Petroleum news

page 23 Pioneer Natural Resources looks to build Alaska drilling portfolio

Vol. 9, No. 23 • www.PetroleumNews.com   *North America's source for oil and gas news*   Week of June 6, 2004 • $1

Enstar sets record on west side

COURTESY OF ENSTAR

Enstar installed the longest horizontal directional drilled pipe in Alaska when it replaced a portion of 20-inch transmission line last winter on the west side of Cook Inlet. The line was in danger of being washed out after middle channel of the Susitna River moved. See story on page 14.

Husky eyes Newfoundland gas from White Rose within a decade

Husky Energy is taking one of the boldest steps yet to exploit offshore Newfoundland's natural gas potential.

The Canadian integrated, which is operator of the White Rose oil field, is now exploring the viability of producing and transporting gas from the same field.

It has invited expressions of interest from contractors and engineering firms to weigh the key technical, economic and regulato-

see **HUSKY** *page 27*

CBM could account for 20% of Canada's gas output by 2020

MIKE SIMPSON

The long-range importance of coalbed methane in Canada's gas supply picture has been emphasized by an executive with Nexen, who predicts the resource could grow to 1 billion cubic feet per day by 2008 and 3 bcf per day by 2024.

Mike Simpson, coalbed methane manager at Nexen, told a Calgary audience May 27 that Canada is following the trend in the

see **OUTPUT** *page 26*

● NPR-A

Talisman high bidder

Bureau of Land Management's NW NPR-A sale draws 123 bids for 165 tracts

By KRISTEN NELSON

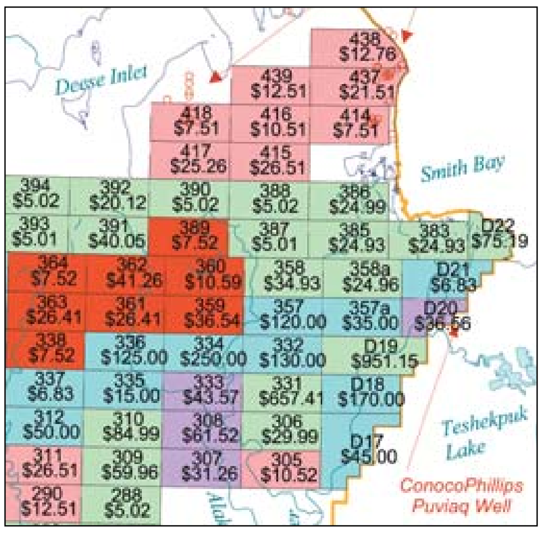
Petroleum News Editor-in-Chief

Five companies, singly and in partnerships, put up $53,904,491 in high bonus bids at the Bureau of Land Management's northwest National Petroleum Reserve-Alaska sale in Anchorage June 2.

Bidders were: Anadarko Petroleum Corp., ConocoPhillips Alaska Inc., Pioneer Natural Resources Alaska Inc., Petro Canada Alaska Inc. and Fortuna Exploration LLC.

The highest bid, $13,745,000, was from Talisman subsidiary Fortuna for tract D-19, 14,451 acres near the Ikpikpuk River, at the junction between the northwest and northeast NPR-A plan-

see **LEASE SALE** *page 12*



See full map, page 13

● GULF OF MEXICO

Noble Energy to expand Gulf deepwater program

By RAY TYSON

Petroleum News Houston Correspondent

Noble Energy says it intends to accelerate exploration and development activity in the deepwater Gulf of Mexico, hoping to carve out a third core area in the region, while pursuing more geologically deep natural gas plays in shallower waters of the Gulf's continental shelf.

Over the past few years, the Houston-based independent has quietly assembled and evaluated an impressive acreage position in the deepwater Gulf and appears ready to strike on the exploration front.

"We haven't drilled that many wells over the last few years purposely," Dick Peneguy, Noble's offshore manager, said in a May 26 meeting with industry analysts. "We have been generating more prospects than we have drilled. We have now put together a multi-year prospect portfolio."

Discovery in first quarter

Actually, Noble began putting its foot to the pedal in the deepwater Gulf during the 2004 first quarter, announcing a discovery at its Ticonderoga prospect and increasing its working interest in two

see **NOBLE** *page 26*

● ALBERTA

Canadian oil sands production expected to double by 2015

Report says country would move to fourth in ranks of world's oil producers

By DON WHITELEY

Petroleum News Contributing Writer

A National Energy Board report says production from Canada's oil sands is expected to reach 2.2 million barrels of oil a day by 2015, more than double today's production.

In a special report entitled Canada's Oil Sands: Opportunities and Challenges to 2015, the National Energy Board says the increased production will move Canada from ninth place to fourth place in the world's rankings of oil producers.

But with global demand expected to be about 80 million barrels of oil per day in 2015, the oil sands won't make a big splash on the world scene.

Reserves estimated at 178 billion barrels

Canada's oil sands deposits, located mostly in Northern Alberta, are considered to be one of the largest hydrocarbon deposits in the world, with reserves estimated at 178 billion barrels.

But extracting oil from the sands is an energy-intensive, costly process, and production is economic only at relatively high prices for both oil and natural gas. For this report, the National Energy Board based its projections on an oil price of $24 per barrel, and an equivalent natural gas

see **OIL SANDS** *page 27*

BREAKING NEWS

Alaska - Mackenzie Rig Report

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Alaska Rig Status			
North Slope - Onshore			
Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Milne Point, rig workover MPF-18	BP
Sky Top Brewster NE-12	15 (SCR/TD)	Deadhorse yard	Available
Dreco 1000 UE	16 (SCR)	W pad workover W-20	BP
Dreco D2000 UEBD	19 (SCR/TD)	Alpine, drilling CD2-57	ConocoPhillips
OIME 2000	141 (SCR/TD)	Infield Kuparuk, drilling 1E-123	ConocoPhillips
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Stacked, Prudhoe Bay	Available
Dreco 1000 UE	2-ES (SCR)	Prudhoe Bay, 01-04A	BP
Mid-Continent U36A	3-S	Prudhoe Bay, 2T-220	ConocoPhillips
Oilwell 700 E	4-ES (SCR)	Prudhoe Bay, X-16	BP
Dreco 1000 UE	7-ES (SCR/TD)	Prudhoe Bay, A-30	BP
Dreco 1000 UE	9-ES (SCR/TD)	Prudhoe Bay, V-02	BP
Oilwell 2000 Hercules	14-E (SCR)	Stacked, Deadhorse	Available
Oilwell 2000 Hercules	16-E (SCR/TD)	Stacked, Prudhoe Bay	Available
Oilwell 2000	17-E (SCR/TD)	Stacked, Point McIntyre	Available
Emsco Electro-hoist -2	18-E (SCR)	Stacked, Deadhorse	Available
OIME 1000	19-E (SCR)	Stacked, Deadhorse	ConocoPhillips
Emsco Electro-hoist Varco TDS3	22-E (SCR/TD)	Stacked, Milne Point	Available
Emsco Electro-hoist	28-E (SCR)	Stacked, Deadhorse	Available
OIME 2000	245-E	Stacked, Kuparuk	ConocoPhillips
Nordic Calista Services			
Superior 700 UE	1 (SCR/TD)	Drill site 2 well 24	BP
Superior 700 UE	2 (SCR)	Endicott, drill site 14 well 6A	BP
Ideco 900	3 (SCR/TD)	Meltwater, drill site 3N-311	ConocoPhillips
North Slope - Offshore			
Nabors Alaska Drilling			
Oilwell 2000	33-E (SCR/TD)	Stacked, NorthStar	BP
Emsco Electro-hoist Canrig 1050E	27-E (SCR/TD)	Stacked at 12-acre pad	Kerr-McGee
Cook Inlet Basin – Onshore			
Aurora Well Service			
Franks 300 Srs. Explorer III	AWS 1	Nicolai Creek, NCU3 workover	Aurora Gas
Evergreen Resources Alaska			
Wilson Super 38	96-19	Moving into data evaluation from core drill	Evergreen Resources Alaska Corporation
Inlet Drilling Alaska/Cooper Construction			
Kremco 750	CC-1	Stacked, Kenai	Forest Oil
Kuukpik	5	Swanson River, drilling 241-16	Unocal
Marathon Oil Co. (Inlet Drilling Alaska labor contractor)			
Taylor	Glacier 1	Working on well Beaver Creek #12	Marathon
Nabors Alaska Drilling			
Rigmasters 850	129	Kenai, Red #1	Unocal
National 110 UE	160 (SCR)	Stacked, Kenai	Available
Continental Emsco E3000	273	Stacked, Kenai	Available
	51	Steelhead platform, done 12-1-03	Unocal
IDECO 2100 E	429E (SCR)	Stacked, removed from Osprey platform	Available
Water Resources International			
Ideco H-35 KD		Prep to resume operations	Pelican Hill
Cook Inlet Basin – Offshore			
Cudd Pressure Control	340K	Workover, Osprey Platform	Forest Oil
Unocal (Nabors Alaska Drilling labor contractor)			
Not Available			
XTO Energy (Inlet Drilling Alaska labor contract)			
National 1320	A	Idle	Idle
National 110	C (TD)	Idle	XTO
Mackenzie Rig Status			
Mackenzie Delta-Onshore			
AKITA Equtak			
Dreco 1250 UE	62 (SCR/TD)	Stacked Tuktoyaktuk, NT	EnCana
Dreco 1250 UE	63 (SCR/TD)	Stacked, Lucas Point, NT	Chevron Canada
National 370	64	Stacked, Inuvik, NT	Available
Central Mackenzie Valley			
AKITA/SAHTU			
Oilwell 500	51	Stacked in Norman Wells, NT	Available
Nabors Canada			
	62	Racked	Available

The Alaska - Mackenzie Rig Report as of June 3, 2004. Active drilling companies only listed.

TD = rigs equipped with top drive units WO = workover operations
CT = coiled tubing operation SCR = electric rig

This rig report was prepared by Wadeen Hepworth

Osprey platform JUDY PATRICK

Baker Hughes North America rotary rig counts*

	May 28	May 21	Year Ago
US	1,169	1,172	1,059
Canada	195	201	258
Gulf	93	91	110

Highest/Lowest		
US/Highest	4530	December 1981
US/Lowest	488	April 1999
Canada/Highest	558	January 2000
Canada/Lowest	29	April 1992

*Issued by Baker Hughes since 1944

Rig start-ups expected in next 6 months

Rig Owner/No.	Rig Location/Activity	Operator
Aurora Gas		
AWS1	Will be moving to Kaloa 3 and then to Long Lake 1 for a re-entry	Aurora Gas
XTO Energy		
A & C	Planning on firing the rigs back up by the end of summer 2004	XTO

The Alaska - Mackenzie Rig Report is sponsored by: ConocoPhillips

GULF OF MEXICO

Deepwater Gulf's K2 North produces another 165 feet of net oil pay for Anadarko

Anadarko Petroleum has found another 165 feet of net oil pay at its 100 percent owned K2 North satellite discovery in the deepwater Gulf of Mexico, greatly expanding the field's size and firmly establishing it as a commercial discovery.

The K2 North field, on Green Canyon block 518, is now expected to begin production through the nearby Marco Polo platform in 2005, Anadarko said June 2, noting that the field's oil-water contact has yet to be established.


Jim Hackett, Anadarko's CEO

"We have yet to determine the field limits, but the delineation well extends the discovery significantly," said Jim Hackett, Anadarko's chief executive officer.

The well's bottom-hole location is about one mile northwest of Anadarko's K2 North No. 1 discovery, which was announced in November 2003.

The K2 North exploration well, including a water depth of 4,000 feet, was drilled to a depth of 26,700 feet and was the deepest offshore well drilled in Anadarko's history. The subsalt well encountered 128 feet of net oil pay in the same zone present at Anadarko's K2 discovery.

Reserve estimates for the K2 North field have not been disclosed. But the initial exploration well extended the K2 field two miles north.

The No. 2 well was spud in December 2003 in about 4,000 feet of water and was drilled to a total depth of 29,180 feet. The semi-submersible rig remains on location to further delineate the field, Anadarko said.

see **ANADARKO** page 4

Issue Index

Petroleum news

North America's source for oil and gas news

Dan Wilcox	CHIEF EXECUTIVE OFFICER
Mary Craig	CHIEF FINANCIAL OFFICER
Kay Cashman	PUBLISHER & MANAGING EDITOR
Kristen Nelson	EDITOR-IN-CHIEF
Gary Park	CALGARY CORRESPONDENT
Larry Persily	GOVERNMENT AFFAIRS EDITOR
Ray Tyson	HOUSTON CORRESPONDENT
Steve Sutherlin	ASSOCIATE EDITOR
Wadeen Hepworth	ASSISTANT TO THE PUBLISHER
F. Jay Schempf	CONTRIBUTING WRITER (HOUSTON)
Alan Bailey	CONTRIBUTING WRITER
Allen Baker	CONTRIBUTING WRITER
Pat Healy	CONTRIBUTING WRITER (HOUSTON)
Paula Easley	COLUMNIST
Patricia Liles (formerly Jones)	CONTRIBUTING WRITER (FAIRBANKS)
Laura Erickson	SPECIAL PROJECTS COORDINATOR
Judy Patrick Photography	CONTRACT PHOTOGRAPHER
Firestar Media Services	DIRECTORY PROFILES
Mapmakers Alaska	CARTOGRAPHY
Susan Crane	ADVERTISING DIRECTOR
Forrest Crane	CONTRACT PHOTOGRAPHER
Steven Merritt	PRODUCTION DIRECTOR
Tom Kearney	ADVERTISING DESIGN MANAGER
Heather Yates	CIRCULATION MANAGER
Tim Kikta	CIRCULATION REPRESENTATIVE
Dee Cashman	CIRCULATION REPRESENTATIVE

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

EDITORIAL
Anchorage
907.522.9469
Juneau
907.586.8026

EDITORIAL EMAIL
publisher@petroleumnews.com

BOOKKEEPING & CIRCULATION
907.522.9469
Circulation Email
circulation@petroleumnews.com

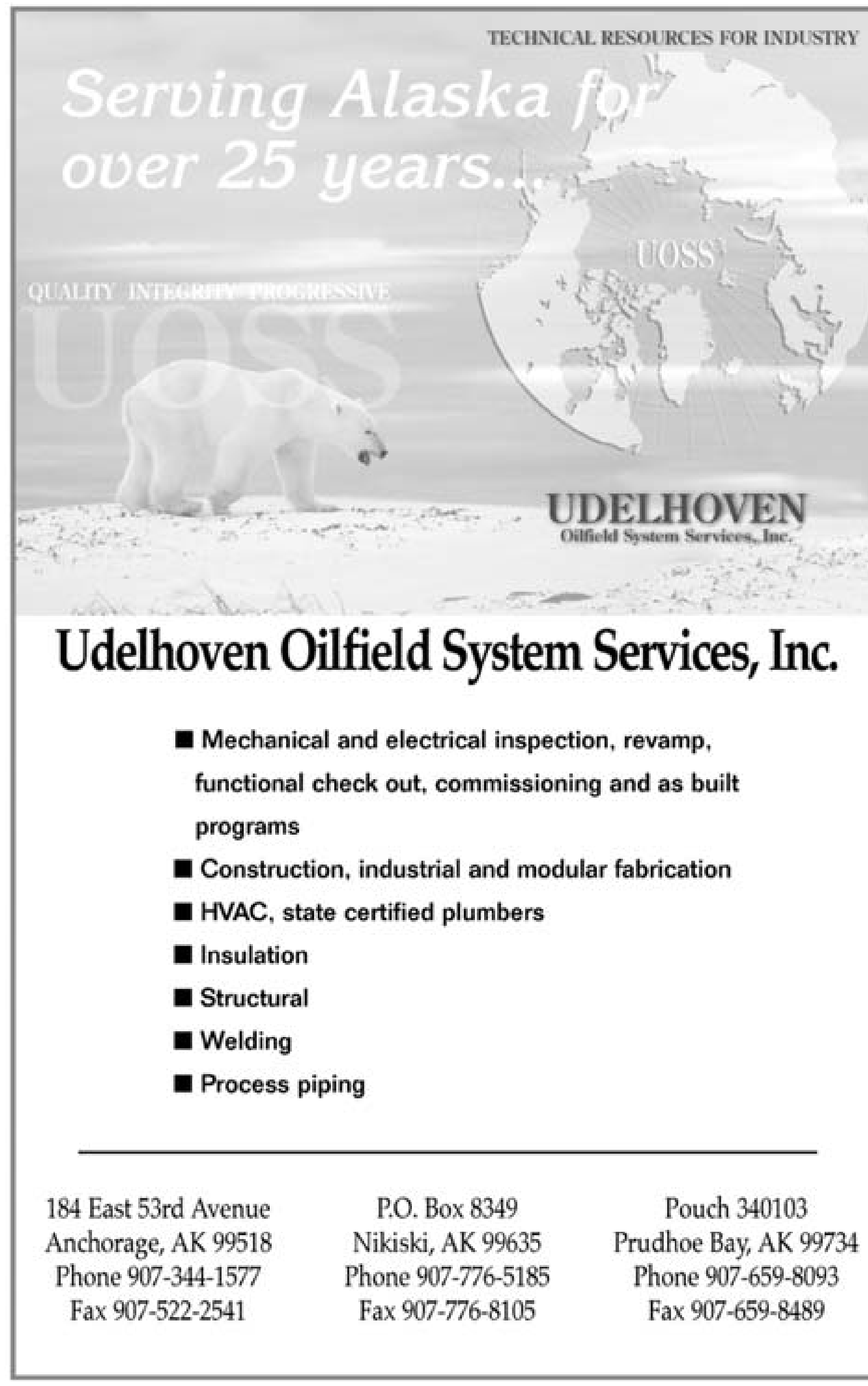
ADVERTISING
907.770.5592
Advertising Email
scrane@petroleumnews.com

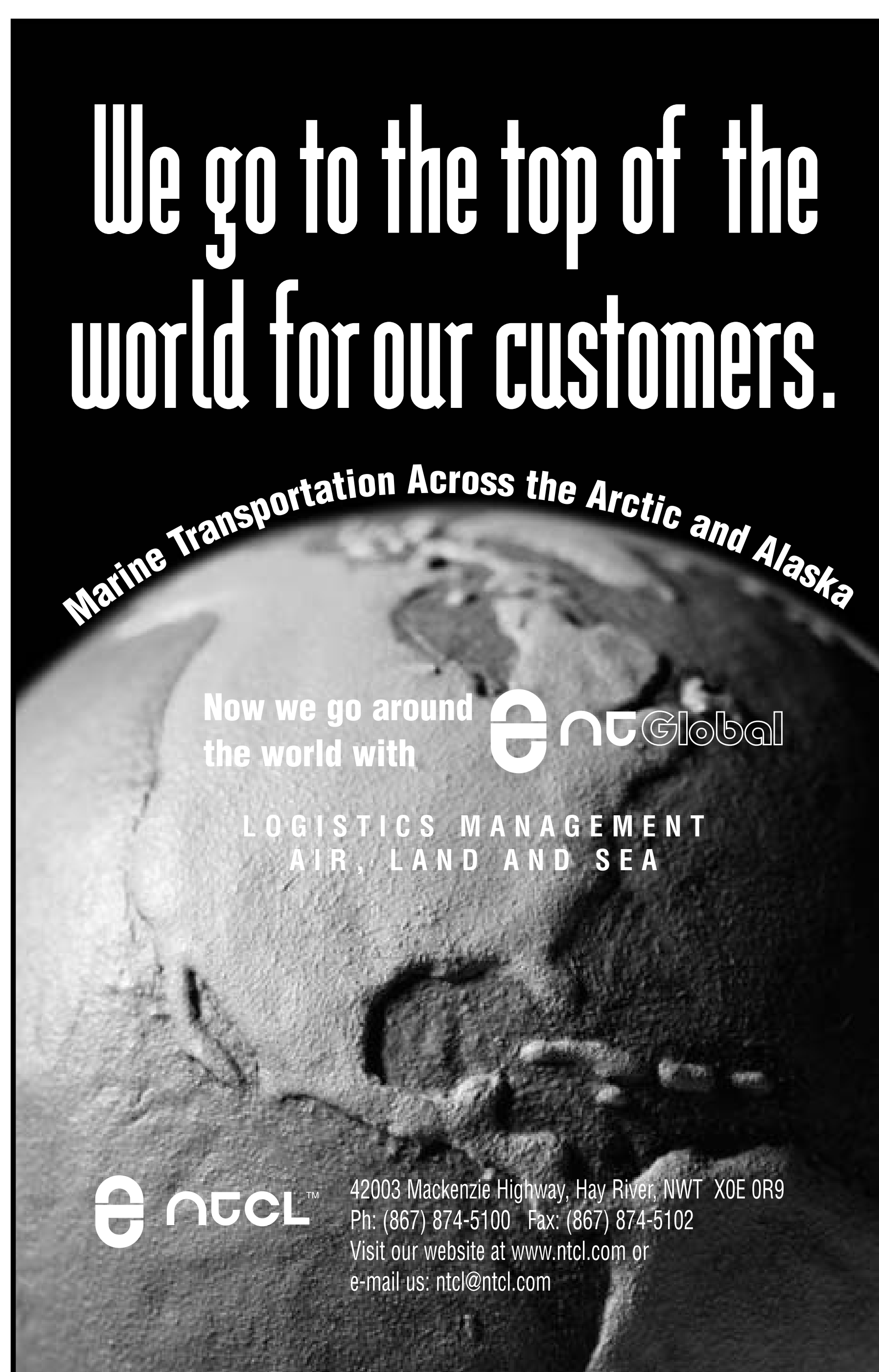
CLASSIFIEDS
907.644.4444

FAX FOR ALL DEPARTMENTS
907.522.9583

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

Petroleum News (ISSN 1544-3612) Week of June 6, 2004
Vol. 9, No. 23
Published weekly. Address: 5441 Old Seward, #3, Anchorage, AK 99518
(Please mail ALL correspondence to:
P.O. Box 231651, Anchorage, AK 99523-1651)
Subscription prices in U.S. — $52.00 for 1 year, $96.00 for 2 years, $140.00 for 3 years. Canada / Mexico — $165.95 for 1 year, $323.95 for 2 years, $465.95 for 3 years.
Overseas (sent air mail) — $200.00 for 1 year, $380.00 for 2 years, $545.95 for 3 years.
"Periodicals postage paid at Anchorage, AK 99502-9986."
POSTMASTER: Send address changes to Petroleum News, P.O. Box 231651 • Anchorage, AK 99523-1651.





● ALASKA

One more Alaska natural gas line plan

TransCanada submits application to state, says 2012 start-up possible

By LARRY PERSILY

Petroleum News Government Affairs Editor

Assuming everyone involved in the proposed Alaska natural gas line project can strike a deal to divvy up the financial risks, and assuming no permitting delays or other political or regulatory problems, TransCanada Corp. said it believes it could help build the pipeline and have gas flowing by 2012.

The Calgary-based pipeline operator submitted an application June 1 under Alaska's Stranded Gas Development Act, the fifth such application the state has received since late January to negotiate a long-term fiscal deal for payments in lieu of all state and municipal taxes on the proposed pipeline.

"This project is complex and entails significant risk. Its success — and similarly the future well-being of the Alaska economy — will depend upon the goodwill and cooperation of many stakeholders," the company said in its application.

TransCanada has said it does not want to own the gas or take the risk of future commodity prices but it does want to hold an interest in the pipe and perhaps share the equity with others, including possibly Alaska Native corporations. "The nature and size of that interest will be determined later as the commercial structure of the proposed pipeline project becomes better defined," it said.

The company proposes a 48-inch-diameter line from the North Slope to Boundary Lake in northern Alberta, carrying 4.5 billion cubic feet per day, feeding into existing pipeline systems for distribution across North America. That equals almost $6 billion worth of gas a year, at $3.50 per thousand cubic feet, with transportation charges expected to consume more than half of that amount.

Construction of the 745 miles of pipe in Alaska is estimated at $6.8 billion in 2004 dollars. TransCanada did not provide an estimate for the almost 1,000 miles of pipe in Canada or the extensions required for its existing pipeline system. The estimate also does not include the $3 billion or so that North Slope producers would need to spend on a conditioning plant on the slope to remove carbon dioxide, water and other impurities before putting the gas into the line.

2012 start-up contingent on shipping contracts

The 2012 start-up date is contingent on getting contracts with shippers in 2005 and starting construction in late 2009, TransCanada said. Ship-or-pay contracts could provide the financial security needed to borrow money for construction.

TransCanada believes a 1977 U.S. regulatory certificate and 1978 Canadian certificate to build an Alaska gas line give it exclusive rights to the project, saving two years of permitting work that would confront any other project developer. The company also holds right-of-way permits for much of the route, left over from unsuccessful development efforts in the 1970s and 1980s.

Other gas line hopefuls, however, dispute TransCanada's exclusive rights to any gas line development, and it's likely the issue will need to be resolved as the company, North Slope producers, U.S. and Canadian agencies and others try to put together a team to build the line.

The certificates are held by TransCanada's wholly owned subsidiaries Foothills Pipe Lines Ltd. and Alaskan Northwest Natural Gas Transportation Co., which was formed in 1978 to build the line from Prudhoe Bay to the Alaska-Yukon Territory border.

Regardless of the regulatory dispute, TransCanada's far-reaching pipeline network offers strong opportunities to move Alaska gas from the end of any new pipe in Alberta.

TransCanada offers access to several markets

"TransCanada's network of pipeline assets provides Alaskan gas with unparalleled access to growing markets across the continent," the application said. "The Pacific Northwest and California; the U.S. Midwest, including the Chicago hub; eastern Canada; and the U.S. Northeast, including New England and New York City."

TransCanada's proposal is similar to its Calgary colleague Enbridge Inc., which submitted its application to the state April 30 and also touted its ability to use existing lines to move Alaska gas out of Alberta to Midwest markets. Enbridge, however, proposed using 36-inch pipe to reduce the risks of construction cost overruns and possibly delivering too much gas to market too quickly. If the market could handle more gas, the company would run a second line, with each carrying 2.6 bcf per day.

In addition to Enbridge and TransCanada, the state has received a Stranded Gas Act application from the three major North Slope producers.

It also received an application in January from MidAmerican Energy Holdings Co., which later withdrew its application after negotiations with the state broke down, and from the municipally owned Alaska Gasline Port Authority, which withdrew its application last month after electing to sign an information-sharing protocol with the state instead of negotiating a fiscal contract. ●

OFFSHORE DIVERS
Alaska's Underwater Professionals
907-563-9060
Anchorage, AK
BUY ALASKA

FRIENDS OF PETS
P.O. Box 240981
Anchorage, AK 99524

OLIVIA IS A GENTLE, SPAYED FEMALE 2-YEAR OLD TABBY LOOKING FOR A LOVING HOME. FOR ADDITIONAL INFO CALL 333-9534 OR APPLY-ONLINE @ WWW.FRIENDSOFPETS.ORG.

JUNE IS ADOPT A SHELTER CAT MONTH. CONSIDER GIVING A HOMELESS FELINE A LIFETIME OF LOVE!


COURTESY ALASKA PETOGRAPHY

JUNEAU

Persily called back into state service


TOM KEARNEY
LARRY PERSILY

Larry Persily, Petroleum News' government affairs editor, is leaving the weekly Anchorage-based newspaper to go back into state government.

Persily, who had been a Juneau-based journalist for a number of years prior to going to work for the Knowles administration, was a special assistant to the commissioner of the Department of Revenue from 1997-99, and then a deputy commissioner from 1999-2003.

On August 4 he came to work for Petroleum News as a Juneau correspondent. Persily was promoted to government affairs editor earlier this year.

At the request of the Murkowski administration, Persily is returning to Revenue as a special assistant to Commissioner Bill Corbus, effective June 14. He will be working on gas line issues, as well as oil and gas fiscal issues.

continued from page 3

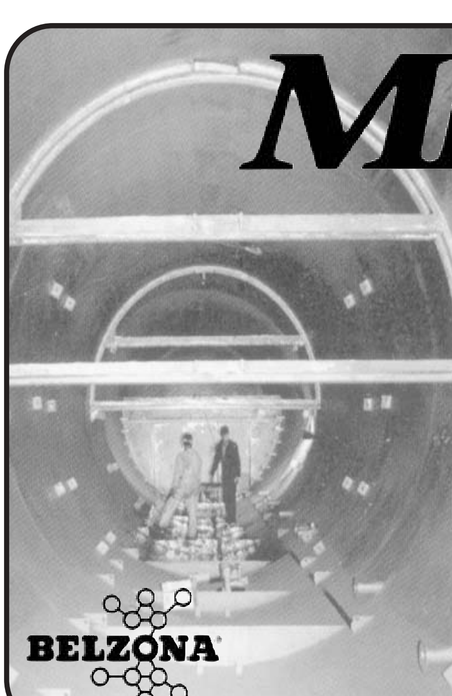
ANADARKO

"This well also has positive implications for the neighboring K2 field," Hackett said. Anadarko holds a 52.5 percent interest in that field.

The K2 field also will be tied back to the Marco Polo platform with first production expected next year. Anadarko said it is currently completing the first of six pre-drilled development wells from its Marco Polo field, which is on schedule for first production in July 2004.

The Marco Polo platform was designed to handle up to of 120,000 barrels per day of oil and 300 million cubic feet per day of natural gas. Anadarko made its first deepwater Gulf discovery at Marco Polo in 2000.

—RAY TYSON, Petroleum News Houston correspondent

MRO Sales Inc.

— Brings You —
Belzona Polymeric
Repair Solutions
Erosion/Corrosion Coatings
Anchorage: (907) 248-8808
fax: (907) 248-8878
5631 Silverado Way, Suite G
Anchorage, AK 99518
www.mrosalesinc.com
BELZONA

North America's Source for Oil & Gas News

Petroleum news
Get your subscription today
call (907) 522-9469

● MALIBU, CALIF.

Malibu votes no on LNG

City council opposes two proposed offshore receiving terminals

By LARRY PERSILY

Petroleum News Government Affairs Editor

Although it has no jurisdiction over either project, the Malibu City Council has voted unanimously to oppose two liquefied natural gas receiving terminals proposed for waters north of the California coastal community.

One of the proposed projects is looking to become a main receiving terminal for Alaska LNG.

Fear of terrorist attacks and environmental damages from the offshore terminals and the tankers that would move through the area motivated the council vote, said Malibu City Manager Katie Lichtig. "There's a possibility and a risk that our community could be impacted."

She acknowledged that any worry of damage to marine resources primarily involves recreational opportunities for the town of 13,000 residents. Malibu is about 25 miles south of where the gas would come ashore in buried pipe near Oxnard. The terminals would be about 15 to 20 miles from Malibu. The city of Oxnard, which would have to approve the pipelines coming on shore, has questioned both projects in letters to state and federal officials but has not taken such a strong step as Malibu's city council resolution.

"In a day and age when they can fly planes into the Twin Towers, I see no reason they couldn't do the same thing with liquid gas and obliterate a couple of coastal communities," Malibu Mayor Sharon Barovsky told the Los Angeles Times May 25, the day after the city council vote.

Developers say risk is overstated

The projects' developers — and supporters of LNG terminals to meet the nation's growing demand for natural gas — say the super-chilled gas is not nearly as volatile as critics allege, and that double-hull tankers, other safety features and port security would minimize the risk to residents.

Developers of the two proposed terminals are Crystal Energy LLC, a Houston company that wants to break into the LNG terminal business, and Australian mining and energy giant BHP Billiton. Both have started the application process for permits, and both hope to get online in three or four years. Crystal Energy has a memorandum of understanding with the Alaska Gasline Port Authority to work toward converting a 25-year-old former Chevron oil production platform in the Santa Barbara Channel into an LNG receiving terminal.

The port authority, a joint venture of the city of Valdez and Fairbanks North Star Borough, wants to build a municipally owned pipeline to move North Slope gas to Valdez for liquefaction and shipment to West Coast and Far East markets.

And in a bid to assist BHP to gain entry to the California natural gas market, Australian Prime Minister John Howard visited Los Angeles and met with California Gov. Arnold Schwarzenegger while on a U.S. tour the last week of May. The prime minister was looking to help build support for bringing LNG to West Coast consumers. ●

HOUSTON, TEXAS

Front Runner spar installed in Gulf

Project troubled J. Ray McDermott, the marine construction unit of oilfield service company McDermott International, has finally completed installation of the Front Runner production spar in deepwater Gulf of Mexico, the company said June 1.

In March, McDermott projected about $85 million in negative cash flow during the first, second and fourth quarters of 2004, due to additional costs associated with completion of its Front Runner spar, as well as the Carina Aries project in Argentina, and the Belanak FPSO Batam Island facility.

COURTESY J. RAY MCDERMOTT

J. Ray McDermott's DB50 and Shear Leg Crane perform the dual lift of the 6,220 short ton topsides on the Front Runner Spar hull.

J. Ray said it installed the 6,220 short ton topsides on the Front Runner spar hull and has commenced hook-up and commissioning activities. The spar is moored in 3,330 feet of water in the Gulf of Mexico Green Canyon block 338, about 100 miles south of Fourchon, La.

The lift was completed using J. Ray's Derrick Barge 50 and Oceanic 93 "Shear Leg Crane." The Front Runner project is operated by Murphy Exploration & Production. Partners are Dominion Exploration & Production and Spinnaker Exploration Co.

J. Ray also said it was awarded a $47 million contract by Apache Energy, a subsidiary of Houston independent Apache Corp., on behalf of the WA-214P joint venture participants, to procure, fabricate, transport and install the John Brookes platform and pipeline system offshore the North West Shelf in Western Australia.

J. Ray said it will fabricate the jacket and piles at its Batam Island, Indonesia, facility beginning in August 2004. Loadout of the substructure is expected to take place in January 2005. The pipeline and platform will be installed using J. Ray's combination Derrick Barge DB26 commencing mid-January 2005.

Additionally, J. Ray has been awarded a contract by its Mexican joint venture company Construcciones Maritimas Mexicanas, valued at about $60 million. The contract between J. Ray and CMM calls for the charter of J. Ray's Derrick Barge 101, Shear Leg Crane and Intermac 404, as well as related engineering work.

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

MAJORVILLE, ALBERTA

Canadian junior sets major drilling program

Junior E&P company Endev Energy is poised to launch a drilling program in the Majorville area of southeastern Alberta, including 50 wells this spring.

So far, 21 wells have been drilled and cased and are ready for completion and tie in, likely in July. Assuming upbeat results, Endev plans a 90-well program in the same area, hoping for tie-ins in the final quarter. The company's production grew by 189 percent in the first quarter from a year earlier to 3,428 barrels of oil equivalent per day, stemming from increased gas output from the Majorville area. Gas volumes were up by 82 percent to 14.45 million cubic feet per day, boosted by a C$22 million takeover in mid-2003 of Moxie Exploration. Endev's capital budget for 2004 is C$32 million, financed from available bank credit, existing working capital and cash flow, with C$22 million tagged for the core southeastern Alberta area.

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

ATTENTION PETROLEUM NEWS READERS

Part 3 of Heinze interview coming next week

Parts 1 and 2 of in interview with Harold Heinze, executive director of the Alaska Natural Gas Development Authority, appeared in May editions of Petroleum News. Part 3 will appear in the June 13 issue.

For the love of a Golden Retriever

The Midnight Sun Golden Retriever Club is hosting a Golden Retriever Family Fun Day on Saturday, June 5, at the Waldron Park Soccer field in Anchorage. Activities include a silent auction, relay races, agility introduction, best tricks, a talent show and lots of games. Email info@msgrc.org or call Ken at 907 345-4072 for more information.

UMIAT Commercial Company

Umiat Lodge
907-452-9158

OPEN 24 HOURS ALL YEAR

Lodging • Meals • Logistics
• Equipment Rentals
• Aviation Fuel Sales

The Umiat airstrip is
the best on the
CENTRAL NORTH SLOPE.

UCC PROVIDES FULL-SERVICE accommodations and logistical support for northern remote activity from our scenic Colville River Site.

2700 S. Cushman
Fairbanks, AK 99701
907-452-6631
907-451-8632 fax
www.umiat.com

OUR BUSINESS IS GETTING YOUR BUSINESS ON THE ROAD!

This board is
one in a million.

In the past year, Carlile shipped over one million board feet of finished lumber throughout the Last Frontier. But when you get right down to it, the most important board we deliver is the one you need for your project. And that's the Carlile difference. We ship more lumber in Alaska than anyone, but we never forget about all the hard-working Alaskans who need to nail down that one project, one board at a time.

Carlile TRANSPORTATION SYSTEMS
www.carlile.biz
1.800.323.2296

ALASKA • EDMONTON • TEXAS • WASHINGTON

finance&economy

MOSCOW, RUSSIA

U.S. energy secretary: U.S., Russia should move from words to deeds on oil exports

The United States wants to increase imports of natural gas and oil from Russia but the two countries must move from words to deeds to get it accomplished, U.S. Energy Secretary Spencer Abraham said May 28.

"We want to see Russian oil and gas more available to the U.S. market," Abraham said at a business round-table in Moscow.

"This could be done via a northern Russian port," he said, adding that the Baltic Pipeline System would be a key element in this process.

Abraham said he was satisfied with his discussions on the issue with Russian authorities on May 27, but said no exact dates had been set.

"It's too early to say when it will happen," he said, warning that the projects would demand "substantial investment".

However, he said it was the time for Russia and the United States to "move beyond the talking state" to a more "action-oriented" focus.

He said the fact that Russian President Vladimir Putin had called for an increase in Russia's oil export capacity in his state of the nation address was "very positive news for the energy market".

In order to accelerate an increase in Russian oil exports, the U.S. government will encourage American companies to take part in Russian energy projects, Abraham said.

Abraham traveled to Russia to sign an agreement on removing uranium fuel from dozens of Soviet-built nuclear reactors worldwide to prevent it from falling into terrorists' hand.

—THE ASSOCIATED PRESS

CANADA

E&P companies fight back in Canadian M&A market

After starting to lag behind income trusts in 2003, the traditional E&P sector made a comeback in the first quarter of 2004, according to Calgary-based Sayer Securities, which tracks the M&A market.

The firm said E&P companies spent C$2.8 billion on acquisitions in the January-to-March period, or about 74 percent of all M&A transactions, compared with 50 percent for all of last year.

Leading the trend shift were British Gas Group, which acquired El Paso Oil and Gas Canada for C$456 million and Thunder Energy's C$147 million purchase of Impact Energy.

Sayer said the E&P companies are showing their muscle by competing strongly for assets and takeover targets with "upside" such as large probable reserves and undeveloped land with drilling potential.

Thunder reflected that approach by paying about C$70,000 per daily producing barrel of oil equivalent, compared with the median acquisition price of just under C$27,000 per boe in 2003.

see **FIGHT** page 7

● HOUSTON, TEXAS

Panel rejects Leucadia's bid for Plains Resources

The Leucadia group failed to improve its March 19 proposal, Plains' special review committee said; it had expected a 'superior proposal'

By RAY TYSON
Petroleum News Houston Correspondent

A special committee formed to review offers for independent Plains Resources has rejected a bid from an investment group led by Leucadia National and Pershing Square, appearing to strengthen the hand of a rival investment group led by Microsoft co-founder and billionaire Paul Allen.

Plains already has entered into a merger agreement with the Vulcan Group, a subsidiary of Allen's Vulcan Capital, to acquire Plains for $16.75 per share in cash, or roughly $400 million based on the company's market value. Vulcan's initial bid of $14.25 per share was rejected by Plains' board of directors.

In addition to Allen, the Vulcan takeover team includes Plains Chairman James Flores and Chief Executive Officer John Raymond, the son of ExxonMobil Chairman Lee Raymond. The deal would require shareholder approval.

Leucadia's offer for Plains, considered after the board accepted Vulcan's offer, proposed that Plains stockholders receive a combination of cash, preferred stock, and debt securities that would be issued by Plains.

According to Securities and Exchange Commission filings, Pershing Square, which owns 5.33 percent of Plains' general partnership, proposed a $75 million cash offer, which would pay Plains shareholders $3 per share, with the balance in new, unregistered securities to be issued by a new holding company. Those securities would be valued between $17 and $17.60 a share, according to SEC documents.

Committee expected "superior proposal"

Nevertheless, the Plains special committee said

see **BID** page 7

● CANADA

How trusts will survive

Experts count on acquisitions rather than drill bit to fuel sector; expect energy trusts to tighten screws on cash flow distributions to unit holders

By GARY PARK
Petroleum News Calgary Correspondent

Canada's energy trusts will grow through deal-making rather than the drill bit, those involved in the trust sector told a Conference Board of Canada seminar at the end of May.

Although the market capitalization of the trusts now stands at C$26 billion, a 13-fold increase from 1998, the trust firms account for only 11 percent of production from the Western Canada Sedimentary basin, meaning there is ample room for expansion, said Bruce McDonald, an analyst at Canaccord Capital.

He said the trusts, aided by their low capital costs, can outperform the conventional E&P companies through both acquisition and exploration during a period of sustained high commodity prices.

Keith McPhail, chief executive officer of Bonavista Energy Trust, said one of the biggest headaches facing the trusts has been a sharp per-unit decline in production and reserves.

But he is confident the trusts are now taking measures to more efficiently replace those losses as they realize that the cash flow paid out to unit holders needs to be trimmed.

To reinforce that trend, trusts must also hire strong technical teams and provide them with undeveloped land and strategic, timely acquisitions.

Those who can achieve those ends "with the least amount of capital" will emerge on top, McPhail said.

On a broad front, he is certain trusts that combine a technical focus, low costs and reasonable payouts will survive, even if some are forced into

see **TRUSTS** page 7

● ALASKA

Reserves continue to make Alaska attractive

Costs high, taxes moderate, for low overall return on investment; state now attracting medium-sized, not big players

THE ASSOCIATED PRESS

Alaska remains the most costly place on the planet to produce oil and gas but the state could take steps to attract major oil company investment, according to the head of the Alaska Oil and Gas Association.

Judy Brady spoke May 25 to the Kenai chapter of The Alliance, a trade organization representing nearly 400 businesses, organizations and individuals that derive their livelihood from providing products and services to oil and other natural resource companies.

Brady based her remarks in part on a 2002 study by Wood Mackenzie of Edinburgh, Scotland, an international energy consulting firm. The firm is working on an update for 2004 that could change Alaska's ranking.

Two years ago, Alaska ranked last out of 60 oil- and gas-producing regions in 50 countries in costs for producing oil and gas.

Alaska's ranking was based on North Slope fields starting up production since 1995, although earlier studies found that production costs at Prudhoe Bay and the Kuparuk oil fields also are among the highest in the world.

Despite the expense, Alaska was not the least profitable region. The state ranked slightly above average in "total government take" of both federal and state royalties, taxes and net profit shares of oil and gas production. When both costs and "government take" were considered together, Alaska ranked 55th in "post-take value" per barrel of oil.

Alaska ranks low on overall investment return

"Of the places you could go, according to this study, there are five or six places you would make less than if you go to Alaska and there are 55 or 56 places you would make more," Brady said.

Oil and gas companies are looking to invest where they can get the best return. With so many other more profitable places to go in the world, she said, it's difficult to make a boardroom pitch for investing in Alaska.

The state's saving grace, according to Brady, is that Alaska has relatively high reserves compared to other parts of the world.

"We're going to continue to be attractive if we have those reserves," she said.

Current high oil prices make production more profitable, but do not make Alaska fields more attractive for investment since a producer will get that same price anywhere on the globe, Brady said.

Medium-sized companies interested now

Oil companies remain interested in investing in Alaska, she said, but the size of the companies has changed.

"We're not getting the big players we used to get," said Brady. The companies investing are medium-size regional companies. To continue attracting investment, especially from larger companies, Brady said, the state could do a couple of things: create a "steady" tax system and streamline the permitting process.

The state and federal "total government take" of 64 percent, with the state accounting for 47 percent, of oil and gas revenue is not excessive compared to other areas around the globe.

"It's not that our taxes are terribly high here, they're in the middle," said Brady. However, the tax rate combined with the high cost of doing business in the state "pushes us over the edge," she said.

Alaska has attributes that cannot easily be quantified that the study did not consider, such as political stability, Brady said. The pressure on oil companies to produce steady returns on investments has ratcheted up to the point that they are willing to commit to regions with questionable stability they would not have considered exploring five years ago, Brady said. ●

continued from page 6

FIGHT

To trim that ultimate acquisition price and boost production from the assets, Thunder will inject the needed capital to grow Impact's large base of non-producing reserves, Sayer said.

For British Gas, the El Paso package included 630,000 net acres of undeveloped land that the buyer believes holds considerable exploration potential that will support its drilling plans for many years.

Another new wrinkle on the M&A front was demonstrated by Great Northern Exploration, which paid C$39,000 per boe for assets in the central Alberta area, with about 40 percent classified as proved non-producing or probable. But the deal was a strategic fit for Great Northern which increased its working interest in the area to 97 percent from 65 percent.

Bolstering the competitiveness of the E&P companies was the backing of capital markets, Sayer said, noting that for 2003 E&P equity financings of C$2.4 billion were up 118 percent from 2000, the best annual dollar figure for six years.

Sayer said the attractiveness of E&P equity in the stock market has enabled those companies, in some circumstances, to trade at high enough values to compete with income trusts on acquisitions.

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

continued from page 6

TRUSTS

consolidation.

Buying assets will remain key

Roger Serin, an analyst at TD Securities, said that buying assets will remain the key to offsetting production declines, given that finding and development costs will be high due to the shrinking productivity and reserves in the Western Canada Sedimentary basin.

Proven finding, development and acquisition costs for 23 junior E&P companies averaged about C$18 per barrel of oil equivalent in 2003, while for trusts they averaged C$18.50 per boe, Serin said.

However, he cautioned that finding, development and acquisition costs are an ineffective measure of value creation because they don't reflect differences in asset quality.

The changing complexion of the trust world was commented on by Leslie Lundquist, a portfolio manager at Bissett Investment Management, who noted some of the shifts taking place.

She said Bonavista has moved to relatively low payout ratios, Vermilion Energy Trust has extended its reach to France and the Netherlands, Provident Energy Trust has acquired major midstream assets and Enerplus Resources Fund has embarked on a joint venture in coalbed methane with MGV Energy through the trust's takeover of Ice Energy.

In addition, Enerplus along with Acclaim Energy Trust were two of the three buyers of conventional assets

Roger Serin, an analyst at TD Securities, said that buying assets will remain the key to offsetting production declines, given that finding and development costs will be high due to the shrinking productivity and reserves in the Western Canada Sedimentary basin.

unloaded by Chevron Canada Resources, with Enerplus forking over C$466.3 million to gain 11,500 boe per day of production and Acclaim paid C$433.7 million for 17,000 boe per day.

Lundquist said while there is no certainty that these new strategies will succeed, they are evidence that trusts are flexible.

She said the trusts serve a valuable role in producing reserves in a cost-effective manner, waste less capital on marginal projects and put their emphasis on results, not promises.

For those reasons, exploration and production of the Western Canada basin will be more disciplined and the distribution of capital between exploration and production will become more efficient.

Mark McMurray, an acquisition specialist at Kobayashi Partners, said that as trusts enter their "mid-life crisis" they must become more involved in portfolio management and ensure that they buy only high-quality junior E&P companies to replace reserves and increase output.

He said the competition will intensify for companies that have producing properties and a string of moderate-risk investment opportunities. ●

continued from page 6

BID

May 26 it dismissed Leucadia's proposal and terminated negotiations. The Leucadia group failed to make any improvements on its March 19 proposal, the committee said, adding that it had expected a "superior proposal."

The committee said it was concerned that the tax and leverage issues raised in the Leucadia offer would adversely impact Plains' ability to pay the interest and distributions on the proposed debt and preferred stock.

Moreover, the committee expressed concern the small amount of cash offered in Leucadia's proposal would be insufficient for most Plains shareholders to pay taxes on their gains resulting from the transaction and "could create immediate negative selling pressure on the proposed new debt and preferred securities."

Also, the deal would create "phantom" taxable income in excess of interest payable to holders of the proposed debt securities, the committee said.

The committee said that despite conceding the validity of the tax issues, Leucadia sent a letter to the committee "indicating an unwillingness to improve its offer, and did not offer any alternative solutions to the issues raised by the special committee."

Leucadia cancelled proposed meeting

Nevertheless, the committee said it invited Leucadia to meet to discuss its proposal.

"After accepting the invitation and scheduling the meeting, Leucadia cancelled the proposed meeting, declined to provide all of the requested information, declined to execute a confidentiality agreement and stated that it would not modify the March 19 proposal," the committee said.

Leucadia did not respond to the committee's allegations, nor indicate its next move at Petroleum News' deadline.

The main objective for both the Vulcan and the Leucadia-Pershing groups appears to be fast-growing Plains All American Pipeline. It so happens that Plains Resources, a small exploration and production independent, owns 44 percent of the general partnership of Plains All American, a publicly traded master limited partnership, and a 24 percent aggregate ownership interest in the pipeline company.

In early April, Plains All American announced the $330-million acquisition of Houston-based Link Energy, a transaction that essentially doubled the amount of pipeline miles held by Plains All American in the United States and Canada.

Allen's Vulcan Capital committed $40 million to the Link deal. It marked Allen's first direct venture into the midstream energy sector, preceded by Vulcan's still pending takeover bid for Plains Resources. ●

Solving Engineering & Environmental Challenges in Alaska
Alpine-Meadow Inc.
Environmental Consulting Services
George R. Snodgrass
President
phone/fax
694-7423
Eagle River
Alaska
email: grsnodgrass@alpine-meadow.com
website: www.alpine-meadow.com


1000 hp Turbine Otter
Renew Air
Exploration & Seismic Support Statewide
Wheels • Wheel Skis • Amphibious Floats
Cargo • Fuel • Passenger
1-888-684-0177
renew1@aol.com
1-907-457-7287
www.renewair.com

INDONESIA

Indonesia should quit OPEC if can't boost output, ex-oil minister says

Indonesia's status as Asia's only member of the Organization of Petroleum Exporting Countries is under question following reports that it now imports more crude oil than it exports. A former energy minister, Ginandjar Kartasasmita, said Indonesia might as well drop out of the cartel "if we can't boost our crude oil production."

"There are no advantages for us to stay with OPEC," said Ginandjar, who was Indonesia's mines and energy minister from 1988-1993 under dictator Suharto. Indonesia "will do fine without OPEC," he told reporters.

Dow Jones Newswires reported in May that Indonesia for the first time became a net crude oil importer in March, undermining its already marginal role in the group.

Mines and Energy Minister Purnomo Yusgiantoro — who is also OPEC's current president — said in late May that temporary oil field glitches have caused Indonesia's decline in crude oil exports. He said Indonesia had 1 billion barrels of reserves it plans to roll out in the next two or three years.

Analysts, however, say unclear investment laws and regulations are discouraging international companies from developing the country's oil and gas reserves.

With crude output of around 980,000 barrels a day in April, Indonesia can't meet its daily OPEC output quota of 1.2 million barrels per day. Some analysts have urged the government to quit OPEC because Indonesia has to pay an annual membership fee, and doesn't have much of a say in the group anyway. However, the government insists Indonesia should stay in OPEC to help influence global oil prices.

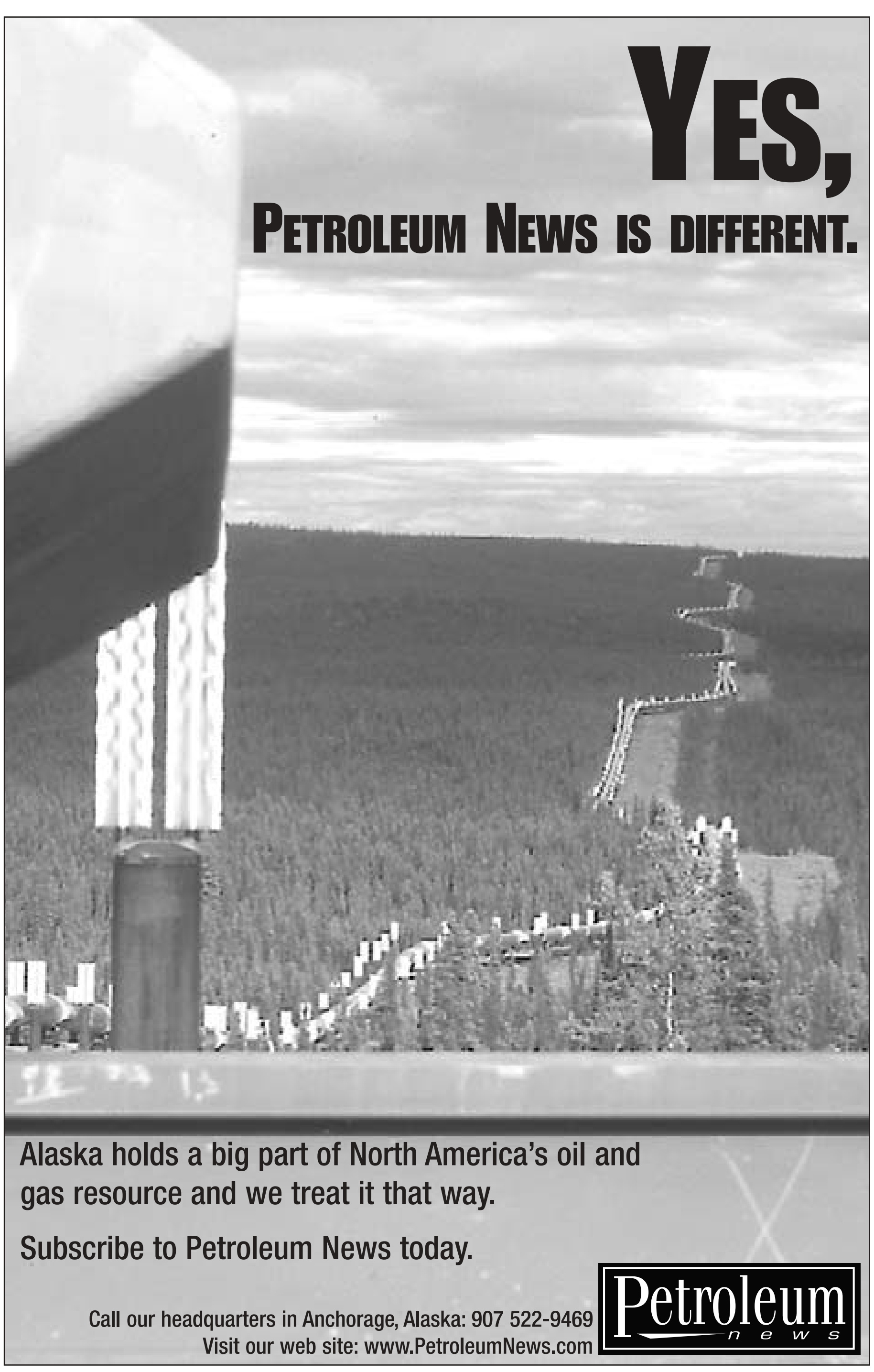
—THE ASSOCIATED PRESS

Rose & Associates

Rose & Associates, LLP is pleased to announce the offering of its popular 5-day course

"Exploration Economics, Risk Analysis and Prospect Evaluation"
At the ConocoPhillips facilities in Anchorage, August 23-27, 2004

Detailed course and registration information may be found on our website at:
http://www.roseassoc.com/Courses/CrsExplore.html
Or contact Kim Pederson — Phone: **713-528-8422** Email: **kimpederson@roseassoc.com**



● GULF OF MEXICO

Petsec plans $28M capital program, much going into Gulf

By ALLEN BAKER
Petroleum News Contributing Writer

Petsec Energy Ltd. is planning to spend US$28 million this year on capital projects, with the bulk of the Australian firm's funds being plowed into the Gulf of Mexico.

The company expects natural gas production from the Gulf of 6.5 billion cubic feet this year, up from 4.5 bcf in 2003 and just 46 million cubic feet in 2002, when the company was just getting back on its feet. This year's higher production should provide sufficient cash flow to fund the 2004 exploration and development budget, Petsec Chairman Terry Fern told the company's annual meeting May 25.

But Fern said three wells drilled off China this spring produced disappointing results, with two dry holes and the third well yielding relatively heavy 18-20 degree API oil, though in high quality sands.

The three wells, drilled in April and May in the Beibu Gulf about 36 miles off the southern coast of China, cost the company $2 million. Petsec holds a 25 percent working interest.

Work in that region with partner Roc Oil of Australia will continue over the next three months, Fern said. Concentration will be on the successful new 12.8.3 well, which showed 36 feet of pay, confirming an estimate of oil in place of 80 million to 90 million barrels, and on the 12.8.1 field, about a mile to the west, which contains an estimated 10 million barrels of recoverable oil.

In the Gulf of Mexico, Petsec is planning four wells from the Vermilion 258 platform, with drilling to start in September.

Four Gulf wells planned

In the Gulf of Mexico, Petsec is planning four wells from the Vermilion 258 platform, with drilling to start in September. Company engineers think there's a potential for 20 bcf of recoverable gas there. The first well drilled on that block this year, the Vermilion 258 No. 2, found an estimated 9 bcf of recoverable gas, with 42 feet of pay. That well followed on Vermilion 258 No. 1, punched in December, which showed 85 feet of net gas pay.

Petsec, which has a 100 percent working interest in Vermilion 258, expects the initial pair of wells to flow 15 million to 25 million cubic feet daily when production starts later this year. The lease is about 70 miles off the coast of Louisiana.

Overall, Petsec holds five contiguous leases in Vermilion and interests in a total of 13 leases in the Gulf of Mexico, including productive wells in West Cameron blocks.

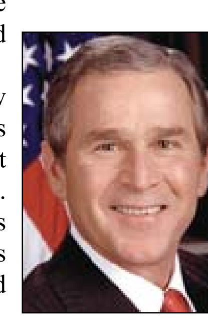
The company estimates that its Gulf reserves hold 36 bcf of recoverable gas, and executives see "continuing opportunity to acquire additional Gulf of Mexico leases that will have a further substantial impact on the company," according to Fern, Petsec's chairman. ●

MERIDIAN, MISS.

Business professor says high oil prices could topple U.S. President George Bush

U.S. President George W. Bush's success in November is tied to what happens in June when the Iraq government is turned over to local control, a business professor says.

"The political aspect of Iraq is if we still have the problem we have right now and oil prices go up to $48 or $50 a barrel, I'm afraid we're going to have a new administration," Habib Bazyari said May 25 during a civic club speech in Meridian, Miss.


U.S. President George W. Bush

"Everything depends on the end of June when the new Iraqi administration comes into power," he said. Bazyari is dean of the College of Business at the University of West Alabama. He moved to the United States from Iran in 1960.

Bazyari said there was a 4 percent growth in the gross domestic product for the first quarter of 2004. The GDP is the output of goods and services produced by labor and property in the United States.

But the last four of five recessions in the United States started with an increase in the price of oil, Bazyari said.

"I'm afraid if oil prices stay about $42-$45 (per barrel) we are going to go back into another recession," he said.

If that happens, Bazyari said unemployment may increase to close to 6 percent.

"The whole thing depends on oil," Bazyari said.

He said the main triggers for higher oil prices are the purchase of gas-guzzling sport utility vehicles; an increased demand for oil in China and India where manufacturing jobs are on the rise; and the need for more oil refineries in the United States.

He also said the war has affected oil prices because terrorists continually puncture pipe lines, wasting millions of barrels of oil in a day.

—THE ASSOCIATED PRESS

● OKLAHOMA CITY, OKLA.

Kerr-McGee raises production target for 2004 second quarter

BY RAY TYSON

Petroleum News Houston Correspondent

Kerr-McGee has raised its oil production range for the 2004 second quarter to 130,500-136,500 barrels per day to reflect greater natural gas liquids output and strong performances from the North Sea and the company's Nansen and Boomvang fields in the deepwater Gulf of Mexico.

The Oklahoma-based independent also has increased its total production outlook, including natural gas, for full-year 2004 to an average range of 306,000 to 323,000 barrels of oil equivalent per day, Kerr-McGee said in a May 26 conference call with industry analysts.

"With these volumes, we believe the range for total production for the 2004 second quarter to be about 253,000 to 267,000 barrels of oil equivalent a day." **—Rick Buterbaugh, Kerr-McGee's head of investor relations**

Guidance for overall production this year was raised because of first oil expected from the Red Hawk field in the Gulf of Mexico this July and from China's Bohai Bay during the third quarter, four months ahead of schedule, Kerr-McGee said.

Also, total production for the year will benefit from Kerr-McGee's $3.4 billion acquisition of Denver-based independent Westport Resources. Kerr-McGee's total daily production volume is expected to increase more than 34 percent, 54 percent of which is natural gas. The deal is expected to close June 25, pending shareholder approval the same day.

For the second quarter of 2004, Kerr-McGee is projecting daily natural gas production to range between 735 million and 785 million cubic feet with about 85 percent of the volume coming from the United States.

"With these volumes, we believe the range for total production for the 2004 second quarter to be about 253,000 to 267,000 barrels of oil equivalent a day," said Rick Buterbaugh, Kerr-McGee's head of investor relations.

Majority of production hedged

However, Kerr-McGee has taken hedging positions on a significant portion of its oil and gas production at much lower commodity prices than what they are so far averaging during the 2004 second quarter.

The company locked in 75 percent of its U.S. oil production at $28.23 per barrel and about 85 percent of its North Sea production at $26.27 per barrel. So far, West Texas Intermediate oil prices are averaging about $38.25 per barrel and North Sea Brent $34.90 per barrel. Second-quarter WTI is currently up about $3 per barrel compared to the first quarter, while Brent is up about $3.60 per barrel.

Kerr-McGee also hedged about 80 percent of its U.S. natural gas volumes at a fixed $4.74 per thousand cubic feet, considerably less than the $6.05 average so far in the second quarter. NYMEX gas prices are currently about 30 cents higher than they were in the first quarter.

Meanwhile, Kerr-McGee said it expects to spend about $65 million on oil and gas exploration in the 2004 second quarter and about $350 million for the year, which includes about $70 million in non-cash charges associated with non-producing leasehold.

"The increase in annual exploration expense results from the addition of expected Westport activities for the second half of the year," Buterbaugh said.

The addition of Westport's reserves will increase Kerr-McGee's proved reserves by nearly 30 percent, mainly from North American natural gas. At year-end 2003, Westport had 1.8 trillion cubic feet of gas equivalent proved reserves, consisting of 76 percent natural gas and primarily located in the Rocky Mountain and Texas Gulf Coast areas. Westport also has a reported 1.8 trillion cubic feet of equivalent in probable and possible resources, about 50 percent of which are located in and around the Natural Buttes field, in the Uinta basin of northeast Utah. ●

BEIRUT, LEBANON

OPEC chief wants to boost output

OPEC must boost oil output further to make a "really significant impact" on surging crude prices, the group's president said June 2, even though it is pumping close to capacity already.

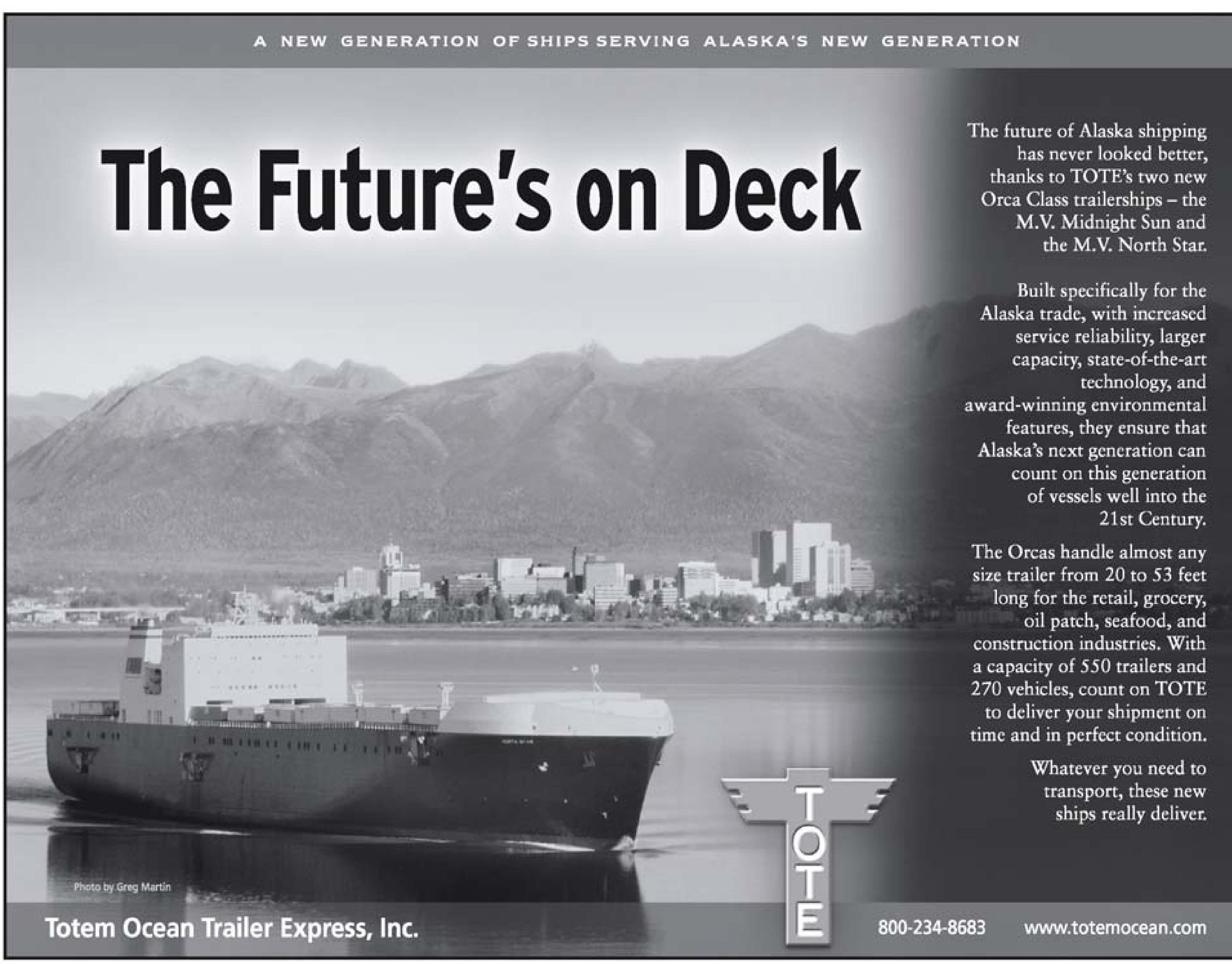
The Organization of Petroleum Exporting Countries needs to assess its 11 members' ability to produce more now that prices for oil futures contracts have hit new highs after a terror attack in Saudi Arabia at the end of May, OPEC President Purnomo Yusgiantoro told reporters. He spoke upon arrival in Beirut for talks ahead of a formal OPEC meeting on production policy June 3.

The weekend attack on oil-related offices and foreign workers in the eastern Saudi oil hub of Khobar stoked fears the Saudi government, which controls the world's largest proven crude reserves, cannot protect its vital oil installations.

"We are fully ready to increase production, but there is fear that the market will be overflooded," Saudi Oil Minister Ali Naimi said. "So, therefore, we should be cautious about such action because this is what happened in 1997-98."

The Khobar attack caused fresh alarm about the reliability of oil supplies from key Gulf producers. Saudi Arabia is the world's leading crude exporter and the only producer with

see **OPEC** *page 10*



SOUTHWEST ALASKA

Holitna Energy still working on remote Alaska shallow gas project

Phil St. George still believes in the gas potential for Holitna basin, despite a series of setbacks since filing in May 2003 for four shallow gas leases in the remote region of southwestern Alaska.

His company, Holitna Energy, and its Native corporation partner, TKC, plan to convert their shallow gas lease applications covering more than 19,000 acres of land to exploration licenses under the state's conventional gas leasing program. That's because Alaska's non-competitive, shallow gas leasing program, also referred to as its coalbed methane program, has been legislated out of existence.

House Bill 531, passed May 11, abolished the shallow gas leasing program, leaving a number of pending applications. In addition to Holitna Energy's four leases about 50 miles from the Donlin Creek gold mine project, Usibelli Coal Mine at Healy has an application pending for eight shallow gas leases.

House Bill 531, passed May 11, abolished the shallow gas leasing program, leaving a number of pending applications. In addition to Holitna Energy's four leases about 50 miles from the Donlin Creek gold mine project, Usibelli Coal Mine at Healy has an application pending for eight shallow gas leases.

And 13 applications are also pending in the Mat-Su Valley, according to Jim Hansen at the Alaska Division of Oil and Gas. Those applicants can convert their lease selections into a non-competitive exploration license application, Hansen said. Before approving an exploration license, the state must issue a best interest finding, which typically takes about a year to complete, he said.

Companies could do some preliminary fieldwork prior to receiving an exploration license, Hansen said. "Any work they do on exploration would count toward their work commitment," he said. "But they are at risk whether the license will be awarded or not."

Still positive about Holitna Basin

St. George remains positive about his company's chances of finding gas to supply power and heat for Donlin Creek.

"We've got new information that there's a good possibility of finding conventional gas, so we think there's a better chance," he said, on May 25. "We've got some more data on the basin and I don't want to say any more about that."

Holitna Energy and TKC plan to conduct some exploratory work this winter, pending successful fund-raising for seismic work and initial drilling. (On Jan. 3, Holitna said it plans to drill two exploratory wells this past winter for shallow gas and coalbed methane occurrences had been cancelled because funding had fallen through at the last minute.)

St. George said state officials told him they would "try to speed up" the best interest finding process, possibly completing it in six months.

Donlin Creek may not be the only potential large mine customer for Holitna Basin gas. St. George said he was approached by state development employees interested in taking Holitna basin gas about 100 miles south to Illiamna Lake, where the Pebble gold-copper-molybdenum project is generating considerable interest.

—PATRICIA LILES, Petroleum News contributing writer

continued from page 9

OPEC

significant spare capacity to pump more oil.

Oil prices eased somewhat early June 2, slipping 37 cents to $41.96. That came a day after a surge on June 1, the first day of trading on major markets since the Khobar attack. U.S. light crude for July delivery climbed $2.45 to $42.33 per barrel — the highest settlement price in the contract's 21-year history on the New York Mercantile Exchange.

—THE ASSOCIATED PRESS

● SOUTHWEST ALASKA

Alaska mine power options down to three

Placer Dome tightens scope of power options for Donlin Creek mine; one on-site and two off-site options being considered

By PATRICIA LILES

Petroleum News Contributing Writer

Placer Dome, operator of the remote Donlin Creek gold deposit in southwest Alaska, has narrowed its consideration of electric power options from 11 to three scenarios in its preparation of a pre-feasibility study for the large-scale mine project. Two off-site options and one on-site option to generate up to 70 megawatts of electric power needed for a large hard-rock mine at Donlin Creek are now being considered in more detail by Placer Dome, according to the company's project manager, Gregg Bush. In a May 24 interview with Petroleum News, Bush said the company requested "expressions of interest" from local and international energy firms for options to provide power to the remote project. "We received very enthusiastic responses," he said.

The on-site generation being considered is either a diesel or LPG-powered generation plant.

One of the off-site generation options involves building a transmission line connecting Donlin Creek to Alaska's existing Railbelt power grid.

The third option being considered is building a coal-fired power plant at Bethel and building a transmission line up the Kuskokwim River, a scenario advocated by Calista, the region's Native corporation.

After narrowing the focus of power options, Placer Dome requested specific cost details and the related scope of work needed in those top three considerations. Bush said the company requested that information be provided by Sept. 15, so it can be incorporated in Placer Dome's pre-feasibility study for the Donlin Creek mine project. That study should be complete in late September or early October, Bush said.

On-site requires barging, lots of storage

Electric power for the remote gold mine is a key obstacle for its successful development. Because Donlin Creek ore is associated with a sulfide material, extracting gold involves an autoclave process, which requires adding oxygen and heat to crushed ore. That ups the ante for power needs, with estimates of peak needs at 70 megawatts of power.

Installing and operating diesel generators to meet that power need would require about 30 million gallons of fuel each year, Bush said. That's in addition to about 15 million gallons of diesel that would be used annually by the mine's dirt moving equipment. The barge shipping season for the Kuskokwim River is about 122 days per summer, according to Placer Dome's partner in the project, NovaGold Resources. In its previous analysis of the Donlin Creek project, NovaGold estimated that seven tug and barge deliveries per week would be required during the shipping season.

Bush said Placer Dome is leaning towards shipping LPG, or propane, to Donlin Creek for fuel to power on-site generation, rather than diesel. Propane requires lower-pressure storage and handling equipment, Bush said, and its cost is usually comparable to diesel. LPG has lower per unit power generation capability, so about 60 million gallons of LPG would be required, he said. "We're looking at some underground storage," Bush added.

Transmission line from Railbelt

One of the off-site generation options involves tying Donlin Creek into Alaska's existing power grid that serves the Railbelt communities. "It would not necessarily have to connect in Nenana, but that would be the logical place to bring the line across the terrain," Bush said. That tie-in access point at Nenana could keep the transmission line on the north side of the Alaska Range, eliminating a crossing point for the state's central dividing line of mountains, Bush noted.

But power generation capacity on the Railbelt is already relatively tight, particularly in the northern portion of the state. A December 2003 report by the Alaska Energy Policy Task Force states that Railbelt energy studies predict electric power generation needs could grow 39 percent from 2008 through 2028.

see OPTIONS *page 11*

AVALON

DEVELOPMENT CORPORATION

AVALON DEVELOPMENT CORP.

Mineral Exploration Consulting Services

Property Evaluations

Exploration Design & Management

Field Exploration and Logistics

Curt Freeman, Cert. Prof. Geologist #6901

P.O. Box 80268 Fairbanks, AK 99708

Phone 907-457-5159 Fax 907-455-8069

email avalon@alaska.net

web site www.avalonalaska.com

● HEALY, ALASKA

Offer for coal plant rejected by state agency

AIDEA turns down purchase offer from Golden Valley Electric for Healy Clean Coal Project

By PATRICIA LILES

Petroleum News Contributing Writer

Golden Valley Electric Association's $70 million offer to purchase the shuttered, experimental coal-fired power plant in Healy, Alaska, has been turned down by board members of the Alaska Industrial Development and Export Authority.

GVEA's board members learned of their rejected offer during a meeting with the state agency's board members on April 30, according to Kate Lamal, vice president of power supply for GVEA.

"They did not like our offer. There was no counter-offer, no alternative offered," she told Petroleum News on June 2. "They are continuing to work on permitting a retrofit (of the experimental plant.)"

AIDEA's Executive Director Ron Miller told Petroleum News on June 3 that board members did not see "any substantial benefit to AIDEA" from GVEA's offer. "There were too many contingencies, and we feared that AIDEA might have to pay out of pocket for Golden Valley to take over the power plant."

He also said the annual payments offered by GVEA would only be paid if the plant was generating electricity, and that AIDEA's continued warranty and liability of the plant's operation was not acceptable.

After nearly a year of joint board meetings to discuss the lengthy legal debate about ownership and operation of the Healy Clean Coal Project, GVEA submitted a purchase offer on March 19 to AIDEA. That state agency owns the $300 million-plus Healy Clean Coal Project, built mostly with federal and state funds during the mid-1990s. The 50-megawatt experimental plant is located outside of Healy, adjacent to a 25-megawatt coal-fired plant owned and operated by GVEA since 1967.

After nearly a year of joint board meetings to discuss the lengthy legal debate about ownership and operation of the Healy Clean Coal Project, GVEA submitted a purchase offer on March 19 to AIDEA. That state agency owns the $300 million-plus Healy Clean Coal Project, built mostly with federal and state funds during the mid-1990s.

In its purchase offer, GVEA agreed to pay AIDEA $70 million for the plant over a 40-year period, paying $1,750,000 per year after the plant became operational.

The Healy plant has been shut down since January 2000 after conclusion of a 90-day test period, used to evaluate performance, reliability and safety of the experimental technology.

AIDEA has spent about $9 million a year on the plant since construction was completed in 1997, according to a former project manager. That includes debt payments on the bonds and about $3 million a year to keep the plant in standby mode.

GVEA's purchase offer was contingent on completion of a full retrofit of the plant, which would change out some of the experimental technology to "environmentally equivalent, proven technology," similar to that in the smaller, operating Healy coal plant, Lamal said. Estimated cost for that work was $65 million.

Collaborative work to obtain an emissions permit from the Alaska Department of Environmental Conservation for the retrofitted plant is continuing, an effort that Lamal said began in earnest in February with encouragement from Alaska Gov. Frank Murkowski.

While not designated in the GVEA purchase offer, one potential source for the retrofit funding is a $125 million federal appropriation included in the pending U.S. energy bill. The remaining amount could be used to pay off some of the $85 million in bonds issued by AIDEA to raise its share of the initial construction costs.

"When you make an offer for something that's for sale and they say no, what do you do? We're building North Pole," Lamal said. "We have the ability to go two-on-one at North Pole."

GVEA plans North Pole power plant

On May 24, GVEA's board members gave final approval for construction of a new, gas-fired power plant in North Pole.

"We don't have a signed contract yet, but we're working out the details on the equipment," Lamal said. That decision was not dependent on AIDEA's rejection of the HCCP offer, she said on June 3.

"We've been working on that project for more than a year." GVEA's board decided to spend $75 million for the naphtha-fired power plant, selecting a one-on-one configuration, according to GVEA spokeswoman Corinne Bradish.

It will consist of a 47-megawatt simple circuit generator and a 13-megawatt steam turbine. The design allows GVEA to add a second 47-megawatt gas-fired generator, which, if combined with the steam turbine in a two-on-one configuration, will produce 120 megawatts of electricity.

Construction of that facility should begin in late June, and be complete in early 2006. It will be located adjacent to GVEA's existing 120-megawatt heavy atmospheric gas oil fired power plant that operates within the security confines of Alaska's largest oil refinery, now owned by Flint Hills Resources. North Slope crude oil is tapped from the nearby trans-Alaska pipeline system and distilled, providing gasoline, jet fuel, diesel and fuels for electric generation in Interior Alaska. ●

continued from page 10

OPTIONS

Deficiencies in generation capacity are projected in areas of the Railbelt other than on the Kenai Peninsula, the study said.

Power generation capacity in the Fairbanks area currently is 183 megawatts, according to the Interior's electric supplier, Golden Valley Electric Association. Golden Valley plans to build another gas-fired power plant in North Pole, adding another 47 to 120 megawatts of power generation in the Interior by early 2006. It also produces 25 megawatts of coal-fired power in Healy, fed north by two transmission lines that run between Healy and Fairbanks.

Nenana is about halfway between Healy and Fairbanks. Golden Valley counts in its generation capacity 20 megawatts of power from the hydroelectric plant at Bradley Lake. That power is supplied to the Interior by the Alaska Intertie, which can carry 75 megawatts of power north from Willow to Healy, then to Fairbanks via one of the two northern transmission lines.

Demand growing quickly

Golden Valley set a new record for its peak demand of electricity this January: 192.9 megawatts. Electric demand in the Interior is expected to increase dramatically in the near future, even without Donlin Creek.

Large new consumers in Fairbanks such as Wal-Mart, Home Depot, Lowe's and the expanded Westmark Fairbanks Hotel will bump the immediate draw of power. Another 30 megawatts of demand for Golden Valley power is expected in the near future from large-scale industrial projects and a residential increase in Fairbanks-area military personnel. Development of the national missile defense system at Fort Greeley, construction of the Pogo gold mine northeast of Delta Junction and electrification of some pump stations on the trans-Alaska pipeline system all are expected to increase Golden Valley's demand.

Calista favors coal-fired plant at Bethel

The third power option Placer Dome is considering is some version of a coal-fired power plant in Bethel, advocated by the region's Native corporation, Calista Corp. Calista's non-profit subsidiary, Nuvista Light & Power, released a draft feasibility study this spring recommending construction of a 100-megawatt-plus power plant at Bethel, either on two barge structures or on land south of town.

A connecting 138-kV transmission line would be built from Bethel to Donlin Creek, an estimated 191 miles, to provide the mine with power. (See story in May 9 issue of Mining News.) Timing of that large-scale project, estimated to cost about $370 million, could provide a logistical hurdle, according to the Nuvista report.

"Realistically it will be difficult to construct (the coal-fired plant and transmission line) prior to 2010," the tentative date for Donlin Creek's mining start. Placer Dome has hired consultants to look at the Nuvista proposal, from the mine developer's perspective, Bush said. "They are looking at what our cost and construction criteria are, separating our needs from those of the obvious community benefits from that study." ●

www.efs-fire.com

ENGINEERED FIRE & SAFETY

The Total Protection Team

Your One Complete Source for Design, Installation & Service

- Safety Training
- Fire Alarm & Detection
- Fire Brigade Training
- Facility Survey
- Special Hazard Suppression
- Portable Fire Extinguishers
- Marine Systems
- Fire Sprinkler Systems
- 24 Hour U.L. Central Station Monitoring
- Electrical Security Systems

274-7973

Certification Inspections
Quarterly ▪ Semi-Annual ▪ Annual

Licensed ▪ Bonded ▪ Insured

Fax: 274-6265
Statewide:
800-478-7973
www.efs-fire.com
3138 Commercial Drive

Kidde

● BRITISH COLUMBIA

B.C. closer to call for bids in Muskwa-Kewchika area

Northeast part of province a natural westward extension of traditional exploration areas

By DON WHITELEY

Petroleum News contributing writer

The British Columbia government is one step closer to a call for bids on oil and gas leases in the 64,000 square kilometer Muskwa-Kechika area in northeast British Columbia.

The Ministry of Energy and Mines, in conjunction with the Ministry of Sustainable Resource Management, has issued new pre-tenure plans that outline environmental requirements for oil and gas exploration activities.

"This is good news for our oil and gas industry that last year increased its investment in the province to $3.5 billion from $3 billion the previous year," Energy Minister Richard Neufeld said in a release. "It provides the certainty that industry needs to proceed with exploration and development of the tremendous resource potential in this area."

Ministry officials have estimated that $16 billion worth of natural gas may lie beneath the eastern parts of this area, which is about the size of the Province of Nova Scotia. It is a natural westward extension of traditional exploration terrain in the northeast part of British Columbia, but to date there has been no drilling activity because of environmental issues.

Plans would give assurance of access

The pre-tenure plans provide potential bidders for exploration rights with the certainty that they will be able to get access to this remote exploration area. They also give direction for conservation of biological diversity, soil and water resources, as well as targets for minimizing disturbance to the general area, and remediation once exploration and development are completed. The plans become part of any oil and gas tenure sold in the area.

Oil and gas activities must comply with the Muskwa-Kechika Management Act, which was enacted because of the unique nature of an area that has often been called the Serengeti of the north. Resource activities will be governed by the Muskwa-Kechika Management Plan, which was developed after consultations with residents, local municipalities, First Nations and tourism, wildlife and resource development interests.

"With clear guidelines in place to protect environmental values while providing resource access, industry can now acquire the oil and gas rights that form the basis for future development," said Sustainable Resource Management Minister George Abbott.

"This will ensure new sources of energy and provide additional jobs and revenue that will benefit our communities and residents," added Neufeld. "B.C. has succeeded in attracting an increasing share of industry investment, and oil and gas exploration and production activity has steadily increased in recent years from 821 wells drilled in 2002/03 to a forecast of 1,328 wells this year." ●

"This is good news for our oil and gas industry that last year increased its investment in the province to $3.5 billion from $3 billion the previous year. It provides the certainty that industry needs to proceed with exploration and development of the tremendous resource potential in this area." —Energy Minister Richard Neufeld

continued from page 1

LEASE SALE

ning areas.

Anadarko took two tracts bidding by itself for $155,356 and paid out another $2,308,290 as a 30 percent partner with ConocoPhillips and Pioneer, for a total of $2,463,646.

ConocoPhillips Alaska bid $1,860,500 for eight tracts by itself, $2,871,540 in partnership with Pioneer and $3,847,150 in partnership with Anadarko and Pioneer for a total of $8,579,190.

Fortuna, bidding by itself, had $26,480,300 in high bids, 49 percent of the high bids at the sale.

Petro Canada, bidding by itself, had $13,614,835 in high bids, 25 percent of the high bids at the sale.

Pioneer, bidding in partnership with ConocoPhillips and Anadarko, and in another bidding group with ConocoPhillips, had $2,769,520 in high bids.

No new players

None of the bidders are new to Alaska. ConocoPhillips Alaska is a major North Slope producer and operates both the Kuparuk River and Alpine fields. Anadarko Petroleum is ConocoPhillips' partner at Alpine and in northeast NPR-A acreage and also holds substantial North Slope state, federal and Native corporation acreage.

Pioneer Resources Alaska, a subsidiary of Dallas, Texas-based Pioneer Resources, is a partner, and operator, in the Oooguruk exploration unit assembled by Denver, Colo.-based Armstrong Oil & Gas in Harrison Bay offshore Kuparuk and also has a large acreage position on state lands south of Prudhoe Bay.

Petro-Canada holds a major acreage position in the Foothills area north of the Brooks Range, and Fortuna farmed in on Total's exploration acreage in the northeast NPR-A and was a partner in the exploration well drilled there last winter.

Dick Garrard, ConocoPhillips Alaska exploration manager responsible for the NPR-A area, said after the sale that ConocoPhillips expected "some Canadian companies would come here, it's been a trend recently." And it's logical, he said, as "they're accustomed to working in northern latitudes" and have experience in the Arctic.

Petro-Canada is Calgary-based and Fortuna is a subsidiary of Calgary-based Talisman Energy.

A blocky affair

Most of the tracts drawing bids were in good-sized blocks.

The only outlier was two tracts Anadarko bid on by itself, adjacent to the southern edge of the northeast NPR-A planning area and the most southerly of tracts receiving bids.

In the southwestern portion of the sale area the ConocoPhillips (50 percent)-Anadarko (30 percent)-Pioneer (20 percent) partnership took 13 tracts and the ConocoPhillips (70 percent)-Pioneer (30 percent) partnership took 14 adjacent tracts.

On the northwestern edge of the sale area, southwest of Barrow, Petro-Canada took a block of 10 leases, and the ConocoPhillips-Anadarko-Pioneer bidding group took a block of 19 tracts in an arc south of Barrow.

The remaining 65 leases receiving bids are in a single block beginning at Smith Bay in the Beaufort Sea and along the boundary between the northeast and northwest NPR-A planning areas, and extending to the southwest.

Thirty-one of the 65 leases in this block received multiple bids, the only tracts in the sale that did, so the pattern of lease holdings does not necessarily reflect the plans of the companies bidding at the sale. Most of the leases drawing multiple bids are in the center and on the eastern edge of this large block.

All of the Fortuna leases are in this block: those 22 leases include a band near the top of this lease block and leases trending down to the southern edge of the block. Petro-Canada took 18 leases in this block, three on the eastern edge, eight running through the middle of the block and the remainder on the western edge.

The eight tracts ConocoPhillips bid on by itself are in the upper half of this block. Five of the ConocoPhillips-Anadarko-Pioneer tracts are in this block, one to the north, one to the east and three on the southern edge. Twelve of the ConocoPhillips-Pioneer tracts are on the northern and southern edges of the block.

see **LEASE SALE** *page 13*

BLM legal battle the first hurdle

As for future plans in the NPR-A northwest planning area, the first hurdle is a suit filed by environmental groups.

"As everyone here is probably aware, a consortium of environmental groups sought preliminary injunction against all lease sales associated with the northwest National Petroleum Reserve-Alaska EIS," Henri Bisson, BLM Alaska state director said before bids were opened June 2 at the agency's northwest NPR-A sale.

"Last Friday, after hearing oral arguments on Thursday, May 27th, the court ruled that the BLM could proceed with today's scheduled lease sale in the northwest planning area of the petroleum reserve, but cannot permit surface disturbing activities prior to the final determination on the merits of this case," he said.

The litigation was filed by the Northern Alaska Environmental Center, National Audubon Society, the Wilderness Society, Natural Resources Defense Council, Sierra Club, Alaska Wilderness League and Center for Biological Diversity.

The plaintiffs have challenged BLM's final integrated activity plan/environmental impact statement, arguing that the agency did not give a "hard look" to each possible lease in its environmental impact statement. U.S. District Court Judge James Singleton ruled that the Department of the Interior must notify

see **LEGAL** *page 13*

PANALPINA
on 6 continents
Integrated Solutions For Supply Chain Management
Domestic and International Freight Forwarding
Air • Ocean • Ground
Prudhoe Bay • Sakhalin Island • Alberta • Gulf • Texas
West Africa • North Sea • Middle East • Caspian Sea
4305 W International Airport Rd
Anchorage, AK 99502
Anchorage: 907.245.8008 Calgary: 403.291.1137
Houston: 281.446.0600

www.panalpina.com


Serving the Alaska Petroleum Industry Since 1982
Phone: (907) 745-6988
Email: gne@mtaonline.net
Web: www.GreatNorthernEngineering.com
GREAT NORTHERN ENGINEERING

continued from page 12

LEASE SALE

What do the companies see?

The multiple bids made it evident that several companies see opportunities in the same area.

Anchorage geologist David Hite said after the sale that the companies are probably looking for stratigraphic, not structural plays. Stratigraphic plays, like the Alpine trend, are associated with "ancient shorelines," he said. Looking at the big block of leases he noted it was "running sort of northeast-southeast, so I suspect that they're looking at paleo shorelines…"

As for earlier drilling in the area, Hite said the Brontosaurus well, which is in the sale area southwest of Barrow, is a case of companies probably looking for structural features when it was drilled, and now going back to revisit the area as ideas have changed.

Brontosaurus (see map) appears to be adjacent to tracts taken by ConocoPhillips-Anadarko-Pioneer southwest of Barrow. The well was drilled to a measured depth of 6,660 feet and a true vertical depth of 6,635 feet in section 18 township 18 north range 20 west, Umiat Meridian. It was plugged and abandoned in February 1985. ConocoPhillips Alaska is the successor to ARCO Alaska, the Brontosaurus operator.

Ken Boyd, a geophysicist and former director of the Alaska Division of Oil and Gas, said he thought the companies were probably looking for an Alpine-type trend in the northern part of the sale area, and noted that ConocoPhillips Alaska drilled the Puviaq well on the western edge of the northeast NPR-A planning area. That well, which ConocoPhillips' Garrard said is a "very tight hole," on which the company has not released any information, was drilled on a tract in the northeast planning area adjacent to tract D-20, acquired by the ConocoPhillips-Anadarko-Pioneer partnership for $251,600. The tract also received a $240,835 bid from Petro-Canada.

As for the Brontosaurus well, Boyd noted that "they were chasing something else 20 years ago."

Garrard said Brontosaurus is the "only industry well ever drilled" in this area, although the government, first the U.S. Navy in the 1940s and 1950s and then the U.S. Geological Survey in the 1970s and 1980s, drilled in the area. The Navy discovered the Barrow gas field and USGS discovered the Walakpa gas field, he said. "But largely, both of those campaigns were unsuccessful in terms of finding commercial volumes of hydrocarbons."

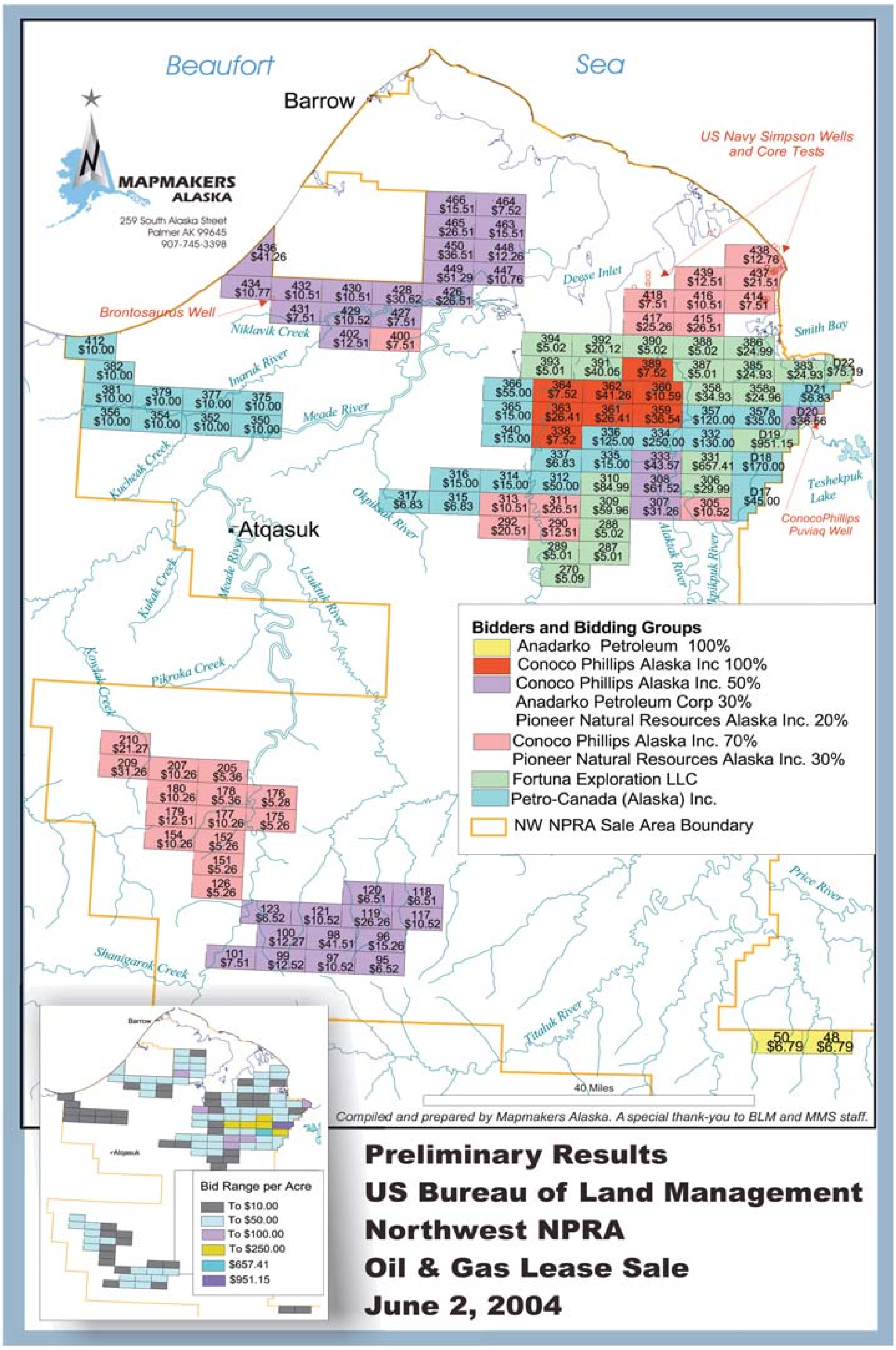
Distance will be a challenge

As for plans for the area, ConocoPhillips' Garrard said work in such a remote area requires a lot of planning — and regulatory and permitting work. He should know, as ConocoPhillips is the only company to have drilled even close to this area in recent years.

Predecessor ARCO drilled the Brontosaurus well, and ConocoPhillips drilled the Puviaq well at the far western edge of northeast NPR-A leases. "Drilling the Puviaq well was a two-year process," he said. The rig was staged on an insulated ice pad, where it over-summered, and the well was drilled the following season.

And before ConocoPhillips was allowed to drill, BLM did an environmental assessment of the project.

Bisson said after the sale that the "area is far from the infrastructure developing along the eastern border of the reserve" and the agency is "gratified to see industry's vote of confidence and willingness to invest in the future." ●



continued from page 12

LEGAL

prospective lessees of the pending litigation, because rights under such leases are contingent on resolution of the litigation, "and that no right to drill or build roads on any lease will be permitted until the termination of this litigation."

Surface occupancy of leases will not be allowed until the litigation is settled, so BLM will not be allowed to accept applications for permits to drill, geological permits to conduct seismic activities, right of way permits, etc., the judge said.

Bisson said after the sale that the agency would now "do what we have to do to defend the sale, and see where we go from there."

If the judge makes a decision this fall, he said, then BLM will be able "with some certainty" to make decisions about next year.

WSI
Industrial Safety Division
WELL SAFE
Expediting
OSHA Training
Breathing Air Systems
Gas Detection Systems
Remote Medical Support
H2S & Safety Consultants
Confined Space Rescue Teams
ph: 907 743-9871 fax: 907 743-9872
www.wellsafe.com
We're all about your safety.

CALIFORNIA

Attorney general seeking buyer for Bakersfield oil refinery

California Attorney General Bill Lockyer has hired an oil industry consultant to help find a buyer for Shell Oil Co.'s Bakersfield refinery, a spokesman for Lockyer said.

"Shell has said the refinery is not a marketable commodity. We're going to find out if that's true," Lockyer spokesman Tom Dresslar said. "The ultimate objective is to try to find a viable buyer."

Experts believe closing the refinery would force the state's already record gas prices even higher. Shell has said it would close the plant in October.

Although the facility is among the state's smallest and makes only 2 percent of California's gas and 6 percent of its diesel, economists believe the effect of its closure on gas prices could stretch as far as Washington, Arizona and Nevada.

In response to what he believes is a halfhearted attempt to sell the facility, Lockyer May 26 hired Dallas-based consulting firm Turner Mason & Co. to "locate a buyer with the financial capability, who will increase production of refined products and implement the clean-products technologies while increasing gasoline output to the California market," according to the state's contract with the firm.

Lockyer will pay consultant Malcolm Turner as much as $35,000 through the end of July for the services.

If it is determined that the plant can be sold, the firm will work to find a buyer, Dresslar said.

"We welcome Malcolm Turner as we would any other inquiring party, and we would provide him with information once he signs a confidentiality agreement," said Shell spokesman Stan Mays.

The company has 21 inquiries in various stages but has not received any "credible offers" for the refinery, Mays said.

—THE ASSOCIATED PRESS

ALASKA

Trans-Alaska pipeline workers to be polled on satisfaction

The federal and state agencies that oversee the trans-Alaska oil pipeline will survey workers to find out if they still fear reprisals against whistle-blowers.

The Joint-Pipeline Office will send out questionnaires to Alyeska Pipeline Service Co. employees and contractors starting June 1, said Rhea DoBosh, a JPO spokeswoman.

"We definitely want to see if there has been any improvements or changes since the last survey," DoBosh said.

see POLL page 18

● COOK INLET, ALASKA

COURTESY OF ENSTAR

Horizontal directional drilling at the middle channel crossing of the Big Susitna River

Enstar installs longest horizontal directional drilled pipe in Alaska

Work done last winter on west side of Cook Inlet to replace portion of 20-inch transmission line in danger of being washed out

By KRISTEN NELSON

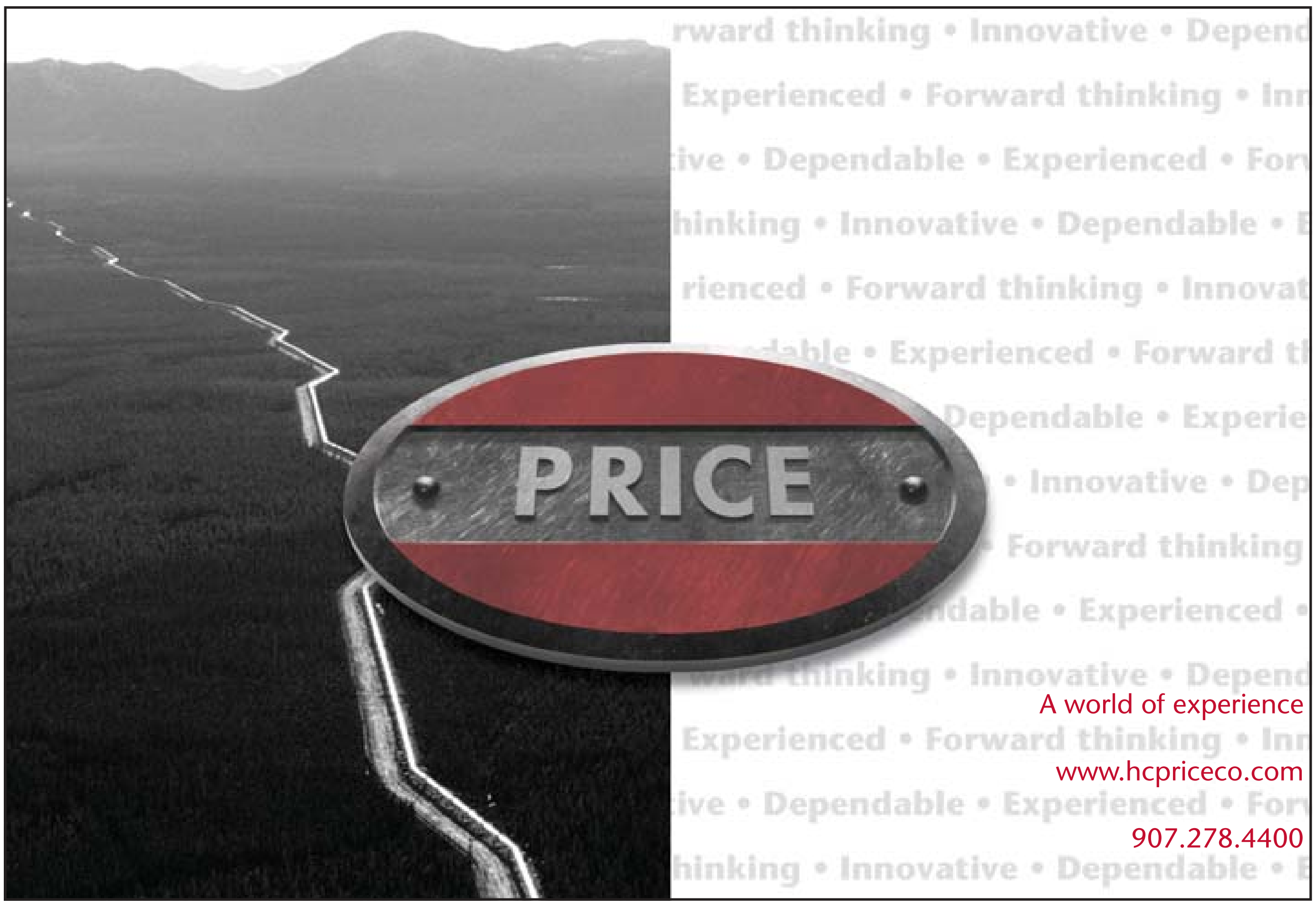
Petroleum News Editor-in-Chief

In 1991, Enstar Natural Gas Co. did the first horizontal directional drilling in Alaska when it replaced a section of its Beluga pipeline under the middle channel of the Susitna River on the west side of Cook Inlet. Enstar, a subsidiary of Semco Energy, is the natural gas transmission company for Southcentral Alaska. Its Beluga line brings gas from the west side of Cook Inlet to Anchorage, primarily from the Beluga gas field but also from the Steelhead platform and smaller fields along the way.

Last winter, Enstar did the longest horizontal directional drill in the state to date when — after the river shifted again — the company relocated the crossing 2,000 feet to the north, with a 4,305-foot horizontal directional drill under the middle channel.

Horizontal directional drilling was also done when

see ENSTAR page 15



Kaktovik Hotel For Sale or Lease

Built in 2001, in the middle of **ANWR**, 3500 sq ft +/- **Gift Shop, Restaurant & Office**, heated garage, six rooms/14 beds, cable, phones. Potential uses: offices for ANWR oilfield services, man camp, hunting lodge, tourism. Below cost $450,000. For marketing package contact:

Shawn Evans
Alaska Commercial Properties
907-456-6008 Phone
907-388-8585 Cell
907-456-6474 Fax
shawn@realtyalaska.com

COURTESY OF ENSTAR

Fly-cutter reamer used to enlarge hole for natural gas transmission pipe

COURTESY OF ENSTAR

Sections of 20-inch natural gas transmission pipe have been welded together and are being pulled through the drilled and reamed hole

continued from page 14

ENSTAR

ARCO Alaska (now ConocoPhillips Alaska) installed the Alpine pipeline under the Colville River on the North Slope, a distance of 4,279 feet, and more recently as part of the Kenai Kachemak Pipeline installation on the Kenai Peninsula. It requires a special drilling rig that sits at an angle to the ground, allowing it to drill shallow horizontal holes.

John Lau, Enstar's director of transmission operations, told Petroleum News the company had to wait for a real winter in the Cook Inlet area of Southcentral Alaska. It didn't get cold enough in the winter of 2002-03 to build the ice road necessary to reach the work site. But, he said, as soon as weather projections for 2003-04 indicated cold weather, pipe was ordered and preparations begun.

That included bringing in 10,000 feet of coated 20-inch pipe and the horizontal directional drilling rig needed for the job.

Hole drilled, expanded, pipe pulled through

The horizontal directional drilling was done to get the pipe, which carries about two-thirds of the natural gas coming into Anchorage, 60 feet under the middle channel of the Big Su — far enough beneath the bed of the river that it wouldn't be washed out as the channel changes.

Lau said in the worst case this crossing should last 50 years: "But the best case is, it'll last forever," depending on what the river does.

The pictures illustrate part of the procedure: The horizontal directional drill was used to create an initial hole from one side of the channel to the other; then the hole was reamed out to 30 inches so that the 20-inch transmission pipe could be pulled through; the 20-inch pipe was welded together and pulled through; that pipe was then welded to conventionally laid pipe and the whole new section of pipe welded into the existing line.

Ice road, ice bridges required

The work had to be done in the winter because the site is in the Susitna Flats State Game Refuge, and could only be done when the ground is frozen, Enstar engineer Steve Cooper, the project manager, told Petroleum News.

Cooper said the work started the second week of January with the ice road construction. Fifteen miles of ice road had to be built from the end of the road system off of Knik Goose Bay Road, as well as five ice bridges across the Little Susitna River, Fish Creek, a tributary of Fish Creek and the east and middle channels of the Susitna River.

COURTESY OF ENSTAR

Pipe exiting after being pulled through horizontal directional drilled crossing under channel

By the end of January, Cooper said, the ice on the river channels was five feet thick, adequate for the heaviest equipment.

They started stringing pipe at the end of February, beginning of March.

The horizontal directional drilling portion of the project began Feb. 21 and pulling the 20-inch pipe through was completed March 26. Before the 4,300-foot section was pulled it was welded, x-rayed and hydro-tested.

Twelve-hour window to connect

When the new section of pipe was connected, Enstar had to shut down approximately 40 miles of pipeline between two block valves. And the window to accomplish that work was 12 hours.

"In that 12-hour window," Cooper said, "the gas supplies from the Beluga field had to be shut down. The pipeline was shut in and blown down between the block valves, we had to do the cutover, pig the line and pressure it back up." In that 12-hour window, supply for Anchorage came in on Enstar's two 12-inch lines from the Kenai Peninsula. "It took cooperation between all the producers to get gas swapped over," he said.

The tie-in was completed on April 4, and equipment was moved out of the site by April 7, just as the weather was warming up and the ice road was melting.

Project cost right at $5 million

In addition to having to wait for a winter cold enough for ice roads, the $5 million project also faced sea challenges: 54 joints of pipe were washed overboard in the Gulf of Alaska on the way to Whittier and 46 additional joints were damaged, so Enstar had to find about 5,400 feet of replacement pipe and get that coated and barged to Alaska.

Lau said an advantage of the standard pipe Enstar uses is that it was able to replace the lost and damaged pipe in time to meet project schedules.

And as for the weather, Lau said "it never froze up out there winter before last." This winter, however, there were "some long cold snaps and a warmer week here and there — but it didn't stop us." ●

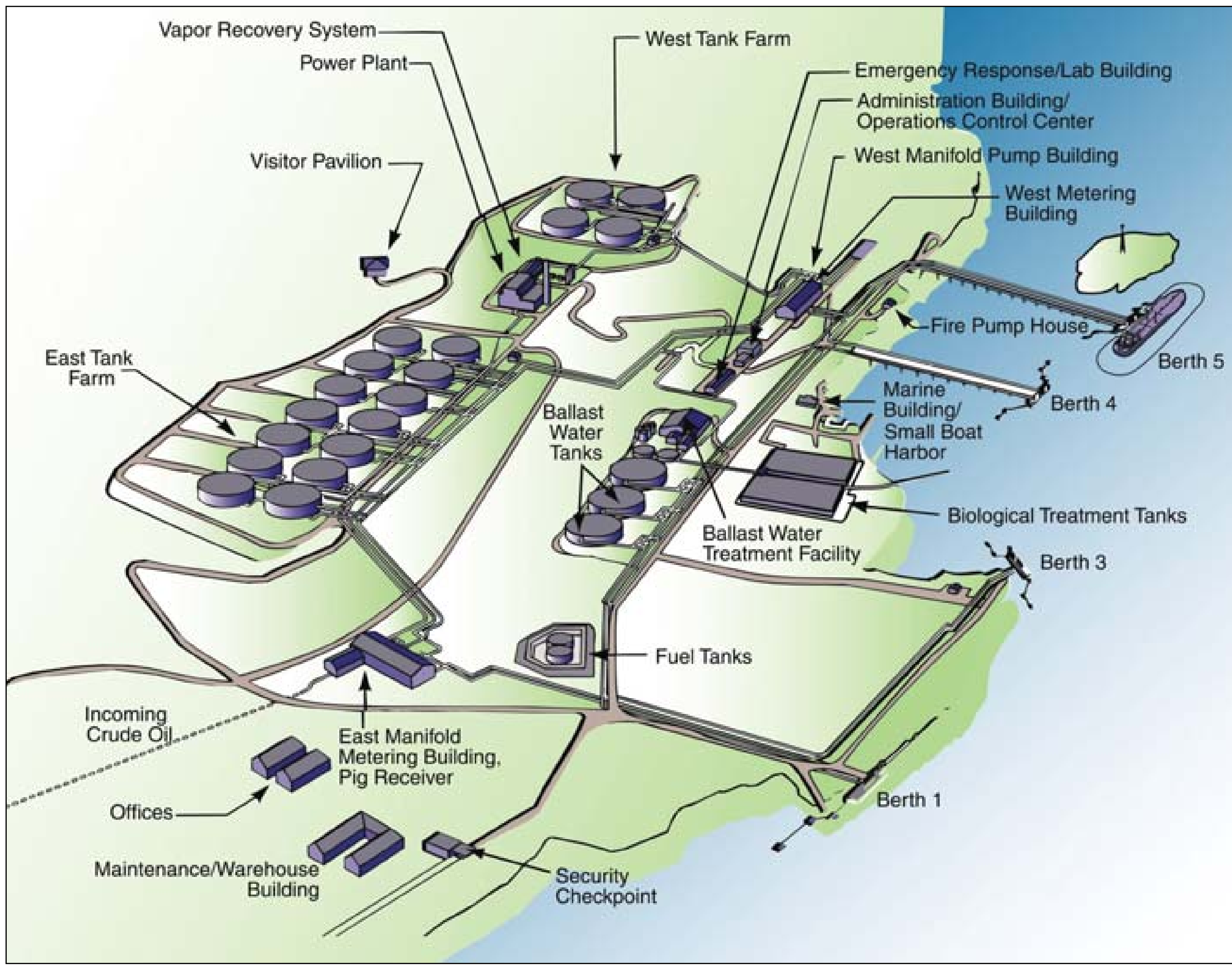
● VALDEZ, ALASKA

Right sizing for Valdez Marine Terminal

Tank work could start early next year, with tank and power/vapor and firewater work to be completed by 2007; metering and changes to ballast water treatment would be done later

By KRISTEN NELSON

Petroleum News Editor-in-Chief



COURTESY ALYESKA PIPELINE SERVICE CO.

Owners of the trans-Alaska pipeline system have authorized Alyeska Pipeline Service Co. to proceed with preliminary engineering for reconfiguration of the Valdez Marine Terminal, a step which will provide firmer project schedules and costs, necessary before the owners give final approval for the work.

1 2 SERIES

Goals of the reconfiguration are to downsize the terminal to better fit current and expected throughputs of crude oil — about half of what the terminal handled at its peak in the 1980s — reducing transportation costs for Alaska North Slope crude oil, and making it more competitive with crude worldwide.

Rod Hanson, Alyeska's Valdez Marine Terminal manager

In the preliminary engineering phase Alyeska is looking at costs and scheduling for two types of projects identified in the conceptual engineering phase, interrelated changes and standalone projects at the terminal.

The related projects include: a reduction in the amount of tankage in service and addition of internal floating lids to the remaining tanks; handling tanker vapors with vapor combustors; and replacing the existing electric generating system with either new diesel-fired generators or electricity purchased from Copper Valley with backup diesel power generation at the terminal (see part 1 of this story in the May 30 issue of Petroleum News).

More work before sanctioning

In a May 24 interview, Alyeska managers told Petroleum News that work at the terminal hasn't been authorized yet.

John Barrett, Alyeska's strategic reconfiguration program manager, said the conceptual engineering work at the terminal generated "a set of ideas that hold a lot of promise, but they have not been validated yet.

"Preliminary engineering goes to a higher level of detail, where you more accurately determine the cost and the savings to determine if the project really is viable, and if it is, then it's sanctioned to go forward and that's when larger amounts of money are spent."

Both costs and scheduling will be looked at in much greater detail over the course of this year.

Chuck Strub, Alyeska special projects manager in charge of the terminal changes

"We have to get to a point where we see that this has an economic return, and we're not there yet," said Chuck Strub, Alyeska special projects manager in charge of the terminal changes.

Rod Hanson, Alyeska's Valdez Marine Terminal manager, said the changes in the tanks, vapor control and power generation are the biggest piece of work being looked at in the preliminary engineering: "Those all have to happen together or it doesn't make sense, so that all has to stand on its own from a business case."

Detailing the costs and schedule for the tank and power/vapor work is the first step in the preliminary engineering, said Strub. Preliminary engineering for the tank, vapor control and power generation "requires us to go through and do the tank work, the internal floating roofs," he said, along with the vapor combustors for the tanker vapors, and providing power resources for the facilities.

The changes in the tanks, vapor control and power generation are the biggest piece of work being looked at in the preliminary engineering: "Those all have to happen together or it doesn't make sense, so that all has to stand on its own from a business case."
—Rod Hanson, Alyeska's Valdez Marine Terminal manager

"And to do that we have to understand all of the cost elements involved in this and then how we'll pay back for the investment as reduced operations and maintenance costs over time," Strub said.

Goal is completion around 2007

The goal, said Strub — subject to approval of the project at the end of this year — is to complete the tanks and power/vapor portions of the project in 2007. (See part 1 of story for interrelationship of tanks and power/vapor work.)

The retrofit for the internal floating roofs will take the longest, he said. "We calculate we can only do about five tanks a year because of the amount of effort required inside each of the tanks" and because only that many tanks could be taken out of service at one time.

That time estimate came out of the conceptual study, he said, and "now we have to go back in and first of all validate whether we can achieve that schedule and how much it will cost."

That work will be the major focus through the end of this year: developing

see SIZING page 17

NATCO CANADA
An ISO 9000 Company
NATCO GROUP
The Leader in Process Equipment, Solutions & Technical Service
* Separation * Gas & Oil Processing Systems * Oily Water Treatment
Porta-Test Revolution, Amine Gas Sweetening, Gas and Oil Dehydration, Process Heaters, Hydrocyclones, Tridair Induced Gas Floatation
Calgary, Alberta Phone: (403) 236-1850 Fax: (403) 236-0488
Visit our web site at www.natco.ab.ca
e-mail: sales@natco.ab.ca

Kenworth Alaska
SERVING ALASKA FOR OVER 25 YEARS
YOUR OILFIELD VEHICLE SUPPORT
For higher profits you need productivity. That's where Kenworth performs the best. The trucks work hard and owners appreciate the durable, comfortable cabs. It's said that when you "think success" you succeed.
We say "think Kenworth."
Anchorage
2838 Porcupine Drive
Anchorage, AK 99501
AK Toll-Free: 800-478-0602
Phone: 907-279-0602
Fax: 907-258-6639
Hours:
Mon. - Fri.: 7:00 a.m. - Midnight
Saturday: 8:00 a.m. - 4:30 p.m.

Fairbanks
3730 Braddock Street
Fairbanks, AK 99701
Phone: 907-455-9900
Fax: 907-479-8295
Hours:
Mon. - Fri.: 7:00 a.m. - 6:00 p.m.
Saturday: 9:00 a.m. - 1:00 p.m.
Email: Parts • parts@kenworthalaska.com
Email: New/Used Truck Sales • sales@kenworthalaska.com

continued from page 16

SIZING

the cost and schedule so economic models can be run to determine if the changes would be economic. That analysis would be presented to the owners at the end of this year or early in the first quarter of 2005.

Installing the internal floating lids will take at least a couple of years of construction work, Hanson said.

Strub said the work inside the tanks is "the critical path for this project: It's the single activity that has the longest duration," and so the plan is to start that work first.

In fact, Strub said, they'll request funding in August for the first two tanks, for work to begin in January. That allows lead time for materials and contractors, so that — subject to overall project approval at the first of the year — work can begin on the first two tanks, which will be emptied for regularly scheduled maintenance. On that schedule, major work would be completed in 2007.

John Barrett, Alyeska program manager strategic reconfiguration

Work done inside the tank

Installation of a floating lid requires that a hole be cut in the side of the tank, Strub said. First the tanks are emptied and cleaned, and any needed internal repairs are done to the tank.

There are columns inside the tank, supporting the external roof. The internal floating roof is constructed inside the tank, around the columns and sits on landing legs.

"It floats on the surface of the oil," Hanson said, but has legs so it "can only come down to within about six or seven feet" of the floor of the tank because there is equipment in the bottom of the tank.

"And then that allows you later to drain a tank and let it sit on its legs and then you can get access in to do inspection and repair work, to do maintenance work," he said.

Firewater system would be changed to freshwater

Preliminary engineering will also look at the largest of the standalone projects: changing the terminal's firewater system, currently a pump-driven seawater system, to a freshwater gravity system.

The seawater system accounts for "a huge amount of cost" at the terminal, Hanson said, more than $30 million in just the last five or six years, "a lot of it driven by the corrosiveness of saltwater." The system uses a number of main pumps, plus smaller pumps, to move seawater around the terminal in a buried loop.

There is a rock quarry above the west tank farm, from terminal construction days, and Alyeska has done some geotechnical analysis and some engineering work and is proposing to create a freshwater retention basin in the old quarry: "a gravity freshwater supply system for our firewater system … sized for three times the amount of firewater we would need," Hanson said.

The first advantage, he said, is that it's no longer saltwater. And because it's gravity driven you don't have to rely on pumps, so it's "even more reliable than the current system. And it pulls a lot of maintenance costs out of the system."

The bottom of the reservoir in the proposed firewater retention pond is at an elevation of 700 feet, Strub said, compared to an elevation of 421 feet at the bottom of the highest tank in the east tank farm.

Hanson said they've been asked if the gravity firewater system would provide enough pressure. Because of the elevation change there would be "so much pressure that we're going to have to put pressure-reducing components in to avoid over pressuring the lower terminal," he said. While this project is separate from the tank and power/vapor changes, it would likely be implemented around the same time, Hanson said.

This project is for onshore firewater only. There are saltwater firewater pumps on the berths in use, berth 4 and berth 5, the only two berths in use at the terminal, "and we haven't yet decided what the right answer is out there," he said.

Ballast water changes have own justifications

Alyeska is also looking at changes to the ballast water system, Hanson said, but that proposal isn't as far along as the tank, power/vapor and firewater changes, and would be done later.

The ballast water plant "is currently running at about 33 percent capacity," he said. The volume of ballast water processed will continue to decline, Hanson said, and in the next five or six years, the current volume of water processed will be cut in half.

Older tankers carry ballast water in their crude oil tanks, so their ballast water "has remnants of oil from the last cargo load," he said. When the tankers arrive at the terminal, they pump the ballast water through buried piping to three ballast water treatment tanks — the first of three steps in ballast water treatment. The oily water sits in the tanks, the oil rises to the top and is skimmed off and reinjected into the crude oil system.

"The water is pulled off the bottom and runs through the second state of treatment … dissolved air flotation," Hanson said. Air is injected into the water column, creating bubbles which are mixed with a polymer and rise to the surface, taking more oil out of the water and bringing it to the surface where it can be skimmed off. The water is then routed to biological treatment tanks where microbes eat the remaining components of oil in the water.

The entire process takes a couple of days, and at the end the water is discharged into the port.

New tankers have segregated ballast tanks

The new double hulled tankers, however, have segregated ballast tanks, so the water doesn't come into contact with crude oil, and doesn't require treatment, and as more come into service, the amount of ballast water needing treatment will continue to decline.

At some point, Hanson said, there is just a little ballast water which is coming in batches, and "this system is really not designed to operate that way. It's designed to operate more in a steady-state mode."

Of particular concern, he said, is the final biological stage, which may not be a viable process for batches.

The conceptual thinking is that the first stage, gravity separation, would remain, although probably with two tanks rather than three.

The second stage — dissolved air floatation — could be replaced with induced gas floatation, which works on about the same principle, forcing gas through the water instead of air, again with a polymer that brings oil to the surface.

The induced gas floatation system is enclosed in a vessel and any emissions are contained within the system.

Hanson said it is a simpler process technologically, less costly to operate and is more environmentally friendly.

"We're actually doing some pilot work right now to prove out whether that technology is going to work for us or not," he said.

Alyeska is looking at replacing the third stage, the biological process, with carbon absorption, but Hanson said that change is far enough out in the future that the company is waiting to see what new technologies might be developed over the next several years.

Metering changes could happen by 2008

Another standalone project is changing crude oil metering. Oil is metered when it enters the terminal at the east metering facility. Metering performs an important leak detection function, Hanson said, because a variation between oil received between metering stations indicates a possible leak.

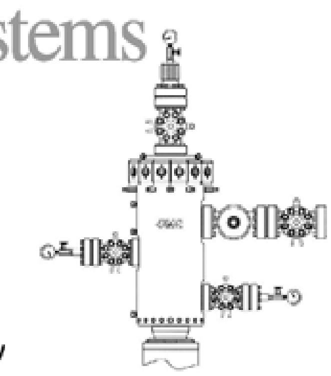
Another metering facility contains separate meters for oil going to berth 4 and berth 5. Keeping track of all of the oil is an important part of the terminal's business, Hanson said: "It's kind of the cash register side of the business," so maintaining the metering system is "a pretty critical part of what we do."

The current meter systems are in-line turbine meters, with the turbines spun by the oil as it passes, and "that spinning turbine basically tells you … for each spin, how much oil goes by." It's very high maintenance, he said.

There is a new technology that uses "ultrasound, not moving parts, to measure the flow of oil," and Hanson said that while this technology is still a few years down the road, it could be in use at the terminal by 2008. The ultrasonic meters would be placed directly on the crude

see **SIZING** *page 17*

FMC EnergySystems



FMC Surface Wellhead

Adding Value Through:

- Field-proven Technology
- Technical Excellence
- Design for Product Life-cycle
- Engineering Expertise
- Superior Technical Service and Support
- Innovative Leader in Wellhead Technology

FMC Energy Systems • 700 W. Int'l Airport Rd., Anchorage, AK 99518
www.fmc.com • Phone: (907)563-3990 • Fax: (907)563-5810

PERFORMANCE UNDER PRESSURE

American Marine Services Group

6000 A Street, Anchorage, AK 99518

907-562-5420

www.amsghq.com • alaska@amarinecorp.com

AMERICAN MARINE CORPORATION

- Commercial Diving
- Marine Construction Services
- Platform Installation, Maintenance and Repair
- Pipeline Installation, Maintenance and Repair
- Underwater Certified Welding
- NDT Services
- Salvage Operations
- Vessel Support and Operations

PENCO PACIFIC ENVIRONMENTAL CORPORATION

- Oil-Spill Response, Containment and Clean-Up
- Hazardous Wastes and Contaminated Site Clean-Up and Remediation
- Asbestos and Lead Abatement
- Petroleum Vessel Services, e.g. Fuel Transfer
- Bulk Fuel Oil Facility and Storage Tank Maintenance, Management, and Operations

Anchorage Honolulu Los Angeles

F.S. Air Service, Inc. ALASKA

Charter/Contract
HAZMAT
Cargo
Passenger

24 hours a day / 365 days a year
Toll Free: 800 478-9595
Local: 907 248-9595
Email: dispatch@fsair.com
Web Site: www.fsair.com
6121 South Airpark Place • Anchorage, Alaska 99502

D.O.D. APPROVED

continued from page 14

POLL

JPO's last surveyed pipeline workers in 2000, finding that employees believed that Alyeska's top management retaliated against whistle-blowers. The office also found that concerns were never fully resolved once they were brought up.

The upcoming survey was ordered by federal regulators when they issued a renewal of Alyeska's right of way permits for the 800-mile trans-Alaska pipeline in 2002.

"We view it as a measuring stick," DoBosh said.

Employees complained to Congress in 1991

JPO took a stronger interest in Alyeska employee concerns in 1991 after a group of pipeline employees took complaints to Congress about worries over safety and environmental issues relating to pipeline operations.

The employees said Alyeska's management harassed, intimidated and retaliated against employees who brought up those types of issues, and Congressional hearings were held.

In response, JPO established a toll-free hot line for anyone to report concerns directly to the consortium. In 1993, the Bureau of Land Management hired a third-party contractor to investigate the allegations raised during the congressional hearings.

That probe confirmed widespread operational problems and claims of employee harassment.

As result, Alyeska established an employee concern program in 1996 and hired an independent firm to conduct several employee surveys.

The surveys also documented employee dissatisfaction, distrust and fears about retaliation for reporting problems.

The JPO has conducted more surveys, finding improvement over the long-term in some areas.

> *The upcoming survey was ordered by federal regulators when they issued a renewal of Alyeska's right of way permits for the 800-mile trans-Alaska pipeline in 2002. "We view it as a measuring stick."*
> **—Rhea DoBosh, Joint Pipeline Office spokeswoman**

Last survey conducted in 2000

JPO's last survey, conducted in 2000, resulted in three recommendations. First, Alyeska should see if claims of harassment from Alyeska's top management were true. If so, Alyeska must take steps to eliminate the harassment. Second, Alyeska should make sure its contractors, which employ 68 percent of the pipeline work force, comply with established employee concerns programs. Third, Alyeska should make sure employees' concerns are fully addressed and recommended the company formalize a procedure on how to do so.

Alyeska took the recommendations seriously and has worked on the issues since then, DoBosh said.

Curtis Thomas, Alyeska's spokesman, said the company doesn't wait until survey results are revealed to find out what their workers feel about their work environment.

"Managers and supervisors are continuously receiving training designed to keep them in tune with employee concerns. That will continue," Thomas said.

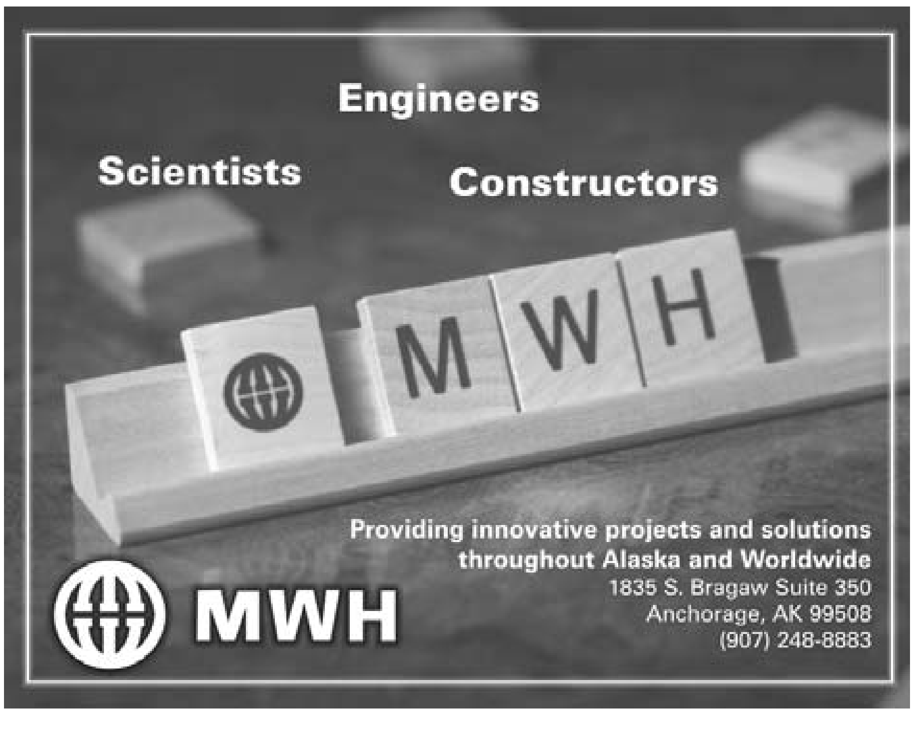
Thomas said some employees will likely voice concerns about upcoming layoffs as the result of the company streamlining operations by upgrading equipment and converting to electrical energy to power some pump stations along the 800-mile pipeline.

—THE ASSOCIATED PRESS

Klondike Hotel
Construction Crews Welcome

- 1, 2, 3, 4 bedrooms available
- Bar and restaurant
- Ample parking lot for heavy equipment

907-479-6211
907-479-6241
Cell: 907-388-8585
1316 Bedrock St.
Fairbanks, AK 99709



continued from page 17

SIZING

lines. The metering facility to the berths wouldn't be needed, and operations and maintenance work associated with metering would no longer be needed.

"The same thing with the incoming meter system here that we use for leak detection — ultrasonics is a potential replacement for that," he said.

Company will rethink how it operates

All of the proposed changes, Hanson said, give the company "an opportunity to rethink how we operate, how we maintain, how we staff the organization for this." The terminal has operations, maintenance and support teams.

Operations are divided into four major areas: power/vapor; marine; ballast water; oil movements and storage — metering, tank farms, etc. "In the future, with what we're describing here, we'll probably just have a single operations team that will have a different set of responsibilities from what we currently have laid out."

> *"We have to get to a point where we see that this has an economic return, and we're not there yet."*
> **—Chuck Strub, Alyeska special projects manager in charge of the terminal changes**

"It will still likely be a 24-hour a day, seven-day-a-week operation," Hanson said. Maintenance now works just during the day, and there will continue to be a maintenance team, "but as you can imagine the amount of maintenance that we're having to do in the future is going to be a lot less than what we do now."

And Alyeska is just starting to look at the ship escort response vessels system to see what change could be possible for changing that cost structure.

Headcount will be affected

There are now 300-plus Alyeska employees at the terminal and the ship escort response vessels system and an equal number of contractor employees, Hanson said, although the contractor count is a year around average, and there are more contractors in the summer when major projects and maintenance are done.

Hanson said that while it is too early yet to know the impact on employees, "we've committed to letting our employees know as soon as we have something to share, and then sharing it outside the company as well." He said Alyeska "made a decision early on that we will provide our employees as much opportunity to plan for their future as we can, and so as information is available we're sharing that with employees."

And, he said, the company is also trying to help employees understand that "there's a lot that's changing, but there's a lot that stays the same. In the end, we're still in the same business, we're still doing the same thing, we're still having the same level of high standards around safety and environmental performance that we have now."

There will be opportunity, he said, and "some kind of neat technology to do our jobs with in the future. …

"But it's going to be a smaller organization."

Organizational changes part of cost

Included in the commercial analysis are the costs of organizational transition, Strub said: You have "to run what you've got, build what's new, start up what's new and then, finally, ramp down what's old and continue to operate on what's new, and that all becomes part of the commercial cost of your investment."

"We've got basically three organizations in place, or being put in place," said Hanson: "Chuck (Strub) is responsible for the project management of these changes; I'm responsible for the day-to-day operations of the current facility and helping design the organization to maintain and operate the future Valdez terminal; there's another team that we're forming up, called a transition team, and this team is going to help us get from here to there."

Hanson said planning includes: training employees for the new systems; determining how to staff the organization; outlining benefits for those leaving the organizations; and making sure that documents in the future match the new equipment and that the old documents are retired. "It's a large piece of work that has to be done right," he said, and so one team will focus specifically on the transition.

"We put as much effort into planning the transition as we do planning the project — it's that big," said Barrett.

Spill preparedness

Hanson said that Alyeska has been asked if there will be enough employees left to respond in the event of an emergency.

The company is going to review the issue of the resources needed for spill response, so that it knows during the preliminary engineering phase, "how many people we need for emergency response."

As for overall changes, "at a minimum we're going to maintain safety and systems integrity, but in many respects I think we're going to improve." For example, he said, "power/vapor is one of our most complex facilities in the system" and the only facility Alyeska has governed by process safety management standards because it handles vapors, generates power and uses steam-fired turbines and boilers. "And that all presents risk and that basically goes away — it becomes a much simpler operation."

Operations control central also relocating

Although it isn't a part of the reconfiguration, Alyeska's operations control center will be relocating from Valdez to Anchorage in 2006, in the midst of the proposed reconfiguration changes. That move, announced in February, allows control center personnel to work more closely with the oil movements and scheduling departments, which are in Anchorage, Alyeska said in a February statement. ●

KUUKPIK
ARCTIC CATERING
KUUKPIK ARCTIC CATERING
5761 Silverado Way, Suite P
Anchorage, Alaska 99518
Phone (907) 562-5588
Fax (907) 562-5898
Remote Camps, Catering, Security, Medical & Maintenance Services

natural gas

MACKENZIE VALLEY

Mackenzie Gas Project to go before joint review panel

Canada's Indian and Northern Affairs Minister Andy Mitchell has opened the door for a joint review panel to conduct an environmental impact review of the C$4 billion Mackenzie Valley natural gas pipeline. He approved a request from the Mackenzie Valley Environmental Impact Review Board to enter into an agreement with federal Environment Minister David Anderson to set up the panel.

Next, the Canadian Environmental Assessment Agency and the Inuvialuit Game Council will settle on the draft terms of reference for the developer's environmental impact statement and the draft joint review panel agreement. The decision to order a panel review flowed from concerns raised at public meetings in Norman Wells, Inuvik and Fort Simpson along the proposed pipeline route in the Northwest Territories. The issues which attracted most concern were: Economic and infrastructure; social and cultural; and cumulative effects.

The environmental review board decided that the review should include all facilities and activities in the three anchor gas fields on the Mackenzie Delta and a central gas processing plant.

It should also cover a 1.9 billion cubic foot per day pipeline and the extension of the Alberta transmission system to link up with the Mackenzie pipeline.

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

RUSSIA

Petro-Canada dabbling in LNG field, looking at plant in Russia

Petro-Canada is going top shelf as its starts to explore the liquefied natural gas supermarket. The Calgary-based integrated has cozied up to gas giant Gazprom as it explores the possibility of a C$1.8 billion LNG plant in Russia — the first foray by a Canadian E&P company into the LNG world, although pipeline companies TransCanada PipeLines and Enbridge are actively seeking a deal.

Russian news reports say Petro-Canada is weighing an LNG plant at St. Petersburg that is capable of handling 3 million to 5 million tons a year of gas from Gazprom's Siberian fields.

Both Petro-Canada and Gazprom, which controls 25 percent of the world's gas reserves, have indicated they are engaged in tentative discussions, although Petro-Canada refuses to characterize the talks as being at the stage of a full proposal. A spokeswoman for Petro-Canada, reacting to a disclosure by Gazprom deputy chief executive officer Alexander Ryazanov, told the Calgary Herald May 26 that the conversations are "very early days ... to say there is a proposal on the table would be stronger words than we would use."

However, she conceded that Petro-Canada is attracted to Gazprom because of its size and scope and its array of assets.

Russian news reports say Petro-Canada is weighing an LNG plant at St. Petersburg that is capable of handling 3 million to 5 million tons a year of gas from Gazprom's Siberian fields.

An LNG venture would be consistent with Petro-Canada's global ambitions since its takeover of Germany's Veba Oil & Gas two years ago for C$3.2 billion which has opened up Europe, Africa, Asia and South America to a company that was once Canada's state-owned oil firm.

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

CANADA

Canada promotes natural gas for vehicle fleets, C$3 carrot

Canada's government wants fleet owners to switch to natural gas for their vehicles. And there's a carrot — well, better yet, 3,000 Canadian dollars toward the purchase price.

The idea is to reduce emissions of greenhouse gases. Natural gas power means a 21 percent cut in those gases.

The government says fleet owners will save on fuel costs as well as doing their bit for the environment.

The pilot project is targeted at urban areas in Ontario, Alberta and British Columbia.

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

● TEXAS GULF COAST

Texas LNG project moves ahead; first in U.S. since '82

FERC issues EIS for Freeport site; construction to start later this year

By LARRY PERSILY
Petroleum News Government Affairs Editor

The Federal Energy Regulatory Commission decision to issue a final environmental impact statement for the Freeport Development LNG L.P. project on the Texas Gulf coast is a boost to proponents of building new liquefied natural gas terminals to fulfill domestic energy needs.

FERC's May 28 announcement means developers on are target to start construction later this year and to start taking LNG deliveries during the second half of 2007, putting Freeport in a good position to be the first new LNG receiving terminal in the United States since 1982.

FERC staff concluded the project would have "limited adverse environmental impact," according to a press release from Cheniere Energy Inc., which holds a 30 percent interest in the Freeport venture.

The proposed 233-acre terminal, on Quintana Island in front of Freeport, a city of 13,000 residents about 40 miles south of Galveston, is planned for an initial daily send-out capacity of 1.5 billion cubic feet. Dow Chemical Co. and ConocoPhillips Co. have contracted for the full capacity.

Plans include storage facilities for 6.9 bcf, and a 9.4-mile pipeline to take the gas to Stratton Ridge, Texas, a major connection point for Texas intrastate pipes.

The impact statement is the last step in FERC's environmental review of the project, with a final order expected soon for construction and operation. Freeport Development filed its FERC application in March 2003.

ConocoPhillips, Dow take 100% of capacity

ConocoPhillips in December 2003 signed an agreement with Freeport Development to take on primary construction and operation management of the facility, and to contract for 1 bcf per day of the capacity. In exchange, ConocoPhillips agreed to provide construction funding, estimated at about $500 million, and paid Freeport LNG a "nonrefundable capacity reservation fee of $10 million," according to Cheniere Energy.

Also as part of the deal, ConocoPhillips is taking a 50 percent interest in the general managing partner Freeport LNG-GP Inc., which had been owned 100 percent by Michael Smith, a former president of Basin Exploration Inc., of Denver, Colo. Smith formed the Freeport venture in 2002 specifically to build the LNG terminal.

In addition to the managing partnership of ConocoPhillips and Smith, the Freeport project includes Cheniere Energy, of Houston, and Contango Oil and Gas as limited partners. Contango is a Houston-based independent Gulf

see **TEXAS LNG** *page 20*

● ALASKA

Alaska looks at gas liquids

Consultant advises state on NGLs from proposed North Slope gas project

By LARRY PERSILY
Petroleum News Government Affairs Editor

Making money from the ethane, propane and other natural gas liquids that come up with the methane in North Slope natural gas isn't as easy as simply building a gas pipeline and stripping out the liquids somewhere along the way.

A consultant advising the state of Alaska said the challenges include deciding where to strip the liquids from the gas stream; figuring out an affordable way to get the ethane and other liquids to manufacturers; and finding manufacturing capacity for turning the raw materials into plastics and other products — whether building, expanding or using existing plant capacity.

"The petrochemical industry is notorious for some pretty horrendous cycles," said Lesa Adair, a vice president at Muse Stancil, a worldwide energy industry consulting firm headquartered near Dallas. The Alaska Department of Revenue signed a $90,000 contract with Muse Stancil in March, and company officials presented an initial NGL briefing to state officials the last week of April.

The state wants to learn more about potential uses for the liquids produced from a North Slope natural gas project as it negotiates with producers and others interested in building a multibillion-dollar pipeline to move the gas to market. Muse Stancil's job is to analyze the economics of possibly creating a petrochemical industry in Alaska, including whether the liquids' volume would be sufficient to supply a new facility.

The analysis includes looking at a possible liquid-stripping plant in Fairbanks or elsewhere, grabbing the ethane and other liquids from the gas line as it takes the methane from the North Slope and into Canada for distribution across North America.

Consultant looks at Alaska economics

Muse Stancil's contract also calls for a review of the advantages and disadvantages of stripping the liquids in Alaska and finding a way to ship the products to markets vs. sending liquids-rich gas to Alberta for processing and then shipment through existing pipe and rail systems to customers.

"It's one of those balancing acts," Adair said, measuring the cost of new plants and/or new pipelines vs. using existing or expanded facilities.

Alberta has more natural gas liquids than it needs for its own petrochemical plants and exports a lot of Western Canada's liquids to U.S. and Eastern Canada plants, Adair said. Much of the liquid production from Canada ends up traveling a long distance to petrochemical plants in Texas. "That's where the bulk of the demand is," Adair said in an interview last month.

Ethane is used for petrochemical feedstock; propane for industrial, commercial and retail customers, crop-drying and other farm uses; and butane for gasoline blending, aerosols and fuels.

Depending on market conditions and Btu requirements for the end users of Alaska gas, a North Slope gas project supplying 4.5 billion cubic feet per day, as proposed by the major producers, could create NGL volumes of up to 100,000 barrels a day. That's

see **GAS LIQUIDS** *page 20*

continued from page 19

TEXAS LNG

Coast oil and gas exploration and production company.

For its part of the deal, Dow reserved 500 million cubic feet per day of capacity for 20 years. The chemical giant's facilities in the Gulf Coast region consume nearly 700 million cubic feet per day of natural gas. Dow will be able to market what it doesn't need from Freeport to other industrial consumers and gas distribution hubs in the area.

Neither Dow nor ConocoPhillips have announced any LNG supply deals for Freeport, though the oil and gas major has said it is looking at possibly bringing in gas from Venezuela, Nigeria or Qatar.

Cheniere also looking at two other LNG projects

Cheniere, looking to become a leader in the Gulf Coast LNG business, also is working to develop two other receiving terminals along the Gulf of Mexico coastline — at Corpus Christi, Texas, and Sabine Pass, La. The company submitted its FERC applications for both projects in December 2003.

The Corpus Christi terminal would be adjacent to the Sherwin Alumina Co. plant on 600 acres along the La Quinta Ship Channel. Sherwin Alumina, formerly the Reynolds Metals Co. Sherwin plant, extracts aluminum oxide from bauxite ore.

The Sabine Pass terminal is proposed for 570 acres along the Sabine Pass Channel in extreme southwest Louisiana, just across the border from Texas.

Each project would include storage for 10 bcf of gas, and capacity to handle as much as 2.6 bcf per day of LNG deliveries, with start-up of operations scheduled by 2008. Cheniere plans to operate both terminals as tolling facilities, and is looking to sign up users for long-term deals. ●

A rendering of the proposed Freeport, Texas, LNG plant.

continued from page 19

GAS LIQUIDS

about 5 percent of total U.S. demand.

"The natural gas liquid is not the consumable," Adair said. "It has to have many other things done to it."

Ethane, for example, is used to make ethylene, which then can be manufactured with other components to make a wide range of products, including polyethylene plastic for packaging, antifreeze and aircraft de-icer, vinyl siding and even garden hoses.

Review will consider possible Alaska incentives

Many Alaskans have long dreamed of a petrochemical industry in the state, creating jobs and diversification in the oil and gas industry that dominates the state's economy. The Department of Revenue contract with Muse Stancil pointedly addresses that very issue, asking the consultant to look at what kind of subsidies might be needed to make an Alaska petrochemical complex economic compared to the alternative of sending North Slope liquids to Alberta or elsewhere.

Perhaps the state's tax structure or pipeline tariff may need to include incentives or a separate rate to assist in bringing NGLs to market or developing an industry in Alaska, Muse Stancil said in its opening presentation to the state. That could include flexibility in valuing the products for royalty or tax purposes.

"They're really just some thought points," Adair said in an interview a few weeks after the presentation.

"This (report) does not attempt to advise on any course of action, but rather simply describes the industry into which Alaska gas and NGLs will compete," Muse Stancil said in its opening presentation.

Utilizing the liquids is a matter of deciding where they have the highest value. Taking out the liquids from the gas stream and breaking them apart — fractionation — into ethane, propane, butane and other components is not always so profitable.

That's a separate operation from the gas conditioning plant that would be needed on the North Slope to take out the carbon dioxide, hydrogen sulfide, water and other impurities from the gas before putting it into a pipeline.

Gas liquids business not always profitable

Depending on market conditions, the second step, taking out the gas liquids, is a tough business. A Muse Stancil chart of average net operating margins for NGL plants from 1990 through March 2004 shows U.S. Midcontinent and Gulf Coast plants operated at losses for five periods of several months each over the years — the longest lasting about a year in 1998-1999. The operating margin for Gulf Coast plants, excluding overhead, capital expenditures and return on capital, was under 20 cents per thousand feet of gas fed into the plant for all but two brief periods over the past 14 years.

"The sale of natural gas liquids is certainly not a slam dunk from a profitability standpoint," said Dave MacDowell, natural gas project spokesman for BP Exploration (Alaska) Inc. in Anchorage.

That's also what the numbers say in the annual reports of Canadian pipeline operator Enbridge Inc., which owns 42.7 percent of the Aux Sable Liquid Products plant in Illinois. Aux Sable strips the NGLs from the more than 1.5 bcf per day of wet gas delivered through the Alliance Pipeline from Western Canada. Enbridge's share of the loss from Aux Sable was $6.9 million in 2003, $3.1 million in 2002 and $6.2 million in 2001, according to Enbridge's annual reports.

Regardless of whether North Slope gas line project developers can turn a consistent, reasonable profit from the liquids, much of it has to be removed from Alaska gas somewhere before delivery to utilities and other customers. Otherwise, the gas would be too rich — too high of a Btu level — for customers, MacDowell said.

Much of the heavier liquids are already pulled from the gas during oil production from North Slope reservoirs and mixed in with the oil down the trans-Alaska oil pipeline, leaving a higher proportion of lighter ethane and propane for later recovery during a gas line project.

The biggest fractionation centers in North America, Muse Stancil explained, are in Sarnia, Ontario, just across the Michigan border and fed by a couple of large pipeline systems reaching from Western Canada, through the Midwest and into Ontario; Conway, Kan., served by multiple pipelines from north and south; and Edmonton, Alberta. The reference price point for North America NGL is at Mount Belvieu, Texas, in the center of the Gulf Coast petrochemical industry.

Propane to Midwest, ethane to Gulf Coast

NGL markets tend to be geographically isolated, Muse Stancil said, with a lot of the propane going to the Midwest for crop drying and other agricultural uses. Most of the ethane, however, is shipped by pipe or rail to the Gulf Coast to feed the petrochemical plants.

"There is no ethane market in Chicago, never has been," said Ed Small, a consultant and 30-year veteran of the natural gas industry in Calgary. Depending on market conditions, he said, much of the ethane can often earn more staying in the gas stream than paying its own way from Canada to the Gulf Coast for delivery to a plastics plant.

And though ethane usually sells for more than dry gas, a Muse Stancil chart presented to state officials shows ethane selling at close to natural gas or less in early 1996, 1997 and 1998, and pretty consistently the same or less since natural gas prices started their run-up in early 2001. And while that is good news for gas producers looking for the best price for their liquids, it's been very hard on U.S. petrochemical plants that need affordable feedstock. ●

Alaska gas could affect price, consultant says

Finding buyers for all the natural gas coming down the pipe from a large Alaska gas line project could require some initial price discounting, cutting into profitability in the early years, says a consultant helping to advise the state.

But the markets would anticipate the delivery of Alaska gas after a decision is made to build the line and would adjust to the new supply, said Lesa Adair, a vice president at Muse Stancil, a worldwide oil and gas consulting firm under contract to the state of Alaska.

"I agree there is going to be some impact on price," she said in an interview last month. "But it's not going to be a situation … (where) the next day it's going to be magically delivered in Chicago." The market will have a lot of advance notice to plan for Alaska gas.

"Everyone who is looking at liquefied natural gas projects or Alaska gas … will all be making decisions," she said.

Industry observers have said they expect any go-ahead announcement for an Alaska gas line would deter potential LNG developers from building more receiving terminals than the market will need in the years ahead when an Alaska line starts competing with perhaps 4.5 billion cubic feet per day of new supply.

The Alaska Department of Revenue has Muse Stancil on contract to advise state officials on natural gas and gas liquids issues as the state negotiates with the major North Slope producers and others for possible development of a multibillion-dollar pipeline project. Muse Stancil presented an initial briefing to state officials in late April.

Market penetration a matter of price

"Although overall (natural gas) demand growth is expected … penetration of desti-

see **CONSULTANT** *page 22*

● ALASKA

Natural gas price risk sharing an issue

Utilities not likely to guarantee take-or-pay price for Alaska gas

By LARRY PERSILY

Petroleum News Government Affairs Editor

Looking around for candidates to share in the financial gamble of a multibillion-dollar Alaska natural gas pipeline, it doesn't appear likely that state regulators would allow gas utilities to take on much of the price risk.

Although long-term, take-or-pay contracts could protect gas producers and pipeline investors from the financial fear of low market prices, they also could put utilities in the position of paying above-market prices for Alaska gas in the future. That's something that utility regulators, and consumers, don't like.

But finding a way to spread the risk between parties is one of the key unresolved issues in getting North Slope producers to commit to the project.

An Alaska gas line moving 4.5 billion cubic feet per day would carry almost $5.8 billion worth of gas a year, at $3.50 per thousand cubic feet. And with the projected pipeline tariff possibly eating up two-thirds of the revenue — if construction cost estimates come true — the producers worry who will help share the risk during periods of low gas prices.

"You're probably not going to see LDCs (local distribution companies) take a big share of the risk," said Bill Garner, a managing director of energy investment bank Petrie Parkman & Co., in Houston. "Naturally, LDCs are a little gun-shy about signing these long-term contracts."

Utilities aren't necessarily required to obtain regulatory approval of their gas supply contracts but they do need approval of their rates, and consumers can protest if they believe the utilities are overcharging for gas.

"We know of a number of utilities that are discouraged (by state regulators) from signing long-term contracts," said Michael Zenker, senior director for Cambridge Energy Research Associates' North American Natural Gas Service.

Regulators may shift thinking, but it's too early

Some public utility commissions have expressed interest in perhaps moving away from their opposition to long-term gas supply contracts, though it's still early in the evolution, Zenker said. "We have not seen any material shift away from that."

Utilities have a responsibility to ensure that their customers have adequate supplies of gas, but it's impossible to know how much gas might cost in the future and how much utilities should promise to pay for that supply. "What always happens to these deals is the market turns on you," Garner said.

"Generally, it comes down to the prudency standard. Was it prudent to enter into the contract at that point in time," he said. "The problem with prudency, it's always second-guessed."

Contracts for long-term pipeline shipping capacity are different than contracts to buy gas at a set price, said John Cita, chief economist for the Kansas Corporation Commission, which regulates utilities in the state. Signing a long-term deal for pipeline tariffs, or even for gas at prices tied to a floating market index, isn't a problem compared to a long-term supply contract at fixed prices, he said.

"Gas LDCs in the Lower 48 have a responsibility to serve," Cita said, but taking on the price risk for future gas deliveries could overstep that responsibility.

Utilities tried long-term contracts in the '80s

Utilities took such risks in the early 1980s, Garner said, when tightening gas supplies and steeply rising prices worried a lot of people. The wellhead price for natural gas in the United States averaged 50 cents per thousand cubic feet in the 1970s, jumping to $2 per mcf by the 1980s. The worst year was 1984, when wellhead prices averaged $2.66 — a record that held for 16 years.

The problem is utilities signed long-term, take-or-pay contracts during the time of tight supplies and high prices, only to see prices slide back to under $2 by 1986 and stay there until 1996.

see **SHARING** *page 22*

Enbridge may want 20% stake in pipeline, but not nearly that much gas

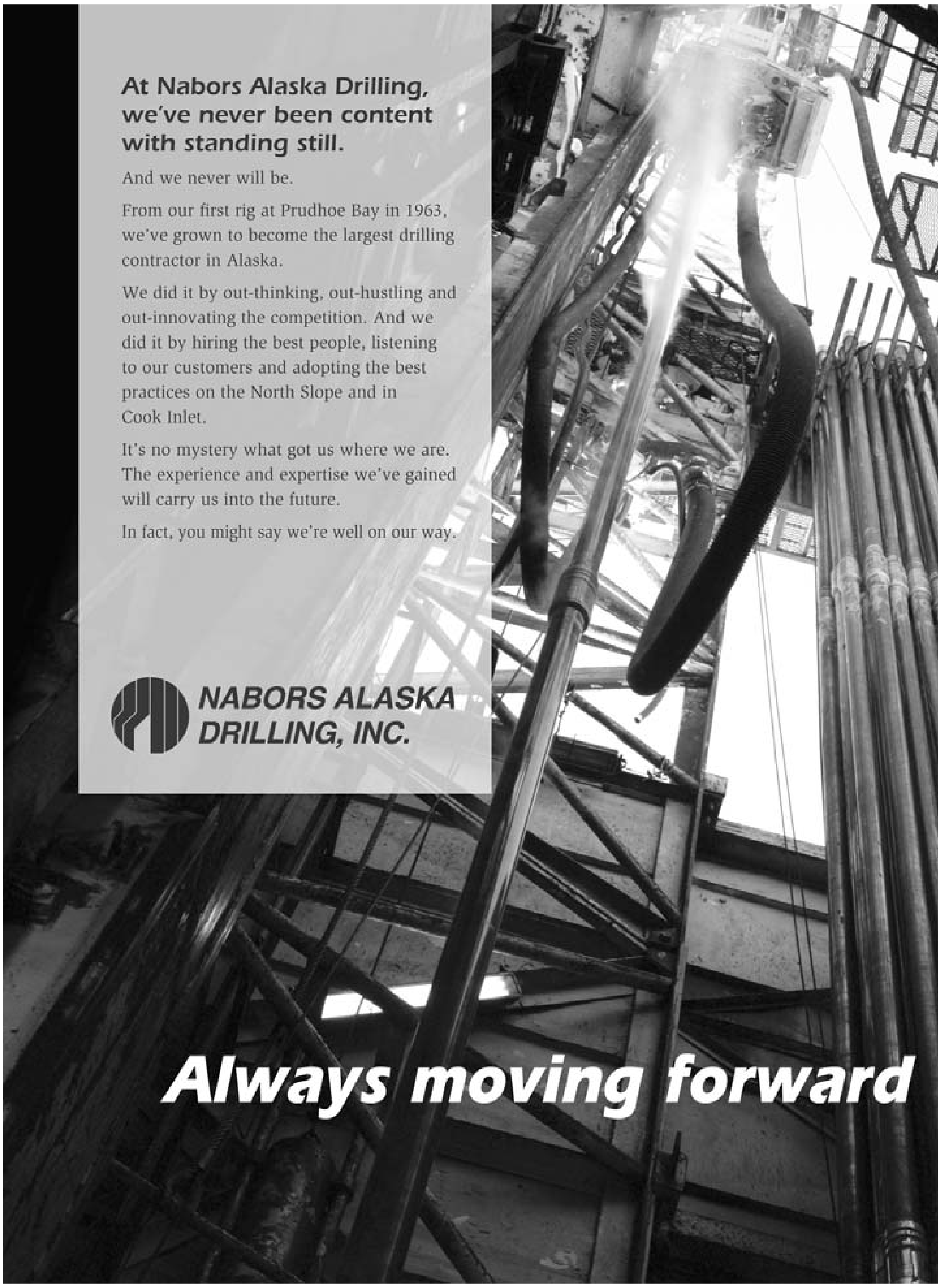
Gas pipeline owner and operator Enbridge Inc. is looking to take maybe a 20 percent stake in the proposed Alaska gas line project, but isn't interested in signing up for the market price risk on that much of the gas moving through the line. The 20 percent stake in the pipeline from Alaska's North Slope to the North America distribution system in northern Alberta is not a hard number but is "indicative" of the company's potential financial interest, said John Carruthers, vice president for upstream development at Enbridge Pipelines Inc. in Calgary.

"We potentially could take some shipping commitments, but not in that range," Carruthers said May 31. "That's way more than we could."

A commitment by its marketing and distribution affiliates to take 20 percent of the gas from a project moving 4.5 billion cubic feet per day, as proposed by the North Slope producers, would mean signing up for more than $1.1 billion a year in gas at $3.50 per thousand cubic feet. Enbridge in 2003 generated about $4.8 billion in total operating revenue.

The problems for advocates of an Alaska pipeline has been finding not only long-term buyers for that much gas but working out the potentially costly issue of sharing the price risk.

see **ENBRIDGE** *page 22*



BRITISH COLUMBIA

Duvernay Oil makes tight sands gas discovery west of Dawson Creek

British Columbia's tight sands gas plays continue to rack up successes, as junior exploration company Duvernay Oil Corp. says it has made a significant natural gas discovery west of Dawson Creek.

In a press release, the company said a 13-well program has tapped into a gas pool in the company's Sunset-Groundbirch-Saturn area with potential recoverable reserves of 250 billion cubic feet. The company says the wells are currently producing 10 million cubic feet of gas per day, and will increase to 30 million cubic feet per day by the middle of 2005. The gas play, part of the larger Triassic-Doig tight gas sand formation, is estimated to be 80 kilometers long and two kilometers wide. The find is small compared to EnCana Corp.'s Greater Sierra (2.5 trillion cubic feet) and Cutbank Ridge tight gas plays, but adds weight to the growing importance of the play.

Tight gas, found in porous rocks such as sandstone, is more costly to produce and often requires fracturing techniques to get the gas flowing. But with gas prices well above $4 per mcf, the economics work.

Duvernay controls another 115 potential drilling locations on the play, but it will take two to three years of successful exploration and drilling to realize the upper end of the reserve potential.

The initial Groundbirch discovery has been delineated by 13 gas wells, along with a series of successful exploration new pool wildcats both north and south of Groundbirch. Duvernay has a 100 percent working interest in the majority of these wells. Gilbert Laustsen Jung Associates Ltd. prepared a reserve report for the company, identifying average proved reserves of 1.7 bcf per well bore and 1.9 bcf proved plus probable reserves per well bore in the initial Groundbirch pool.

Gas production is being processed at a new sour gas treating facility, constructed by Duvernay in the fourth quarter of 2003.

Duvernay will drill eight to 10 delineation wells along the trend in the next 12 months in an effort to further refine reserve and production potential.

—DON WHITELEY, Petroleum News contributing writer

continued from page 21

SHARING

"The price of gas collapsed and they didn't want to take the gas anymore," Garner said of utilities' reaction to the market change. Utilities signed contracts stretching 10, 15 or even 20 years back in the 1980s, but the norm today is usually just one or two years, he said.

A utility could be forced to swallow the loss if state regulators reject its rates based on above-market gas prices under a long-term contract. "It's almost a bet-your-company kind of decision," Garner said.

Without utilities to take on much of the long-term price risk of an Alaska gas line, the great bulk of the financial hazard is left to the producers, possibly industrial users of the gas, and maybe marketing affiliates of pipeline companies. Federal law prevents interstate pipeline companies from owning the gas moving through their lines, leaving that role for their affiliated companies, Garner said. ●

continued from page 21

ENBRIDGE

The risk of construction cost overruns, permit or regulatory delays, and the fear that future market prices could fall short of a profitable return for producers — or perhaps even short of the pipeline tariff in a down market cycle — are all part of the equation, Carruthers said.

Enbridge has announced its willingness to work with the state and North Slope producers to put together a financially feasible project, and has gone so far as to apply to the state to negotiate a fiscal contract governing company payments in lieu of potential taxes on the project.

In looking to come up with its share of the money needed for construction, Carruthers said the company envisions using cash to cover 30 percent of its share and borrowing the rest. Enbridge, just as some of the producers, said the pending federal loan guarantee under consideration in Congress is key to a go-ahead for the gas line.

—LARRY PERSILY, Petroleum News government affairs editor

PRA
Petrotechnical Resources Alaska
Alaska's Oil and Gas Consultants
Geology, Geophysics, Engineering
www.petroak.com (907)272-1232

● ALASKA

JUDY PATRICK

Although month-to-month production averages were down at several North Slope fields, including the largest — Prudhoe Bay and Kuparuk— production was up at Northstar, Alpine and Milne Point.

Three North Slope fields show production increases in May

By KRISTEN NELSON
Petroleum News Editor-in-Chief

Average daily crude oil production from Alaska's North Slope was down almost 1 percent in May compared to April, with an average of 966,900 barrels per day in May compared to 976,428 bpd in April.

Although month-to-month production averages were down at several North Slope fields, including the largest — Prudhoe Bay and Kuparuk— production was up at Northstar, Alpine and Milne Point.

BP Exploration (Alaska)-operated Northstar had the largest April to May increase, averaging 75,424 bpd in May, up 19 percent from an April average of 63,351. Production in April was down due to work on the crude stabilizer at the field. The Alaska Department of Revenue said Northstar had output reductions May 11-12 and May 23-25 for plant repairs. Production at the field dipped to 29,775 barrels May 25, but also got above the 80,000 bpd mark on seven days during May.

Production from BP's Milne Point field was up 1.6 percent, averaging 50,492 bpd in May compared to 49,685 bpd in April.

And the ConocoPhillips Alaska-operated Alpine field averaged 106,543 bpd in May, up 1 percent from an April average of 105,454 bpd. Revenue said Alpine lost a power transformer May 17, and had a three-day planned throughput reduction May 24-26. Production exceeded 100,000 bpd on all but four days in May, and exceeded 110,000 bpd on three days.

BP Exploration (Alaska)-operated Northstar had the largest April to May increase, averaging 75,424 bpd in May, up 19 percent from an April average of 63,351.

Other fields down

The BP-operated Endicott field averaged 27,293 bpd in May, down 5.3 percent from an April average of 28,817 bpd. The BP-operated Lisburne field (including Point McIntyre and Niakuk) averaged 53,571 bpd in May, down 5.1 percent from an April average of 56,449 bpd.

BP-operated Prudhoe Bay (including Midnight Sun, Aurora, Polaris, Borealis and Orion) averaged 461,562 bpd in May, down 3.5 percent from an April average of 478,176 bpd.

Production from the ConocoPhillips Alaska-operated Kuparuk River field (which includes West Sak, Tabasco, Tarn, Meltwater and Palm) averaged 191,984 bpd in May, down 1.3 percent from an April average of 194,496 bpd.

The North Slope temperature at Pump Station No. 1 averaged 26.3 degrees Fahrenheit, compared to 4.6 degrees F in April, and compared to a three-year average for May of 24.1 degrees.

Crude oil production in the Cook Inlet basin in Southcentral Alaska averaged 25,130 bpd, up 2.4 percent from an April average of 24,548 bpd. ●

continued from page 20

CONSULTANT

nation markets may initially require price discounting to facilitate displacement of existing supply sources," the consulting firm said.

"Initially, displacement of existing sources of supply may be necessary to realize full utilization of the available gas line capacity. Shippers may have to displace not only the highest-cost sources of existing supply, but may also have to displace relatively inexpensive sources of existing supply in order to achieve maximum utilization."

The consulting firm cautioned the state: "Maximum utilization may not achieve maximum profitability, especially in the early years of operation."

And, it warned the state, temporary bottlenecks in moving so much gas to where it's needed in North America could cause lower short- or medium-term prices until additional pipeline capacity is available to break the jam.

— LARRY PERSILY, Petroleum News government affairs editor

● ANCHORAGE, ALASKA

Pioneer looks to build Alaska drilling portfolio

Dallas independent opening permanent Alaska office in ConocoPhillips building, has concerns about state increasing oil industry taxes

By KAY CASHMAN

Petroleum News Publisher & Managing Editor

Alaska is one of four key exploration hot spots for Pioneer Natural Resources, Ken Sheffield told members of the Alaska Support Industry Alliance May 27. Sheffield is the president of Pioneer's Alaska subsidiary.

The Dallas-independent is opening a permanent, 15-person office in Anchorage and is looking for more North Slope drilling prospects.

Ken Sheffield, Pioneer's top executive in Alaska

Sheffield told Alliance members that could all change if the state of Alaska increases the tax burden on the oil and gas industry.

"We came to Alaska because it has a world-class petroleum system. … It's a great place to find oil, but sometimes it's not such a great place to make money," he said.

Sheffield acknowledged the state has been "improving the regulatory environment in the last couple of years."

Nonetheless, the North Slope is challenging for independents such as Pioneer, he said.

"It's the most expensive basin in the world," Sheffield said, citing the geologic risk common in any oil province, as well as Alaska's unique situations that add to the risk, including the high cost of transporting crude oil to West Coast markets; protracted project timelines because of limited winter access; and low activity levels which reduce the number of oilfield service and supply contractors in the state and ultimately drive up costs because of a lack of competition.

The stability of the state's fiscal policy is also a concern, Sheffield said, and could change his company's enthusiasm for Alaska.

"I'm concerned about the talk of increasing taxes. It would be hard for us to move forward if there were any new taxes. The margins are too thin on the projects we're looking at."

Alaska's competition for Pioneer's investment dollars — i.e. the company's other three key exploration hotspots — are the Gulf of Mexico, particularly the deepwater Gulf, North Africa and West Africa, Sheffield told Alliance members.

Portfolio of drilling prospects

In Alaska, Pioneer hopes to build a "portfolio" of drilling prospects: "We're not just looking to drill one to two wells per year," he said, noting the company would achieve an "economy of scale" by drilling several wells each year.

Pioneer currently has four North Slope prospects that it has either drilled or hopes to drill, including Storms, south of Prudhoe Bay where Pioneer plans to shoot 3-D seismic next winter; Gwydr Bay, north of the ConocoPhillips-operated Kuparuk field; Caribou, which is "north of Point McIntyre on trend with (BP's) Northstar" (unit); the new Oooguruk unit, which Pioneer successfully drilled the winter before last and, according to Sheffield, expects to sanction for development in the fourth quarter of this year.

Goal to achieve step change

One of Pioneer's goals in Alaska is to "achieve a step change in the North Slope cost structure," Sheffield said.

"In looking for big reservoirs, you're going to find small reservoirs," against which Pioneer is applying what he calls the "independent mindset," which involves "challenging existing methods."

One thing that needs to be done, Sheffield said, is to "decrease project cycle times," from the time of the lease sale until a project is in production. He believes this can be done without jeopardizing the environment.

Leveraging existing North Slope infrastructure is another way to bring down costs — something Pioneer is looking at doing in order to bring the Oooguruk unit online.

The unit is in the shallow waters of Harrison Bay offshore the North Slope, north and west of, and contiguous with, the ConocoPhillips-operated Kuparuk River unit. Due to a farm-in executed earlier this year by operator Pioneer and partner Armstrong Oil & Gas's affiliate in Alaska, ConocoPhillips retains the right to participate in any Oooguruk project sanctioned by Pioneer and Armstrong. Pioneer executives have talked about possible production synergies with the Kuparuk unit's existing facilities versus a standalone production facility.

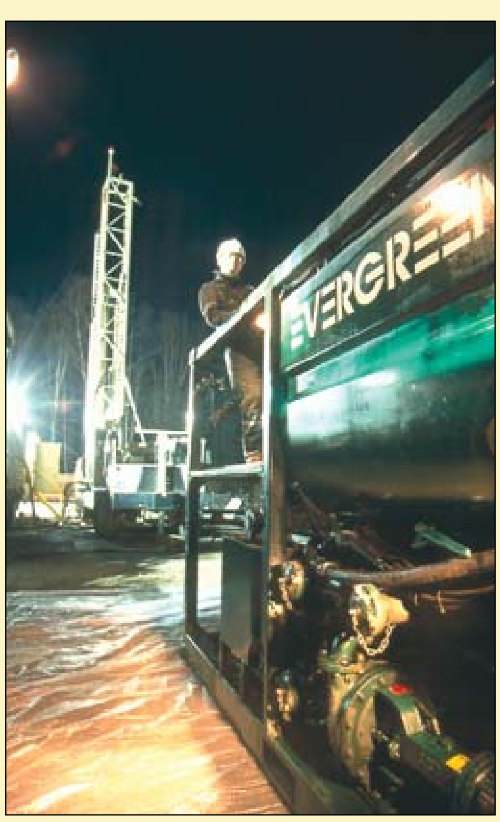
Pioneer to open permanent Alaska office

Sheffield lent credence to the speculation that the Kuparuk facilities will be tied into the Oooguruk unit's development when he told Alliance members May 27 that Pioneer has leased half of the sixth floor of the ConocoPhillips building in downtown Anchorage. Pioneer, which opened a small, 1,000 square foot office in Anchorage at Pacific Office Center on K Street earlier this year, was expected to expand its square footage in that building.

Sheffield said the sixth floor space is in the process of being remodeled and by August will have a staff of 15, including Sheffield; Pat Foley, manager of land, commercial and regulatory affairs; Mike Dunn, manager of engineering and development; Don Bryson, manager of exploration; as well as support staff that includes two engineers and five geoscientists. ●

No plans yet for Evergreen's Alaska coalbed methane properties, says Sheffield

The people who came to hear Ken Sheffield speak at a May 27 Alliance breakfast in Anchorage were hoping to hear Pioneer Natural Resources' plans for the Alaska coalbed methane properties it will inherit as part of its proposed acquisition of Evergreen Resources. But Sheffield, president of Pioneer's Alaska subsidiary, said until the Evergreen deal is approved by both groups of shareholders, no plans for the coalbed properties in Southcentral Alaska will be discussed.



JUDY PATRICK

A decision from shareholders is expected in August or September, he said. Until that time, Pioneer and Evergreen will continue to operate as separate companies.

Sheffield reminded attendees that the primary reason Dallas-based Pioneer decided to buy Denver-based Evergreen is because of Evergreen's Raton basin properties in southeastern Colorado and northeastern New Mexico. From March 31, 1995, through Dec. 31, 2003, Evergreen grew its estimated proved reserves in the Raton Basin from 58 billion cubic feet of natural gas equivalent to 1,393 bcfe, which represents a compound annual growth rate of approximately 44 percent. During the same period, the company's net average daily gas sales from the basin increased from just over 1 million cubic feet of natural gas equivalent to approximately 131 million cfe.

Evergreen's mineral rights on 300,000-plus acres in Alaska represent only about 2 percent of Evergreen's assets, Sheffield told Petroleum News.

Consequently, Pioneer's evaluation team is focused first on the natural gas-producing Raton Basin and will eventually get around to Evergreen's Alaska acreage, which is still in the exploration and production evaluation stage.

Like petroleum, imagination is a resource.

Hire an agency who knows the drill.

At Marketing Solutions, we explore. We test. We drill. Then, *and only then*, we tap into targeted advertising strategies.

Effective marketing is work. Hard work. And if an advertising firm tells you it's about having fun, playing games or getting lucky, we recommend a weekend in Vegas. The odds of success will definitely be better.

But if you're ready for a roll-your-sleeves-up, strategy-driven, market-centered advertising firm, give us a call or visit our web site today.

marketing solutions
advertising • public relations

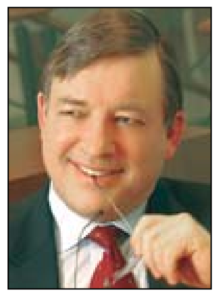
Ph: 907.569.7070 • www.marketingsol.net

APPALACHIA

Talisman U.S subsidiary Fortuna reaches milestone in Appalachians

Fortuna Energy, a subsidiary of Canada's Talisman Energy, has surpassed 100 million cubic feet of daily natural gas production from its Appalachian properties in the Corning area of New York, Talisman said June 1.

The company said it also completed the SRA3 No. 1 gas well, drilled horizontally to a measured depth of 11,704 feet. The well tested a new structure in the upper Black River formation. It flowed tested at 19 million cubic feet of gas per day at a wellhead pressure in excess of 2000 psi, the company said.



"These are prolific wells and their location close to major U.S. markets means that they are particularly valuable," said Jim Buckee, Talisman's chief executive officer, adding that production in the area has increased from 60 to over 100 million cubic feet per day in recent months.

"These are prolific wells and their location close to major U.S. markets means that they are particularly valuable," said Jim Buckee, Talisman's chief executive officer, adding that production in the area has increased from 60 to over 100 million cubic feet per day in recent months.

The northeastern United States now accounts for more than 12 percent of Talisman's consolidated North American natural gas production and generates about 18 percent of the operating cash flow from North American gas operations.

"Fortuna is continuing to build its land base in the area and is putting together plans for 2005," Buckee said.

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

OFFSHORE NEWFOUNDLAND

Newfoundland's Terra Nova field dealt a setback, reserves slashed by 13%

The Canada-Newfoundland Offshore Petroleum Board has slashed its proven plus probable oil reserves for the offshore Terra Nova field by 13 percent to 354 million barrels from its previous 405 million barrels.

Of the revised total, 87 million barrels has already been produced at the Petro-Canada-operated project, which is Newfoundland's second offshore project after Hibernia.

The updated estimates also slashed total discovered gas resources to 44.9 billion cubic feet from 269 billion cubic feet, although gas production is not on the immediate horizon for Newfoundland.

The regulator listed Terra Nova's proven reserves, those given a 90 percent chance of recovery, at 224 million barrels. Probable are given a 50 percent chance of recovery.

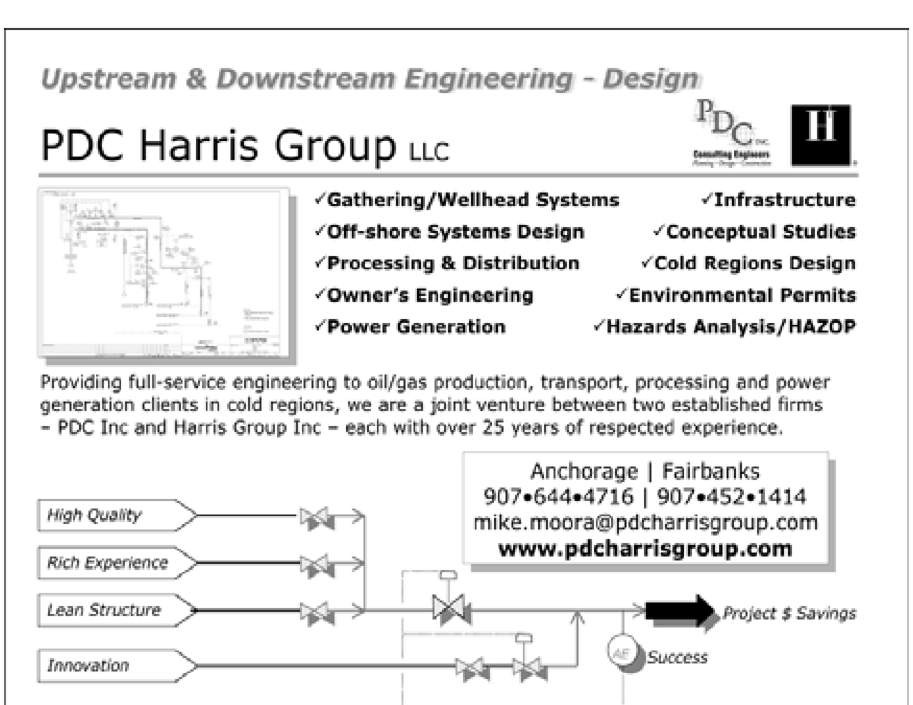
The board said the biggest setback occurred in the so-called Far East region of the field, which tumbled to 45 million barrels of proven plus probable from 162 million barrels, while the East Flank region lost 4 million barrels to stand at 144 million barrels. Offsetting those losses, the Graben region surged to 165 million barrels from 95 million barrels.

In a separate assessment, the board said undiscovered hydrocarbon resources in the newly emerging Flemish Pass basin are rated at 1.7 billion barrels, with a 50 percent probability of being recovered, with expected field size ranging from 44 million to 528 million barrels.

The basin, comparable in size to the Jeanne d'Arc basin, which holds the Hibernia, Terra Nova, White Rose and Hebron-Ben Nevis fields, has barely been scratched by explorers who have so far drilled only five wells.

Although no commercial accumulations of hydrocarbons have yet been found in the Flemish Pass basin, hydrocarbon shows have been encountered, raising hopes along with the Orphan basin that Newfoundland can still become a long-term producing region.

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



● NORTH SLOPE, ALASKA

Oil officials keep eye on high water at Alpine field

THE ASSOCIATED PRESS

Spring thaw in the Colville River Delta has surrounded the Alpine oil field in floodwater, prompting a suspension of drilling and other steps to keep workers and the environment safe.

Alpine is the third most prolific field on the North Slope. Production of about 100,000 barrels of oil a day has not been interrupted.

Melting and ice jams on the Colville and some channels have caused the highest water levels at Alpine since the field started producing four years ago.

Floodwaters came within 16 inches of the base of the main pipeline at Alpine, according to officials at the Alaska Division of Oil and Gas. The pipeline transports crude oil from Alpine to the Kuparuk field about 34 miles away. Water also came within 14 inches of the lowest point of an access road connecting two drilling pads. The pads sit on gravel about 4 to 6 feet above the ground.

Flooding is a concern at oil fields because pipeline supports can erode out from underneath, destabilizing lines, said Leslie Pearson, a state spill-response manager.

As of the morning of May 28, the water levels appeared to be receding, but city officials at nearby Nuiqsut remained on heightened alert. Mayor Rosemary Ahtuangaruak asked the North Slope Borough to provide a staff person to monitor water levels in the channel nearest town. The water was about 6 feet from topping its bank the last time she checked, Ahtuangaruak said.

"I'd rather be proactive than to wake up and have an ice chunk banging against the house," Ahtuangaruak said.

Hydrologists for ConocoPhillips Alaska, the company that runs Alpine, are checking gauges and monitoring river conditions daily by helicopter. Microwave communications have been set up in case fiber optics fail due to flooding. A drilling rig was shut down and put in maintenance mode as a precaution, according to an e-mail Conoco sent to government agencies alerting them to the situation.

Conoco spokeswoman Dawn Patience downplayed the severity of the risks.

"We haven't executed anything operationally different. Everything right now is normal," Patience said.

The Colville River Delta is a well known flood plain. Environmentalists had opposed the field going forward, in part because of the flood risks.

Precisely because of the topography and conditions, structures at Alpine were built to withstand a 200-year flood, Patience said. ●

NORTH AMERICA

Rig count falls by 9 to 1,364

The number of rotary rigs operating in North America fell by nine to 1,364 during the week ending May 28, with both Canada and the United States suffering losses, according to rig monitor Baker Hughes.

The Canadian rig count fell by six to 195 compared to the previous week, and also declined by 63 rigs versus the same period last year.

The total number of rigs operating in the United States in the recent week decreased by three to 1,169, but was up by three compared to the year-ago period. Land rigs alone actually increased by three to 1,059, while offshore rigs decreased by two to 93 and inland water rigs dropped by four to 17.

Of the total number of rigs operating in the United States during the recent week, 1,012 were drilling for natural gas and 156 for oil, while one was being used for miscellaneous purposes. Of the total, 760 were vertical wells, 284 directional wells, and 125 horizontal wells.

Among the leading producing states in the United States, Oklahoma gained nine rigs in the recent week for a total of 163 rigs. Wyoming's rig count was up by two to 72, while New Mexico's was up by two to 66. Alaska picked up one rig for a total of eight rigs. Louisiana suffered a loss of 11 rigs, dropping its count for the week to 160 rigs. Texas' rig count fell by six to 501, while California's decreased by two to 21.

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

Companies involved in North America's oil and gas industry

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

Petroleum news

Business Spotlight

By PAULA EASLEY

FORREST CRANE

Allie Huston, co-owner

Totem Equipment & Supply Inc.

Totem Equipment and Totem Rentals offer sales, service and rentals of construction and industrial equipment. The manufacturing division recently began designing and building compact, easily transportable heater systems. A recent market expansion involves exports to South Korea. Cliff and Allie Huston started the business in 1961. Although Cliff is retired, the companies are still managed by Allie and their son Michael.

"Jill of all trades" Allie Huston has worked in every department, including sales, manufacturing and parts. Interacting with customers makes for some hilarious moments, especially being a woman in a man's construction world, says Allie. While the Hustons enjoy their active Alaska life, they supplement it with frequent doses of warm sunshine at their Palm Desert home.

FORREST CRANE

Rob Halpin, senior account manager

Alaska Railroad Corp.

Alaska Railroad Corp.'s interstate service includes weekly rail-barge trips between Anchorage and Seattle. Intrastate transportation includes passenger and full freight services along Alaska's railbelt. ARRC works with domestic railroads, ship and barge lines, and local and interstate trucking companies to provide full-service shipping.

Rob Halpin has a 30-year history performing various management and marketing functions within Alaska's freight transportation sector. He's been the railroad's senior account manager for 16 years. Rob is also treasurer for the National Defense Transportation Association. A typical day on the job, he says, is full of "intrigue, passion, drama and suspense," so he is seldom bored. Rob's two daughters were reared in Alaska and now live in Portland, Ore. Elizabeth is a successful artist and Katie attends college there.

continued from page 1

OUTPUT

United States, where coalbed methane hit a "steep growth curve over a 15 year period" and is now contributing 4.4 bcf to 4.6 bcf per day to U.S. volumes of 52 bcf per day.

Simpson said that although coalbed methane output is expected to be a mere 100 million cubic feet per day this year, 1,000 coalbed methane wells have been drilled in central Alberta and 100 coalbed methane wells are being licensed each month.

He said the Canadian Gas Potential Committee has projected coalbed methane reserves of 200 to 600 trillion cubic feet in the Western Canada Sedimentary basin, although the bulk of experts believe ultimately recoverable reserves will be in the range of 20 tcf to 100 tcf.

Among the challenges, Simpson said Canada is discovering that the reservoirs are complex and each requires a distinctive approach. "Finding the right technology is the key challenge," he said.

George Enyon, a natural gas researcher with the Canadian Energy Research Institute, said coalbed methane development is a natural extension of the shallow gas industry in Western Canada because most of the coalbed methane deposits are close to the surface.

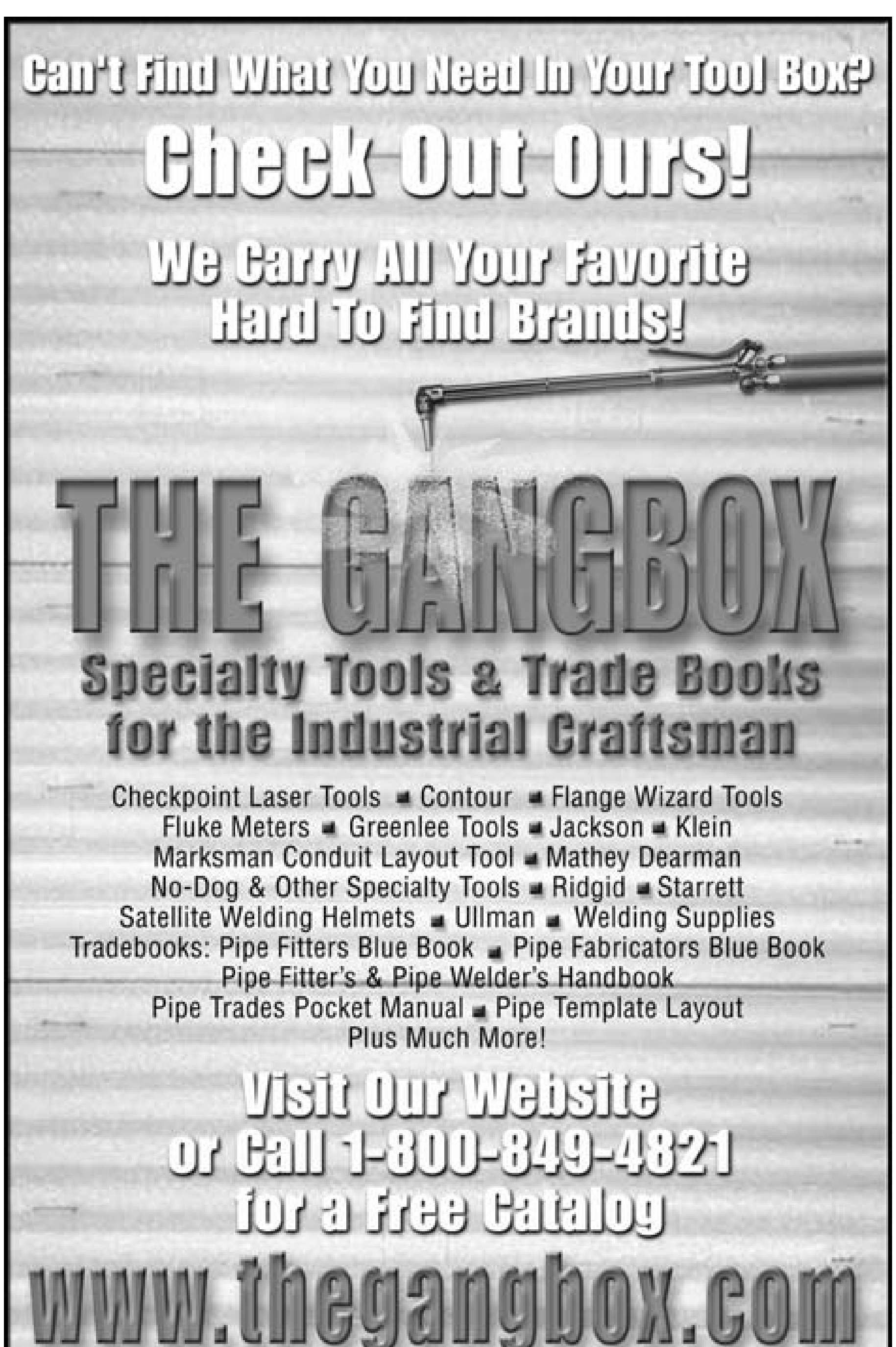
He said the rig fleet in Western Canada is dominated by shallow equipment, which is suitable for coalbed methane, thus the industry does not have to make a radical departure from its existing development.

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

WEAVER BROS INC.

Kenai (907) 283-7975
Anchorage (907) 278-4526
Fairbanks (907) 456-7704

Safety and service is our commitment to you.



continued from page 1

NOBLE

development projects, Lorien and Swordfish.

Noble purchased an additional 50 percent stake in Swordfish, pushing its interest there to 60 percent. The field, located on Viosca Knoll block 917, is expected to come on stream late in the first quarter of 2005, backed with estimated reserves of 20 to 25 million barrels of oil equivalent. Two wells have been drilled thus far and a third is planned for this summer.

Noble bought an additional 40 percent stake in Lorien, increasing its interest there to 60 percent. A 2003 discovery, Lorien is situated on Green Canyon block 199. The partners are currently putting together an appraisal program for the prospect, with the hope of launching production as a tieback in the 2005 fourth quarter. The field contains estimated reserves of 20 to 30 million barrels of oil equivalent.

Ticonderoga production planned for 2006

Fifty-fifty Ticonderoga owners Noble and Kerr-McGee are hoping to bring their recent discovery on stream in the third quarter of 2006, Peneguy said, adding that the discovery well logged "well over 230 feet of beautiful oil pay."

In fact, the only reason Noble gave up operatorship of Ticonderoga to Kerr-McGee is because production would be funneled through Kerr-McGee's production facilities at nearby Constitution, thus reducing overall development costs at Ticonderoga.

"The trade off was for us is to have accessibility to the spar they are currently preparing," Peneguy said. He said appraisal work will continue on Ticonderoga this year and that a second development well likely would be drilled in the first quarter of 2005.

On an oil equivalent basis, he said, Noble would receive 11,000 barrels per day in net production from Swordfish, 9,000 barrels per day net from Lorien and 15,000 barrels per day net from Ticonderoga.

Deep opportunities maturing

Despite working hard to advance the Swordfish, Lorien and Ticonderoga development projects, Noble's current portfolio of deep opportunities is "maturing and we now need to start expanding," Peneguy said.

He added: "So we are moving forward with acceleration of our current program and expanding into new areas of the deepwater."

Three prospects are under consideration for drilling this year, including Sable at Green Canyon block 228, a 10 to 35 million barrel of oil equivalent target Peneguy says "is ready to go."

Noble owns 100 percent of Sable and is looking to sell down its interest to help spread financial risk, he said, adding that infrastructure in the area would make Sable a candidate for a subsea tieback to an existing platform.

"We have been discussing with a few operators, if we are lucky enough here, where we might go," Peneguy said.

Company now looking for larger targets

Noble, which in the past has focused on smaller deepwater reserves of 20 to 50 million barrels to tie back to existing infrastructure, is now actively looking for targets "well over" 50 million barrels, Peneguy said.

"Those opportunities, if successful, will yield standalone opportunities for us," he said.

In the shallower waters of the Gulf's continental shelf, Noble is being far more selective than in the past when its offshore acreage domain stretched from the southern tip of Texas to southern Alabama.

The company has not given up on mature and largely depleted shelf plays above 15,000 feet, but is now concentrating on deeper gas plays at 15,000 feet and below.

"We have literally reduced our dependency on the shelf, that is the conventional shelf," Peneguy noted. "But there are deep opportunities below that. We have selectively high-graded our deep-shelf portfolio."

Deep gas trend the focus

Noble is now focusing its exploration efforts on the shelf in the West Cameron-South Marsh Island area, in a deep gas trend just east of Louisiana and south of Mississippi-Alabama.

Because of the company's existing infrastructure in the area and experience in the play, "we believe Noble has an enviable geological and geophysical competitive advantage as it relates to focusing in this trend," Peneguy asserted.

He noted that because the 15,000-foot play is not as deep as some, it costs just $4 million per well compared to the roughly $1 million per thousand feet it costs for wells drilled between 17,000 and 30,000 feet.

"We believe there are additional shallow and deep opportunities, yielding significant resources anywhere from 50 to 400 billion cubic feet of gas equivalent per prospect," Peneguy said.

Despite the shift away from conventional plays on the shelf, the area is still reaping benefits for Noble. The company's 17-well recompletion program at core properties on Main Pass blocks 305 and 306 is expected to triple current production in the field to 6,900 barrels of oil per day from 2,400 barrels last December.

The company also believes there are "deep opportunities" beneath the Main Pass acreage.

Deepwater would provide biggest opportunities

However, the numbers show that as far as the offshore Gulf of Mexico goes, it's the deepwater that would provide Noble with its biggest opportunity for future production. The company noted that while the majority of its acreage on the continental shelf already is developed, more than 90 percent of its deepwater acreage is undeveloped.

Still, of the 42,100 barrels of oil equivalent per day produced by Noble during the 2004 first quarter from the Gulf of Mexico, a hefty 80 percent came from the shelf. "But the deepwater is growing and growing fast," Peneguy said.

Noble said it increased its 2004 offshore capital budget to $325 million, 70 percent of which is earmarked for deepwater Gulf of Mexico, primarily because of deepwater successes.

"Deepwater has been kind to Noble Energy over the last few years," Peneguy said. "We believe it to be an attractive play and a play we have a very strong position in. We like deepwater because of the high-impact resources and moderate geologic and mechanical risks."

He said Noble also likes the deepwater because of the availability of infrastructure that allows discoveries to be tied in to offshore production facilities and pipelines in a timely fashion, "yielding excellent returns on those investments." ●

continued from page 1

OIL SANDS

price of $4 per thousand cubic feet.

Oil sands operating costs range from $4 to $14 for bitumen and $12 to $18 for synthetic crude oil. The estimated supply costs ranges from $10 to $19 for bitumen and from $22 to $28 for synthetic crude oil.

High prices one factor in projection

The board bases its projections of increased oil sands production on several factors:

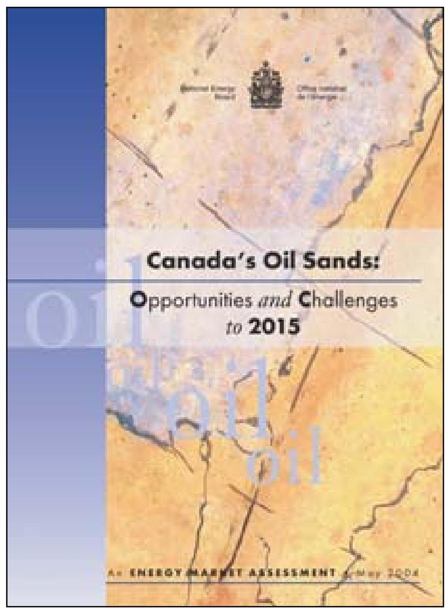
• Global petroleum prices are likely to remain at levels high enough to maintain economic viability over the long term.

• Markets will remain strong for oil and natural gas despite a slow, evolutionary transition to other energy forms over time.

• Technological advancements, particularly in environmental controls, will continue to lower unit costs of oil sands production.

But the national energy body also offers some cautionary words, particularly on the sensitive topic of natural gas supply and prices.

"Natural gas requirements for the oil sands industry are projected to increase substantially during the projected period from 0.6 billion cubic feet per day in 2003 to a range of 1.4 to 1.6 billion cubic feet per day in 2015.



"In response to higher and more volatile gas prices, producers are seeking ways to reduce their dependence on natural gas as the major sources of energy and hydrogen for their operations."

Natural gas supply and price has been controversial, as Alberta shut in some natural gas production this year to ensure a sufficient supply for oil sands production. Along with record high prices for crude oil recently, natural gas has also remained at very high levels for this time of year, hovering around $6.70 US per thousand cubic feet.

Canadian gas production expected to be flat

Canadian gas production, which increased dramatically in the 1990s, is expected to stay relatively flat, producing about 17 billion cubic feet per day until about 2010. Conventional supply from the Western Canada Sedimentary basin is expected to decline by 2006-2007.

The board estimates that oil sands development and related infrastructure will require a capital investment in excess of C$60 billion over the next 10 years to achieve the productions levels projected in the report. About C$20 billion has already been invested.

"Ongoing volatility in crude oil prices is expected and suggests that it is unlikely that the entire $60 billion in projects will be constructed within the planned time frame," the report states. "Market conditions will determine the pace of oil sands development."

The report also suggests that Alberta's petrochemical industry, facing tight supplies of feedstock gases from conventional natural gas production, could use the ethane and ethylene produced during the bitumen upgrading process.

The National Energy Board credits the oil industry for making significant technological advancements in environmental controls that reduce emissions. The industry uses low nitrogen oxides burners, sour water treaters and flue gas desulphurization to reduce emissions.

New technology has resulted in significant reductions in greenhouse gas emissions despite an increase in production. The board's report shows a 53 percent reduction in carbon dioxide emissions per barrel for the period from 1990 to 2010 due to investment in new technology. Multi-stakeholder groups have been established in recent years to create policies and programs to address greenhouse gas emissions. ●

continued from page 1

HUSKY

ry issues essential to a safe and reliable gas development on the Grand Banks, as well as the capital and operating costs of such a development.

Following a review of the responses, Husky said it may select one or more firms to participate in a request for proposal process. The Canada-Newfoundland Offshore Petroleum Board has estimated that White Rose has gas resources of 2.7 trillion cubic feet, while the entire offshore Newfoundland and Labrador region is rated at 9.6 tcf.

But to date developing the gas has been relegated to second place behind oil because of the costs of getting the gas to market.

Husky President and Chief Executive Officer John Lau said in a statement June 1 that the Husky evaluation is "the first step which may help realize gas production from White Rose within a decade.

"In order to evaluate natural gas development in the Jeanne d'Arc basin (which contains the Hibernia and Terra Nova oil-producing projects as well as White Rose, which is due on stream by late 2005 or early 2006) new technologies will need to be developed and today we believe this is possible," he said.

Husky owns 72.5 percent of the White Rose development, with Petro-Canada holding the remaining 27.5 percent. The oil venture carries a price tag of C$2.35 billion.

Compressed or pressurized natural gas has potential

Husky said its initial assessment indicates that a marine transportation system using compressed natural gas/pressurized natural gas has potential as a commercial venture. But the company wants to consider other technologies and is inviting proposals that delve into those prospects.

> *"In order to evaluate natural gas development in the Jeanne d'Arc basin new technologies will need to be developed and today we believe this is possible."*
> **—Husky Energy President and CEO John Lau**

The program will include:

• A quantified evaluation of viable alternatives and a methodical selection process to identify a preferred development option. This will include identification of potential opportunities for activities that could be carried out in Newfoundland and Labrador and elsewhere in Canada.

• A capital and operating cost estimate for each option.

• An evaluation of any unproven technology issues and operating procedures, including proposed work programs, testing to address these uncertainties and an estimate of the development time and costs required.

• An estimate of system operations based on simulation modeling including reliability and weather related factors.

• Identification and quantification of safety and environmental related issues and risk factors.

• An evaluation of regulatory issues during all stages of the gas development, including national and international regulations, protocols and codes.

Husky has set a June 30 deadline for expressions of interest.

—GARY PARK, Petroleum News
Calgary correspondent

Quality construction on tough sites throughout Alaska

- Petroleum industry construction
- Heavy civil construction
- Underground utilities
- Gravel and rock products
- Reclamation
- Cold weather construction
- Erosion control
- Sitework

FAIRBANKS BASED

(907) 452-5617

E-mail: info@grtnw.com

www.grtnw.com

We can help you achieve drilling efficiency with environmental responsibility.

The engineers at M-I SWACO* have been helping operators keep Alaska pristine with environmentally responsible drilling and reservoir drill-in fluids, cost-effective cuttings re-injection and other drilling-waste-management techniques for more than 30 years.

Call us today to see how we can give you the competitive edge in protecting our environment and your AFE.

MI SWACO

Customer-focused, solutions-driven

©2004 M-I LLC. All rights reserved. *Mark of M-I LLC

JACKOVICH

INDUSTRIAL & CONSTRUCTION SUPPLY, INC.

With 30 years of experience, we're experts on arctic conditions and extreme weather!

Come see us; ask us questions.

907.277.1406
1716 Post Road
Anchorage, AK 99501

907.456.4414
1600 Wells Street
Fairbanks, AK 99701

Critical Timing?
Remote Location? Heavy Freight?
Lynden Delivers These & More.

At Lynden Air Freight we link our customers to the world. A personalized approach to air and ocean forwarding results in superior service. Dedication to technology such as e-commerce, Internet tracking, and EDI place critical shipping information at our customers' fingertips.

LYNDEN

Logistics Services • E-Commerce Services • Bulk Chemical Transport • Heavy Equipment Transport
Alaska Barge & Steamship Service • Alaska LTL & Truckload Freight • Worldwide Air Cargo Charter
International & Domestic Air Freight Forwarding • International Ocean Freight Forwarding

ALASKA MARINE LINES • ALASKA WEST EXPRESS • LYNDEN AIR CARGO • LYNDEN AIR FREIGHT • LYNDEN INTERNATIONAL (A Division of Lynden Air Freight, Inc.) • LYNDEN LOGISTICS • LYNDEN TRANSPORT

www.lynden.com — ***The Lynden Family of Companies***

1-888-596-3361 — ***Innovative Multi-Modal Transportation Solutions***