline is to clean up and repair the construction right of way. The company also is allowed to add insulation and fill dirt around the exposed pipe to prevent damage, the corps said.

New pipeline construction cannot resume until Ohio River Pipeline submits a plan detailing how it will comply with permit requirements, the corps said. Corps officials will review that plan and determine whether to reinstate, modify or revoke Ohio River Pipeline's permit for the project.

About 100 of the 600 employees and contractors on the project were working to ensure environmental compliance, Marathon Ashland spokeswoman Jennifer Robinson said July 7. The company will shift duties to double the compliance workers to 200.

—THE ASSOCIATED PRESS

Contractor quits Marathon Ashland pipeline project

A week after the U.S. Army Corps of Engineers halted construction of an underground fuel pipeline across southern Ohio, the general contractor on the job has quit.

Marathon Ashland Petroleum says the HL Crouse Construction company of Perrysburg has voluntarily left the project. Marathon Ashland spokeswoman Jennifer Robinson says the company is negotiating with another contractor.

Just 29 miles remained on the 149-mile project when the government halted the project on July 2 because of environmental concerns. (See adjacent story.)

Officials said construction will remain idled pending approval of a long-term environmental-corrections plan the company must submit to the Corps.

The pipeline is to cross eight Ohio counties, sending gasoline, diesel fuel, jet fuel and kerosene from a Marathon storage terminal in Kenova, West Virginia, to a terminal in Columbus.

—THE ASSOCIATED PRESS

● ANCHORAGE, ALASKA

Alyeska looking at modular pump station facilities

Electrification of stations, replacement of 42 turbines with fewer than 10 under consideration by trans-Alaska oil pipeline operator

By KRISTEN NELSON
Petroleum News Editor-in-Chief

Alyeska Pipeline Service Co. has completed the conceptual engineering phase of strategic reconfiguration for the pipeline and is working on preliminary engineering, expected to be completed this year, which will give the company the cost and benefit figures needed for a go-no go decision by the pipeline's owners.

One of the issues Alyeska is addressing, John Barrett, Alyeska's program manager for strategic reconfiguration, told Petroleum News June 19, is how to deal with changing volumes of crude oil. The company has to consider how it would accommodate the change if forecasts of flow rates suddenly went up.

"This project actually makes that easier, because as we put the new facilities in (see part 1 of this story in the July 6 issue of Petroleum News), they're going to be modular and scaleable, which means that if we needed additional pumping horsepower, we would bring in more modules," Barrett said. If flow rate goes up, you bring in more modules — if it goes down, you shut them down, either leaving them in place or moving them to another location.

Those kinds of future changes wouldn't have the impact that shutting down a pump station has today, Barrett said. "Today, if we shut down a station because the flow rates are going down, it impacts 20 to 25 people at that station. … With the new mode of operation, you wouldn't have that because you wouldn't have people that are tied to pump stations."

New pumps with electric motors

The base case being evaluated now is that for pump stations currently in use, "we would put in new pumps with electric motors and these would be in …

see ALYESKA page 10

● MIDLAND, TEXAS

Jury: Company covered up spill

Pipeline company hit with $56.2 million for clean-up costs, punitive damages

THE ASSOCIATED PRESS

A Texas jury concluded July 2 that Texas-New Mexico Pipeline Co. committed fraud, gross negligence and willful misconduct in concealing a 1992 crude oil leak beneath a Midland residential subdivision before selling a pipeline to EOTT Energy in 1999.

The jury awarded EOTT $6.2 million for its costs to date to clean up the contamination and $50 million in punitive damages because Texas-New Mexico Pipeline, a subsidiary of Shell Oil Co., concealed the problems while negotiating the sale of the pipeline to EOTT.

EOTT bought the pipeline for $33 million and signed a purchase agreement assuming environmental liabilities.

But 10 of 12 jurors concluded July 2 that Texas-New Mexico Pipeline was to blame for the contamination of the Kniffen Estates subdivision water supply from the estimated 9,000 to 13,000 barrels of crude oil that leaked into the soil.

"The people of Texas have sent a message to (Texas-New Mexico Pipeline), its owner and to the industry that this is not how to run a pipeline, not the way to handle a leak and spill, and not the way to sell a pipeline to somebody else," EOTT Energy chairman Tom Matthews said.

As jubilant EOTT officials celebrated in the courtroom, calling associates in Houston with the news, Texas-New Mexico Pipeline lawyers and officials packed their bags, leaving the courtroom quickly and silently, the Midland Reporter-Telegram reported in its July 3 editions.

"We're not going to have much to say. Obviously, we're disappointed with the jury's decision," Texas-

see SPILL page 10

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ALYESKA

truckable modules. So that these could be fabricated and delivered to the site, placed on foundations and connected to the pipeline system."

Pump stations at the northern end of the line are currently powered by natural gas. A line from Prudhoe provides fuel to run those turbines, and Barrett said Alyeska is looking at the possibility of connecting pump station 1 to the power grid at Prudhoe Bay. Turbines on the lower end of the pipeline run on liquid fuel, he said, and Alyeska is evaluating whether to put in turbine generators that run on liquid fuel or tie into a commercial power source, such as Golden Valley, which is a possibility for pump station 9.

There are some 42 turbines running on the pipeline today, Barrett said.

"And when we finish this we will probably have less than 10."

That will reduce maintenance on the turbines.

Each of the pump stations has several utility systems that have to be operated and maintained, and those are not needed with electric motors and unmanned stations.

And most of the equipment is driven by liquid fuel, "and most of our spills are liquid spills, not crude oil. So the potential for spills goes down as we simplify and upgrade this equipment," Barrett said. Reducing the number of turbines from 42 to fewer than 10 will significantly reduce air emissions.

"And bottom line is, the environmental benefit is fairly significant, as well as the economic benefit and the efficiency and ease of operation," Barrett said.

Control system upgrade

Alyeska's supervisory control and data acquisition system at the control center in Valdez is being upgraded.

Right now, Barrett said, the pipeline is controlled and monitored at Valdez, "but we also have people at every pump station who are doing monitoring and some controlling at the station."

That monitoring and controlling would all be centralized under the new system that would be installed.

"You really don't need someone to walk around and take readings in this day and age. That can all be done through the computer systems and the communications systems that are there. And it can be displayed, it can be analyzed, alarms can be set so that if something is outside of a range that it automatically tells you what is there and you don't have to worry about someone making the rounds every hour and did something change right after he walked by it?" Barrett said.

Alyeska is designing and getting ready to install a new supervisory control and data acquisition system that will work for the existing system and for the new system, he said.

Goal: minimize cost of transportation

The goal: "Minimize the cost of transportation of oil," Barrett said. "The producers are trying to … minimize the cost of producing the oil and we have to minimize the cost of transporting it."

When companies compare the costs of doing business in different parts of the world, he said, "the overall cost of getting a barrel to market is what people compare."

Reducing the cost of transportation will encourage investment in Alaska, he said.

"So we want this to be as efficient as possible, but … we will not sacrifice safety or operational integrity and we want to be able to move all the barrels that are produced. Those are guidelines as we go through this final study phase. And I believe that we can come to a solution that will accomplish all of that and provide significant efficiencies for this pipeline system."

The goal of the reconfiguration, he said, is to move the oil that's there as safely as that oil is moved now, and "to be able to respond in the same way if anything happens."

Larger scale change

Upgrades have been done to the pipeline system over the years, Barrett said, and the supervisory control and data acquisition system has been upgraded before. One of the reasons that system is being upgraded now is because computer technology advances so rapidly that you eventually reach the point where it's easier to buy a new system to take advantage of new technology. That upgrade is "also to take advantage of the new communications systems that we have, the new control systems that we will have on the pipeline system," he said.

"And all of this works together to give you the end result of a fully automated pipeline system that you can run from one control center with the appropriate level of monitoring, control and response."

It will be a better system than Alyeska has today, Barrett said, and it is a fairly significant change.

"We're changing some equipment at stations and we're going to make it a much more efficient, easier to operate and maintain, easier to change for future changes to flows, flow rates. Those are the things that we get from this.

"And the lower cost of transportation — the end result is the lower cost of transportation — encourages investment on the North Slope. It makes Alaska more competitive with other parts of the world." ●

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SPILL

New Mexico Pipeline spokesman Wes Harris said.

In Houston, Texas-New Mexico Pipeline spokeswoman Helen Bow said the company expects to file an appeal.

EOTT attorney Paul Bohannan said a statutory ceiling on punitive damages could reduce that portion of the award to two times the actual damages.

Final cleanup cost not yet determined

The final cost for cleanup has not been determined. During opening arguments, EOTT claimed to be out of pocket slightly more than $11 million.

After the contamination was discovered in 2000, EOTT paid remediation costs and provided new appliances and plumbing for some of the 130 affected residents.

The homeowners sued both companies and were paid a publicly undisclosed settlement from Texas-New Mexico Pipeline before the trial — an amount that a source close to the case told The Associated Press amounted to $9.8 million. The residents also settled with EOTT in an agreement yielding a cash value of about $1.4 million.

With the homeowners compensated, that left the companies to battle their dispute in court.

EOTT said it found two areas of underground pipe that appeared to have been recently replaced, with oil-drenched soil concealed with new soil prior to acquisition.

Just prior to trial, EOTT — acting on a tip from a former Texas-New Mexico Pipeline employee — unearthed hundreds of pages of Texas-New Mexico Pipeline documents from a 45-foot hole in southeastern New Mexico. The process of restoring the documents was recently completed. ●

exploration&production

UNITED STATES

BLM to hold lease sale July 16

The U.S. Bureau of Land Management is offering oil and gas leasing rights on 126 parcels in New Mexico, Oklahoma, Kansas and Texas.

A total of 150,032 acres will be up for lease.

The oral auction will be on July 16 in Santa Fe, New Mexico.

NORTH AMERICA

Baker Hughes U.S. rig count jumps by 32 in June to 1,067

The U.S. rig count for June 2003 was 1,067, up 32 from the 1,035 counted in May 2003 and up 224 from the 843 counted in June 2002, rig monitor Baker Hughes said July 8.

The Canadian rig count for June 2003 was 308, up 158 from the 150 counted in May 2003 and up 103 from the 205 counted in June 2002, the company reported.

The worldwide rig count for June 2003 was 2,144, up 204 from the 1,940 counted in May 2003 and up 366 from the 1,778 counted in June 2002, the company said.

—PETROLEUM NEWS HOUSTON STAFF

HOUSTON, TEXAS

Independent Swift Energy boosts capital spending 15 percent to $150 million

Houston independent Swift Energy has increased its 2003 capital budget 15 percent to about $150 million to help pay for projects, the company said July 8.

The additional $20 million in capital specifically will go toward development drilling, facility upgrades and initial 3-D seismic work in the Lake Washington field in Plaquemines Parish, La., and additional drilling and exploitation activity in New Zealand, the company said.

The increase in the capital budget is supported by the recent operational successes and higher than anticipated cash flow in 2003, both domestically and in New Zealand, the company said.

The increase in the capital budget will be used in part to increase the facility capacity at Lake Washington to about 20,000 gross barrels per day, the company said. Facility upgrades are continuing on schedule in the field and should be completed during the fourth quarter, the company added.

The increased capital budget also enables the company to drill a total of 60 to 70 wells in Lake Washington during 2003, or about 10 more wells than previously reported, Swift said. Additionally, the company said it is considering shooting 3-D seismic over a portion of the field.

—PETROLEUM NEWS HOUSTON STAFF

● EAST COAST CANADA

Canada's East Coast teeters

Lightly explored basin keeps optimism alive, despite dusters

By GARY PARK

Petroleum News Calgary Correspondent

The prospects of Canada's East Coast becoming a growing and long-term source of oil and natural gas, especially for the U.S. Northeast, are drawing closer to the tipping point.

Several years of demoralizing drilling results have spread a cloud over the region that only a major discovery will clear away.

1 2 3 SERIES

FirstEnergy Capital has calculated the cost of dry holes offshore Nova Scotia and Newfoundland at about C$600 million.

Pipeline plans have been put on hold and analysts are openly challenging Canada-Nova Scotia Offshore Petroleum Board optimism that seven exploration wells will be drilled this year and that operators will start venturing into the region's deepwater prospects — all part of C$1.56 billion in work commitments on 59 license blocks.

For Newfoundland, which is expected to surpass 500,000 barrels per day from three fields by 2006, the outlook is equally worrying in an area that hasn't seen a new discovery in almost 20 years and where majors have been shelving projects, assets are being unloaded and land sales have crumbled.

What keeps optimism alive is the relative infancy of both basins. Newfoundland has tallied less than 200 exploration wells compared with more than 5,000 in the North Sea; Nova Scotia has also logged about 200 wells against 50,000 in the Gulf of Mexico, an area roughly the same size.

Newfoundland Energy Minister Lloyd Matthews said earlier this year that more than C$30 billion is earmarked for spending over the lifetimes of East Coast projects, including C$2.1 billion in work commitments for 100 exploration licenses.

"We're actively promoting our potential on the global stage," he said.

East Coast success needed soon

But the voices from those making the high-risk decisions reflect a growing unease.

"We need a discovery fairly soon," Gordon Carrick, vice president of East Coast operations for

see EAST COAST page 12

● COOK INLET, ALASKA

State approves Trading Bay expansion in Cook Inlet

Both Hemlock and Grayling Gas Sands participating areas expanded

By KRISTEN NELSON

Petroleum News Editor-in-Chief

The state of Alaska has approved an expansion of the Trading Bay unit in Cook Inlet and expansion of both the unit's Hemlock oil pool participating area and its Grayling sands participating area.

The Department of Natural Resources' Division of Oil and Gas approved the application from Trading Bay unit operator Union Oil Company of California June 25. Unocal applied to expand the Trading Bay unit and Hemlock participating area last November and in December, applied for expansion of the Grayling gas sands participating area. Unocal also applied for an alternate allocation formula for the Grayling participating area.

The unit and Hemlock participating area expansion includes 560 acres of submerged lands in two segments at the northern edge of the unit. This expansion area is in lease ADL 18731. The Grayling gas sands participating area expansion, 3,200 acres, is within the unit.

In addition to Unocal, Forest Oil and Marathon Oil also have working interests in the Trading Bay unit.

The unit includes four participating areas: the Hemlock oil pool participating area, the West Foreland oil pool participating area, the Middle Kenai "G" oil pool participating area and the Grayling gas sands participating area.

The expanded Trading Bay unit and Hemlock participating area encompass 17,859.5 acres within 11 oil

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EAST COAST

Petro-Canada, said in a luncheon address. "I think we are approaching a crossroads."

David Collyer, Shell Canada's vice president of frontiers, told a Canadian Energy Research Institute gas conference last winter that "we need to reverse the recent trend of exploration drilling (offshore Nova Scotia) and get some encouraging results."

Paul Barnes, manager of the Canadian Association of Petroleum Producers' office in Newfoundland, conceded: "What we do need in this basin — in Newfoundland and Nova Scotia — is some success in the next year or two ... or we certainly may lose momentum."

One of the most anxiously-awaited decisions is expected from EnCana later this year on the future of its C$1 billion Deep Panuke gas project — scheduled to come on stream in 2006 at 400 million cubic feet per day as Nova Scotia's second producing gas field after Sable.

To the surprise of few, EnCana said that without reserves to supplement its existing 935 billion cubic feet, Deep Panuke could be deep-sixed.

It has been granted a time-out by the National Energy Board and the Canada-Nova Scotia Offshore Petroleum Board to hunt for new reserves and wrestle with the project economics.

This summer will be crucial

The make-or-break point looms this summer, when EnCana drills two exploration wells at either end of the Deep Panuke reservoir.

Chief Operating Officer Randy Eresman said in May that EnCana needs to "build confidence" that the field has the reserve volumes previously estimated "before we go ahead."

Gwyn Morgan, EnCana president and chief executive officer, took an even harder line, saying efforts are focused on a comprehensive review designed to improve Deep Panuke's "risk-weighted return" after it became evident that the project in its present form "wasn't going to make the grade."

Despite the latest Canada-Nova Scotia Offshore Petroleum Board estimates that Nova Scotia's shallow and deep water plays hold 33 trillion cubic feet of recoverable reserves — with other wildly ambitious estimates ranging as high as 100 tcf — that potential is likely to go unrealized over the near-term if EnCana pulls the plug.

Introduction

More than at any time in the 30 years since the landmark Arab oil embargo, North American energy security has become the goal towards which government thinking and industry strategy has increasingly pointed.

The Bush administration's open desire to reduce dependence on the Middle East has put the spotlight squarely on Canada and Mexico, its two partners in the North American Free Trade Agreement.

In a three-part series beginning in the June 29 issue, Petroleum News' Canadian correspondent Gary Park examines the main planks in Canada's petroleum platform and their ability to support increased exports to the Lower 48.

- **PART I** — Arctic natural gas, issue of June 29
- **PART II** — Alberta oil sands, issue of July 6
- **PART III** — East Coast oil and gas, ithis issue

Production down

Calgary-based consultant Ziff Energy Group has forecast Nova Scotia production will quadruple to 2 bcf per day by 2010.

Instead, volumes from Sable actually declined to 458 million cubic feet per day in the first quarter of 2003 from 530 million cubic feet a year earlier, a drop that operator ExxonMobil blamed on routine maintenance.

But analyst Ian Doig, one of the harshest critics of the Sable venture, argued the problems are more deeply-rooted and has predicted Sable could be depleted in less than half its projected 25-year life span.

Shell Canada, which owns 31.3 percent of Sable, has lowered its own share of reserve estimates to 700 billion cubic feet from 1.1 trillion cubic feet, with Collyer describing the reservoirs as a "lot more complex in terms of geology and production outlook than initially." ExxonMobil has also written down its reserves this year and Imperial Oil announced a 16 percent write down in 2001.

In a bid to offset those setbacks, the Sable owners are moving to the next development phase that is expected to see the first of three new fields start producing late this year from reserves of 230 billion cubic feet.

Attempts to expand beyond Sable have fallen short of hopes, especially during the last year as the region has grown perplexed over costly exploration failures by ChevronTexaco, Shell, EnCana and Canadian Superior.

Not all walking away

But not all the majors are walking away. Imperial Oil, Canada's largest integrated oil firm and a 69.6 percent-owned subsidiary of ExxonMobil, pulled a surprise June 5 by awarding contracts for its first deepwater exploration well that should start drilling in July.

Imperial has 100 percent exploration rights to two parcels covering 620,000 acres about 180 miles east of Halifax, Nova Scotia, and south of the producing Sable fields.

Despite the risks and high costs, the unproven potential of the deepwater play has encouraged Imperial to "test this significant opportunity now," said Senior Vice President K.C. Williams.

John Hogg, EnCana's vice president for Atlantic Canada, gave another boost to spirits in early June when he predicted 10 deepwater wells in the next two years, describing the potential for large new finds as "very good, although today they remain elusive."

Four exploration licenses up for bid

The Canada-Nova Scotia Offshore Petroleum Board is trying to capitalize on the region by calling bids for four exploration licenses covering 620,000 acres east of the Sable fields.

The one bright exploration spot in recent years was the discovery by a Marathon Oil-led partnership at its Annapolis G-24 deepwater wildcat that needs more drilling to determine its commercial viability.

However, despite its estimates of 5 tcf to 15 tcf of reserves in Annapolis, Marathon has postponed a further exploration well until 2004.

Nova Scotia Energy Minister Ernie Fage said the partners need time to arrange financing and contract a rig. Brian Prokop, with Peters & Co., is more dubious, suggesting Marathon is "probably backing off and looking at the economics."

Injecting some optimism into the region, Canadian Superior Energy and El Paso Oil and Gas Canada, despite the disappointment of abandoning a well in the Deep Panuke geological structure last year, announced in May they will spend up to C$60 million on a 19,700-foot well on its Marquis project this summer.

Canadian Superior estimates the potential exists at Marquis for a discovery of up to 2.4 tcf, with another 1 tcf in the offing for its wholly owned Mariner project. As well, it has identified three sizeable prospects on its Mayflower project, which it rates as similar to basins offshore West Africa, Brazil and the Gulf of Mexico, with potential for 1 billion barrels of oil or 10 tcf equivalent.

"When you hear there's been a dry hole out there, it doesn't really mean a lot," Canadian Superior chief executive officer Greg Noval told his company's annual meeting June 27.

He said Canadian Superior opted for El Paso over other potential partners because of the U.S. company's access to key pipeline markets in the northeastern United States.

El Paso delays pipeline

However, even El Paso has indicated some uneasiness. In April it postponed its planned C$2.3 billion Blue Atlantic Transmission System pending a decision by EnCana to develop Deep Panuke. The 1 bcf per day pipeline was designed to serve the U.S. Northeast and Nova Scotia markets. El Paso will make a decision on a regulatory filing in late 2004.

Doubts also hang over plans by Maritimes & Northeast Pipeline, which operates the existing line from Sable to New England, to spend C$1 billion doubling capacity of the line to 1.2 bcf per day. Like El Paso, Maritimes & Northeast has been sidetracked by the Deep Panuke delay.

Oil-prone Newfoundland has taken two setbacks in the last month. Operator Petro-Canada, EnCana and Norsk Hydro have abandoned two exploration wells costing a combined C$80 million in the Flemish Pass, 300 miles east of St. John's, Newfoundland. Using the semi-submersible Eirik Raude rig, the partners reported some oil but not in commercial quantities from the first and offered no details from the second other than saying the results will be evaluated as part of next year's drilling program.

"We're certainly not in a position to condemn that whole basin," said Petro-Canada Chief Executive Officer Ron Brenneman. "These were high-risk wells going in. We recognize that."

Newfoundland offshore oil production may have peaked at 500,000 bpd

Within three years, offshore Newfoundland may have attained its pinnacle, pumping more than 500,000 barrels per day from three fields — Hibernia at 220,000 barrels, Terra Nova at 200,000 barrels and White Rose at 92,000 barrels.

But beyond there the prospects look shaky, unless there is a sudden turnaround in exploration fortunes, or companies respond positively to a call for bids covering 7.8 million acres in three areas.

The Hibernia reservoirs, estimated by the Canada-Newfoundland Offshore Petroleum Board at a combined 884 million barrels, 134 million barrels more than the Hibernia owners, have regulatory approval to increase to 220,000 barrels per day from 180,000 barrels.

The main Hibernia reservoir, according to the Canada-Newfoundland Offshore Petroleum Board, has 702 million barrels of recoverable crude and has been flowing since 1997.

But the 182-million-barrel Ben Nevis-Avalon reservoir is untapped. Whether it will be hinges on an evaluation by

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● CANADA

Canada's oil exports could triple; gas in doubt

Study: Focus on oil sands; gas resource 'major uncertainty'

By GARY PARK

Petroleum News Calgary Correspondent

Relying heavily on Alberta's oil sands, Canada's oil shipments to the United States could double and possibly triple by 2025, but its natural gas resource base is a "major uncertainty," especially frontier regions and unconventional resources, the National Energy Board reported July 3. The 98-page study, covering scenarios for supply and demand over the next 22 years, said the Western Canada Sedimentary Basin — the mainstay of Canada's fossil-fuel wealth for more than 50 years — can no longer be counted on to retain that role.

The federal regulator said signs that the basin is maturing as a gas play make it "necessary to develop unconventional and frontier sources to maintain or potentially increase Canadian production.

"However, since there has been little development of unconventional gas or frontier gas to date, there is considerable uncertainty about future potential production."

Gas deliverability will peak in 2010

Under the National Energy Board's most conservative scenario, gas deliverability will peak at about 18 billion cubic feet per day in 2010, barely ahead of output in 2001, then start a gradual decline. Applying a more technology-intensive model, the study says deliverability could reach 19 bcf per day in 2015, then start to shrink.

The federal regulator expects the price of natural gas to rise to at least 90 percent of crude oil values and suggested it could reach parity by 2010.

It predicted gas prices will continue to be volatile, resulting in demand-side adjustments as industrial users are forced to relocate or switch to other fuels.

see EXPORTS page 15

What's next for Canada's East Coast?

The unexplored real estate offshore Newfoundland and Nova Scotia is as vast as the risks of drilling are great at C$30 million to C$60 million a well.

But the opportunities in new basins are starting to beckon.

• **LAURENTIAN SUB-BASIN:** Settlement last year of a 38-year offshore boundary dispute between Newfoundland and Nova Scotia has opened the door to a highly prospective exploration opportunity. The sub-basin has projected reserves of 9 trillion cubic feet of natural gas and 700 million barrels of oil. Acreage holders include ConocoPhillips Canada, ExxonMobil, Imperial Oil, Kerr-McGee and Murphy Oil. A draft environmental study is now being circulated and operators are anxious to start exploring within 12 months.

• **GULF OF ST. LAWRENCE:** Regulators in Nova Scotia and Quebec are moving closer to allowing exploration of several basins within their territorial waters. Government-owned utility Hydro Quebec is in talks with an unidentified multinational partner to spend C$1.5 billion over seven years in search of reserves estimated at 5 tcf. Junior E&P company Corridor Resources is also seeking a partner to drill a number of its licenses. Offshore Cape Breton in Nova Scotia, Corridor and Hunt Oil have permission to conduct seismic programs this winter in a region that could match the 3 tcf in Nova Scotia's Sable field.

• **OFFSHORE NEWFOUNDLAND:** With land sales plummeting over the past four years, the Canada-Newfoundland Offshore Petroleum Board has tried to fuel interest by offering 14 parcels covering 7.8 million acres located in the Northeast Newfoundland Shelf, Orphan Basin and Flemish Pass, although Petro-Canada failed to find economic quantities of oil this year from a C$40 million well in the Flemish Pass. To sweeten the offering, the board has agreed to complete an environmental assessment before the mid-December deadline for bids, along with raising the allowable day-rate for drilling to C$600,000 from C$400,000 in recognition of deepwater costs, while crediting 25 percent of all expenses against the security deposit paid on each parcel.

• **LABRADOR SHELF:** Seismic shooting resumed last year after a 20-year hiatus in an iceberg-infested region, where 26 exploration wells have been drilled, yielding discoveries of 4.2 tcf of gas and 123 million barrels of gas liquids in five fields. The Canada-Newfoundland Offshore Petroleum Board is expected to include parcels in its next land sale.

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EAST COAST

ExxonMobil, Hibernia's major stakeholder, that expects to complete a revised development program by late 2005.

Petro-Canada-operated Terra Nova with 370 million barrels has been on stream for 16 months and has just received Canada-Newfoundland Offshore Petroleum Board permission to raise its rate to 150,000 barrels per day from 100,000 barrels and could get a further jump to 200,000 barrels.

What after White Rose?

Next in line is the 250-million-barrel White Rose project, owned by Husky Energy and Petro-Canada which is on track for a late 2005 start-up.

What comes after those three is a question that is fast gathering momentum, now that Chevron Canada Resources has shelved plans for its 700-million-barrel Hebron/Ben Nevis discovery, which it has decided is too geologically complex to be commercially viable.

The three producing fields are all in the Jeanne d'Arc Basin, where the Canada-Newfoundland Offshore Petroleum Board estimates reserve potential at 2.1 billion barrels of oil and 5.6 tcf of gas, of which 1.55 billion barrels of oil and 2.1 tcf of gas have been found.

In the meantime, the Canadian Association of Petroleum Producers is pressuring the Canadian government to tackle a "burdensome" regulatory process on the East Coast to ensure the region "remains competitive."

The association pointed out that Nova Scotia approvals can take up to 90 days, compared with 40 days in the Gulf of Mexico. ●

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EXPANSION

and gas leases. The expanded Graying participating area includes 6,520 acres within four oil and gas leases.

Monopod well expands production

In addition to four platforms within the unit, Unocal also operates the Monopod platform on non-unitized lease ADL 18731 north of the unit. Oil and gas from the Trading Bay unit is also produced from the Monopod and in 2002, the state said, Unocal drilled several sidetracks of the A-15 well from the Monopod. One of those sidetracks extended south into lease ADL 18772 within the unit, producing oil from the Hemlock reservoir both inside and outside of the existing unit boundary.

The division approved allocation of production between leases in 2002, but also required Unocal to apply to expand the unit and the participating area to include the portion of ADL 18731 producing from the Hemlock reservoir. The division also recognized that in 1991 the Alaska Oil and Gas Conservation Commission approved an expansion of the Middle Kenai gas pool, which encompasses the Grayling gas sands, and requested that Unocal apply to expand the Grayling participating area with a request of allocate gas produced on the volume of gas underlying each tract instead of on a surface-acreage basis.

Gas pool area expanded in 1990

Grayling participating gas is produced from the Steelhead platform, one of the four platforms in the Trading Bay unit, and after additional wells were drilled in 1990 to test the extent of the Grayling gas sands reservoir, the commission approved an expansion of the Middle Kenai Gas pool area. In 1991, the working interest owners began allocating production to the larger area.

The division said Unocal's recent delineation activity included using new 3D seismic, engineering and log analysis to re-examine the area north of the Trading Bay unit; two wells established oil production outside of the unit boundary, the Trading Bay Unit No. A27RD, drilled in 1997, and the Trading Bay Unit No. A-15RD2L2, drilled in 2002. That well produced at initial gas-lift test rates of more than 3,000 barrels of oil per day.

Unocal's 39th plan of development for the Trading Bay unit includes optimizing oil recovery from the Hemlock, Middle Kenai and West Foreland participating areas within completed wells and studying potential workover or redrill opportunities. The division said Unocal is also considering rig projects on the Steelhead and Grayling platforms to improve deliverability and recovery of gas reserves from the Grayling participating area and will "continue to evaluate the possibility that oil reservoirs exist within the Jurassic section within" the unit. ●

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Petroleum news

Business Spotlight

By PAULA EASLEY

COURTESY CARLILE

Harry McDonald, president and co-founder

Carlile Transportation Systems

Carlile Transportation Systems offers transportation and logistics services, primarily for companies operating in Alaska. It recently added a 12,000 square foot airplane hanger to the Prudhoe Bay Logistics Center. Carlile has two other hangers with 78 foot by 24 foot doors, a cargo warehouse, helicopter hanger and a passenger terminal serving air carriers and customers in various North Slope locations.

President Harry McDonald has been with the company since starting it with his brother in 1980. He worked on tugboats until 1974, then switched to trucks. His favorite thing is heading for the boonies in his Cessna 180. With wife Pat, a son, three daughters, five grandchildren, a niece and several live-in exchange students who also get the wanderlust, a larger plane might be in order.

FORREST CRANE

Crystal Nygard, co-owner and business development manager

PSI Environmental

PSI Environmental provides environmental services and instrumentation; specifically waste management, remediation and regulatory compliance. It has 14 employees in Anchorage, Fairbanks and Soldotna, and is headed by Scott Yancy, Alaska operations manager. PSI also sells, rents and services safety and environmental instrumentation.

Crystal Nygard is co-owner and business development manager, well trained in hazardous waste management, marketing, government contracting and account management. Her business philosophy: Never forget those true customers who've supported you from the beginning. With husband Scott and daredevil offspring Eric, Alex and Nick, every day is an adventure, including emergency room visits to repair broken body parts. She finds negotiating with a 6-year-old "amazing." Growing up, Crystal never envisioned herself becoming a pro in the "trash and gas" business, but there she is.

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LNG

countries covering some 18 million tons. As those contracts expire the company has projected supply gaps to fill: 2.4 million tons in 2007, 5.3 million tons in 2010 and 17 million tons in 2015.

The contracts for the new supplies are expected to differ from existing contracts, he said, because current LNG long-term contracts don't look compatible with changes in the market environment. Korea Gas is looking for flexibility in its off-take obligation to meet increasing uncertainty in demand and removal of a final destination clause. The "take-or-pay" clause needs to be relaxed, he said. And the price needs to be more market driven and competitive.

Mead Treadwell said Tokyo Gas expects changes in the LNG market to result in a "downward trend in prices."

"Reliable and flexible forms of LNG trade should replace traditional ways of LNG trade," Jean said.

Tokyo Gas even more explicit

Mead Treadwell, managing director of the Institute of the North, told the summit that he and former Alaska Gov. Walter Hickel met in June with LNG buyers in Japan, including Shigeru Muraki of Tokyo Gas Co. Muraki wanted to come to the summit, Treadwell said: "basically I'm making his presentation," based on a talk Muraki gave in February.

When they met with him, Treadwell said, Muraki discussed some of the same changes in the LNG market as those described by Hong-Shih Jean of Korea Gas: "an attempt to get the market oriented to competitive positions and opportunities for trading."

The Tokyo Gas overview describes an LNG market in transition: from a regulated market to sharpened competition in a liberalized market; from buyers such as gas and power utilities with government investment to an increased number of sellers and buyers, including marketers and traders; from buyers' consortiums to more individual contracts; from closed negotiations to emergence of an open market including short-term and spot sales; from long-term contracts to a variety of trading opportunities including spot, swap and arbitrage; from take-or-pay contracts with limited flexibility to contracts tailor-made for individual buyers; from pricing tied to a crude oil index to pricing de-coupled from crude oil; and from an upward trend in prices to a downward trend.

Treadwell said there were about six suppliers when Alaska started shipping LNG, compared to a larger number of suppliers now. What Tokyo Gas sees now, he said, is "sharpened competition in the liberalized market" with "an increased number of sellers and buyers" and the possibility of an open tender, rather than closed negotiations.

And Tokyo Gas expects, he said, that as these changes take place, they "may tend toward a downward trend in prices."

Japanese interested in upstream investment

And, he said, they heard on their trip a couple of times that Japanese parties have an interest "in investing in the upstream side."

As far as an Alaska project, Treadwell said, "we were told, very clearly, that supply is essential to project success. … (Potential buyers) have not seen gas supply committed to a project and they believe that's important."

Authority also sees contracts changing

Rigdon Boykin of O'Melveny & Myers, speaking for the Alaska Gasline Port Authority, agreed that we "have to break the model of past contracts to sell this volume of gas in Asia." The price in most contracts, he said, has been tied to a basket of oil, and that needs to start changing to "gas-on-gas" pricing.

"Most of these (Asian) countries have been severely damaged by big swings in gas pricing that's caused by the basket-of-oil approach," he said, and "we believe if we deviate from that and go to a base price and that base price only changes if gas-on-gas in the domestic market changes substantially," then it would be possible to get the kind of contracts needed to put Alaska LNG into Asian markets.

That type of a contract, he said, would involve a floor price with slight escalation for variable costs and then an index based on gas-to-gas competition. There are, he said, "a number of analysts that believe that it's going to be true gas-on-gas competition worldwide in the next five to 10 years." ●

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GREENLAND

Canadian independent EnCana last year. EnCana is bolstered by last year's success as lead operator in the huge United Kingdom North Sea Buzzard discovery off Aberdeen.

They include a corporate tax of 30 percent, a surplus royalty scheme and a carry of 12.5 percent for national oil company, Nunaoil, in any exploration phase.

Offshore exploration began in the '70s

Explorers started dabbling in offshore Greenland in the 1970s and have since drilled seven wells, without finding enough oil to embark on commercial development. Traces of hydrocarbons were found in only two wells.

GronArctic, a small, now-defunct Canadian producer, unsuccessfully drilled an 8,200-foot wildcat well in 1996 on the rugged west coast of Nuusuaq Peninsula before returning its licenses covering 820,000 acres to the Danish government in spring 1998.

Statoil and Phillips have also returned their licenses after fruitless exploration efforts.

The bureau's 2002 licensing round also proved to be disappointing to the bureau, when EnCana was the only bidder, despite expressions of interest from Shell, TotalFinaElf and Conoco.

Nunaoil President Arne Rosenkrands Larsen said at the time that the poor turnout was "a surprise because we know a large number of companies are engaged in looking at data offshore Greenland. But I think there will be more longer-lasting interest in the future."

"The acreage on offer has hardly been picked when you look at the size of it," said bureau head Hans Schonwandt. "And the technology has taken giant leaps since the drilling campaign in the 1970s."

Statoil, which has been an active player in the region, said Greenland did not fit into its current portfolio of specific core areas.

Seismic permits awarded last year

One of the most hopeful signs was last year's award of three five-year permits for seismic studies — one off the west coast to Nunaoil and two onshore permits to Cambridge Arctic Shelf Program.

Based partly on the many dry holes drilled in the North Sea before the big discovery breakthroughs, the bureau is emphatic that it sits on the doorstep of a world-class sedimentary basin sprawling over more than 100,000 square miles.

Having drawn up a revised licensing policy in 1999 to stimulate exploration by re-establishing an open-door procedure for licensing, the bureau has insisted Greenland is "one of the few frontier areas with a potential for giant oil and gas fields."

The U.S. Geological Survey has also said the regional geology points to significant hydrocarbon accumulations.

The bureau is optimistic that the Fylla area is comparable to Norway's Ekofisk field, which has been producing since 1971 and is projected to have an ultimate recovery of 3.5 billion barrels.

It also said in a report that areas indicating natural gas in the subsurface have been identified in several large geological structures in Fylla.

In addition, there have been proven seepages of oil onshore in Nuusuaq, about 360 miles north of Nuuk.●

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EXPORTS

Over the next seven years, the National Energy Board expects Canada's coalbed methane drilling to climb from 300 wells this year to 3,000-3,500 wells in 2010 and projects coalbed methane output could contribute 2.5 bcf per day by 2025.

Oil sands will produce surge in exports

There is less doubt surrounding Canada's oil outlook, with the study projecting growth from the "enormous reserves" of oil sands in Alberta that will translate into a corresponding surge in exports to the United States.

It said an assumed price of US$22 per barrel "provides adequate returns to support investment in the oil sands and offshore oil development."

But the National Energy Board did not factor in the cost impact of the Kyoto Protocol, saying there is insufficient information on which to build projections.

It also predicted that oil sands output will grow regardless of a likely shortage of condensate for diluting bitumen to aid pipeline transportation over the next three years, coupled with the supply and price of natural gas used in the extraction and processing of bitumen.

The National Energy Board said the condensate shortfall will require the use of non-traditional diluents such as light synthetic crude and naphtha, which would add to production costs. Alternatives to natural gas include the possible gasification of bitumen, the use of "clean" coal or the possible use of nuclear energy, an option that is currently being evaluated. ●

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ASRC

fall and, potentially, if it comes together, an agreement by the end of the calendar year."

As for being able to drill on the North Slope this coming winter, he said that was a "very desirable" possibility, but a "challenge" given the timeframes involved with permitting exploration activities.

For BP: More Alaska prospects could get developed

For BP, the agreement will help get unit and near-unit North Slope prospects explored and developed that might not get approved by the company's board in London due to stiff competition from investment opportunities outside Alaska.

JUDY PATRICK

Theresa Imm, ASRC land manager

"Any opportunities that we have in Alaska ... have to compete against opportunities we have around the world. That applies to development opportunities, the gas pipeline, the 125 wells we'll drill this year and the 125 wells we'll probably drill next year," BP's president in Alaska, Steve Marshall, said. "The criteria for those are set higher and higher and we allocate dollars where we think we've got the best chance of return, of finding big fields. This agreement is … hopefully going to provide an opportunity for a company like ASRC to invest where BP would choose not to."

For ASRC: jobs for shareholders

For ASRC, the deal is expected to provide badly needed jobs close to home for its shareholders. The agreement, which ASRC said is designed to enhance its existing exploration, development and operating capabilities, helps the company take the next critical step toward being an independent producer in Alaska — a producer that Bagne points out is "an Alaska corporation, with its shareholder base in Alaska, that is going to be here forever."

JUDY PATRICK

Conrad Bagne, ASRC's chief administrative officer and in-house counsel

"This agreement provides a critical next step in providing ASRC with access to the tools and knowledge we need to become a competitive, independent producer in Alaska," ASRC President and CEO Jacob Adams said. "It gives ASRC exposure to BP's industry expertise and 'best practice' business experience, and it builds on capabilities that have been developed within our Land Department, energy services division and refining operations."

For the state: jobs, revenues

For the state of Alaska, Marshall said, the agreement should spur oil and gas exploration and development on the North Slope and generate business for Alaska-based suppliers and service companies, as well as enhance career opportunities for Alaskans.

"This agreement … is a way to get what are highly attractive prospects, we hope, into exploration and development," Bagne said, pointing out that ASRC Energy Services "might not be the only (service) company working on these opportunities because they provide services for other oil companies as well."

Talks began in 1999

The agreement between the two companies "grows out of a relationship which is made up of both the resource side and the oilfield service side of ASRC. There were discussions (with the resource side) that went on between ASRC and BP back at the time of the ARCO acquisition that started some of this dialogue," Bagne said.

Talks between the two companies resumed about a year ago, shortly after BP announced it was going to stop all frontier exploration in Alaska.

Marshall said BP went to its oilfield contractors and said it was looking "for innovative ways" to do business, "not just to squeeze costs, but to … find new ways of working. ASRC has been very aggressive … and come forward with a number of ideas, of which this is one."

"In the last year there was a lot of discussion … (between BP and) our service group," Bagne said. ASRC's oilfield service, construction and operating subsidiary recently changed its name from Natchiq to ASRC Energy Services in order to more closely align itself with its parent company. The service arm also restructured into three business units — operations and maintenance; pipeline, power and communications; and engineering and technology. (See "Natchiq rebranded," in the April 27 edition of Petroleum News.)

The dialogues with BP "came together both on the resource side and the service side. … ASRC particularly pushed that agenda because we are in a unique position to be able to look at both the service and equity issues together," Bagne said, noting that ASRC owns the mineral rights to prospective acreage in several areas in northern Alaska, including the Colville River area, Brooks Range Foothills and the coastal plain of the Arctic National Wildlife Refuge, where BP is a leaseholder with ChevronTexaco.

The deal will give the Native corporation access to land and resources it was precluded from selecting under the 1971 Alaska Native Claims Settlement Act.

Mentoring has not yet begun

Although the discussion of opportunities has begun, mentoring has not.

"We are still in the very early stages. We don't have any employees working at ASRC — yet. That's still to come. … There are a lot of things we need to work out … in terms of … logistics and … personnel issues. …Those aren't barriers. They are just things we need to address," Marshall said.

He said it was "too early to tell" how many BP employees will be working with ASRC: "A lot will depend on the opportunities we identify."

Why the mentoring versus a more traditional farm-in agreement?

Marshall said even in-field exploration and development is "a risky business. … And it's why we're not just providing acreage; it's about providing data and it's also about trying to provide some intellectual capital through the mentoring."

Not frontier exploration, not Liberty

Marshall said the agreement with ASRC does not involve the company's acreage in ANWR, the one spot on the North Slope where BP has kept exploration leases that could produce the type of monster fields the company is currently seeking in other parts of the world.

Nor does the agreement involve any other type of frontier exploration: "This (agreement) is very much focused in and around the existing units," such as "Prudhoe, Kuparuk, Endicott and Badami," Marshall said.

When asked about the likelihood of a deal with ASRC for taking over the soon to be shut-down Badami field, he said, "We certainly have discussed Badami with ASRC but it's really just in the formative stage at the moment, it's just an idea."

When asked about BP's offshore Liberty prospect, Marshall said, "That's an area we are still looking at very hard. It's certainly not on my radar screen as a likely opportunity to be discussed with ASRC. … We are thinking very hard about whether or not a development scheme can be permitted there."

When asked if the agreement could eventually lead to ASRC taking over BP's operatorship of the giant Prudhoe Bay unit, Marshall said, "That's not what this is intended to do from our perspective. The thing that Prudhoe Bay offers BP is a fantastic gas resource — in addition to all of the oil that is yet to be produced. It is still a field with a huge life and billions of dollars of investment both on the oil side and indeed on the gas side. So, it's an area of strategic importance for BP."

Imm in charge of project

Bagne said ASRC is "going to have to staff up. … We're going to have to build our core staff for what will eventually become an operating oil company."

Long-time ASRC Land Manager Teresa Imm is currently in charge of the ASRC-BP agreement.

Imm sees the arrangement between ASRC and BP as a "very mutually beneficial relationship. … BP is challenged for exploration dollars, for even unit exploration. Those are traditionally areas that are off-limits for a newcomer, for an independent or for a hope-to-be independent, like us." ●