Petroleum news

Vol. 9, No. 13 • www.PetroleumNews.com | *North America's source for oil and gas news* | Week of March 28, 2004 • $1

page 10 Louisiana's Merlin Oil & Gas looking north for gas plays

Conoco drilling Placer No. 2

JUDY PATRICK

ConocoPhillips Alaska drilled Placer No. 1 on the west side of the Kuparuk River unit on Alaska's North Slope this winter. See story about a second well and prospect development on page 13.

B.C. First Nation draws line on coalbed methane development

The message is clear to those who have any notion of applying U.S. methods to developing coalbed methane in northeastern British Columbia: Forget it.

The West Moberly First Nation, after taking a first-hand look at the environmental impact of coalbed methane plays in Colorado and Wyoming, has issued a warning notice to "all parties."

It has told them to pay heed to the community's claims to

see **LINE** *page 23*

Pemex bets hinge on Cantarell

Major oil companies eager to partner with Mexico's state-owned oil monopoly Pemex in deepwater offshore exploration may be in for a long wait, industry observers say.

Mexico's giant producing Cantarell field, off the coast of the Yucatan Peninsula in the Gulf of Mexico, holds the key to whether the country will take the politically painful step of altering its constitution to allow that to happen. No one knows for sure how long Cantarell can continue to produce at its current rate of 2 million barrels a day, except perhaps Pemex reservoir experts, and they're not talking, said oil consultant

see **PEMEX** *page 23*

BREAKING NEWS

CANADA

Free at last

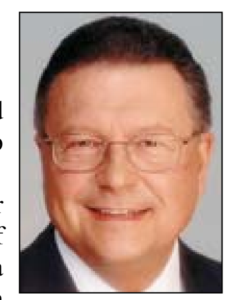
After 30 years Canada is ready to cut final ties to Petro-Canada

By GARY PARK

Petroleum News Calgary Correspondent

There were the bumper stickers. "I'd rather push this car a mile than fill up at Petro-Canada."

There was the cold shoulder. For long enough, Petro-Canada's then Chief Executive Officer Bill Hopper was not a welcome figure in the Calgary Petroleum Club.



Finance Minister Ralph Goodale

There were the cheap shots. Petro-Canada's ochre-colored head office in Calgary was commonly known as Red Square.

There was the scorn. Over the use of taxpayers' money in the 1970s and 1980s to acquire Canadian assets from Atlantic Richfield, Pacific Petroleums, Petrofina Canada, BP and Gulf Canada. Over Hopper's extensive use of corporate jets and executive chefs and his lavish spending on a corporate art collection.

It was a C$10 billion exercise in providing the government with a "window" on the industry at a time of volatile oil prices and a chance to seize Canadian control of the Arctic and East Coast frontiers through subsidized exploration.

Those days are gone.

see **FREE** *page 22*

NORTH SLOPE, ALASKA

Discovery yields not just oil, but high-quality oil

Kerr-McGee finds oil at Northwest Milne Point prospect on Alaska's North Slope

By KRISTEN NELSON

Petroleum News Editor-in-Chief

Kerr-McGee said March 24 that it encountered "high-quality hydrocarbons" at its first Nikaitchuq exploration well in the Spy Island area in shallow waters of the Beaufort Sea off Alaska's North Slope.

This is the Northwest Milne Point prospect assembled by Denver, Colo.-based Armstrong Oil and Gas, which last year brought in Oklahoma City-based Kerr-McGee as 70 percent working interest owner and operator.

Rick Buterbaugh, Kerr-McGee's vice president

see **QUALITY** *page 23*

JUDY PATRICK

Photo of oil from Nikaitchuq well taken in mid-March

JUNEAU, ALASKA

MidAmerican drops out

Firm withdraws state application for Alaska gas line, wanted exclusive position

By LARRY PERSILY

Petroleum News Government Affairs Editor

MidAmerican Energy Holdings Co. has withdrawn its application to the state and shut down its effort to build an Alaska natural gas pipeline, less than two months after state and corporate officials crowded a stage in Fairbanks to loudly announce the proposal amid cheers and congratulations.

The company said it decided to walk away from any further negotiations after the state declined to grant MidAmerican exclusive development rights to the project.

"We are extremely disappointed the state of Alaska rejected this approach, which we had clearly discussed with Governor Murkowski before filing our application," MidAmerican Chairman David Sokol said in a prepared statement released March 25.

> *"We believed our request to be the state's sole development partner for the initial project development period was reasonable,"* **—Robert Sluder, president of MidAmerican's Alaska Gas Transmission Co.**

MidAmerican, a pipeline operator and power company based in Des Moines, Iowa, had wanted the state to grant it exclusive five-year development rights for the Alaska gas line, during which time the state could

see **OUT** *page 22*

● HOUSTON, TEXAS

Halliburton fires back

Company says it did nothing wrong in Iraq; also says liquidity not a problem, has $1 billion in working capital

By RAY TYSON
Petroleum News Houston Correspondent

Besieged U.S service company Halliburton has gone on the offensive, publicly refuting accusations surrounding its fuel and military food contracts in Iraq and assuring industry analysts that it does not expect additional "issues" to surface, or any government penalties related to its business activities in the war-torn country.

"I don't expect we're going to get fined. We haven't done anything wrong," Halliburton general counsel Bert Cornelison said in a March 12 conference call with industry analysts.

Halliburton, once run by Vice President Dick Cheney, also believes it has sufficient "liquidity" or working capital to stay the course in Iraq, despite a $2.5 billion payment it plans to make later this year to settle asbestos claims against the company.

"We will continue to have daily scrutiny and slapping at every aspect of our company from the critics," said Randy Harl, president of Halliburton business unit KBR. "This is unprecedented for a U.S. corporation. We do not expect this … to stop until after the (presidential) election."

Is Iraq worth it?

In light of a criminal investigation into Halliburton's fuel contract and other unresolved issues that have damaged the company's standing with shareholders, one analyst even questioned whether Iraq "was worth it."

"We take our obligation very seriously and we're going to perform," responded David Lesar, Halliburton's chief executive officer. "We will work with all government agencies to establish that our contracts are not only good for the United States, but also the company is the best and most qualified contractor to perform these difficult and dangerous tasks."

Regarding the accusation that Halliburton overcharged the government $61 million for fuel supplies sourced in Kuwait and delivered to Iraq, the company said its critics and the media instead chose to ignore that Halliburton actually saved the government "well over $100 million" by supplying two-thirds of Iraq's total fuel requirements through Turkey.

"KBR initiated the idea to source from Turkey as a second fuel supplier, as the Department of Defense wants to maintain two sources of supply (because) it's too dangerous to supply south Iraq from Turkey," said Chris Gaut, Halliburton's chief financial officer.

He said that while fuel supplied from Kuwait did cost $1 more per gallon than in Turkey, "We purchased as much fuel from Turkey as possible and a much smaller volume from Kuwait, with the full approval and authorization of the U.S. military."

Company has tried to subcontract fuel delivery to local supplier

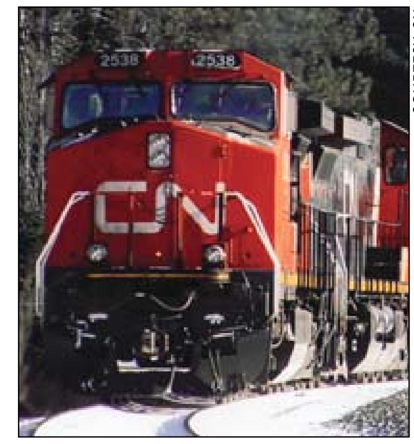
Gaut said the company also "repeatedly tried unsuccessfully to transfer the fuel delivery mission to a local supplier because it is very dangerous for our people. For many months, no one … was able to find a replacement for Halliburton. But this should come as no surprise as the drivers transporting the fuel face the real risk of being killed or wounded and vehicles and contents being destroyed."

As of March 18, Halliburton and its subcontractors have lost about 30 workers performing services under various government contracts in the Kuwait-Iraq area. Currently, KBR has more than 24,000 employees and subcontracted personnel working in the region.

Gaut said that KBR also was forced to purchase fuel from the only supplier sanctioned by state-owned Kuwait Petroleum Corp. He said fuel from Kuwait averaged $2.64 per gallon, adding that the expense includes not only the

see **HALLIBURTON** *page 24*

ALASKA, ALBERTA


COURTESY CN

Klein said his government, CN Rail, oil sands producers and municipalities are now examining the feasibility of a 265-mile link from the heavy-equipment staging area at Nisku, near Edmonton, to the oil sands "capital" of Fort McMurray.

Resource railroads on the table in Alaska, Alberta

Multi-billion dollar resource-based railroads are getting a fresh airing in both Alaska and Alberta.

Alaska Gov. Frank Murkowski has suggested an Alaska Highway gas pipeline opens the door to a railway from Alaska through the Yukon to British Columbia.

With that decades-long dream being brought back to life in Alaska, Alberta Premier Ralph Klein has revived talk of a railroad to serve the oil sands region of northern Alberta.

"This is not pie-in-the-sky," he said March 17. "This could be a gold mine."

Klein said his government, CN Rail, oil sands producers and municipalities are now examining the feasibility of a 265-mile link from the heavy-equipment staging area at Nisku, near Edmonton, to the oil sands "capital" of Fort McMurray.

He said the heavy equipment moving north "really ties up highways and causes safety problems."

A railroad would "not only benefit the oil sands ... it could benefit the movement of people, freeing up the highways."

With the prospect of C$50 billion in oil sands investment over the next 25 years, the Fort McMurray area is of "huge economic impact and huge economic significance."

A spokesman for CN Rail said his company has participated in early talks and a spokesman for Syncrude Canada said the oil sands consortium is interested in exploring the idea.

—GARY PARK, Petroleum News Calgary correspondent

GUEST EDITORIAL

On anniversary of Exxon Valdez, Alaska oil practices provide international model

By JOHN S. DEVENS, PH.D.
Executive Director
Prince William Sound Regional Citizens' Advisory Council

In my job, I frequently point out perceived shortcomings of the oil industry, but this time I want to recognize how much better the industry performs in Alaska than in many other parts of the world.

During the first week of February I flew to Scotland for a two-day meeting with people from Shetland, Angola and Nigeria. The purpose of this meeting was to form an organization to help African countries see examples of the best practices of the oil industry and learn from them.

This new 'North/South Platform' grew out of the United Nations' 2002 World Summit on Sustainable Development in Johannesburg. Funding for the effort comes from the U.S. Agency for International Development and the project is being coordinated by the United Nations Stakeholder Forum. One of the conditions placed on funding the program was that there should be a representative from Alaska.

Thus far two areas of best practice have been identified, Alaska and the Sullom Voe oil terminal in Scotland. The element that Alaska and Sullom Voe have in common is active involvement by citizens of the area in the safe handling and transportation of oil. While citizens in these areas are not hostile to the oil industry, they are demanding that best practices be followed.

Alaska has much to show other areas of the world. In the 12 months of 2003 not a single drop of oil was spilled from tankers to water in the state.

In many parts of the world oil development is taking place without the involvement of local citizens and often the governments of these areas lack the knowledge or the motivation to demand best practices. It is the goal of the North/South Platform, through exchange programs and academic research, to provide examples and training in what should be expected and the good that can be achieved if the revenues from development are used in a constructive manner.

In the next few months there will be an effort to identify other developing areas in Africa and other parts of the world experiencing oil development and to also identify other oil provinces where best practices are exhibited. Sometime in the fall we expect to have another meeting in Scotland and later a meeting in Alaska.

Alaska has much to show other areas of the world. In the 12 months of 2003 not a single drop of oil was spilled from tankers to water in the state. The tanker companies coming to Alaska have designed and are building double hull tankers that not only meet, but exceed, federal requirements. The tugs we use in Prince William Sound are some of the finest in the world. Our best available technology laws are examples of how seriously we take preservation of and response to oil spills.

This international interest in Alaska practices comes on the 15th anniversary of the Exxon Valdez oil spill and is another reminder of the importance of the safety improvements in crude oil transportation triggered by the devastating spill.

see **EDITORIAL** page 4

Issue Index

Petroleum news
North America's source for oil and gas news

ADDRESS
P.O. Box 231651
Anchorage, AK 99523-1651

EDITORIAL
Anchorage
907.522.9469
Juneau
907.586.8026

EDITORIAL EMAIL
publisher@petroleumnews.com

BOOKKEEPING & CIRCULATION
907.522.9469
Circulation Email
circulation@petroleumnews.com

ADVERTISING
907.770.5592
Advertising Email
scrane@petroleumnews.com

CLASSIFIEDS
907.644.4444

FAX FOR ALL DEPARTMENTS
907.522.9583

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.

Petroleum News (ISSN 1544-3612) Week of March 28, 2004
Vol. 9, No. 13
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 known as Petroleum News Alaska.

● ALASKA

North Slope Borough helps gas line effort

Financial backing from borough allows consultant to start socioeconomic study

By LARRY PERSILY

Petroleum News Government Affairs Editor

While waiting for the Alaska Legislature to appropriate state funds for the job, the North Slope Borough has agreed to guarantee payment so that a consultant could start work on the study of possible social and economic effects of an Alaska natural gas line project.

The Department of Revenue has been looking for state funding to cover the consultant's contract and other costs related to studying the project's possible effects on the state and how Alaska could best profit from a gas line. But lawmakers have been slow to appropriate funding, and the borough volunteered to help get the socioeconomic contract started.

The report will assist the state and municipalities as they continue negotiating a possible fiscal contract for the proposed gas line project. The intent of such a contract under Alaska's Stranded Gas Development Act is to set up a long-term schedule of payments in lieu of existing state and municipal taxes that would otherwise apply to construction and operation of the line.

The state can require applicants under the Stranded Gas Act to reimburse up to $1.5 million of the state's negotiating costs and contract analysis, but the administration has told lawmakers it will need more than that to get the job done. In addition to the socioeconomic study, the state is contracting with tax law, tariff and other fiscal consultants.

The Senate on March 17 approved $1 million for the state's efforts to study a possible gas line project and negotiate fiscal contracts with the two Stranded Gas Act applicants — a partnership of North Slope producers, and MidAmerican Energy Holdings Co. The House Finance Committee approved the measure March 23, with approval by the full House expected quickly.

Contract estimated at $50,000 to $200,000

The final cost and delivery date for the socioeconomic contract will be decided after the Department of Revenue gets funding for the work and signs a contract, said Steve Porter, deputy commissioner at Revenue. He estimated the contract at between $50,000 and $200,000.

"The state is going to pay, the borough is just going to guarantee it to get started," said David Harding, government affairs spokesman for the North Slope Borough mayor's office. "The borough was able to do it and wants the process to go ahead."

Information Insights, of Fairbanks, has started on the study and will take an estimated 45 to 60 days to look at how a multibillion-dollar gas line from the North Slope across Alaska and into Canada might affect communities statewide and especially in its path, Harding said.

The department selected Information Insights for the work because of its knowledge of Alaska's communities and economics, Porter said. The Stranded Gas Act exempts the department from the state's competitive-bidding requirements.

As the lead agency in the Stranded Gas Act negotiations, the Department of Revenue set up a municipal advisory group — as required by law — to assist the department in its contract talks. The North Slope Borough volunteered to guarantee the consultant's contract at the advisory group's March 3 meeting, Harding said.

"The advisory group thought it was a great idea to get the company going," he said.

Municipalities concerned about property taxes

Municipalities, which depend on property tax revenues for much of their income, are taking a strong interest in the state's negotiations for a contract in lieu of taxes. Communities in the gas line's path are especially concerned about getting enough revenue to cover the cost of dealing with the thousands of construction workers who would use municipal services.

Porter said he provided advisory group members in early March with information on how a system of payments in lieu of taxes might be structured. The group's next meeting is set for March 24, he said. "We'll meet as often as we need to."

In addition to communities directly in the route of the proposed pipeline, the Department of Revenue broadened the group's membership to include cities and boroughs that might serve as staging areas, freight depots or construction sites for project components. The expanded membership includes the North Slope Borough, Fairbanks North Star Borough and Kenai Peninsula Borough, and the cities of North Pole, Fairbanks, Delta, Valdez, Anchorage, Seward, Kenai, Haines and Skagway. ●

● GULF OF MEXICO

Dawson Deep prospect looks commercial

Appraisal drilling extends oil column by 600 feet; Dawson is Kerr-McGee's deepest Gulf of Mexico well

By RAY TYSON

Petroleum News Houston Correspondent

It now appears Kerr-McGee and partners may have a commercial discovery at their Dawson Deep prospect on Garden Banks Block 625 in deepwater Gulf of Mexico.

Operator Kerr-McGee is not ready to discuss reservoir size pending further evaluation. But preliminary results from a sidetrack drilled to a measured depth of 27,953 and a vertical depth of 25,940 feet and to a point about a half-mile northeast of the initial discovery well are encouraging indeed.

The Dawson Deep No. 2 Sidetrack No. 1 appraisal well, the deepest drilled by Kerr-McGee in the Gulf of Mexico, not only encountered hydrocarbons in several sand intervals, but extended the Dawson Deep oil column down dip by an impressive 600 feet plus, Kerr-McGee disclosed in a March 24 conference call with analysts.

"Logging and evaluation activities are currently under way," said Rick Buterbaugh, Kerr-McGee's head of investor relations. "We are encouraged both geologically and operationally by the results to date on this prospect."

He said Dawson Deep is a "potentially commercial reservoir" that could be tied back to the company's Gunnison facility just three miles away. Gunnison was recently brought on line producing 3,600 barrels per day of oil and 125 million cubic feet of natural gas, with peak daily rates of 30,000 barrels of oil and 180 million cubic feet of gas expected by year-end when field development is completed. Gunnison is some 150 miles offshore Texas in more than 2,900 feet of water.

"The results of the Dawson Deep prospect will provide valuable insight to other satellite prospects which surround the Gunnison facility," Buterbaugh said.

Kerr-McGee holds a 25 percent working interest in Dawson Deep. Fellow independent McMoRan and its partner own a 50 percent working interest, followed by Canada's Nexen with 15 percent and CalDive with the remaining 10 percent.

Sidetrack targeted to intervals in initial well

McMoRan said the Dawson Deep sidetrack was specifically targeted to intercept intervals encountered in the initial well at a down dip position, adding that a zone pointing to an oil bearing sand at 22,568 feet in the original hole was intercepted in the appraisal well and roughly 600 feet below the original hole.

Log analysis and tests point to a 120 foot single sand interval with 90 feet of true vertical depth of oil indicating a potential commercial reservoir, McMoRan said. Information gained from the original and appraisal wells on Garden Banks Block 625, along with the information from Kerr-McGee's Garden Banks Block 669 No. 2 Dawson well, will be analyzed and integrated with new seismic that is expected by the operator in May, the company said.

"A study of the data … will determine if there is an optimum location in this potentially productive oil reservoir to select a 'take point' in the possible 700 feet of oil column and further evaluate the multiple hydrocarbon shows in the Garden Banks Block 625 and Garden Banks 669 wells," McMoRan said. ●

continued from page 3

EDITORIAL

Most of those improvements are the result of partnership between industry, regulators and citizens, which is perhaps the most valuable lesson we can teach people in other countries facing the prospect of major oil development.

John Devens was major of Valdez at the time of the Exxon Valdez oil spill. The Prince William Sound Regional Citizens' Advisory Council is an independent non-profit corporation whose mission is to promote environmentally safe operation of the Valdez Marine Terminal and the oil tankers that use it. The council's work is guided by the Oil Pollution Act of 1990, and its contract with Alyeska Pipeline Service Co. The council's 18 member organizations are communities in the region affected by the 1989 Exxon Valdez oil spill, as well as aquaculture, commercial fishing, environmental, Native, recreation and tourism groups. ●

● ALASKA

Municipal gas line group loses member

North Slope Borough leaves port authority to focus on private projects

By LARRY PERSILY

Petroleum News Government Affairs Editor

The North Slope Borough says there are several reasons it decided to drop out of the Alaska Gasline Port Authority, the 5-year-old municipal partnership committed to building a North Slope natural gas pipeline.

The borough wants to focus on protecting its property tax revenues under either of two proposed privately owned gas line projects, said Mayor George Ahmaogak Sr.

JIM WHITAKER

It also wants to avoid any appearance of a conflict of interest in its membership on the municipal group advising the state on those private projects while at the same time promoting its own gas line proposal with the port authority, the mayor said in a prepared announcement March 23.

And, with the slope's regional Native corporation signed on as a partner in one of those private projects, the borough doesn't want to compete against itself.

"We are part of an advisory group that is helping the state to understand the local impacts of a gas line and what should be done about them," the mayor said. "Some of the other advisory group members argue that there's a conflict if we're on the advisory group at the same time as we're applying to build the project.

"I think they've got a point," Ahmaogak said in announcing the borough was ending its participation in the municipal port authority.

Valdez, Fairbanks still at work

GEORGE AHMAOGAK SR.

The borough's departure leaves the city of Valdez and the Fairbanks North Star Borough as the remaining two members of the port authority.

"We fully understand their position," Fairbanks Borough Mayor Jim Whitaker said of the North Slope announcement. "It does not affect the port authority, and we will continue on."

The municipal authority filed an application with the Alaska Department of Revenue last month to negotiate a long-term revenue-sharing contract to split the profits from a port authority-owned gas line with the state and municipalities across Alaska. Proponents believe the possible tax and bond financing advantages of a municipally owned project give it a significant boost over any privately developed pipeline.

The Fairbanks-Valdez team wants to build a $26 billion project that would include a line to move 6 billion cubic feet a day of natural gas from the North Slope, taking a little more than half to the Canadian border for distribution to Lower 48 markets and moving the rest to a liquefaction plant and shipping terminal at Valdez for LNG deliveries to the Far East and U.S. West Coast. A smaller spur line would feed Southcentral Alaska's urban markets.

The port authority is working to put together a deal for North Slope natural gas supplies, pipeline financing and construction and sales contracts needed to build the project that has eluded private developers for almost 30 years.

Regional Native corporation part of private proposal

But it's not alone in working toward that goal. The two private proposals before the state are from the three major North Slope producers and from Iowa-based pipeline operator MidAmerican Energy Holdings Co. The Arctic Slope Regional Corp. is among the regional Native corporations that have signed on as partners with the MidAmerican proposal.

"It doesn't make sense for the borough to compete with Arctic Slope Regional Corporation over a gas line project," Ahmaogak said in explaining one of the reasons for the borough's decision to drop out of the municipally owned project.

"One of our purposes as a port authority was to jumpstart gas development at a time when very little was happening," he said, complimenting the authority on doing just that. The borough has contributed $130,000 to the port authority since it was established in 1999, said David Harding of the borough mayor's office.

"We just need to pull back and make it clear that the borough is coming at this as a municipality with a significant stake, not as a developer," the mayor said.

Property tax big money for North Slope Borough

The borough's stake is hundreds of millions of dollars in property tax revenues over the long life of a natural gas project.

Alaska's Stranded Gas Development Act — under which the North Slope producers and MidAmerican are negotiating — allows the state and a private developer to set up a long-term contract for payments in lieu of all state and municipal taxes on a gas line project. Negotiations have been under way for almost two months between the state and the producers and separately between the state and MidAmerican.

"We are a major revenue stakeholder in this process … so we have to zero in on stranded gas. We can't have our voice diluted by our active participation in other groups with other interests," Ahmaogak said.

The North Slope Borough is one of 12 boroughs and cities serving on the Department of Revenue's municipal advisory group for the Stranded Gas Act negotiations. ●

ALASKA

Jensen elected president of Prince William Sound RCAC

The Prince William Sound Regional Citizens' Advisory Council elected Tom Jensen president at its March quarterly meeting in Anchorage, Alaska. Jensen represents the Alaska State Chamber of Commerce on the council board.

Jensen represents the Alaska State Chamber of Commerce on the council board.

Other officers named to the council's executive committee are: Marilynn Heddell, representing the city of Whittier, vice president; Steve Lewis, representing the city of Seldovia, secretary; Patience Andersen Faulkner, representing Cordova District Fishermen United, treasurer.

Members at large of the council's board are: Jane Eisemann, city of Kodiak; Blake Johnson, Kenai Peninsula Borough; Stan Stephens, Alaska Wilderness Recreation and Tourism Association.

The council also seated two new board members: Walter Parker representing the Oil Spill Region Environmental Coalition and Nancy Bird representing the city of Cordova.

—PETROLEUM NEWS

WASHINGTON, D.C.

Key Colorado agricultural group backs federal landowner protection bill

Colorado's largest agricultural organization has endorsed a bill by Rep. Mark Udall, D-Colo., that would increase protections for landowners when gas companies drill on their property.

The Colorado Farm Bureau, often aligned with Republicans on land-use issues, is concerned about the impacts of drilling on water, The Denver Post reported March 24.

"Now more than ever, it is vitally important that we in Colorado and the West take the necessary precautions to protect our water supplies," said Colorado Farm Bureau president Alan Foutz. He said water and private property rights are among agriculture's top priorities, Udall's bill addresses both.

Development of traditional natural gas wells and coalbed methane, which pumps groundwater to release gas trapped in coal seams, is increasing from Montana to New Mexico. The Bush administration is exploring ways to streamline the environmental reviews and permitting process of drilling on public lands in the Rockies, home to vast gas reserves.

The jump in the number of new wells has led to conflicts, especially in the case of the so-called "split estate," when the mineral and surface rights to the land are owned by different people. The split occurred across the West when the government retained the mineral rights to large swaths of land it manages. Some private landowners sold the minerals while retaining surface rights.

Those who own or lease the mineral rights are legally entitled to develop the resources. Udall's bill is intended to give more protection to the surface owners.

"My bill is designed to address these conflicts in a way that gives farmers and ranchers equal footing with oil and gas developers," Udall said.

Industry representatives say companies are trying to work with landowners. They say Udall's bill isn't needed because landowners already have many of the proposed protections.

"The bill is misinformed in its conception," said Ken Wonstolen of the Colorado Oil and Gas Association, a trade group. "Everything that's in this bill is already covered by federal or state law."

Colorado law requires notifying property buyers if mineral rights aren't included. State and federal government officials throughout the region also urge companies to negotiate agreements with surface owners and can require bonds to cover damages.

Landowners, however, have complained most of the power rests with the companies.

The legislation, introduced in December, hasn't yet been heard by any committees.

—THE ASSOCIATED PRESS

● FAIRBANKS, ALASKA

Needs leases, mining company agreement

Holitna Energy wants to drill shallow gas project in southwest Alaska, needs finalized leases, agreement with mining company

By PATRICIA JONES
Petroleum News Contributing Writer

Phil St. George, president of recently formed Holitna Energy, needs leases from the state of Alaska and a working agreement with a mining company considering construction of a large hard-rock mine neighboring his company's shallow gas prospect in remote southwest Alaska.

Those two pieces of paper are keeping the upstart exploration company from drilling on gas prospects in the Holitna basin, a teardrop-shaped formation that stretches for some 70 miles along the Farewell Fault east of the Holitna River and southeast of the Kuskokwim River village of Sleetmute.

State regulators overseeing the shallow gas leasing program are currently working on surveys and land status of the area, St. George told the Alaska Miners Association in Fairbanks March 17. He's waiting for a moratorium on shallow gas leasing to end, in order to receive leases his company applied for in May 2003.

"May is our drop-dead date for planning summer work," St. George said, when asked when the company's first drilling work will start. "We'll be out there the week after we get money for drilling."

Holitna Energy Corp. and its partner in the project, The Kuskokwim Corp., TKC, have "two good looking private financing options," St. George said, for the initial $1.7 million needed for core drilling and some additional gravity surveys. "Financing is easy, with cooperation from the mining company in a take or pay agreement."

Such agreements are standard in the oil and gas exploration industry, St. George added.

He's hoping to negotiate such an agreement with Placer Dome, a major mining company working on a feasibility study for the Donlin Creek gold deposit some 50 miles northwest of the Holitna Basin shallow gas prospect.

Operation of a large-scale hard-rock mine, envisioned by developers of Donlin Creek, will require some 60 megawatts of electric power. St. George hopes to provide shallow gas for that energy source.

But he can't finalize financing for the first stage of exploration, he said, without leases in hand and without a working agreement with the potential user of the field's resources.

State benefits

Alaska state geologists identified the potential gas-prone region, based on grassroots geological and geophysical work that includes analysis of low quality coals exposed in sections of the fault.

Gravity surveys indicate the basin is more than 10,000 feet deep, with exposed intervals of 537 feet of coals or carbonaceous shales, St. George said.

"It has good potential for conventional gas or coalbed methane," he said. "Personally, I think gas is the cleanest fuel for use in this region."

Shallow gas development could replace up to 2.6 million gallons of diesel fuel used in electric generators by 20 or so local villages and could save the state and federal governments more than $3 million a year in electric power subsidies to the region, St. George said.

In addition, he estimates the state would receive $1.2 million a year in royalties and about $400,000 in corporate income taxes from the proposed gas development.

The project would need to produce approximately 300 million cubic feet of gas per day to meet the needs of the proposed gold mine at Donlin Creek and to supply electric power needs for villages.

That translates to 5.9 billion cubic feet per year, St. George said.

Project finances

During his presentation, St. George outlined development costs for the proposed shallow gas project. In addition to the $1.75 million for initial core testing, about $6.6 million in production tests would be required.

Field development costs are estimated at $42.19 million, and gas transmission lines, involving burying a four to six inch pipeline, would cost about $20 million. Total project costs are estimated at $70 million.

The technology is "amazingly simple," said St. George, who has a long career as a minerals geologist. "Typical production facilities are contained in a 150 by 150 foot building. This is not a North Slope appearance."

A buried gas line, vs. building a power plant at the gas field and transmitting electricity by power lines, is the preferred alternative. "A buried pipeline is cheaper … and is more visually appealing," St. George said. "About $200,000 per mile is the lowest price we've seen for transmission lines."

Villages and the mine would benefit more from having gas on location, rather than just buying electricity. In villages, gas could be used for heat as well as power generation, he said. ●

Want to know more?

If you'd like to read more about Holitna Energy and the Holitna basin, go to the Petroleum News Web site and search for the following articles:

Web site: www.PetroleumNews.com

2004
- **Feb. 8** Shallow gas leasing uncertainty delays Holitna project
- **Jan. 4** State of Alaska receives winter seismic, core hole….

2003
- **Nov. 2** Struggle simmers over power source
- **Nov. 2** DGGS geologist advocates drilling Holitna basin
- **Oct. 19** Partners team up for gas development
- **Aug. 3** Donlin Creek power … might come from local gas, not B.C. coal
- **Aug. 3** Providing remote power
- **July 27** Federal grants would spur rural Alaska energy development
- **June 1** Alaska miner turns to gas play, forms Holitna Energy
- **June 1** State geologists find promise in Holitna Basin

● CANADA

Canadian profits returning to more normal levels

By GARY PARK

Petroleum News Calgary Correspondent

Oil patch profits in the Canadian industry could be slashed in half this year, the Conference Board of Canada has predicted — but that assumes an easing of commodity prices.

The report forecasts profits of C$13 billion for 2004, down from last year's staggering C$28.7 billion, with a further drop to C$10.4 billion in 2005, where the industry will hold the line in 2006 and 2007.

But the board says that even those levels are high by historical standards.

For the 2003 to 2007 period, the board expects light crude prices from Edmonton will fall to C$36.80 per barrel from C$44.70 as supplies from Iraq and non-OPEC countries rise; heavy crude will slide to C$26.60 per barrel from C$36.10; and gas will decline to C$5.50 per gigajoule from C$6.40.

The conference board expects a combination of falling gas production and lower crude prices will see total revenues shrink by 13 percent in 2004 and 1.5 percent in 2005 before edging back up by 1.7 percent in 2006 and dropping again by 0.5 percent in 2007.

Production costs expected to grow

The combined costs of oil and gas production are predicted to grow by 2.1 percent this year and capital costs are anticipated to climb by almost 12 percent, reflecting the investments in exploration and processing oil and gas off Canada's East Coast and the Western Canada Sedimentary Basin.

Conventional crude output will drop by about 6 percent in 2004 and continue slipping by about 1.8 percent a year over the medium term, reflecting a loss of productivity in Western Canada.

Gas production is targeted to decrease to 5.89 trillion cubic feet by 2007 from 6.18 tcf in 2004.

But the board says the prospects for synthetic crude and bitumen are rosy, forecasting that refineries across Canada will convert their operations from conventional crude as those volumes decline.●

CANADA

Petroleum institute lends a helping hand to juniors with overseas ambitions

The Canadian Petroleum Institute is proposing a fund to help Canadian-based companies explore in developing countries.

Through a combination of government and private funds, it hopes to create an Emerging Energy and Exploration Investment Fund of about C$100 million.

Through a combination of government and private funds, it hopes to create an Emerging Energy and Exploration Investment Fund of about C$100 million.

For now the institute is engaged in a two-part feasibility study to assess the level of interest in a fund and to examine a fund structure and governance.

The study is being jointly financed by the institute, Western Economic Diversification Canada and Alberta Economic Development and includes a questionnaire of Canadian Association of Petroleum producers member companies.

Driven by the diminishing prospects for juniors in the Western Canada Sedimentary Basin, the institute believes the only answer lies overseas.

The initial focus is on West Africa, which it says is rich in opportunities, given that the entire African continent logs only 1,000 wells a year in 120 prospective basins, despite holding about 13 percent of the world's proven oil and natural gas reserves.

If the fund is set up, it will target equity participation and count on a 20 percent return on investment over the long term.

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

CANADA

Forest takes write-down in Canadian gas reserves

Canadian Forest Oil joined the growing list of companies to shrink its Canadian reserves, reducing its natural gas holdings to just under 118 billion cubic feet entering 2004 from 135 billion cubic feet a year earlier.

In a 10-K filing by its parent company, Forest Oil, with the U.S. Securities and Exchange Commission, the Canadian unit said its gas reserves took a negative revision of 19.14 bcf in 2003, while production totaled 12.61 bcf, more than offsetting extensions and discoveries of 14.65 bcf.

However, proved liquids reserves in Canada edged up to 7.25 million barrels from 6.91 million at the end of 2002.

Canadian Forest reported 39 gross wells in 2003 with a 95 percent success rate.

Gas sales volumes for the year averaged 34.6 million cubic feet per day, down from 37 million in 2002, while full-year liquids sales averaged 2,800 barrels per day, off 400 bpd from the previous year.

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

MIDLAND, TEXAS

Parallel looking for deals in 2004

Small exploration and production independent Parallel Petroleum, whose 2003 fourth-quarter net income soared to $1 million from $200,000 a year earlier on strong production and commodity prices, said March 18 that it wants to do more deals this year.

"We are actively working on acquisition and exploitation joint venture targets but do not presently have any definitive agreements in place," Parallel President Larry Oldham said. Earlier the company outlined a projected three-year investment plan of about $50 million on its existing portfolio of projects, of which about $17 million was estimated to be spent in 2004 from operating cash flow.

For full-year 2003, Parallel's oil and gas production volumes increased 106 percent to 1.2 million barrels of oil equivalent compared to the previous year's 576,000 barrels of oil equivalent, while commodity prices during the same period jumped 36 percent.

—RAY TYSON, Petroleum News Houston correspondent

INTERIOR ALASKA

Tri-Valley forms mining company

Tri-Valley Corp., primarily an oil and gas exploration and producing firm based in Bakersfield, Calif., announced plans to spin off its gold exploration property in Interior Alaska as a stand-alone mining company.

F. Lynn Blystone, Tri-Valley president and CEO, told Petroleum News March 15 about his company's plans for its 42-square mile land block some 65 miles south of Fairbanks, between the Richardson Highway and the trans-Alaska pipeline corridor.

"There's been no recognition of the value of our gold property in our stock," he said. "The market is at a point where we can raise the amount of capital needed for working the project."

Blystone anticipates raising about $5 million initially in private offerings. He is also looking for a seasoned mining executive to lead the new company, which he has yet to name.Tri-Valley's mining claims are highway accessible and have access to power infrastructure. The company, in a partnership with Moscow-based mineral research institute TsNIGRI, has explored some 250 square miles in the Richardson Mining District, identifying visible gold at 60 locations along a 20-mile swath, according to the company's press release.

Tri-Valley has optioned the property to different partners in past years, Blystone said, a process that has not been fruitful. "The joint venture thing just never gets to the finish line," he said. "They do some work for a season and then that's the end of it."

Past exploration has identified three definite hard rock targets, and some placer gold mining targets, he said.

On the energy side, Tri-Valley has several oil and gas prospects in various stages of completion and is preparing to drill exploratory wells in California and Nevada.

—PATRICIA JONES, Petroleum News contributing writer

LONDON, ENGLAND

BAE appoints BP's Dick Olver new chairman

BAE Systems, Britain's largest aerospace and defense contractor, has named Dick Olver as chairman, the company said March 24. Currently deputy chief executive at BP, he will take over from retiring BAE chairman Sir Richard Evans on July 1.

Olver, 57, has worked at BP for 30 years. BAE will appoint him as a non-executive director on May 17 before his becoming chairman.

He will continue his association with BP, serving as deputy chairman of its Russian joint venture TNK-BP starting in May. Olver joins BAE as it tries to expand its already substantial business in the United States and profit from U.S. government defense spending. The firm has long expressed its openness to a trans-Atlantic merger, arguing that European defense groups won't be able to compete in the future without access to U.S. technologies. General Dynamics reportedly broke off exploratory talks about a merger with BAE in October.

—THE ASSOCIATED PRESS

● OKLAHOMA CITY, OKLA.

Chesapeake piles on acquisitions in core producing areas

By RAY TYSON

Petroleum News Houston Correspondent

Natural gas producer Chesapeake Energy keeps layering on the acquisitions, despite saying a month ago that competition and high prices were making quality properties increasingly difficult to find.

The Oklahoma-based independent said March 24 that it has entered into or is completing agreements to acquire $100 million of additional U.S. Midcontinent, Permian Basin and Texas Gulf Coast oil and natural gas assets in four separate transactions.

Last year Chesapeake concluded three separate deals totaling $510 million, including $420 million it paid for independent Concho Resources. In those transactions alone, the company added reserves of 320 billion cubic feet of gas equivalent and daily production of 70 million cubic feet of gas equivalent.

Through its recent agreements with undisclosed sellers, Chesapeake said it expects to acquire another 68 billion cubic feet of gas equivalent proved reserves, 39 billion cubic feet of probable and possible reserves and current production of 15 million cubic feet of natural gas equivalent production per day.

Chesapeake said the acquisitions, located in areas where the company already produces, would help boost its total 2004 proved oil and natural gas

Last year Chesapeake concluded three separate deals totaling $510 million, including $420 million it paid for independent Concho Resources.

reserves to about 3.6 trillion cubic feet of natural gas equivalent.

After allocating $16 million of the purchase price to unevaluated leasehold, probable and possible reserves and other assets, Chesapeake's acquisition cost per thousand cubic feet of gas equivalent of proved reserves associated with the transactions will be $1.24, the company said.

$1.39 per thousand cubic feet

Including unevaluated leasehold and anticipated future drilling costs for fully developing the proved, probable and possible reserves, the company estimates that its all-in acquisition cost for the 107 billion cubic feet of equivalent reserves would be $1.39 per thousand cubic feet.

The proved reserves have a reserves-to-production index of 12.5 years, are 66 percent oil and 74 percent proved developed, the company said.

Two of the acquisitions are expected to close April 1, two on May 1, Chesapeake said, adding that it intends to finance the acquisitions with proceeds from a new $255-million private issue of cumulative convertible preferred stock, some of which would be used to pay down debt. ●

LONDON

Oil price riot may be out of OPEC's hands

Members of the Organization of Petroleum Exporting Countries might have lost control of a surge in oil prices that ministers claim is being driven by forces out of the cartel's hands.

Ministers from OPEC meet in a few days in an effort to stem an upward price spiral, when most were bracing for a seasonal slump on world crude markets. OPEC has long fretted openly that a drop in global fuel demand after the northern hemisphere winter and a recovery in Iraq to pre-war crude export volumes would bring oil's five-year price bonanza to a screeching halt. Instead, in mid-March U.S. crude hit a 13-year high in New York of more than $38 a barrel, raising the alarm on energy costs for importing nations. OPEC's decision to slice production quotas by 4 percent from April 1 now looks to be one step too far in its campaign of supply restrictions that is designed to keep prices in a $22 to $28 range.

Ministers must decide whether to defer or cancel the April cut, and risk a big fall in prices, or go ahead with it and upset consuming nations.

"By not cutting, it runs the risk that prices fall precipitously if stocks continue to build and [petrol] is unsupportive," said William Buchanan of Standard Bank in London. "Cutting as planned could encourage more funds to push prices even higher."

OPEC blames external forces, rather than any shortage of its crude, for lifting benchmark U.S. crude futures to an average of more than $35 a barrel this year, well above last year's $31 average, itself the highest in two decades. China's rampant fuel demand growth, geopolitical security fears and low U.S. stocks of a new green fuel have turned oil futures into a buying magnet for big-money fund managers.

The speculative buying has fueled OPEC's fear that a sudden exodus could send prices into freefall. The big question now is whether OPEC, and Saudi Arabia in particular, think prices are too high for the cartel's own good. Self-interest indicates OPEC best avoid allowing high prices choking off fuel demand but so far U.S. and Chinese demand growth suggests consumers are getting used to more expensive fuel.

Many expect the cartel to make no change to quotas and to manage prices by leaking supply.

—THE ASSOCIATED PRESS

● ALBERTA

Alberta lowering greenhouse gases

By GARY PARK

Petroleum News Calgary Correspondent

Alberta, often labeled as the stumbling block in Canada's efforts to develop a climate change strategy, is setting the pace for other provinces.

Environment Minister Lorne Taylor released an 18-month progress report that he said will lay the foundation for substantial reductions in greenhouse gas emissions over the next year.

He said the Alberta government has:

• Adopted Canada's first legislation to tackle emissions.

• Established North America's largest green power contract by committing itself to buy 90 percent "green power" for government facilities by 2005 at a cost of C$200 million.

• Offered a C$100 million interest-free loan program to help municipalities with energy efficiency initiatives.

• Made more than C$30 million in commitments for technology and innovation.

Taylor said that the work done so far will be a model and a starting point for future discussions with the Canadian government and other provinces in developing a national plan on climate change.

Rather than adopting the objectives of the Kyoto Protocol, Taylor said Alberta prefers to invest in technology and change behavior to achieve permanent and more significant cuts in emissions without taking the Kyoto approach of short-term actions that could carry a heavy economic cost with little or no benefit to the environment.

He said Alberta wants to achieve a 50 percent reduction in emissions intensity below 1990 levels by 2020, or slash "business as usual" emissions by 60 million tonnes.

Also, Alberta aims to lower emissions by 20 million tonnes by 2010.

With the Alberta Energy Research Institute in a coordinating role, the government will invest C$27 million over three years on the research and development of sustainable energy technologies.

In addition, its 2003 royalty credit program offsets up to 30 percent of costs of projects that capture or inject carbon dioxide into oil and gas pools to both improve resource recovery and store the CO_2.

The province is also offering royalty reductions for those who use CO_2 in enhanced oil recovery projects. ●

ONTARIO

Ontario aims to close coal-fired plants by 2007, use renewable energy

The Ontario government is signaled its determination to pursue renewable energy sources by setting a goal of shutting down its five coal-fired electricity generating plants over the next three years.

Energy Minister Dwight Duncan said Canada's most populous province and largest natural gas consumer has hired a technical advisor to oversee a competitive contracting process to deal with Ontario's immediate supply issues and increase renewable capacity.

Duncan said the province wants 2,500 megawatts of new generating capacity and energy conservation initiatives in place by 2007 and 300 megawatts of renewable energy in place as soon as possible.

He said those combined 2,800 megawatts account for one-third of the energy needed to replace coal-fired plants, which meet 25 percent of Ontario's electricity needs.

To that end, Ontario is asking the Canadian government to help shut down coal-fired plants, stressing that the closure would be a key factor in meeting the Kyoto Accord targets for reducing greenhouse gas emissions.

Without identifying the likely source of "new" energy, Duncan said conservation must be a priority.

"It is one of the single-most important things we can do over the long-term," he said, referring to a "beer fridge" bounty program to get old, inefficient appliances out of houses.

Duncan also said his government will also allow local electricity distributors to earn their full commercial return starting next year if they reinvest a year's worth of that money in conservation programs, an amount that could total about C$225 million a year.

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

FAIRBANKS, ALASKA

Natural gas fuel cell experiment successful

An experimental natural-gas fired solid oxide fuel cell has completed more than 5,000 hours of operation, producing five kilowatts of electricity and up to six kilowatts of auxiliary heat used by its host business, Fairbanks Natural Gas, in Fairbanks, Alaska.

Unique due to its small size, the fuel cell was installed last July. Siemens Westinghouse built the fuel cell stack and Ontario-based Fell Cell Technologies assembled the operating unit. Researchers at the University of Alaska Fairbanks coordinated the $383,000 experimental project, with the bulk of funding awarded by the U.S. Department of Energy, through its Arctic Energy Office.

The fuel cell has operated continuously since last September, when a power failure on the local electrical grid shut down its operation. "We needed to do some work on our installation, so the unit was down for about 10 days before we restarted it," said Dennis Witmer, director of the Arctic Energy Technology Development Laboratory at the university. "Since the biggest questions surrounding fuel cells have been longevity and reliability, this is an exciting achievement in fuel cell technology and testing."

Operating efficiency is more than 50 percent with direct current power, DC, and more than 40 percent when converted to alternating current, AC. "A typical small generator would be about 25 percent efficient," Witmer said.

Additional research may involve similar-sized units that use propane or diesel, fuels readily available in rural Alaska locations, he added.

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

SPRINGFIELD, VA.

Government leases land in Arkansas, Mississippi for oil and gas exploration

Eighteen federal oil and gas leases in Arkansas and Mississippi brought in more than $96,000 through a competitive lease sale conducted by the U.S. Department of the Interior's Bureau of Land Management on March 18 in Springfield, Va. Bonus bids, filing fees, and rental revenue amounting to $65,736 will go to the U.S. Treasury and $30,894 will be shared with the states of Arkansas and Mississippi.

Federal regulations required the bidding to open at $2 per acre.

Seeco Inc. of Fayetteville County, Ark., paid $7,000 for a 25 acre parcel. Its bid of $280 per acre was the highest per-acre bid of the auction.

Leases are awarded for a term of 10 years and as long thereafter as there is production of oil and gas in paying quantities. The feds receive a royalty of 12 1/2 percent of the value of production. Also, each state receives a 25 percent minimum share of the bonus bid and the royalty revenue from each lease issued in that state.

RESTON, VA.

USGS allows access to unique database

The U.S. Geological Survey said March 24 that the public now can access a USGS database that includes chemical analysis of crude oil, natural gas and rock samples from thousands of locations worldwide. The agency said it is the only database of its kind and this is the first time it has been made available to the public

USGS scientists use the information in the organic geochemistry database to assess domestic and world energy resources. The agency said the information will help people understand the geochemistry of many of the world's major oil and gas producing regions.

"It will also be a useful reference for federal, state, and local agencies involved in land and resource planning, oil and gas production, oil and gas assessments, public safety, and environmental concerns. The database will also be a valuable tool for academic research into the processes responsible for the formation and accumulation of petroleum," USGS said in its press release.

Information within the database includes rock pyrolysis data, organic mass spectrometry, vitrinite reflectance, gas chromatography, column chromatography, stable carbon isotopes, and a number of other related petroleum geochemical analyses. The sample types are primarily rock, oil, and gas samples collected from outcrops or from exploratory or production wells.

To access the data base go to http://energy.cr.usgs.gov/other/oglab/ogindex.htm/.

—PETROLEUM NEWS

ALASKA

Potential Alaska, federal oil gas lease sales

Agency	Sale and Area	Proposed Date
MMS	Sale 191 Cook Inlet	May 19, 2004
DNR	Cook Inlet Areawide	May 19, 2004
DNR	Foothills Areawide	May 19, 2004
BLM	NE NPR-A	June 2004
BLM	NW NPR-A	June 2004
DNR	North Slope Areawide	October 2004
DNR	Beaufort Sea Areawide	October 2004
MMS	Sale 195 Beaufort Sea	March 2005
DNR	Cook Inlet Areawide	May 2005
DNR	Foothills Areawide	May 2005
BLM	NE NPR-A	June 2005
DNR	North Slope Areawide	October 2005
DNR	Beaufort Sea Areawide	October 2005
DNR	Alaska Peninsula Areawide	October 2005
MMS	Sale 199 Cook Inlet	2006
MMS	Sale 202 Beaufort Sea	2007
MMS	Chukchi Sea/Hope Basin	interest based
MMS	Norton Basin	interest based

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

** Or before the five-year plan expires.*

● LOUISIANA/ALASKA

Merlin looking north

Louisiana-based independent looks to Alaska for new opportunities; focused mainly on natural gas plays

By PATRICIA JONES

Petroleum News Contributing Writer

Louisiana-based Merlin Oil & Gas is one of 19 independents the state of Alaska is working to woo north, according to Tom Irwin, commissioner of the Alaska Department of Natural Resources.

And if any of the other independent operators are as enthusiastic as Mark Miller, president and CEO of Merlin, Irwin's job should go smoothly.

"I'm so excited to have a chance to come to your state," Miller told Petroleum News in a telephone interview on March 17. "We're interested in all opportunities for small companies like ourselves, not just shallow gas but Cook Inlet … I think the slope is a little beyond where I can go as a small company."

MARK MILLER

Irwin mentioned the state's interest in encouraging independent operators during a speech before the Alaska Miners Association in Fairbanks on March 15. "We have 19 independents seriously talking to us," Irwin said. "We need a gas line to give them access to markets."

Access to the oil pipeline and resolution of land issues in Alaska would also help lure additional investment, he said in an interview following his speech.

Merlin has been looking at Alaska

Irwin connected with Merlin's president at a conference in New Orleans last fall, the commissioner said.

But the head of the independent exploration and production company has considered investing in Alaska for some time.

Miller first came to Alaska about eight years ago, he said, with a friend who was then working for Exxon during pipeline renegotiations. His trip included visits to Prudhoe Bay as well as a number of communities around the state. "I fell in love with it."

He has since returned to Alaska several times, including one trip that included purchase of some recreational land on Trapper Lake, a few miles west of the Parks Highway, about midway between Talkeetna and Willow.

"That just further cements my belief in the state," Miller said.

Recent interest includes meetings in Juneau with the commissioner and the governor, whom he described as "obviously pro-business."

"We talked about opportunities for shallow gas, with the incentives being put forth to bring small companies into the fold," Miller said.

Alaska's oil and gas exploration structure offers economic incentives that are "strong" for small companies, he said. "There are real opportunities to go drill wells."

CBM, shallow gas interest

Miller also attended a public meeting in Anchor Point on coalbed methane development. Controversy in the community surrounding the development new to Alaska hasn't scared off Miller: "I was trying to understand their concerns."

Misunderstanding about legalities surrounding mineral rights and worries about development approaches were issues expressed during that meeting. "Their main concern was that a company would come in and drill next to their home. It's a concern that's valid, but not realistic," Miller said. "It's not the classical approach to coalbed methane development."

The atmosphere at the public meeting contained "a lot less tension and abrasiveness" than he expected, Miller said. "I saw it, I understand it and I'm willing to go back and work with the community."

In fact, Miller's company has experience developing natural resources next to and within populated areas. Currently Merlin Oil & Gas is producing some 15 million cubic feet per day of gas and approximately 200 barrels of oil a day from four wells drilled just outside the city limits of New Orleans, he said.

Royalty payments go to about 44,000 entities, Miller said. "The community benefits from the leasing, from money spent on exploration and they actually participate in royalties."

Exploring for that resource involved coordination of 3-D seismic work through several neighborhoods, he added, a time-consuming task. "Our niche is to work in developed areas, to work with a community hand in hand."

Focused on gas

Primarily focused on gas exploration, Merlin has also drilled in coastal, swampy areas, providing experience that could be transferred to low-impact areas in Alaska, Miller said. "We have a lot of very delicate marshes here and we have shown that we can operate in the coastal environment," he said. "Some people don't like to operate in those areas, but that part of working in Alaska is something we can cope with."

In addition, Merlin has drilled some offshore wells, the deepest in about 100 feet of water, he said.

The privately held company formed in 1986, Miller said. He's planning to attend lease sales in Alaska this May, and said he was going to "spread the word amongst other small companies about the tantalizing opportunities … I hope to be bringing a group back for the lease sale." ●

JUNEAU, ALASKA

Murkowski signs bills moving Bristol Bay sales forward

Alaska Gov. Frank Murkowski has signed two bills facilitating oil and gas exploration in the Bristol Bay area in the southwest part of the state. Residents of the area approached the administration last year, asking that the state take a look at possible onshore oil and gas development, because the area's fishing industry is in decline.

Both bills, signed March 22, passed the Alaska Senate unanimously Feb. 25 and the Alaska House unanimously March 16.

Senate Bill 265 fixes a technical hitch: state statute had only allowed the Alaska Department of Natural Resources to present oil and gas lease sale schedules to the Legislature every two years, at the beginning of the regular session, which meant a Bristol Bay areawide sale would have been delayed because a new schedule couldn't be presented until January 2005. Proposed sales have to be on the schedule for a year before they are held, and the state wanted to do an areawide Bristol Bay sale in 2005.


Alaska Gov. Frank Murkowski

SB 265 calls for annual presentation of the Division of Oil and Gas five-year proposed oil and gas leasing program, but also allows the commissioner of Natural Resources to make revisions, including additions, in the plan at any time, provided that the Legislature is notified, and allows for electronic notification: "Notification to each legislator, by electronic message or other written means, constitutes notification to the legislature under this subsection."

In a fiscal note to SB 265, Bill Van Dyke of the Division of Oil and Gas said the amendments to the five-year schedule "will ultimately allow DNR to hold sales in the frontier areas sooner, therefore bringing the state additional revenues…"

In a fiscal note to SB 265, Bill Van Dyke of the Division of Oil and Gas said the amendments to the five-year schedule "will ultimately allow DNR to hold sales in the frontier areas sooner, therefore bringing the state additional revenues…"

SB 266 approves an action already taken by the commissioner of Natural Resources, closing land within the proposed Bristol Bay areawide sale to oil and gas exploration licensing and shallow natural gas leasing.

Mark Myers, director of the Division of Oil and Gas, said in a fiscal note for SB 266 that the bill "ensures that land remains available for the competitive sale program" by approving "an interim classification by the commissioner of Natural Resources closing lands in the proposed Bristol Bay (Alaska Peninsula) competitive oil and gas areawide lease sale to oil and gas exploration licensing … and shallow natural gas leasing…"

—PETROLEUM NEWS

● NORTH SLOPE, ALASKA

How much is left?

USGS assessing undiscovered hydrocarbons in North Slope's 'middle ground'

By KRISTEN NELSON

Petroleum News Editor-in-Chief

Billions of barrels of oil have been discovered on Alaska's North Slope, but how much more could there be, yet undiscovered?

The U.S. Geological Survey has assessed undiscovered oil and gas resources in the Arctic National Wildlife Refuge on the eastern side of the North Slope and in the National Petroleum Reserve-Alaska on the western side, and is now looking at what it calls the "middle ground."

The middle ground of the North Slope, says Ken Bird of the USGS, is the area between ANWR and NPR-A, north of the Brooks Range and south of the three-mile offshore limit of state land.

"The basic assessment unit is the play, and this method really works only if you've got seismic data," so that "you can really see the types of traps and get some rough idea of the number and size and distribution."
—Ken Bird, USGS

It includes all of the fields currently producing on the North Slope, but the assessment the USGS is doing doesn't include discovered oil and gas, he said. Instead the agency is assessing the amount of resource — in place, technically recoverable and economically recoverable — that remains undiscovered in the area.

Bird, project team leader for the USGS Alaska Petroleum Studies Project, said in a preliminary report to the Alaska Geologic Society in Anchorage March 18 that while the assessments in ANWR and NPR-A "consisted primarily of federal land, the assessments that we're working on right now are composed primarily of state and Native lands with a relatively small proportion of federal land."

What is known

The data USGS has to work with includes a network of seismic lines and some 200 wells in a digital database, plus some additional magnetic and paleontology data and several seasons of field work in the area. Bird said the purpose of the March 18 presentation was to describe how the assessment is being done and to get some feedback. The schedule calls for completion of the preliminary assessment in May, the final assessment in October and release of the results early in 2005.

The North Slope has been relatively lightly explored, Bird said, with only some 400 exploration wells drilled, probably three-fourths of those in the middle ground area. According to the Alaska Division of Oil and Gas web page, Bird said, there are almost 70 known accumulations across the North Slope, with some 80 million barrels of oil discovered and 20 billion barrels of that believed to be recoverable, along with some 35 trillion cubic feet of recoverable natural gas.

Assessment methodology

The assessment methodology the USGS is using is the same method it used for ANWR and NPR-A. "The basic assessment unit is the play," Bird said, "and this method really works only if

see LEFT page 12

Non-conventional gas later; Yukon Flats, other basins in the works

The USGS's Ken Bird says the agency's current assessment of undiscovered oil and gas resources on Alaska's North Slope does not include non-conventional resources.

But, he said, "on the assessment schedule years down the road, we've got unconventional resource evaluations scheduled" including coalbed methane and gas hydrates.


FORREST CRANE

Ken Bird, USGS

The USGS also has other projects under way in Alaska.

It is collaborating with the Minerals Management Service on a synthesis of petroleum geology and resources of onshore and offshore northern Alaska; completing data compilation, analysis and assessment of the Yukon Flats basin in central Alaska; continuing baseline measurements of gas content of coal in various Alaska basins; and initiating data collection in Cook Inlet basin in preparation for a new oil and gas assessment.

continued from page 11

LEFT

you've got seismic data," so that "you can really see the types of traps and get some rough idea of the number and size and distribution."

"This is our first time to use it in the middle ground area, basically because we have seismic for the first time."

Plays are volumes of rock with similar geologic features such as petroleum charge, reservoir and trap — features that determine petroleum potential. Bird said the team had not finalized the list of plays it would include, but once that work is completed, probability distributions are run for the characteristics of individual plays and for the distribution of the sizes of accumulations, with a minimum cutoff of 50 million barrels of oil in place.

Plays are volumes of rock with similar geologic features such as petroleum charge, reservoir and trap — features that determine petroleum potential.

You can't just sum individual plays to get a total, because the plays are related to one another, Bird said. "What are the dependencies in terms of the charge, reservoir and trap? If the source fails in one of these plays then it's going to have an effect on the overlying play, which was relying on the same source rocks.

"Those dependencies are incorporated into the aggregation process," he said.

An economic assessment is then run, with the resources allocated to geographic blocks so factors of distance to infrastructure can be included in determining economic recoverability.

Major middle ground plays

In the NPR-A assessment some two dozen plays were identified. The Ellesmerian sequence plays included the Ivishak and Lisburne, Beaufortian sequence plays included upper and lower Jurassic, and Brookian plays included the Torok.

In the middle ground area, Bird said, the Ellesmerian Ivishak sandstone play is the main reservoir at Prudhoe Bay, and also includes Sandpiper, Northstar, Gwydyr Bay, North Prudhoe, Sag Delta North and Eider. He said it's hard to find closures in this area that haven't been drilled, because the Ivishak is the "most intensely explored of plays in this area."

"The Ivishak has been the primary target of frontier exploration outside of the Prudhoe area," Bird said, "and most of these (middle ground exploration) wells … the primary target was the Ivishak."

What the assessment is looking for in undiscovered resource, he said, would be "small Ivishak accumulations."

There are more discoveries in the Beaufortian than in any of the other mega sequences, Bird said, including the Kuparuk field, the largest at 2.5 billion barrels recoverable, Alpine and recently discovered accumulations in northeast NPR-A.

Brookian deposits include heavy oil deposits at both West Sak and Ugnu. ●

DENVER, COLO.

Forest Oil releases test results on Gulf of Mexico discovery

A discovery well at West Cameron block 112 in the Gulf of Mexico, drilled to a total depth of 15,325 feet, tested at a daily rate of 15.4 million cubic feet of natural gas and 322 barrels of condensate with a flowing tubing pressure of 10,475 psi, operator Forest Oil said March 18.

Initial production from the well is projected to be 20-25 million cubic feet per day of gas equivalent, Forest said, adding that the well is scheduled to come on line in the third quarter of this year.

Forest has a 55 percent working interest in the well. Dominion Exploration & Production holds the remaining 45 percent interest.

—PETROLEUM NEWS

NORTH AMERICA

Canadian rig count drops 70

The combined U.S. and Canadian rotary rig count fell by 76 to 579 rigs during the week ending March 19, according to rig monitor Baker Hughes. The number of rigs operating in Canada alone dropped by 70 compared to the previous week to 451, down by two rigs versus the same weekly period a year earlier.

In the United States, the count slipped by a net six rigs from the prior week to 1,128, still up by 182 rigs compared to the same period last year. Land rigs alone fell by four to 1,018. The offshore count was down by one to 93 rigs. And the number of active inland water rigs decreased by one to 17.

Of the total number of rigs operating in the United States dur-

see COUNT page 14

GULF OF MEXICO

Helicopter down in Gulf

Four bodies have been recovered from an Era Aviation helicopter that went down en route to a Unocal drilling location in the Gulf of Mexico the evening of March 23.

The helicopter, a Sikorsky S-76 A under contract to Unocal, had eight passengers and two crew members aboard, and was last contacted about 70 miles south of Galveston while transporting workers to a drill ship that was in transit to a drill site in Alaminos Canyon block 859 located 200 miles south of Galveston, Unocal said March 24. Rowan Cos., which owns Era, said Era and other private air and sea transportation companies were assisting in search and rescue operations by the U.S. Coast Guard out of Corpus Christi, Texas.

The passengers included four employees of Halliburton, one from Dril-Quip, two from Offshore Energy Services, all contracted to Unocal; and one Unocal employee.

The Coast Guard used infrared scanners to search waters off Galveston through the night, and the search continued March 25.

—THE ASSOCIATED PRESS CONTRIBUTED TO THIS STORY

● NORTH SLOPE, ALASKA

Placer No. 2 tract operations approved

ConocoPhillips Alaska says second well this winter at west Kuparuk prospect could expedite development, cutting one year off timetable

By KRISTEN NELSON

Petroleum News Editor-in-Chief

JUDY PATRICK

Nordic 3 drilling at Placer this winter.

In mid-March the Alaska Division of Oil and Gas approved a request for tract operations to drill the Placer No. 2 exploration well in a western Kuparuk River unit expansion area southwest of the Palm discovery and development.

Tract operations were approved for the Placer No. 1 well in January, and Rick Mott, ConocoPhillips Alaska's vice president of exploration and land, told Petroleum News March 4 that "we've already run the surface casing, we're down below 3,000 feet."

The company already received a drilling permit for the second well, and Mott said that was "a contingency."

If results at the first well were encouraging, "we

see PLACER page 14

● NOVA SCOTIA

Troubles in Nova Scotia

EnCana well lags behind schedule and overruns budget, but partners ready to see job completed; Marathon plans only other exploration well in basin this year

By GARY PARK

Petroleum News Calgary Correspondent

Reeling from the confusion swirling around the Canadian Superior Energy well, offshore Nova Scotia has been rocked by a setback to the only exploration well under way in the basin.

At the same time the industry, government and analysts were trying to make sense out of Canadian Superior's decision to plug and abandon its Mariner I-85 well drilled in partnership with El Paso, EnCana confirmed the Weymouth A-45 well is behind schedule and over budget by an unknown amount.

Instead of reaching its targeted depth by late February, completion is now unlikely before mid-April, a spokeswoman for EnCana told Petroleum News.

Partners in A-45 are EnCana 55 percent, Shell Canada 30 percent and 15 percent held by Norway's Ocean Rig, whose semi-submersible Eirik Raude is drilling the well.

Problems blamed on weather, geological conditions

Ocean Rig said that despite the problems, which EnCana blamed on challenging weather and geological conditions, data gathered during drilling has convinced it to maintain full participation in the well so that it can share in the "full potential of any discovery."

see TROUBLES page 14

continued from page 13

TROUBLES

It insisted the delay was not linked to the performance of Eirik Raude, which it described as "satisfactory." The well is being drilled in 5,600 feet of water and is currently close to 19,500 feet on its way to a projected depth of 21,736 feet.

Citing confidential agreements, the EnCana spokeswoman declined to say how much was budgeted for the well, although she said wells in the region often cost in the range of C$80 million.

Ocean Rig said that under a revised agreement it has a right to cap its cost at US$13.5 million and the right to sell its interest.

Shell Canada farmed into the well last October, ready to take on the "high risk" project in return for a "possible high pay off opportunity," Chief Executive Officer Linda Cook said at the time.

The gamble is well understood by Shell, which abandoned the 100 percent owned C$90 million Onondaga B-84 well in May 2002 after deeming the gas shows it encountered to be uneconomic.

Only one new wildcat scheduled for '04

Attention is now turning to the Crimson K-81 well, which a partnership of Marathon Oil 40 percent, EnCana 35 percent and Murphy Oil 25 percent expects to spud in May — currently the only new wildcat scheduled for 2004. Houston-based Transocean said March 11 it has contracted the Deepwater Pathfinder rig for 110 days to drill the well on the same exploration license as the Annapolis-24 wildcat discovery by Marathon, EnCana, Murphy and Norsk Hydro Oil & Gas Canada, which Marathon has estimated could be part of a block holding 5 to 15 trillion cubic feet.

Just reaching this point with Crimson K-81 was a challenge for Marathon, which had to fend off efforts by Ocean Rig to persuade the Canadian Transportation Agency to give preference to Eirik Raude over the Deepwater Pathfinder.

Marathon also has interests in two other exploration properties in the deepwater Scotian Slope — 100 percent of one license that carries a work commitment of C$176.7 million and 50 percent of a second license with a work bonus bid of C$193.6 million. The initial expiry period for both is the end of 2006. ●

continued from page 13

PLACER

would try and go for a second well," he said. That could allow the company to expedite development if results were commercial.

"We could cut a whole year off the cycle time by doing that," he said.

Development of the Kuparuk River unit Palm discovery northeast of Placer, announced in May 2001, took less than 20 months from the time the discovery well was spud to first production, and that discovery also saw two penetrations drilled in the same winter season, in that case a well and a sidetrack. Construction work on the pad at Palm, Kuparuk River unit drill site 3S, began in late January 2002, development drilling began that November, and the field came on line Nov. 14, 2002, with initial production of 29,000 barrels of oil per day.

The tract work approved by the Division of Oil and Gas at Placer No. 2 was "to drill and test the well and commingle the test fluids with the other KPA (Kuparuk participating area) production." The company told the division that the target is the Kuparuk C sand at a vertical depth of 6,060 feet. Drilling was expected to begin "on or about" March 18. The Kuparuk C sand was also the objective of the Placer No. 1 well. ConocoPhillips told the division there was no secondary objective at the well, "although the Jurassic Alpine C interval will be penetrated" at approximately 6,545 feet true vertical depth.

If the Placer No. 2 is tested that would be done in the first or second quarters, "depending on equipment availability," ConocoPhillips told the division. If there were test production, the crude oil would be given to the Kuparuk River unit owners "in lieu of payment for use of the facility." Working interest owners at Placer are: ConocoPhillips Alaska (55.29 percent); Arctic Slope Regional Corp. (35.35 percent); Unocal (8.88 percent); ExxonMobil Alaska Production (0.36 percent); and Chevron (0.11 percent). ●

continued from page 13

COUNT

ing the recent week, 963 were drilling for natural gas and 162 for oil, while three rigs were being used for miscellaneous purposes. Of the total, 739 were drilling vertical wells, 295 directional wells, and 94 horizontal wells.

Among the major producing states in the United States, Wyoming lost three rigs during the recent week for a total of 60 rigs. New Mexico's rig count also fell by three to 65. Louisiana's was down by two rigs to 163. And the number of rigs operating in Alaska was down by one to 10. Texas gained one rig for a total of 489. Oklahoma picked up one rig for a total of 152. California was unchanged at 19 rigs.

—RAY TYSON, Petroleum News Houston correspondent

● NORTH SLOPE, ALASKA

Cairn gas prospect dropped from Kuparuk unit

Alaska Division of Oil and Gas, ConocoPhillips Alaska don't agree on plan to defer formation of participating area

By KRISTEN NELSON

Petroleum News Editor-in-Chief

ConocoPhillips Alaska's Cairn gas prospect has been dropped from the Kuparuk River unit on Alaska's North Slope after the company failed to reach agreement with the Alaska Division of Oil and Gas to extend the leases beyond the required date for inclusion in a participating area. The leases on which gas was found in the Cairn prospect were part of an expansion of the Kuparuk River unit. Six leases were contracted out of the unit, along with a portion of a seventh lease. Parts the seventh lease are in the Tarn participating area, and those portions of the lease remain in the unit.

ConocoPhillips told the division in a June letter that the Kuparuk River unit working interest owners "have discovered and delineated a significant Cairn formation gas resource in the southwest" area of the Kuparuk River unit on seven leases. (See story in June 27 issue of Petroleum News.) The leases are near the southwestern tip of the Kuparuk River unit between the Tarn and Meltwater developments.

Terms of the 1998 expansion agreement adding these leases to the Kuparuk River unit called for "automatic contraction of leases not included within a participating area by July 1, 2003." Participating areas are formed prior to production of an accumulation, but uses of natural gas on the North Slope are limited because there is no way to move the gas to market.

Changes to expansion plan proposed in June

In June ConocoPhillips proposed an extension of the date for formation of a participating area, and said the Kuparuk working interest owners would identify a marketing strategy for the Cairn accumulation gas by July 1, 2005. The company said such a strategy could include use of the gas as fuel or for enhanced oil recovery within the Kuparuk River unit, nominations of the gas for a gas pipeline when a pipeline is available for delivery of gas off the North Slope, or a combination of both.

The schedule proposed by the company included a Cairn gas test by July 1, 2006, and creation of a Cairn participating area by July 1, 2007. Upon formation of the participating area, the company said, development and production would proceed "in compliance with an approved plan of development."

In earlier discussions with the division and with the Alaska Oil and Gas Conservation Commission, ConocoPhillips Alaska predecessor Phillips Alaska described the Cairn interval as thinner than the Bermuda oil interval produced at Meltwater, and said the sandstone reservoirs were discrete from but analogous to the Tarn reservoir some 10 miles to the north. Phillips told the division in 2001 that it penetrated oil in the Cairn interval at the Tarn No. 4 exploratory well, but the permeability was too low for economic development. Phillips shot 3-D seismic over the area south of Tarn, and said the seismic data suggested "that a prospective channel feature in the Cairn interval exists in the Meltwater development area (and) … may have improved reservoir quality" compared to the interval in the Tarn

see **CAIRN** *page 16*

Want to know more?

If you'd like to read more about Cairn, go to Petroleum News' Web site and search for these articles.

Web site: www.PetroleumNews.com

2003
● **July 27** Kuparuk owners find gas formation

2002
● **Oct. 13** As many as five new pads possible for Kuparuk River unit

CANADA

Arctic, oil sands, East Coast offshore dominate Imperial's growth prospects

Imperial Oil underscored the importance of frontier plays such as the oil sands, Arctic and East Coast offshore to the future of Canada's largest producers as it reported further evaporation of its conventional assets in 2003.

In a filing with the U.S. Securities and Exchange Commission, the largest integrated oil company in Canada reported that since 1999 its net oil and natural gas liquids reserves, including bitumen interests at its huge Cold Lake operation, but excluding its oil sands mining assets, have shrunk by 19 percent or 219 million barrels, while its gas holdings are down 40 percent or 669 billion cubic feet.

An internal evaluation showed that proven gas reserves fell 16 percent last year and crude dropped 6 percent, after subtracting production.

When its oil sands mining reserves are factored in, Imperial's net proved reserves entered 2004 at 1.67 billion barrels of oil and liquids and 1.023 trillion cubic feet of gas, a drop of 5.7 percent in 2003.

Waiting in the wings are Imperial's major stake in the Mackenzie Gas Project (3 tcf from its 100 percent control of the Taglu field) and stages 14 to 16 of its Cold Lake operation (375 million barrels), both of which will be booked once the company puts money into the developments.

Imperial's current assets include a gross interest in 6,367 conventional oil and gas wells and 3,524 wells in the Cold Lake heavy oil region.

The Toronto-based company had cash flow in 2003 of C$2.35 billion and spent C$1.53 billion on capital projects, including C$769 million at the Cold Lake and Syncrude operations.

It has budgeted about C$1 billion for its natural resources division in 2004, the bulk tagged for the Syncrude Canada expansion, which has soared over budget.

Other spending includes planning on the Mackenzie project, development drilling at Cold Lake and offshore Nova Scotia gas ventures.

—GARY PARK, Petroleum News Calgary correspondent

● COOK INLET, ALASKA

Unocal plans three pads at Nikolaevsk unit

Red pad first of three planned gas exploration sites; company will also test for oil in deeper horizons

By KRISTEN NELSON

Petroleum News Editor-in-Chief

Unocal is in the permitting stage for the first exploration pad at its "Red Gas Exploration Project" near Ninilchik on the lower Kenai Peninsula in Southcentral Alaska. The Red well is part of the company's 2004 south Kenai gas exploration program and will be the company's first exploration well in the Nikolaevsk unit.

Cook Inlet Region Inc. is the surface owner at the site of the Red pad and the state of Alaska is the subsurface owner, Unocal told the state in early March.

"While this is essentially a gas exploration program," Unocal said, "the Nikolaevsk Unit Agreement requires Unocal to test at potential oil-producing intervals, which may include the Hemlock, West Forelands and Upper Cretaceous formations." The company said the formations lie below the gas target zone at the Red No. 1 well.

Unocal said it has acquired oil and gas leases on the lower Kenai Peninsula from the state of Alaska, Cook Inlet Region Inc. (an Alaska Native corporation) and from a number of private subsurface owners.

The Red pad is the first in an exploration program that "includes up to three new exploration drilling sites for drilling up to four new subsurface targets," Unocal said, with the Red No. 1 the first well planned.

Unocal said other possible wells in its 2004 south Kenai gas exploration program include: the Middle Happy Valley No. 1 and the Happy Valley Saddle No. 1 from the Happy Valley MID pad and the Blue No. 1 from Blue pad. Happy Valley is Unocal's discovery in the Deep Creek unit northwest of the Nikolaevsk unit. Unocal said it may drill these additional delineation, appraisal and/or development wells based on drilling results at Red pad. The Blue pad would be the second pad at the Nikolaevsk unit.

More than one well possible from Red pad

The company also said that it is possible that more than one exploration well might be drilled from Red pad, although only the Red No. 1 is currently planned.

Unocal said it will begin site preparation in March, "with drilling planned to begin in early June 2004, depending upon road restrictions." Drilling is expected to take up to three months.

The Red pad, in section 8, township 4 south, range 13 west, Seward Meridian, is approximately 14 miles southeast of Ninilchik and four miles northeast of the community of Nikolaevsk in an upland logged area, and is accessed by Tall Tree Road, then east along the Ninilchik Native Association 7000 logging road and then by approximately 0.8 miles of new access road on private property. Blue pad would be to the northeast in section 22-T3S-R13W, SM.

Red pad will be approximately 250 feet by 350 feet, two acres, but may be increased to up to 300 feet by 400 feet, 2.8 acres, "depending on results of drilling and well testing," Unocal said.

Following drilling this summer, testing of the well is expected to run from September to November, but Unocal said it could last up to 18 months. If a second well is drilled, that would extend work at the site.

Unocal said it plans subsurface disposal of drilling wastes and is seeking to permit a Class II injection well, the NNA No. 1, on the Kenai Peninsula. In the interim, the company said, there is annular disposal capacity available at the NNA No. 1 site, and the NNA pad has an Alaska Department of Environmental Conservation-approved waste treatment plan for grind and inject.

If commercial reserves are not found, the well will be plugged and abandoned and the site cleaned and reclaimed to the satisfaction of the surface landowner.

A plan of development will be submitted if commercial reserves are discovered and a commercial field is defined.

The Red pad would be in the southwest corner of the Nikolaevsk unit, approved by the state at the end of January, extending lease terms in exchange for a drilling commitment. Two exploration wells and seismic are required over the next three years, with the first well required in the first year of the unit plan, i.e. before the end of January 2005. ●

Want to know more?

If you'd like to read more about the Nikolaevsk unit, go to Petroleum News' Web site and search for the following articles:

Web site: www.PetroleumNews.com

2004
● Feb. 15 Unocal moves forward on Kenai gas exploration

2003
● Dec. 21 Unocal buys out Alliance
● Nov. 9 New independent files for Kenai Peninsula unit

HOUSTON

Transocean to sell deepwater rigs to JCE Group of Sweden for $52.7 million

Offshore drilling contractor Transocean has agreed to sell the semi-submersible rigs Sedco 600 and Sedco 602 to JCE Group AB of Sweden for $52.7 million, Transocean said March 19. Both deepwater rigs, which began active service in 1983, are expected to be converted to multi-service vessels, ending their use as mobile offshore drilling units, Transocean said. The Sedco 600, idle in Singapore since April 2003, is currently being reactivated in preparation for an expected one-well contract. The rig is expected to complete the drilling project during the fourth quarter of 2004, with closing on the transaction expected to follow. The sale of the Sedco 602, idle in Singapore since February 2003, is expected to close during the second quarter of 2004.

Both deepwater rigs, which began active service in 1983, are expected to be converted to multi-service vessels, ending their use as mobile offshore drilling units, Transocean said.

—PETROLEUM NEWS

continued from page 15

CAIRN

No. 4 well.

Cairn was to be tested in Meltwater development wells, the company said, and the gas accumulation reported to the state in 2003 paperwork reflected results of that testing.

Kuparuk unit now discontinuous

The division did not agree with ConocoPhillips' plan for deferring creation of a participating area, but said in July 2003 that it would hold off contracting the leases out of the unit while it worked with the company on a proposal, and deferred the contraction until September, and then again until Jan. 29 this year.

The division said in a March letter that the latest extension had expired and that ConocoPhillips had not requested a further extension, so leases ADL 375073, 375077, 375078, 375079, 375080 and 373111 were contracted effective Jan. 30.

These leases are between the Tarn and Meltwater oil developments in the Kuparuk River unit, so the unit is now discontinuous, with a gap between Tarn and Meltwater at the southwestern corner of the unit. ●

natural gas

JUNEAU, ALASKA

Murkowski administration to brief legislators on gas line talks, prepare for contracts

The administration says it will provide updates to lawmakers as contract talks proceed under Alaska's Stranded Gas Development Act.

At the administration's request, legislative leaders have appointed four lawmakers to serve as "points of contact" for briefing House and Senate members as negotiations proceed for a state fiscal contract covering a possible North Slope natural gas pipeline, said Steve Porter, deputy commissioner at the Department of Revenue.

House Speaker Pete Kott and Senate President Gene Therriault each named two members from their respective chambers: Reps. Bruce Weyhrauch, R-Juneau, and Reggie Joule, D-Kotzebue; and Sens. Ben Stevens, R-Anchorage, and Gretchen Guess, D-Anchorage.

Therriault, R-North Pole, will share the job with Stevens when Stevens is not available, said Porter, who serves as the administration's spokesman on Stranded Gas Act issues.

Negotiations under the act are confidential, as are generally all documents related to the contract talks until the two sides are ready to release a draft contract setting up a system of payments in lieu of state and municipal taxes on the proposed project. The law requires that a draft contract go out for at least 30 days of public comment before the administration can submit it to the Legislature for approval.

Briefings intended to help prepare lawmakers

Setting up a team of legislators early in the process will allow the administration to brief lawmakers on issues under discussion in the contract talks, with the House and Senate teams able to share the information with their colleagues, Porter said. The intent is to help prepare legislators on the issues in advance of their formal consideration of the contract, he said.

The first round of briefings for all four legislators likely will be completed by March 26, Porter said.

Gov. Frank Murkowski told lawmakers in January he hoped to have a draft contract for their consideration before the end of the legislative session in May, but the House speaker said this month sometime before the end of the year is more likely. Kott said lawmakers could return in a special session if either of the two applicants reaches a contract during the summer or fall.

Negotiations have been under way since late January with the two Stranded Gas Development Act applicants: the three major North Slope producers, and MidAmerican Energy Holdings Co. And although MidAmerican had said it wanted to complete its draft contract by mid-March, the company missed its self-announced target date and state negotiations continue with the Des Moines, Iowa-based pipeline and power company.

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

● F A I R B A N K S , A L A S K A

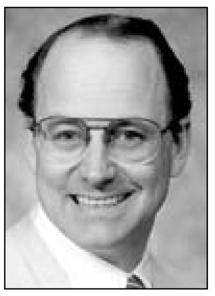
Borough wants proof gas line needs tax relief

Fairbanks Borough mayor says he will work against a state contract with a developer that contains property tax deferrals

By LARRY PERSILY

Petroleum News Government Affairs Editor

The Fairbanks North Star Borough is not interested in accepting a deferral of any property tax revenues from a proposed Alaska natural gas pipeline unless it is convinced such action is needed to make the project economically viable.



"It is clear that the intention is that there be a rationale in the reduction of a tax regime. It is unacceptable not to show proof." — Fairbanks North Star Borough Mayor Jim Whitaker

Unless he sees such proof, Borough Mayor Jim Whitaker says he will work against any state contract with a private developer for payments in lieu of taxes that would deprive his community of its full property tax receipts from a gas line.

The borough has a seat on the municipal advisory group advising the state on its negotiations for a long-term fiscal contract covering the proposed North Slope natural gas line. Proponents of a contract for payments in lieu of all state and municipal taxes say it could bring a stronger measure of fiscal certainty to the $20 billion privately built project to pipe gas across Alaska, through Canada and into Lower 48 markets.

"Certainty does not mean decrease," Whitaker said.

"It is clear that the intention is that there be a rationale in the reduction of a tax regime," he said. "It is unacceptable not to show proof."

No argument there, said Steve Porter, deputy commissioner at the Department of Revenue and liaison to the municipal advisory group. "In any negotiations we should

see **PROOF** *page 18*

● W E S T E R N U N I T E D S T A T E S

As gas prices rise, utilities plan new coal-fired plants

Environmental groups concerned air pollution could increase

BY DAN D'AMBROSIO

The Associated Press

Spurred on by stubbornly expensive natural gas prices, Western utility companies are contemplating new coal-fired electric power plants for the first time in more than a decade, a move that could worsen already deteriorating air quality across the region.

Utility regulators in at least six Western states are in the process of considering new plants or additions to existing ones.

The push, prompted by industry concern over the volatility in natural gas prices, comes as the Environmental Protection Agency is debuting a regional air pollution plan intended to clear haze lingering over wilderness areas.

While utility companies say the shift from natural gas to coal-fired plants will help them fill an increased demand at a cheaper price, environmentalists find the trend disturbing.

"We haven't seen a coal plant built in Colorado in two decades and there's a reason for that," said Robin Hubbard of Environment Colorado. "Denver just had the dirtiest summer we've had in 18 years. We clearly need to look at other means of power generation."

Utilities turned to natural gas for new power in the 1990s because the plants — essentially a jet turbine

see **PLANTS** *page 18*

continued from page 17

PROOF

understand the fiscal impacts."

Whitaker sent a letter March 12 to state Revenue Commissioner Bill Corbus, whose department is the lead agency in the contract negotiations. "The intent of the Stranded Gas Development Act is to require full understanding of the economics of a North Slope natural gas pipeline project in order to provide conclusive evidence as to the necessity of a revised tax regime on the part of the state and affected municipalities," Whitaker said in his letter.

Borough to protect its legal rights

"The Fairbanks North Star Borough's mandate is clear: to protect and advance the best interests of its citizens," the letter said. "Please be advised that the … (borough) can only support a contract that follows the spirit, intent and letter (of the law) … and will oppose through all legal means necessary a contract that fails in this regard."

Whitaker said his push to ensure that the state follow the law in its contract talks for a privately built gas line is separate from the borough's effort through the Alaska Gasline Port Authority for a municipally owned project.

While he wants the state to remember the borough's legal rights, he also intends to continue advocating that the port authority's proposed natural gas project would be in the best interests of the state and municipalities.

Negotiations have been under way for almost two months with two contract applicants under Alaska's Stranded Gas Development Act: MidAmerican Energy Holdings Co., a pipeline and power company from Des Moines, Iowa; and a joint venture of the three major North Slope producers.

The borough likely would see the greatest effects during project construction when thousands of workers will be on the job, pushing up municipal expenses for a wide range of services, Whitaker said. He is worried that any effort to defer property tax payments until a gas line is up and running and generating cash flow could hit the borough when it most needs the money.

"It is counter-logical" to reduce borough tax revenues during the period of its greatest expenses, he said.

State aware of construction impact concerns

The state is aware of the problem, Porter said. "It is our intent to protect the municipalities from the construction impact." How to do that will depend in part on a socioeconomic impact study under way for the Stranded Gas Act negotiations.

For example, Porter said, a municipality with a 20 mill annual property tax rate would receive $40 million if $2 billion worth of gas line property were within its boundaries. But if the socioeconomic study showed the community would incur $20 million worth of construction-related costs during the year, such as police and fire and road services, perhaps the Stranded Gas Act contract could ensure that the municipality receives the $20 million it needs that first year with the remainder deferred until the gas line starts producing income for its owners.

Whatever comes out of the negotiations, there will be no tax holiday, he said. "It could be a deferral or a changing in timing."

Whitaker, however, is worried his community could come up short. As a legislator, he helped block passage in 2002 of a project-incentive measure that would have cost municipalities millions of dollars in property tax revenues during construction of a gas line. He left the House last fall, after winning the borough mayor's job.

State law sets out contract requirements

The Stranded Gas Act is specific in its instructions to the Department of Revenue regarding terms for a contract in lieu of taxes:

• The terms should improve the competitiveness of the project.

• The state and municipal share of the economic rent of the project should be progressive, with a higher share for government as the project gains in profitability and a lower share for government when profits are down.

• The state and municipal share of the economic rent should be lower in the earlier years than in the later years.

• Payments to municipalities should be based on any anticipated economic and social expenses that would be imposed on municipalities during construction and operation of the line.

Under existing property tax laws — and unless a different structure is adopted under a Stranded Gas Act contract — municipalities along a gas line route would see their tax revenues fall as the pipeline gets older, just as has happened for the trans-Alaska oil pipeline. Because the property tax assessment would take into account depreciation on a gas line, its value — and tax payments — would decrease over the life of the project.

Municipal property tax revenues also generally would be immune to the value of the gas through the pipeline, shielding the communities from periods of low prices but giving them no benefit during times of high prices — unless this too were addressed in a Stranded Gas Act contract.●

continued from page 17

PLANTS

powering a generator — are cheaper to build and cleaner to operate.

But then came the run-up in fuel costs, which piled onto the higher capital costs.

Fuel costs for gas-fired plants are as high as 4 cents per kilowatt hour, while coal plants come in at about 1 cent, said Robert McIlvaine of McIlvaine Co., an energy consulting firm based in Northfield, Ill.

Breaking point at about $3 per million Btu

"The breaking point is somewhere around $3 per million Btus of natural gas," McIlvaine said. "Below $3, gas-fired generation is more attractive than coal."

A Btu, or British thermal unit, is roughly equivalent to the amount of heat generated by burning a kitchen match, according to Xcel Energy spokesman Steve Roalstad.

At the current price of $6 to $7 per million Btu, natural gas is not even close to competitive with coal. Some gas-fired plants around the nation are being shuttered because the cost to run them equals the sales price for the electricity generated, McIlvaine said.

Nationwide, as many as 90 new coal-fired plants are being considered with a combined capacity of 50,000 megawatts, McIlvaine said. That equals about 7 percent of the total power generation available in the United States and carries a price tag of about $75 billion.

One megawatt supplies the amount of electricity used by 400 to 900 homes in one year.

In Colorado, Xcel Energy is planning to build a 750-megawatt coal-fired plant near Pueblo, Colo., for $1.3 billion, while a comparable gas-fired plant would cost about $533 million.

Xcel had seen a 13 percent increase in per capita demand for electricity in the last decade, thanks to a proliferation of household appliances from big screen televisions to cell phone chargers, Roalstad said.

Over the next 10 years, the United States will need about 140,000 megawatts of increased power, with about one-half or more to come from coal plants, McIlvaine said.

Less than half of planned plants usually built

Jim Owen of Edison Electric Group, an industry trade organization, said it is too soon to tell just how big the coal-fired boom will be, given that less than half of planned plants are usually built.

The downside for coal-fired plants is that they are a major source of carbon dioxide emissions, the leading cause of global warming. Coal plants also emit sulfur dioxide, which creates acid rain; nitrogen oxide, which turns to ozone creating smog; and mercury, a neurotoxin especially dangerous to children.

Neither carbon dioxide nor mercury are currently regulated for coal-fired plants by the EPA, but proposed mercury rules are expected by the end of the year.

The technology for dealing with both types of emissions is just emerging. "I have not heard of any really viable carbon control technologies," Roalstad said.

EPA debuts regional air pollution plan

As the plants are being built, the EPA is debuting a regional air pollution plan intended to improve visibility in 16 national parks and wilderness areas, including the Grand Canyon National Park in Arizona.

The Western Regional Air Partnership hopes to reduce sulfur dioxide emissions from coal-fired plants by 50 percent to 70 percent by 2040.

Environmentalists believe the EPA's actions are another reason utilities are turning to coal plants now. "The theory is the industry sees carbon and mercury regulations coming and they have to get in their last push to get permits, because once those kick in, coal-fired electricity could cost more than wind," said Matt Lewis of Resource Media in San Francisco.

Xcel's new plant in Pueblo will meet all current emission requirements, as will any other plants the company builds in the future, Roalstad said. "Legislators and regulators can certainly draft legislation to accomplish what they want to accomplish," Roalstad said. "We will comply with all regulatory requirements. We have no choice."

Base load demand growing

Utilities are also gravitating toward coal because of base demand, which is the average amount of power a utility needs to produce for its customers. Coal has been the fuel of choice for base demand because it's cheap compared to other fuels, and because once turned on, coal-fired power plants run 24 hours a day, seven days a week.

Peak demand is the amount of power a utility needs to have at its command when customers are cranking their thermostats to fend off extreme weather.

Roalstad said the last Xcel study, produced in 1999, called for an additional 2,000 megawatts of power to serve greater peaking loads, but not a greater base load.

Today, it's a different story. Xcel now believes they do need a greater base load capacity because of more customers in Colorado.

Brunetti said recently that Xcel's customer base has increased by 20 percent in the last decade, while peak load has gone up by 60 percent.

Coal-fired power plants are in the works in Arizona, Colorado, Montana, New Mexico, Utah and Wyoming. The biggest plant being contemplated is a 1,500-megawatt station on Navajo land in the Four Corners region.

McIlvaine said coal accounts for more than 50 percent of the nation's electrical power and natural gas appears to be on the wane as a fuel source.

"Natural gas production is going to decline, there's no question about that," McIlvaine said. "There's a 300-year supply of coal." ●

● JUNEAU, ALASKA

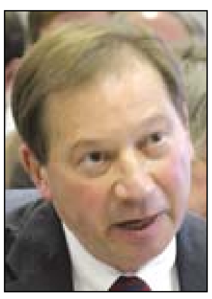
Alaska moves ahead on natural gas issues

Funding closer for state project, private development negotiations

By LARRY PERSILY
Petroleum News Government Affairs Editor

With less than seven weeks left in the session, Alaska lawmakers are moving toward funding — and expanding — the state's efforts to get a natural gas pipeline built.

The Senate Finance Committee has approved a bill adding to the job of the Alaska Natural Gas Development Authority to include consideration of a state-owned gas line to Canada in addition to its original task of preparing a project plan for a line to Valdez and construction of a liquefied natural gas shipping terminal at that port city.



Not all of the work needs to be done this spring, said Harold Heinze, chief executive officer of the gas authority, adding that the board looks forward to receiving additional state funding for the fiscal year that starts July 1.

The bill's sponsor, Sen. Scott Ogan, R-Palmer, said he favors expanding the state gas authority's list of options because he does not believe a stand-alone LNG project is economically competitive against the strong supply of cheaper gas around the Pacific Rim. The only hope for an Alaska LNG project, the Palmer Republican said, would be as a cost-sharing branch of a larger gas line through Canada to Lower 48 markets.

"It is important that we expand (the gas authority's job) … to allow them to look at building a line all the way to the border," Sen. Scott Ogan told Senate Finance, which passed his measure, Senate Bill 271, on March 23.

"It is important that we expand (the gas authority's job) … to allow them to look at building a line all the way to the border," Ogan told Senate Finance, which passed his measure, Senate Bill 271, on March 23. The bill will go next to the full Senate for a vote, then to the House.

Bill would give authority more time

In addition to expanding the work assignment, the bill extends the due date for the gas authority's project development plan from this summer to January 2005.

Meanwhile, later in the same day, the House Finance Committee agreed to a Senate-approved plan to appropriate $1 million for sharing between the state gas authority and the administration's negotiations with two private ventures and possibly a municipal partnership that want to build a North Slope gas line to feed North American markets.

The full Senate approved the appropriation a week earlier, as Senate Bill 241, with action by the full House expected quickly. The money could be available by early April.

The administration has not said exactly how it would spend the $1 million or how much it would give to the state gas authority, which started the session in January with a request for $2.15 million for its own work. But the authority's board supports the shared appropriation as the best way to get immediate funding for the consultants it wants to hire this spring.

"We would love to have the additional funds, but I seriously doubt it would get out of the Senate," gas authority board member Bob Favretto of Kenai told the House Finance Committee on March 23.

More money possible later in session

The Senate Finance Committee on March 17 deleted the $2.15 million gas authority appropriation and replaced it with the $1 million shared appropriation to cover expenses this spring and early summer — with a statement that both the authority and the administration could request additional funding in next year's budget being drafted by lawmakers.

"I'm disappointed that they are willing to settle," House Finance member Rep. Eric Croft, D-Anchorage, said of the gas authority's support for the lower, combined appropriation.

Croft tried unsuccessfully in committee to amend the measure to boost the total to $3 million, shared 50-50 between the gas authority and the administration, or even $1 million but with explicit language that the money must be split in half between the two needs.

In material handed out to the House Finance Committee, the gas authority said it needs funding for consultant contracts covering possible business structures and tax consequences for a state-owned gas line, estimates for building a spur line to serve Southcentral Alaska, construction estimates for building LNG tankers and a shipping terminal at Valdez, and market prices and forecasts for LNG sales around the Pacific Rim.

Authority looks forward to additional funding

Not all of the work needs to be done this spring, said Harold Heinze, chief executive officer of the gas authority, adding that the board looks forward to receiving additional state funding for the fiscal year that starts July 1.

The Department of Revenue told House Finance it needs money for its own consultants to study the possibilities for a petrochemical industry in Alaska, in-state uses and benefits from North Slope natural gas, social and economic effects on the state of a

see ISSUES page 20

WYOMING

Cheyenne Plains pipeline project approved

Two Houston, Texas, firms got approval from the federal government in March to build and expand natural gas pipelines in the western United States.

The Federal Energy Regulatory Commission speeded approval of El Paso Corp.'s $425 million, 380-mile, pipeline that will boost the amount of Wyoming natural gas heading to eastern markets. Kinder Morgan Inc. got approval for a $28.6 million expansion of its TransColorado pipeline that runs from Rio Blanco County, Colo., to New Mexico's San Juan County.

El Paso's Cheyenne Plains Gas Pipeline is expected to increase Wyoming's total export capacity by 560 million cubic feet per day. The 36-inch diameter pipeline will run from the Cheyenne, Wyo., hub to Greensburg, Kan., and could be in service by January next year.

Portions of the pipeline will follow existing pipeline routes while others will be "green field" routes, crossing lands previously without pipeline systems.

FERC considered the Cheyenne Plains project a priority because of its benefit to the nation's natural gas transmission system, FERC spokeswoman Tamara Young Allen said.

Some 14 shippers, a combination of producers, marketers and end-user distribution companies, have signed firm contracts for capacity totaling 560 million cubic feet per day. El Paso said the company secured additional 10-year contracts to support expanding the pipeline to 730 million cubic feet per day.

The significant interest among potential gas shippers prompted the expansion. Construction of facilities to add pipeline capacity will begin shortly after initial construction, El Paso said.

Work could begin as early as June.

Proven gas reserves in the Rockies have increased 6.5 percent annually from 1990 to 2001, but new pipeline construction has lagged behind the drill bit.

Kinder Morgan's expansion plans include adding new compressor stations in Montrose, Montezuma and Mesa counties and a unit in Dolores County designed to boost the 292 mile TransColorado pipeline's capacity from 300 million cubic feet of gas per day to 425 million cubic feet of gas per day.

—THE ASSOCIATED PRESS CONTRIBUTED TO THIS REPORT

WASHINGTON, D.C.

Federal regulators say they, not states, have say over approving gas terminals

Regulators on March 24 rejected arguments by California that states and the federal government have authority over approving liquefied natural gas facilities. The Federal Energy Regulatory Commission said the federal government has sole jurisdiction over siting and construction of the terminals. The California Public Utilities Commission had argued that companies seeking to build an LNG terminal at the Port of Long Beach must submit an application to the state as well as to the federal agency.

FERC Chairman Pat Wood

The issue of jurisdiction over LNG terminals — including siting decisions and environmental impact reviews — is expected to grow in importance in the coming years. There are nearly 30 proposals for LNG facilities in various stages of development.

FERC Chairman Pat Wood emphasized that the agency would work with state and local officials in considering such proposals. He also urged companies seeking approval for such facilities to do their "local homework first" before submitting an application to FERC, said an agency spokeswoman.

—THE ASSOCIATED PRESS

MIDLAND, TEXAS

Texas Energy Planning Council to meet

Members of a state panel studying Texas' future energy needs want to review research of the National Petroleum Council.

The newly formed Texas Energy Planning Council's second meeting was scheduled March 22 in Midland.

Jerry Langdon, a National Petroleum Council subcommittee member, was scheduled to make a presentation to the energy council on a study the council completed in September.

Langdon, who is also an energy council member, said he will help council members review the study on natural gases. The United States, according to the study, has plateaued on natural gas production and more importation from foreign countries could be expected.

"I will walk through the process and offer the data as something that doesn't need to be re-created by the energy council," Langdon told the Odessa American.

He said information from the NPC study can be isolated to reflect Texas' demand for natural gas.

Langdon, of Houston, is an executive vice president for Reliant Energy. Victor Carrillo, chairman of the Texas Railroad Commission and an energy council member, said this will be the first time the council has met outside of Austin.

"The Permian Basin obviously is one of the key oil-producing areas," Carrillo said. "There are a lot of producers out there that can provide input."

In its inaugural meeting in Austin in February, the 22-member council discussed creating an energy plan that helps meet the immediate needs of the oil and gas industry while setting the groundwork for a mixed energy supply that incorporates new and renewable energy sources.

—THE ASSOCIATED PRESS

ALBERTA

Energy big hope to eliminate Alberta's debt

With a helping hand from oil and natural gas prices, Alberta could wipe out the last of its remaining C$3.7 billion debt by next spring, in time to celebrate its centennial as a province of Canada.

Finance Minister Pat Nelson, in releasing the 2004-05 budget March 24, targeted a C$1 billion payment against the debt, based partly on predictions by analysts of a drop in oil and gas prices this year.

"If, and I say if, resource revenues are considerably higher than our forecast," Nelson said she and Premier Ralph Klein want to hand Albertans "the gift of a debt-free province."

Since Klein's election as premier in 1993 the debt has been shrunk from C$23 billion.

Typically, the government is low-balling its commodity price forecasts, predicting West Texas Intermediate oil will average US$26 a barrel for the fiscal year, down from its 2003-04 forecast of US$30.75. It is budgeting for AECO spot gas prices of C$4.20 per thousand cubic feet, a sharp decline from last year's C$5.64.

On that basis, resource revenues are forecast at C$4.784 billion for the upcoming year, compared with C$7.446 billion last year, contributing 20.8 percent of Alberta's predicted revenues of C$22.952 billion.

"I know that many people looking at today's budget will say the forecasts are too low," Nelson told the legislature.

"How could we expect oil and gas prices and our resource revenues to drop when things are looking so good?" she said.

But Nelson said "most industry observers expect energy prices to go down. The question is when and by how much."

She told reporters that she hopes her estimates are "soft."

The Canadian Energy Research Institute has targeted oil prices of US$31 a barrel for 2004 and nine national forecasters have averaged US$28.27.

Each increase of 10 cents in the price of gas adds C$100 million to Alberta's coffers over a full year, while a $1 jump in oil prices adds C$65 million.

—GARY PARK, Petroleum News Calgary correspondent

continued from page 19

ISSUES

pipeline construction boom, and a risk analysis of a gas line project.

The administration is in negotiations with two applicants under Alaska's Stranded Gas Development Act for a long-term fiscal contract in lieu of all state and municipal taxes on a gas line project. Although the law allows the state to charge the applicants for the cost of consultants hired to assist the state in the negotiations, not all of the expenses can be charged to the companies, said Deputy Revenue Commissioner Steve Power.

Another financial issue is that one applicant — the three major North Slope producers — has agreed to reimburse the state for much of its expenses, while the other private applicant — Iowa-based pipeline operator MidAmerican Energy Holdings Co. — has so far declined to sign a similar reimbursement agreement.

Senator prefers private ownership

Private construction and operation of a gas line is preferable to a state-owned project, Ogan told the Senate Finance Committee. "I don't think that's an appropriate role for government," he said, adding, however, that state ownership is an option if that's what it takes to get a project built.

The state also is considering a project application from the Alaska Gasline Port Authority, a partnership of the Fairbanks North Star Borough and city of Valdez. The two municipalities want to build and own the gas line, sharing the profits with the state and other municipalities.●

● FAIRBANKS, ALASKA

Time is right for gas line, professor says

Analysis by UAF's Doug Reynolds suggests pipeline would be profitable now; North Slope producers group says still not viable

By PATRICIA JONES

Petroleum News Contributing Writer

Analysis by University of Alaska Fairbanks economics professor Doug Reynolds supports construction of a natural gas pipeline from Alaska's North Slope to existing pipe infrastructure in Alberta, feeding into the Midwest and eastern portions of the United States.

Supplies from the Atlantic Basin — Norway, Russia and Trinidad and Tobago — are tightening up, and prices for gas are increasing. Demand for natural gas in the Midwest and in the eastern United States is also increasing quickly, at a rate of 2 percent a year, Reynolds said in a speech "This is going to happen. It would be a shame if it doesn't," he said. "The economics are there … there's the potential of prices being high for quite a few years, even with LNG competition in the Pacific Rim."

He compares recent spikes in natural gas prices and the current 66-year supply of gas reserves in the Atlantic Basin with the 1970s oil crisis in the United States.

Back then, crude producers reported a 37-year reserve in oil resources, Reynolds said. A reduction in production and an increase in prices helped create a crisis that resulted, in part, in the construction of the trans-Alaska oil pipeline.

"It's harder to develop natural gas and get it to market, so (the 66-year Atlantic Basin reserve) is on par with the 37-year (oil) reserve," he said.

The state's royalty benefits would be greater with a gas pipeline project selling to users in the Lower 48, compared to a liquefied natural gas project selling to Pacific Rim buyers, Reynolds said, because wellhead values for gas piped to the Lower 48 would be about $2 per thousand cubic foot, compared to about $1.30 for a LNG project selling to the Pacific Rim.

Reynolds also expects the North Slope producers to build the gas pipeline, in order to control tariff rates, allowing them to shift profits from gas production to the transportation system.

"They will want the pipeline first so they make sure they keep as much profit as they can there," Reynolds said. "High tariffs mean much lower wellhead profits, so the profit is in the tariff, not the wellhead. That's the game they'll be playing."

Producers' presentation

But according to a presentation the same day made by Frank Roach of ConocoPhillips, the producers group still views the gas pipeline project as economically unfeasible.

"We did a feasibility study starting January 2002 with every intention to move a project forward and develop a commercially viable project designed to go to the permitting phase," he said. "When it all came together, we communicated that the risks are just too much for the rewards."

Part of the problem includes significant infrastructure, such as the state-owned railroad, ports and highways that need to be upgraded, Roach said, to avoid bottlenecks of materials. For example, he said, the producers group has identified 50 to 60 bridges that need upgrades.

Transportation infrastructure is key to such a large construction project, which will involve moving significant amounts of pipe, construction materials and equipment.

An estimated 35,000 to 50,000 truckloads of construction materials will need to be moved to sites for use, Roach said.

Additionally, pipe must be shipped to various construction sites, through ports in Alaska and through Canada. For example, construction will require 10,400 rail cars carrying pipe to Fairbanks and 20,500 to 30,750 truckloads through the Yukon Territory, he said.

Roach said estimates of equipment needed for construction of the pipeline include: 134 loaders; 275 automatic welders; 18 trenchers; 250 backhoes; 1,300 pickup trucks; and 230 buses.

Open access stressed

At the beginning of Roach's speech, he stressed that the producers' pipeline application would allow open access to the gas transportation system. An open season would be required prior to final design, to allow for accommodation in the pipe's carrying capacity.

North Slope gas could be made available for in-state usage, "if it is technically economic and feasible," he added.

The group has estimated several more years of work remain before the three-year construction project could begin. Another year of field environmental work remains, Roach said.

The group estimates a two-year permitting process and figures on spending $1 billion during that phase of the project, Roach said. That spending would also include technical work going on at the same time as permitting, he later clarified.

The group would also need about a year for site preparation and setting up marshaling yards, Roach said, prior to construction startup.●

Want to know more?

If you'd like to read more about Alaska North Slope gas pipeline economics, go to Petroleum News' Web site and search for some of the articles on this subject published in the newspaper in the last two months.

Web site: www.PetroleumNews.com

2004
- **March 14** BP Canada exec says Alaska gas line filing unlikely before 2007
- **March 14** Special report: Gas project proponents square off
- **Feb. 29** Alaska on the brink
- **Feb. 8** Murkowski eyes state share of gas line, briefs lawmakers
- **Feb. 1** Natural gas pipeline plans not the same

Companies involved in North America's oil and gas industry

ADVERTISER PAGE AD APPEARS

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

Petroleum news

Business Spotlight

By PAULA EASLEY

FORREST CRANE

Mark Nelson, executive vice president

ASRC Energy Services, operations and maintenance

Formerly Alaska Petroleum Contractors, this Anchorage-based company provides construction, fabrication, maintenance and operations services to the oil and gas industry, with 1,400 people in Alaska and 120 Russians supporting operations on Sakhalin Island.

Mark Nelson joined the original company in 1983, moving up within the ranks to executive vice president. Mark, who is working toward a masters degree in project management, has enjoyed extensive travel and finds nothing more exciting, educational or humbling than learning about other cultures. Blessed with an active family, he chaired a United Way committee this year and is on Covenant House's board. The Nelson children, Christian, 5, and Audrey, 3, are active in Tae Kwon Do, and Mark and wife April enjoy outdoor activities with them. How does he do it? He never sleeps.

FORREST CRANE

Kathy O'Connor, administrative and accounting manager

H. C. Price Co.

The Alaska division of H. C. Price opened in 1974. The company is best known for constructing Section 3 of the trans-Alaska oil pipeline, and has long specialized in Arctic construction and logistically difficult projects. The Alaska division, based in Anchorage, also provides general contracting and management services to public and private clients building utilities and infrastructure projects.

Kathy O'Connor, administrative and accounting manager, has some 30 years experience in construction accounting and administrative management. She rejoined the H. C. Price team in 2001, having worked for them in the early 1980s. Favorite aspects of her job are working with field staff and seeing the finished projects. Off duty, Kathy enjoys golfing, and spending time with son Bryan, his wife Carrie, and grandsons Colby and Takker.

continued from page 1

FREE

The Canadian government's experiment in running a state-owned oil company is fast winding down.

Government will sell remaining stake

Within the next year, its remaining 18.74 percent stake in the company will be sold off.

That's the final step needed to privatize Petro-Canada and remove any cloud of government meddling in the industry.

At current market values, the government's 49.4 million shares are worth about C$2.8 billion, although the net proceeds are expected to be close to C$2 billion, after deducting the book value of about C$600 million.

"Obviously, we've come to the conclusion that the appropriate time has been reached to divest ourselves of this asset," Finance Minister Ralph Goodale said March 23 when unveiling the 2004-05 budget.

In fact, his hand had been forced earlier in the day when a wave of speculation ahead of the budget triggered an announcement before the North American stock markets opened.

Exactly how and when the shares will be unloaded has yet to be determined.

But years of speculation have finally been put to rest. The sell-off started in 1991 with an initial public offering of 20 percent of Petro-Canada and continued in 1992 and 1995 when two further chunks went on the block. Those three transactions totaled C$2.59 billion, likely less than the last 19 percent will return.

Goodale has indicated that half of the proceeds will go to pay down the federal debt and half to environmental initiatives, including the development of technologies for clean coal, carbon dioxide sequestration and renewable energy as part of Canada's program to reduce greenhouse gas emissions.

Who'll buy?

Now attention shifts to the likely buyers.

Petro-Canada Chief Financial Officer Harry Roberts said in a statement that the company's interest in repurchasing shares "will be decided at the time of the sale, based on an evaluation of market conditions and competing priorities.

"We will work with the government to ensure an effective placement of the shares in the market," he said.

Otherwise the change will have no affect on Petro-Canada's "business strategies or daily operations," Roberts said.

Randy Ollenberger, an analyst with BMO Nesbitt Burns, said in a research note that given the strength of Petro-Canada's balance sheet — with C$588 million of cash available at the end of 2003 — it could purchase the entire block, but is unlikely to do so. Petro-Canada even indicated at a recent investor day that it could handle an acquisition of C$4 billion to C$5 billion.

Martin Molyneaux, an analyst with FirstEnergy Capital, does not expect the sale to a single entity, telling the Canadian Press that "politically, that would not be as palatable."

Restrictions limit ownership of company

There was no indication from Goodale whether the government will lift current federal restrictions that prevent any single investor or related group of investors from owning more than 20 percent of the company. A change might open the door to a larger chunk of foreign ownership at a time when Petro-Canada and Suncor Energy are still in the control of Canadian shareholders, while Canada's other three integrated oil companies are dominated by outside interests — Imperial Oil is 69.6 percent owned by ExxonMobil; Shell Canada is 78 percent owned by Royal Dutch Shell; and Husky Energy is 72 percent owned by Hong Kong billionaire Li Ka-shing and members of his family.

Despite a setback earlier this year when Petro-Canada trimmed 5 percent off its year-end 2003 proven reserves to 1.22 billion barrels of oil equivalent and lowered its 2004 production outlook by 3 percent to 450,000 barrels of oil equivalent per day, the company is strongly positioned in all of Canada's long-term plays (Alberta oil sands, Arctic and East Coast offshore) and has a valuable international portfolio since its 2002 purchase of Germany's Veba Oil & Gas for C$3.2 billion. ●

continued from page 1

OUT

not negotiate with any other potential developer.

"We believed our request to be the state's sole development partner for the initial project development period was reasonable, given the magnitude of the risk involved," said Robert Sluder, president of the MidAmerican subsidiary established for the Alaska project.

Company: Exclusive rights essential

The company needed the five-year exclusive rights to allow three years for permitting, financing and marketing, and two years to order steel pipe and compressors and start construction, said Susan Flaim, spokeswoman for MidAmerican. It needed the assurances of exclusive rights before risking the investment on a multibillion-dollar project, she said.

But it was too much for the state to accept, said Mike Menge, Gov. Frank Murkowski's special assistant on oil and gas issues.

"He didn't think it was fair at this time to cut everyone else off at the knees," Menge said the morning of March 25, just as MidAmerican was distributing its press release.

The state did tell MidAmerican it would grant the company exclusive rights to state processing of right-of-way permits for the pipeline. "That wasn't good enough," Menge said.

Winning fully exclusive development rights was crucial to the company's plans for a pipeline from Alaska's North Slope to Canada, Sokol said in a March 1 letter to Murkowski. "We will agree to utilize reasonable best efforts to move all of the … project elements forward … in exchange for the exclusive right to own, build and operate the project," Sokol said.

State continues talks with producers

While losing MidAmerican as a potential project developer, the state is continuing to negotiate with the three major North Slope producers for a gas line contract. The companies — BP Exploration (Alaska), ExxonMobil and ConocoPhillips — applied about the same time as MidAmerican under Alaska's Stranded Gas Development Act to negotiate a long-term fiscal contract for payments in lieu of state and municipal taxes on the project.

The state hopes it can reach a draft contract with the producers by the end of the year, Menge said.

"Certainly we're disappointed," he said of MidAmerican's decision, especially after the optimism of January's press conference in Fairbanks. "There was a high degree of enthusiasm, this was a fresh face in town."

Though owner of thousands of miles of gas pipe in the Lower 48, MidAmerican is new to Alaska, and the governor, legislators, labor unions and municipal officials had welcomed the company's interest in building the gas line that Alaskans have been waiting for since the 1970s.

"Gas line development is a very emotional issue," Menge said. "Everyone will put their own spin on this."

The state's negotiations with MidAmerican have been strained for the past several weeks, according to material released by both sides.

In his March 1 letter to the governor, Sokol complained about some of the state's proposed contract terms. He called the negotiations "misfocused," and touted his company as a much better choice to build the line than the producers. He said the producers, as owners of the gas, have an inherent conflict of interest in also owning the pipeline.

It appears the governor at least agrees with the company on that point. "We also believe that it is in the best interest of the state for the pipeline to be owned and operated by an unaffiliated pipeline company, assuming that such a company is able to provide the lowest possible tariff," Murkowski said in a March 25 letter to Sokol.

In a mid-March letter to the governor, Sokol asked if Alaska had a "change of heart" regarding what the company had understood was a commitment to exclusive development rights.

The governor replied he had made no such deal.

"We made no commitment to enter into a contract under the Alaska Stranded Gas Development Act to provide you with an exclusive right to build, own and operate the Alaska portion of the pipeline," Murkowski said in a March 16 letter to Sokol. "I know this to be the case because the act does not authorize the state to convey such a right. In fact, I know of no authority that would allow the state to convey such a blanket exclusive right."

State OK with limited exclusive rights

However, in the March 25 letter to Sokol, the governor acknowledges offering at least a piece of an exclusive deal to MidAmerican.

"We had hoped that our proposal to grant you sole rights to a state pipeline right of way for five years in connection with the commitment of the state to support, and take no action to inhibit, your eventual construction, ownership and operation of the Alaska portion of the gas pipeline would provide you with the security you needed to proceed with development efforts," the governor said.

The state's discussions with MidAmerican started back in November, two months before the company submitted its actual Stranded Gas Act application. MidAmerican proposed in November to spend $100 million on gas pipeline development costs over three years if the state would agree to reimburse the company for half the amount if the project did not go forward. Exclusive development rights to the project were part of the company's proposal.

The governor's office rejected the reimbursement agreement in December, while encouraging the company to proceed with formal fiscal contract talks.

Murkowski and MidAmerican officials met most of March 22 in Anchorage, discussing the project and contract problems, before exchanging press releases three days later. ●

continued from page 1

QUALITY

of investor relations, said in an interim first-quarter conference call that the company "encountered high-quality hydrocarbons from the initial Nikaitchuq well.

"We are currently testing this well, which is expected to finish this week," he said.

Buterbaugh said the company was "encouraged by these results, which confirm hydrocarbons nearly five miles to the northwest of a well that encountered pay from the same intervals on this prospect."

The company is currently drilling the Nikaitchuq No. 2, he said, with an expected bottom hole some 9,000 feet from the initial well.

"This well," he said, "may test the down-dip limit of the reservoir."

Drilling at the No. 2 well is expected to be finished "within the week."

The Nikaitchuq No. 1 was permitted from a surface in section 16-township 14 north-range 9 east, Umiat Meridian, to a bottom hole in section 9-T14N-R9E, UM.

The No. 2 was permitted from a surface in 22-T14N-R9E, UM, to a bottom hole in 15-T14N-R9E, UM.

Wells in proposed unit

The wells are in the proposed Nikaitchuq exploration unit, applied for in January by Armstrong Alaska on behalf of itself and proposed unit operator Kerr-McGee. The unit covers some almost 13,000 acres in eight oil and gas leases. In their unit application the companies told the Alaska Division of Oil and Gas that they planned to test prospective intervals in the Cretaceous Brookian sandstone, the Jurassic Nuiqsut sandstone and the Triassic Sag River sandstone.

They said exploration and development drilling in the area of the Nikaitchuq unit "establishes an overall prospective trend for improved Sag River sand quality and thickness to the north/northwest of the Milne structure and within our proposed Nikaitchuq exploration unit."

The companies said the Jurassic interval, the secondary interval of interest, has been tied to 3-D seismic and to the Thetis Island No. 1, Ivik No. 1, Oooguruk No. 1 and Kalubik No. 1 wells.

The third objective, the Brookian interval, was found "with good reservoir quality and hydrocarbon shows" in wells directly to the southwest of Nikaitchuq, Armstrong said in the unit application.

The companies said the Nikaitchuq No. 1 had a proposed true vertical depth of 9,150 feet.

What's next?

The wells are being drilled with a land-based drilling rig from an ice pad and required approximately four miles of ice road, with access from the existing North Slope road system at Oliktok Point.

The companies said in their unit application that three wells were planned, one each in 2004, 2006 and 2008, but both the companies have said they would like to drill more than one well this winter, depending on results of the first well and the North Slope drilling window.

Buterbaugh said that "data collected from these wells will be the foundation for better calibrating the 3-D seismic that we have over this area. The 3-D will be reprocessed this summer in preparation for the next drilling season."

Kerr-McGee has a 70 percent interest in the prospect, he said, owns 12,000 acres in the area and has an option to acquire an additional 54,000 acres. ●

continued from page 1

LINE

almost 5,000 acres about 50 miles southwest of Fort St. John and the combined lands of the Treaty 8 First Nations covering 55,000 acres.

A spokesman for West Moberly said the U.S. experience shows that water use is extreme, development density is 16 to 20 times greater than conventional gas projects and the Native rights to hunt, fish and trap would be greatly impacted.

In a public notice document, West Moberly said coalbed methane is a "separate energy resource" from conventional gas and is not covered by the British Columbia Oil and Gas Commission.

—GARY PARK, Petroleum News Calgary correspondent

continued from page 1

PEMEX

George Baker, owner of the Houston-based firm Baker & Associates.

"The future of Cantarell is the subject of conjecture on both sides of the border," Baker said. "How long can it produce 2 million barrels a day? Five years? Ten years? No one knows how long." Cantarell, discovered in the 1970s, now provides Mexico with two-thirds of its crude production.

Mexico's constitution currently bans foreign ownership of Mexico's oil wealth, and oil companies would be loathe to share deepwater technology without getting to share in production.

"It takes five to six years to develop a major oil program, and Pemex has no ability to explore in deep water. There is a political under-investment," Baker said, adding that the political will must exist in order to establish the regulatory and legal framework for joint ventures.

Opposition to change in Mexico

Yet in Mexico, there is continuing opposition not only to changing the constitution to allow such joint ventures with Pemex to go forward, but also to maintaining the current levels of Cantarell production. Recent natural gas contracts with foreign oil companies that paid the companies fees instead of a share in production also have sparked protest.

At a recent ceremony marking the 66th anniversary of the nationalization of Mexico's oil industry, Cuauhtemoc Cardenas Solorzano, a leftist political leader and son of the Mexican president who nationalized the oil industry, accused Mexican President Vicente Fox of trying to sell out the country to foreign oil companies, according to the Mexico City daily La Jornada.

"There shouldn't be any ceremony marking this day, because no one is defending this country's sovereignty," Cardenas said. He also was critical of Pemex's increase in Cantarell's production level, saying it only hastens the day when Cantarell will run dry.

Meanwhile, Pemex is increasing its budget for production and exploration for 2004. According to Pemex, the company will spend $12 billion on capital expenditures this year, with 79.4 percent going to production and 13.3 percent to exploration.

Pemex also has started a program to build 47 new drilling platforms. While Pemex pays about 61 percent of its revenues to the government in taxes, much of the money it spends on exploration comes from bank-financed loans.

"It's a major commitment," said Baker of the budget. "It's not in Pemex's power to change the political, regulatory and legal environment to put in place everything needed to replace Cantarell."

—DEBRA BEACHY, Petroleum News contributing writer

RUSSIA

Russian oil companies almost double dividend payments, says ministry report

Interfax reported March 24 that Russian oil companies will "nearly double dividend payments from $3.5 billion in 2002 to $5.6 billion in 2003," attributing the information to a Russian Finance Ministry report for the country's Cabinet on ways to improve tax legislation.

The ministry estimates oil company revenues grew 30 percent to $71.8 billion, including growth of 40 percent to $40.7 billion from crude oil exports and 12.4 percent to $14.5 billion from oil product exports, Interfax said.

According to the report, eight companies produced 80 percent of Russia's oil. Those companies are Lukoil, Yukos, Surgutneftegaz, TNK-BP, Sibneft, Tatneft, Rosneft and Slavneft.

The Finance Ministry is proposing a new scale for oil export duties and to raise VAT in order to extract $2 billion more in taxes from the oil industry, Interfax said, noting that the amount is based on the assumption that oil prices will hold at more than $27 a barrel.

Canadian companies visit Sakhalin

Representatives of 21 Canadian companies were in Sakhalin in mid-March to discuss the possibility of participating in Russian oil and gas projects, Pravda Online reported March 15.

The Canadian economic mission, which arrived in Sakhalin March 14, was lead by Canada's Ambassador to Russia, Christopher Westdal. In a meeting with Sakhalin Governor Ivan Malakhov, Westdal "expressed Canada's great interest in participating in tenders to build the requisite oil and gas infrastructure, including the construction of social projects," Pravda reported. Malakhov recommended Canadian companies enter into joint ventures with Russian companies. According to Pravda he also said that Sakhalin had a positive experience with this practice during the implementation of the Sakhalin-1 and the Sakhalin-2 projects, citing the work of an Australian firm that visited Sakhalin twice last year as an example. The Australian company and its Russian partners reportedly received subcontracts for oil and gas projects worth $20 million. The Canadian businessmen took part in the two-day seminar – "Conducting Business in Sakhalin" — while on the island.

continued from page 2

HALLIBURTON

direct cost of fuel and the delivery itself, but also costs associated with waiting time for trucks, equipment and personnel.

"It appears other numbers that have been quoted are only the direct costs, ignoring the fact a given truck can only make two round trips per month from Kuwait to Baghdad as the equipment must wait for loading and security," Gaut said. "It also ignores any overhead costs for personnel, equipment and other administrative-related expenses."

Cost of meals unresolved

Halliburton acknowledged its disagreement with the government concerning bills for meals ordered and actually served to U.S. troops in Iraq. Until the issue is resolved, the company said it has suspended subcontractor billings for meals totaling $36 million and is voluntarily holding $140 million of subcontractor invoices for food services that already have been provided to the military.

"The preliminary results of our review of the meal issue indicate to us that the amount of dispute will be far less than the $176 million currently being withheld," Gaut said.

Halliburton's Cornelison said company auditors have reviewed "tens of thousands of invoices" and "we haven't found any other issues to date. If we had found them, we would have notified the Inspector General's office … just like we did the last time."

Liquidity concern in markets

Despite the company's recent assurance that it has the necessary liquidity to finish its work in Iraq, Halliburton's contract problems have raised doubts in capital markets. In a Feb. 20 filing with the U.S. Securities and Exchange Commission, Halliburton warned investors that its ability "to secure future government contracts business or renewals of current government contracts business in the Middle East or elsewhere could be adversely affected."

Nevertheless, while acknowledging "there is no dispute that our financing of the government work in Iraq has required a sizeable working capital investment," Halliburton now says "we feel that we've got a very strong liquidity position" to cover both Iraq and its huge asbestos settlement.

Halliburton said it had $1.8 billion in cash at year-end 2003, plus cash available through its credit facility, a bond deal, an insurance settlement and other financial sources that would bring the total to roughly $3.5 billion. When subtracting the $2.5 billion asbestos settlement, that would give the company at least $1 billion in working capital. Halliburton said since entering Iraq about a year ago, its working capital investment exceeds $1.2 billion.

Gaut said that Halliburton expects its workload in Iraq to increase during the first half of 2004 and then possibly decrease during the second half. "If activity begins to decrease as we expect … then our working capital requirement will be reduced as well," he added, "and that would improve our liquidity situation."

In addition to providing fuel, food and housing for troops, Halliburton also was commissioned to douse well fires in southern Iraq and to bring some wells back into production. The company also inspected oil facilities and assisted in surpassing Iraq's prewar oil production of 2 million barrels per day with 2.4 million barrels per day last December, three months ahead of schedule.

"I think that is a big untold story and something that gets lost in much of the media criticism that's out there," Halliburton's Lesar said. ●