PAGE 9: ALASKA GAS PROJECT PRIMER

Petroleum news

page 17 Bill allows Permanent Fund to loan money for gas pipeline

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ConocoPhillips spuds in NPR-A

JUDY PATRICK

ConocoPhillips Alaska has two exploration wells under way in the National Petroleum Reserve-Alaska. The first well to spud was the Carbon well, (above) on March 4. Doyon rig 19 is drilling Carbon and Doyon 141 is on the Scout well, which spud a few days later.

BP Canada exec says Alaska gas line filing unlikely before 2007

North Slope gas owners must move a mountain of economic and political obstacles before they can file regulatory applications, an Arctic Gas Symposium was told in Calgary March 8.

An application is likely at least three years away because of the engineering and environmental studies that have yet to be completed and the challenge of developing a plan that is commercially viable, said Ken MacDonald, vice president with BP Canada Energy's Alaska-Canada pipeline group.

In suggesting that 2007 is the earliest date for a filing, he cautioned: "That's just a guesstimate."

But because "risks still outweigh rewards ... we don't have a (commercially viable) project yet," MacDonald said.

"We're waiting on energy legislation in the U.S. (where the

see **2007** *page 22*

ExxonMobil expects North Slope gas line to be built

Oil Patch Insider

EXXONMOBIL PRESIDENT Rex W. Tillerson told anaylsts March 10 he expects an Alaska gas pipeline to be built and delivering gas to the marketplace, "probably slightly beyond the end of this decade."

This is the same timeframe ExxonMobil, BP and ConocoPhillips officials in Alaska have been targeting.

Although ExxonMobil has been criticized for allowing production levels to dip, company Chairman and CEO Lee R.

see **INSIDER** *page 23*

BREAKING NEWS

ALASKA

Focus on exploration

Three Conoco wells under way in NPR-A; second Placer well possible

By KRISTEN NELSON

Petroleum News Editor-in-Chief

ConocoPhillips Alaska has three exploration wells under way on Alaska's North Slope, two in the National Petroleum Reserve-Alaska and one on the western edge of the Kuparuk River unit.

1 2 SERIES

Rick Mott, ConocoPhillips Alaska's vice president of exploration and land, told Petroleum News March 4 that drilling was under way at the Placer exploration well on the western edge of Kuparuk.

The company has completed its winter exploration ice roads and ice pads, he said March 4, with drilling at the Carbon well in NPR-A starting that day, and drilling at ConocoPhillips' second NPR-A well, Scout No. 1, expected by the following Monday, March 8.

Rick Mott, ConocoPhillips Alaska

ConocoPhillips' spokeswoman Dawn Patience confirmed March 10 that the Scout well was spud March 8.

The third NPR-A well will be spud around April 1.

Nordic rig 3 is drilling at Placer, Doyon rig 19 at Carbon and Doyon 141 at Scout. One of the rigs drilling in NPR-A will be used to drill the third NPR-A well, and Mott said right now the best guess is that it will be Doyon 19, since work started on that well first.

see **FOCUS** *page 24*

GULF OF MEXICO

MMS: Record dozen rigs working ultra-deepwater

By RAY TYSON

Petroleum News Houston Correspondent

The U.S. Minerals Management Service says a record dozen rigs are currently drilling at water depths greater than 5,000 feet in the Gulf of Mexico.

"This is an important milestone and demonstrates how industry continues to focus on new frontiers," MMS Director Johnnie Burton said.

Burton noted that deepwater oil production in the Gulf rose 535 percent and natural gas output 620 percent between 1995 and 2002. Oil from the Gulf now accounts for 30 percent and gas 23 percent of the country's entire domestic hydrocarbon

see **RECORD** *page 22*

Anadarko Petroleum is drilling an 8,730-foot prospect on Atwater Valley 349, using Transocean's Deepwater Millennium.

CANADA

Canada out to bust the trusts?

Secretive pre-budget meetings raise fears government about to lower tax boom

By GARY PARK

Petroleum News Calgary Correspondent

Clandestine high-level meetings of Canadian Finance Department officials and the private sector have set off alarm bells that the government is preparing to stage a tax grab in the income trust sector.

With studies estimating that the government is losing as much as C$1 billion a year in tax revenue because of the special treatment afforded the booming trusts, there is a fear that the issue might be addressed in a March 23 budget.

Prime Minister Paul Martin

Finance officials either refuse to comment on what might be in store or dismiss the secretive meetings as just a normal part of pre-budget talks.

Sources indicate that the options range from taxing trusts at the same 33 percent level as other corporations to doing nothing at all.

The government is also said to be closely tracking the rising level of foreign ownership of trusts.

Because foreigners are not taxed at the same level as Canadians, there is a concern that sizeable tax revenues are draining out of Canada.

see **TRUSTS** *page 22*

FORT WORTH, TEXAS

Range hikes capex 17% to $126 million; quarterly profit falls to $4.6 million

Texas-based independent Range Resources has set a 2004 capital expenditure budget of $126 million, a 17 percent increase compared to 2003, the company said March 2, adding that this year's budget does not include any acquisitions it could make.

Projects this year include the drilling of 409 wells and 35 recompletions, with more than two-thirds of the drilling budget directed toward finding and developing new reserves, the company said. Range expects about 75 percent of the projects to be paid through internal cash flow.

Range said its 2004 spending is allocated about 50 percent to the U.S. Southwest region and 25 percent each to the Gulf Coast and Appalachian regions. The capital program, together with its Conger field acquisition, is anticipated to generate 10 to 15 percent growth in year-over-year production.

However, while the company's full-year 2003 profit jumped 37 percent to $35.4 million compared to 2002, its fourth-quarter 2003 profit versus the same period a year earlier dropped 5 percent to $4.6 million or 7 cents per share. Remington attributed the decrease in net income to several non-cash items, including a deferred compensation expense, an ineffective hedging loss and an increase in deferred income taxes.

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

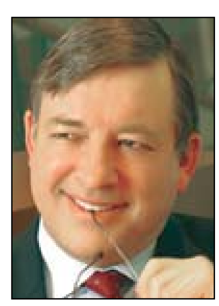
NORTH AMERICA

Talisman stays mum on North Slope well

Talisman Energy is not succumbing to loose lips when it comes to releasing data from its initial exploration well on the North Slope.

Jim Buckee, chief executive officer of the Canadian independent, told a conference call March 3 that testing is under way on the Total E&P USA farm-in acreage now that the rig has been released.

But he said that because so few wells have been drilled in the National Petroleum Reserve-Alaska land, the Talisman well remains a tight hole.


Jim Buckee, Talisman CEO

Buckee said that "any information we give out, positive or negative, will help our competitors in an area where data is scarce, well costs are high and the prize is big."

Through its Fortuna Exploration subsidiary Talisman signed an agreement last June to farm-in to 360 square miles.

Fortuna was committed to drill an exploration well on a selected prospect to earn a 30 percent interest, with the right to earn a similar interest in the remaining prospects.

Immediately prior to the Total deal, Buckee, whose stops during his days with BP included Alaska, said his company hoped to target at least four 300 million to 500 million barrel prospects on the North Slope.

Despite a 40 percent drop in fourth quarter earnings last year, Talisman exited 2003 with profits of C$1.01 billion, almost double 2002, and cash flow for the year of C$2.729 billion compared with C$2.645 billion.

Production for the year averaged 398,000 barrels of oil equivalent per day, down from 445,000 boe per day in 2002, reflecting the sale of Talisman's Sudan holding. The 2004 target is 415,000 to 445,000 boe per day.

Buckee said the exploration and development budget for 2004 could reach C$2.4 billion, slightly down from 2003, with a heavy focus on natural gas and activities covering the Americas, Southeast Asia, the Caribbean and the North Sea.

Fortuna is expected to drill 11 wells in the Appalachian Basin of New York state this year and expects U.S. production to average 80 million cubic feet per day, up 30 percent from 2003.

Talisman expects organic growth of its North American gas assets to range from 3 to 5 percent over the next five years.

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

● ALASKA

Report: Cook Inlet gas supply runs deep

THE ASSOCIATED PRESS

There is likely enough gas in Alaska's Cook Inlet for all uses — home heating, generation of electricity, fertilizer and liquefied natural gas — through about 2025, according to a consultant conducting a study for the U.S. Department of Energy.

But gas prices probably would have to rise to encourage companies to drill for the new supplies, said Charles Thomas.

Thomas told engineers at a March 9 luncheon that he expects to formally unveil the $500,000 study, commissioned out of concern that Cook Inlet gas seems to be running low, by May 1.

But a statistical analysis Thomas has run with the help of geologists and others indicates that there's much more gas in and around Cook Inlet — in fact, almost double the quantity already found.

That's true for the supplies in known gas fields, Thomas said, most of which were prior to 1970 by companies hunting for oil.

But a statistical analysis Thomas has run with the help of geologists and others indicates that there's much more gas in and around Cook Inlet — in fact, almost double the quantity already found. His best estimate is that 15-20 trillion cubic feet could come from new discoveries or expansion of existing fields. To date, 10 trillion cubic feet has been found.

Cook Inlet ought to yield ample gas through at least 2025, with field expansion and "aggressive and successful exploration" for new supplies, he said, noting that if geologists are wrong there's plenty more available from unconventional sources such as coalbed methane.

Mark Myers, director of the state of Alaska's Division of Oil and Gas, said in late February that he had seen a draft of the study and thought it contained good information. He said he agrees with "a lot of the baseline data" in the study.

"It does a reasonable job of saying there's exploration potential out there. One of the challenges, though, is … that potential onshore is being drilled up pretty rapidly," Myers said.

What that leaves is offshore, and that requires mobilizing a jack-up rig, which can cost some $10-$12 million just to get to Alaska: "The fields you'd have to find would be substantial in size … because setting a platform out there is pretty expensive." And the big unknown for Cook Inlet — and a potential big source of natural gas — is CBM, Myers said, but neither of the two pilot programs drilled so far have demonstrated CBM to be commercial.

"But if it were to work, there could be a substantial gas," he said. "That gas would most likely relieve local needs in the areas where it's found" in the Matanuska-Susitna Borough, "and then put it into the Enstar system to come farther south."

—Petroleum News contributed to this article

COOK INLET, ALASKA

Aurora to shoot 2D, drill new wells, recompletions on west side of Cook Inlet

Aurora Gas said in a March 8 statement it has contracted with Veritas DGC to acquire and process approximately 100 miles of 2-D seismic on the west side of Cook Inlet, with work scheduled to begin in March. Aurora, a privately held independent focused on onshore natural gas development in the Cook Inlet area, said the seismic will "better delineate Aurora's next generation of gas prospects," with drilling is expected to start as early as mid-year.

Andy Clifford, Aurora'a executive vice president of exploration, said Aurora has "a new well planned for the Kaloa prospect, recompletions at Lone Creek, Moquawkie and Nicolai Creek fields, plus a re-entry well at another prospect."

He said the seismic would help the company evaluate its Aspen, Olsen Creek and Three Mile Creek prospects. Forest Oil is a partner on Olsen Creek and Three Mile Creek in the 8,101-acre Three Mile Creek unit on the west side of Cook Inlet approved by the state of Alaska earlier this year. Aurora has a 79 percent interest and Forest holds the remaining 21 percent. Aurora said it met its production target of 20 million cubic feet per day by the end of 2003 with production from the Nicolai Creek unit No. 1B, No. 2 and No. 9 wells, which account for about half of the production, along with the Lone Creek No. 1 well, which has been on line since August.

Aurora's production target for 2004 is daily production of 40 mmcf per day by the end of the year, including production from the Moquawkie No. 1 beginning in June, plus planned recompletions and drilling.

—PETROLEUM NEWS

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North America's source for oil and gas news

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YUKON TERRITORY

Yukon sets land sale, helps finance a seismic survey in Whitehorse Trough

The Yukon is stepping up the pace of oil and gas activity by launching its fourth land sale and contributing to a seismic survey.

Energy, Mines and Resources Minister Archie Lang announced the call for nominations March 8 for two areas — one straddling the Dempster Highway in Eagle Plains and the other in the Peel Plateau next to the Yukon-Northwest Territories border.

He said the call areas have "untapped potential and are located next to existing dispositions with known reserves.

"Coupled with the increasing demand for gas and the future pipeline development in Alaska and the Northwest Territories, I am confident these parcels will be of interest to industry," he said.

Yukon Premier Dennis Fentie told the Arctic Gas Symposium in Calgary that his government is "serious about creating investment opportunities for industry by opening up access to promising new areas."

He said the parcels being offered are "rich in potential and relatively unexplored." The call for nominations closes May 11.

In its first three land sales, the Yukon issued three permits for the Eagle Plains area to Devon Canada in 1999 and 2001 and one Peel Plateau permit to Hunt Oil in 2002.

An Informetrica paper two years ago rated potential reserves for Eagle Plains at 1 trillion cubic feet of gas and 28 million barrels of oil, but noted that more exploration and pipeline infrastructure is needed for further development.

The potential of Peel Plateau was estimated at 2.3 trillion cubic feet of gas and 21 million barrels of oil, but again access is needed to a pipeline.

Seismic survey near Whitehorse

Meanwhile, the government has announced that geologists are spending C$930,000 this year on an oil and natural gas seismic survey near the Yukon capital of Whitehorse — an area believed to be rich in potential.

The Geological Survey of Canada and the Yukon Geological Survey have been teamed up to probe the potential of the Whitehorse Trough.

Earlier projections have estimated the field could hold close to 200 billion cubic feet of natural gas, 8 million barrels of oil and unknown coalbed methane deposits.

If an Alaska Highway gas pipeline crosses the Yukon, the resources could have improved commercial prospects.

Lang said the survey, which will include up to C$230,000 in government money, took place in the last two weeks of February "entirely within the highway right of way" and for that reason there was "virtually no environmental impact."

—GARY PARK, Petroleum News Calgary correspondent

● NEW ORLEANS, LA.

MMS expects ‘subdued’ bidding at Gulf lease sale

March 17 Sale 190 to offer 4,324 unleased blocks, new incentives for gas drilling on GOM Continental Shelf

By RAY TYSON

Petroleum News Houston Correspondent

Commodity prices are strong. Explorers are flush with cash. And the federal government is offering attractive incentives to encourage drilling. These are key ingredients for a blockbuster Gulf of Mexico oil and gas lease sale. But don’t expect one when bidders gather March 17 in New Orleans, La.

“There could be hot spots, but I think it’s going to be a little subdued,” said Chris Oynes, Gulf regional director for the U.S. Minerals Management Service.

Chris Oynes, Gulf regional director for the U.S. Minerals Management Service

Oynes told Petroleum News that in spite of new royalty relief incentives for gas drilling in shallower waters of the Continental Shelf, Central Gulf Lease Sale 190 appears to lack the necessary drivers among available blocks that typically attract large bids for oil prospects in the deeper waters.

“Look at the deepwater stuff,” Oynes said. “The deepwater doesn’t seem to have too much going on to have a real strong interest. There are no new wells that could drive this one way or the other. There’s going to be some bidding out there, but probably not in terms of a strong level of activity.”

2003 sale netted $297.6 million

MMS netted $297.6 million in high bids from last year’s Central Gulf Lease Sale 185, with 561 tracts receiving bids and 545 accepted. Sixteen bids totaling $17.9 million were rejected because they did not meet the agency’s standard of fair market value. They will be reoffered in next week’s sale.

Exploration and production independents dominated last year’s Central Gulf lease sale, taking four of the top five top slots in terms of tracts won and all five positions in terms of accepted high bids. Oklahoma’s Kerr-McGee led the pack with 63 blocks and $28.1 million in bonuses, followed by Newfield Exploration with 49 blocks and $11.8 million in bonuses, BHP Billiton with 49 blocks and $9.6 million in bonuses, ChevronTexaco with 38 blocks and $9.3 million in bonuses, and Magnum Hunter with 38 blocks and $7.7 million in bonuses.

… there are only 218 so-called “newly available leases” offered in this year’s sale, compared to 393 last year. These represent both deepwater and shallower water leases that expired or were relinquished by their owners during the past year, as well as leases terminated by MMS for failure to meet work commitments.

Of the 16 rejected high bids in last year’s lease sale, two of them were offered by ChevronTexaco on adjacent deepwater blocks, Green Canyon 468 and 512, and could draw spirited bidding in this year’s sale, based on combined bids of $11.5 million, or nearly 65 percent of the $17.9 million in previously rejected bids.

“One question is whether Chevron will come back on those blocks,” Oynes said. “Or because of the high dollars involved, is anyone else interested in them.”

Some blocks could draw because of deep gas plays

Because of robust natural gas prices, new government incentives and industry’s general interest in geologically deep gas plays in shallower waters of the Gulf, available blocks in the areas of East and West Cameron and Eugene Island also could draw interest. They also were hot spots in last year’s Central Gulf lease sale.

A total of 4,324 blocks covering 22.7-million acres will be offered at the March 17 areawide sale. Of these, 1,390 blocks are at water depths less than 400 meters, 128 blocks at water depths between 400 and 799 meters, and 2,806 blocks at water depths greater than 800 meters.

However, there are only 218 so-called “newly available leases” offered in this year’s sale, compared to 393 last year. These represent both deepwater and shallower water leases that expired or were relinquished by their owners during the past year, as well as leases terminated by MMS for failure to meet work commitments. They generally draw interest simply because they have been off the market for years and can account for roughly a quarter of all leases receiving bids in any given Gulf sale.

Deep-gas drilling incentives expanded

Incentives for deep-gas drilling in water depths below 200 meters on the continental shelf were greatly expanded in January, essentially replacing the former rule providing for royalty suspension on just the first 20 billion cubic feet of production on newly issued leases below a geological depth of 15,000 feet.

The new package increases both the size and scope of the program to include not only future leases in the upcoming sale, but 2,400 existing leases offshore Texas, Louisiana, Mississippi and Alabama.

Under the new program, the government specifically is offering a royalty suspension on the first 15 billion cubic feet of gas produced from depths greater than 15,000 and less than 18,000 feet, or on the first 25 bcf produced from 18,000 feet or deeper. A royalty suspension volume of 15 bcf can be increased to 25 bcf from a second successful well to 18,000 feet or deeper. The rule applies to all qualified wells on a specific lease.

Under the new program, the government specifically is offering a royalty suspension on the first 15 billion cubic feet of gas produced from depths greater than 15,000 and less than 18,000 feet, or on the first 25 bcf produced from 18,000 feet or deeper.

Deep dry holes also qualify for relief

In the event of a dry hole below 18,000 feet, a producer would qualify for a royalty suspension supplement of 5 bcf of gas equivalent that could be applied to future oil or gas production from any depth. Two of these supplements are available per lease prior to production from a deep well. The maximum relief a lease can earn from either successful or unsuccessful deep wells is 35 bcf.

Additionally, sidetrack wells could earn royalty suspensions in amounts based on drilling depth and sidetrack length. Royalty relief would be discontinued if natural gas prices exceed $9.34 per thousand cubic feet. And deep gas must be drilled and production started by March 1, 2009.

Recent royalty suspension measures for deepwater oil and gas production will continue with Central Gulf Lease Sale 190. Leaseholders can claim exemption on the first 5 million barrels of oil equivalent from water depths ranging from 400 to 799 meters, 9 million barrels of equivalent from water depths between 800 and 1,500 meters, and 12 million barrels of equivalent from water depths greater than 1,600 meters. ●

ALASKA

Alaska North Slope exploration well, Cook Inlet natural gas well permitted

Among eight wells permitted by the Alaska Oil and Gas Conservation Commission the week ending March 5 were a Beaufort Sea exploration well and a development well at a new onshore Cook Inlet gas field where first production is expected by year end.

Kerr-McGee Oil and Gas permitted the Nikaitchuq No. 2 exploration well March 5 on Alaska lease ADL 0355021 in the shallow waters of the Beaufort Sea north of Milne Point. With a surface in section 22, township 14 north, range 9 east, Umiat Meridian, the well is targeted northeast to a bottom hole in section 14-T14N-R9E, UM. Kerr-McGee’s Nikaitchuq No. 1 was permitted in late January from a surface in section 16-T14N-R9E, UM, north to a bottom hole in section 9-T14N-R9E, UM.

These are the wells at Spy Island, a prospect developed by Armstrong Alaska, which brought in Kerr-McGee as majority partner and operator. The companies had three targets in mind for wells from their proposed Nikaitchuq unit, and Kerr-McGee told a committee of the Alaska Legislature Feb. 9 that it expected to start the first of two offshore wells within two days.

In Southcentral Alaska, Union Oil Company of California permitted the Happy Valley No. 6 March 4, a development well at the Deep Creek unit, where Unocal announced a gas discovery in November. The company said the discovery well found 110 feet of natural gas pay, and was followed by a successful appraisal well.

Unocal said then that it would likely drill three development wells in 2004, with first production planned for fourth quarter 2004 through an extension to the Kenai Kachemak Pipeline.

Other wells permitted include a development well and two service wells at the North Slope Prudhoe Bay field, a Cannery Loop redrill development well onshore Cook Inlet and one service and one development well at the Colville River unit (the Alpine field) on the North Slope.

—PETROLEUM NEWS

● COOK INLET, ALASKA

Cook Inlet natural gas supply goes short

Major industrial gas user Agrium working with exploration companies exploring for gas, might even partner to find more gas

By KRISTEN NELSON

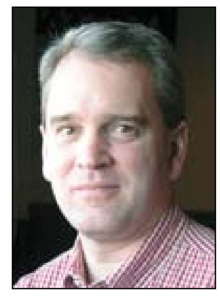
Petroleum News Editor-in-Chief

The fertilizer plant on the Kenai Peninsula south of Anchorage, Alaska, was built to take advantage of a stranded gas situation, as was the liquefied natural gas plant next door: big gas discoveries had been made on the Kenai and in Cook Inlet by companies exploring for oil.

That plants started up in 1969, Bill Boycott, general manager of Kenai Nitrogen Operations for Agrium, told the Resource Development Council in Anchorage March 4.

Today Agrium, which acquired the Nikiski facility when it purchased Unocal's fertilizer operations in 2000, is struggling in Cook Inlet with both shortages of natural gas to run the plant and with rising gas prices.

"2001 was the last year that the plant operated at full capacity, and that was roughly 53 billion cubic feet" of natural gas for the year.



FORREST CRANE

Bill Boycott, Agrium

Last year the plant only got 40 bcf of natural gas," Boycott said.

"In 2004 we're projecting roughly 36 billion cubic feet of gas deliveries to the facility," he said.

Cost of plant written down last year

Agrium, a global producer and marketer of fertilizer based in Calgary, Alberta, wrote down the carrying cost of the Alaska nitrogen facility at the end of last year by $140 million.

Mike Wilson, Agrium's president and chief executive officer, said in a Dec. 2 statement that the write-down occurred because Unocal failed to meet the plant's natural gas requirements. An arbitration hearing is scheduled to begin in May.

When the sale to Agrium was completed in September 2000, Unocal said its Alaska oil and gas business unit would continue to supply natural gas to Agrium "from certain Cook Inlet fields and other sources pursuant to a 1998 agreement…"

Agrium said in December: "The indicated gas supply from Unocal to the Kenai, Alaska, facility will be insufficient to operate the facility past the end of 2005."

Unocal has made or participated in new gas discoveries on the Kenai and is selling that gas to the local gas distribution company, Enstar Natural Gas, under a contract which bases the price of the gas on a 36-month NYMEX average. Enstar negotiated that contract with Unocal because it was running short of natural gas for its customers (see story in March 7 issue of Petroleum News.)

Gas supply picture has changed in Cook Inlet

Boycott said he was sure most people were aware that "the gas supply situation has changed in the Cook Inlet." It is still a stranded gas play, he said, but Cook Inlet no longer has long-term stranded gas; now it only has short-term, i.e., Cook Inlet is still not connected to a larger natural gas market, and its supply of gas has dwindled.

"The reality of that is that our future is threatened by that. We've seen the gas availability to our plant decline and we've seen upward pressure on pricing in the Cook Inlet."

Agrium's Alaska ammonia and urea competes with producers around the Pacific

see **SUPPLY** page 24

● JUNEAU, ALASKA

House committee passes first shallow gas bill

Compromise measure requires more public notice for new leases, offers some protection for residents

By LARRY PERSILY

Petroleum News Government Affairs Editor

Alaska's House Oil and Gas Committee has passed out its first shallow gas leasing bill of the year, halfway through the legislative session. The compromise measure requires more public notice for new leases and offers some protection for residents worried about damage to their water wells.

The almost 300,000 acres the state has under shallow gas, or coalbed methane, leases allows explorers to look for gas beneath the lots of Alaska homeowners who didn't realize until after the public notice process that the state held the subsurface rights to their property. The realization provoked a strong emotional response from many homeowners last year.

House Bill 395, as amended by the Oil and Gas Committee, does not abolish the state's over-the-counter, non-competitive shallow gas leasing program, as proposed in a Senate bill under consideration, but instead requires much more public notice of the leases.

MARK MYERS

"There are some strong protections in here." —Mark Myers, director of the Oil and Gas Division at the Department of Natural Resources

The bill also requires the Alaska Oil and Gas Conservation Commission to set up a public forum process for resolving complaints about shallow gas activities.

The committee version of the bill combined provisions from the original HB 395, sponsored by four House members whose districts include shallow gas leases, with HB 420, sponsored by Oil and Gas Chair Vic Kohring, R-Wasilla, a strong supporter of resource development in Alaska.

Committee passes bill with little discussion

Committee members moved the bill in about five minutes March 9, with little discussion and no objections to the latest version that was passed out at the start of the meeting.

But with the session half over, the bill still has to make its way through three more committees in the House and a vote by the full chamber before moving to the Senate for action there.

Included in the Oil and Gas version of the bill — but not in either of the two original measures — is a provision that would block state permits for shallow gas exploration if the gas would come from the same aquifer that supplies drinking or farm water. The provision also would allow the state to regulate hydraulic fracturing in shallow gas wells to protect drinking water sources.

And, if the state requires reinjection of water produced in the drilling operation, the bill says the reinjection would have to occur at depths below any known sources of drinking or farm water.

"There are some strong protections in here," Mark Myers, director of the Oil and Gas Division at the Department of Natural Resources, told the committee.

The measure also would require setbacks from the property line for compressor stations and "reasonable and appropriate measures" to lessen noise from gas compressors and other drilling or production equipment.

see **BILL** page 23

ALBERTA

Alberta easily outpaces 2003's oil, gas land sales

Oil and gas exploration land is fetching premium prices in Alberta this year, with operators forking over C$185.5 million in the first three sales of the year — more than double the same period last year.

The third sale of the year on March 3 yielded C$61 million worth of petroleum, natural gas and oil sands rights — the first time in more than three years that the province had topped the C$60 million mark.

The latest sale disposed of 380,000 acres, pushing the total for the year so far to 1.4 million acres. To the same point last year, the Alberta government collected C$83.5 million from about 815,000 acres, reflecting a strong gain this year in average per acre prices.

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

LAFAYETTE, LA.

Stone Energy's profit soars 40 percent to $27.2 million

Stone Energy, a small Louisiana-based exploration and production independent, saw its profit in the 2003 fourth quarter rocket 40 percent to $27.2 million or $1.02 per share, compared to $19.5 million or 74 cents per share for the quarter a year earlier.

Company production during the 2003 fourth quarter of 15.3 billion cubic feet of natural gas and 1.5 million barrels of oil was relatively flat to the year-ago period. For the comparable periods, however, commodity prices during the recent quarter soared with oil averaging $30.33 per barrel and gas $4.63 per thousand cubic feet.

Stone said it expects production during the first quarter of 2004 to be roughly flat with the 2003 fourth quarter, assuming no production from its new South Pelto wells or additional production from wells in the Gulf of Mexico.

Stone's total proved reserves at year-end 2003 were estimated to be 816.3 bcf of gas equivalent, up 9 percent over the prior year's estimates and a 167 percent replacement of 2003 production volumes.

—RAY TYSON, Petroleum News Houston correspondent

HOUSTON, TEXAS

Grey Wolf, New Patriot Drilling merge in $51 million deal

Contract land driller Grey Wolf of Houston, Texas, has agreed to acquire Wyoming's New Patriot Drilling for about $51 million in cash, stock and assumed debt, Grey Wolf said March 8.

The merger would give Grey Wolf an additional 10 rigs for a total of 127. Eight of the Patriot rigs are currently working with the remaining two under contract and expected to begin work in Wyoming during the next two months, Grey Wolf said.

The merger would give Grey Wolf an additional 10 rigs for a total of 127. Eight of the Patriot rigs are currently working with the remaining two under contract and expected to begin work in Wyoming during the next two months, Grey Wolf said. Three of the rigs currently working are in Wyoming and five are in Colorado.

Patriot's drilling rig fleet consists of three diesel electric rigs ranging in horsepower from 1,000 to 3,000 and seven mechanical rigs ranging in horsepower from 450 to 700. The company employs about 250 people.

"We will consolidate the Rocky Mountain management and operations of both companies in Casper with a total of 14 rigs in the market," said Tom Richards, Grey Wolf's chief executive officer. "We believe the Rockies hold great potential for increased natural gas drilling."

The agreement calls for Grey Wolf to pay Patriot $16.3 million in cash, 4.6 million shares of Grey Wolf valued at about $21.4 million, and assume about $13.7 million in Patriot debt. The transaction is expected to close in April. Patriot is currently owned by Lime Rock Partners, a private equity company.

In addition to the Rockies, Grey Wolf operates in Arkansas, Louisiana, Texas, Gulf Coast, Mississippi and Alabama, with a current rig fleet of 117.

—RAY TYSON, Petroleum News Houston correspondent

● WASHINGTON, D.C.

Record gasoline prices predicted this summer

Federal report sees $1.74 as nationwide average for summer months

By LARRY PERSILY

Petroleum News Government Affairs Editor

The U.S. Energy Department's short-term price and production outlook warns of record gasoline prices this summer, oil prices centered near $30 a barrel all year and natural gas likely to average $5.20 per thousand cubic feet for 2004.

None of which is particularly good news for airlines, trucking companies, electrical generating plants or summer vacationers on the nation's highways.

"The prospects for oil prices diminishing significantly prior to the driving season have weakened," said the Energy Information Administration report issued March 9.

"National monthly average regular gasoline pump prices are projected to reach about $1.83 per gallon this spring. Summer gasoline prices are now expected to average about $1.74 per gallon," the report said. "This would be a record in nominal dollar terms and the highest inflation-adjusted summer average since 1985."

West Texas Intermediate prices averaged almost $35 a barrel in February, with the Energy Department expecting a slow decline and prices to average near $30 for the entire year. "Modest oil price declines (also) are expected in 2005 as Iraqi oil production continues to increase and inventories are rebuilt to normal levels," the report said.

TOM KEARNEY

U.S. summer gasoline (regular) prices are expected to average about $1.74 per gallon. The above photo was taken March 3 in Anchorage, Alaska.

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● HOUSTON, TEXAS

John Raymond goes after the big enchilada

Young executive turns in hat at Plains E&P to focus on Plains Resources' lucrative tie to growing Plains All American Pipeline L.P.

By RAY TYSON

Petroleum News Houston Correspondent

John T. Raymond, son of ExxonMobil chairman Lee Raymond, has relinquished two executive positions at the same exploration and production company to concentrate on his job at another E&P independent that leads to a much bigger prize, a personal stake in fast-growing Plains All American Pipeline L.P.

Raymond and his colleague in financial adventure, James Flores, along with Microsoft co-founder Paul Allen, stirred up a controversy among investors several weeks ago with their bid for Plains Resources, a small publicly traded independent that happens to own a considerable position in Plains All American.

Plains Exploration & Production Co., which doubled in size with its recent acquisition of fellow independent Nuevo Energy, announced March 3 that Raymond would no longer serve as president and chief operating officer of Plains E&P, a spin-off of Plains Resources, where Raymond remains as president and chief executive officer.

Flores remains chairman and CEO at Plains E&P

However, Raymond has not left himself without a conduit to Plains E&P. Flores remains as chairman and chief executive officer of that company,

see **RAYMOND** *page 7*

● HONOLULU, HAWAII

Panel advances proposal to tweak fuel price cap

Amendments would change 2002 law scheduled to take effect July 1; Hawaii only state legislating gasoline prices

By B.J. REYES

Associated Press Writer

A move by the Hawaii Senate's money committee to modify the state's one-of-a-kind gasoline price cap drew harsh criticism from the chamber's top Republican, who accused Majority Democrats of playing election year politics.

The proposal advanced March 3 by the Ways and Means Committee tweaks the price cap before it takes effect July 1 by extending it to cover all grades of gasoline, including diesel, and basing it on a national average of prices.

It still faces final approval by the full Senate before being sent to the House, where a similar measure died in committee after lawmakers were unable to agree on changes to the 2002 law.

Hawaii Senate Minority Leader Fred Hemmings, R-Lanikai-Waimanalo, called the proposal a "hoax" and accused Democrats of trying to appease angry consumers with a law that may ultimately be proven unconstitutional.

"This is simply another opportunity," Hemmings said, "to try to single out one group in the free market system and demonize them for political gain in this coming election, knowing full well that if they pass this law that this will not be tested constitutionally until well after the election."

Hawaii only state regulating gasoline prices

Democrats who supported the measure countered that constituents have been gouged at the pump for too long.

"Consumers in our state clearly feel that they're being ripped off," said Sen. Gary Hooser, D-Kauai-Niihau. "I hear it from my constituents every single day and they, quite frankly, would like us to do something about it.

"I think this is a good faith effort to seek a solution."

Hawaii remains the only state with a law allowing regulation of gasoline prices.

The law passed two years ago sets a maximum price for wholesale and retail regular, unleaded gasoline based on an average of prices in Los Angeles, San Francisco and the Pacific Northwest. It also caps profit margins on retail gas at 16 cents per gallon.

The amended proposal sets a maximum price for all grades of gasoline sold at the wholesale level only and removes the retail profit margin limits. It also ties the maximum price to an average of prices nationwide and exempts gasoline sold on Molokai and Lanai because of their unique markets. Opponents argue that Hawaii's high taxes and barriers to entry, such as geography, all contribute to the high cost of gasoline in the islands. Owners of small gas stations, mostly on neighbor islands, also have testified that low profit margins would force them out of business.

Law found unconstitutional

Hemmings said U.S. District Judge Susan Oki Mollway supported that argument in her 2002 ruling which said the state's 1997 law placing rent caps on dealer-run gas stations was unconstitutional because it unfairly infringed on the company's ability to use its property.

That law, which was never enforced because of the legal challenge, also aimed to bring down the cost of gasoline. Mollway said it would have had the opposite effect because oil companies likely would have raised wholesale gasoline prices to make up for reduced rental income.

The amended price cap proposal passed out of Ways and Means by a vote of 9-4, with two members absent. Majority Sens. Lorraine Inouye, D-Hilo-Honokaa, and Cal Kawamoto, D-Waipahu, sided with Hemmings and Sen. Sam Slom, R-Diamond Head-Hawaii Kai.

Inouye said she felt the measure would drive up costs on neighbor islands because it doesn't take into account the added costs associated with delivering gasoline to small, remote gas stations. Kawamoto said he feared the measure would force "jobbers" — middlemen who buy gasoline at wholesale prices and sell to stations — to leave the market altogether.

"If they walk, we have no competition in the gasoline market," Kawamoto said.

The bill faces an uncertain future in the House, where a proposal to tie the price cap to a national average and further delay its start date never made it out of committee.

House Consumer Protection Chairman Ken Hiraki said March 3 he hadn't seen the Senate's latest version.

"I know some of the (House) members had concerns about the retail cap because that sort of affects the mom and pop stations, so I'd like to take a look at it," said Hiraki, D-Kakaako-Downtown. "This might be a way to alleviate their concerns, but at the same time we want to make sure we pass a bill that will stand constitutional muster."

2002 law would take effect July 1

If no new measure is passed this year, the 2002 law would take effect on July 1 as scheduled. It includes a provision that the governor can withhold enforcement if it is determined that the cap would negatively affect the economy. Gov. Linda Lingle opposes a price cap but has said in recent months that she would not stand in the law's way.

The national average retail gasoline price was $1.75 per gallon, according to the most recent Lundberg Survey released Feb. 29. On March 3 the average price for regular, unleaded in Honolulu was $2.02 per gallon, according to AAA. The average was $2.22 in Hilo on the Big Island and $2.33 in Wailuku on Maui. ●

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RAYMOND

as well as chairman of Plains Resources. The pair go back to at least Ocean Energy, where Flores served as chairman and chief executive officer and Raymond was vice president of corporate development. Ocean eventually was taken over by big Oklahoma independent Devon Energy.

"With the recently announced Nuevo transaction, (Plains E&P) is in an excellent position for the future and I wish all of the employees continued success," Raymond said. "Additionally, I look forward to a prosperous future with everyone at Plains Resources."

Provided shareholders give the final nod, Raymond could indeed look forward to a prosperous future, as a stakeholder in what would become privately held Plains Resources and its large interest in Plains All American Pipeline. Plains Resources also participates in oil production in Florida through its wholly owned subsidiary Calumet Florida.

The board of directors of Plains Resources ended up accepting a $16.75 per share offer from the Vulcan Group, an affiliate of Vulcan Capital, the investment arm of Allen Vulcan Inc., after rejecting a bid of $14.25 from the group. However, the board failed to notify investors until after the deal that it had received and rejected an offer from another group led by Pershing Square L.P. and Leucadia National Corp.

Raymond also on board of All American Pipeline

Raymond also is listed as a board member of All American Pipeline, which has grown into one of the largest independent midstream oil companies in North America, handling more than 1.6 million barrels of crude per day through its network of assets in key producing basins and transportation gateways in the United States and Canada.

The company operates some 7,000 miles of gathering and mainline pipelines, primarily in Texas, Oklahoma, California and Louisiana and in the Canadian provinces of Alberta and Saskatchewan. It also is involved in marketing, terminaling and storage operations.

Plains All American is actually a publicly traded master limited partnership. Currently, Plains Resources owns 44 percent of the general partnership and 12.4 million limited partnership units, which represents about a 24 percent aggregate ownership interest in Plains All American.

For its pipeline operations, Plains All American generated $658.6 million in revenues in 2003, up nearly 36 percent from $486.2 million in 2002. The company received an additional $12 million in revenue from its other operations in 2003 versus $7.9 million in 2002. At year-end, it reported long-term debt of $519 million, representing a debt-to-total capitalization ratio of about 41 percent.

A key strategy of Plains All American is growth through acquisitions. Just weeks ago Plains All American closed a $158 million deal with Shell Pipeline, which gave the company a 22 percent interest in the Capline Pipeline System and about a 76 percent stake in the Capwood Pipeline System. ●

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PRICES

Forecast assumes OPEC production cut

The Energy Department's forecast of continued above-average oil prices assumes OPEC members, other than Iraq, will reduce production by about 1.5 million barrels per day by May, close to the target announced by the Organization of Petroleum Exporting Countries.

However, political turmoil in Venezuela and uncertainty whether OPEC will cut production too much could cause price spikes, the department said.

Making up for OPEC production cuts in the market will be 1.2 million barrels per day of increased oil flow in 2004 and the same amount in 2005 from non-OPEC nations, primarily from Russia and the Caspian Sea region, with some help from Africa, Canada and Mexico.

The report's price forecast also is based on the assumption that worldwide oil demand grows by 2 percent a year in 2004 and 2005.

Natural gas prices are predicted to fall a bit from 2003 averages to around $5.20 for 2004, and then marginally lower for 2005, the report said. "As in other recent projections, this outcome depends on domestic and imported supply continuing to grow modestly in 2004 and 2005.

Continued growth in number of gas wells

"(Domestic) natural gas production is expected to continue to expand through 2005 as natural gas well completions, which totaled an estimated 20,000 in 2003, continue to grow to between 22,000 and 23,000 wells per year over the next two years."

The average residential natural gas heating bill for the winter of 2003-2004 was up 12 percent from a year ago.●

DALLAS, TEXAS

Remington aiming to boost production, reserves by 15 percent

Remington Oil & Gas, a small but rapidly growing independent, has set its sights this year on increasing both production and reserves by 15 percent over 2003 levels through its ongoing exploration and production program, the company said March 5.

For the full-year 2003, Dallas-based Remington reported that oil and gas production increased by 25 percent to 34.8 billion cubic feet of gas equivalent compared to 27.8 bcf in 2002. In the 2003 fourth quarter alone, Remington's production increased 54 percent versus the same period a year earlier.

For the full-year 2003, Dallas-based Remington reported that oil and gas production increased by 25 percent to 34.8 billion cubic feet of gas equivalent compared to 27.8 bcf in 2002. In the 2003 fourth quarter alone, Remington's production increased 54 percent versus the same period a year earlier.

Remington's year-end 2003 reserves were 212 bcf of gas equivalent, up from 204 bcf of equivalent reported at year-end 2002.

Higher volumes, coupled with a 61 percent increase in gas prices and a 21 percent in oil prices, propelled Remington's net income roughly nine-fold to $8.9 million or 32 cents per share on revenues of $47.7 million, compared to net income of $855,000 or 3 cents per share on revenues of $27.7 million for the same period a year earlier.

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

● ALASKA

Alyeska owners OK pipeline upgrades

By KRISTEN NELSON

Petroleum News Editor-in-Chief

Stage one of a modernization of the trans-Alaska oil pipeline is a go.

Alyeska Pipeline Service Co. said March 4 that it has received approval from owners BP Pipelines (Alaska), ConocoPhillips Transportation Alaska, ExxonMobil Pipeline Co., Williams Alaska Pipeline Co. and Unocal Pipeline Co. to invest more than $250 million in a project to upgrade the pipeline's pump stations.

Alyeska called the project one of the most significant investments in the trans-Alaska pipeline since construction. The pipeline system was built in the 1970s and crude oil has been flowing through the line since 1977.

The pipeline reconfiguration includes installing electrically driven crude oil pumps at four critical pump stations, increasing automation and upgrading control systems. Alyeska said the project "will position TAPS well into the future with systems that are proven in the pipeline industry."

Pipeline reconfiguration is a major component of several change efforts under way, the company said, and could reduce the cost of operating the pipeline by approximately 10 percent annually and eliminate maintenance costs for equipment and facilities no longer required, with at least 75 buildings placed in non-operational status.

"This use of modern technology and automation will maintain current pipeline reliability at a lower cost," the company said.

In a brochure describing the upgrades Alyeska said the "control systems and automation and electrification technology are used in the pipeline industry all over the world, including cold weather climates similar to Alaska."

Remotely controlled pump stations

Pump stations Nos. 1, 3, 4 and 9 will be reconfigured and controlled and operated remotely.

The company said the new pump stations units to be installed will be "modular and scalable to more easily accommodate changes in pipeline throughput." The new configuration will support current and projected oil flows, Alyeska said, "and can be modified in about 24 months to accommodate significant increases in throughput — long before new fields can be developed."

The pump stations to be upgraded are the ones "required for pipeline operations at any flow rate."

Maintenance and spill response has been based at pump stations. Under the new configuration there will be maintenance and spill response bases at Prudhoe Bay (Pump Station 1), Galbraith (Pump Station 4), Prospect (Pump Station 5), Fairbanks and Glennallen, and field offices at the Yukon River and Delta Junction.

Work force reductions

Alyeska said that some 350 job reductions will occur over the next two to three years from the Alyeska work force of approximately 1,600, including contractors, and will be "roughly split between Alyeska and contract employees."

The number of initial responders will not change, although staff in the field will be reduced. The oil spill contingency plan amendments for pipeline reconfiguration were approved in December and include pre-staging of response equipment at some locations, enhancement of pre-determined containment sites and use of longer-range helicopters that can carry larger payloads for initial response.

Alyeska said it "is working with regulators to increase emphasis on drills and training, and to ensure that all response requirements will be met prior to project conclusion."

Changes to the system will not happen all at once, the company said. The next step in the project will be detailed engineering and ordering long-lead materials. Electrified station modules are scheduled to arrive at sites in 2005, with commissioning and startup of electrified pump stations to follow, and project completion scheduled by the end of 2005. ●

Gas project proponents square off

Advocates of four plans to commercialize Alaska North Slope gas pitch their projects to Commonwealth North

By KRISTEN NELSON

Petroleum News Editor-in-Chief

It all boils down to answering some basic questions: Who? What? When? Where? And, of course, how much — how much money will it cost and how much gas will it move?

Proponents of four projects to move Alaska North Slope natural gas to market summarized their projects — and answered questions — at a meeting of Commonwealth North Feb. 27 in Anchorage, Alaska. The Anchorage-based public policy group also provided answers to questions the organization had asked proponents in advance of the meeting.

Dave Dengel, Alaska Gasline Port Authority

These are all projects that would bring North Slope natural gas south through Alaska. The Alaska Legislature has said the state will not allow an "over-the-top" route taking gas east across the Beaufort Sea and then south through Canada.

That said, there are a number of questions which have not yet been resolved:

• Is the project economic?

• Will Alaska's North Slope natural gas reach markets in this decade, or not until the next, and how much gas will be shipped — 2 billion cubic feet per day, 4.5 billion or 6 billion?

• Will the gas go primarily to Midwest markets or will portions go to the West Coast, or even to the Far East, and will the gas leave Alaska in a pipeline or on liquefied natural gas tankers — or both? Will there be just a pipeline to Alberta, or a "Y-line" with branches to both Canada and Valdez? And what about a spur to Southcentral Alaska?

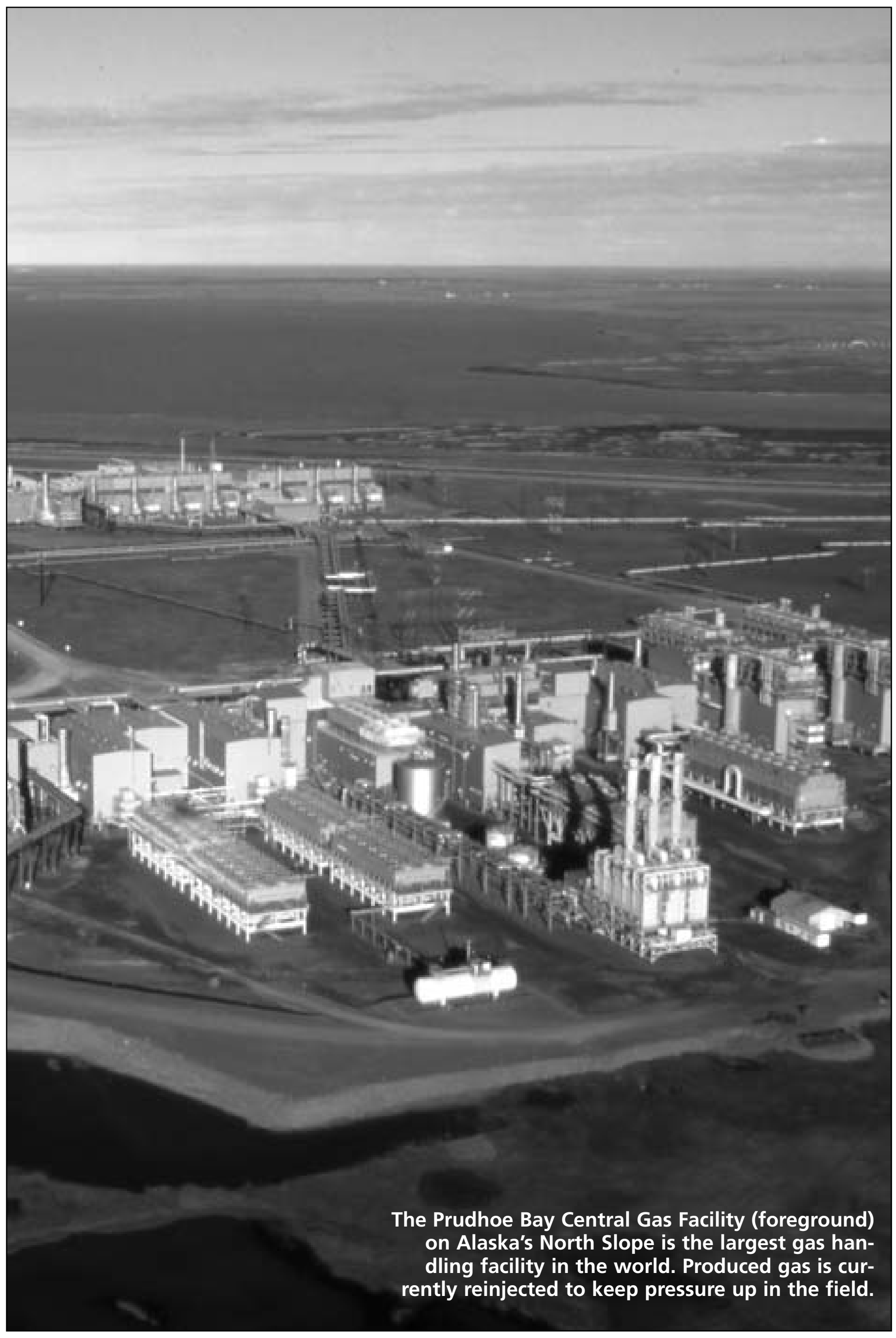
• If there is a pipeline taking gas to a liquefaction plant to be chilled and pressurized into LNG, will that line go to a new LNG plant near Valdez or to the existing ConocoPhillips-Marathon LNG plant north of Kenai?

• What about the sequence of projects: should a line be built first into Canada, with a later spur to tidewater within Alaska, or first to tidewater, or simultaneously into Canada, to tidewater and to a connection with the existing Southcentral distribution system?

• Who will build the pipeline — the North Slope gas producers, a pipeline company, a municipal port authority or a state gas authority — and will Alaskans own a piece of the pipe?

• Will the cost for the project be $12 billion, $14 billion, $19 billion or $26 billion?

• What will be included in the project: new pipe all the way into the Midwest or just into Alberta; an LNG facility at Valdez; a liquids extraction plant; and who will build the gas treatment plant on the North Slope?



JUDY PATRICK

The Prudhoe Bay Central Gas Facility (foreground) on Alaska's North Slope is the largest gas handling facility in the world. Produced gas is currently reinjected to keep pressure up in the field.

Alaska Gas Project Primer

Players represented at Commonwealth North Feb. 27

ALASKA GASLINE PORT AUTHORITY: established in 1999 by a vote of residents of the North Slope Borough, the Fairbanks North Star Borough and the city of Valdez.

ALASKA GAS TRANSMISSION CO.: formed in 2004. MidAmerican Energy Holdings Co., a Berkshire Hathaway affiliate, 80.1 percent; Cook Inlet Region Inc., an Alaska Native corporation, 9.95 percent; Pacific Star Energy LLC, a consortium including Alaska Native corporations, 9.95 percent.

ALASKA NATURAL GAS DEVELOPMENT AUTHORITY: established by Alaska voters by a referendum on the November 2002 general election ballot to pursue taking ANS natural gas to market as LNG, and delivering gas for in-state use.

NATURAL GAS OWNERS: BP Exploration (Alaska) Inc. and ConocoPhillips Alaska Inc.: North Slope oil producers; with ExxonMobil, majority owners of ANS natural gas; state of Alaska has 12.5 percent royalty interest in natural gas.

All projects head south — initially

All of these projects head south from the North Slope initially, taking North Slope natural gas by pipeline along a route similar to that already used by the trans-Alaska oil pipeline. Some 500 miles south of the North Slope, however, differences appear.

"Our project is basically a three-line project," said Dave Dengel, executive director of the Alaska Gasline Port Authority. A pipeline runs "from the North Slope to Valdez for LNG," he said, but with this Y-line concept the line splits at Delta Junction and one pipeline continues to the Canadian border while the other heads south to Valdez, with a spur line coming off at Glennallen to connect to the Southcentral Alaska gas grid.

Ken Thompson of Pacific Star Energy, representing the Alaska Gas Transmission Co., said that company would "design, construct, own and operate this line from the North Slope to the Alaska-Yukon border" where it would meet up with a Canadian line to be built by TransCanada.

The Alaska Natural Gas Development Authority, said its chief executive officer, Harold Heinze, was "specifically authorized by the ballot measure" to build a gas pipeline from Prudhoe Bay to Prince William Sound, with "a spur line coming

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PRIMER

from Glennallen into the Sutton area so that the Cook Inlet area could be supplied with gas, also."

Ken Konrad, gas performance unit leader for BP Exploration (Alaska), said the producers' project is a pipeline through Canada to the North American market.

Both gas and LNG proposed

Some projects are all pipeline gas, some a mix of pipeline gas and LNG.

"Our project is really all about a large-diameter, high-volume, high-pressure gas pipeline to serve North American markets," BP's Konrad said of the producers' plan. "The North American market is the biggest, deepest, most vibrant gas market in the world. It's clearly the place we want to sell our gas, and we think … using a leading-edge technology gas pipeline is clearly the lowest cost way to get that gas to market."

The ballot initiative establishing the development authority, Heinze said, authorized a line to Valdez where gas would be liquefied and shipped by LNG tanker, and included the spur line to bring pipeline gas into the Southcentral grid. LNG would go both into the Pacific Rim — Japan, Korea and Taiwan — and to the West Coast of North America, the development authority said in its prepared response.

Alaska Gas Transmission will deliver pipeline gas "to Canada and the Lower 48 markets," Thompson said.

And the port authority project would deliver pipeline gas to the North American market and LNG from Valdez to the Pacific Rim and West Coast.

How much gas would be shipped?

The port authority proposes to ship the largest initial amount of gas, 6 billion cubic feet a day, it said in its written responses, "with necessary flexibility in the allocation between an LNG pipeline, a gas pipeline to the Canada border and a gas pipeline to the Southcentral gas grid."

Alaska Gas Transmission is proposing 4.5 bcf, but Thompson said deliveries are expected to "grow substantially," to 6 bcf.

The Alaska Natural Gas Development Authority plans a 2 bcf a day line, the authority said in its written responses, and said that with additional compressor throughput could be increased to 3 bcf a day.

The producers said in their written response that their "preliminary design" is for approximately 4.5 bcf a day "at the inlet of the gas treatment plant on the North Slope" but has the potential to be expanded to 5.6 bcf a day.

They questioned higher initial delivery rates. Joe Marushack, vice president Alaska North Slope gas commercialization for ConocoPhillips Alaska, said the producers think initial delivery rates of 6 bcf per day are "unrealistic" because the known resource on the North Slope is only 32 trillion cubic feet, and to deliver 6 bcf a day over a 30-year period would require a resource of 66 trillion cubic feet. "So we think an initial base project without exploration of 6 bcf a day is … unrealistic."

And how much will all this cost?

Pricing for the projects varies a good deal, with part of the variation due to differences in the projects.

Konrad said the producers' project would cost about $19 billion: $2.3 billion for the gas treatment plant on the North Slope; $4.4 billion for the Alaska segment of the pipeline. In their written response the producers said the total pipeline cost would be $11.8 from Alaska to Alberta, a natural gas liquids plant would cost $400 million and the pipeline from Alberta into the U.S. Midwest would be $4.5 billion.

Heinze said the development authority is looking at a $12 billion project. In its written statement the development authority broke that amount down into: $2 billion for a gas treatment plant on the North Slope; $4 billion for a gas pipeline to Valdez; $4 billion for the LNG plant; $2 billion for LNG tankers; and $300 million for the spur line to Southcentral.

Alaska Gas Transmission is proposing a project that totals some $13.8 billion. Thompson said the Alaska portion of the gas pipeline would cost $6.3 billion, the Canadian segment of the line $5 billion and the gas treatment plant on the North Slope roughly $2.5 billion.

Dengel said the port authority project, at $26 billion, is a "not-to-exceed" cost estimate and "includes all the costs, all the short costs and all the hard costs…" In its written response the port authority noted that this includes "pipelines to both Valdez and the Canada border, and additional statewide distribution system through the Mat-Su to Southcentral."

Who cares what it costs?

The cost issue isn't just a numbers game: the cost of the project directly affects the tariff, the fee companies will pay to move natural gas on the pipeline. The higher the construction cost, the higher the tariff. The higher the tariff, the lower the wellhead value to the producers and to the state, which has royalty gas to move — and the lower the taxes the state will collect on the value of the gas shipped.

Asked how confident they were, on a scale of 1 to 10, of their numbers, the port authority and the development authority were the most confident, the producers the least confident.

Dengel said the port authority has a "high level of confidence," a 10 on a scale of 1 to 10, based on the more than 55,000 man hours Bechtel Corp. put into the numbers and because the construction cost is a "hard bid number that if it goes over, the contractor will absorb that cost."

Thompson said he hadn't asked MidAmerican about their level of confidence in the numbers, but noted that Alaska Gas Transmission has a technical agreement with TransCanada, which "has spent over $400 million in regard to cost estimates and all the issues related to the pipeline in Alaska, as well as the Canadian segment." And, he said, MidAmerican has assigned a project team "comprised of two executives that worked on the Taps oil line with Bechtel and other companies, so they know and understand Alaska" and "handpicked some of their best from their various affiliate companies and assigned (them) to this project, which is a sign I look for." He said that while he hadn't asked David Sokol, CEO of MidAmerican, about the

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PRIMER

number, based on what he knew of the project, "and on a scale of 1 to 10 of the people they've assigned to this, I would definitely rate that as a 10 or close…"

Heinze quipped that "if it was me I'd probably be a 13, but since it's the state, and I represent you all, it will be an '8' — that's probably a little more realistic. He said the development authority's confidence in its numbers is based on the years Yukon Pacific spent studying a standalone LNG project. "And that design has been made available to us to look at" and, since it follows the trans-Alaska pipeline route, "there are basically no unknowns." Heinze noted that since Yukon Pacific did its work there have been breakthroughs reducing the cost of liquefaction plants. And, he said, another thing that adds to his confidence "of both economics and in terms of the judgments that are being made," is that Shell is spending $10 billion in Sakhalin to develop about half the volume the authority would produce.

ConocoPhillips' Marushack said the producers have "a million man hours into this project," with $125 million spent recently "plus some individual work that's being done on this," plus the experience they have building projects on the North Slope and building mega projects worldwide. "We've got a cost estimate that's maybe plus or minus 20 percent," he said. "We are at least a 4 out of 10 and I really, really question how anybody could be much more than that."

BP's Konrad agreed. There is still a lot of work to be done, he said. "We've clearly done more work than anybody, but there's a long ways to go for all parties up here."

Producers, others disagree on how long it will take

It was three to one on how long it will take to get the project to market, with the producers in the minority.

The port authority said in its written response that its project would be up in "approximately 2009/2010."

Thompson, speaking for Alaska Gas Transmission, drew a chuckle when he said: "Of course, this is dependent on regulatory approvals and successful commercialization, (but) we're targeting December 31st at noon, 2010, for gas sales."


Ken Thompson, Alaska Gas Transmission Co.

Thompson said "an early in-service date" is "going to be very important," and said Alaska Gas Transmission believes a gas line from Alaska will "moderate U.S. gas prices for all consumers, as well as provide some energy security benefits" for the United States and maximize value for the state of Alaska.

Thompson argued the 2010 date was feasible. He said Alaska Gas Transmission has a technical agreement with TransCanada, which has been working on both the Alaska and Canada segments of the project for the last 15 years, to share information.

And MidAmerican Energy's affiliates in the gas transmission business "own today and operate over 18,000 miles of interstate natural gas transmission lines — the second largest in the United States in terms of gas transmission."

In May 2003, he said, MidAmerican Energy affiliate Kern River Gas Transmission "completed the largest diameter and largest natural gas expansion project that's been undertaken in the last 10 years in the U.S. With that Kern River line in California, it had a $1.2 billion expansion. It was completed within nine months, it was on schedule and it was $79 million under budget."

The Alaska Natural Gas Development Authority said in its written responses that it was targeting to have the project in full operation in 2009.

BP and ConocoPhillips said in their written response that they believe: "It will take about 10 years to plan, engineer, construct and start up a gas pipeline project once the necessary state and federal government legislation is secured."

"This project will be won or lost in the front end … Errors can cost billions," said ConocoPhillips Alaska's Marushack, and reminded the audience of the $800 million trans-Alaska oil pipeline project, which ended up costing $8 billion.

Marushack said the parts of this project — the plants and pipeline segments — are so large each "is a world-scale project by itself," and coordination is necessary in "logistics, procurement, construction, labor, environmental commit (and) stakeholders' (issues) … (because) each of these projects has the potential to move the markets in terms of labor and market supply, so we've got to optimize."

He said these cost overrun and coordination issues "are in direct conflict with fast tracking and taking short cuts."

In "a project of this size and complexity, imprudent speed will destroy all potential value," Marushack said.

He also said he is "very suspect about those schedules that are clearly not achievable and introduce additional risk…"

The producers have done work on feasibility, he said, and have worked on other large projects, and think it will take about 10 years from approvals before the first gas moves through a line.

Projected wellhead price for natural gas?

All of the participants were asked what they expect the wellhead price of the gas will be, the price that the producers — and the state for its royalty gas — get from a natural gas sale.

"The equation is wellhead equals market less tariff," said ConocoPhillips' Marushack. "And the tariff has to be all the way to the market, not Alaska border, not somewhere else, all the way down to the market."

"All of us are price takers, none of us are price makers," he said, and over the last 10 years the market for natural gas "has averaged a Henry Hub price of $3.07." We've quoted a tariff at around $2.50, Marushack said, so that would leave about 50 cents at the wellhead, and "that's not adequate."

Over the last two, two and a half years, however, "the average market price has been bumping up against $5," a much better number. But, Marushack said, "we need a project that works in any environment," because if prices go back down you could be in a situation where you'd

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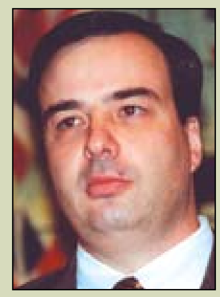
ConocoPhillips: Once gas flowing, a line to Kenai for LNG 'might one day be an opportunity'

The producers studied a standalone liquefied natural gas project several years ago, said Joe Marushack of ConocoPhillips.

At the end of that study, "we concluded that only the Alaska gas pipeline project works…


Joe Marushack, ConocoPhillips Alaska Inc.

"Well, things really haven't changed very much in three years."

He told Commonwealth North Feb. 27 that the companies' view "is driven by economics that do not allow Alaska LNG to be competitive with other LNG projects," where the typical cost is about $3 billion to $5 billion for 1 billion cubic feet of project. "The LNG project recently being promoted is about 2 bcf costing $12 billion or about $6 billion for the project, per bcf."

That compares to about $5 billion per bcf for a pipeline project, "assuming we have to build all the way to Chicago," he said.

"In essence, the requirement to build an 800-mile pipeline before you even start on an LNG plant makes it almost impossible to have a standalone project," Marushack said, because of "very fierce" competition in the Pacific Rim.

But, Marushack said, "I want to give you a positive message about LNG also."

If, he said, the producers can make the pipeline project to the Lower 48 economic, "it could make sense, at a later time, to expand that project for a spur line down to Kenai for LNG."

There isn't enough known gas right now for both a pipeline to the Lower 48 and gas for an LNG project, he said, but if more gas is found, "this might one day be an opportunity."

ConocoPhillips is the operator of Kenai LNG plant (ConocoPhillips 70 percent, Marathon Oil 30 percent).

But even Kenai wouldn't work on a standalone basis, Marushack said in response to a question about a pipeline to continue or expand the Kenai LNG facility.

"We've been in the market there (at Kenai) for 30 years, never missed a delivery. Even with that advantage — and Kenai will always have an advantage — we couldn't make that project happen on a standalone basis."

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PRIMER

cover your tariff, but that's all.

"Well I have no idea what the wellhead is going to be, because I have no idea what the market price is going to be," said the development authority's Heinze. He said projects need to be tested "against the price of gas that makes sense, and most of the people I know believe that in the long term the test for economics of these gas projects, all around the world, is somewhere in the range of $3 to $3.50 in the marketplace."

Alaska Gas Project Primer

That range is used, Heinze said, because that range is quoted for delivery of gas from Qatar. "They have 900 trillion cubic feet — that's the 8,000-pound gorilla if you will of the gas world," he said. He said the $3-$3.50 number is what he used to reflect the general view. "At times when prices are better than that, somebody's going to realize a lot of extra money above and beyond that. How that's split, how that's shared, what it's used for, all those things, I think is to be worked out through the negotiations," he said.

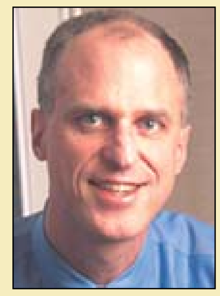
Thompson, speaking for Alaska Gas Transmission, said he didn't have a specific wellhead price, and agreed with Heinze that it's based on market price. He said the goal at Alaska Gas Transmission is to have the lowest tariff possible, because the lower the tariff is, the most likely the producers and the state are to go with the Alaska Gas Transmission project.

The Alaska Gasline Port Authority has said that at a certain price it would pay $1.48 at the wellhead, Dengel said, "but if the price of gas in Chicago drops substantially, so would the wellhead price that would be paid for gas on the slope." One of the advantages of the port authority project, he said, is that because they plan to sell both LNG and pipeline gas, the longer-term LNG contract prices would help level out any spikes in the shorter-term market for pipeline gas into Chicago.

North Slope producers concerned about risk

BP's Ken Konrad and ConocoPhillips Alaska's Joe Marushack spent a considerable amount of time addressing the issue of risk at the Feb. 27 Commonwealth North forum on projects to commercialize Alaska's North Slope gas.

Konrad called a natural gas pipeline to Lower 48 markets "an exciting project," but said, "it is a project of unprecedented scale and hence it has quite a few risks. So while the rewards are there, currently the risks outweigh the rewards."



Ken Konrad, BP Exploration (Alaska) Inc.

Marushack said the companies have been focused, over the last two years, on "minimizing risk associated with the project." There are, he said, three types of risk: "market or commodity risk; government or regulatory risk; technical or capital risk." The companies have been working to reduce "market and regulatory risk through federal legislation" and through the application to the state under the Stranded Gas Development Act, he said.

Why the concern with risk? "It's very clear," Marushack said, "that under most scenarios the producer and the state, who will either be the shipper or directly tied to the shipper, will ultimately bear most if not all of the risk."

Why is that?

Whoever builds the project will require a firm commitment from the producers to ship on the line, Marushack said, and that means a firm commitment to pay the tariff, projected to be a "$4 billion per year tariff commitment, assuming that we don't have any overruns, penalties or delays. It's a commitment nobody will enter into lightly," he said.

Independent analysis of mega projects has found that "50 percent of all projects have 50 percent overruns, and that number's growing," Marushack said.

"So we've got to be very, very comfortable that we know what the cost is going to be and that someone's going to deliver on those costs, because even the big projects that anyone does right now, they have a lot of overrun potential."

Konrad said the risks that prices in the market will fall below the tariff and the risk that project costs will be significantly greater than projected can be borne by either the resource owner or the pipeline builder.

"If someone says, I'll build the line, it's going to cost you $2.40 (per mcf in tariff) no matter what, then that's a firm estimate.

"If it's, I'll build the pipeline if you promise to pay for it, that's an entirely different proposition."

Typically in the North American market the shipper pays for the cost of the line, he said, so the risk falls back to the resource owner. "Certainly if someone steps up and says I promise that this is what the tariff will be, no matter what, then they're taking on some risk."

What are the hurdles?

One of the questions Commonwealth North asked was: "What are the principal hurdles your project needs to overcome?"

Not surprisingly, a commitment from the North Slope producers to sell gas or to ship gas showed up on two lists, while "commercialization of the project" on the third non-producer list probably could be construed to include the same item.

BP and ConocoPhillips listed "a clear and durable fiscal contract with the state of Alaska, a federal fiscal mechanism in the U.S. and efficient regulatory frameworks in the U.S. and Canada."

Asked what it would take for them to sell gas, BP's Konrad said, "I think what we need is a credible party with a credible engineering estimate and letters of credit, because there's going to be lots of risk in an exchange we do negotiate with anybody, so there's no sense in negotiating with somebody unless there's confidence

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JUDY PATRICK

The Alyeska Marine Terminal

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PRIMER

that either side can pay the other side in the event that things don't quite work out."

Standard for a gas pipeline would be "take or pay, long-term commitments," he said.

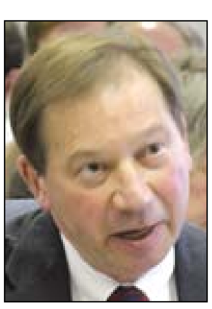
"Provided they've got a letter of credit that says they're willing to stand behind their pen, then let's do business."

ConocoPhillips' Marushack said cost overrun potential on big projects is a real risk, so the gas owners would have to be very comfortable that cost terms could be met. "After that, it's just depending on the terms and the time.

"The gas is for sale. The gas has always been for sale," Marushack said.

"But we've got to have a project that makes sense." And, he said, "we're looking at the lowest cost possible tariff. When folks come to us and want to buy the gas, we're going to have to be very comfortable that that's the tariff that you end up with, that it doesn't blow up and you get twice the cost. Because gas isn't like oil," he said, there are "very small margins on gas, generally."

FORREST CRANE



Harold Heinze, Alaska Natural Gas Development Authority

Alaska Gas Project Primer

Who would build what?

BP and ConocoPhillips described their project in their written response as including approximately 3,600 miles of pipeline with 1.2 million to 1.4 million horsepower of compression required to deliver natural gas from the North Slope to U.S. upper Midwest markets. BP's Konrad said a gas treatment plant would be needed on the North Slope to remove carbon dioxide, compress and chill the gas, and "a natural gas liquids treating plant located somewhere along the line, probably in Alberta, that is to reduce the Btu level of the gas down to a level that is saleable into the market." Of the four elements, Konrad said, the pipeline from Alberta into the upper U.S. Midwest might not be needed. "There's a possibility that there will be excess capacity on existing infrastructure at that point in time. Existing infrastructure could be expanded. Some combination of those three — new build, excess capacity, expansion — will take the gas out of Alberta and the market will decide what the lowest cost way out of that basin is."

The Alaska Natural Gas Development Authority project also involves four major components: a gas treatment facility, the pipeline, the LNG facility and the tankers.

"It may be that the authority is not involved in all four of those components," Heinze said. "It may be that the producers, for instance, are involved in gas treatment on the North Slope. And we certainly don't intend to own tankers."

And it may be, he said, that the authority wouldn't even be involved in the pipeline, maybe it's just involved in the liquefaction plant, "maybe it chooses to perform that service at basically no margin, just at cost, like building a highway.

"Why would we do that? Because that's the same thing that happens in Indonesia and other parts of the world that we compete against." Heinze said that is one of the things on the table.

"We are not in competition with anybody," he said, and will only "take on those things that we can uniquely do better than someone else," because the authority is a public corporation of the state, not a profit-making organization.

Alaska Gas Transmission company's plan goes only to the Alaska-Yukon border. The company said in its written answers that it "envisions that a gas conditioning plant be constructed and owned by the ANS producers," and plans just to build the pipeline from the North Slope to the Yukon border, where it would connect with a pipeline built by TransCanada.

The Alaska Gasline Port Authority project is the largest, with pipelines from the North Slope to Valdez, a line from Delta Junction to the Canada border and from Glennallen into the Matanuska-Susitna Borough, an LNG plant and a gas conditioning plant.

What about the financing

The port authority plans to use debt financing for 100 percent of the project. Tax-exempt bonds would be issued for that part of the project providing gas for in-state use, estimated at 10 percent, the authority said in its written responses.

Alaska Gas Transmission's equity investors are MidAmerican Energy

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JUDY PATRICK

Trenching work near Deadhorse and Fairbanks in the winter of 2001-02 sought to verify the accuracy of North Slope gas producers' trenching estimates for the proposed gas pipeline from the North Slope to Lower 48 markets.

Some contention over benefits to Alaska

Alaska Gas Project Primer

Proponents were asked about the benefits of their gas projects to Alaska and in-state access to natural gas at the Commonwealth North Feb. 27 panel on North Slope natural gas development.

"The mission, the main mission (of the port authority) is to maximize Alaska's North Slope gas for the maximum benefit of all Alaskans," said Alaska Gasline Port Authority Executive Director Dave Dengel. The authority said in its prepared response that the state will receive maximum wellhead value in excess of $1 billion a year from royalty, severance and income taxes, and the authority will also provide a community dividend program based on population, with a minimum of $50,000 a year, "and in the case of Anchorage, potentially in excess of $100 million per year."

On the access issue, Dengel said the "port authority concept requires an in-state distribution system from Prudhoe Bay to Glennallen and from Glennallen throughout Southcentral Alaska."

Ken Thompson, speaking for Alaska Gas Transmission, said the company "believes that an independently owned pipeline and acceleration of the Alaska pipeline project in-service date is in the state's best interest." The combination of production declines from the Western Canada sedimentary basin and the increasing demand for natural gas in the Lower 48, "largely resulting from gas-fired elec-

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PRIMER

Holdings, 80.1 percent, Cook Inlet Region Inc. 9.95 percent; Pacific Star Energy 9.95 percent. The company said in its written response that a final financing plan is not available, but it "is interested in pursuing tax-exempt financing." Thompson told Commonwealth North that MidAmerican Energy Holdings is an affiliate of Berkshire Hathaway, which has "220 billion in assets, very little debt and $26 billion in cash.

"So this is a project of great interest … as an investment," he said.

Thompson also said that because "Alaskan companies have been brought in, Alaskans will own a piece of the pipe this time, at just under 20 percent.

"This changes the fundamental business model from service and support to equity ownership for Alaskans," he said. "Equity ownership brings the real wealth in any natural resource industry, and we're excited to be part of it," Thompson said.

"The equity element of financing could be zero if we adopt a state infrastructure approach to bonding," the Alaska Natural Gas Development Authority said in its written response. "A number of bonding consultants have indicated that multi-billion dollar bonding of a gas project is possible," the authority said.

Heinze told the Commonwealth North audience that because of the authority's "unique tax status, its unique financing status," it may be that the authority would treat infrastructure needed to commercialize North Slope gas the way a state treats a highway: "We go out and issue bonds, we retire the bonds and that's it. We believe that the economic activity we create pays for them."

That approach, he said, could drop the tariff cost by as much as a dollar.

BP and ConocoPhillips said in their written responses that it is too early to identify equity investors, but that "potential investors must add value and accept the project risks, not simply pass the risks through to the resource owners."

And, the companies noted: "Regardless of the source of the financing, the project sponsors/producers are the ultimate credit standing behind the pipeline, either through direct investment or supporting with a throughput and deficiency commitment.

"If the project has this backing, we are confident that appropriate financing will be available."

ConocoPhillips' Marushack said that people seem to want to address financing first, "but it's actually a second-tier issue."

Financing doesn't make a project work, he said. "Attractive projects stand on their own merit and their own capital."

And as for all-debt financing, he questioned that concept: "Why would any financier lend money to a massive project if the sponsors weren't going to do so themselves? We have a lot of experience in project financing and this leads us to put little stock in any sort of 100 percent financing scheme. Equity is the shock absorber … that addresses financial distress and makes creditors comfortable the project sponsors are serious and committed," Marushack said.

The producers are, however, interested in loan guarantees or Alaska Railroad based funding that has "the potential to reduce the interest rate and make the project tariff a bit lower.

"At the appropriate time, all financing issues have to be addressed," he said, "but financing is not going to be the panacea to compensate for any fundamentally weak project." ●

● NORTH AMERICA

Alaska gas would have small effect on price

Federal report says prices 4.5 percent higher in 2025 without Alaska gas line

By LARRY PERSILY

Petroleum News Government Affairs Editor

A Department of Energy report says failure to construct an Alaska natural gas pipeline to feed North American markets could push gas prices 4.5 percent higher in 2025 than they otherwise would be if the line is built in the next decade.

The lack of supply from Alaska also would mean more reliance on imported liquefied natural gas — but even more of the market demand would be picked up by increased production from U.S. and Canadian fields, aided by the slightly higher prices, the report said.

The Energy Information Administration report, released March 1, compares a no-Alaska pipeline scenario against the department's Annual Energy Outlook 2004 released in January, which assumes North Slope natural gas deliveries start in 2018.

Alaska Gas Project Primer

Rep. Barbara Cubin, R-Wyo., chair of the Energy and Mineral Resources Subcommittee of the House Resources Committee, requested the report Feb. 3.

Congress is stuck in a stalemate between House and Senate Republican leaders over the federal energy bill that contains key tax, loan guarantee and permitting incentives to promote construction of the Alaska gas line, along with billions of dollars of other incentives and tax breaks for domestic energy producers.

Report looks at supply possibilities

In addition to the no-pipeline possibility, the report also compared three other scenarios with the department's 20-year outlook for U.S. natural gas production and consumption:

• No significant increase in tight-sands and other unconventional natural gas production.

• Failure to win permits for construction of more than three new LNG receiving terminals along the East and Gulf coasts to serve U.S. markets.

• A combination of all three: No Alaska gas line, little new domestic production, and too few new LNG receiving terminals.

The base case for the report — the department's annual outlook from January — assumes natural gas prices and market conditions result in the final go-ahead for an Alaska pipeline in 2009, with deliveries starting in 2018. And under that base case, natural gas prices would average $4.40 per thousand cubic feet (2002 dollars) in 2025.

Without gas from Alaska, prices would be at $4.60 per mcf in 2025, the report said. "The lack of Alaska gas supplies to the Lower 48 raises gas prices, which reduces consumption and stimulates higher Lower 48 gas production."

Worst case gas at $5.61 in 2025

It gets worse if there is Alaska gas but limited LNG imports, with prices projected at $4.74 in 2025, and a bit worse than that if there is Alaska gas but little success in new, unconventional gas production. Under that scenario, the report foresees gas at $4.85 per mcf in 2025.

The worst of all combinations — no Alaska gas, limited LNG and little gain in unconventional production — would put 2025 prices at $5.61.

In addition to significantly higher prices, the supply shortage would cut deeply into electrical generation and industrial uses, pushing them toward other fuels or, in the case of gas-reliant manufacturing, to move out of the country.

Although the Department of Energy modeled the worst-of-everything scenario, it made certain to state it is unlikely such a possibility could ever occur. "The combined case is a severely restricted gas supply scenario that goes beyond what might be plausibly expected in the future."

More plausible, the report continued, are possible constraints on constructing new LNG terminals or lower success rates in unconventional gas production, but not everything bad happening at once.

Under the reduced-LNG possibility, lack of new terminals would restrict imports to 5.75 billion cubic feet per day vs. the more than 13 bcf per day the department really expects in 2025.

The department's base-case outlook assumes the Alaska gas line would carry almost 5.5 bcf per day to North American markets by 2025.

Differing opinions from two reports

The report also forecasts that the introduction of Alaska gas into the market in 2018 would knock down prices by just 10 cents per mcf the following year, as the market responds to the large, new supply.

That strongly contradicts a report issued in late October by an 18-member national commission that said an Alaska gas line could push down gas prices by an average of 56 cents per mcf during the first 10 years of operation.

Lower 48 and Canadian producers would quickly react to the new supply coming into the market, reducing their investments in production until consumer demand rose sufficiently to burn up the added supply, according to the report from the National Commission on Energy Policy, funded by a collection of nonprofit foundations.

A key difference between the commission's 2003 report and the Energy Department report of February 2004 is each study's projection of future gas prices. While the Energy Department predicts natural gas at $4.60 per mcf in 2025 without an Alaska gas line, the commission forecasts gas at between $5 and $5.50 through 2025 without Alaska. The higher the price without Alaska gas, the further it has to fall with an Alaska pipeline. ●

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CONTENTION

tric generation, create a window of opportunity.

"Alaska should aggressively compete with LNG import terminals to bring Alaska gas to market at the earliest possible date."

Thompson also said "an independently owned natural gas pipeline will provide non-discriminatory open access for receipts and deliveries throughout the state of Alaska."

"The gas authority you created — one of the major reasons you created it, and one of the major focuses — is to ensure that benefits of gas are available throughout Alaska," said the Alaska Natural Gas Development Authority's CEO Harold Heinze.

He said that while Alaskans can appeal to the Federal Energy Regulatory Commission in Washington, D.C., for gas line access, "you have no guarantee as to what the tariff or charge will be at that point. And that is a process that's set outside of Alaska.

"The authority's approach is that we would like to participate in whatever project happens, to make sure that we have assured Alaskan gas can be delivered here in Alaska at a price that is very reasonable and frankly, the lowest cost of service possible for us, not worrying about what it costs to get to other markets, but worrying about what it costs to get to this market."

"The right proposal for Alaska is the one that can actually advance," BP Exploration (Alaska) and ConocoPhillips Alaska said in their prepared responses. A pipeline to the North American markets "is the most promising option to develop North Slope gas" and "has the potential to provide 30-plus years of significant state revenues," clean fuel, jobs, "incentives to explore for and develop new gas resources and access to gas for in-state use," they said.

Ken Thompson, speaking for Alaska Gas Transmission, said the company "believes that an independently owned pipeline and acceleration of the Alaska pipeline project in-service date is in the state's best interest."

On the access issue, BP's Konrad said the pipeline would be regulated by FERC in the United States and by the National Energy Board in Canada. "There are thousands and thousands of pipelines in the U.S., they are all open access and any party wanting service from point A to point B and anywhere along that (line), can buy firm transportation for that service," he said.

In response to Heinze's remarks about his authority's concerns about ensuring fair prices, Konrad said that while the companies talk about FERC, "just imagine why anyone would want to transport gas 3,500 miles if they could sell it 500 miles away. Any gas that can be sold in Alaska is a great thing for any investor, and I think it's almost as simple as that.

"It's not just regulations," he said, "it's just commercial motivation."

"The issue isn't one of selling," Heinze shot back, "it's what the charges to transport it are. And again," he said to the audience, "if you all are prepared to accept that the companies in their very best interest will do the right thing by us, then fine."

natural gas

CANADA

Yukon-NWT still at odds: leaders have a different view of Arctic pipeline timing

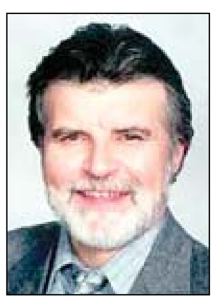
A thaw in once-chilly relations between the Yukon and Northwest Territories has stopped short of a love-in.

The premiers of the two northern territories left no doubt at an Arctic Gas Symposium in Calgary March 8 and 9 that they sit at polar opposites when it comes to whether the Mackenzie Valley or Alaska Highway gas pipeline should be built first.

Northwest Territories Premier Joe Handley

Northwest Territories Premier Joe Handley was emphatic that the Mackenzie project should be built first, fearing that opening up the North Slope for deliveries of 4-5 billion cubic feet per day could swamp the market, drive down prices and undermine the Canadian pipeline.

Yukon leader Dennis Fentie objected to giving priority to one pipeline over the other, arguing that the challenge is to "make sure they both get built."



Yukon leader Dennis Fentie

That sign of tension was a flashback to a couple of years ago when then premiers — Pat Duncan of the Yukon and Stephen Kakfwi of the Northwest Territories — were constantly at loggerheads over the timing of the mega-projects.

Handley also expressed concern about delays in the regulatory phase that could delay the Mackenzie pipeline beyond 2009.

He said the "market is there, the demand is there, the supply is there," but slowing the environmental review process could see the Mackenzie Delta producers scrap the project.

Randy Ottenbreit, Imperial Oil's development executive with the Mackenzie Gas Project, said the review was taking longer than anticipated and could extend the regulatory filings by a few months.

On another front, Handley expressed concern that the labor-hungry oil sands sector in Alberta poses a challenge for the Mackenzie Valley project.

"I don't think you can afford to delay this pipeline because of a shortage of labor," he said.

Other industry sources have suggested that a bigger problem would come from any decisions by Enbridge or Terasen to proceed with multi-billion dollar pipelines from the oil sands to the British Columbia coast.

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

ALBERTA

Quicksilver pumps US$89 million into Canada

MGV Energy, the Canadian subsidiary of Texas-based Quicksilver Resources, will drill 350 (280 net) wells on seven coalbed methane prospects in the Palliser block of southern Alberta.

One of the pioneers in tapping coalbed methane in Canada, Quicksilver will spend US$89 million on exploration and development as it builds on a production of about 20 million cubic feet per day.

Once conventional activity is factored in, Quicksilver expects to participate in 450 gross wells in Canada.

MGV currently holds 525,000 net acres in Canada and acquired a 100 percent working interest in January in another 76,800 acres of the Wood River area of southern Alberta.

Of its proved reserves of 881 billion cubic feet equivalent at the end of 2003, Quicksilver assigned 131.3 billion cubic feet equivalent to Canadian coalbed methane, up almost 100 million cubic feet from a year earlier.

Company President and Chief Executive Officer Glenn Darden told a conference call that 20 percent of the Canadian drilling will be targeted at exploration.

The program will include about 20 net wells on a conventional shallow-gas field operated by EnCana in southeastern Alberta.

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

● NORTHWEST TERRITORIES

Picking up the pace

Canadian minister promises to tackle Mackenzie regulatory hurdles

By GARY PARK
Petroleum News Calgary Correspondent

Canada's Natural Resources Minister John Efford has thrown his weight behind the Mackenzie Gas Project, pledging to do whatever he can to remove regulatory obstacles.

He said the federal government is committed to the project and will get more involved in heading off delays that Imperial Oil, the project's lead partner, is worried could increase costs and push the start-up date to 2010.

Efford told reporters in Washington, D.C., on March 3 that the major sticking points are aboriginal land claims, completing environmental assessment and speeding up the pace of other regulatory approvals.

He said "there hasn't been enough (Canadian) government involvement" in dealing with first nations — a challenge he described as crucial.

(Efford) also impressed on Bingaman that Canada prefers to let market prices determine whether the Alaska gas project goes ahead rather than see the U.S. Congress introduce price guarantees to get North Slope gas to market.

"We haven't done our job in a timely fashion, so speeding up that process and getting a settlement is absolutely crucial to getting the pipeline started," he said.

"We are now getting refocused and are going to set

see **PACE** page 18

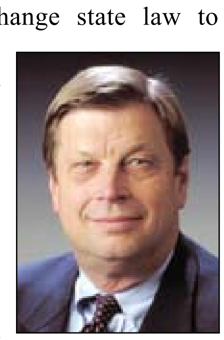
● JUNEAU, ALASKA

Alaska could loan to natural gas authority

Legislation would allow Permanent Fund loans for gas pipeline

By LARRY PERSILY
Petroleum News Government Affairs Editor

An Alaska House committee has endorsed legislation that would change state law to specifically allow the $28 billion Alaska Permanent Fund to make loans for a state-owned natural gas pipeline.



Permanent Fund Executive Director Bob Storer

The State Affairs Committee on March 8 passed out House Bill 466 without objection, including an amendment from Committee Chair Bruce Weyhrauch allowing loans to the Alaska Natural Gas Development Authority.

"I simply wanted to have that pool of funds available to the authority," said Weyhrauch, R-Juneau. "It was not my intent to force the hand of the corporation to invest in the authority."

The bill moves next to the House Finance Committee and then, if successful there, to the full House before going to the Senate, running against the Legislature's May 12 adjournment deadline.

The measure's main intent is to update the Permanent Fund's investment restrictions in state law. In addition to setting out limits for the fund's investments in stocks, bonds and real estate, state statute also allows the fund to put up to 5 percent of its assets in other investments. The bill would allow investments in that so-called "basket clause" to reach 15 percent of the fund's total assets.

Bill's main intent is investment flexibility

"This is necessary because the 5 percent limit is

see **LOANS** page 18

● JUNEAU, ALASKA

Senators trim gas line money

Committee OKs $1 million for state gas authority, pipeline negotiations

By LARRY PERSILY
Petroleum News Government Affairs Editor

Senate Finance Committee members balked at approving the administration's request for $3 million in immediate funding for consultants to help negotiate a state fiscal contract for a proposed North Slope natural gas pipeline and to move forward with a state-owned gas project.

The committee March 10 trimmed the appropriation to $1 million, with the administration to share the money between its contract negotiations and the Alaska Natural Gas Development Authority.

"I'm in agreement that there is an immediate need for the $1 million," said committee member Sen. Ben Stevens, R-Anchorage. Anything beyond that amount, he said, should be part of the normal budget process later in the session.

The administration said it needs at least $1 million to cover the next few months, with the rest targeted for spending in Fiscal 2005 that starts July 1. The Legislature is still working on putting together the Fiscal 2005 budget.

Stevens gained support from Sen. Lyman Hoffman, D-Bethel, who said he wanted to see more details for the full spending request than just the one page handed out at the committee meeting.

Senator questions immediate need for money

Stevens also noted that almost $1 million of the administration's $3 million request is for consulting

see **MONEY** page 22

● JUNEAU, ALASKA

Alaska special session possible this summer

House Speaker expects lawmakers to reconvene for gas line contract

By LARRY PERSILY

Petroleum News Government Affairs Editor

The speaker of the Alaska House said he did not expect MidAmerican Energy Holdings Co. would meet its March 12 target date for a fiscal contract with the state, setting out a schedule of payments in lieu of taxes for a North Slope natural gas pipeline. As such, a special session of the Legislature is possible this summer.

"I'm not sure when the gas line contracts are coming," Speaker Pete Kott, R-Eagle River, said March 8.

The state was continuing to negotiate with MidAmerican in the days before the company's self-proclaimed target date, Deputy Revenue Commissioner Steve Porter said March 9. Company and state officials were meeting in Anchorage.

Alaska's Stranded Gas Development Act requires a 30-day public comment period after the state and a contract applicant reach an agreement, with legislative approval the final step. The Legislature faces a May 12 adjournment deadline, and lawmakers have said they want sufficient time to go through the details of the contract before taking a vote.

MidAmerican submitted its Stranded Gas Act application to the state just seven weeks ago, and Kott said he's skeptical the state and MidAmerican can so quickly negotiate all of the provisions of a long-term contract in lieu of state and municipal taxes on the multibillion-dollar pipeline project.

JUDY PATRICK

MidAmerican's pronouncement of a March 12 completion date "was based on … them getting everything they want" in the negotiations. "I'm sure the administration is not going to give them everything they want." —Alaska House Speaker Pete Kott

The first face-to-face meeting of the state's expanded municipal advisory group was just held March 10 in Anchorage. The communities are there to watch out for their own interests in a contract that would set up a system of payments in lieu of municipal property taxes.

Speaker sees summer session

If the deal isn't finished soon, Kott expects lawmakers will need to reconvene. "I would hope the administration would call us into special session if that contract is available and ready for scrutiny sometime over the summer months.

"It behooves everybody to get it ratified," Kott said.

MidAmerican officials told legislators Feb. 25 the Des Moines, Iowa-based natural gas pipeline and utility company needs state approval of its contract this spring so as not to lose time in the field this summer in Alaska. There is nothing in state law, however, that would prevent MidAmerican from doing field surveys or other preliminary work for the proposed pipeline project before reaching a fiscal deal with the state.

The company filed its application under the Stranded Gas Act on Jan. 22, a week after the major North Slope producers filed their own application for a natural gas pipeline fiscal contract.

The producers have been careful not to announce any target dates for concluding their contract talks with the state, which have been ongoing for several weeks.

State contract one step in decision

Neither MidAmerican nor the producers have said they definitely would build the pipeline from the North Slope to feed North American markets, even if they are successful in negotiating a fiscal contract with the state. Both applicants point to federal tax and loan incentives in the stalled energy bill as key to their decision, and MidAmerican has said it would need the producers or others to sign ship-or-pay contracts to guarantee revenue for the line before committing to construction.

MidAmerican's pronouncement of a March 12 completion date "was based on … them getting everything they want" in the negotiations, Kott said. "I'm sure the administration is not going to give them everything they want."

Porter declined to discuss specific issues in the negotiations. A MidAmerican official did not return a phone call for this story.

And while negotiating terms of the long-term fiscal contract, the state also is negotiating a reimbursement agreement with MidAmerican to cover the state's costs in the Stranded Gas Act negotiations — something the producers already have signed but MidAmerican still had not accepted as of March 9, Porter said. The law only says the Revenue commissioner may require a reimbursement agreement; it does not mandate that applicants cover the state's costs.

State still looks to recover costs

As of early March, the state had spent $170,000 on its contract negotiations with MidAmerican, Porter said. The state has spent $270,000 on its negotiations with the producers, billing the companies for the full amount as per the reimbursement agreement. In addition to forecasting a summertime special session, which Kott said could last a week, the speaker said the House is considering setting up a special committee to manage legislative review of the deal.

The committee could contract for experts to help lawmakers analyze the contract, he said. And although he said House leaders are considering a joint committee with the Senate, the House could go it alone if need be.

"I just wasn't sure what another committee brings," said Senate President Gene Therriault, R-North Pole. The Stranded Gas Act already directs the Legislative Budget and Audit Committee to coordinate public review of a draft contract, he said, and the standing committees of Finance, Resources and perhaps Judiciary also would get a look at the deal.

Therriault said he remains hopeful that state negotiators and MidAmerican can put a deal before lawmakers with enough time left in the session for legislative action. ●

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LOANS

too small to allow the trustees enough flexibility to keep up with changes in investment practices," the Permanent Fund said in its statement of support for the legislation.

The legislation also would allow the fund to venture into hedge funds that use futures contracts and other areas currently off-limits to the state's 27-year-old oil royalty savings account.

Weyhrauch's amendment would allow the fund to make loans to the gas authority without counting the investments against the basket clause.

The amendment would clarify in statute that the fund could loan money to the state gas authority, as long as the investment met all of the fund's standards including the prudent investor rule. The provision "would not lessen the fund's ability to say 'no,'" the representative said.

The freshman legislator earlier this session said Alaskans are frustrated with the lack of progress in building a project to carry North Slope natural gas to market, and he believes there would be support for loaning money from the Permanent Fund to help the project.

The Alaska Natural Gas Authority, created by voters in November 2002 to build a gas pipeline from the North Slope and a liquefied export terminal at Valdez, has no money for construction and would need to borrow money to finance its estimated $12 billion venture. Its state funding covers only feasibility studies and other preliminary reviews.

Investor rule would still cover Permanent Fund decision

Permanent Fund Executive Director Bob Storer told the State Affairs Committee the board of trustees has not taken a position on the provision allowing direct loans to the gas authority. He did, however, explain to the committee that the fund is limited by the prudent investor rule in how much money it can put into any one investment.

The rule requires the fund to diversify its investments, to minimize potentially large losses in any one company or asset, Storer said. "As we diversify our portfolio, we own over 4,000 stocks.

"In our equity portfolio, our largest holdings are probably Pfizer (pharmaceuticals) or GE, around $250 million each," he said.

"As a practical matter … probably the most we would be able to invest (in the state gas authority) would be $50 million, $100 million tops," Storer said. "I'm assuming any loans to the authority would be ill-liquid and below investment grade."

Permanent Fund would look at collateral, risks

Ill-liquid, Storer explained, means there likely would be no secondary market for the Permanent Fund to sell its loan, as there are for publicly traded stocks and bonds. "The less liquid the investment, the less one would be inclined to invest in it."

The fund also would look at whether the loan was backed by any collateral, and whether the expected rate of return was comparable to other investments with similar risks, Storer said. ●

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PACE

a direction and address the issues of concern."

Deh Cho want land claim resolved

The acknowledgement comes amid a growing insistence by the Deh Cho First Nations that its land claim must be resolved and the current approval process must be revised.

The Deh Cho, whose lands cover the lower 40 percent of the Mackenzie Valley pipeline route through the Northwest Territories, say they have not been fully consulted and are ready to take their case to the federal court.

Efford said the prospect of delays is a "legitimate concern," putting pressure on his government to work with industry and stakeholders in a "timely manner."

Imperial Chief Executive Officer Tim Hearn gave a rare display of frustration last month, telling reporters he was "concerned right now about the pace of things," especially with the Mackenzie Valley Environmental Impact Review Board's dithering over when and how its hearings should take place.

Hearn warned the slow pace could add six months to the regulatory process and postpone the start of construction.

The Mackenzie gas producers (Imperial, Shell Canada, ConocoPhillips Canada and ExxonMobil Canada) along with the Aboriginal Pipeline Group hope to complete all of their regulatory applications this year.

Efford said the prospect of delays is a "legitimate concern," putting pressure on his government to work with industry and stakeholders in a "timely manner."

While in Washington, Efford told Sen. Larry Craig of Indiana and Sen. Jeff Bingaman of New Mexico that the Mackenzie project is a top priority for Prime Minister Paul Martin.

He also impressed on Bingaman that Canada prefers to let market prices determine whether the Alaska gas project goes ahead rather than see the U.S. Congress introduce price guarantees to get North Slope gas to market.

Pierre Alvarez, president of the Canadian Association of Petroleum Producers, who attended an energy seminar sponsored by the Canadian embassy in Washington, welcomed Efford's pledge to get the Mackenzie project on the move.

He told reporters that there is a "great deal of frustration from an applicant's point of view" in negotiating the regulatory process.

Piling on layers of new regulations "doesn't necessarily lead to a better regulatory result or environmental assessment," he said. ●

NORTH AMERICA

U.S., Canadian rig counts drop to 1,685 in weekly survey

The number of rotary rigs operating in North America fell by nine to 1,685 during the week ending March 5, according to rig monitor Baker Hughes.

The Canadian rig count, compared to the previous week, slipped by four to 556 rigs, but was still up by 35 rigs compared to the same period a year earlier.

In the United States, the count fell by a net five rigs in the recent week to 1,029, still up by 200 rigs versus the period last year. Land rigs alone decreased by five to 1,011, while the offshore fleet contracted by one rig to 97. The rig count for inland waters increased by one to 21 rigs.

Of the total number of rigs operating in the United States, 964 were drilling for natural gas and 161 for oil, while four were being used for miscellaneous purposes. Of the total, 736 were vertical wells, 302 directional wells and 91 horizontal wells.

Among the leading producing states in the United States, Texas

see **COUNT** *page 20*

ALASKA

ANS output down for January

Alaska North Slope crude oil production averaged 959,250 barrels per day in February, down 4.25 percent from a January average of 1,001,832 bpd. The drop came primarily from the mid-month outage at BP Exploration (Alaska) operated-Northstar, which went down Feb. 8 when a compressor motor failed and only began to come back on production Feb. 22.

The Alaska Department of Revenue's Tax Division said March 5 that Alaska North Slope production has averaged 996,000 bpd for the fiscal year to date (June 2003 through May 2004), compared to the division's projection of 973,000 bpd, 23,000 bpd lower than the projection. On the other hand, the division forecast ANS oil prices of $27.70 per barrel for the fiscal year, and to date the price has averaged $30.18 per barrel or $2.48 per barrel above the estimate.

Thirteen-day outage at Northstar

The 13-day total outage at Northstar, plus reduced production the day the motor failed and for two days as production ramped back up after the replacement work was complete, dropped the field's average monthly production for February by 50 percent, to 39,291 bpd from an average of 78,667 bpd in January.

North Slope production was also down January to February at Endicott, Lisburne, Alpine and Prudhoe Bay.

BP-operated Endicott averaged 26,088 bpd in February, down 6 percent from January production of 27,746 bpd.

Production at BP-operated Lisburne (includes Point

see **OUTPUT** *page 20*

● ALBERTA

Oil sands bombshell

Expansion costs at giant Syncrude operation could double original projections; start-up delayed by 12 months; Canadian Oil Sands Trust hammered

By GARY PARK

Petroleum News Calgary Correspondent

Oil prices of US$25 per barrel are the threshold for the Alberta oil sands to more than double production over the next 13 years to 2.2 million barrels per day and for operators to achieve an "adequate" return on investment of about 10 percent.

So said the Canadian Energy Research Institute on March 3 when it released the findings of a comprehensive study.

The research organization, funded by industry and government, said the target for synthetic crude and unprocessed crude bitumen could reach 2.8 million bpd with oil prices at US$32 per barrel and 3.5 million bpd at an "unconstrained" level.

Bob Dunbar, CERI's senior research director, rated the future of the oil sands as "very robust" based on his belief that "there is a much higher likelihood of oil prices above than below $25."

Under the $32-a-barrel scenario, capital spending would average C$4.4 billion (US$3.3 billion) a year between now and 2017, CERI said.

Just as the industry was absorbing this upbeat message it got hit by a bombshell.

Two days after CERI's study was released, Syncrude Canada set a new benchmark for the cost overruns that have plagued the sector in recent years.

Worst case, expansion could cost double original projections

The consortium owners disclosed on March 5 that an expansion of the world's largest synthetic crude operation had skyrocketed by C$2.1 billion to C$7.8 billion, with a 50-50 chance that it could reach C$8.1 billion by completion.

In the worst case, the Stage 3 expansion would cost double the original projections in 2001 to boost Syncrude volumes to 350,000 bpd from 253,000 bpd.

At that time, Syncrude Chairman Eric Newell, who turned over the reins to Charles Ruigrok in December, was confident that completing 80 percent of detailed field engineering before major construction started would head off incremental costs.

"We believe this approach will be key to managing the project within budget and schedule," he said.

Adding to the latest litany of woes, the partners said the project will now not come on stream until mid-2006, close to 12 months behind schedule, potentially costing about 36 million barrels of lost output.

Williams Lacey, institutional research vice president at FirstEnergy Capital, told the Financial Post the escalating cost will increase the cost of a flowing barrel — the incremental output tied to the capital expenditure — to C$58,000 a barrel, compared with C$38,000 at Shell Canada's Athabasca operation and C$31,000 at Suncor Energy's Millennium expansion. Both of those projects were at least 50 percent over budget.

Dunbar estimated the expansion's unit cost will now be about C$78,000 per barrel of new production capacity.

Canadian Oil Sands Trust hammered

In the immediate fallout, Canadian Oil Sands Trust, whose 35.49 percent stake in Syncrude is its sole asset, was hammered on the Toronto Stock Exchange. Its units dropped almost 16 percent on March 6 to C$44.90 and almost C$730 million was wiped off the trust's market value.

The other Canadian-based partners in Syncrude —

see **BOMBSHELL** *page 20*

Tracking the ripples

The collateral damage from Syncrude Canada's blockbuster overrun is still being measured.

In the initial aftermath, the 12-month delay in construction is seen as a drag on other oil sands operators who are trying to hire workers in a tight market and persuade jittery investors to finance their projects.

At the worst, the spillover could affect proposed major pipelines from the oil sands.

Now that Syncrude is faced with keeping a workforce of up to 5,500 on site for another year to complete its expansion, other oil sands developers are having to rethink their schedules.

For now, the focus is on the C$8.5 billion Horizon project by Canadian Natural Resources and the C$3.4 billion Long Lake joint venture by Nexen and OPTI Canada.

Having obtained regulatory approvals, Canadian Natural expects to make a final decision this year on when to proceed.

Before Syncrude's bad news, company officials had indicated construction work could start this fall, peaking in the second half of 2006 at 3,500 workers and remaining above 2,000 for five years.

see **RIPPLES** *page 20*

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BOMBSHELL

Imperial Oil, Petro-Canada and Nexen — escaped the initial backwash, because of their more widely held interests.

Word of the overrun "surprised, stunned and shocked" analysts, with Tom Ebbern, at Tristone Capital, noting that the C$2.1 billion cost was announced after all the engineering work had been completed, 90 percent of materials had been purchased and the project was 37 percent finished.

But construction workers at Syncrude say they have been voicing their concerns for months about engineering-related hitches.

One source told Petroleum News that in his own area, engineers had refused to heed the warnings and were unwilling to discuss solutions.

Canadian Oil Sands Trust Chief Executive Officer Marcel Coutu, who is also chairman of the Syncrude joint venture, blamed the cost increases on upfront engineering and the challenge of building a new upgrader within old operations.

Detailed engineering tasks were completed in the wrong order, he said, adding: "We did not recognize that and could not quantify that until much later on."

In fact, it wasn't until a detailed review by independent experts and Syncrude staff was commissioned this winter that problems in project management and engineering were exposed.

"Significant reorganization" triggered by new information

The new information has triggered a "significant reorganization," including the enlistment of international-caliber professionals, although no executives will lose their jobs, Coutu said.

However, Syncrude will attempt to recover some of the overrun from contractors, who are led by KBR, a unit of Halliburton. "We will be pursuing any potential that we see," he said, while conceding the chances are slim because Syncrude, in the midst of a tight labor market, used a cost-plus rather than a fixed-price form of contracting.

The labor force, which has ranged from 4,500 to 5,500, was exempted from any blame and will remain on site to cash in on the delays, which will extend their work time by 40 percent to 25 million hours from 15 million.

As for the Syncrude owners, Coutu said they all "remain committed to the project." Imperial Oil, the second largest partner with a 25 percent interest, is "concerned about the escalating costs and schedule delay, (but is) prepared to support Syncrude in whatever way we can to address these issues," said Senior Vice President K.C. Williams.

Reaching for any lifeline, Coutu said it was "only fortuitous this setback is occurring during a period of robust crude oil prices, which may prevail for some time and should help Canadian Oil Sands fund much of its (C$700 million) share of this project from cash flow."

Heaviest cost overrun in oil sands history

The heaviest cost overrun in oil sands history, leaving Suncor Energy and Shell Canada well behind, has given another jolt to the search for alternative strategies, dominated by new thinking that projects are best approached in smaller stages.

Syncrude has an early chance to apply the lessons learned, with Coutu suggesting Stage 3 could be the last multi-billion-dollar undertaking by Syncrude.

"The industry has shown it can pretty handily manage billion-dollar type projects, but multiples of that become a different animal," he said, referring to strategies favored by newer oil sands players Petro-Canada and Husky Energy, who are opting for staged developments, with each phase financed out of cash flow.

The "bite-sized" approach is expected to be Syncrude's only hope of gaining owner-approval for its next two stages.

Stage 4 is already identified as less ambitious, scheduled to take place between 2005 and 2010 and raise production from Stage 3's peak of 350,000 bpd to between 384,000-425,000 bpd.

Stage 5, targeted for 2010 to 2015, is aimed at production of 507,000 bpd-548,000 bpd.

Coutu said Stage 4, with a preliminary capital budget of C$1 billion-$1.5 billion, is unlikely to encounter the logistical problems of Stage 3. Stage 5 is heading back to the drawing boards. ●

Feeding the oil sands

The demand for natural gas to fuel the extraction and processing of raw bitumen in Alberta's oil sands could soar to 3.7 billion cubic feet per day by 2017, close to one-quarter of Western Canada's current gas output.

In a new analysis by the Canadian Energy Research Institute, that prospect was fingered as one of the major obstacles to oil sands growth.

Senior Research Director Bob Dunbar said that even more modest growth in output to 2.2 million barrels per day would need 1.5 billion to 2 billion cubic feet per day, more than the start-up volume of 800 million to 1.2 bcf per day expected from the Mackenzie Gas Project.

The CERI scenarios included an "unconstrained" outlook of 3.5 million barrels per day of synthetic crude and unprocessed raw bitumen over the next 13 years, pushing gas consumption to 3.7 bcf.

With oil prices at US$32 per barrel, production was forecast at 2.8 million bpd and at US$25 per barrel — the level deemed necessary to yield an adequate return on investment — output was set at 2.2 million bpd.

Current oil sands production of 900,000 bpd requires 500 million cubic feet per day of gas.

But Dunbar said operators are "working very hard" on developing greater energy efficiencies, new technologies and alternative sources of energy, which could include a nuclear reactor to generate steam and power.

Nuclear an option, as is igniting oil in reservoir

The nuclear option, although dismissed by Alberta Energy Minister Murray Smith, could still be employed in northern Alberta within a decade, said Jerry Hopwood, director of business development with Atomic Energy of Canada, a Canadian government agency.

He argued at a conference last month that oil sands and heavy oil producers have little choice but to diversify their energy supply sources and "free up natural gas for its most highly-valued uses."

Dunbar, conceding that gas consumption of 3.7 bcf per day is likely unsustainable, said high gas demand could see some projects deferred and others cancelled.

He said the technologies and alternative fuel sources under study include a C$30 million test project recently approved for Petrobank Energy and Resources, which plans to ignite oil in the reservoir, converting bitumen to 20-degree API gravity crude, allowing it to flow to the surface.

If successful, that technology would lower capital and production costs and reduce gas consumption to minimal levels, Petrobank has claimed.

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

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OUTPUT

McIntyre, Niakuk and West Beach) averaged 56,219 bpd in February, down 4 percent from a January average of 58,561 bpd.

The ConocoPhillips Alaska-operated Alpine field averaged 104,569 bpd in February, down 0.3 percent from a January average of 104,893 bpd. Alpine production was reduced for three days beginning Feb. 20 to repair aerial coolers.

BP-operated Prudhoe Bay (includes Midnight Sun, Aurora, Polaris, Borealis and Orion) averaged 483,820 bpd in February, down 0.23 percent from a January average of 484,956 bpd.

Production up at Milne, Kuparuk

Production was up at both Milne Point and Kuparuk.

BP-operated Milne Point (includes Schrader Bluff) averaged 50,808 bpd in February, up 2.76 percent from a January average of 49,443 bpd.

And the ConocoPhillips-operated Kuparuk River field (includes West Sak, Tabasco, Tarn, Meltwater and Palm) averaged 198,455 bpd, up 0.45 percent from a January average of 197,566 bpd.

The temperature at Pump Station No. 1 on the North Slope averaged –20.8 degrees Fahrenheit in February, compared to –8.1 degrees F in January.

In Southcentral Alaska, Cook Inlet crude oil production averaged 25,863 bpd, up 0.85 percent from a January average of 25,645 bpd.

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

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RIPPLES

The plant is scheduled to be built in stages, with production starting in 2007 at 135,000 barrels per day and growing to 270,000 bpd by 2012.

That timetable is now in doubt until Canadian Natural can assess Syncrude's impact on its ability to hire manpower and buy materials without over-extending the system.

Just as uncertain is Long Lake, which had scheduled field construction work in the third quarter, targeting a 2007 start-up at 72,000 bpd, with volumes doubling by 2011.

Financing the real test

The real test faces OPTI Canada, a small, private start-up company that is 35 percent owned by Ormat Industries, a public Israeli power technology company.

OPTI is faced with completing a C$1.7 billion combined equity and debt financing packages, expected to be one of the largest in Canada this year.

Two months ago, OPTI Chief Executive Officer Sid Dykstra described the market outlook as "very positive" given the prevailing commodity prices and a "high degree of interest in pure play oil sands investment opportunities." OPTI has yet to react to the Syncrude news.

But Credit Suisse First Boston has echoed a January analysis entitled "Oil Sands: NOT Saudi Arabia." It warned that oil sands projects would have difficulty generating "acceptable returns" unless they took an "aggressively positive view" of future oil prices.

The analyst said the Syncrude announcement raised questions about upcoming projects, especially the Horizon venture.

Although the jury is still out, the Syncrude squeeze on labor could pose a headache for Enbridge and Terasen if either or both proceed with major oil sands pipelines from Alberta to the Pacific Coast.

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

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COUNT

lost the most rigs during the recent week, down by seven to 476 rigs. And Oklahoma's rig count decreased by two to 159 rigs. Louisiana gained three rigs for a total of 169, while New Mexico picked up three rigs for a total of 64. Wyoming's rig count increased by one to 65, California's was up by one to 19 and Alaska's was unchanged at 14 rigs.

The U.S. rig count for February was 1,119, up 18 from the 1,101 counted in January 2004 and up 212 from the 907 counted in February 2003, according to Baker Hughes. The Canadian rig count for February 2004 was 568, up 14 from the 554 counted in January 2004 and up 14 from the 554 in February 2003.

The worldwide rig count for February 2004 was 2,477, up 20 from the 2,457 counted in January 2004 and up 264 from the 2,213 counted in February 2003.

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

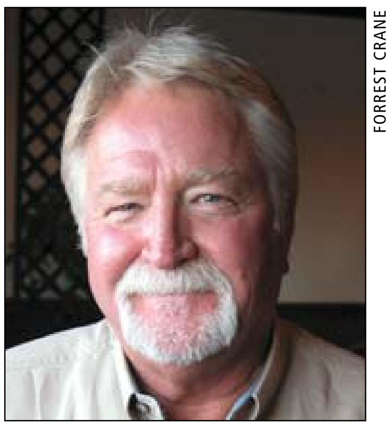
Companies involved in North America's oil and gas industry

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

Petroleum news

Business Spotlight

By PAULA EASLEY



FORREST CRANE

Milton Allen, district manager

Udelhoven Oilfield System Services

Udelhoven Oilfield System Services offers modular design and construction, plus a broad range of industrial engineering, project management, and general construction and logistics services. The firm has operated on the North Slope for 30 years and in Venezuela, China and across the United States. Udelhoven thrives on meeting all project needs of its clients.

Milt Allen, in U.S. oilfields for three decades, joined Udelhoven Alaska in 1996. His favorite challenge at the Nikiski office is accurately bidding projects. His second-favorite challenge (the first, if truth be known) is catching big fish. When not working, sleeping or eating, he fishes, often taking the whole family. The clan is also active in Kenai Boys and Girls Club. Milt sometimes dreams of retirement – a little camping, hunting…FISHING!

FORREST CRANE

Randy Siebert, national sales manager

Alaska Textiles Inc.

Drilling and oilfield service companies requiring flame-resistant work wear that meets OSHA regulations appreciate the comprehensive selection offered by Alaska Textiles and Korbana Protective Apparel. Other popular items are weather-resistant garments, uniforms and promotional goods. Company logos and other artwork can be easily applied right in the Anchorage warehouse. See what's available at alaskatextiles.com or visit the showroom at 620 West Fireweed.

Randy Siebert, with the firm five years, says he's constantly amazed with technological advances in fabric comfort and protection and loves to show off the latest designs. He's a single dad with two children, Jessica and Matthew, who come first; whenever possible it's off to the golf course. Noted philosopher Randy says, "nothing in life changes until it gets different."

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MONEY

work dependent on events that may not even happen: passage of the federal energy bill currently stalled in the U.S. Senate, and whether the state accepts the Alaska Gasline Port Authority's application to negotiate a pipeline fiscal contract.

Senate Bill 241 started in January as a $2.15 million request from the Alaska Natural Gas Development Authority to continue its work toward building a state-owned pipeline and liquefied natural gas shipping terminal at Valdez.

The administration, however, later changed it into a single request for all work "related to bringing natural gas from the North Slope to market." That included the authority's own effort and the administration's negotiations with applicants under Alaska's Stranded Gas Development Act for a long-term state fiscal contract in lieu of state and municipal taxes on a North Slope pipeline.

The committee's version of the bill does not specify how the $1 million is to be shared.

State gas authority could get $450,000

"We realize that not all of the monies are designated in our name as we might like," said Harold Heinze, chief executive officer of the state gas authority.

The administration's spending plan, presented to Senate Finance, allocated $450,000 to the state gas authority, with the rest targeted for two Stranded Gas Act negotiations with North Slope producers and MidAmerican Energy Holdings Co., possibly a third set of contract talks with the Alaska Gasline Port Authority, and also the state's response if Congress passes an energy bill with gas line incentives.

Almost half the money the Revenue Department said it needs immediately is to cover the state's costs of negotiating a fiscal contract with MidAmerican, which as of March 10 had declined to sign a reimbursement agreement to cover the state's expenses. North Slope producers last month signed a reimbursement agreement with the state for their own negotiations.

Stranded Gas Act expenses include hiring tariff and legal experts to assist the state in the negotiations.

No decision on port authority application

While talks are ongoing with MidAmerican and the producers, the administration has not yet decided if the port authority meets the requirements of the Stranded Gas Act, said Steve Porter, deputy commissioner at Revenue. The port authority, comprised of the North Slope Borough, Fairbanks North Star Borough and Valdez, wants to sell bonds and take out bank loans to build a pipeline into Canada to feed North American markets and also a line to Valdez for LNG shipments.

Meanwhile, the state gas authority, created by a voter initiative in 2002, is out of funds for any further studies and has been asking for more money since late last summer. The authority has said it needs more money to study its possible exemption from federal corporate income taxes, LNG marketing and financing options. Similar to the municipal authority, the state authority believes it could raise money for its $12 billion project by selling bonds to investors.

The state authority, while not abandoning its goal of building an LNG plant at Valdez, has said it is looking at how it could work with the producers or MidAmerican to add in-state benefits to a project if either goes ahead and builds a line from the North Slope into Canada. ●

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2007

passage of an energy bill has been stalled), fiscal certainty (in Alaska) and then the producers have to come together and decide what structure to move forward, assuming everything is in place," he said.

At that point the proponents have to complete engineering and environmental studies to prepare an application.

Allowing for all those matters "it would take us, probably, until 2007 to file an application," MacDonald said.

Against that background, he conceded the Mackenzie Valley pipeline proposal "has at least a three-year advantage on us."

John Carruthers, northern development vice president with Enbridge, the Canadian pipeline company, said the fundamental gas supply/demand outlook in North America lends weight to the Alaska pipeline.

But he rejected the push for an Alaska LNG terminal, arguing that would be unable to compete against global LNG suppliers.

—GARY PARK, Petroleum News Calgary correspondent

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RECORD

supply, she said.

Burton also mentioned several announced oil and gas discoveries made in the Gulf's ultra-deepwaters over the past three years, most notably five in 2001, three in 2002 and six in 2003.

ChevronTexaco drilling deepest

ChevronTexaco, using Transocean's Discoverer Deep Seas, is drilling the deepest well among the dozen rigs currently active in waters over 5,000 feet. The major is targeting a 9,020-foot prospect on Alaminos Canyon block 818. The company also is drilling a 6,989-foot well at Mississippi Canyon 696, using Transocean's Deepwater Pathfinder.

Big exploration and production independent Anadarko Petroleum is drilling an 8,730-foot prospect on Atwater Valley 349, using Transocean's Deepwater Millennium.

Shell Offshore is currently drilling separate wells using GlobalSantaFe's Jack Ryan at Alaminos Canyon block 943 (7,962 feet) and Transocean's Deepwater Nautilus at Mississippi Canyon Block 657 (7,570 feet).

BHP Billiton Petroleum also is drilling two ultra-deep wells. One is planned for 6,257 feet at Atwater Valley block 618, using GlobalSantaFe's Explorer, and the second is targeting a 5,065-foot prospect at Green Canyon Block 826, using Diamond Offshore's Ocean Confidence.

Independent Dominion Exploration & Production has three ultra-deep wells under way in Mississippi Canyon. The company is using Transocean's Cajun Express to drill a 5,724-foot well on block 734, Pride International's 1503 rig to drill a 5,610-foot well on block 773, and Transocean's Marianas to drill a 5,413-foot well on block 772.

And Unocal is currently drilling a 5,314-foot well on Green Canyon Block 943, using Transocean's Discoverer Spirit.

Anadarko sets record, reduces cost

Meanwhile, Anadarko, drilling in 9,000 feet of water at its Hawkeye and Atlas prospects on Lloyd Ridge blocks 50 and 360 in the Eastern Gulf of Mexico, achieved record-setting penetration rates using MI Swaco's new inhibitive water-base mud system.

When compared to similar deepwater projects elsewhere in the Gulf, drilling costs were said to be reduced by $1.1 million. Specifically, the fluid enabled discharge of cuttings generating a direct cost savings of $432,000, while minimal mud loss saved the operation roughly $700,000 as compared to wells drilled with synthetic base mud.

While Hawkeye was a dry hole, Anadarko's Atlas, Atlas NW, Jubilee and Spiderman prospects all turned out to be natural gas discoveries. Operators in the Eastern Gulf region are currently working on a plan to tie Anadarko's finds, along with Kerr-McGee's Merganser and BHP's Vortex discoveries in Atwater Valley, into a central production hub.

Anadarko plans to start booking reserves in the Eastern Gulf and appears confident a development plan for the region could be in place by year-end. Anadarko says it also may drill another well at Jubilee and possibly another at the Atlas-Mondo complex. ●

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TRUSTS

At another level, the government is trying to determine to what extent the trusts are siphoning investment away from conventional firms.

Meanwhile, the Alberta and Ontario governments have started exploring ways to make trusts, which currently have no limited liability, more appealing to pension funds.

Trust sector growing rapidly

All this is taking place amid a meteoric expansion of the trust sector, which has more than tripled in value on the Toronto Stock Exchange over the last five years to C$63 billion (US$47 billion), with oil and natural gas trusts making up 36 percent of the total market.

Jack Mintz, who co-authored a study last year for the C.D. Howe Institute on the impact of trusts, said the government has to take a serious view of the lost tax revenues.

He has calculated that the Canadian and provincial governments are losing between C$500 million and C$700 million a year, stemming from the fact that trusts convert equity into debt and redistribute profits to unit holders.

Other studies have estimated the losses are nothing at all or as high as C$1 billion.

The Canadian Association of Income Funds said the mature companies that comprise the bulk of trusts are the job creators of the Canadian economy.

The oil and gas trusts, which generated average returns last year of about 17 percent, insist they are in a different league from other trusts.

While the royalty trusts pay a large portion of their profits to unit holders, they also continue to raise capital to invest in exploration and development.

In contrast to the conventional oil and gas company that is owned 60-70 percent by institutional investors, trusts say they are owned 80 percent by individuals.

John Dielwart, chief executive officer of ARC Energy Trust, said 90 percent of units of his own trust are in the hands of Canadians, raising doubts in his own mind that those investors would be punished by the government.

Other trust executives don't believe the upcoming budget will contain changes, arguing that Canada's new Prime Minister Paul Martin would be unlikely to take such drastic measures without open discussions. ●

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INSIDER

Raymond said ExxonMobil will continue to take the conservative approach: "We are not going to invest in low-return projects."

The company estimates a pipeline from Alaska's North Slope to Lower 48 markets could cost $19-$20 billion, executives said at ExxonMobil's annual meeting in New York.

"That's just such a huge investment and would carry with it obviously a lot of risk. … Cost is the big issue. …We've got to find some way to try to reduce that cost or to deal with the risk," Tillerson said.

ExxonMobil, BP and ConocoPhillips recently filed an application under the Alaska Stranded Gas Act to negotiate fiscal terms with the state for a North Slope gas commercialization project.

ExxonMobil wants favorable terms from those negotiations. It also wants the U.S. Congress to approve a streamlined permitting process as part of a pending energy bill, Tillerson said.

Pioneer Suncor won't keep on trucking

ALBERTA OIL SANDS PIONEER SUNCOR ENERGY is hoping to eliminate the use of mammoth trucks at its northern Alberta mine sites to reduce operating costs and improve efficiencies.

Suncor Chief Executive Officer Rick George said that instead of operating the trucks from shovels to a crusher system the company is exploring ways to put the crushers on mobile platforms behind the shovels.

RICK GEORGE

The change could take place within five years, he said, but the company has yet to estimate the cost savings it might achieve.

Other cost-reduction methods include efforts to lower natural gas consumption by injecting light hydrocarbons downhole with steam to loosen the bitumen deposits and force them to the surface.

George said Suncor will continue to "work hard on R&D to drive productivity and to drive costs down."

Denbury wants to sell 81 wells in Gulf of Mexico

SMALL EXPLORATION AND PRODUCTION INDEPENDENT Denbury Resources says it wants to sell its offshore properties in the Gulf of Mexico to better focus on its core operations, including CO2 tertiary recovery oil projects in Mississippi.

Denbury said March 10 that it has retained investment bank Credit Suisse First Boston to assist with the sale. The company owns interests in 81 offshore wells with average daily production during 2003 of 47.7 million cubic feet of natural gas equivalent. January production averaged just over 50 million cubic feet of equivalent per day.

So far, no buyer has been identified, Denbury said, adding that if its sales price is less than anticipated, it may withdraw the sales package. Denbury is looking to sell the properties by the end of June.

"Our long-term plan is to concentrate our energy and investment on our tertiary operations where we have lower risk, greater predictability, virtually no competition in our areas of operation and higher profitability," Denbury CEO Gareth Roberts said.

Tom Boggs to speak at Alliance annual meeting

WANT TO GET AN INSIDER'S VIEW of Washington, D.C., as the country gears up for the November general election? Mark your calendar for the Alaska Support Industry Alliance's Sept. 23 annual meeting.

Alliance General Manager Larry Houle told Petroleum News that Tom Boggs, a "Washington insider" and "one of the most powerful lobbyists on Capitol Hill," will be the keynote speaker.

Boggs is a founding partner of the Patton Boggs law firm in Washington, the son of the late Hale Boggs (lost in a plane crash in Alaska in 1972 with Rep. Nick Begich, D-Alaska), majority leader of the U.S. House of Representatives and member from Louisiana's second district in the 77th and 80th to 92nd Congresses, and Corinne Clairborne Boggs, member from Louisiana's second district in the 93rd to 101st Congresses, and the sister of newswoman Cokie Roberts.

Houle said Boggs' take is "totally irreverent."

ASRC subsidiary to work on GOM network

ANOTHER CONNECTION BETWEEN ALASKA and the Gulf of Mexico comes with the announcement that ASRC Communications Ltd. will be teaming up with Gulf Fiber LLC on a subsea fiber optic network on the floor of the Gulf of Mexico.

The new fiber network will meet industry demand for reliable communications with remote installations on the continental shelf and in deep water.

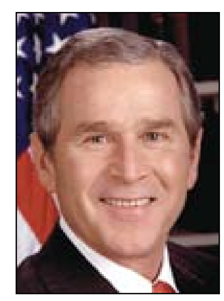
The joint venture's fiber network can be teamed with microwave and fixed satellite technology to provide enhanced reliability, ASRC said in a release March 10. The new venture, called Gulf FiberNet, will provide video, voice and data services to the industry and the government.

Gulf Fiber had already been awarded a contract to provide fiber optic connections to some BP deepwater platforms.

ASRC serves oil companies with an extensive network on the North Slope. It is a subsidiary of Arctic Slope Regional Corp., an Alaska Native corporation.

U.S. Senate drops ANWR lease sale revenues from budget resolution

THE U.S. PRESIDENT'S ATTEMPT to start counting revenue from oil and gas leases in the Arctic National Wildlife Refuge has been dropped from the federal budget resolution, expected to come up for a final vote in the Senate on March 12.



President George W. Bush

President George W. Bush included projected revenue from ANWR lease sales in his budget proposal to Congress last month, although few expected the provision would remain in the resolution. The president's proposal merely counted ANWR leases in federal revenue totals and would not have actually opened the area's coastal plain to drilling. That would have required a separate piece of legislation.

Filibuster threats by opponents of opening ANWR to oil and gas exploration have repeatedly blocked the Senate from removing the 24-year-old congressional ban on leases in the environmentally sensitive area, which the Department of the Interior believes could contain several billion barrels of economically recoverable oil.

The annual budget resolution sets caps for what the appropriation committees may give to each department, said Chuck Kleeschulte, spokesman for Sen. Lisa Murkowski, R-Alaska. "It is a blueprint for what the budget will contain."

House members already have adopted their version of the budget resolution, with a House-Senate conference committee expected to settle the differences between the two versions. Congress faces an April 15 deadline to pass a single version in both chambers, Kleeschulte said. Actual spending bills would follow. The federal fiscal year starts Oct. 1.

Canadian crude oil, gas prices take a dive

LIGHT AND HEAVY CRUDE and spot natural gas prices have taken a beating in Canada so far this year, while holding their own in the United States.

To the end of February, light crude in Edmonton averaged C$44.32 (US$33.24) a barrel at Edmonton, a drop of 15 percent from a year earlier; Flint Hills heavy crude averaged C$31.78 (US$23.84) a barrel, off 21 percent; and AECO-NGX spot gas prices averaged C$6.14 ($4.61) per gigajoule, a drop of 19 percent.

Editor's note: Contributions to this week's Oil Patch Insider came from Gary Park, Allen Baker, Kristen Nelson, Larry Persily, Ray Tyson and Kay Cashman.

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BILL

Measure does not include several items from original bills

Several provisions of the original two bills were not included in the Oil and Gas Committee bill:

• The original version of HB 395 would have repealed last year's legislation that gave the Department of Natural Resources — in cases of coalbed methane development — the authority to override municipal land-use laws. The committee dropped the repeal provision, as Kohring had promised at the bill's first hearing.

• The original HB 395 also would have set the rental payment to property owners at $300 per month for each wellhead and $600 a month for each compressor station on their land. Existing statute does not specify how much rent, if any, developers must pay property owners for installing equipment on their property.

• And the original HB 420 would have imposed a tax on shallow natural gas production to fill a new state water well restoration fund for residents to draw from if shallow gas drilling damaged their well. Payments would have been limited to property owners within 1,500 feet of a shallow gas drill site. ●

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SUPPLY

Rim.

"Gas is far and away the largest component of our cost of production and so as you start looking around the world, and looking at who your competition is and what sets the … value of your product, you're going up against folks that are pulling gas from other stranded gas fields in the world," Boycott said.

Cook Inlet natural gas prices are in the $1.50 to $3 range, he said, but in Indonesia and Malaysia gas is $1-$2 and in Trinidad $1.

"We have to have a large supply of gas at a competitive rate to stay economically viable," Boycott said. Based on forecasts of natural gas availability in Cook Inlet, he said, the economic viability of the Nikiski plant "is threatened beyond the end of 2005, if the picture doesn't change."

Employees have taken over on maintenance

Agrium isn't sitting idly by waiting for Cook Inlet gas to dwindle away, Boycott said.

Over the winter, when the plant could only be operated at 50 percent of capacity, Agrium reassigned people to maintenance. Within the last two weeks, some of the gas has come back, and "we're now running about 80 percent of capacity," Boycott said.

The company is trying to find new gas, but if it doesn't succeed, and Agrium closes down, "the Cook Inlet would go from a short position to a long position of gas, and the incentive for exploration would be reduced."

Agrium also brings value to the gas industry because it has a large, stable gas demand, not dependent on weather.

And while there is promising exploration going on in Cook Inlet, and discoveries have been made, "we are still short in the market … We need to see continued exploration and we need to see success."

Price is also a concern, Boycott said: "We're actually seeing pressure towards Lower 48 type pricing, and quite frankly, if we were to see Lower 48 pricing the way it exists today, our business cannot economically exist."

Agrium is "aggressively seeking a solution" on the supply side, Boycott said.

"We are trying to encourage exploration. … I believe we're probably working with everybody who is or has the potential to produce natural gas in the Cook Inlet."

Agrium is also concerned that independents have access to pipelines to move their gas, he said, and access at reasonable rates. "And so we're interested in ensuring that we have reasonable pipeline tariffs, that we have reasonable access to pipelines."

Agrium might even look at partnering in exploration

Chris Tworek, Agrium's Calgary-based vice president of supply and management, told Petroleum News that Agrium is looking at several ways to work with companies who want to explore for new supply.

The easiest thing is a commercial contract, Tworek said, but Agrium will take "any version of a take or pay contract," anything that will provide supply security.

"We'll even prepay for the gas to allow the producer to use the prepay to do his development."

Agrium is also working with producers to see if there is "a way of actually participating in the venture, and that's were we do some sort of farm-in type situation," Tworek said, "some sort of situation where we'll put in some of the capital to de-risk his exploration effort" in exchange for a contract assigning the gas to Agrium. "And so it's a bit of a pre-buy."

A third option, Tworek said, would be for Agrium to get "directly involved in exploration and production." It's not the company's area of expertise, he said, "so we're stepping outside of our core competency," but "in Alberta we do have a small oil and gas company." If Agrium exercised that option, it would probably be looking at a partnership, "preferably with a little more experienced operator," and "what we bring to the party is some capital and what we also bring is a take-away gas contract."

Tworek agreed that Agrium has talked to everyone working in Cook Inlet.

"There is no one in Cook Inlet that we have not talked to," he said. "… We've got a developed track record of exploration and production, and we've talked to people who've got more ideas than money, so we've covered the gamut." ●

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FOCUS

Second well permitted at Placer

ConocoPhillips had run surface casing and was below 3,000 feet at the Placer well on the western side of Kuparuk, Mott said. The company has permitted a second well at Placer and Mott said that well is a contingency.

The company "would try and expedite a development there … if we possibly could," he said. If it has encouraging results at the first well, it could go ahead with a second well.

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

Placer is southwest of the company's successful Palm discovery and development on the western edge of Kuparuk. Placer is in a Kuparuk unit expansion area: ConocoPhillips, the Kuparuk River unit operator, negotiated unit expansions to include leases believed to contain oil and gas, with the proviso that wells must be drilled by certain dates, or the tracts would contract out of the unit and the state would we owed a penalty to make up for what the leases might have earned in bonus bids at a lease sale, had they not been incorporated into the unit, extending the term of the lease.

ConocoPhillips' partners at Placer are Unocal, ChevronTexaco, ExxonMobil and Arctic Slope Regional Corp., which farmed into BP's acreage at the prospect, assuming a portion of the cost of the well in exchange for a 35 percent working interest, leaving BP with no production from Placer, should the well be successful.

ASRC entered into a "mentoring" agreement with BP last summer, including sharing information on unit and near-unit oil and gas investment opportunities, ASRC and BP told Petroleum News in July. BP said then that the mentoring arrangement would help get unit and near-unit North Slope prospects explored and developed that might not get approved by BP's board in London due to stiff competition in investment opportunities outside Alaska.

Palm on line in 20 months

ConocoPhillips' predecessor Phillips Alaska partnered with BP Exploration (Alaska) on the Palm prospect northeast of Placer, where a well and sidetrack were drilled in the 2001 winter exploration season, the discovery of an estimated 35 million barrels of recoverable reserves announced in May and applications for a drill site at the discovery filed in August.

The new drill site 3S, came on line in November 2002, just 20 months from the spud of the discovery well to the first production.

Development drilling at 3S was completed last summer, and Patience told Petroleum News in July, "The project came in under budget and ahead of schedule."

And production, expected to peak at 16,000 barrels per day in 2004, was producing 29,000 bpd in July, exceeding pre-development expectations.

Looking for co-venturer at Cosmopolitan

While the North Slope is ConocoPhillips primary exploration focus in Alaska, it also has an active oil exploration prospect at Cosmopolitan in Cook Inlet off the southern Kenai Peninsula.

In the first well at that prospect, 18,000-plus measured feet, the company "saw some things of interest, and we came back and side tracked it the following year," Mott said, going out a similar distance, "at an angle from the original bore."

Phillips Alaska (now ConocoPhillips Alaska) filed a unit application with state and federal agencies in 2001 to unitize nine leases, some 24,600 acres, at Cosmopolitan and drilling began at the Hansen No. 1 in October 2001; the sidetrack, the Hansen No. 1A, was drilled last year. The wells were drilled from onshore to the offshore prospect, discovered in the 1960s when Pennzoil drilled the prospect, in the lower Cook Inlet offshore north of Anchor Point, from a jack-up rig.

"We saw some things that were encouraging to us," Mott said of the Cosmopolitan sidetrack, but he also said the prospect is "not near" a "commercial threshold" at this point.

ConocoPhillips is "carrying a 70 percent working interest (at Cosmopolitan) and considering how much we've already invested in the project," the company would like to find another co-venturer before doing more work: "some additional 3-D seismic" probably needs to be shot over the feature, and possibly a second independent well.

Mott said Cosmopolitan is "an exciting but challenging project" and because the prospect is offshore, ConocoPhillips is "going to have to proceed carefully."

Other possibilities in Cook Inlet?

Asked if ConocoPhillips planned to look for more natural gas in Cook Inlet, Mott said the company's "strategy would be to … exploit opportunities near our infrastructure." He said he doesn't think "we're going to be aggressively going out looking for new frontier plays or new areas that are significant distances from our infrastructure." The company does "hold various blocks of exploration acreage down in the Cook Inlet" and so it has opportunities both there and on acreage that is currently producing.

Some of the exploration acreage holds discoveries that haven't been developed, and some are just exploration blocks, he said.

"I see our focus now as … near infrastructure — the Cosmo area and near infrastructure," Mott said.

The company's Cook Inlet exploration acreage appears to be concentrated in the vicinity of the North Cook Inlet gas unit near the Tyonek platform and offshore the Beluga gas field on the west side of Cook Inlet.

Mott said the company is just finishing up processing 3-D seismic data near the Tyonek platform, "primarily … for development," he said, "but … if there's anything else…" ●

Part II of this article will appear in the March 21 issue of Petroleum News.

NORTH OF 60 MINING NEWS

Advancing Rock Creek

NovaGold to spend $5M on Nome hard rock deposit, new resource, feasibility study expected

Pogo waits on permit

Teck-Pogo completes 50-mile ice road to remote Pogo gold mine, half supplies and equipment there

Tough times at Fort Knox

Production dropping at Alaska's largest gold mine, operations at True North suspended

PHOTO BY CHRIS AREND/COURTESY USIBELLI COAL MINE

A special supplement to Petroleum News

WEEK OF
March 14, 2004

Petroleum news

● NOME, ALASKA

NovaGold: Advancing Rock Creek

Company plans to spend $5 million this year on Nome-area hard rock deposit, new resource, feasibility study anticipated

By PATRICIA JONES
Mining News Editor

PATRICIA JONES

Current scoping of Rock Creek has identified a potential gold mine that would produce more than 100,000 ounces per year with a total cash cost of about $200 per ounce of gold.

Developers of the Rock Creek gold deposit near Nome plan to spend $5 million in 2004 to develop the hard rock deposit, with the ultimate goal of gold production starting in 2006.

Vancouver, British Columbia-based NovaGold Resources anticipates releasing a new resource number and geological model later in March, based on last year's 30,000-foot drill program exploration work.

The permit process should begin in the second half of 2004, following completion of a feasibility study, according to a company update released March 1.

Crews are gathering background monitoring data for groundwater and surface water, Doug Nicholson, vice president and general manager, told Mining News on March 5, shortly before a weekend company meeting to discuss projects.

Initial tailings dam design and review of water balance and rock characterization studies have also begun, he said.

"We'll do a bulk sample this summer and depending on what we see this weekend (during the company meeting), we'll have more drilling this summer," he said.

Current scoping of Rock Creek has identified a potential gold mine that would produce more than 100,000 ounces per year with a total cash cost of about $200 per ounce of gold.

Year-round operation anticipated

NovaGold anticipates a year-round mine and milling operation, producing about 5,000 tons of material to process a day, with a 4:1 strip ratio, Nicholson said. Overall recovery with a gravity floatation plant is projected at 96 percent.

Past exploration has identified a gold resource containing more than 1 million ounces of gold at Rock Creek and the adjacent Saddle deposit. Both deposits are open along strike and down dip; further drilling will likely increase the size of both deposits, the company's website said.

NovaGold has hired John Odden as the chief geologist for Rock Creek and the company's Nome Gold project, Nicholson said. "He will be involved in planning our project this summer."

Odden formerly worked as a geologist for several years at the Fairbanks-area Fort Knox gold mine and as the project manager for the neighboring Gil deposit.

Additionally, the Alaska Department of Transportation has allocated and approved $5 million in funds in 2004 for construction of the Glacier Creek by-pass road, a three-mile route that will improve access from the community of Nome to the Rock Creek area.

"With two crew changes a day at 30 to 40 people and support staff and vendors coming in and out, that will greatly enhance our ability to access the mine," he said. ●

● FAIRBANKS, ALASKA

Tough times at Fort Knox gold mine

Production dropping at mine, 55 million tons of waste rock must be moved, mining operations suspended at True North

By PATRICIA JONES

Mining News Editor

Production at the Fort Knox gold mine northeast of Fairbanks, Alaska, declined 5 percent last year to 391,831 ounces of gold and that downward trend is expected to continue in 2004 and throughout 2010, the estimated remaining life of Alaska's largest gold mine.

A number of factors contributed to last year's gold production decline, according to owner Kinross Gold, including lower gold grades and lower recoveries from ore mined and trucked about 10 miles to Fort Knox from a satellite mine, True North.

In addition to lower production, cash costs to produce gold at Fort Knox increased 5 percent to $243 per ounce in 2003. Those costs should drop in 2004 to $220 per ounce, although production is also expected to drop to 340,000 ounces, according to the fourth quarter and year-end report released March 1 by Kinross.

Representatives from Fairbanks Gold Mining Inc., a Kinross subsidiary that operates Fort Knox, announced March 4 that mining operations at the True North satellite, some 10 miles from Fort Knox, would be temporarily suspended for three to seven months.

"Mining equipment and personnel will be moved to the Fort Knox Mine to assist in constructing the tailing impoundment embankment raise, minimizing contract costs for construction in 2004," the company statement said.

According to state regulators who received an annual Fort Knox operations report in early March, some of that smaller-sized True North earth-moving equipment will also be used to begin moving 55 million tons of waste rock in order to gain access to additional mineralized material at the Fort Knox pit.

In addition, the company plans to purchase six more haul trucks and another loader to handle waste rock, according to the Kinross Gold website.

"Stripping of Phase-6 is scheduled to begin in 2004 on the 2200 bench," the company website said. "Before sustained mill feed rates can be reached in mid-2006 on the 1460 bench, 55 million tons of waste rock will be mined, at an average rate of 60,000 short tons per day."

Typical mine production rates vary between 94,000 and 130,000 tonnes per day of total material, the company said.

"They're very optimistic and presented an optimistic picture that they will continue mining until 2009," Ed Fogels, large mine project manager for the Alaska Department of Natural Resources, said after the annual operations report.

Production is anticipated to conclude at Fort Knox with 62,000 ounces of gold planned in 2010 when the mill will process final stockpiles, according to a Kinross technical report available on the company website.

Waste removal considerations

In relation to the life of Fort Knox, the company's technical department discussed removal of the 55-million ton waste rock in the technical report dated April 2003.

Kinross told Petroleum News March 10, "With approval of Phase 5 and Phase 6, we're on track with new ore zones in the Fort Knox pit. We don't foresee a period when we won't be able to supply the mill with ore."

Fairbanks Gold Mining spokeswoman Lorna Shaw also said that Kinross would release a statement about the Phase 6 layback of the waste rock material. It was not available at press time.

see **TOUGH** *page 7*

JUNEAU, ALASKA

Feds extend Kensington comment period

The U.S. Forest Service, lead regulatory agency overseeing the environmental assessment for the Kensington gold project near Juneau, Alaska, has extended the public comment period by 30 days.

The move to close public comment submissions sought by the draft supplemental environmental impact statement on April 7, rather than March 8, came on requests from the Environmental Protection Agency and also from a Juneau-based environmental group.EPA requested additional time to evaluate recently received information about the project's tailings and their potential effect on aquatic life in the proposed tailings impoundment, according to Ed Fogels, project manager for the Alaska Department of Natural Resources.

"EPA also felt they did not receive a complete NPDES application," Fogels told Mining News on March 9, referring to the National Pollutant Discharge Elimination System permit required by the project.

A number of comments have already been submitted, include a "swamp" of email messages from environmental groups that oppose mining development.

Project developer Coeur Alaska Inc., a subsidiary of Coeur d'Alene Mines Corp., the world's largest silver producer, wants to build mine and mill facilities at Kensington that would produce approximately 2,000 tons of gold-rich ore per day, requiring a year-round workforce of about 225 people.

According to the company's fourth-quarter and 2003 year-end report, Coeur estimates capital costs necessary to put Kensington into production at approximately $75 million, significantly less that prior estimates of up to $150 million.

The company completed a final pre-feasibility study in late 2003, which identified significant capital and operating cost savings, according to a Coeur press release that came out shortly after draft SEIS was released on Jan. 23.

Coeur estimates production averaging 100,000 ounces of gold per year, at an average cash cost of approximately $195 per ounce.

Based on past exploration work, Kensington contains an estimated 1.8 million ounces of gold in the proven and probable gold reserves and 1.4 million ounces in resources. Average grade at Kensington is .12 ounces of gold per ton of rock.

"Coeur believes that significant exploration potential exists at Kensington that could materially increase the project's total resources," the press release said.

Additional exploration work is planned following the start up of mine production, the company said.The company expects to receive all major permits by June 2004, according to Coeur's statement, and a company construction decision will follow. Mine construction, which would require from 135 to 179 workers, will take an estimated 18 months. Potential production could start as soon as 2006, the company said.

Kensington is 45 miles north of Juneau and a few miles inland from Comet Beach on Lynn Canal.

Petroleum news

North of 60 Mining News is a monthly supplement of the weekly newspaper, Petroleum News. It will be published in the second or third week of every month.

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ALASKA

State mining summary released

Estimates of $1.05 billion for Alaska's mineral industry value in 2003 were released by state officials on March 9, making it the eighth straight year the industry's value exceeded $1 billion.

Rising prices for almost all metals, including gold, silver, zinc, and lead, increased the 2003 value of metal production in Alaska by 2 percent from 2002 levels, according to the annual report released by the state Division of Geological and Geophysical Surveys.

Contributing heavily to Alaska's mineral industry are the state's three hard-rock mines.

Greens Creek Mine near Juneau attained record production for the second consecutive year.

Mining decreased slightly at the Red Dog zinc and lead mine in remote northwest Alaska and at the Fort Knox gold mine near Fairbanks. Improved metal prices helped Red Dog, the largest zinc producer in the world and a large component of the Alaska mineral industry, post an operating profit of $59 million in 2003 compared to a loss of $28 million in 2002.

The amount spent in 2003 for placer gold production is expected to be similar to 2002 expenditures once final reports are received, while sand, gravel, rock, and other industrial materials may see a moderate decrease due to a decline in North Slope oil and gas activity and reduced statewide infrastructure projects.

Preliminary values for the mining industry totaled $1,017.1 million for 2003, a slight decrease from the $1,073.3 million in 2002.

In addition, development spending decreased in 2003 to $15.9 million, from the $33.5 million spent in 2002.

Exploration investment also declined in 2003 to $20.9 million, compared to the $26.5 million spent in 2002.

Lackluster exploration activity can be attributed to late season availability of venture capital, continued weakness of the Canadian dollar, and attractive tax incentives for investors in Canadian based projects.

Total minerals industry employment in 2003 is estimated at 2,496 full-time-equivalent jobs, a drop of about 328 jobs from the 2,824 jobs reported in 2002. Most of the decline was in the development, exploration, and industrial minerals sectors.

The annual state report, Information Circular 50, Alaska's Mineral Industry 2003: A Summary, is available at no charge from DGGS, 3354 College Road, Fairbanks, Alaska 99709-3707 (907-451-5020) The summary is available in Adobe Acrobat PDF format through the DGGS Web site at http://www.dggs.dnr.state.ak.us.

—**PATRICIA JONES,** Mining News editor

● CANADA

Canadian miners raise C$3 billion

Greatest influx of cash since '97 targeted at foreign and domestic exploration, development and acquisitions

By GARY PARK

Mining News Calgary Correspondent

Canada's junior mining companies are cash rich for the first time in seven years, having led the way in raising C$3 billion in 2003 to signal the revival of exploration plays along with development and acquisitions both overseas and on the domestic front.

The industry has not seen such an influx of cash since the 1997 scandal accompanying the collapse of Bre-X Minerals, followed by a prolonged period of low gold and base metal prices that ended in mid-2003.

As a result the stage is set for the liveliest exploration program in Canada since the hunt for diamonds in the Northwest Territories a decade ago, but along with that there are high expectations of a discovery.

Private placements accounted for about C$1 billion of the money raised on the Toronto Stock Exchange and the Canadian Venture Exchange in the final three months of 2003 and have shown no signs of abating this year.

Industry sources say much of the private money came from European investors.

Although those placements avoid some of the costly disclosure and legal problems, they also set the stage for shares sold as private placements to be resold in the market, adding to the number of shares outstanding.

This month alone has seen Apex Silver Mines attract C$50 million, while DiamondWorks has announced plans to raise C$29 million and Tiberon Minerals is targeting C$8 million.

Flurry of financing at year-end

The industry wound up 2003 with a flurry of financing deals — about 100 in the C$1 million to C$6 million bracket and 30 raising C$7 million to C$15 million.

Leading the pack were Nevsun Resources C$68 million, Ivanhoe Mines C$50 million, Thistle Mining C$44.7 million, Bolivar Gold C$26 million, DRC Resources C$24.1 million, International Minerals C$22.3 million, Anooraq Resources C$20 million and SEMAFO C$16.5 million, with Ivanhoe concluded a bought deal for US$115 million in December.

An undetermined amount of the money will be spent in Canada, but the bulk is destined for South America, Africa, China, Mongolia and the former republics of the Soviet Union.

China is a particular hot spot now that the Chinese government has instituted regulatory changes that remove previous deterrents from the gold sector.

Taking advantage of the reforms, Calgary-based junior TVI Pacific became the first foreign company to establish a wholly owned company in the Chinese mining sector and is expecting to spend C$10 million on exploration this year.

Placer Dome, which is negotiating for a possible joint venture, heads a line-up of Vancouver-based explorers in various stages of exploration programs. The others include Southwestern Resources, Mandorin Goldfields and Minco Mining and Metals. ●

FAIRBANKS, ALASKA

Irwin, Canadian speakers to address miners at 19th Biennial Conference

Tom Irwin, commissioner of the Alaska Department of Natural Resources, will be one of the luncheon speakers at the 19th Biennial Conference on Alaska Mining in Fairbanks, beginning March 14 and concluding with a number of mine tours on March 20.

Irwin, formerly general manager and a key member of the development team at the Fort Knox gold mine near Fairbanks, will present a speech at the March 15 luncheon, titled "Progress Toward Resource Development."

Technical sessions will be held March 15 through 17 at the Westmark Fairbanks Hotel and Convention Center. The Fairbanks branch of the Alaska Miners Association is coordinating the conference titled Mining: The Road to Alaska's Future.

Other keynote speakers include Kels Boland of Prolog Canada, who will present "Arctic Gas Pipeline Construction Impacts" at the March 16 luncheon and Michael McDougal from Klondike Placer Miners Association. He will provide an update on the Yukon placer gold mining industry during the March 17 luncheon.

Technical sessions with a number of presenters scheduled for March 15 through 17 include placer deposits and industrial minerals, technical advances and tools for mining related businesses, presentations on northern mineral deposits and an overview of current and planned Alaska infrastructure projects.

A short course on Alaska's industrial minerals is scheduled for March 14. Lecturers are Dr. Paul Metz from the University of Alaska Fairbanks and Thomas Bundtzen, president of Pacific Rim Geological Consultants.

A trade show will run concurrently with the three days of technical sessions. On March 16, an evening reception and program is planned to induct new members of the Alaska Miners Hall of Fame.

The conference banquet is scheduled for March 17, with local historian and writer Dermot Cole featured as the speaker. Gov. Frank Murkowski will also be in attendance at the banquet, according to event organizers.

—**PATRICIA JONES,** Mining News editor

● DELTA JUNCTION, ALASKA

Ice road freighting continues near Pogo

Teck-Pogo completes 50-mile ice road up the Goodpaster River valley, half of fuel and equipment moved to remote mine site

By PATRICIA JONES
Mining News Editor

Contractors hired by developers of the Pogo gold deposit northeast of Delta Junction completed construction of a 50-mile temporary ice road in early February and transportation of fuel and equipment into the remote site should be complete by the later part of March.

"Things are moving along well," Karl Hanneman, Teck-Pogo's manager of public and environmental affairs and special projects, told Mining News on March 8. "We have about half of the necessary fuel and equipment mobilized over the road."

The freight hauling work, which started the first week of February, should be complete "by the end of the next week or so," he said, putting the freighting work completion around March 19.

A cold spell, dropping temperatures down to 30 below Fahrenheit in recent days, has helped preserve the ice road, he said. "The road is in good shape. Our goal is to get things staged on site and get the construction camp built on site so we are prepared to begin."

The ice road starts at Quartz Lake and follows historical trails that wind up the Goodpaster River valley to the Pogo deposit near the confluence of the Goodpaster and Liese Creek. It's the same route that Pogo developers used in 1998 to construct a winter ice road to haul in camp equipment, fuel and underground mining equipment used to construct a tunnel during advanced exploration and development work.

JUDY PATRICK

A Cruz Construction water truck travels the Pogo ice road.

Teck-Pogo, a joint venture between Teck Cominco and Sumitomo Metal Mining Co. of Japan, is still waiting for its final regulatory permit before making a final decision to proceed with the $250 million mine construction project.

The project needs approval from the Environmental Protection Agency for water discharge under the National Pollutant Discharge Elimination System.

Bill Riley, EPA's mining coordinator for the region 10 office in Seattle, told Mining News in early March that the permit should be issued by March 15.

Following the EPA action, Teck-Pogo joint venture partners will meet and "hopefully make a positive project decision," Hanneman said. "It will be soon after, hopefully within weeks."

Contracts awarded

Several contractors have already been selected for work at Pogo. Cruz Construction, based in Palmer, built and is operating the winter ice road.

Alaska West, based in Anchorage, was selected to haul the freight, fuel and equipment needed for the first construction season. That includes 300,000 to 400,000 gallons of fuel — both diesel and gasoline. It also includes the 250-person construction camp, made up of Atco units.

Anchorage-based AIC will build the 50-mile all-season road, once project approval is given by developers. AIC will also perform earth moving and site construction work at Pogo.

Fairbanks-based City Electric was selected to install the 50-mile power line needed to transmit electricity to the remote site.

Construction crews are expected to peak at 500 workers, and will be housed on-site in the construction camp and in permanent crew quarters that will later be used for the mine and mill staff, expected to be about 250 full-time workers.

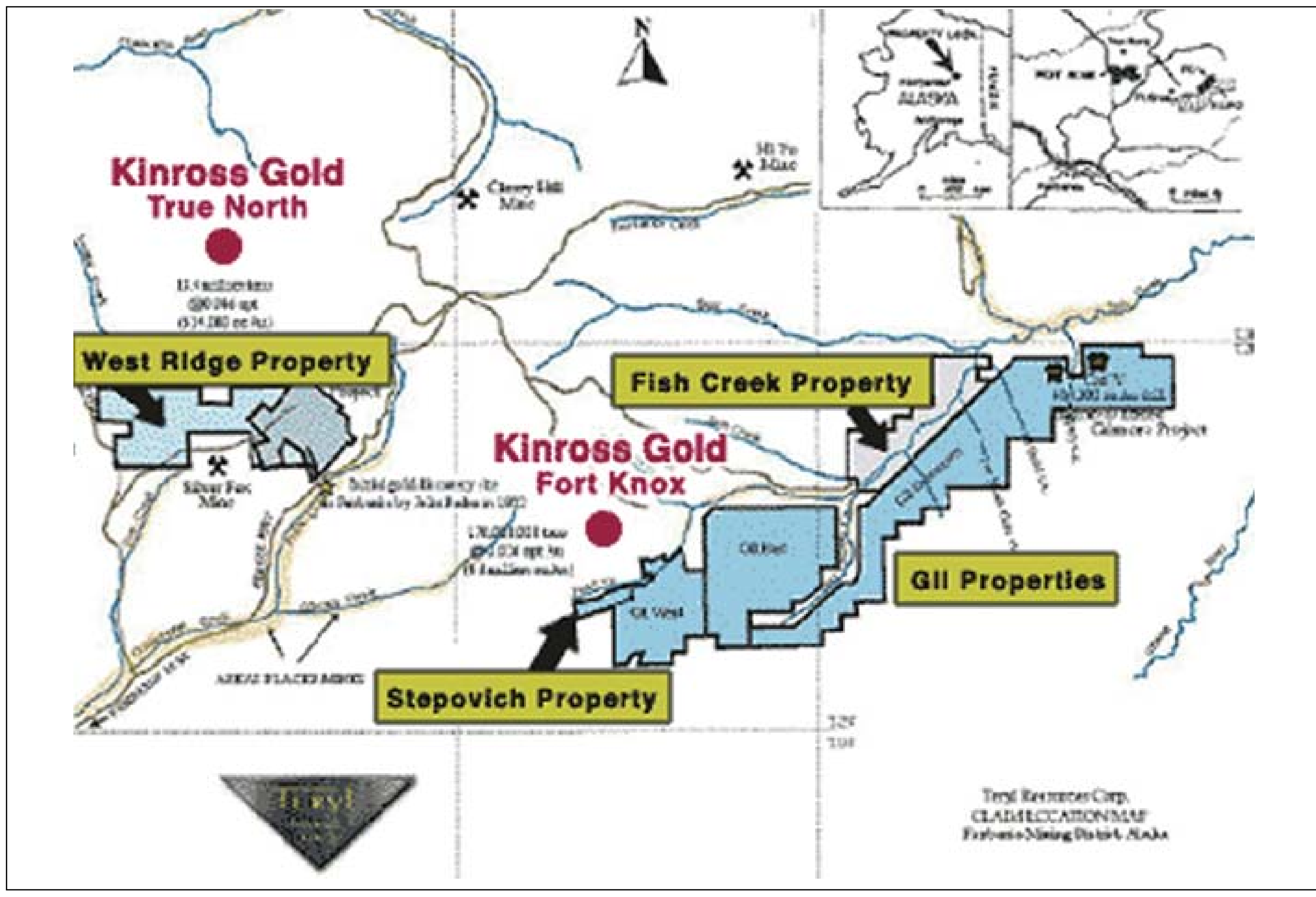
The underground Pogo deposit is believed to contain 5.5 million ounces of gold, with an average grade of about one-half ounce of gold per ton of rock. Annual production from the underground hard rock mine is estimated to be 375,000 ounces of gold per year, for a 10-year mine life. ●

● FAIRBANKS, ALASKA

Teryl Resources: Going for the gold

Teryl raising money for Fairbanks-area exploration projects, drilling to start at West Ridge, awaiting budget for Gil

By PATRICIA JONES
Mining News Editor



COURTESY OF TERYL RESOURCES

John Robertson, president of Vancouver, British Columbia-based Teryl Resources, is focused on raising funds for his company's Fairbanks-area exploration properties.

The company offered a private placement of 2 million units at 55 cents per unit in a Feb. 25 release, with a treasury share and a half-warrant attached for every one unit purchased. One warrant is exercisable at 70 cents for one year for additional treasury shares. There is a four-month hold on the treasury shares.

Teryl plans to drill up to 15 reverse-circulation holes on the property, as soon as a drill rig can be moved to the snow-covered property. "We were expecting to be drilling on the property before now." —John Robertson, Teryl Resources

The goal is to raise a little more than $1 million for exploration and working capital.

Initial spending will go to Teryl's 100-percent owned West Ridge property just south of the True North Mine operated by Kinross Gold.

Teryl plans to drill up to 15 reverse-circulation holes on the property, as soon as a drill rig can be moved to the snow-covered property.

CURT FREEMAN

Avalon geologist Dimitri Kondik sampling mineralized shear zone at the Old Glory trenches on the West Ridge property.

"We were expecting to be drilling on the property before now," he told Mining News on March 8.

All holes will be relatively shallow, with a maximum depth of about 300 feet, he said. Mineralization encountered at the property is close to the surface, within three to four feet in some places, he said.

"That's the most economical way to produce gold — to not move too much overburden," Robertson said.

Past trenching, soil sampling and a geophysical survey revealed some "pretty exciting drill targets," he said. "The drill holes will test the intrusive targets on West Ridge."

The property's proximity to True North, which has been supplying ore to the Kinross-owned Fort Knox gold mill for almost four years now, is a leading attribute. "Our interest is to come up with enough ore to make available with Kinross to feed into their mill," Robertson said. "They could use additional ore for the mill, and it looks like True North will be running out of ore soon, so it's perfect timing." (See Fort Knox operations story, page 3.)

PATRICIA JONES

Reverse-circulation crews work at the Gil exploration project, currently being advanced by Kinross Gold and Teryl Resources, during the spring of 2000. The companies hope to make a development decision on the property this fall.

Gil plans pending

Teryl's other involvement with Kinross includes the Gil exploration project, within the large Fort Knox claim block about 10 miles to the east of True North and West Ridge. Kinross, the operator of Gil, holds an 80 percent interest, while Teryl holds 20 percent.

Robertson budgeted $300,000 for Gil spending this year, outlined in the private placement terms. But he doesn't know yet the actual amount Teryl will be asked to contribute to the project's budget.

"I'm not sure what their plans are … it's up in the air," he said. "I'm still waiting for the year end report (on the exploration property)."

Rather than pushing forward on Gil, Kinross' attention is focused on plans to construct another lift on the Fort Knox tailings dam and to start Phase-6 stripping, Robertson said, information he received during a recent conference call.

"It seems like it will require quite a bit of manpower and equipment. After they are done with that, they will do more work on Gil," he said.

The $300,000 Robertson outlined for Teryl's share of Gil is based on exploration spending of about $1.6 million during 2003 for the gold exploration property.

Most of that spending went to drilling. The joint venture completed 27,590 feet of reverse circulation drilling in 127 holes and 7,917 feet of diamond core drilling in 28 holes.

Initial drilling results continued to advance the project, according to a Jan. 20 press release. One hole hit some significant intercepts of higher-grade material, including 105 feet grading 0.170 ounces of gold per ton of rock.

Results from that press release showed that four other holes produced assays of 0.1 ounces of gold per ton or higher, with intercepts ranging from 20 to 40 feet.

Fish Creek auger drilling

Robertson also plans to spend about $75,000 on the company's Fish Creek property, which also neighbors Fort Knox. In fact, construction of the mine's tailings dam impoundment revealed some "very rich" placer gold mineralization back in the mid-1990s, Robertson said.

Geophysical work conducted in November and December revealed two anomalies, very close to those placer gold sources, he said.

The next step is to conduct auger drilling, sampling soils up to 12 feet deep. "We'll get a large sample and have a good idea of the values of gold there," Robertson said. "Placer mining is easy to go into production to generate some good cash flow if it's economic."

Should that plan pan out, Teryl could get a double value from mining at Fish Creek. Tailings generated by placer mining could be used in road construction to Gil, should that deposit ever be put into production.

"One of the biggest costs of building a mine at Gil is the six-mile road," Robertson said. "If we can use tailings to reduce costs it could save millions. The situation kills two birds with one stone." ●

● NORTHWESTERN BRITISH COLUMBIA

Scoping study, drilling planned at Galore Creek

Startup SpectrumGold plans $5 million budget for gold-silver-copper deposit in northern British Columbia

By PATRICIA JONES
Mining News Editor

Geologists working for NovaGold Resources are going to be busy across the border in northwestern Canada this summer.

The company's Canadian subsidiary, SpectrumGold, plans to spend $5 million for its Galore Creek advanced stage exploration project in remote northwestern British Columbia, and up to $1 million on other grassroots properties in the Yukon Territory.

Galore Creek is the "new sexy project for NovaGold," said Doug Nicholson, vice president and general manager of NovaGold's Rock Creek gold project near Nome. "We're planning a big program this year … I think we will do well with it."

PATRICIA JONES

"This is the same type of opportunity as Donlin Creek. We take an exploration play from one of the majors and go in with a fresh set of eyes and enlarge the project." —Doug Nicholson, NovaGold

The company plans to drill a minimum of 60,000 feet at Galore Creek this summer, following completion of an updated geological model and resource estimate, expected to be released later this month. A preliminary economic assessment study or scoping study is also scheduled to be completed before the summer drilling begins, according to a Feb. 12 press release.

The goal is to identify zones of higher grade material within the existing known deposit, and to test possible mineralization extensions, thereby defining new resources within Galore Creek and in 10 other surrounding target areas, according to a company statement released last fall.

"This is the same type of opportunity as Donlin Creek," Nicholson said. "We take an exploration play from one of the majors and go in with a fresh set of eyes and enlarge the project."

In 16 months of intensive exploration drilling at Donlin Creek in southwest Alaska, NovaGold geologists doubled the size of that gold deposit, producing a resource of nearly 28 million ounces of gold and spending $10 million to do so.

Now Donlin Creek is back in the hands of a major mining company, Placer Dome, which must spend $30 million on development to regain a 70 percent interest in the project.

Expanding Galore Creek

NovaGold hopes to translate that exploration success across the border to the gold-silver-copper deposit at Galore Creek some 37 miles west of the Cassiar Highway, and some 46 miles east of Wrangell, Alaska.

The property has been explored by a number of companies since the early 1960s. Past drilling outlined a resource of 5 million ounces of gold, 60 million ounces of silver and 5 billion pounds of copper. Mineralization occurs at surface and is open at depth.

The company plans to drill a minimum of 60,000 feet at Galore Creek this summer, following completion of an updated geological model and resource estimate, expected to be released later this month.

Current access to Galore Creek is by air, although the scoping study will evaluate in detail access and infrastructure needs, as well as look at the best approaches to mining, processing and transportation of the concentrate product. The study will also estimate capital and operating costs and manpower needed for developing the deposit.

Following the summer drilling program, SpectrumGold plans to complete a pre-feasibility study of Galore Creek in early 2005.

In addition to hiring Hatch Engineering to complete an updated resource estimate, the company has also retained Rescan Environmental to initiate an environmental baseline monitoring program.

Fall drilling successful

Last October, SpectrumGold completed an eight hole, 10,000-foot drilling program on the property, designed to test previous drill results and to better understand deposit variability, zonation and mineralization controls.

Results demonstrated the presence of increased gold and copper grades in the deposit through a focus on potential structural controls; grades were higher than anticipated, according to a company statement accompanying drilling results.

An average of assay intercepts produced three grams (0.09 ounces) per ton of gold equivalent, or 2 percent copper equivalent over 390 feet.

One hole drilled tested both the upper mineralized horizon and a potential lower mineralized zone. Drilling successfully intersected the upper horizon, producing a 520-foot intercept grading 2.6 grams (0.083 ounces) per ton of gold equivalent, or 1.7 percent copper equivalent.

The same hole bottomed in strongly mineralized material, with a 214-foot intercept grading 2.3 grams (0.073 ounces) per ton of gold equivalent, or 1.4 percent copper equivalent.

Yukon property will be worked

SpectrumGold also plans to spend between $500,000 and $1 million on its other grassroots properties in the Yukon Territory. One option is drilling at the Brewery Creek property, work designed to identify a major sulfide gold target along a 15-kilometer mineralized trend.

SpectrumGold also holds a 70 percent interest in the McQuestern gold project located near Mayo, Yukon. ●

PATRICIA JONES

A 200-ton diesel over electric haul truck, the newest in the Fort Knox fleet, dwarfs the mine's 150 ton trucks. The company plans to purchase six more haul trucks and another loader in order to handle waste rock.

continued from page 3

TOUGH

Kinross indicated in its annual report that last year's exploration within the existing Fort Knox pit contributed to the company's decision to move the waste rock.

"Results from the (2003) Fort Knox in-pit work confirmed the continuity of the mineralized zones to justify the Phase 6 lay-back at an assumed gold price of $325 per ounce," the report said.

One positive from the waste rock removal effort — some of the material can be used in constructing the tailings dam lift, Fogels said.

Satellite shut-down

True North mining will extend into mid 2005, according to Kinross. In addition to providing earth-moving equipment at Fort Knox, the suspension "keeps the hauling out of the dusty summer months," Fogels said.

Fairbanks Gold Mining said the company will continue monitoring work and inspections of the site. Reclamation will begin during the summer of 2005, after mining at True North is complete.

Production rates at the True North open pit mine varied between 18,100 and 36,300 tonnes per day.

New equipment

Six new Caterpillar haul trucks and another piece of earth-moving equipment, either a shovel or a loader, are scheduled to be delivered to Fort Knox this summer, Fogels said.

That's on top of more than $9 million spent in late 2002 and early 2003 for new equipment. A new 27.5 yard shovel, four new 200-ton diesel over electric haul trucks and seven rebuilt Kenworth semi-trucks were placed into service last March, boosting the mine's dirt-moving production capability by 30 percent.

"We had a period of adjustment for both operators and maintenance staff when we introduced the diesel/electric Unit Rigs. The drivetrain is different than that of the existing fleet," the company said in response to questions about the new trucks. "After some initial growing pains, all four trucks are operating and the availability has improved." ●

BRITISH COLUMBIA

B.C. government takes heat from industry

Simmering frustration among British Columbia's miners over the government's failure to settle aboriginal land claims and reduce red tap boiled over March 3 as the industry unloaded on British Columbia Minister of State for Mining Pat Bell.

A series of speakers said the industry was paying a heavy price for government cutbacks in gathering geo-science data and other related functions.

A recent survey by the Vancouver-based Fraser Institute found 159 mining executives gave the government a poor grade for its policy climate after a period when British Columbia's mining sector has declined to six companies with six producing mines from 30 to 40 operating base and precious metals mines at the industry's peak.

The Kemess copper and gold mining operation owned by Northgate Exploration is the only one of the six mines to have sufficient deposits to last into next decade, the Mining Association of British Columbia has predicted.

But a proposed expansion of that mine has collided with two local aboriginal communities.

With investors deterred by the land claims uncertainty, the industry is pessimistic that exploration spending can climb from C$50 million a year to the C$150 million-$200 million needed get back on a growth curve.

Nick Ferris, president of J-Pacific Gold, told Bell that British Columbia lacks the regional geologists, inspectors and staff to process staking claims after slashing staff to the bone in "virtually every category."

As he result, he said those left won't be able to handle any exploration rush triggered by rising commodity prices.

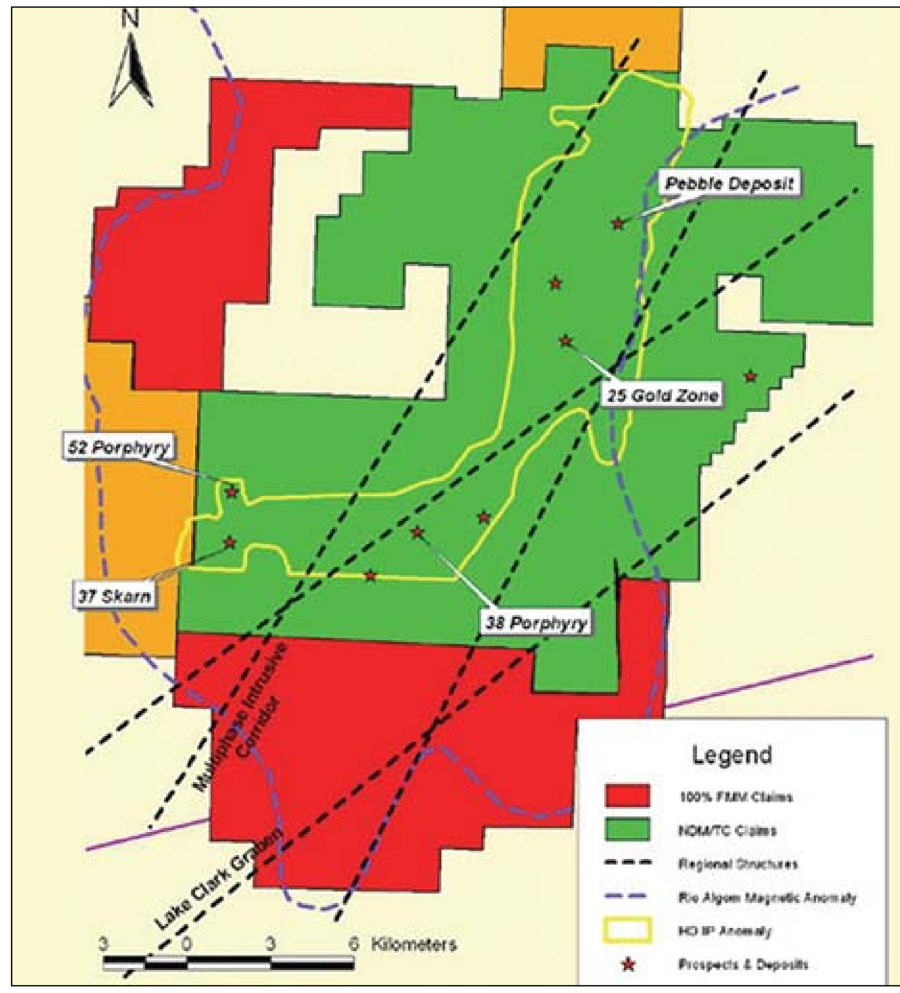
The British Columbia Geological Survey's 2003 review pointed to renewed exploration of gold and copper deposits that have gone untouched for many years, while predicting that mines owned by Imperial Metals and Taseko Mines could reopen within two years.

Bell, who has just been appointed to his portfolio, said the government is endeavoring to reverse a dramatic decline in direct mining jobs over the last decade by preparing a draft mining plan for release this year.

Bob Dickinson, co-chairman of Hunter Dickinson, which manages eight exploration and mining companies, said the industry's patience has been stretched.

But he credited the government for eliminating its corporate capital tax and for taking steps to reactivate the industry.

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



● ILIAMNA, ALASKA

Land leased, geophysical work starts near Pebble

Alaska Earth Sciences signs land deal with exploration upstart for recently staked claims next to Pebble deposit

By PATRICIA JONES
Mining News Editor

Anchorage-based Alaska Earth Sciences has transformed the firm's first-ever land acquisition into a lease deal with an exploration upstart, Full Metal Minerals.

Alaska Earth, a geological consulting firm with years of experience throughout southwest Alaska, staked a large land position last December adjacent to the Pebble gold-copper-molybdenum deposit.

Full Metal Minerals also holds an exploration option for the Ganes Creek gold property, located about 25 miles west of McGrath in Interior Alaska.

The company negotiated a land lease deal for the 261 state mining claims with Full Metal Minerals, announced in early March. No financial terms were released on the company's website.

Full Metal can earn 100 percent of the property, called Pebble South, which is located to the southwest and the northwest of Northern Dynasty's Pebble deposit, estimated to contain 26.5 million ounces of gold and 16.5 billion pounds of copper in the near-surface porphyry zone.

"Full Metal Minerals plans on initiating a reconnaissance mapping and regional stream sampling on the property, as well as grid geochemical sampling and reconnaissance IP and ground magnetics. Based on gathered geological, geochemical and geophysical data, drill targets will be identified," the company said on its website announcing the new prospect property.

Full Metal Minerals also holds an exploration option for the Ganes Creek gold property, located about 25 miles west of McGrath in Interior Alaska.

Geophysical work starts soon

Alaska Earth Science will manage the exploration program, Bill Ellis, part owner, told Mining News on March 5. "We'll be starting that soon — the geophysical program in the next couple of weeks."

A crew of about six will set up camp in the area a few miles northwest of Lake Iliamna in southwest Alaska, across Cook Inlet from Homer. Snow cover will allow workers to conduct IP, indicated potential, surveys on a few square miles of the property, which totals about 65 square miles in size.

"If sulfides are there, they show up (using IP)," Ellis said. "We'll be able to cover only the flatter parts of the country this time of the year."

Access will be by helicopter, supported by snowmachines, he said. The geological consultants should be onsite for two to three weeks, Ellis said.

Past work on the claims includes an airborne magnetic survey flown in 1999 by Rio Algom, and a brief follow-up geologic reconnaissance. Some wide-spaced government-generated geochemistry is also available, according to Full Metal's website.

Geological characteristics

Full Metal provided on its website a detailed description of the geological setting for its new prospect, which is underlain by a Late Cretaceous granodiorite pluton and related hypabyssal intrusives which intrude Cretaceous clastic rocks.

Higher elevations above 150 meters are capped by bi-modal Tertiary volcanics. The area is part of the Mesozoic Peninsular Terrane that lies along and flanks a Jura/Cretaceous northern Aleutian Range batholith. Cretaceous to Tertiary intrusive and Tertiary to Recent volcanic rocks

see **PEBBLE** page 9

● ALASKA MINING NEWS ANALYSIS

Drilling in progress at several locations

Summer season planning proceeding at 'frenetic pace' as demonstrated by short supplies of drill rigs, helicopters and project managers

By CURT FREEMAN

For North of 60 Mining News

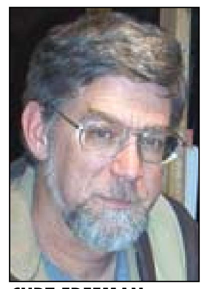
Alaska's exploration season is well under way with drilling in progress at several locations and planning for the summer season proceeding at a frenetic pace not seen in more than five years. Anyone who has tried to line up a drill rig, a helicopter or a project manager will tell you the same thing: all are in short supply, even at this early point in the year. Projects under way and planned for the coming year include numerous gold projects, several base metal projects, a number of platinum group element projects and one diamond project. Active regions for the year look to be Interior Alaska, Alaska Range, Southwestern Alaska, Southeastern Alaska and the Seward Peninsula. Metal prices remain strong with some metals up over last month's prices. Platinum in particular recently topped $900 per ounce, a 24 year high. As a result, interest in Alaska is coming from major, intermediate and junior companies alike.

Western Alaska

Teck Cominco American has reported fourth quarter and year-end 2003 results from its **Red Dog** mine. In the fourth quarter the mine produced 142,800 tonnes of zinc in concentrate and for the year the mine produced 579,300 tonnes of zinc in concentrate. Zinc ore grade and mill recoveries increased to 22.2 percent and 85.5.9 percent respectively from 21.6 percent and 84.5 percent in the year previous quarter. The mine also produced 34,100 tonnes of lead in concentrate during the fourth quarter and 125,000 tonnes of lead in concentrate for the year. As a result primarily of higher zinc and lead prices (average 42 cents and 29 cents per pound respectively for the quarter), the mine posted a $51 million operating profit for the quarter and a $50 million operating profit for the year.

NovaGold Resources said it will complete additional infill drilling and bulk sampling for metallurgical tests as part of its $5 million 2004 development budget at the **Rock Creek** gold deposit near Nome. Final feasibility work currently in progress is expected to allow mine permitting to commence in the second half of 2004.

The author



PATRICIA JONES

CURT FREEMAN

Curt Freeman, CPG #6901, is a well known geologist who lives in Fairbanks. He prepared this column February 29.

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St. Andrew Goldfields announced interim results from its continuing exploration and development program at the **Nixon Fork** mine near McGrath. Work completed included an additional 140 meters of exploration drifting that will allowed commencement of a 1,800 meter drilling program to define the limits of the C3000 and C3300 zones. Once this drilling is completed a 23,500-meter underground drilling program will be conducted to upgrade resources to the reserve status. The drilling is expected to add an additional 120,000 tonnes to the current indicated and inferred resource of 145,000 tonnes grading 0.94 ounces of gold per tonne. The company also plans to drive 650 meters of drift to connect the Crystal to the Mystery declines.

Northern Dynasty Minerals said it raised $22 million via a public offering, much of which will be directed toward delineation drilling and detailed engineering and environmental/permitting studies at its **Pebble** copper-gold project near Iliamna.

Liberty Star Gold Corp. said it completed acquisition of its 237 square mile **BC** property near Iliamna. The company indicated that staking was prompted by pattern recognition through a variety of geologic procedures including satellite imagery interpretation, geomorphology, geologic compilation, structural interpretation and relation to known porphyry systems. This effort suggested that the nearby **Pebble** deposit alteration zone was part of a much larger volcanic caldera, a favorable location for porphyry copper-gold-molybdenum deposits. The company indicated that it would begin geophysical, geochemical and geological studies on its claims in early spring with the goal of conducting initial diamond drilling before the end of the summer field season.

Eastern Interior

Kinross Gold has reported 2003 fourth-quarter and year-end results for its **Fort Knox-True North** operations in the Fairbanks district. For the year the company indicated that it had recovered 391,831 ounces of gold at a cash cost of $243 per ounce. The lower production and higher cash costs compared to year-end 2002 (410,519 at $232 per ounce) were the result primarily of lower recoveries from sulfide-bearing ore from the satellite **True North** open pit. In-pit exploration at **Fort Knox** resulted in a 10 percent increase in proven and probable reserves to 102,939,000 tonnes grading 0.89 grams of gold per tonne (2,945,000 ounces) at a gold price of $325 per ounce. Increasing the assumed gold price to $400 per ounce adds an additional 419,000 ounces to the proven and probable reserves. In 2003 the operation milled 13.6 million tons of ore grading 1.07 grams of gold per tonne. Mill recoveries averaged 83 percent and total production costs were $346 per ounce. Projected production for 2004, from the combined **Fort Knox** and **True North** open pits, is 340,000 ounces of gold. The reduced production schedule is due in large part to a planned temporary suspension of mining at **True North** to allow use of the mining fleet on the next phase of the **Fort Knox** tailings dam lift. Operations at **True North** will then resume in the second half of 2004 and extend into 2005 before final closure due to exhaustion of reserves.

Freegold Ventures Ltd. and joint venture partner **Meridian Gold** announced that diamond core drilling would begin in late February at its **Golden Summit** project in the Fairbanks district. Details of the intended program were not released.

Golden Spirit Minerals announced processing results from a 1,000 cubic yard gravel sample at its **Ester Creek** property in the Fairbanks district. Analysis of tailings from the jig indicated significant levels of gold, silver and palladium remained in tailings, suggesting methods other than simple jigging will be required to recover precious metals from the property. Additional work is planned.

Teryl Resources announced that ground magnetics surveys over its **West Ridge** property have indicated mineralized intrusive found in trenching at the **Old Glory** prospect may extend for at least 700 feet to the south of surface outcrops into an area where anomalous gold in soils was encountered during 2003 auger soil sampling. The company also announced plans to complete reverse circulation drilling on the property in late February. Drilling will consist of up to 15 holes targeted primarily at the intrusive target.

Alaska Range

Golconda Resources announced plans to commence a 3,000-foot diamond-drilling program at its **Shulin Lake** diamond project near Talkeetna. Two holes drilled on the project in 2003 intersected volcanic ash and tuff indicative of a volcanic center. Indicator minerals derived from this drilling possess a chemistry that is similar to eclogitic minerals derived from lamproites, a geologic setting permissive for diamond deposition. The planned March drilling program will include approximately 10 holes in various parts of the volcanic feature.

Northern Alaska

Little Squaw Mining Co. announced that work has begun on the first-ever technical report on the property designed to bring all previous technical data into a single digital database to allow recommendations for future work on the lode and placer prospects on the property.

Southeast Alaska

Hecla Mining (29.73 percent) and **Kennecott Mining** (70.27 percent) announced fourth-quarter and year-end production results from its **Greens Creek** mine near Juneau. For the year the mine produced 11,709,411 ounces of silver, 99,453 ounces of gold, 27,884 tonnes of lead and 76,729 tonnes of zinc. Cash operating costs were $1.10 per ounce while total costs were $3.64 per ounce. Average head grade mined for the year was 27.72 ounces of silver per tonne.●

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PEBBLE

intrude the Peninsular Terrane and are products of northwest dipping subduction along ancestral and modern Aleutian trenches.

The Pebble South claims were staked at the conjunction of two regional trends, the Lake Clark Graben and the multi-phased intrusive corridor holding the Pebble Copper deposit. Portions of the Pebble South claim group in the low-lying areas near Iliamna Lake are covered by recent glacial till or drift.

The claims largely cover areas of low to moderate elevation where the mineralized system is likely to be close to the surface and amenable to open pit mining methods.

The northwestern claim group covers the western margin of the Kaskanak Batholith in a similar geologic setting to the main Pebble trend on the east margin of the batholith.

Within the sulfide system defined by Northern Dynasty's IP and soil anomalies, three copper gold molybdenum porphyry systems have been discovered: the Pebble Deposit, the 38 Porphyry and the 52 Porphyry. In addition to porphyry deposits, the 37 Copper-Gold Skarn and the 25 Gold Zone were discovered within the sulfide system.

Additionally, there are other high-intensity IP zones that are potential mineralized centers that have not yet been drilled. The IP-defined sulfide system appears to be open-ended to the south and southwest onto Full Metal's Pebble South claim block.●

● ALASKA

Improving mineral development

Alaska Minerals Commission makes recommendations to state lawmakers to reduce constraints on mineral development

By PATRICIA JONES
Mining News Editor

In a 16-page report released in January, the Alaska Minerals Commission made 12 recommendations to the state Legislature and Governor on ways to mitigate constraints on mineral development in Alaska.

In addition, the commission identified seven federal issues of concern and made suggestions that the state and/or the governor should pursue to rectify those issues.

Recommendations include suggestions involving government regulatory reform, access and infrastructure development, state's rights issues, data acquisition, regional economic development and supporting mineral education and research.

The report evolved from a teleconference work session and a public meeting held in Anchorage by the 11-member commission, made up of representatives from Alaska's placer, hard rock and coal mining industries.

Irene Anderson, Alaska Minerals Commission chair, represented the Bering Straits Native Corp. on the panel. In her 2004 report message, she commented on the limited success of recommendations the same industry panel made in 2003.

"Highlights during 2003, however, were limited to completion of expedited land transfers along the Denali Highway, and legislation to address the public interest litigants issue," Anderson wrote. "These actions were important incremental gains, but significant obstacles to mining industry growth and desperately needed rural development remain."

COURTESY USIBELLI COAL MINE

The report provided a synopsis of Alaska's $1 billion annual mining industry. Contributions from the state's four large mines — Red Dog zinc and lead mine in northwest Alaska, Fort Knox gold mine near Fairbanks, Greens Creek polymetallic mine near Juneau and Usibelli Coal Mine at Healy (pictured above) were noted.

Industry overview

The report provided a synopsis of Alaska's $1 billion annual mining industry. Contributions from the state's four large mines — Red Dog zinc and lead mine in northwest Alaska, Fort Knox gold mine near Fairbanks, Greens Creek polymetallic mine near Juneau and Usibelli Coal Mine at Healy were noted.

"All turned in a strong performance and contributed significantly to the employment base and economic vitality of their respective host communities and rural regions," the report said.

Four development projects were also noted, including Pogo near Delta Junction, Kensington near Juneau, Donlin Creek in remote southwest Alaska and Rock Creek near Nome. All four are hard rock gold properties in various stages of development.

Despite these developments, the report said, "… the potential benefits of a healthy and growing mining industry as an engine for economic development in Alaska remain elusive, particularly in rural areas of the state where they are needed most."

Overcoming obstacles

Increases in metal market prices stimulated additional exploration activity at known mineral occurrences near transportation corridors in Alaska, the report said.

Despite those upward market trends and a global expanding mining industry due to "explosive demand for mineral commodities," Alaska's mining industry has some significant hurdles to overcome.

"Alaska is one of the most poorly mapped regions of the world and ranks far behind many third world countries in spending for geologic data acquisition," the report said. "… Poor infrastructure, a minimal geologic database and the perception that Alaska can be a difficult place to do business continue as disincentives to exploration investment."

Stimulating exploration and improving the state's business climate are key to improving Alaska's mining industry.

"Alaska's mineral rich terrain and high discovery potential are universally acknowledged, but mining industry growth will not reach its potential without an increase in exploration activity and continued improvement in the business climate," the report said.

Other members of the Alaska Minerals Commission are Eric Neil MacKinnon from Hyak Mining Co. in Juneau, Del Ackels of Goldust Mines in Fairbanks, Leo Mark Anthony of C-D Development Co. of Anchorage, Greg Beischer of Bristol Environmental & Engineering in Anchorage, Charles Boddy of Usibelli Coal Mine in Healy, Karl Hanneman of Teck-Pogo Inc. in Fairbanks, Rich Heig of Kennecott Greens Creek Mining Co of Juneau, Charlotte MacCay of Bristol Environmental & Engineering of Anchorage, Lance D. Miller of the Juneau Economic Development Council of Juneau and Ron Sheardown of Greatland Exploration Ltd. of Anchorage.

The commission is supported by Rich Harris, mining and minerals development specialist in the Alaska Division of Trade and Development, part of the state Department of Community and Economic Development. ●

Alaska Minerals Commission recommendations

Following are recommendations outlined in the 2004 Alaska Minerals Commission report to the state Legislature and the governor.

State regulatory reform

1. The governor carefully consider the state's report, The State of Alaska Assumption of the National Pollutant Discharge Elimination System. If the program presented is beneficial to the state, pursue and fund state primacy.

2. The administration vigorously defend the new Public Interest Litigant statute against legal challenges.

3. The administration continue to develop more efficient and timely permitting processes, maintaining high quality internal staff, using third party contractors, requiring a periodic permitting status report accounting for agency staff and management and seek improved participation and coordination by federal agencies.

4. The governor direct the Alaska Department of Environmental Conservation to develop mixing zone regulations.

Access and infrastructure

5. The administration assist in infrastructure development to benefit mining and other industries, including a prioritized list of potential "Roads to Resources," and seek funding for a long-term program that would create unrestricted public road links between potential developments and existing overland supply lines, major rivers or tidewater.

6. Modify the statute governing rural airstrips to eliminate unauthorized use of such remote mining access strips by individuals and commercial entities.

7. Support state agencies in extending electrical grids into areas where mineral development is occurring or is anticipated.

State's rights issues

8. Resolve land tenure, navigability and right of way access issues, to include pursuing precedent-setting "quiet title" actions, asserting an access route under the Alaska National Interest Lands Conservation Act, funding a centralized systematic navigability program and navigability determination process, and to pursue expedited transfer of state-selected lands along the Denali Highway.

Data acquisition

9. Acquire baseline geological and environmental knowledge statewide, investing $5 million per year on airborne geophysical surveys and complementary geological and geochemical surveys, and to endure that state agencies provide baseline standards for water quality standards mandated by the Alaska Clean Waters Act.

Regional economic development

10. Fund a $250,000, two-year project marketing relevant mineral development opportunities in southeast Alaska.

Education and research

11. Support the Alaska Minerals & Energy Resource Education Fund with $50,000.

12. Provide adequate budgetary support to the UAF School of Mineral Engineering maintaining the school as a separate entity so that its mission is not diluted through assimilation into broader programs.

Federal issues of state concern

13. Federal and state agencies work together to clarify that disposal of tailings into wetlands is either regulated as a treatment works or as a disposal site, and that regulation would not require tailings and associated waters to comply with water quality standards until discharged from tailings area.

14. Until the Jones Act is repealed, the governor shall publish an annual report documenting its harmful effects on Alaska commerce.

15. The Legislature pursue reinstatement of the Alaska Mineral Resources Assessment Program, required by ANICLA, by lobbying the congressional delegation.

16. The Alaska Legislature support SB1466, the accelerated land conveyance bill proposed by Sen. Lisa Murkowski, provided the bill contain language that makes rescinded withdrawal lands immediately subject to public land laws of the U.S. and to mineral entry; and that it contains language and funds that allows BLM to make a detailed inventory of other Alaska land withdrawals that are no longer necessary and that should be rescinded.

17. The governor and Legislature work with the congressional delegation to require the National Marine Fisheries Service to define the scope and application of the "Essential Fish Habitat" program, limit NMFS authority to marine waters and leave management of anadromous fish within state waters to state regulators.

18. The governor assert one RS 2477 access route through a Conservation System Unit, and insist that no more CSU lands be created in Alaska, and to exchange mineralized areas from existing CSU lands, allowed by ANICLA.

19. The governor communicate with the U.S. Department of Labor to ensure that appropriate funds are available for the required unfunded mandate of annual training for gravel operations throughout Alaska now required by the Mining Safety and Health Administration.

● FAIRBANKS, ALASKA

CURT FREEMAN

Cleary Hill was the largest lode gold producer in the Fairbanks mining district prior to World War II. Estimated production from Cleary Hill from the early 1900s until 1942 was 281,000 ounces of gold with an average grade of 1.3 ounces of gold per ton of rock.

Drills turning

Freegold and partner Meridian Gold start core drilling at Cleary Hill Mine, airborne surveys completed on Golden Summit property

By PATRICIA JONES
Mining News Editor

Diamond core drill rigs started turning in early March on the Golden Summit gold exploration property some 25 miles northeast of Fairbanks, Alaska.

Partners in the project, Freegold Ventures Ltd. and Meridian Gold Inc. plan to complete six holes, taking a total of 1,500 meters or almost 5,000 feet of core samples in this first stage of drilling.

The holes will be in the vicinity of the historic Cleary Hill Mine, according to Kristina Walcott, mining lands manager for Freegold Ventures, a Vancouver, B.C.-based mineral exploration company that has worked Golden Summit for more than a decade.

"We're targeting some of the old high-grade veins at the mine," she told Mining News on March 5.

One of several shuttered hard rock gold mines on the 18,000-acre Golden Summit property, Cleary Hill was the largest lode gold producer in the Fairbanks mining district prior to World War II. Estimated production from Cleary Hill from the early 1900s until 1942 was 281,000 ounces of gold with an average grade of 1.3 ounces of gold per ton of rock.

Production from the underground mine took place over six levels, descending approximately 400 feet. Limited prior drilling in the area hit some of the high-grade veins and identified potential bulk tonnage style mineralization.

Drilling extends depths of mining

Drill intercepts taken in 2000 produced intercepts of 64 feet grading 4.74 grams per ton, two feet of 86.12 grams per ton and 300 feet of 1.38 grams per ton at the Currey Zone, located approximately 1,600 feet south of the Cleary Hill Mine, according to a Freegold press release.

"The current drilling is targeting the strike extension of previously intersected high-grade mineralization, which extend the depths of the previous underground mining," the company said in the March 5 release.

Meridian Gold, which in late January signed a joint venture agreement with Freegold to earn up to a 70 percent interest in the Golden Summit property, has committed to spend $740,000 for exploration in 2004. An airborne magnetic survey flown over the 18,000-acre property has been completed and that data is currently being interpreted, Walcott said.

Under terms of the deal, Golden Summit is divided into three project areas, A, B and C. Meridian may earn up to a 70 percent interest in areas A and B.

The airborne survey was flown over the entire area, and Meridian has a first right of refusal to explore Area C, on terms to be agreed on in exchange for funding the survey. ●

BRITISH COLUMBIA

Historic mine could come back to life

Anglo Swiss Resources, a Vancouver-based junior miner, is moving ahead with plans to reactive the Kenville mine in southeastern British Columbia as it starts gold and gemstone exploration of the property.

The company plans a detailed geological evaluation to determine current and prospective ore reserves at Kenville, which produced 2 million grams of gold from 1890 to 1954, making it the 26th largest producer in British Columbia history.

Anglo Swiss also owns 16,800 acres in the Slocan Valley that hosts sapphire, iolite and gemstone quality garnet.

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

NUNAVUT TERRITORY

Tahera diamond mine close to go-ahead

Tahera Corp. is within sight of operating the first diamond mine in Canada's Nunavut Territory.

The Nunavut Impact Review Board has recommended approval by Indian and Northern Affairs Minister Andy Mitchell of the Jericho project, about 210 miles southwest of Cambridge Bay, near the Northwest Territories border.

Toronto-based Tahera has indicated construction of the C$50 million mine will begin in 2005 and the first diamonds will be produced later that year.

Based on proven reserves, the mine and processing plant will have an eight-year operating life.

Jericho is scheduled to be Canada's third diamond mine after the Ekati and Diavik projects in the Northwest Territories that are about 250 miles and 105 miles, respectively, south of the Jericho site. The Snap Lake project in the Northwest Territories is expected to come into development in the next few years.

Jericho is expected to employ up to 60 people during the mine and plant construction, 120 in its open pit operation and 40 to 50 in its underground mine and processing plant.

Inuit to fill 60 percent of jobs within five years

Tahera has promised to hire Inuit to fill 60 percent of the jobs within five years — a goal company Vice President for Nunavut affairs Greg Missal said is "very aggressive."

He said Tahera will encourage its contractor to maintain the same Inuit employment level.

An agreement-in-principle has been signed with the Inuit community to cover training, education and business opportunities.

A year ago Tahera made an important step forward by signing a deal with Lazare Kaplan International that would see the New York-based firm purchase and market Jericho diamonds.

The deal gave Lazare the right to purchase 100 percent of the mine's production with an expected annual value of US$36 million, while Tahera retained an option to market as much as 25 percent of the production independently.

Tahera also negotiated a 50-50 joint venture with Lazare for polishing the diamonds, including special stones of 10.8 carats and larger.

Tahera Chairman and Chief Executive Officer Joseph Gutnick said the deal was important recognition by a boutique diamond company of the quality of Jericho diamonds.

The hope is that final approval for Jericho will stimulate exploration by other companies in the region, such as Diamonds North Ashton Mining and Kennecott, along with two of the world's largest explorers.

Nunavut issued a record 1,518 prospecting permits last year covering more than 64 million acres, compared with just 190 permits in 2002.

De Beers Canada Exploration snapped up the biggest chunk, securing 633 permits covering 28 million acres, while BHP Billiton Diamonds was granted 394 permits covering 16.4 million acres.

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