Petroleum news

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Week of December 14, 2003 • $1

page 6 Alaska must have reasonable tariffs, access to ANS facilities

COURTESY ENCANA

The Norwegian-owned Eirik Raude is the world's largest semi-submersible rig.

Cuba: U.S. oil companies welcome to explore off island's coast

Cuba welcomed American petroleum companies on Dec. 4 to join efforts by the government and other firms to find oil off the island's coast in the Gulf of Mexico.

"The Cuban government does not object to letting American petroleum companies participate in exploration and drilling in our zone as long as it is based on mutual benefit," said an official notice in the Communist Party daily Granma.

Spain-based Repsol-YPF plans to begin offshore explo-

see **CUBA** page 19

Shell, BP announce first production at Gulf of Mexico deepwater hub

Shell and BP said Dec. 8 they have achieved first production at their jointly owned Na Kika project hub in deepwater Gulf of Mexico.

Na Kika consists of five independent fields — Kepler, Ariel, Fourier, Herschel and East Anstey — and is located at the Mississippi Canyon Block 474 about 140 miles southeast of New Orleans.

The five fields are being developed with a shared semi-submersible floating production facility — the first time a hub-type system has been used to develop a group of fields, all of which are of small to medium size and none of which, the companies said,

see **HUB** page 19

BREAKING NEWS

JUNEAU, ALASKA

Coming down

Alaska forecasts 4% less oil production through 2010 than a year ago

By LARRY PERSILY

Petroleum News Juneau Correspondent

The state's oil production forecast through the end of the decade is down from a year ago. The Alaska Department of Revenue's price forecast, however, is up.

North Slope oil is expected to average $27.70 per barrel for the fiscal year ending June 30, 2004, then slip to $24.65 in fiscal 2005 before settling in at a long-term average of $22 a barrel for the rest of the decade, the department said in its December forecast.

Those high prices, coupled with cuts in state spending, will extend the life of the state's budget-balancing savings account to May 2007, the department said in

see **DOWN** page 20

JUDY PATRICK

The trans-Alaska oil pipeline

ALBERTA

Imperial Oil ponders major oil sands step

Drilling to establish reserves at multi-billion dollar project; concerned about cost

By GARY PARK

Petroleum News Calgary Correspondent

Imperial Oil is pushing a multi-billion dollar oil sands project to the next phase, but hesitating over a final decision until it has a better idea of the reserves available and the cost.

Canada's largest integrated oil company will drill 200-250 wells this winter on its Kearl Lake leases to "size up the resource," said Imperial Chief Executive Officer Tim Hearn.

"We think they're high-quality leases and once we've got that in place, then I think we're in a better situation to determine how we go forward," he told a conference call.

Imperial CEO Tim Hearn.

Preliminary estimates have pointed to an operation yielding 200,000 barrels per day over 70 years from

see **IMPERIAL** page 20

CANADA

New Canadian prime minister cool on Kyoto climate treaty

Russia's wavering on treaty opens door for Canada to reassess its commitment

By GARY PARK

Petroleum News Calgary Correspondent

Canada has installed a new prime minister and the oil patch is holding its breath that the change of power spells the end of the Kyoto Protocol.

While Russia wavers on whether to collapse the climate change treaty altogether, Paul Martin, who was sworn in as Jean Chrétien's successor Dec. 12, has wobbled on Canada's commitment to implement the accord fully.

> *"What we need is a plan. And we have not yet developed that plan, certainly not to my satisfaction."*
> **—newly elected Canada Prime Minister Paul Martin**

He said Canada hasn't even developed a plan that would determine whether it can achieve the Kyoto targets for reducing greenhouse gas emissions.

"What we need is a plan," Martin said. "And we have not yet developed that plan, certainly not to my

see **MARTIN** page 20

● MALLIK, MACKENZIE DELTA, NORTHWEST TERRITORIES

Participants call Mallik 2002 gas hydrate research well a success

PETROLEUM NEWS

Results of the 2002 Mallik gas hydrate research well were released at a symposium in Japan Dec. 9. Mallik, drilled from Richard's Island in the Mackenzie Delta, Northwest Territories, Canada, "represents one of the highest concentrations of gas hydrates found to date in the world," project head Natural Resources Canada said in a statement. The gas hydrates, naturally occurring 'ice-like' combinations of natural gas and water, underlie large portions of the world's Arctic continental areas and marine continental shelves, and are believed to exceed the volume of all known conventional gas resources, the U.S. Geological Survey said.

COURTESY USGS

An aerial view of the Mallik site.

"A major achievement of the program was the first modern production test of natural gas hydrates," the project sponsors said in a statement, proving "for the first time" that gas production from hydrates is technically feasible.

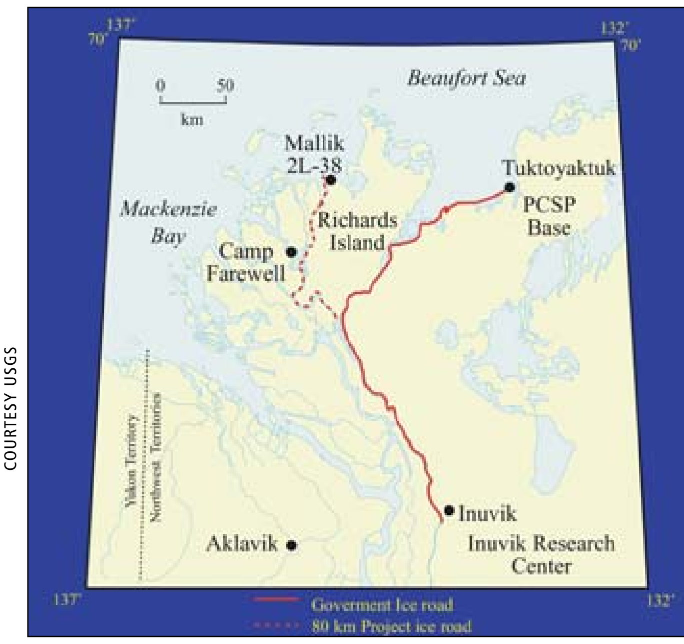
The Mallik partnership drilled three wells to 1,166-plus meters to intersect and test the gas hydrate field. The wells, at 50-meter spacing, consisted of a production test well with observation wells on either side. The partners said an extensive suite of open-hole logs and advanced gas hydrate logging tools were run and continuous wireline core was recovered through the hydrates intervals.

The U.S. Geological Survey said in a statement that while additional research is needed, the "depressurization and thermal heating experiments at Mallik site were extremely successful" and "demonstrated that gas can be produced from gas hydrates with different concentrations and characteristics, exclusively through pressure stimulation."

The USGS said data from Mallik "supports the interpretation that the gas hydrates are much more permeable and conducive to flow from pressure stimulation than previously thought.

"In one test, the gas production rates were substantially enhanced by artificially fracturing the reservoir."

Partners included the government of Canada, with Natural Resources Canada heading the project, and the Geological Survey of Canada; Japan National Oil Corp.; the U.S. Geological Survey and the U.S. Department of Energy; the government of Germany; the government of India; a Chevron-British Petroleum-Burlington joint venture group; and the International Continental Scientific Drilling Program. ●



COURTESY USGS

COURTESY USGS

Examining core samples at the Mallik project.

DENVER, COLO.

Western expands Julesburg play

Western Gas Resources has drilled and logged two test wells in the Denver Julesburg basin and plans six more exploratory holes early next year to see what the area holds.

The Denver, Colo.-based company recently increased its position in the area to about 315,000 net acres.

Western Gas is targeting the Niobrara Formation, an unconventional reservoir at about 2,500 feet. It's expecting 300 million to 500 million cubic feet per well, with a drilling cost of $200,000 per well.

If production testing pans out, development drilling will start in the middle of next year and gas should be flowing by the end of that year.

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

GULF OF MEXICO

Gulf lease sale draws just $8.376M

Eastern Gulf of Mexico Lease Sale 189 will go down in history as one of the smallest areawide sales thus far for the Gulf, attracting only 16 bids on 14 tracts and generating just $8.376 million in apparent high bids.

The lackluster response to the Dec. 10 sale indicates the best prospects were taken when the region was reopened to leasing in late 2001 with Sale 181. That sale drew 190 bids on 95 tracts and raised $340.5 million in high bids, among the best performances in gulf history considering the relatively small sale area.

"I'm satisfied and not really surprised by the level of bidding," said Chris Oynes, gulf regional director for the US Minerals Management Service. "They went all out for the first sale. There was very heavy competition."

In contrast, there was little competition in Sale 189. Only six companies participated — Shell Offshore, Nexen Petroleum, Murphy E&P, Dominion E&P, Newfield Exploration and Spinnaker Exploration. And of the 14 tracts that received bids, only one received more than one bid, DeSoto Canyon Block 353, located next to Marathon Oil's Stegodon prospect. Shell and Nexen Petroleum joined forces to capture block 353 with a bid of $793,521, beating out a $443,000 joint bid by Dominion and Spinnaker and a $261,777 joint bid by Murphy and Newfield Exploration.

Highest bid at sale $2.23 million

However, the highest bid in Sale 189, for $2.23 million, was a single bid submitted by partners Shell and Nexen for DeSoto Canyon block 398, located just southeast of block 353. The companies also took nearby block 397 on a single bid of $616,251. Shell and Nexen also submitted single bids of $793,521 for DeSoto Canyon blocks 486

see **BIDS** *page 4*

Issue Index

Petroleum news

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● NORTHWEST ALASKA

Upswing in zinc helps Red Dog mine

Teck Cominco posts third-quarter profit in remote Alaska mine; metal price increase, streamlined operations contribute

By PATRICIA JONES
Petroleum News Contributing Writer

Higher zinc prices and lower operating costs put the world's largest zinc mine, located in remote northwest Alaska, in the black for the third quarter of 2003, boosting operating profits for its operator Teck Cominco.

Located near Kotzebue, Alaska, the Red Dog zinc, lead and silver mine posted an operating profit of $8 million in the third quarter of 2003, a significant turnaround from a loss of $10 million for the same period in 2002, according to the company's Oct. 22 press release.

The company hopes to continue improving the mine's bottom line, through a cost-cutting program that will eliminate a total of 60 workers.

Zinc production increased — 150,400 tonnes in 2003 versus 143,200 tonnes in 2002 — for the three months ending Sept. 30. In addition, the company realized a slightly higher average price for zinc, 37 cents per pound compared to 34 cents per pound for the same period in 2002, a 9 percent increase.

Average lead prices have also increased by 21 percent in the same period, jumping from 19 cents per pound in 2002 to 23 cents per pound in the third quarter of 2003.

The Red Dog mine near Kotzebue, Alaska.

During the third quarter of 2003, Red Dog produced 31,600 tonnes of lead in its concentrate, versus 28,000 tonnes in the third quarter of 2002.

The grade of ore processed at Red Dog during the third quarter also helped the mine's bottom line. Red Dog ore averaged almost 22 percent in the third quarter of 2003, versus 20.9 percent in 2002.

Recovery of zinc declined slightly, due to an increase in lead production in the concentrate.

Optimization reduces workers

In addition, total production at Red Dog increased in the third quarter, thanks to a higher throughput at the facility. Earlier this fall, Teck Cominco announced plans to cut operating costs at Red Dog, a move expected to reduce costs by about $11 million year, or about 1 cent per pound from the existing 9.5 cents per pound for zinc.

"With the roughly 1.1 billion pounds of zinc we process annually, a 1 cent (reduction in costs per pound) is a very significant number," Teck Cominco's Senior Vice President Mike Lipkewich told investors in late September.

The company said then that they hoped to trim costs through a combination of automation and optimization, which would reduce mine employment by about 60 people. The mine employs about 500 full time workers and about 60 temporary workers, mine manager Rob Scott told Petroleum News this fall.

The mine supports a $42 million payroll annually. A little more than half of its workers are NANA Regional Corp. shareholders. NANA is the Native corporation for Northwest Alaska.

Since it started producing in 1990, Red Dog has brought in millions of dollars in benefits to locals, according to Helvi Sandvik, president of NANA Development Corp, a subsidiary of NANA Regional Corp, owner of the mine.

Sandvik said Red Dog generated a $6.6 million royalty payment for NANA last year, and paid more than $5.5 million to the Northwest Arctic Borough as payment in lieu of taxes, said Bob Jacko, Red Dog general manager.

The mine has turned a profit in only five of the past 12 years, Sandvik said. In 2001 and 2002, it lost $25.3 million and $32.6 million respectively, said Jacko.

High labor and energy costs were under the microscope for cost cutting, Lipkewich said in September. The company holds four shallow gas leases on more than 23,000 acres of state land adjacent to the mine site. Plans to conduct exploratory drilling last summer were put on hold. ●

The Associated Press contributed to this story.

continued from page 3

BIDS

and 487, adjacent to blocks acquired by Shell in the 2001 lease sale.

In contrast, the largest bid in Sale 181 was for $26 million and was submitted by Anadarko Petroleum for Lloyd Ridge block 91, located in the southern part of the sale area. Dominion and Spinnaker, partners with Anadarko on the Spiderman discovery, submitted the second highest bid in Sale 189, for $1.31 million, for DeSoto Canyon block 663, southwest of Spiderman and next to Marathon's Mammoth prospect. Separately, Dominion took nearby blocks 707 and 751 on single bids for a total of $551,100.

Murphy and Newfield also joined forces on DeSoto Canyon block 178, with a single winning bid of $442,700. The block is located next to BP's King's Peak, one of three gas field that feed the Canyon Express Pipeline.

Separately, Murphy nailed down acreage near Spiderman, including DeSoto Canyon block 578 for $227,500 and block 662 for $222,500. The company also paid $228,500 for DeSoto Canyon block 313, located next to Shell's Shiloh prospect.

Murphy picked up DeSoto Canyon block 972 for $222,500. The block is adjacent to the company's undrilled Dachshund prospect. Separately, Dominion submitted winning bids of $246,400 for DeSoto Canyon block 707 and $304,700 for block 751. Both are southwest of the Spiderman discovery.

—PETROLEUM NEWS

ANDERSON, IND.

Anderson hopes to tap century-old gas fields that once fueled industrial boom

Anderson, Ind., officials want to know if there still may be natural gas left in the gas fields that fueled an industrial boom in the city in the late 1800s and early 1900s.

The city and the Corporation for Economic Development have agreed to fund a preliminary study to determine if the gas fields are depleted or if gas remains that could be extracted at competitive cost.

Several industries moved to Anderson after gas was discovered there in 1887, according to information posted to the Anderson Public Library's Web site.

"Those gas fields have been sitting there for 100 years. With so many energy-related companies, it is hard to believe that none would have looked into oil or natural gas reserves in central Indiana and Ohio," John Hagen, director of the Corporation for Economic Development, said Dec. 9.

Mayor J. Mark Lawler declined to say how much the city was paying for the study. If any natural gas is left, it could serve as an energy source for the city of 59,000 about 40 miles northwest of Indianapolis, he said.

Several industries moved to Anderson after gas was discovered there in 1887, according to information posted to the Anderson Public Library's Web site. The city's population boomed and a Cincinnati newspaper editor dubbed it the "Pittsburgh on the White River."

The boom ended when the gas ran out in 1912.

"Natural gas was explored and exploited years ago. We want to know with the new technology available if there are reserves that are available," Lawler said.

—THE ASSOCIATED PRESS

● ANCHORAGE, ALASKA

Governor's office: No new royalty gas sales

Administration clarifies statement on Stranded Gas Act

By LARRY PERSILY

Petroleum News Juneau Correspondent

The governor's office said there is no direct connection between Alaska's Stranded Gas Development Act and sales contracts for royalty gas, and it is unfortunate if the governor's recent reference to royalty sales was confusing.

Alaska Gov. Frank Murkowski said at a Dec. 4 press conference in Anchorage and in a Dec. 5 press release that the state was inviting companies to apply to purchase state royalty gas under the Stranded Gas Act. "The purchase of Alaska's North Slope gas would be a key step in the construction of a natural gas pipeline," the governor's office press release stated.

But the act, which allows a natural gas pipeline sponsor to negotiate a contract with the state for regular payments in lieu of taxes, does not include any provisions for the sale of state royalty gas. Such royalty sales are covered under a separate law.

And the state already has a valid royalty gas purchase offer on hold from last year, waiting to see if anyone builds the pipeline.

"It was a bit of a confusing reference," Mike Menge, the governor's special assistant on natural resources issues said Dec. 10.

Royalty gas moot without pipeline

The governor used the royalty gas reference to point out the state's interest in the Stranded Gas Act and what it may be able to accomplish, Menge said. "We understand there is no direct connection" between the act and royalty gas offers, he said.

The governor's point, Menge said, was that the state's proposed sale of its royalty gas is moot unless someone builds the multibillion-dollar pipeline to move the producers' gas — and the state's gas — to market.

Murkowski called the press conference to publicly invite qualified companies to submit an application under the Stranded Gas Development Act to begin negotiations with the state. Any contract for payments in lieu of state and municipal taxes on the project requires legislative approval, and the governor wants to put the issue before lawmakers early enough in next year's session to win approval before the scheduled mid-May adjournment.

The Stranded Gas Act, designed to provide some level of long-term fiscal certainty for pipeline investors as opposed to the fear of fluctuating taxes, addresses royalty issues only to the extent that it allows negotiation of the timing of state decisions whether to take royalty gas in-kind or in-value and a valuation method for royalty gas.

Anadarko, AEC contract on hold

The state Division of Oil and Gas negotiated a royalty sales contract last year for a joint proposal submitted by Anadarko Petroleum Corp., AEC Oil & Gas Inc. and AEC Marketing Inc. (both now part of EnCana Corp.). The contract covers 70 percent of the state's share of whatever is produced on the North Slope for the proposed gas pipeline.

The state later put the contract on hold, saying it would be better to wait for the federal energy bill and how that might affect the proposed pipeline project. The energy bill, with its Alaska gas line provisions, in on hold until the U.S. Senate returns to work toward the end of January.

Meanwhile, the state still has the $350,000 bonus bid paid by Anadarko and AEC, while the contract is on hold. ●

SAN RAMON, CALIF.

ChevronTexaco plans to sell more North America assets, layoff 200

ChevronTexaco Corp. plans to sell more of its North America oil fields and shed up to 200 more U.S. jobs as part of a purge designed boost the oil giant's profits.

The moves, announced Dec. 8, continue a 4-month-old overhaul undertaken to improve the returns from a $39 billion merger that formed the company in October 2001.

ChevronTexaco's stock is worth roughly 10 percent less than when the deal was completed. On Dec. 9, shares gained 61 cents to $79.22 on the New York Stock Exchange.

The latest divestitures will include about 60 percent of ChevronTexaco's U.S. oil fields in 15 states. The San Ramon-based company said the fields haven't been that important, accounting for just 5 percent of ChevronTexaco's U.S. production.

The asset sales, coupled with a decision to combine some operations in Texas and Louisiana, will eliminate between 150 and 200 jobs, the company said.

ChevronTexaco also plans to sell several older oil fields and other assets in western Canada that produce 35,000 barrels of oil per day. The company said it's too early to tell how many jobs will be lost in the Canadian reshuffling.

The company will absorb fourth-quarter charges to account for the latest restructuring. The charges aren't expected to have a significant impact on ChevronTexaco's fourth-quarter earnings, but the company said some of the asset sales might produce windfall profits next year.

ChevronTexaco hopes to raise its pretax profits $500 million by selling about $6 billion in assets during the next few years. The company's assets totaled $81 billion as of Sept. 30.

—THE ASSOCIATED PRESS

PARIS, FRANCE

International agency says Yukos, Sibneft saga threat to Russia oil output

The uncertainty surrounding Yukos and its on-again-off-again merger partner Sibneft is a potential threat to 200,000 barrels per day of oil production growth in 2004, the International Energy Agency said in its December report. The merger of the two Russian oil giants would create the world's fourth largest oil company.

"Prospects for growth in 2004 will be critically dependent on how the current legal and political procedures surrounding Russia's large producer Yukos play out," IEA said.

"Any impediment to their continued expansion would have a material impact on total Russian supply growth," the agency said, noting that it continued to assume short-term operations would not be affected.

Production from outside the Organization of the Petroleum Exporting Countries is expected to grow by 1.5 million bpd next year, with half of that expected to come from the former Soviet Union, IEA said.

Russian crude oil production was 8.53 million bpd in October and an estimated 8.56 million bpd in November, IEA said.

—PETROLEUM NEWS

NEW ORLEANS, LA.

ChevronTexaco exploration unit leaving New Orleans for Houston

ChevronTexaco said Dec. 8 that it is moving its deepwater exploration operations to Houston as part of a restructuring that will eliminate 150 to 200 jobs nationwide.

The New Orleans office currently employs 900 people. Company executives say they don't know how many will be cut from that office as a result of the restructuring. ChevronTexaco's Deepwater Gulf of Mexico Business Unit, which employs about 300 workers in New Orleans, will be renamed the Deepwater Gulf of Mexico Exploration and Projects Business Unit and relocated to Houston.

However, a local company spokesman told the Houston Chronicle not all of the New Orleans unit's 300 workers will be transferred to Houston; Employees associated with deepwater production assets in the gulf will stay in New Orleans.

The Chronicle said there are 120 such employees, but "that does not imply that all the remaining 180 will move." That decision, the ChevronTexaco spokesman said, will be determined later.

The company's Gulf of Mexico Shelf Business Unit, which employs more than 1,500 workers, will remain in New Orleans, the newspaper reported.

"We will continue to be the number one producer on the Gulf of Mexico shelf," the company spokesman was quoted as saying.

Earlier this year ExxonMobil said it was closing its New Orleans office and moving it to Houston, eliminating aabout 380 local jobs. Shell Exploration & Production has also said it will move up to 100 geologists and engineers to Houston before the end of this year.

—PETROLEUM NEWS

DOHA, QATAR

ConocoPhillips to develop GTL plant

Qatar Petroleum and ConocoPhillips signed a statement of intent Dec. 8 for construction of a gas-to-liquids plant in Ras Laffan, Qatar.

ConocoPhillips said the signing initiates detailed technical and commercial pre-front-end engineering and design studies and establishes principles for negotiating an agreement for an integrated reservoir-to-market GTL project.

Jim Mulva, president and chief executive officer of ConocoPhillips, said ConocoPhillips and Qatar Petroleum will be working toward a heads of agreement over the next 12 months. "With our technology, resources and experience in executing large-scale developments, we are well positioned to carry out global GTL projects, and look forward to more definitive agreements in 2004."

ConocoPhillips began a GTL research and development program in 1997 and began operation of a 400 barrel-per-day GTL demonstration plant in Ponca City, Okla., in July.

"The demonstration plant is designed and operated to assure successful technology scale-up and reliable commercial plant operation," the company said.

ALASKA

Lease buyback will be state's last resort, Murkowski says

Alaska Gov. Frank Murkowski's office released a statement Dec. 8, clarifying comments made by the governor Dec. 4 on buyback of coalbed methane leases.

The statement said the governor was clear that consideration of the state buying back any coalbed methane leases in the Mat-Su and on the Kenai Peninsula would only be after all other options are exhausted.

"The state will consider buybacks of shallow natural gas leases only as a last resort," Murkowski said in response to a question at a Dec. 4 press conference in Anchorage.

The state has some 270,000 acres of active shallow gas leases, almost 230,000 acres in the Matanuska-Susitna area, some 23,000 acres near Homer on the Kenai Peninsula and 23,000 acres near the Red Dog mine in northwestern Alaska.

The Department of Natural Resources is engaged in crafting rules for coalbed methane development and the governor's office said the state remains committed to the development of coalbed methane, both for use in Southcentral Alaska and as a significant source of rural energy.

The department is working with other state agencies and the Matanuska-Susitna Borough to write specific guidelines for coalbed methane development and has said rules for coalbed methane development in the Mat-Su Borough will be crafted through public workshops. The first workshop had been scheduled for Dec. 9, but the department said Dec. 4 that it was rescheduling that first public workshop at the request of the Mat-Su Borough.

Workshops are now scheduled for Jan. 14, Jan. 21, Jan. 28 and Feb. 4. Each workshop will address specific topics, and the department said it would be determining those topics in the near future.

—PETROLEUM NEWS

● ALASKA

Alaska wants more business

Governor meets with companies; report on North Slope facilities due next month

By LARRY PERSILY

Petroleum News Juneau Correspondent

As part of its efforts to attract more independent oil and gas companies to explore in Alaska, the state expects to have a report ready by the end of January identifying and analyzing existing North Slope production facilities that might have room to handle new flows of oil and gas.

Even if the state is able to convince companies to explore in Alaska and even if they find new reserves, "ultimately it comes down to your commercial economics," state Oil and Gas Division Director Mark Myers told representatives from about a dozen oil and gas companies meeting in the state capital.

PATRICIA JONES

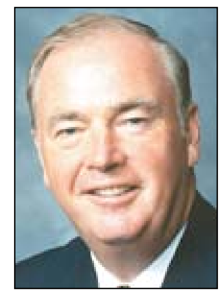
"We want to know, we need to know … what you need, what it is going to take to encourage your participation in Alaska," said Tom Irwin, commissioner, Alaska Department of Natural Resources.

The companies answered Alaska Gov. Frank Murkowski's invite to meet and tell him what the state could do to help attract more exploration investment dollars to the 49th state. In addition to a private session with the governor, the group listened to Myers and several other state officials explain the opportunities in Alaska, the state's leasing structure, tax and royalty provisions, and permit rules.

North Slope facilities, access, lower tariffs are important, says governor

Reasonable access to existing North Slope production facilities and affordable pipeline tariffs to move oil off the slope are key to attracting new exploration ventures to Alaska, Murkowski said.

Myers told the gathering Dec. 9 that the report on North Slope production facilities should be done by the end of January. Although it will list existing facilities, their capacity and constraints, it will not go so far as to set up negotiations or speculate on user rates between facility owners and potential new entrants on the slope.



Reasonable access to existing North Slope production facilities and affordable pipeline tariffs to move oil off the slope are key to attracting new exploration ventures to Alaska, Alaska Gov. Frank Murkowski said following the meeting.

"There is no ultimate template on how you do that," he said of negotiating rates for access to facilities.

The Anchorage-based consulting firm of Petrotechnical Resources of Alaska is preparing the $50,000 study for the Alaska Department of Natural Resources. The contract, which was awarded almost six months ago, is funded by a federal grant, Myers said.

Report called 'shoppers guide'

The report — which has been called a "shoppers guide" to unused capacity — will include:

• Analysis of oil, gas and water production details to determine facility limits and potential excess capacity or constraints at Prudhoe Bay, Kuparuk, Point McIntyre, Lisburne, Endicott, Milne Point, Badami, Alpine and Northstar.

• A survey of existing facility operators to identify areas of possible mutual benefit to the owners and any new producers that could help fill excess handling capacity.

• Estimates for the cost of facility expansion.

• Methodologies for determining what share of capital costs and operations and maintenance costs a new producer could expect to pay on the slope.

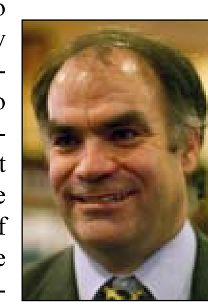
• Discuss the owner's "inherent competitive advantages" in charging for use of its production facilities.

• "Propose alternative approaches that attempt to balance the interests of both facility owners and third-party operators."

In addition to pipeline and facility issues, the governor said the oil company representatives also discussed shared access to cleanup equipment and a suggestion that perhaps the state could make it easier for exploration companies to sell any state tax credits they might accumulate.

Companies ask about exploration credits

The new exploration credit provision, which was adopted by the Legislature this past session, may be applied only to state production taxes. The governor said the companies asked if the state might consider expanding the program to allow application of the credits against corporate income taxes, in addition to the easier sale of any tax credits to producing companies to ensure that exploration companies get some value for the tax credits even if they do not have their own production.



JUDY PATRICK

Mark Myers, director of the Alaska Oil and Gas Division, told the gathering Dec. 9 that the report on North Slope production facilities should be done by the end of January.

In addition to attracting officials from a dozen oil and gas companies, the Juneau meeting drew several oil field service companies. Federal officials also participated in the information presentations to the group. The Department of Natural Resources sent 13 people to the meeting.

Exploration and production companies in attendance included Total E&P USA, Aurora Gas, Anadarko Petroleum, Pioneer Natural Resources, Merlin Oil & Gas, Evergreen Resources (Alaska), Eni Petroleum, Talisman Energy, Armstrong Oil & Gas, Winstar Petroleum, North Star Energy, Prodigy Oil and Gas and EnCana.

State looks for future income

"We want to know, we need to know … what you need, what it is going to take to encourage your participation in Alaska," state Natural Resources Commissioner Tom Irwin said to open the meetings. "We need to generate that new wealth for future generations."

The governor is looking to increased oil and gas production to solve the state's budget problem blamed, in great part, on declining North Slope production. The region's oil flow is at just under 1 million barrels a day, half of its peak rate of 2 million barrels a day in 1988.

"There is tremendous potential that remains," said Don Brizzolara, petroleum geologist with the Division of Oil and Gas. ●

finance&economy

NORTHWEST TERRITORIES

Resources push Northwest Territories to top of heap

A possible construction start on a Mackenzie Valley natural gas pipeline and diamond mining will turn the Northwest Territories into Canada's economic pacesetter until at least 2006, says Toronto-Dominion Bank economist Derek Burleton.

Already one of the hottest economic regions, the Northwest Territories should grow by 7 percent a year from 2004 to 2006, easily outstripping other regions, and if the gas line gets approval the "sizzling growth performance would likely extend into the next decade," he said.

Burleton is confident that unresolved Native land claims and environmental issues will be resolved, clearing the way for construction of the Mackenzie project and opening the door to a chain of spin-off benefits, including hydroelectricity, telecommunications and tourism.

But there is a current blip for the territories' 42,000 residents, with real gross domestic product slipping to 3 percent this year before rebounding to 13 percent annually from 2000 to 2003.

That stemmed from a short-term slowdown following completion of the Ekati and Diavik diamond mines, but work is scheduled to start next year on the third diamond mine at Snap Lake, which is due to be in full production by 2007.

Perhaps the biggest trouble spot is the failure so far by the Northwest Territories government to reach a revenue-sharing deal with the Canadian government.

As a territory rather than a province, the Northwest Territories turns over 100 percent of its resource royalties and is totally dependent on the senior government for covering its C$900 million a year budget.

Burleton suggested the territories may be forced to introduce a sales tax or use public debt markets to cover more of its needs.

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

TULSA, OKLA.

Unit finishes Serdrilco buy

Unit Corp. has completed its acquisition of Serdrilco Inc. and its subsidiary, Service Drilling Southwest LLC, the Tulsa, Okla., company said Dec. 8. Unit paid $35 million in cash, plus the sellers will receive half of the operation's cash flow beyond the first $10 million annually for the next three years.

Serdrilco, also based in Tulsa, was privately held. Service Drilling Southwest is located in Borger, Texas.

Serdrilco has a dozen rigs with depth capacities from 6,500 to 18,000 feet. All are currently under contract. The deal also includes 12 trucks to move the rigs, plus the district office and equipment yard at Borger.

Unit now has 88 land drilling rigs, with 83 of them currently under contract.

Serdrilco had operated in the Anadarko basin and the Texas Panhandle for more than half a century.

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

● WASHINGTON, D.C.

EIA boosts winter crude price estimate

OPEC's decision to maintain current quotas squeezes world supply

By ALLEN BAKER
Petroleum News Contributing Writer

With crude prices remaining strong in November, the Energy Information Administration has boosted its winter estimate by $1.75 per barrel compared with the figure just a month ago. November's crude prices ranged from $29 to $33 a barrel for West Texas Intermediate, the agency reported.

The EIA now expects that crude to average $30.50 per barrel for the winter, and remain in the $28 to $30 range for all of next year.

That forecast is based on low inventories in the consuming countries, as well as the decision by the Organization of Petroleum Exporting Countries Dec. 4 to keep the current production quotas in place. The cartel plans to hold sales to 24.5 million barrels daily for the 10 OPEC members except Iraq.

OPEC ministers plan to meet again in early February and said after the December meeting they might even cut the quotas at that time.

World oil demand is expected to rise about 1.3 million barrels daily in 2003 and 2004, with next year's growth expected to soak up all the added production outside the OPEC countries over the year. About half of the production increase is expected to come from Russia and the Caspian region.

The U.S. demand is expected to grow by 310,000 barrels per day on average for this year, a gain of 1.6 percent over the 2002 number. For 2004, demand would grow 300,000 barrels more, or 1.5 percent, to 20.4 million barrels each day under the scenario painted by the Energy Department economists.

Natural gas to stay above $5

For natural gas, spot prices are expected to remain

see **EIA** page 8

● NEW YORK

Dollar joins OPEC calculus, hits importers

Dollar down against both euro and yen, at record lows against euro

By CHARLES ROTH
The Associated Press

OPEC oil ministers have taken to talking like central bankers and finance ministers. And no wonder, given the swoon of the dollar.

Traditionally, when the Organization of Petroleum Exporting Countries decides to restrain its production levels, fuel prices stay firm or rise, supporting member revenues and those of other emerging market oil exporters.

But the dollar's weakness has tweaked that dynamic, as oil is priced in the greenback, which is at record lows against the euro around $1.2223 and a three-year bottom against the yen of 107.31 yen.

Fareed Mohamedi, chief economist at PFC Energy, an international energy consulting firm, said OPEC states "are going to get hammered by this," as their payments in euros and yen have risen sharply.

Indeed, Saudi Oil Minister Ali Naimi, among others, was quoted as saying OPEC's decision Dec. 4 to maintain its collective output target of 24.5 million barrels was based on a current "real value" of $25 dollars a barrel, and not the $28 at which OPEC's crude basket is now trading.

That's because, he explained, the dollar has declined 30 percent against the euro over the last two years. OPEC economies, he argued, need high oil prices not to make up for the slide in the dollar. OPEC is also looking to maximize revenues ahead of an

see **OPEC** page 8

OPEC considering trading oil in euros to compensate for U.S. dollar decline

OPEC Secretary General Alvaro Silva said the organization is considering trading oil in euros to compensate for the U.S. dollar's decline in value.

Another alternative is to trade in a basket of currencies other than the greenback, Silva told Venezuela's state news agency, Venpres.

"There is a talk of trading crude in euros. It is one of the alternatives," the former Venezuelan oil minister said from Vienna Dec. 8.

"It is possible that the organization will discuss that, and make a decision at some point in time," he said.

Silva did not provide more details.

At its meeting in Vienna the Organization of Petroleum Exporting Countries expressed concern that the U.S. dollar's decline against the euro and yen was eroding its members' purchasing power.

Many OPEC members are Middle Eastern countries reliant on imports from Western Europe and Japan.

OPEC decided to keep its target output ceiling stable at 24.5 million barrels a day. Saudi Oil Minister Ali Naimi said the decision was due in part to the weakening dollar.

The U.S. dollar hit a new low against the euro Dec. 9, with the European common currency reaching US$1.2276. The greenback is at a three-year low against the yen at 107.19 yen

OPEC will meet next Feb. 10 in Algiers, Algeria, to review production policy.

—THE ASSOCIATED PRESS

continued from page 7

OPEC

expected seasonal decline in oil prices in the second quarter, when demand slackens as the Northern hemisphere moves into spring.

Most OPEC members are Middle East nations, and thanks to the dollar's fall, have seen their purchasing power decline sharply vis-à-vis their top commercial partners. OPEC kingpin Saudi Arabia sources about two-thirds of its imports from Western Europe and Japan. Many also have euro- or yen-denominated debts, raising their foreign debt servicing costs.

For oil importers, OPEC's decision means energy import bills will continue to stay hefty, potentially pressuring trade balances and spurring inflation. This is particularly true in many high-growth Asian countries that are highly dependent on oil imports to fuel their industrial sectors.

As Asian countries align their currencies closely with the dollar and have more yen-denominated borrowings, they face both high oil prices — January crude on the New York Mercantile Exchange closed at $32.10 a barrel Dec. 8 — and debt servicing costs. Their purchases of Japanese exports are also more expensive.

Among many other emerging market oil importers, though, the dynamic is far more benign, thanks mainly to currency appreciation against the dollar.

Turkey's currency, for example, has risen 15 percent against the dollar this year, making its oil purchases that much more affordable. The same is true in Chile, where the peso has climbed 19 percent to a 37-month high against the dollar. Both countries' dollar-linked debt has also become easier to service.Brazil and, to a lesser extent, Peru fall into this camp, as well. For independent oil exporters such as Venezuela, Russia and Mexico, the value of their dollar-based oil revenues has weakened just as it has with OPEC countries. But at least strong crude prices alleviate that pinch.

Even Russia, which trades primarily with Europe, hasn't felt any appreciable pain. To the contrary, it's posting current account and fiscal surpluses thanks largely to high energy prices and expanding oil and natural gas production and exports. ●

Editor's note: Charles Roth is a correspondent for Dow Jones Newswires.

continued from page 7

EIA

above $5 per million British thermal units for the next few months, unless temperatures are warmer than normal. High oil prices will help support the price of the competing fuel.

Natural gas prices were a bit lower in November than expected, but they spiked early in December as cold weather hit the East and storage levels declined. Storage is still above average for this time of year, however, and that could dampen any price increases.

Overall U.S. gas demand is expected to show a decline of 2.3 percent for this year, once all the numbers are in. Demand was down in the electric generating and industrial sectors due to high prices for the fuel. But with the economy rebounding, demand in 2004 is projected to rise by 1 percent.

Production for this year will show an increase of 2.4 percent, the economists figure, but that should fall back again in 2004 as drilling activity declines. The decline may not put too much pressure on prices because storage requirements are expected to be lower this coming summer.●

NORTH SLOPE

Alaska regulator OKs ASRC's interest in Alpine pipeline

The Regulatory Commission of Alaska said Dec. 9 that is has approved a joint application filed in August by Alpine Transportation Co. and ASRC Pipeline Co. for ASRC Pipeline to acquire a 16.67 percent minority interest in Alpine Transportation Co.

Arctic Slope Regional Corp., a royalty owner in the Alpine oil field, exercised its option to acquire a minority interest in Alpine Transportation Co. through a subsidiary company, ASRC Pipeline.

The commission ruled the application complete after Arctic Slope Regional Corp., the parent company of ASRC Pipeline, filed a guaranty that the parent company would be responsible for the pipeline company's common carrier pipeline obligations.

ConocoPhillips and Anadarko Petroleum discovered and developed the Alpine field and are partners (ConocoPhillips 78 percent, Anadarko 22 percent) in the field and in the pipeline. After the ASRC acquisition, Alpine Pipeline Co. (a wholly owned subsidiary of ConocoPhillips Alaska) will own 65.333 percent, Anadarko Alpine Pipeline will continue to own 22 percent and ASRC Pipeline will own 16.667 percent.

—PETROLEUM NEWS

COOK INLET, ALASKA

Beluga natural gas pipeline to be relocated this winter

Alaska Pipeline Co. plans to relocate a portion of the Beluga natural gas transmission pipeline this winter due to river erosion caused by Susitna River meander.

Alaska Pipeline is proposing a new route which parallels the existing channel crossing 2,000 feet to the north. Horizontal directional drilling will be used to cross under the channel.

The state of Alaska has begun review of an application for the work, and said some 120 feet of riverbank remains between the pipeline and the river, but the integrity of the pipeline crossing is threatened.

Alaska Pipeline is proposing a new route which parallels the existing channel crossing 2,000 feet to the north. Horizontal directional drilling will be used to cross under the channel. Construction access will be via ice road from the end of the Point McKenzie Road and along the existing right of way.

The pipeline crosses the Susitna River drainage within the Susitna Flats State Game Refuge in section 9 of township 15 north, range 7 west, Seward Meridian, an area of mostly lowlands and muskeg swamps.

Completion of the pipeline relocation is expected by mid-March.

—PETROLEUM NEWS

● CANADA

Carriers go from pipedreams to pipelines to ship oil sands

Terasen, Enbridge race to lock up shipping contracts for proposals to transport oil sands production to the coast of British Columbia

By GARY PARK

Petroleum News Calgary Correspondent

An all-out race is developing between Terasen and Enbridge, Canada's two leading crude oil carriers, to lock up shipping contracts for their multi-billion dollar proposals to deliver oil sands production to the British Columbia coast.

From there, the big prize is the prospect of opening up new markets in the United States, with the Orient beckoning as a bonus.

With a flurry of new oil sands projects in the offing, the two pipelines are out to woo shippers as they head towards crucial decisions sometime in 2004.

The latest bar-raising came from Terasen on Dec. 3, when it not only revived its Bison project to move production out of northern Alberta, but indicated it is ready to almost double the volumes it delivers to 610,000 barrels per day. It already operates the Corridor pipeline from the oil sands to Edmonton.

With a flurry of new oil sands projects in the offing, the two pipelines are out to woo shippers as they head towards crucial decisions sometime in 2004.

The Vancouver-based company, formerly BC Gas Utility, said the 300-mile Bison line to Edmonton, originally targeted at 320,000 bpd, could be built in three stages — 172,000 bpd by 2006, 320,000 bpd by 2008 and 610,000 bpd by 2010 at a total cost of C$1 billion.

The original Bison scheme, carrying a price tag of C$510 million, was sidelined in May after

see **CARRIERS** page 10

● ANCHORAGE, ALASKA

Exxon Valdez oil spill suit is back in federal court

THE ASSOCIATED PRESS

The Exxon Valdez oil spill lawsuit was back in federal court with a judge reconsidering the $5.3 billion in punitive damages against the oil giant.

Nearly a decade has passed since a jury awarded the punitive damages against Exxon Mobil Corp. and nearly 15 years since the 11 million gallon tanker spill in Prince William Sound.

The plaintiffs, composed of commercial fishermen, Natives and others, still say they should get $5 billion in punitive damages to punish the oil giant. Exxon says it should pay $25 million.

U.S. District Court Judge Russel Holland has been ordered by the 9th U.S. Circuit Court of Appeals to reconsider the damages. The judge is to consider a U.S. Supreme Court decision earlier this year involving a Utah traffic accident and damages awarded in that case.

Holland said Dec. 3 he would try to have a decision by the end of January.

Holland already reduced the Exxon punitive damages award to $4 billion a year ago after a three-judge panel sent the original $5 billion verdict back, saying it was excessive.

Attorneys from both sides argued that the Supreme Court case, State Farm Mutual Automobile Insurance Co. v. Campbell, supported their damages claims.

In that case, the Supreme Court ruled 6-3 that a state court jury's award of $145 million to punish the insurance company was grossly excessive when actual damages were $1 million. The high court held that the ratio of punitive to actual damages should not exceed single digits, or 9-to-1. It also said juries could

see **LAWSUIT** page 10

KEMMERER, WYO.

BLM seeking comments on southwest Wyoming resource management plan

The Bureau of Land Management in Kemmerer, Wyo., is finishing up work on a revision of its resource management plan for the area it manages in southwestern Wyoming.

Public comments are being taken on the plan, after hearings in Kemmerer, Evanston and Rock Springs.

Issues brought up so far include oil and gas development and its impact on winter range for wildlife, as well as corridors for pipelines, roads and power lines.

Comments can be mailed to the Kemmerer Field Office, BLM, Attention Don Ogaard, RMP Project Manager, 312 Highway 189 North, Kemmerer WY 83101.

Comments may also be sent electronically at the Kemmerer RMP revision website: http://www.Wy.Blm.Gov/Kfo.

continued from page 9

CARRIERS

TrueNorth Energy scuttled its oil sands plans and Petro-Canada took a time-out to rethink its possible C$5.8 billion oil sands strategy.

A number of new projects launched, proposed or hinted

That picture has changed dramatically in recent weeks as U.S.-based ConocoPhillips and Devon Energy have launched their own projects; Nexen and Canadian Natural Resources have pointed to imminent decisions on their own ventures; Imperial Oil has reignited talk of a possible C$5-$8 billion development; Petro-Canada has hinted it could proceed with its plans in smaller stages; and two juniors, Synenco and Petrobank Energy and Resources, have floated their own proposals.

In addition, the current operators, Syncrude Canada, Suncor Energy and Shell Canada, are also in various stages of expanding operations that could add another 800,000 bpd over the next 12 years.

On top of its Bison plans, Terasen said it is weighing a parallel line to its 280,000 bpd Trans Mountain line to the British Columbia coast and Puget Sound in Washington state.

The parallel system would offer 100,000 bpd of capacity from Fort McMurray, Alberta, to Jasper, Alberta; add another 100,000 bpd from Jasper to Kamloops, British Columbia, and boost capacity by 440,000 bpd from Kamloops to Vancouver. The successive phases would cost C$450 million, C$700 million and C$925 million.

About 200,000 bpd of the new volumes would go to Puget Sound and the balance would go by tanker to California.

Calgary-based Enbridge is also exploring tanker deliveries to California and possibly Asia, where it is trying to line up refineries, as part of its C$2.5 billion Gateway pipeline that would offer 400,000 bpd of capacity from Alberta to either Prince Rupert or Kitimat, both of which are believed to be capable of handling supertankers.

California open to processing more heavy crude

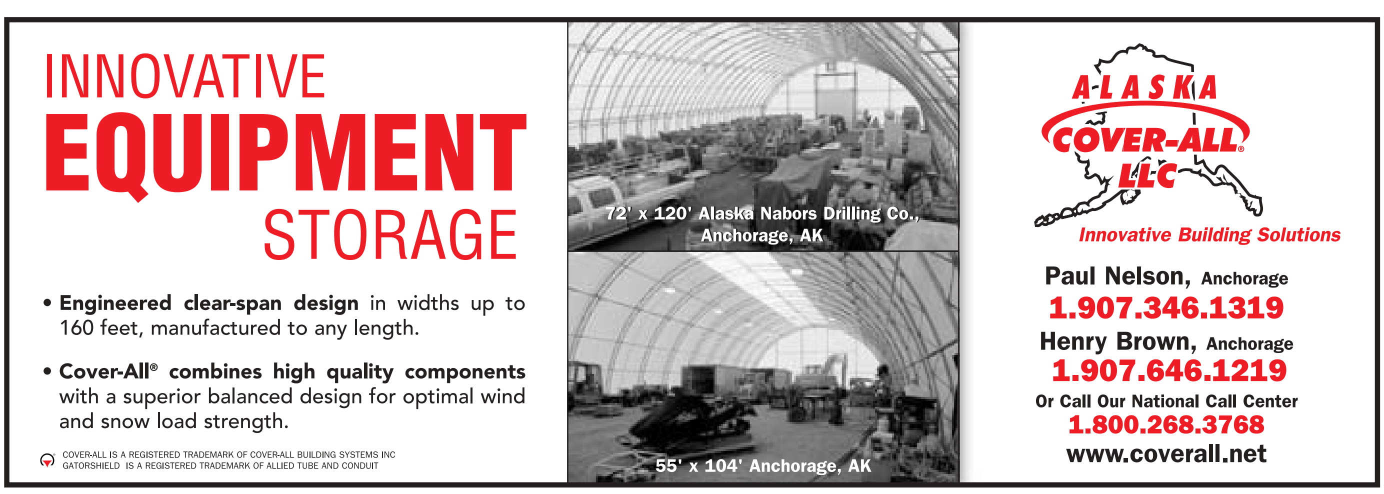
Roughly three-quarters of that total could end up in California, which is open to processing more heavy crude.

Shell announced in mid-November that a lack of San Joaquin Valley heavy crude will force it to close its 70,000 bpd Bakersfield, Calif., refinery in October 2004, while upgrading an adjacent terminal to receive product from its three other West Coast refineries that have combined output of 385,000 bpd.

In the campaign to sway shippers, Terasen Pipelines president Rich Ballantyne said his company's objective in its current discussions with a "number of parties" is to win over anchor tenants and hope smaller producers will follow.

Apart from the toll charges, Edward Koshka, an energy consultant with Purvin & Gertz, told the Financial Post that the shipping costs — which could range from C$2-$2.65 per barrel — are only one factor in the equation.

He said the contest then comes down to who offers very large crude carriers and who can service only smaller tankers. ●



continued from page 9

LAWSUIT

not award giant sums to punish companies just because they're rich, big or considered part of an unsavory industry.

Exxon attorney John Daum said that according to the strict standards laid out in the State Farm case, the injury to plaintiffs was only economic, Exxon did not put the safety of fishermen and other plaintiffs at risk, the tanker spill was an isolated incident and Exxon did not intentionally cause harm. That means an even lower ratio, say 1-to-1 or less, should apply to Exxon, he said. Later, Daum said that ratio would produce damages of about $25 million.

Exxon has already paid $3.2 billion on cleanup, settlements and other fees and penalties, Daum said.

But attorney Brian O'Neill argued for the plaintiffs that the key issue is conduct, and that Exxon's was among the worst. The spill affected more than 32,000 people. Exxon knew that tanker Captain Joe Hazelwood had alcohol problems, but still allowed him to take charge of the Exxon Valdez, O'Neill said.

"To date, Exxon paid only what an innocent spiller would pay," he said.

The highest punitive damages allowed by the State Farm decision should be applied to Exxon, O'Neill argued. He calculates the actual damages caused by the spill at more than $500 million, which equals roughly $5 billion when the 9-1 ratio is applied, he said after the hearing.

Fisherman David Martin attended the Dec. 3 hearing and said he wasn't impressed.

"They're delaying it as long as they can," he said. "They're still making money and fishermen are still at the low end of the totem pole." ●

BRITISH COLUMBIA

B.C. aboriginals share in ownership of drilling rig

A historic advance has been made in the shaky relations between the British Columbia government, the petroleum industry and aboriginals.

The Fort Nelson First Nation has reached a deal with Ensign Drilling to split ownership of an C$8 million rig, with EnCana as a third-party participant, by offering to open a 5 million acre lease area in northeast British Columbia to the rig.

The Fort Nelson First Nation has reached a deal with Ensign Drilling to split ownership of an C$8 million rig, with EnCana as a third-party participant, by offering to open a 5 million acre lease area in northeast British Columbia to the rig.

The agreement will create 20 direct jobs for the 731-member Fort Nelson community and 40 to 50 spin-off jobs, with the first nation collecting half the money earned by the rig's drilling contracts.

There is no estimate yet on how much that might contribute to Fort Nelson revenues.

Fort Nelson Chief Liz Logan said the ground-breaking agree-

see **SHARE** page 12

NEW ORLEANS, LA.

Three shallow Gulf of Mexico successes for Energy Partners

Energy Partners Ltd. has three new widely separated gas discoveries in shallow waters of the Gulf of Mexico.

The New Orleans company says it found 10 feet of gas pay in a 100 percent owned well 180 miles west-southwest of New Orleans. The straight hole in 47 feet of water was drilled to 7,850 feet. Energy Partners plans to complete the well, East Cameron 44 No. 2, with a second rig in the first quarter, and start production in the first half of next year.

A directional well, the High Island 55L No. 4, encountered 58 feet of apparent gas pay in two intervals as the bit worked its way to 8,077 vertical feet below the surface. Vintage Petroleum is operator and holds a 65 percent working interest in that well, with Energy Partners owning 35 percent. Vintage plans two more wells on the block, and will tie back the new discovery to an existing platform early next year. The well is 65 miles east-southeast of Houston in 45 feet of water.

Energy Partners holds a 67 percent working interest in the third successful well, called the Mesa Verde East prospect. It's in the East Bay field 80 miles southeast of New Orleans at the mouth of the Mississippi. Drillers punched through two intervals

see **SUCCESSES** page 12

● CANADA

COURTESY APACHE

One of the biggest successes and biggest disappointments for Murphy is British Columbia's Ladyfern gas field.

U.S. players jettison Canadian assets

Eager to cash in value and chase 'higher growth areas,' ChevronTexaco and Murphy Oil put Western Canada conventional assets on market

BY GARY PARK

Petroleum News Calgary Correspondent

It's not yet a full-fledged retreat, but there is the sound of scampering feet in Calgary as U.S.-based E&P companies pull up stakes in Western Canada's conventional plays, eager to take advantage of a market hungry for assets.

In the space of two days, ChevronTexaco and Murphy Oil have put at least C$1.5 billion worth of holdings up for sale as they chase higher-growth global opportunities and try to make the most of higher commodity prices at a time when Canada's income trusts and junior firms are scouring the market for producing properties.

While retaining "frontier" interests in the Arctic, Alberta oil sands and East Coast offshore, the two have decided that the Western Canada sedimentary basin is a diminishing prospect.

That view was echoed in a National Energy Board report Dec. 9, which said natural gas production from the Western Canada sedimentary basin will stay flat for the next two years at about 16 billion cubic feet per day despite record drilling.

A spokeswoman for Chevron Canada Resources, a unit of ChevronTexaco, said the company is putting daily production of 35,000 barrels of oil equivalent up for grabs, representing all of its conventional volumes in the west and one-third of its total Canadian output, or about 4 percent of ChevronTexaco's global output. The possible price tag for the Canadian properties has been estimated at C$1 billion.

The list includes a key role in the Fort Liard gas

see **ASSETS** page 12

NORTH AMERICA

Canada rigs jump on winter drilling

The North America rotary rig count, spurred by the start of the winter drilling season in Canada, rose by a net 29 to 1,576 rigs during the week ending Dec. 5, according to rig monitor Baker Hughes.

The number of rigs operating in Canada, compared to the previous week, increased by 31 to 465 rigs, up 141 rigs vs. the same period last year.

In the United States, however, the number of operating rigs fell by a net two to 1,111, still up by 259 rigs compared to the same weekly period last year. The loss of six land rigs was partly offset by a gain of two offshore rigs and two inland water rigs.

Of the total number of rigs working in the United States during the recent week, 956 were drilling for natural gas and 153 for oil, while two were being used for miscellaneous purposes, according to Baker Hughes. Of the total, 742 were drilling vertical wells, 273 directional wells and 96 horizontal wells.

Among the leading producing states in the United States, Alaska gained two rigs for a total of 13, while Louisiana also picked up two rigs for a total of 159. Texas increased by one rig to 475. Wyoming registered a loss of five rigs for a total of 60. Oklahoma lost four rigs to 141. New Mexico lost two rigs to 68. And California lost one rig to 25.

Meanwhile, the average U.S. rig count for November 2003 was 1,112, up 10 from the previous month and up 278 compared to the same monthly period last year. The average Canada rig count for November 2003 was 412, up 18 from the previous month and up 131 from the same period last year.

The worldwide rig count for November 2003 was 2,304, up 18 from the previous month and up 429 compared to the same monthly period last year, according to Baker Hughes.

—PETROLEUM NEWS

continued from page 11

SUCCESSES

of gas pay totaling 37 feet on the way to a total depth of 13,900 feet. Newfield Exploration owns the remaining interest in that well. Energy Partners plans other exploratory wells in the vicinity of that find.

The young independent, started in 1998, has seven other exploratory projects going and plans to spud two more by the end of the year.

So far this year, the company says it has had 13 successful wells out of 15 drilled. It focuses on shallower waters in the gulf.

—ALLEN BAKER, Petroleum News contributing writer

continued from page 11

ASSETS

play of the lower Northwest Territories, but the spokeswoman insisted to reporters that "it's definitely not a pullout" from Canada.

Chevron will keep its exploration leases offshore British Columbia, a 20 percent stake in the Athabasca oil sands project, leases in the Beaufort Sea and Mackenzie Delta, and interests in Newfoundland's Terra Nova and Hibernia oil fields as well as its 28 percent operator position in the stalled Hebron-Ben Nevis project.

Murphy inviting offers for conventional properties

Murphy announced Dec. 8 it is inviting offers for its conventional oil and natural gas properties in the Western Canada sedimentary basin — a deal that could fetch upwards of C$500 million.

On the heels of Marathon Oil, which bailed out of the region in August by offloading upstream interests to Husky Energy and EOG Resources for US$588 million, Murphy has decided there are better opportunities elsewhere, notably a recent oil find in Malaysia.

The properties on the block produce 20,000 barrels of oil equivalent per day from proved reserves of 40 million barrels equivalent of heavy oil, light oil and natural gas.

Given prolonged high commodity prices, analysts have valued the package at C$500 million to an estimate of C$650 million by Brian Prokop, with Peters & Co., who said the hunger among energy trusts and junior producers could raise the bidding.

A sale is expected to be completed by mid-2004 and could involve a trust spinning off some of the holdings to juniors.

Murphy president and chief executive officer Claiborne Deming said in a statement that "now is the right time" for his company to monetize many of its assets in Western Canada and pursue plays in "higher growth areas."

The El Dorado, Ark.-based company will retain its 5 percent holding in the giant Syncrude Canada oil sands consortium and stay active off Canada's East Coast, where it has stakes in the two producing oil fields — 6.5 percent of Hibernia and 12 percent of Terra Nova.

Ladyfern success and disappointment

One of the biggest successes and biggest disappointments for Murphy was its discovery of British Columbia's Ladyfern gas field four years ago, with one well testing initially at 100 million cubic feet per day, putting it among the top 10 onshore discoveries in Canadian history.

But competition among the owners to exploit the play dragged the field from 665 million cubic feet per day in spring 2002 to less than 100 million currently — a decline that Harvey Doerr, president of Murphy's Canadian unit, described as "value destruction."

He said disagreement by the companies over how to exploit Ladyfern resulted in an excessive number of wells being drilled and the field being overcapitalized.

Instead of windfall profits to the companies, the only real beneficiaries were governments because of royalties and taxes that were raked in during a compressed period.

Doerr told the Financial Post that there is still an opportunity to explore in the Ladyfern region, but Murphy prefers to redeploy the money and assets it has tied up in Western Canada. ●

continued from page 11

SHARE

ment is a "foundation for future opportunities and benefits for our community."

Despite 18 months of tensions that have led to aboriginal blockades of drilling sites, Logan insisted Fort Nelson was not opposed to development.

"Our challenge has always been with government, not with industry," she said.

"We've always told the industry we want to benefit, to participate ... but we also want to see that the development is done sustainably.

"We want to share the revenue that's been coming out of our backyard since 1951."

Ensign Chief Executive Officer Bon Geddes said the first nation will be able to share its "traditional knowledge of the land and we can reciprocate with our knowledge of oil and gas drilling."

EnCana has negotiated parallel deals with aboriginal communities in Alberta.

Andy Popka, the company's vice president of aboriginal affairs, said eight Alberta first nations own rigs and the majority are working on traditional Native land in British Columbia.

British Columbia Energy Minister Richard Neufeld welcomed the progress towards involvement by aboriginals in job training and economic involvement.

—GARY PARK, Petroleum News Calgary correspondent

NORTH SLOPE

Both Northstar and Alpine back on line

Two North Slope oil fields which had production difficulties at the end of November and the beginning of December are back at normal production rates.

The BP Exploration (Alaska)-operated Northstar field came back on line Dec. 7, with full production expected Dec. 8, and ConocoPhillips Alaska-operated Alpine, where production had dropped by half Dec. 1, had resolved its mechanical issues and was ramping up Dec. 8.

The problem at Northstar was a transformer that had to be replaced, and that transformer drove both oil shipping and the water injection pumps, BP Exploration (Alaska)'s Daren Beaudo told Petroleum News. A transformer was available on the North Slope, but it was at Prudhoe Bay and a heavy duty helicopter was required to get it to Northstar Island. The nearest helicopter was in Oregon, and it didn't arrive in Alaska until Dec. 4. Meanwhile, BP kept Northstar operating at about 5,000 bpd, enough to keep the lines warm.

Beaudo said Dec. 8 that the transformer swap at Northstar went well and that production rates started coming up Dec. 7. As of 6 a.m. Dec. 8, Beaudo said, production was at full rates, some 76,000 barrels per day.

At Alpine, production had dropped by about half due to a problem with one of the oil separators.

ConocoPhillips Alaska spokeswoman Dawn Patience said the mechanical issues at Alpine had been resolved.

Alpine was ramping up Dec. 8, Patience said, with a target of 100,000 barrels.

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

NORTHWEST TERRITORIES

Chevron Canada encouraged by results of Fort Liard gas development drilling

Success at a Fort Liard development gas well in the lower Northwest Territories has prompted operator Chevron Canada Resources to schedule two development wells on the property in the first half of 2004.

Purcell Energy, a 24 percent partner, said the Fort Liard 2K-29 well drilled in the first quarter of this year continues to produce at a constrained rate of 25 million cubic feet per day of raw gas.

Chevron expects to spud 3K-29 in January and 2M-25 in May, one each from the producing K-29 and M-25 well sites. The wells, costing about C$10 million each, will be directionally drilled and tied into existing facilities.

Another C$8-$10 million is earmarked for facilities expansion, which Purcell believes can be recovered within eight months of increased production at current gas prices.

The junior E&P company reported success from a workover and re-completion of the M-25 well, allowing gas production to resume at 15 million cubic feet per day, although it has since been constrained to 10 million.

Purcell said Chevron may sidetrack M-25 early next year to avoid the main fracture, where an influx of water has occurred, and add significant production by mid-2004.

Raw output from the four Fort Liard wells is expected to average 75 million cubic feet per day in the current quarter, giving Purcell a net share of 14 million cubic feet per day.

Overall, Purcell is counting on drilling about 25 wells by spring, giving it 7,000

see **RESULTS** *page 14*

● NORTH SLOPE

Technology, knowledge team up at Lisburne

Alignment, subsurface knowledge, coiled tubing drilling result in two successful wells for BP at North Slope carbonate field

By KRISTEN NELSON
Petroleum News Editor-in-Chief

BP Exploration (Alaska) President Steve Marshall told the Resource Development Council in November that the company is revisiting some of the North Slope's more challenging oil accumulations in an effort to produce known resources.

One of those, he said, is Lisburne, where two recent wells provide hope that the giant carbonate oil field on the eastern edge of the Prudhoe Bay field can be economically produced.

Lisburne started to get another look in 2002, when BP took over operatorship at Prudhoe and associated fields.

Anne Shaw, BP Exploration (Alaska)'s Greater Point McIntyre Area resource manager, told Petroleum News Dec. 5 that in 2002, BP's Point McIntyre subsurface team and the company's coiled tubing drilling team took another look at Lisburne, which is managed as part of Greater Point McIntyre.

There had been a lot of work done on Lisburne over the years, trying "to figure out, how do you unlock the potential" of the 2 billion barrel field, Shaw said.

Production from Lisburne to date has only been about 136 million barrels, less than 7 percent of oil in place, she said, compared to Prudhoe Bay, where expected recovery is 50-55 percent of barrels in place.

Lisburne a different type of field

The problem the companies have had with Lisburne is that it is a different type of reservoir than other North Slope fields. The major North Slope oil reservoirs are in sandstone formations. Lisburne is not.

"It's a huge carbonate field, and the carbonate nature of it is what makes it very different from the rest of the fields on the North Slope, which are sandstone," Shaw said.

The companies started out with high hopes for Lisburne. The Lisburne Production Center was built to handle some 100,000 barrels of oil a day and more than 80 wells were drilled at Lisburne in the 1970s and 1980s.

The limestone reservoir presented drilling challenges: it is hard and difficult for drillers to penetrate. When they did penetrate, they sometimes found good porosity in the reservoir — pore spaces which could contain oil — and sometimes no porosity at all.

Oil rate is also a problem with Lisburne wells, Shaw said: "They come on strong and fall off quickly.

"And then they also have high gas rates."

And limited North Slope gas handling facilities mean "a lot of the wells just weren't economic to produce."

Development drilling at the field ended in 1989 because of the disappointing results.

Production continued, but dropped from a peak of around 40,000 bpd to 10,000 bpd.

No absolute analogues

Shaw said that Lisburne has some similarities to limestone reservoirs elsewhere in the world, but there are differences.

Lisburne has dual porosity, she said, "both matrix and fracture porosity."

The reservoir is also complex, with what are called 'thief zones' — "high permeability streaks at the top of the reservoir" — through which gas from the field's northern gas cap quickly moves to wells drilled elsewhere in the field.

During the earlier development drilling, wells would be drilled in the southern portion of the field, "and within a week" gas would be moving into the well bores from the gas cap to the north.

There are analogues to Lisburne around the world, Shaw said, but "specifically, when you get into this, there's all sorts of little complexities."

see **LISBURNE** *page 14*

● NEW ORLEANS, LA.

Low Gulf of Mexico activity puzzles firms

Energy service firms in Gulf suffering from low activity rates; rig count down from 2000-01 levels

THE ASSOCIATED PRESS

Despite strong commodities prices, natural gas exploration and production activity in the Gulf of Mexico has failed to rebound and energy services companies have seen their business decline.

Energy service companies historically have benefited from high energy prices as oil producers and independents sought to produce more oil and gas.

Tidewater Inc. of New Orleans waited for part of last year and well into this one for a turnaround.

But as Tidewater waited, it bled cash. With many of its ships and crew workers sidelined, Tidewater lost $8 million from its Gulf operations during the quarter that ended in June.

That forced the company to cut 50 ship-based and shoreside jobs and demote 160 other employees, reducing their salaries because of the lack of work.

"We had to do something to right-size our capacity," said J. Keith Lousteau, Tidewater's chief operating officer. "We waited as long as we could.

The rate of use for supply vessels in the Gulf was just 59 percent in September, Citigroup Smith Barney reports, citing the most recent data. That's compared with rates of 68 percent in September 2002 and 80 percent in September 2001. The recent use rate is the lowest since the late 1980s.

Service industry challenged

The industry cannot understand what's happening.

"It's very difficult to say," McMoRan Exploration Co. Co-chairman James 'Jim Bob' Moffett said.

Bill Walker, president of Howard Weil Labouisse Friedrichs Inc., a New Orleans investment bank, said the near future does not look promising.

"Service companies are going to be extremely challenged," he said.

Although Walker said he disagrees with doomsayers who suggest the Gulf of Mexico is on the verge of becoming a dead sea, he said the Gulf is undergoing a fundamental shift.

"The Gulf of Mexico we have grown up with is over," he said.

In 2000 and 2001, business in the Gulf was booming. On average in 2000, 136 rigs were operating there. That number rose to 148 on average in 2001, according to Baker Hughes.

The activity reflected oil prices that averaged $30.29 a barrel in 2000 and gas prices that averaged $4.02 per thousand cubic feet in 2001, according to the U.S. Department of Energy.

But in 2002, as oil prices dipped to about $26 a barrel and natural gas to less than $3 per thousand cubic feet, rig counts dropped to an average of 109.

Then came 2003. Signaling another potential boom, oil prices have again risen, trading at times well above $30 a

see ACTIVITY page 19

continued from page 13

LISBURNE

Subsurface and drilling teams both crucial to Lisburne success

Both the Greater Point McIntyre area subsurface team — geophysicists, geologists, reservoir and petroleum engineers — and BP's coiled tubing drilling team worked on Lisburne.

The subsurface team did a lot of work "developing an improved understanding of the reservoir itself," which increased the "odds of hitting both what we call matrix porosity and then also fractures in the Lisburne," Shaw said. The team has a lot of experience, she said. Some have worked Lisburne and the North Slope for 20 years, and "they've really been able to overcome the odds.

"A year and a half ago people would have just said 'you're nuts to do this,'" Shaw said.

Both new technology and a better understanding of the reservoir have contributed to the current successes.

Without "major breakthroughs" in drilling technology, the new wells could not have been drilled.

Key are coiled tubing drilling in limestone; using "non-damaging fluids, solids-free fluids" so drilling doesn't damage the reservoir; and drilling "near balance, so we're not over balanced — we're not pushing stuff into the formation. So what you end up with is a pristine well when you're finished."

The goal in drilling at Lisburne, Shaw said, is preserving the natural fractures. Past drilling plugged the fractures, and fracture stimulating didn't work very well because the reservoir rock is very hard and fracture stimulating works just near the well bore. With the "matrix porosity, which is your storage volume … you're trying to preserve your natural fractures … which are the connectors to your storage volume."

Merger and alignment allow more flexibility at Lisburne

One reason Lisburne got another look was because, due to the BP-ARCO merger when ARCO's Alaska properties were sold to Phillips Petroleum (now ConocoPhillips), ownership at major North Slope fields was aligned and BP became the sole operator at Prudhoe Bay, which includes Lisburne, one of the Prudhoe Bay participating areas.

"This was a big thing," Shaw said. "Because of the alignment and the merger, we were now able to actually go over and use Prudhoe Bay wells" to drill to the Lisburne reservoir.

Because there were so many wells already drilled into the reservoir, new penetrations can be drilled with coiled tubing drilling as sidetracks from older wells. Coiled tubing drilling is cheaper, and vendors are developing specific bits that can drill through the Lisburne limestone faster. "The faster you can drill through it, the less time you have to spend on it, and that brings the cost down."

K-317B well a success

The first of the two new wells, the K-317B, completed in January, was drilled from an old Prudhoe Bay well on K pad and had a measured depth of 11,935 feet and a true vertical depth of 8,830 feet.

By drilling the first well from K pad, on the western side of Lisburne, BP was able to avoid some of the high permeability zones gas could move through.

K-317B was drilled with a horizontal section through the reservoir, cutting across the fractures and intersecting the matrix.

The well was completed in January and is still producing 800 to 1,000 barrels per day, Shaw said.

In addition to continued oil production, the well's gas production hasn't increased.

Second well more challenging

After the success at K-317B, the team tried something more challenging, and tackled a sidetrack within the Lisburne participating area. The L1-15A was drilled closer to the gas cap and had some 1,500 feet of horizontal section. The well began producing in mid-October, and production has continued to increase.

That is because of the dual porosity at Lisburne, Shaw said: "As the well cleans up, and as the matrix porosity starts to feed the fractures, you get a stabilized flow" with "increasing production," which was at 1,500 barrels per day in early December, with slightly declining amounts of gas.

"It's exactly the type of well we want to emulate throughout the whole field," Shaw said.

BP is learning as it goes at Lisburne, Shaw said, and successful drilling has "been a daunting challenge.

"And this team is just continuing to learn and continuing to innovate." With each well there is information, which can be applied to the next well. "So success will breed success here," Shaw said.

It's also a learning process for drillers on the Nordic 2 coiled tubing drilling rig, she said.

"These are all new things for them. They'd never drilled in limestone with coil. They'd never drilled near-balanced on the slope before."

A third well scheduled for January

A third well, the L2-14, will be drilled early next year, also a coiled tubing sidetrack. And at least two more wells are on tap for next year.

And what have the new wells done for the field so far?

There are 89 reservoir penetrations, about 10 wells on production full time because of the high gas content from the field. There are perhaps another 40 wells that are swing wells, Shaw said, which can be produced for maybe a week or two and then have to be shut in for four or five months.

Total production is about 10,000 bpd. And the two new wells account for 21 percent of that production.

Additional wells will also be coiled tubing sidetracks, and will also be designed to run horizontally through the reservoir. "We're trying to do that because we're trying to hit all the fractures and open up the matrix porosity," Shaw said. One of the things that the team will learn as more well are drilled is how long the horizontal sections need to be: "Do we need 2,000 feet? Or do we need 800 feet?

"It's part of the learning process," Shaw said. ●

continued from page 13

RESULTS

barrels of oil equivalent per day compared with 5,700 boe per day in the fourth quarter.

Capital spending in the final three months is forecast at C$7.5 million, including six exploratory wells and five development wells at an average working interest of about 50 percent.

Among its other activities, Purcell is producing up to 6 million cubic feet per day from its Tenaka property in British Columbia, which is alongside the Adsett field where reserves are estimated at more than 130 billion cubic feet.

—GARY PARK, Petroleum News Calgary correspondent

BRITISH COLUMBIA

Confusion reigns over British Columbia natural gas pipeline

Some say yes, some say no as the future of a natural gas pipeline project to Vancouver Island from the United States continues to negotiate regulatory hoops.

In the latest development, a Canadian government review panel said the Canadian portion of the C$322 million line could proceed so long as a power plant to be fed by the pipeline was also approved.

Three months ago, the British Columbia Utilities Commission rejected the pipeline application by government-owned British Columbia Hydro & Power Authority, arguing there was no proof the gas-delivery system would be a cost-effective means of serving the power plant.

A BC Hydro spokesman has since said the utility plans to sell its stake in the pipeline — a joint venture with Williams Gas Pipeline — as a non-core asset.

The pipeline was due to come on stream in October 2005 as part of the Georgia Strait Crossing Project, a new international pipeline designed to ship gas to markets in northwestern Washington state and Vancouver Island. The U.S. portion got regulatory clearance 15 months ago.

The Canadian section has generated strong opposition, ranging from concerns about the impact on marine life, earthquake risks and economic justification.

Even pulp and paper maker Norske Canada has told regulators it can provide the electricity it needs more cheaply through a combination of energy savings and co-generation at its existing pulp mills.

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

NORTHWESTERN CANADA

Yukon, Northwest Territories team up to advance oil, gas options

A new spirit of cooperation between the Yukon and Northwest Territories has been reinforced in an agreement to explore options for oil and natural gas development in Canada's North.

The two governments signed the pact Dec. 5 that opens up a wide range of possibilities from access to a Mackenzie Valley gas pipeline to development and management of the Beaufort Sea.

Yukon Energy, Mines and Resources Minister Archie Lang said the cooperative measures will help his government achieve its commitment to "help Yukoners receive access to employment, training and business opportunities from oil and gas and pipeline development in both territories."

Northwest Territories Resources, Wildlife and Economic Development Minister Jim Antoine said the "historic" agreement underscores a renewed cooperation and mutual understanding.

It comes after a period of tense, often fractious relationships as both governments advanced their case for the Mackenzie and Alaska Highway pipeline proposals.

Now Lang said the Yukon and Northwest Territories want to ensure northerners benefit, regardless of which pipeline is built first.

see **TEAM** *page 16*

● CANADA

Canada's gas can compete with LNG

So long as costs are kept under control, United States will need imports from the north

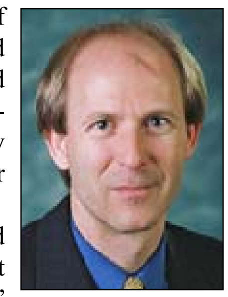
By GARY PARK

Petroleum News Calgary Correspondent

For all the buzz over liquefied natural gas, there is little chance that rising imports in the United States will displace supplies from the Western Canada sedimentary basin, a Calgary conference heard Dec. 2.

Amid a parade of speakers extolling the value of LNG in answering U.S. demands, Greg Stringham, vice president of the Canadian Association of Petroleum Producers, said Western Canada sedimentary basin gas has the edge over LNG in pipeline infrastructure and proximity.

He estimated Canadian conventional gas could be delivered to market at a cost of C$3.90-$6.05 per thousand cubic feet, while LNG would cost C$4.40-$6.20 before transportation, based on a currency exchange of 75 cents (US) per Canadian dollar.



Greg Stringham, vice president of the Canadian Association of Petroleum Producers

Stringham said the "demand pull" emerging on the market now will "pull all supplies," including LNG which is a "very small but very important and growing part of the mix."

He noted that the United States currently operates four LNG terminals, which handle about 1 billion cubic feet per day of total U.S. volumes of 60 billion cubic feet per day.

For proponents of LNG projects, the challenge is to have faith that natural gas prices will still be high when multi-billion-dollar projects come on stream in

see **COMPETE** *page 16*

● NEW JERSEY

BP plans Northeast LNG port

New Jersey facility would provide market for Caribbean production

By ALLEN BAKER

Petroleum News Contributing Writer

With proposals for new LNG terminals popping up all over the map, BP is going for the energy-hungry Northeast market.

The company plans to build a big LNG terminal in New Jersey designed to handle enough liquefied natural gas to pour 1.2 billion cubic feet of natural gas a day into the Northeast pipeline system from about a hundred dockings a year.

That would make it about 20 percent larger than Cove Point, the largest LNG terminal currently operating.

Shipping directly to the big Northeast population centers bypasses pipeline bottlenecks and accesses a market where gas brings a premium price.

BP has plenty of supply from the big LNG plant at Trinidad and Tobago in the Caribbean. The company already is shipping product from there to Dominion's Cove Point LNG port on Chesapeake Bay south of Baltimore, and has secured about 30 percent of the capacity at Cove Point.

BP owns a third of the Atlantic Co. of Trinidad and Tobago, which has the big liquefaction plant there that began shipping LNG in 1999 and still has major expansions in the works.

"This facility (in New Jersey) will provide an exclusive import terminal for BP's use for a lot of the product that's coming up (from Trinidad and Tobago)," said Howard Miller, a BP spokesman.

Permit applications coming

BP is preparing applications for the terminal, and intends to file them this month, Miller said. It'll take about 18 months for the permitting to be completed, and gas could start flowing sometime

see **BP** *page 16*

● ANCHORAGE, ALASKA

Alaska gas authority delays funding request

LNG project office will have to wait for legislative session

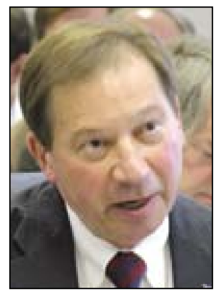
By LARRY PERSILY

Petroleum News Juneau Correspondent

The Alaska Natural Gas Development Authority has abandoned its plan to ask for an additional $200,000 in state funding this month, and its chief executive says it will instead add it to its budget request for when the Legislature comes back to work in January.

"I gave it a go," said Harold Heinze, chief executive officer for the gas authority. "At the end of the day it came down to the fact … there are no funding sources available."

Heinze said he learned from the Department of Revenue and the governor's budget office that in order for a state agency to request additional funding when lawmakers are not in session, the agency must also identify a source for the extra money. Any such funding source is limited to "new" money that was not available to legislators during the past session.



HAROLD HEINZE

The Legislative Budget and Audit Committee — in charge of such requests when the full Legislature is not in session — approved an additional $200,000 for the gas authority in October, taking the money from a one-time pot of federal aid given to the state after lawmakers adjourned this past May.

No reason to even submit request

Heinze said he could not find another such pot of immediately available funds to tap for the gas authority's latest request to add to its budget, so there was no point in turning in a formal request for the funds.

The authority's budget this fiscal year is $350,000 — an original $150,000 appropriated by the Legislature in May plus the $200,000 additional in October. The money is to determine the economics of a proposed state-built, owned and operated $12 billion project to pipe natural gas from the North Slope to Valdez, where it would be liquefied and shipped aboard tankers to any willing customers around the Pacific Rim.

The gas authority board of directors voted at its Nov. 17 meeting for Heinze to request $200,000 more in funding from the Legislative Budget and Audit Committee at its Dec. 12 meeting in Anchorage. The additional money was to have paid for more work by consultants, including studies of a proposed spur gas line to Cook Inlet from the main line, the possibility of using barges to bring LNG to coastal Alaska communities, and the prospect for separating propane from the gas stream and distributing it statewide.

The additional money also was to have paid for review of the legal problems in using non-U.S. tankers to carry Alaska LNG to West Coast terminals vs. the financial hurdles in paying for U.S. tankers to do the job.

The administration supported the authority in its request for the first $200,000 in October but turned away from supporting the second $200,000 request this month, saying the money wasn't needed so soon and the request could be dealt with when lawmakers return to session.

Authority will try again in January

Heinze said he expects the authority will add the $200,000 request to the $1.95 million it already was planning to seek from the Legislature when it starts its 121-day session Jan. 12. All state general fund money is available for appropriation when the Legislature is in session.

If approved at the full amount, the appropriations would bring the authority's budget to $2.5 million for the fiscal year

see DELAY page 17

continued from page 15

TEAM

Antoine said there is a "solid commitment from which we will work to maximize the benefits of northern development for all of our residents."

The agenda includes developing an action plan to identify options and opportunities in several oil and gas areas and sharing geological information.

Gaining access to the Mackenzie pipeline will help the Yukon promote exploration of its promising northern prospects, while the Beaufort Sea has resurfaced on the horizon, with Devon Canada and Chevron Canada Resources both indicating they are interested in resuming exploration of the shallow waters after a long hiatus.

Meantime, the Northern Gas Project Secretariat has opened an office in Yellowknife, the Northwest Territories capital.

With a staff of seven under executive director Brian Chambers, the office will play a key role in the environmental impact assessment and regulatory review of the Mackenzie project, including notifying the public on how and when to become involved.

—GARY PARK, Petroleum News Calgary correspondent

PAC COM Expo to focus on Bradfield/Iskut road & corridor project

A corridor to bring Alaskan resources to market— What is the Canadian perspective?

Wrangell, Alaska— Major steps are being taken to bring about the construction of a new road and utility corridor between Southeast Alaska and Northwest British Columbia, due to a Federal appropriation of 1.2 million dollars by Senator Ted Stevens.

The State of Alaska, DOT/PF working with FHWA/Western Lands Div., and the communities of Wrangell, Petersburg, Craig and Ketchikan has initiated an economic study on the benefits of a road and utility corridor linking their region with Northwest British Columbia. The McDowell Group, an Alaskan based consulting firm is studying the economic benefits, which will occur within the entire region, from the Construction of the Bradfield Road. The McDowell Group has subcontracted the British Columbia portion of the study to McElhanney and Associates, a highly respected, Canadian engineering firm.

Federal Highway Administration, Western Federal Lands Division, is conducting preliminary scoping of the proposed corridor linking Southeast Alaska to the North American highway system. The pre-NEPA scoping effort is a multi-agency effort, including the City of Wrangell, other regional communities, the U.S. Forest Service, and the State of Alaska, Department of Transportation. During this past summer, work in the field included surveying various alternative pioneer lines and the examination of rock near the proposed tunnel portals. Preliminary examination of the rock indicates good tunnel building material. Cost estimates of constructing the tunnel have been reduced by half of previous ones.

Dennis MacKay is a British Columbia provincial legislator and member of the BC Liberal government majority. He represents the geographic area taking in the entire upper Northwestern corner of British Columbia north of Stewart south to the Bulkley Valley. MacKay has agreed to be a guest speaker at the 9th annual meeting of the Pacific Rim Construction Oil Mining Expo and Conference 2004 in Anchorage on February 18-19, 2004. MacKay will speak about the benefits he perceives for his region due to the creation of this road and corridor. MLA MacKay advocated for the Bradfield Road during his election campaign. MacKay is a strong advocate for the sustainable-year around family support jobs that are created by resource development. Known resource interests within his district include the Tulsequah Chief mine, owned by Redfern, located due east of Juneau. He will also briefly address the growing expansion of Oil and Natural Gas development in Northern BC of petroleum and the natural gas and coalfields lying adjacent to southern Southeast Alaska.

Attendees of the session will find out details about project's current status and future development outlook, planed facility construction, financing options, and future expansion and connector roads.

This session is a part of "Construction and Contracting" segment of the PAC COM Conference taking place February 18 at the Sullivan Arena. Other projects will include project updates on Pogo Mine, Donlin Creek Mine, Emma Creek Mine, Rock Creek Mine, Pebbel Copper.

PAC COM is a state-of-the art trade exhibition and conference that brings together key individuals, companies and government organizations from every aspect of construction, oil and mining industries focusing on opportunities for business development in Alaska and the Pacific Rim. Over 200 companies display the latest in products, equipment and related services for these dynamic industries. Revolutionary new oilfield, mining and environmental technology and innovations will be unveiled at the show.

For complete schedule and event information log on: http://www.paccomexpo.com.

Contact organizer, Rada Khadjinova-Jones: 888-509-7469. In Anchorage: 907-277-7469

continued from page 15

BP

in 2008.

"We haven't put a dollar figure on it as yet," Miller said, but the price will be in the hundreds of millions of dollars.

BP has options on the site, about 175 acres along the Delaware in an industrial area. Only about 40 acres will be needed for the terminal facilities, so there is plenty of buffer. The site is in an industrial area adjacent to a coal-fired cogeneration plant and a chemical plant.

There are just a few residences interspersed in the area, Miller said, and officials in nearby cities are being contacted to address their concerns. As for environmental concerns along the river, "we'll have very little need for impacting any of the wetlands areas," he said.

Easy access to three big pipelines

"Two interstate pipelines intersect at this property, and a third is nearby," Miller said. The site is downstream of Philadelphia with plenty of depth to handle the big new LNG supertankers, and the dock will be constructed to handle them, he said.

The LNG would be unloaded and stored at the site, regasified there and then sent out into the pipeline system. It would provide about 60 permanent technical and managerial jobs, with hundreds employed for the construction process. ●

continued from page 15

COMPETE

about five years.

Even so, Stringham cautioned that operators in Canada must keep an emphasis on their cost structures so that they can keep a hold on their U.S. markets.

Phyllis Martin, senior energy analyst with the U.S. Energy Information Administration, said the growth in gas-fired electrical generating plants is projected to push U.S. gas demand to 35 trillion cubic feet by 2025, outstripping domestic production of 26.4 tcf.

Closing that gap will make LNG imports the "big story," with net imports accounting for an estimated 2.2 tcf or 19 percent of the incremental gas supply, the EIA forecast.

The U.S. National Petroleum Council, in a recent report, set the bar even higher at 25 percent of the U.S. market by 2025.

Many variables

What happens depends on many variables, including the future of U.S. energy legislation, when and if gas pipelines are built from the North Slope and Mackenzie Delta, and the future of such unconventional sources as coalbed methane, tight gas and gas shales.

Richard Foley, case manager from the office of energy projects at the U.S. Federal Energy Regulatory Commission, told the conference that 28 LNG projects are currently on the table, including 20 onshore projects that fall under FERC jurisdiction and eight offshore projects for which the U.S. Coast Guard has jurisdiction. In addition, Mexico has seven proposals, Canada three and the Bahamas three.

He said projects now in-service and approved can deliver just over 5 billion cubic feet per day; if all of the pending applications before FERC and the Coast Guard go ahead they will add another 15 billion cubic feet per day.

Chris Ellsworth, manager of fuels forecasting and market assessments for Pace Global Energy Services, said LNG is "highly competitive" so long as prices don't drop below US$3-$3.50 per million British thermal units.

Costs could range from US$2 to almost $4 per million Btu depending on factors such as the cost of feed gas, liquefaction, transport and regasification.

The only question facing LNG is how big a contributor it will be to supply, said Hank Petranik, LNG vice president at TransCanada, which recently launched a partnership with ConocoPhillips for a proposed facility in Hartswell, Maine.

John van der Put, TransCanada's director of LNG development, said that even if the North Slope and Mackenzie Delta projects go ahead, about 7.5 billion cubic feet per day of LNG will be needed in the United States. ●

● WASHINGTON, D.C.

Consumer price tag for gas $111 billion

Industry report pegs cost of natural gas higher prices since June 2000 at $111 billion over the late 1980s prices

By **LARRY PERSILY**

Petroleum News Juneau Correspondent

A report produced by an organization of natural gas industrial consumers pegs the cost of higher gas prices to U.S. users since June 2000 at $111 billion over the prices paid in the late 1980s. And it suggests the nation's electrical power plants burn more coal to help relieve the demand on natural gas supplies, thereby lowering the cost of natural gas.

"The increased price of natural gas (since June 2000) has cost industrial consumers $57 billion, residential consumers $33 billion and commercial consumers $21 billion," said the report issued Dec. 3 by the Industrial Energy Consumers of America.

The group, based in Washington, D.C., is composed of 23 members, including some of the largest natural gas consumers in the country such as Dow Chemical Co., BASF Corp. and Eastman Chemical Co.

The report compared the cost to consumers of natural gas for the 41 months between June 2000 and October 2003 vs. the cost from January 1997 through May 2000. It found that the average price per thousand cubic feet for the 41 months ending October 2003 was $4.34 vs. the average of $2.37 for the 41 months in 1997 through 2000.

"The U.S. natural gas crisis … has had a staggering direct and indirect impact on all consumers, the U.S. economy and especially on manufacturing," said the report.

Report recommends more drilling

As at least a partial answer to the costly problem of high natural gas prices, the report recommended more drilling for new production. "The U.S. is blessed with enormous natural gas reserves yet we do not lift drilling moratoriums. … The blame for these high prices does not rest on the oil and gas companies, it rests mostly on federal and state policy makers.

"Congress and states must work together to break the impasse between the environment and the need to increase supplies of natural gas."

In addition to recommending expanding drilling areas and increased production of natural gas, the report said the nation needs to increase its use of coal for base-load electrical generation. "Using natural gas to produce electric power increases the cost of natural gas and electricity for all consumers.

"Increasing use of coal for power generation solves this problem. Use of clean-coal technology allows use of coal in power generation in an environmentally acceptable manner," the report said. ●

continued from page 16

DELAY

that ends June 30, 2004. The authority faces a June 2004 deadline to present the Legislature with a development plan for a state-owned project.

Funding issues and work plans likely will be discussed when the gas authority meets Monday, Dec. 15, in Anchorage.

The authority, which was created by a voter initiative last year, believes an LNG project to serve U.S. West Coast or Far East markets is a better project for Alaska than waiting for the major North Slope producers to build a larger pipeline to serve mid-America. The authority, however, owns no gas, and will need to cut a deal with the producers to buy or contract for enough gas to fill an LNG project, in addition to finding financing for the project. ●

CALGARY, ALBERTA

Enron Canada in tit-for-tat lawsuits

Enron Canada has launched lawsuits totaling more than C$500 million against companies it alleges broke natural gas and electricity contracts at the time its U.S. parent was tumbling into bankruptcy.

Enron Canada has launched lawsuits totaling more than C$500 million against companies it alleges broke natural gas and electricity contracts at the time its U.S. parent was tumbling into bankruptcy.

The list of 12 defendants includes Anadarko Canada, Marathon Canada (which was acquired in late summer by Husky Energy), Petro-Canada, Talisman Energy and Dynegy Canada, with the suits ranging as high as C$160 million.

Unlike its U.S. parent, Enron, the Canadian subsidiary has never filed for bankruptcy protection and has kept a small staff in Calgary to close out positions and execute contracts, although its energy trading operations have been taken over by Swiss investment banker UBS Warburg.

Filings by Enron Canada in Alberta Court of Queen's Bench accuse the Canadian energy companies of unjustly profiting at its expense.

Under contracts negotiated from the mid-190s to 2001, Enron Canada bought natural gas in long-term deals extending to 2004, but as the cost of gas soared the contracts fell well below market value.

Energy companies have started their own legal actions against Enron Canada, claiming the company failed to pay them millions of dollars for commodities they delivered.

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

Companies involved in North America's oil and gas industry

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Petroleum news

Business Spotlight

By PAULA EASLEY

FORREST CRANE

Charles Wayne Rust Jr., Engineering Manager, Alaska Division

Nabors Alaska Drilling Inc.

Drilling and working over oil wells on the North Slope, Kenai and Cook Inlet offshore is the firm's primary focus. Nabors also offers casing running services, oilfield rental equipment and remote camps. Fifteen rigs operate in the state for drilling grassroots or exploration wells, infield drilling, workovers and coiled tubing drilling.

Wayne Rust joined Nabors Alaska eight years ago, and oversees nine engineers responsible for the Alaska rig fleet. The engineering team also collaborates with the firm's Canadian division in preparing bids and technical concepts for northern rig operations.

Wayne and his wife Jennifer love travel, spending time together, and the Great Outdoors. Two Labrador retrievers, Rufus and Ivan, accompany Wayne on hunting trips.

FORREST CRANE

Rose Patterson, Employment Specialist

Alaska's People

Alaska's People provides employment services to clients and employers throughout Alaska, specializing in oilfield, mining and construction projects. Offices are at 2600 Cordova Street, Suite 211, in Anchorage. CIRI, Cook Inlet Tribal Council and Peak Oilfield Service Co. started the successful operation six years ago to promote Native hire and training.

Rose Patterson has developed and maintained rapport with businesses in numerous Alaska communities since joining the firm in its infancy. Her prior experience was in the fields of higher education, vocational training and direct employment programs. Rose's commitment to training and putting people to work has earned her the respect and friendship of many Alaskans. Receiving thank-you calls and letters from clients keeps her enthusiasm and motivation at high levels.

continued from page 14

ACTIVITY

barrel. Gas prices have also surged, with futures trading at more than $6 per thousand cubic feet during the summer.

So far this year, though, average rig counts have hovered around 104, about the same levels as 2002.

MMS also puzzled

"The bottom line is, I don't know what's going on either," said Chris Oynes, who oversees the Gulf Region for the U.S. Interior Department's Minerals Management Service. "I'm just as bewildered as everyone else."

While Tidewater and similar oil-service firms are sputtering, some companies that drill for oil and gas are surfing the wave of high prices.

Energy Partners Ltd. of New Orleans, for instance, has benefited from rising natural gas prices and has been plowing its new-found cash back into the Gulf.

For the first nine months of this year, Energy Partners' revenue increased to $170 million from $100 million during the same period in 2002. Net income for the period was $28.5 million, compared with a net loss of $7.9 million in the first nine months of 2002.

The company began 2003 with a capital investment budget of $90 million and increased it to $110 million as cash flow increased. The company's directors approved a capital expense budget of $125 million for next year, and executives have said it could rise if commodities prices remain strong.

"Typically what you hear is that the Gulf of Mexico is a dead sea, that there aren't any opportunities out there," said Richard Bachmann, Energy Partners' founder, chairman and chief executive. "We clearly disagree with that."

Likewise, McMoRan Exploration has been exploring for so-called "deep gas," located deep underground in the shallow waters of the Gulf. Recent discoveries have helped send the company's stock from less than $3.50 per share a year ago to $18.95 Dec. 5. ●

continued from page 1

HUB

were economic to be developed alone.

A sixth field, Coulomb, is 100 percent owned by Shell and will be tied into the Na Kika hub as production capacity becomes available.

Initial production from the first well in the development is projected to exceed 100 million cubic feet of natural gas per day.

At its peak, Na Kika is expected to produce about 110,000 barrels of oil and 425 million cubic feet of gas per day. The fields will ultimately produce about 300 million barrels of oil and gas, the companies said.

Field development and platform costs for the project announced to date by the companies make it a $1 billion-plus development.

The Na Kika semi-submersible production facility is moored in water some 6,300 feet deep, the deepest for any installation of its type in the world, the companies said. The individual wells are in water depths that range from 5,800 to 7,000 feet.

The Kepler, Ariel and Herschel fields are primarily oil, while the Fourier and East Anstey fields are primarily gas.

Shell led development of the Na Kika project and is responsible for drilling and completion the project's 10 development wells. BP will be the operator of the production phase of the project.

BP and Shell also announced the startup of the 75-mile Na Kika pipeline segment of the Okeanos Gas Gathering System from Na Kika to Main Pass 260, where the gas will be transported to various onshore markets via the BP/Shell Destin pipeline system. Okeanos will transport gas from deepwater discoveries in Mississippi Canyon and the eastern Gulf of Mexico.

The Na Kika segment of the Okeanos pipeline system was built by Shell, but is operated by BP.

"The facility adds significant production to our deepwater portfolio and is purpose-built for further subsea tie-backs from future discoveries in the area," said Kenny Lang, vice president of BP's deepwater production business unit. "We believe the deepwater Gulf of Mexico offers tremendous opportunities for BP."

Gaurdie Banister, regional technical director of Shell EP Americas, said, "We have used groundbreaking technology to deliver this project, which is our sixth stand-alone hub in the Gulf of Mexico."

—PETROLEUM NEWS

continued from page 1

CUBA

ration next year, putting the Norwegian-owned Eirik Raude rig (pictured above) to work at $195,000 a day drilling for oil in water more than a mile deep. Cuba's current oil production is all from onshore coastal deposits east of Havana.

Havana opened up 51 blocks totaling 43,250 square miles of its Gulf waters in 1999 to foreign exploration and development.

Sherritt International of Canada was one of the takers and has since signed contracts with the government to begin exploration, and Petrobras of Brazil is studying the feasibility of a similar move. In 2001, the two companies dropped $16 million into a wildcat well further east that came up dry.

Despite Cuba's invitation, interested American companies would be unable to explore or drill for oil off the island's coast because of a four-decade-old U.S. trade embargo against the communist-run nation.

The Cuban government statement noted American farmers have been legally selling their agricultural goods to the island for two years under an exception to the trade sanctions.

Cuba, once almost wholly dependent on foreign fuel imports, now produces more than 30 percent of its own crude.

Nevertheless, the government said it was not counting on the possibility of future oil discoveries for the nation's economic development.

"The government of Cuba would like to clarify that our plans for economic development, and especially our social programs that are increasingly admired by many around the world, are not based in the least on the hypothetical possibility of finding new sources of energy," the statement said.

One new report quoted Michael Rodgers, senior director of PFC Energy, a Washington-based consultancy, as saying, "Deep-water Cuba is an exploration frontier. It is fair to characterize it as very high risk."

To develop an oilfield at the depth Repsol plans to drill Rodgers said would cost more than $1 billion.

—The Associated Press contributed to this article

continued from page 1

IMPERIAL

reserves of 1.7 billion barrels.

However, like all oil sands projects, Imperial is grappling with costs that could soar to C$8 billion from C$5 billion.

"I would hope it doesn't cost C$8 billion," Hearn said on a conference call. "That wouldn't be my objective ... I think we would try to find something at the low end for the first phase."

That could point to a phased development similar to those heavily favored by oil sands operators who are looking to manage their costs and use cash flow from each stage to fund the next, rather than be forced to swallow huge overruns.

The biggest single cost element for Kearl Lake could be a C$3 billion upgrader to convert raw bitumen into refinery-ready crude.

Senior Vice President K.C. Williams said the final cost is "highly dependent" on how Imperial does its upgrading.

Company has options for upgrading

However, Imperial is not without a variety of options, ranging from on-site upgrading, integration with the company's Edmonton-area refinery; and shipping some bitumen to the Joliet, Ill., refinery owned by ExxonMobil, which in turn owns 69.6 percent of Imperial.

Hearn said a tentative timetable includes filing regulatory applications in 2005, starting construction in 2007 and bringing the facility on stream by mid-2009 at 100,000 bpd.

"Our intention is to try and move it ahead in that kind of timeframe," he said.

Imperial is already one of the most experienced oil sands players, with a 25 percent holding in the Syncrude Canada consortium and its own multi-stage Cold Lake heavy oil project that could reach 180,000 bpd by 2010, up from its current 130,000 bpd.

ExxonMobil Canada, wholly owned by ExxonMobil, has a lease adjacent to Kearl Lake where it has already done delineation drilling.

The prospect of a joint development is under discussion, with Imperial as overall operator for what Hearn said would be "more of a phased development."

Conceding that Imperial does not know "whether there's capacity to take all of what's envisioned," he said the incremental approach would allow the project to proceed in line with market demand. ●

continued from page 1

MARTIN

satisfaction."

Despite voting with the government a year ago to ratify Kyoto, his comments have given hope to the petroleum industry, the Alberta government and the wider business community that he is ready to rethink Canada's approach.

Just as muddled is Russia's stance, with conflicting messages coming from several senior officials as the anti-Kyoto faction argues the protocol would handicap a developing economy, which is heavily dependent on oil and natural gas production.

China and India are not required under Kyoto to lower emissions and the United States and Australia have refused to sign the accord. That leaves the future of the accord in the hands of Russia, Europe, Japan and Canada, all of whom must ratify to achieve the minimum support of 55 countries accounting for at least 55 percent of global emissions as of 1990.

Some, such as Canada's Environment Minister David Anderson, believe Russia is only trying to bargain for more favorable terms.

Alberta Premier Ralph Klein said Russia's vacillation gives Martin the window he needs to re-assess Canada's commitment.

Companies working on carbon dioxide reduction

Meanwhile, Canadian Association of Petroleum Producers President Pierre Alvarez said his organization "will wait and see where the new (Martin) administration goes."

But he said the concerns raised by Russia are line with those flagged by the association last year.

Even so several companies — especially those immersed in the oil sands, which is seen as the worst emissions culprit — say they intend to press ahead with measures to reduce greenhouse gases, regardless of what route Russia takes.

Spokesmen for Imperial Oil, Petro-Canada, Suncor Energy, Shell Canada and Canadian Natural Resources all say they want to limit their carbon dioxide levels.

Shell's new Athabasca oil sands project has set a target of cutting greenhouse gases in half by 2010 to 1.75 million tonnes; Suncor pledged to continue its wide-ranging plan to cut emissions, including a substantial investment in renewable energy such as wind power; and Imperial will press ahead with measures to improve energy efficiency in its operations and build co-generation plans that use natural gas to generate electricity.

"Irrespective of Kyoto, we're going to continue to do what's right for the economy and what's right for the environment," said Imperial Chief Executive Officer Tim Hearn.

Nancy Hughes Anthony, president of the Canadian Chamber of Commerce, said she hopes Martin will not agree to the same onerous targets that Chrétien did.

"We just blindly signed on to some targets without fully understanding how on earth we would do it," she said. ●

continued from page 1

DOWN

its biannual revenue forecast released Friday, Dec. 12. Oil taxes and royalties provide about 85 percent of the state's unrestricted revenue each year.

The near-record high oil prices and budget cuts since the department's forecast of a year ago have added 23 months to the estimated life of Alaska's Constitutional Budget Reserve Fund, which the state has used since 1991 to cover the gap between declining oil revenues and the cost of public services.

The reserve held $1.898 billion as of Dec. 12, with about $5.5 billion spent over the past 12 years.

Production decline continues

Alaska's profitable news of high oil prices does not extend to production, however. The Revenue Department projects North Slope oil production is not likely to ever climb back above 1 million barrels a day unless there are large discoveries and new production from federal leases in the Beaufort Sea, National Petroleum Reserve-Alaska or the Arctic National Wildlife Refuge — if Congress ever agrees to open ANWR to drilling.

Production is expected to average 972,000 barrels a day through 2010, the department said, down from just over 990,000 barrels this fiscal year.

The forecast of average daily production through 2010 is down 2 percent from the department's April report, and down 4 percent from its forecast of a year ago when the estimate was 1.013 million barrels a day through 2010. The department said the slippage is "due to the re-examination of field reservoir performance and potential."

Even staying just under 1 million barrels by the end of the decade assumes the start of production from NPR-A, Nanuk, Point Thomson and Liberty, the department said, with combined flow from those fields estimated at more than 120,000 barrels a day by 2010. None of the fields are currently in production.

Reasons for lower production forecast

The report provided some specifics for its reduced expectations from 2008 through 2013:

"Enhanced oil recovery from the Milne Point Unit was eliminated because of costs associated with procuring off-lease solvent."

"The production from prospective, undiscovered satellite fields in the Greater Kuparuk Area has also been eliminated in this forecast."

"The Liberty and Sandpiper fields have been delayed one year to allow operators to determine the best development scope and to secure the associated permitting. Likewise, satellite fields in the vicinity of the Point Thomson Unit have been delayed two years."

"The near-term outlook for the Kuparuk River field has been reduced due to greater than expected back-out impacts from satellite fields sharing the limited capacity in the production facilities there."

The department also trimmed its production expectations at Polaris but raised its forecast for Prudhoe Bay satellites Aurora and Borealis, Kuparuk River satellites Meltwater and Tabasco, and from the Water Wheel project at Point McIntyre.

Flow could drop to 844,000 barrels in 2015

But without large, new discoveries somewhere on the slope, the department forecasts average daily production will drop further by 2015, to 844,000 barrels.

North Slope production reached its peak in 1988, at 2.005 million barrels per day.

The department's projections are based on existing, producing fields and discovered fields not yet placed into production.

Without any new discoveries in the Beaufort or NPR-A, the department estimates that almost 17 percent of North Slope production in 2010 will come from discovered fields not currently under production. The amount of that "new oil" in the forecast climbs to 27.6 percent in 2015, or 232,000 barrels a day of new production out of the total estimated flow of 844,000 barrels.

Prices remain high

Production concerns aside, the state and other oil-producing regions in the world have enjoyed a sustained period of high prices. North Slope crude averaged $23.81 between October 1998 and September 2003, with the price averaging $28.97 for the first half of this fiscal year. Even with some fall-back in prices projected for the spring, the Department of Revenue expects the fiscal-year-end average will come in at $27.70 — the third highest price in almost 20 years.

The reasons for today's high prices are production restraint by the Organization of Petroleum Exporting Countries, continued problems restoring production in Iraq, and low global oil inventories, the report said. The department bases its long-term forecast of $22 a barrel on market expectations of an eventual price drop of several dollars and the inevitability that some OPEC nations will cheat on their production quotas.

"Experience has shown that the OPEC cartel is not perfect," the department said.

Assuming the department's oil price and production forecasts are exact, and assuming state spending holds flat at this year's $2.3 billion general fund budget, the department expects the Fiscal Year 2004 draw on the state's budget reserve fund would be just under $300 million but would grow to about $575 million next year unless new revenues or further budget cuts are found.

The gap would expand to $800 million in Fiscal 2006 and the state budget reserve would hit empty before the end of Fiscal 2007, the report said.

Gov. Frank Murkowski is scheduled to announce his budget plan for Fiscal 2005 on Monday, Dec. 15. The Legislature returns to work Jan. 12.

A key element of the governor's fiscal plan is to encourage exploration and new production, reversing the state's long-term decline in oil revenues. The Legislature last year passed a tax credit bill to boost exploration spending, though supporters acknowledged any benefits are several years away.

The forecast also states that Alaska could expect to earn perhaps $600 million a year in state taxes and royalties from a pipeline carrying North Slope natural gas to market, assuming market prices at $4 per thousand cubic feet. But the report said substantial gas line revenues are at least eight years away, dependent on when North Slope producers or others decide to build the multibillion-dollar project. ●