Petroleum news

page 6 ANGDA puts study of route for Gubik gas spur line out to bid

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Petroleum Club hosts book signing

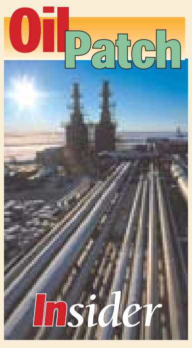
AMY SPITTLER

Former M-I Swaco Alaska manager and Petroleum Club of Anchorage president Craig Bieber hosted a book signing at the club on June 19 for his new novel, "Saylor's Triangle." See story in Oil Patch Insider below.

Sheffield to lead AOGA for 2008-09; Craig Bieber novel 'Saylor's Triangle' makes Anchorage debut

THE ALASKA OIL AND GAS ASSOCIATION named Ken Sheffield, president of Pioneer Natural Resources Alaska Inc., as its new president, effective July 1.

The association's other officers are first vice president, Doug Suttles (president of BP Exploration (Alaska) Inc.); second vice presidents: Mark Hanley (Alaska public affairs manager, Anadarko Petroleum Corp.), John Zager (Alaska general manager, Chevron North America Exploration) and Craig Haymes (Alaska production manager, ExxonMobil Production Co.); and treasurer, Rick Fox (Alaska asset manager, Shell Exploration and Production Co. Alaska).



JUDY PATRICK

KEN SHEFFIELD

AOGA's directors are: Chris Sonnichsen, Agrium Kenai Nitrogen Operations; Kevin Hostler, Alyeska Pipeline Service Co.; Giuseppe Valenti, Eni Petroleum; Mark Gregory, Flint Hills Resources Alaska; Carri Lockhart, Marathon Oil Co.; Torgeir Opdahl, StatoilHydro; Joe Kilchrist, Pacific Energy; Derek Evoy, Petro-Canada (Alaska) Inc.; Doug Chapados, Petro Star Inc.; Steve Hansen, Tesoro Alaska Co.; and Vaughn Vennerberg, XTO Energy Inc.

AOGA is a non-profit trade association whose 17 members represent the majority of the oil and gas exploration, production, transportation, refining and activities in Alaska.

see **INSIDER** *page 22*

GOVERNMENT

ACMP under scrutiny

State seeks ways to improve program to address issues with 2003 reforms

By ALAN BAILEY

Petroleum News

Alaska's Division of Coastal and Ocean Management has launched a reevaluation of the Alaska Coastal Management Program, or ACMP. The reevaluation represents a response to some issues surrounding changes in ACMP enacted in 2003 and will likely result in further changes to the program, Randy Bates, director of DCOM, told Petroleum News July 2.

"It seemed like the right time to reevaluate and make sure we've got the program structured the way we want it," Bate said.

Under the terms of the 1972 federal Coastal Zone Management Act, all projects in Alaska's coastal zone require a review for ACMP consistency, to ensure that policies for environmental protection of coastal areas are met.

> *"The coastal districts want to be able to write policies to effect change to projects … and the way the state has implemented the plan, the districts have very little room to write enforceable policies."*
> **—Randy Bates, director, Division of Coastal and Ocean Management**

Multiple agencies

The ACMP process involves several state and federal agencies working with 33 coastal districts around the state to ensure compliance with enforceable coastal policies. In many cases the

see **ACMP** *page 22*

NATURAL GAS

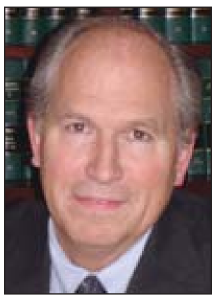
LNG or natural gas project?

Econ One: Pipeline along Alaska Highway probably trumps LNG plan

By ERIC LIDJI

Petroleum News

A liquefied natural gas project can earn more on less, more or less. But more and more, a big pipeline through Canada can earn more on more, according to a legislative consultant testifying during an on-going special session on natural gas issues in Alaska.



BILL WALKER

Broken down: an LNG project sending North Slope natural gas to Asia could likely earn higher netbacks on each unit sold. But the lower volumes of an LNG project mean that over the long term, an overland pipeline along the Alaska Highway would probably produce higher overall values over the life of the project.

"In the end, it's not just about the per-unit value that you get. It's about maximizing the total pie," Barry Pulliam, senior economist with the consulting firm Econ One Research, told state lawmakers June 20 in Anchorage. "You can have a high per-unit netback, but on a low volume it doesn't necessarily get you the same economic value as if you have a little bit lower per-unit netback on a much greater volume."

Pulliam's opinion threads the gap between two contrasting takes on an LNG project: a negative

see **ECON ONE** *page 21*

NATURAL GAS

Galvin on mediation

McGuire wants mediation; Revenue chief says Alaska first has to have position

By KRISTEN NELSON

Petroleum News

Alaska legislators are hearing from a number of constituencies as they debate, and approach a vote on, a TransCanada Alaska license under the Alaska Gasline Inducement Act.

Many Alaskans want natural gas for in-state use — and they want it in a shorter timeframe than a main pipeline to market would provide. Many people still favor an all-Alaska liquefied natural gas project. Others believe the state should not spend money on an AGIA license, which would provide up to $500 million in matching funds in exchange for meeting state requirements for the line, but should instead back the Denali pipeline proposal put on the

see **MEDIATION** *page 18*

Definition, not mediation, please

While Sen. Lesil McGuire, R-Anchorage, has asked the administration to consider mediation before the vote on the Alaska Gasline Inducement Act license application by TransCanada Alaska, fellow Anchorage senators, Democrats Hollis French and Bill Wielechowski, have asked Denali pipeline — the line proposed by BP and ConocoPhillips — to specify how its line would compare on AGIA requirements met by TransCanada, and to do so before the Legislature reconvenes

see **DEFINITION** *page 19*

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Petroleum News *A weekly oil & gas newspaper based in Anchorage, Alaska*

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Alaska - Mackenzie Rig Report

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status

Alaska Rig Status

North Slope - Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Prudhoe Bay DS 12-03	BP
Sky Top Brewster NE-12	15 (SCR/TD)	Kuparuk 3C-17	ConocoPhillips
Dreco 1000 UE	16 (SCR/TD)	Prudhoe Bay L1-09	BP
Dreco D2000 UEBD	19 (SCR/TD)	Alpine CD2-466	ConocoPhillips
OIME 2000	141 (SCR/TD)	Kuparuk warm stack	ConocoPhillips
TSM 7000	Arctic Fox #1	Stacked in Yard	Pioneer Natural Resources
	Arctic Wolf #2	Stacked in yard	FEX
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Stacked, Prudhoe Bay	Available
Dreco 1000 UE	2-ES	Prudhoe Bay DS 02-04	BP
Mid-Continental U36A	3-S	Milne Point MPG-08	BP
Oilwell 700 E	4-ES (SCR)	Prudhoe Bay N-12	BP
Dreco 1000 UE	7-ES (SCR/TD)	Prudhoe Bay DS 06-19	BP
Dreco 1000 UE	9-ES (SCR/TD)	Prudhoe L-205	BP
Oilwell 2000 Hercules	14-E (SCR)	Stacked	Available
Oilwell 2000 Hercules	16-E (SCR/TD)	Stacked	Available
Oilwell 2000	17-E (SCR/TD)	Stacked, Point McIntyre	Available
Emsco Electro-hoist -2	18-E (SCR)	Stacked, Deadhorse	Available
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	Oliktok Point OPi2	Anadarko
Emsco Electro-hoist Canrig 1050E	27-E (SCR-TD)	Stacked	Brooks Range Petroleum
Academy AC electric Canrig	105-E (SCR-TD)	Stacked on ice pad at Chandler #1	Anadarko
Academy AC electric Canrig	106-E (SCR/TD)	Stacked	Chevron
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Prudhoe Bay DS 15 rig maintenance	BP
Superior 700 UE	2 (SCR/CTD)	Kuparuk well 1D-12	BP
Ideco 900	3 (SCR/TD)	Kuparuk well 1D-133	ConocoPhillips

North Slope - Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Nabors Alaska Drilling			
OIME 1000	19-E (SCR)	Oooguruk ODSN-40	Pioneer Natural Resources
Oilwell 2000	33-E	Stacked	BP

Cook Inlet Basin – Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Aurora Well Service			
Franks 300 Srs. Explorer III	AWS 1	North Fork Unit #34-26	Armstrong Cook Inlet
Marathon Oil Co. (Inlet Drilling Alaska labor contractor)			
Taylor	Glacier 1	Grossum Osskolof No. 7	Marathon
Nabors Alaska Drilling			
Continental Emsco E3000	273	Stacked, Kenai	Available
Franks	26	Stacked	Available
IDECO 2100 E	429E (SCR)	Stacked, removed from Osprey platform	Available
Rigmaster 850	129	Beluga River Unit 243-34	ConocoPhillips
Academy AC electric Heli-Rig	106E (SCR/TD)	DS Happy Valley #13	Chevron
Rowan Companies			
AC Electric	68AC (SCR/TD)	On site at Cosmopolitan	Pioneer Natural Resources

Cook Inlet Basin – Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Chevron (Nabors Alaska Drilling labor contract)			
Not Available			
XTO Energy			
National 1320	A	Platform A no drilling or workovers at present	XTO
National 110	C (TD)	Idle	XTO
Kuukpik	5	Mobilized to Tyonek platform	ConocoPhillips

Mackenzie Rig Status

Canadian Beaufort Sea

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
SDC Drilling Inc.			
SSDC CANMAR Island Rig #2	SDC	Set down at Roland Bay	Available

Mackenzie Delta-Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
AKITA Equtak			
Dreco 1250 UE	62 (SCR/TD)	Rig Racked in Inuvik, NT	Available
Modified National 370	64 (TD)	Rig racked in Inuvik, NT	Available

Central Mackenzie Valley

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Akita/SAHTU			
Oilwell 500	51	Rigging up; Bear Island, Norman Wells	Imperial oil

The Alaska - Mackenzie Rig Report as of July 2, 2008.
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 Alan Bailey

JUDY PATRICK

Baker Hughes North America rotary rig counts*

	June 27	June 20	Year Ago
US	1,913	1,906	1,775
Canada	356	259	231
Gulf	64	71	77

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

● PUBLIC OPINION

Prices change public opinion on energy

By H. JOSEF HEBERT
Associated Press Writer

High gasoline prices have dramatically changed Americans' views on energy and the environment with more people now viewing oil drilling and new power plants as a greater priority than energy conservation than they did five months ago, according to a new survey.

The poll released July 1 by the Pew Research Center shows nearly half of those surveyed — or 47 percent — now rate energy exploration, drilling and building new power plants as the top priority, compared with 35 percent who believed that five months ago.

The Pew poll, conducted in late June, showed the number of people who consider energy conservation as more important declined by 10 percentage points since February from a clear majority to 45 percent. People are now about evenly split on which is more important.

The number of people who said they considered increasing energy supplies more important than protecting the environment increased from 54 percent in February to 60 percent and the number of people who favor oil drilling in Alaska's Arctic National Wildlife Refuge also increased.

The poll released July 1 by the Pew Research Center shows nearly half of those surveyed — or 47 percent — now rate energy exploration, drilling and building new power plants as the top priority, compared with 35 percent who believed that five months ago.

"This shows the real impact of higher gas prices on the public," said Carroll Doherty, associate director for the Pew Research Center for the People & the Press, which commissioned the telephone survey of 2,004 adults from June 18 to June 29. The margin of error was plus or minus 2.5 percentage points, slightly larger for subgroups.

Since February, gasoline prices have soared from just over $3 to a national average of $4.08 a gallon, according to the Energy Department.

Broad-based shift

The shift toward embracing more energy production was seen across different age and political groups, reflecting a change in attitudes among Democrats, independents, women, and young people

see **VIEWS** page 6

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● FINANCE & ECONOMY

State could earn $10B plus from oil this year

New AOGA report looks at the role oil plays in employment, wages and charitable giving; updates, expands figures from 2000

By ERIC LIDJI
Petroleum News

The State of Alaska most likely earned more than $10 billion this fiscal year from oil and gas operations, according to a new look at the role of the industry in the state economy.

The revenue figure is part of a larger report on how oil and gas operations figure into job creation, wages and charitable giving in Alaska, conducted by Information Insights and the McDowell Group for the Alaska Oil and Gas Association.

The industry group presented highlights of the report before the Anchorage Chamber of Commerce on June 30, the last day of the state fiscal year.

The $10.2 billion revenue figure, which will be either validated or revised when the state releases year-end financial information, represents the reality of ever-rising world oil prices and the first fruits of a revised production tax enacted last fall, but retroactive to the beginning of the fiscal year.

Still, the number is surprising compared to recent revenues and forecasts.

The state made "only" $5.1 billion from oil revenues in fiscal year 2007. And as recently as the spring forecast released this past March, state economists predicted that revenue from the oil industry would total just under $9 billion this fiscal year.

According to the report, the state has collected more than $75 billion in revenues from the oil industry since 1959, with nearly one third of that coming in the last 10 years.

Industry employs 13,000

The new report updates and expands a similar study AOGA commissioned in 2000, back when the delivered price of Alaska North Slope crude oil averaged $23.27 per barrel, nearly one fourth of the average price for the fiscal year just ended.

The new report found that the oil industry was the largest private sector employer in the state, responsible for 41,744 jobs in 2007. However, nearly 70 percent of those jobs were "induced" by the industry, meaning jobs throughout Alaska made possible by the spending of those in the oil industry.

According to the report, the state has collected more than $75 billion in revenues from the oil industry since 1959, with nearly one third of that coming in the last 10 years.

The 4,497 Alaskans directly employed by the industry through extraction, refineries and operations on the trans-Alaska oil pipeline received $643.8 million in payroll with an average monthly wage of $12,737. That makes the oil industry the highest paying of any industry in the state, more than 3.5 times the statewide average.

The industry also indirectly employs 8,410 people through the support industry, not part of the induced jobs total. Those support positions earned $769.2 million in wages last year.

Collects data in one place

Information Insights and the McDowell Group conducted the study using the purchasing and payroll records for 12 major producers, transporters and refiners of oil in the state, as well as 300 vendors that billed more than $500,000 in 2007.

The new report classifies oil industry jobs under one heading, simplifying the measure of jobs usually categorized under four other existing headings: mining, transportation, construction and manufacturing.

As well as taking a statewide look, the report also breaks out the economic impact of the industry in six municipalities along the road system: Anchorage, the Fairbanks North Star Borough, the Kenai Peninsula Borough, the Matanuska-Susitna Borough, the North Slope Borough and Valdez.

The full report is available at www.aoga.org. ●

Contact Eric Lidji at 907-770-3505 or elidji@petroleumnews.com

● FINANCE & ECONOMY

Canadian juniors emerge from wilderness

Dramatic shift to unconventional plays in B.C.; Saskatchewan pumps life into M&As; Canada expected to remain turn-over leader

By GARY PARK
For Petroleum News

The little engine that could is back on the main line, pulling the heavy load at the bottom end of Canada's petroleum industry after two years of wheel-spinning in the wilderness.

Derailed by the collapse of the income trust sector, a cold shoulder from investors, changes in government climate-change and royalty regulations and a shortage of organic growth prospects, the junior players were driven into a prolonged slump.

The economics for companies that rely on conventional oil and natural gas for a future in the Western Canada Sedimentary basin are daunting.

What has changed is a dramatic shift from the traditional base to the unconventional plays that have made EnCana a raging success and attracted a full array of other players from senior producers to those smart enough to gain a foothold in northeastern British Columbia, northern Alberta and southern Saskatchewan.

With gas prices racing above $10 per thousand cubic feet, after floundering around $4-$6 for two years, and oil prices holding their breathtaking levels, a turnaround is under way.

But the same old rules apply for the little guys. Those who lack credible managements and have failed to lay out convincing long-term strategies are as much out of favor as ever.

The general assumption among analysts is that M&A activity will come back to life in the second half of 2008 after languishing in recent months.

No one is suggesting that the value of deal-making will come anywhere close to last year's record C$49.8 billion, which was up C$20 billion from 2006.

Plenty believe strong Canadian M&A deal making will revive

Even so, there are plenty who believe Canada will retain its lead position in the global M&A marketplace.

In recent years, Canada has seen 8 percent of its oil and gas properties turn over annually, compared with 5 percent in the United States, 2-3 percent in the North Sea and 1 percent in the rest of the world.

Although the major integrated companies and the large U.S.-based companies that have unloaded most of the Canadian properties acquired in the 1990s and early 2000s are expected to remain on the sidelines, large independents are poised to plunge back into the marketplace for the first time in many years, David Vetters, managing director of Tristone Capital — underwriter for seven deals worth almost C$200 million in 2007 — told the Financial Post.

In recent years, Canada has seen 8 percent of its oil and gas properties turn over annually, compared with 5 percent in the United States, 2-3 percent in the North Sea and 1 percent in the rest of the world.

Arthur Korpach, head of global oil and gas at CIBC World Markets, told reporters there is a renewed mood of excitement that juniors are again a viable business for investors.

But he cautions that there is a divide between those who took early stakes in the unconventional plays — notably tight and shale oil and gas in British Columbia and Saskatchewan — and are positioned to reap the rewards and those who have been unable to present credible long-term plans for using their money and creating value for their shareholders.

He said the companies that have "found some exciting things to pursue" and can raise the necessary capital will be poised to buy out their weaker peers.

Don Greenfield, a partner in the Bennett Jones law firm in Calgary, told the Financial Post that more M&A activity is evident "because some of the gas producers are strapped for cash or unable to continue their growth curve."

Despite the firming of prices, some companies are putting themselves in play "because of both gas prices and the impact of royalty rates," he said.

Meanwhile, a lot of juniors simply haven't figured out what to do, regardless of healthy commodity prices.

Optimism rebuilding

But there is a rebuilding sense of optimism.

Ross Freeman, finance committee chairman of the Small Explorers and Producers Association of Canada, told an investors conference "there's a buzz again in the junior sector — people are raising money, mergers are happening and shares prices are starting to come back to where companies are actively interested in raising money."

Regardless of what has happened to Alberta royalties, he said many companies say the impact is "not overly significant, particularly in the current price environment."

But there is still the unknown of government climate-change regulations, Freeman said, adding SEPAC will try to ensure the burden on juniors is not too onerous.

He argued that junior producers should not have to monitor and compile information on their greenhouse gas emissions at the same level as large producers and plant operators because their emissions are so insignificant.

If the upper tier of juniors can grow substantially, turning themselves into intermediate players, they will be able to tackle the more expensive, more rewarding plays in British Columbia's Montney region and Saskatchewan's Bakken formation, Korpach said.

He said consolidation in the junior sector will create larger entities with the ability to succeed in the unconventional trends.

Even so, Korphach concedes that figuring out the best strategies to generate the best returns is as "tough or tougher today as it has ever been," with the challenge of raiding debt or equity capital presenting an obstacle to M&A transactions.

The longer gas prices hold on to their current gains, companies pumping less than 15,000 boe per day and with market-caps under C$1 billion, are starting to see hope of a return to the days when they could reach a production threshold and sell out to eager buyers, especially in the trust sector.

Trusts no longer dominant

While the trusts are no longer the dominant players in the M&A market there is a growing belief in a revival of deal making that could see Canada rebuild an intermediate tier in the 15,000-200,000 boe-per-day range.

Following a sluggish start to 2008, Sayer Energy Advisors counts on the pace picking up, so long as commodity prices stay robust and sharpen the appeal of fringe resource plays in British Columbia and Saskatchewan where a host of juniors have cornered sizeable chunks of property.

Although still struggling to raise equity and debt capital to pursue organic growth in a high-cost, limited-scope exploration environment in Western Canada, smaller companies with solid long-term strategies and strong asset portfolios are coming back to life.

If they can benefit from a building tidal wave of cash flow they can resume their traditional role, building enough reserves to get production to even 1,000 boe per day, then sell out and start the process anew. It's the best chance of drawing investors back to the junior sector.

The most buoyant assessments of the investment outlook for junior companies are tied to companies that are backed by proven management teams and that have credible plans to return value to their shareholders.

Those that haven't figured out what they are going to do got no help from the Alberta government when it modified the proposed royalty structure in a way that satisfied only those engaged in deep oil and gas activity. ●

● NATURAL GAS

ANGDA puts Gubik route work out to bid

Project covers some Enstar work; ANGDA seeks to make more routing information public; contract also covers Nenana, Glenn Highway

By ERIC LIDJI
Petroleum News

The Alaska Natural Gas Development Authority wants to study routes for a pipeline and road connecting the Gubik gas field to existing infrastructure along the trans-Alaska oil pipeline and the Dalton Highway.

The public corporation plans to spend up to $100,000 on the contract, which went out to bid June 27. The money will come from a $4 million allocation state lawmakers approved earlier this year specifically to help ANGDA weigh the various options for delivering natural gas to in-state markets and residents.


FORREST CRANE
HAROLD HEINZE

Gubik is a prospective gas field in the foothills of the Brooks Range currently being explored by Anadarko Petroleum. For most of the year the field has been thrown around as a way to supply in-state markets with natural gas without tapping the North Slope.

Enstar Natural Gas Co. is spending $6 million this year gathering field data about a possible pipeline connecting Gubik to its distribution grid in Southcentral Alaska.

But ANGDA doesn't see its project as "repetitive," according to CEO Harold Heinze.


CURTIS THAYER

Heinze said the work fits with ANGDA's broader and longer efforts to promote a natural gas system across the state. He called the Gubik project a "proactive" attempt to increase the pool of public information to a critical mass that might spur development.

"I think it's of value for us to form at least some idea," Heinze said.

Over the past year, ANGDA has spent more of its budget than usual toward projects designed to gather data for public consumption with the hope of getting entrepreneurs to take the baton. ANGDA recently put out a contract for a propane coordinator to create a business plan for a wholesale propane facility on the North Slope.

Enstar does see the ANGDA project as repetitive, and "a little bit frustrating" to boot, according to spokesman Curtis Thayer.

"It's a waste of government money," Thayer said. "What are they going to find different than what we find out?"

Thayer said Enstar, as the largest natural gas distributor in the state, is prepared to handle a Gubik pipeline, and would like to see the $4 million allocation go toward figuring out ways to maximize that pipeline through value-added industries, the kinds Enstar doesn't have experience managing.

"At the end of the day, there has got to be some synergies there," Thayer said.

Nenana and Glenn Hwy., too

In addition to routing a pipeline from Gubik to existing infrastructure, the ANGDA contract includes two other projects related to in-state gas issues.

The successful applicant will look at preliminary routes for connecting gas fields near Nenana to the population center in Fairbanks, as well as review existing fieldwork from proposed spur line routes along the Parks Highway, the trans-Alaska oil pipeline corridor and the Glenn Highway to look for possible trouble spots.

"We think it's important to understand the alternatives," Heinze said.

The contract is set to begin in August, with the majority of the work to be completed by the start of the year. ●

Contact Eric Lidji at 907-770-3505 or elidji@petroleumnews.com

continued from page 4

VIEWS

— all groups that in the past have generally championed conservation over energy development.

The survey comes as Congress is in the midst of a bitter debate over how to respond to the country's energy problems and as the two major presidential candidates also are sharply divided on energy priorities.

GOP candidate John McCain has called for building more nuclear power plants and ending a blanket moratorium on drilling in 85 percent of the country's coastal waters. His rival, Democrat Barack Obama, has emphasized incentives for conservation and development of alternative energy sources and opposes expanded offshore drilling.

Likewise, Democrats have been pushing for more conservation and energy alternatives in Congress and argued the country cannot drill its way out of its energy problems. Congressional Republicans argue the answer is more domestic energy production, including on federal lands and waters off limits because of environmental concerns.

Differences closing

The Pew poll, however, showed Republicans and Democrats moving closer together on the production vs. conservation dispute. The number of Democrats who said they saw increased production as the top priority jumped by 16 percentage points since February to 46 percent. Republicans holding that view declined from about half to 43 percent.

With the exception of the Arctic refuge, the poll did not address any specific energy proposals such as whether to lift drilling moratoria in some ocean waters, the pros and cons of nuclear energy, or the environmental impacts of coal burning power plants on global warming.

It sought to address general energy priorities, said Doherty.

Among the survey's most astounding findings is the dramatic increase in a span of five months in the support for energy exploration and production among groups that have traditionally championed conservation as being the answer to the country's energy problems.

For example, the percentage of liberals who said expanding energy exploration was their most important priority doubled from 22 percent in February to 45 percent; increased by 19 points to 50 percent among independents; and by 18 points to 46 percent among women.

Young people, who in the past have overwhelmingly leaned toward conservation, saw the most dramatic shift. Just over half of the people from 18 to 29 years of age saw expanding energy exploration more important, double the number in February.

The poll showed people remain sharply divided over oil drilling in Alaska's Arctic National Wildlife Refuge, which is now off limits. But in the June survey the number of people favoring drilling there increased to 50 percent, compared to 42 percent last February. Those who opposed drilling fell from 50 percent to 43 percent.

Public frustration over high gas prices and a warming toward more energy production has surfaced elsewhere as well.

Former House Speaker Newt Gingrich's Web site calling on people to sign a petition to "drill here, drill now" has recorded more than 1.2 million hits. ●

GOVERNMENT

House Republicans block use-it-or-lose-it bill for leaseholders on federal land

House Republicans blocked Democrats June 26 from requiring oil and gas companies to drill on the millions of acres of government land and water on which they already own federal leases.

Seeking to counter a push by congressional Republicans to lift a long-standing drilling ban on most offshore U.S. waters, Democratic leaders maintained the industry should first go after oil and natural gas in areas where they hold leases.

But the measure was defeated 223-195, short of the two-thirds vote required, with only a handful of Republicans voting for it.

Separately, lawmakers moved to help local mass transit systems cope with a rush of new ridership as people turn to public transit in response to high gasoline prices.

The House voted 322-98 to authorize $1.7 billion over the next two years to lower fares and expand operations as more riders flock to public transit. The transit measure, which must still be considered by the Senate, marks the first time federal money would be used to support local mass transit operating costs.

Angst over prices at pump

Democrats proposed the failed drilling mandate and the public transit help as lawmakers struggled to respond to public anger over $4 gasoline with the July 4th holiday and heaviest summer driving season approaching. As the House voted, oil moved into record territory at just over $140 a barrel, signaling that gasoline prices are likely to go higher this summer.

Opening the nation's offshore oil and gas resources has dominated the congressional energy debate in recent weeks. Republicans argue the drilling moratorium, in effect since 1981 over most federal waters outside the western Gulf of Mexico, has kept companies from increasing domestic energy production.

But Democrats counter that the fenced-off waters of the Outer Continental Shelf shouldn't be opened to drilling, when leases already provided by the Interior Department in other areas, mostly the western Gulf and in Alaska, aren't being exploited.

"We believe in use it or lose it," declared Rep. Rahm Emanuel, D-Ill., a key member of the Democrats' leadership.

The White House said President Bush would veto the use-it-or-lose-it legislation if it came to his desk, calling "absurd" the claim that, with today's oil prices, companies are not pursuing all the oil that they can recover economically.

—H. JOSEF HEBERT
Associated Press writer

● EXPLORATION & PRODUCTION

A lot riding on gas-rich Utica shale in Quebec

By GARY PARK
For Petroleum News

A stable of juniors is looking to a couple of thoroughbreds to lead the field to riches in what has emerged as one of the best resource bets in North America.

Talisman Energy and Forest Oil are rolling out plans for various shale properties, with the province of Quebec suddenly thrust into the spotlight.

Wellington West Capital Markets analyst Kim Page said the presence of majors gives weight to the Utica and Lorraine plays in the St. Lawrence Lowlands.

If the play becomes commercially viable, "the return opportunity … is very high," he said.

Vic Vallance of Fraser Mackenzie, Northern Rivers Capital Management hedge fund manager Alex Ruus and Sprott Asset Management Chief Executive Officer Eric Sprott are all hitching their wagons to the juniors.

But it may take Talisman and Forest to establish that new fracturing technologies can unlock the full potential of the shales — something they are gearing up to tackle.

Forest focusing onshore

Having pulled out of the Gulf of Mexico to focus on the "repeatable, low-risk opportunities" of onshore North America — the strategy that has made EnCana so successful — Forest is already buoyed by results from two vertical wells in the Utica shale, which have tested at 1 million cubic feet per day.

Based on its holdings of 339,000 gross acres and 270,000 net acres, Forest has rated its net unrisked potential at 4.12 trillion cubic feet, with two prospective horizons, and access to major markets in the northeastern U.S.

Forest, which has several junior partners in the region, said its Quebec assets may hold as much as 4 tcf and describes the Utica shale as having similar rock properties to the Barnett shale in Texas.

It has scheduled three horizontal wells this summer, is targeting initial production in 2009 and plans to start full-scale drilling in 2010.

Talisman working unconventional potential in North America

Talisman, in deciding to jettison several global assets and concentrate heavily on evaluating its unconventional resource potential in North America, could spend up to C$130 million over the next 18 months on its Utica and Lorraine holdings alone.

It plans to test three to four pilot areas, drilling six vertical and 10 horizontal wells, as it aims to enter the development phase about mid-2010.

Once it has drilled four wells by early 2009 it expects to have 760,000 net acres on land that has an estimated 48 tcf of original gas in place at 75-350 billion cubic feet for every 640 acres. Well costs at depths of 5,000-9,000 feet are calculated to cost C$5 million each.

Market gains posted by a number of smaller players

The "ponies" in the field include Gastem, Questerre Energy, Junex, Altai Resources, Epsilon Energy and Petrolympic, all of which have posted staggering market gains on what were mostly penny stocks entering 2008.

Sprott Asset, which holds 14 percent of Gastem, 15 percent of Questerre and 13 percent of Altai, started to build those interests late in 2007.

Northern Rivers owns 11 percent of Gastem through its four funds — a fact that Ruus said "reflects how bullish we are."

When Forest started drilling on Gastem's property last summer, he "became convinced that there was probably a commercial discovery" in Quebec.

Page initiated coverage of Gastem, Questerre and Junex in late May, confident the most prospective area of the Utica play has the potential for about 25 tcf of recoverable resource.

He believes Junex, with 1.2 million acres making it the largest land-holder in the Lowlands, could be sitting on 1.25 tcf of gas.

However, Questerre Chief Executive Officer Michael Binnion has injected some cautionary notes, suggesting the engineering and commerciality still pose risks and are the main issues that the Talisman and Forest programs will address over the next 18 months.

"We have a play that in terms of its potential value is currently being risked as a full exploration play," he told a Calgary investor conference. "We think we're past the exploration phase, but we certainly are not into the proven commerciality phase."

Binnion said much more information is needed on the recovery rates per well and what the decline curve will look like. ●

NATURAL GAS

Fiscal certainty part of commerciality

ExxonMobil, Chevron tell legislators what companies consider before committing natural gas to a pipeline anywhere in the world

By KRISTEN NELSON
Petroleum News

BP, ConocoPhillips and ExxonMobil have a lot of natural gas on Alaska's North Slope to ship to market once a gas pipeline is in place. Chevron has a lot — or very little — depending on the outcome of the current Point Thomson litigation, because Point Thomson holds the bulk of Chevron's natural gas.

If Point Thomson "gets resolved favorably from our side then we'd be a significant player in a pipeline. If it doesn't, we're just going to be a little trivial part" of gas shipments, Chevron's Alaska manager, John Zager, told legislators in Anchorage June 17. The gas Chevron would have to ship without Point Thomson is based on the company's small interest in Prudhoe Bay.

The Alaska Department of Natural Resources has terminated the Point Thomson unit, a decision which is being litigated, and is in the process of taking back the leases. ExxonMobil (36 percent), BP (32 percent), Chevron (25 percent) and ConocoPhillips (5 percent) are the largest leaseholders at Point Thomson.

Chevron's potential share of Point Thomson gas is some 2 trillion cubic feet, and if it has that gas, there is a pipeline coming and a development plan for Point Thomson, Chevron would nominate natural gas in an open season, Zager said.

"We will commit to firm transportation for our known gas reserves in a pipeline we are confident provides reasonable upstream economics and terms," he said.

Zager said Chevron isn't involved in either the TransCanada or the Denali gas pipeline projects, but might have an interest in equity ownership "roughly commensurate" with a ship-or-pay commitment.

"The reason for that is not to control this industry or the basin; the reason for that is more financial," he said. Chevron likes to see a "big debt, which is what a ship-or-pay commitment is" offset with equity in the pipeline "so it matches up and doesn't really change a company's debt-to-equity ratio," Zager said.

Reasonable upstream economics

"We will commit to firm transportation for our known gas reserves to a pipeline we are confident provides reasonable upstream economics and returns," he said.

Zager said "known gas" is important. If Point Thomson is resolved so that Chevron retains its interest in that gas, that would be about 2 tcf, and if "we've got a pipeline coming and we have a development plan (for Point Thomson), then we would be sure we'd want to nominate and save space for our 2 tcf of gas."

But that's known gas, he said. Chevron won't be

see **CERTAINTY** *page 10*

EXPLORATION & PRODUCTION

Deepwater wells prove up discoveries

Stones, Pony prospects in U.S. Gulf appear confirmed by exploration, appraisal drilling; significant reserve possible at Stones

By RAY TYSON
For Petroleum News

Exploration and appraisal wells appear to confirm important deepwater oil discoveries at the Stones and Pony prospects in the U.S. Gulf of Mexico.

Stones minority partners Petrobras and Eni reported that their Stones-3 well on Walker Ridge Block 508 demonstrated the potential for a significant reserve, but did not disclose any reserve estimates.

"This result confirms the potential of significant oil reserves in this type of reservoir in the Gulf of Mexico," Petrobras said in a regulatory filing.

The Stones-3 well, drilled in 7,500 feet of water, is about 200 miles off the coast of Louisiana. The well was drilled just north of the Stones-1 discovery well, encountering "multiple oil-bearing sands" on its way to a total depth of about 29,400 feet.

"The well data will now be analyzed whilst future drilling activity is currently being planned to further define the size of the discovery," Eni said.

Eni owns a 15 percent working interest in Stones. The other partners are Royal Dutch Shell Plc, the main operator with a 35 percent holding; Marathon Oil Corp. with 25 percent; and Brazil's Petrobras at 25 percent.

Eni holds a considerable exploration portfolio in this area, with several new opportunities being matured for future drilling, the company said. In fact, the Stones unit, consisting of 10 blocks, was part of an exploration portfolio acquired by Eni in July 2007 from Dominion. The Stones discovery itself is near other large Lower Tertiary discoveries in deep reservoir sands, such as St. Malo (in which Eni participates) and the Petrobras-operated Chinook and Cascade fields. Eni also owns interests in 158 leases on the North Slope of Alaska.

Pony sidetrack completed

In a separate development, Hess Corp. successfully completed a sidetracked appraisal well at its Pony discovery on Green Canyon Block 468, the company said. The well was drilled by Diamond Offshore's semi-submersible Ocean Baroness in 3,400 feet of water.

The Pony No. 2 sidetrack encountered the same objective sands as Pony No. 1 and No. 2 wells, Hess said, adding that the sidetracked appraisal well reached a measured depth of 33,362 feet from a surface location 7,400 feet northwest of the discovery well.

"The main pay sand was oil-filled throughout the interval drilled," Hess said.

The appraisal well is part of a comprehensive ongoing data gathering program that is being conducted over the Pony prospect, which is 100 percent owned by Hess. Recoverable resources were estimated to be around 200 million barrels of oil equivalent.

The company said it was evaluating development concepts for production from the Pony prospect before making a final investment decision.

Some industry observers initially believed the Nexen-operated Knotty Head discovery on Green Canyon Block 512 and the Pony discovery actually were part of a single reservoir that could have rivaled some of the largest oil accumulations found in the Gulf of Mexico's prolific Green Canyon area, including such titan discoveries as Tahiti, Atlantis, Mad Dog and Holstein.

At the time Hess' reserve estimate for Pony ranged widely from 100 million to 600 million barrels of oil equivalent. And the company had reported 300 feet of initial oil sands at that well's 29,658-foot level and 475 feet of pay at the 32,448-foot level, an estimated increase of 175 feet from earlier drilling results.

The initial well at the Knotty Head prospect encountered about 600 feet of net oil pay in multiple zones. Nexen's resource estimate for the field ranged from 200 million to 500 million barrels of oil equivalent.●

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CERTAINTY

nominating any yet-to-be-found gas. Zager said that beyond known reserves at Prudhoe Bay and Point Thomson, there is a "big wedge" of gas needed to fill the expected life of a gas pipeline "and I don't think we have any responsibility" for nominating beyond the company's known gas.

As far as "reasonable upstream economics and returns," for Chevron that means "reasonable economics" for Point Thomson, because that is where Chevron has the bulk of its gas.

What kind of confidence does Chevron need to have?

Zager said the company will look at the open season materials and evaluate the quality of those materials.

One issue is, are the key variables controllable. He said that doesn't mean controllable by Chevron or controllable by the state, but whether all of the parties could get together and solve the problem.

The Point Thomson issue is controllable: "We could get together and we could solve that and we'd have confidence going forward in what our reserves are going to be" for an open season two or three years out.

Future gas prices are not controllable: It's a big risk, but it is one companies in the business are used to taking, Zager said.

Construction cost is partially controllable. Steel and labor costs are not controllable, he said, but pipeline design and project management are controllable.

One thing Chevron will look at is the pipeline cost that's included in the open season: "How confident are we that that number will not be exceeded when the actual bill comes due?" Zager said when you sign a shipping commitment "you're giving a blank check" to the pipeline developer and if a $30 billion project becomes a $40 billion project, "your ship-and-pay commitment just went up commensurately. Your wellhead price went down commensurately. And what you thought was an economic project at Point Thomson may not be anymore."

What Chevron will look at is the quality of work done before the open season and its confidence in the pipeline developer. It will also do its own assessment as to whether it thinks the number in the open season will be met.

Referring to the Alaska Gasline Inducement Act provision that an AGIA-licensed pipeline would price expansions using rolled-in tariff rates (the cost is spread over all shippers) for increases of up to 15 percent beyond the original tariff, Zager said Chevron would look at the tariff assuming that at some point there would be a 15 percent increase.

JUDY PATRICK

John Zager said Chevron wants to do projects "in the most economic way. And the state, given the ACES (production) tax, certainly should want us to do projects in the most economic way" because "a certain percent of the capital investment is going to be basically picked up by the state in the form of credit" for upstream development projects.

Much alignment with state

Cost risk is another issue Chevron will look at.

"Right now it looks like basically it's borne by the shipper" in the TransCanada proposal, with "maybe a little wedge of it" going to TransCanada.

"We'd like to see that spread out so that there's some real incentive for the developer to meet the number that they put into the open season proposal. If there's going to be pain to go around the person that's putting together the proposal should share in that, at least proportionately to the other parties and the state." Between current production taxes and royalties "most of that money will directly or indirectly be coming out of the state's pocket," Zager said.

State taxes, fiscal certainty, is an issue that's been discussed and "it's going to be a real issue," he said.

Zager said Chevron wants to do projects "in the most economic way. And the state, given the ACES (production) tax, certainly should want us to do projects in the most economic way" because "a certain percent of the capital investment is going to be basically picked up by the state in the form of credit" for upstream development projects.

Essentially the state is "a co-investor with us," Zager said, and noted that "I haven't seen that reality being percolated down in behaviors yet."

Referring to Point Thomson he said the state should want to see a pilot project done first to prove up the development plan, "because if it doesn't work, we've just put $10 billion into something we could have found out for a billion-two, a billion-three, and you know, we need to be aligned on this and start thinking like investors what's the right and most prudent investment for all of us."

Exxon: commercial includes taxes

ExxonMobil has indicated its willingness to commit its gas to a line on commercial terms.

Craig Haymes, ExxonMobil Production's Alaska production manager, said in response to a question from Sen. Bert Stedman, R-Sitka, at a June 18 legislative hearing in Anchorage, that firm transportation commitments create a liability for the company.

Referring to information in the state's finding on TransCanada Alaska's application for an AGIA license, Haymes noted that the state's consultants document the amount of yet-to-be-found gas that would be required to keep a gas pipeline full for 35 years: 57.5 trillion cubic feet for a 4.5-billion-cubic-foot-a-day line, 22 tcf more than known reserves.

However, the Brown, Williams, Moorhead & Quinn report notes that more than 57.5 tcf will be required "because gas production eventually declines for each vintage of proved reserves," so actually 70-80 tcf would be required to fill a 4.5 tcf a day line for 35 years.

Shippers make a commitment for firm transportation, knowing fields will decline, so a commitment includes an unknown amount of yet-to-be-discovered gas. ExxonMobil will back that commitment and finance it and carry it as a liability, Haymes said.

The company has "to cover that firm transportation commitment whether we've got the gas or not," he said, giving the company the incentive to explore for more gas and to encourage others to explore for more gas.

He said ExxonMobil has stated its willingness to sell gas at the wellhead or commit to a pipeline.

Stedman asked if that meant ExxonMobil will be making commitments for yet-to-find gas or just the known.

Haymes said it revolves around the market: A utility company would be looking for long-term commitments, 25 to 35 years, in buying gas from a producer.

If ExxonMobil committed 1 bcf or 1.5 bcf a day for 25 to 30 years, the company would be "on the hook for that all the way through and we know today we don't have that much gas."

There would be exploration for more gas, but the liability is with the company that committed to the utility, and if no more gas is found, the utility would buy on the spot market, paying a premium. Ultimately the producer that committed to provide the gas pays, he said.

Haymes said there are "substantial uncovered commitments" which ExxonMobil would have to underwrite.

Commitments conditional

ExxonMobil will be able to make commitments in an upcoming open season, Haymes said, noting that: "Those commitments will be conditional."

They would be "conditional on reasonable commercial terms," as anywhere else in the world where the company does business.

"And those conditions would be conditional on reaching a unanimous conclusion between the various agencies on the right offtake rate." That's no different than what ExxonMobil does anywhere in the world, Haymes said.

The Alaska Oil and Gas Conservation Commission's "mantra, as we know, is to maximize resource recovery," so there will be a tradeoff between gas and oil. "In an ideal world you'd like to have both, but reality, anywhere in the world, you never get both. And so at some point there's a tradeoff," he said, since there is never complete recovery from reservoirs.

Are taxes included?

Rep. Carl Gatto, R-Palmer, asked Haymes if commercially reasonable terms would include state tax terms.

Haymes said yes. "When we talk about commercial terms, we're talking about all commercial terms that would impact economics or cash flow for a producer such as ourselves. So yes, it would include the fiscal terms."

He compared it to going to a bank for a home loan — you would want to know the interest rate going in; "this is no different — on a much larger scale."

Gatto pointed out that the state offered 10 years of certainty under AGIA; is 10 years not enough, he asked Haymes.

"If we had firm transportation commitments that were for 10 years, then that would be sufficient," Haymes said. But firm transportation commitments are likely to be for much longer, he said.

Asked by Rep. Les Gara, D-Anchorage, if "Exxon at this point is not interested in the British Petroleum and Conoco deal but is interested in possibly becoming a part owner of the TransCanada deal?" Haymes said ExxonMobil is "looking at both proposals; we're evaluating both proposals very, very carefully. We believe that eventually a gas pipeline will need all of the producers and the state to come together. So we're looking at both. We haven't ruled out either option at this point in time."

Gara asked if reasonably commercial terms would mean production tax cuts.

"I'm not sure yet what those reasonably commercial terms would be," Haymes said. "They would be worked by our gas marketing company and they would look at that and just like they do for every gas deal in the world they will do the commitment on the same basis." ●

● FINANCE & ECONOMY

EIS: Energy demand on the fast track

Agency predicts demand to rise 50% over 20 years, mostly in developing countries

By ERIC LIDJI
Petroleum News

More people driving more cars and using more power means global energy demand could increase at least 50 percent between 2005 and 2030, according to a new federal report released June 25.

The increased demand would overwhelmingly come from nations outside of the Organization for Economic Cooperation and Development, where consumption is expected to increase 85 percent, according to the International Energy Outlook 2008, a new publication from the U.S. Energy Information Administration.

Meanwhile, energy use in nations within the OECD is expected to jump 19 percent.

Total global energy use is expected to hit 695 quadrillion British thermal units by 2030, compared with the 462 quadrillion Btu used in 2005.

Total global energy use is expected to hit 695 quadrillion British thermal units by 2030, compared with the 462 quadrillion Btu used in 2005.

That demand will come from all known fuel sources, but fossil fuels will continue to supply most of the power. Liquids will remain the dominant fuel source because of transportation and industrial use. Demand is expected to jump from 83.6 million barrels of oil equivalent per day in 2005 to 112.5 million boepd in 2030.

But other fuels will grow as well, and the report predicts liquids will represent a smaller share of the energy market in 2030 than it does today. And if high prices continue, consumption is expected to slow across the board.

But "slow" might mean the difference between a sprint and a run. To meet global demand in 2030, the report estimates supplies of liquid fuels will jump 28.2 million bpd above the 84.3 million bpd produced in 2005.

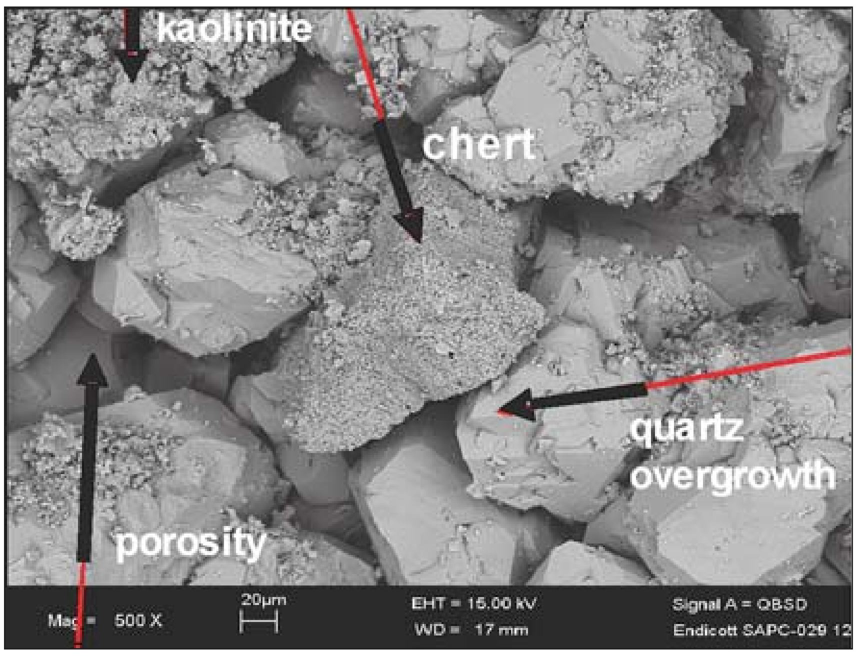
Use the high case for prices?

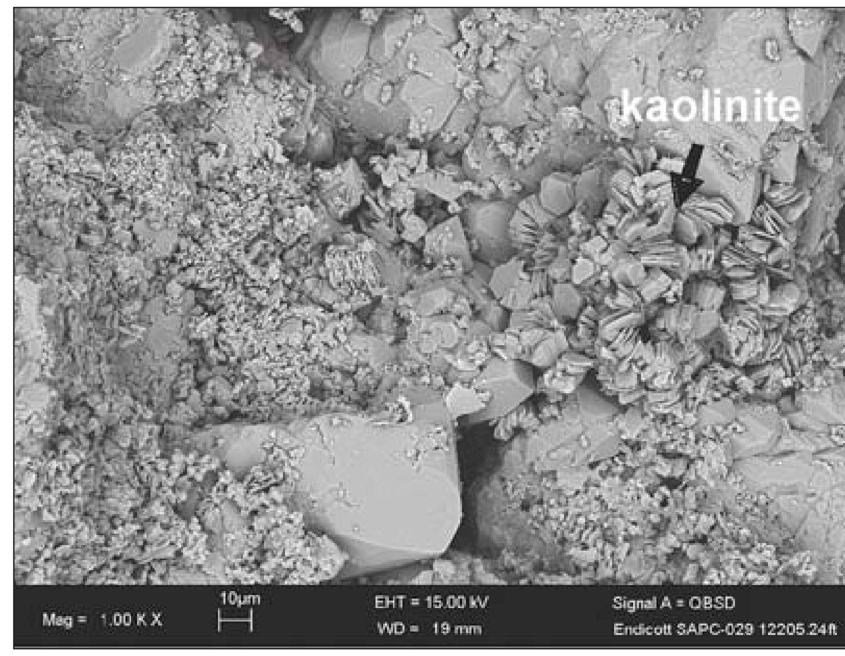
To make these assumptions, the International Energy Outlook uses a reference case based on oil prices that drop to $70 a barrel in nominal dollars by 2015 and rise again to $113 a barrel by 2030.

That might raise eyebrows at a time when prices hover around $140 a barrel, and so the EIA also included a high price estimate where world oil prices reach $186 per barrel in 2030, nearly 65 percent higher than the reference case.

"Given current market conditions, it appears that world oil prices are on a path that more closely resembles the projection in the high price case than in the reference case," the report said.

see **DEMAND** page 13





COURTESY BP EXPLORATION (ALASKA) INC.

Scanning electron micrographs of Endicott reservoir rock showing sand grains and clay (labeled "kaolinite"). During initial production the oil occupying voids (labeled "porosity") between the grains is removed, but residual oil remains adhered to the clay. Low salinity water can detach the residual oil from the clay.

● EXPLORATION & PRODUCTION

Endicott LoSal™ testing enters new phase

Before full implementation BP wants to verify that low salinity water will flush out oil left behind by conventional waterflood

By ALAN BAILEY
Petroleum News

Spurred by the prospect of teasing out more oil from the Endicott oil field on Alaska's North Slope, BP has started pumping low-salinity water at a rate of about 5,000 gallons per day into an injector well in the field. The idea is to flush oil towards a producer well that bottoms out about 1,000 feet from the injector, to test the effectiveness of the company's new LoSal™ enhanced oil recovery technique, John Denis, ACT East resource manager, told Petroleum News June 27.

If the test meets expectations, the water will induce the flow of a bank of oil that will reach the producer well in a few months time — the test should be completed by the end of 2008 and will end up costing something in excess of $10 million, Denis said.

If the new technique goes into full operation at Endicott it could increase waterflood oil recovery by 25 to 30 percent, he said.

On the Web

See previous Petroleum News coverage:

"LoSal(TM) test at Endicott," in the Jan. 29, 2006, issue at www.petroleumnews.com/pnads/891705134.shtml

Waterflood

Conventional waterflood in an oil field involves pumping seawater or oilfield produced water through the field reservoir, to flush residual oil towards produc tion wells. But for a number of years people have investigated the way in which the composition of the water changes the effectiveness of the waterflood technique. BP became interested in this work and in 2003 started ramping up its research into the use of low salinity water to significantly increase waterflood oil recovery, Denis said.

Jim Seccombe, BP team lead for resource planning, explained how low salinity waterflood works.

After the removal of free oil from the pores between the rock grains in an oilfield reservoir, the residual oil left behind tends to stick to the clay that typically coats the grains, Seccombe said. However, the chemistry of the various materials involved is such that low salinity water proves much more effective than saline water in breaking the clay-oil molecule linkages — the water breaks the electric bonds between the oil and the clay, he said.

The oil attaches to the clay somewhat like Velcro, with the water disconnecting the Velcro hooks, Denis said.

Lab testing

After successful laboratory testing of the technique with rock core, BP trademarked its LoSal™ process in 2005, Denis said. And presentations about the technique at various industry conferences created a great deal of interest.

"There's actually recognition throughout the industry that something's really here," Denis said. BP is a front runner in this technology, he said.

But the technique lacked a track record of use in practice.

"BP several years ago started looking worldwide, for where it could start demonstrating this technology," Denis said. "We knew it worked from what we had done in the lab, with the core, but we needed to scale up to field level."

Endicott turned out to be the best location for a field test, as part of BP's efforts to use new technologies to develop new oil reserves in existing oil fields on the North Slope — Endicott is a mature field with a substantial volume of oil remaining in place.

So in early 2006 BP announced that it had sanctioned LoSal™ testing at Endicott.

The initial testing involved pumping water in and out of single wells to find out how effectively the low salinity water shifts residual oil from reservoir rock within 10 to 20 feet of the well. That form of testing has since proved successful both in Endicott and in other North Slope oil fields.

"We've tested four wells in Endicott and across the slope we've tested 30 wells," Denis said. The tests involved a wide range of reservoir rock formations in the various fields.

The response to the technique did vary depending on which field reservoir was involved, but all reservoirs have responded positively to the low salinity water, Seccombe said.

The new dual-well test that has just started goes one step further than the single-well test by verifying that the LoSal™ technique will successfully flush oil across the considerable distance between an injector well and a producer well.

Controlled test location

To establish a suitable location in the Endicott field for this test, BP identified a relatively thin reservoir sandstone in which the fluid flow involved in the test can be constrained within a limited rock volume and to the single pair of injector and producer wells. The company checked the integrity of the test site by tracing the flow of fluids through the reservoir between the wells.

And to provide a baseline oil production level, against which the LoSal™ technique can be assessed, BP applied conventional waterflood to the test location, to a point where 90 percent of the

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LOW SALINITY

fluid coming out of the production well consisted of water.

"We actually started flooding these wells back in December, to sweep them out," Denis said. "You want to strip out as much oil as you can."

Then, as the test proceeds, any reduction in that "watercut" percentage will represent new oil produced as a direct consequence of the use of low salinity water.

However, BP is certain that the LoSal™ technique does work. The Endicott field test will establish some operating characteristics for the technique, to help in reservoir modeling and production planning, Denis said. The test will also give oilfield partners confidence in the technique and will help manage the risk of LoSal™ implementation.

"These are big investments and people shouldn't take them lightly," Denis said.

And the next step would be full deployment of the technique in appropriate locations on the North Slope.

"The expectation is that once you gain this competency, you go full field with all kinds of applications," Denis said.

Then LoSal™ will become part of a toolbox of enhanced recovery techniques that include the use of miscible injectant and, at some time in the future, carbon dioxide injection, he said.

Cost will vary

The cost of implementing and operating a full-scale LoSal™ operation will depend on the circumstances in a particular field location. And the source of low salinity water forms one of the main cost variables.

"The cost could vary quite a bit," Seccombe said. "You might be in places where you can drill shallow wells into aquifers and get water chemistry that works. Or on the other extreme you might be sitting on the ocean and build a reverse osmosis plant to turn sea water into lo-sal."

The amount of well reconfiguration needed for a LoSal™ implementation could also be a significant cost factor. Although in some situations the technique may work effectively using existing wells, in other situations wells may have to be redrilled, Seccombe said.

"So in some places it will actually be quite pricy — you'll be installing a big kit and redrilling all your wells," he said. "In some cases less so, because it's a simple add on to the (existing) kit."

In a new offshore field it may be quite straightforward to install LoSal™ from the get go, using a seawater desalination plant. For example, BP is considering the use of LoSal™ enhanced recovery in the Liberty field that it plans to develop in the Beaufort Sea, Denis said.

"You never know the (cost) answer until you know about the specifics (of a particular field)," Seccombe said. "Having said that, the key is that you now have access to a new (production) drive that you didn't have before."

And across an area such as the North Slope, even a modest percentage of additional oil recovery would represent a huge amount of new oil production. ●

FINANCE & ECONOMY

Crude hits new record on supply report

Oil prices shot to a new high near $144 a barrel July 2 and went on to a record close, as the U.S. government reported a bigger-than-expected drop in crude stockpiles and the threat of conflict with Iran weighed on traders' minds.

Light, sweet crude for August delivery rose as high as $143.91 on the New York Mercantile Exchange, then eased back to $143.57.

For the week ending June 27, crude oil inventories fell by 2 million barrels to 299.8 million barrels, 15.3 percent below year-ago levels the Energy Department's Energy Information Administration said. Analysts expected a drop of just 1.2 million barrels, according to a Platts survey.

With Middle East tensions building, Iran's oil minister warned that an attack on his country would provoke a fierce response. Minister Gholam Hossein Nozari said, however, that Tehran would not cut oil deliveries and would continue supplying the market even if struck by Israel or the United States.

—THE ASSOCIATED PRESS

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DEMAND

Those higher oil prices could slow demand. The report estimates that under the high price scenario, total global consumption of liquids would be 13 million barrels lower in 2030 than the 99.3 million barrels projected under the reference case.

However, the higher prices would most likely also spur development of previously uneconomic supplies of energy. As a result, unconventional fuels account for 20 percent of the total liquid supply in 2030 under the high case, but only 9 percent under the reference case.

Natural gas to replace oil

Under the reference case, global natural gas consumption is expected to jump from 104 trillion cubic feet in 2005 to 158 tcf in 2030, a nearly 52 percent increase.

"Natural gas is expected to replace oil whenever possible," the report said.

That growth could be even more pronounced with any widespread efforts to reduce carbon dioxide emissions around the world, because natural gas is generally a cleaner burning fuel than oil or coal.

Most of the growth in demand for natural gas is expected to come from industrial uses and electric generation, which combined are expected to account for 78 percent of the total demand in 2030.

Most of the additional supplies to meet that demand are expected to come from non-OECD countries, with a significant portion coming from exports like liquefied natural gas out of the Middle East and Africa.

The report expects coal use to increase at an average rate of 2 percent per year, unless there is an international agreement to curb greenhouse gas emissions.

For the full report, visit www.eia.doe.gov/oiaf/ieo/index.html. ●

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FINANCE & ECONOMY

Quality prevails among Canadian trusts

Number of energy trusts down; those that survived initial bloodbath planning for future, led by Penn West Energy, Enerplus, ARC

By GARY PARK
For Petroleum News

The 2006 Halloween mugging of royalty trusts by the Canadian government is starting to look like a trick morphing into a treat.

With 30 months to wait until Ottawa starts taxing trusts like other corporations, leaders of the trust sector have apparently decided that trying to cling to the past is a lost cause and that they're better off preparing for whatever lies ahead.

It seems the government of Prime Minister Stephen Harper has won the day, despite breaking a promise to leave trusts alone.

When it opted on Oct. 31, 2006, to rewrite the trust rulebook rather than risk losing hundreds of millions in tax revenues, the government was faced with plans by EnCana to spin off one-third of its assets into a trust — a move that would surely have set off a stampede into the trust fold by the full range of Canadian corporate giants.

The ensuing financial bloodbath was accompanied by calls for the heads of Prime Minister Stephen Harper and Finance Minister Jim Flaherty on a platter. Time and reality seem to have done the trick.

Number of energy trusts down

The number of energy trusts has declined from 37 at the end of 2005 to 31 by Dec. 31, 2006, and 26 entering 2008, with a host of once-popular names such as Fairborne, PrimeWest and Shiningbank reduced to historical footnotes.

Those who have survived are now busily rebuilding strength, helped by rampant commodity prices and shrewd leadership.

Meanwhile investors are again reaping rewards from trusts that are arranging their affairs to thrive once the tax change takes effect in 2011 by placing a greater emphasis on oil sands and heavy oil, shale and tight gas, stakes in Saskatchewan's Bakken oil play, and even the more exotic longer-term opportunities in carbon dioxide floods and enhanced oil recovery. It's a bit like taking a leaf from EnCana's playbook and opting for an unconventional strategy.

At the top of the heap, Penn West Energy Trust has been thriving on its shopping spree, including takeovers of Canetic Resources Trust and Vault Energy Trust. It ended the first quarter with production of 192,291 barrels of oil equivalent per day (up 49 percent from a year earlier) and revenues of C$1.13 billion (up 94 percent).

Enerplus, the second-largest trust, enjoyed a 32 percent jump in cash flow to C$290.83 million from a mere 3.6 percent increase in production to 90,000 boe per day.

Penn West and Enerplus are as strategically placed as it's possible to be in next-generation plays, with Enerplus looking to offload its 15 percent working interest in Total's Joslyn oil sands project to concentrate on developing its wholly owned Kirby oil sands lease, with 244 million barrels of contingent resources, while hunting for assets in the United States.

ARC, with production at 63,000 boe per day, is another savvy player, having rounded up interests in 77,800 acres of Montney prospects and allocated C$125 million (25 percent of its 2008 cap-ex) to delineation drilling of the play.

It is also engaged in enhanced oil recovery initiatives, notably the Weyburn and Midale CO2 floods in Saskatchewan and is working on a CO2 pilot at Redwater, Alberta, where injections are scheduled for mid-year.

Critics now strongly placed

Reflecting the pragmatism that has kept them thriving, the CEOs of Penn West, Enerplus and ARC (Bill Andrew, John Dielwart and Gord Kerr, respectively), were among the most outspoken critics of the government knee-capping of trusts.

But they apparently didn't let their anger cloud their judgment or their vision. They are strongly placed for whatever happens.

Baytex Energy Trust, Progress Energy Trust and Crescent Point Energy Trust are also rated by Tristone Capital Vice President Christina Lopez as candidates to flourish beyond 2011.

In her view, jumping ship before 2011 and converting to corporations means the wasteful loss of tax pools.

Sayer Energy Advisors President Alan Tambosso says that although asset and property deal making has cooled from 2007's pace in the first quarter, there is no reason to count trusts out of the marketplace, especially if they can target companies with substantial tax pools.

Consolidation is likely to see trusts who still have room to expand under the federal government's limits-to-growth rules seek mergers with those that have hit their limits.

Investment dealer Peters & Co. has forecast median first-quarter payouts of 59 percent of cash flow — down from the median 66 percent in the final quarter of 2007 and a sickly comparison with the 90 percent and more that was common in the trust heyday.

Producer trusts doled out a total of C$6.72 billion in 2007 vs. C$10.57 billion in 2006.

FirstEnergy Capital is upbeat about the 2008 outlook, with cap-ex and distributions making a course correction from the cutbacks of 2007.

The next milestone for trusts is looming, with Flaherty promising to roll out "in a matter of weeks" the new regulations for converting trusts into regulator corporations.

There's no indication whether that will seal the fate of trusts, or give them some more operating room. For now, they seem to have decided to play the hand they've been dealt. ●

● FINANCE & ECONOMY

Bakken shale making N.D. millionaires

By JAMES MACPHERSON

Associated Press Writer

Oscar Stohler was raised in a sod house in western North Dakota and ranched there for nearly seven decades. He never gave much thought to what lay below the grass that fattened his cattle.

When oilmen wanted to drill there last year, Stohler, 83, doubted oil would be found two miles underground on his property. He even joked about it.

"I told them if they hit oil, I was going to buy a Cadillac convertible and put those big horns on the front and wear a 10-gallon hat," Stohler recalled.

He still drives his old pickup and wears a mesh farm cap — but it's by choice.

In less than a year, Stohler and his wife, Lorene, 82, have become millionaires from the production of one well on their land near Dunn Center, a mile or so from the sod home where Oscar grew up. A second well has begun producing on their property and another is being drilled — all aimed at the Bakken shale formation, a rich deposit that the U.S. Geological Survey calls the largest continuous oil accumulation it has ever assessed.

Royalty payments coming in

Landowners in western North Dakota have a much better chance of striking it rich from oil than they do playing the lottery, say the Stohlers. Some of their neighbors in the town of about 120, from bar tenders to Tupperware salespeople, have become "overnight millionaires" from oil royalty payments.

"It's the easiest money we've ever made," said Lorene Stohler, who worked for decades as a sales clerk at a small department store.

State and industry officials say North Dakota is on pace to set a state oil-production record this year, surpassing the 52.6 million barrels produced in 1984. A record number of drill rigs are piercing the prairie and North Dakota has nearly 4,000 active oil wells.

The drilling frenzy has led companies to search for oil using horizontal drilling beneath Parshall, a town of about 980 in Mountrail County, and under Lake Sakakawea, a 180-mile-long reservoir on the Missouri River.

"I have heard, anecdotally, that there is a millionaire a day being created in North Dakota," said Ron Ness, president of the North Dakota Petroleum Council.

Number of millionaires up

Kathy Strombeck, a state Tax Department analyst, said the number of "income millionaires" in North Dakota is rising.

A second well has begun producing on their property and another is being drilled — all aimed at the Bakken shale formation, a rich deposit that the U.S. Geological Survey calls the largest continuous oil accumulation it has ever assessed.

The number of taxpayers reporting adjusted gross income of more than $1 million in North Dakota rose from 266 in 2005 to 388 in 2006, Strombeck said. The 2007 numbers won't be known until October, she said.

Bruce Gjovig, director of the University of North Dakota's Center for Innovation, said his informal survey estimates the number of new millionaires in Mountrail County, one of the biggest drilling areas of the Bakken, may be as many as 2,000 — or nearly a third of the county's population — in the next three to five years.

North Dakota's per capita income in 2007 was $36,846, ranking the state 30th in the nation and up from 42nd in 1997, said Richard Rathge, the state Data Center director and North Dakota demographer.

"The two main drivers are energy and agriculture income," Rathge said. The increasing wealth in the state from oil should push the average annual wage in North Dakota, he said.

The oil boom has spurred several tales of ordinary folks getting rich, said Tom Rolfstad, the economic development director for the city of Williston.

Rolfstad said he hasn't spotted any Ferraris or Rolls Royces in town, though several people can afford them now.

"I'm seeing a lot more big, shiny gas-guzzling pickups," he said.

Some big homes built

Several homes that cost more than a million dollars also are being built in Williston, he said. The community of about 12,500 people is perhaps best known as the hometown of NBA coach Phil Jackson.

Most people "don't want people to know how much money they got and they don't want to be tagged with being wealthy — they want to be themselves," Rolfstad said.

Oscar and Lorene Stohler said their newly found wealth hasn't changed them.

"We still know what tough times are," Oscar said. "We grew up in the Dirty '30s."

"We put our kids through college without that oil money," Lorene said.

The couple moved a few miles east to Beulah and paid cash for their new home, the first one they have owned. They have established trust accounts for their four children.

Lorene said the only thriftless purchase was an automatic sprinkler system for her flowers that surround the couple's new home. And Oscar bought a $1,000 ring for his wife to celebrate their 60th wedding anniversary.

"We got enough now to buy new stuff," Lorene said, "but we like our old stuff." ●

SAFETY & ENVIRONMENT

Groups sue to force decision on belugas

NOAA has proposed listing Cook Inlet whales, delayed decision for six months in April to prepare 2008 population estimate

By DAN JOLING
Associated Press Writer

Five conservation groups have sued the federal government for delaying a listing of Cook Inlet beluga whales under the federal Endangered Species Act.

The National Oceanic and Atmospheric Administration last year proposed listing the white whales that often can be spotted from Anchorage highways as endangered.

However, NOAA Fisheries officials announced in April that they would delay a decision for up to six months. Agency researchers said they needed more time to prepare a 2008 population estimate.

Conservation groups called that unacceptable and sued June 30 in U.S. District Court in Washington, D.C., to force an immediate decision.

"There is simply no lawful reason for further delay in protecting the Cook Inlet beluga whale," said Vicki Clark of Trustees for Alaska, which represents the conservation groups, in a statement.

NOAA Fisheries spokeswoman Connie Barclay said from Washington, D.C. that she had not seen the lawsuit and that agency officials would have no immediate comment.

Five groups sued

The five conservation groups include the Alaska Center for the Environment, the Center for Biological Diversity, the Natural Resources Defense Council, and two Homer, Alaska-based organizations, Cook Inletkeeper and the North Gulf Oceanic Society.

Anchorage is at the head of Cook Inlet, a 180-mile estuary that separates the Kenai Peninsula from mainland Alaska. Cook Inlet branches into Knik Arm and Turnagain Arm on its northern end.

According to the conservation groups, Cook Inlet belugas are genetically distinct and geographically isolated. Their numbers have fallen since the 1980s, when federal scientists estimated the population at 1,300 whales. The population now stands at about 375 animals.

Conservation groups petitioned to list Cook Inlet belugas as endangered in April 2007 and a decision was due in April.

Proposed developments cited

The groups said June 30 there was no reason for a delay and they cite a May 1 letter from the federal Marine Mammal Commission that concludes disagreement over the listing is "not scientifically credible."

The letter signed by executive director Tim Ragen said the delay was particularly troubling and the latest in a series of decisions that have failed to bring in resources needed to encourage the belugas' recovery.

"For two decades, the Service has repeatedly misjudged the plight of the Cook Inlet beluga whale population. It has assumed that alleviation of the primary factor that caused the decline (unmanaged subsistence harvests) would lead to recovery of the population. This assumption discounts the other factors that may now be contributing to the population's decline and impeding its recovery," Ragen wrote.

If the agency had listed the population when it was first petitioned to do so, its high risk of extinction and the eventual cost of necessary recovery actions might have been reduced, Ragen wrote.

Brendan Cummings of the Center for Biological Diversity said Cook Inlet is subject to development pressures including petroleum drilling and production, sewage discharges, contaminated runoff and spills.

Several proposed development projects, including a bridge across Knik Arm, expansion of the Port of Anchorage, and the massive Chuitna Coal Mine, also would directly affect some of the whale's most important habitat, he said. ●

FINANCE & ECONOMY

Oil executives: Costly oil here to stay

At Madrid meeting company heads see no short-term solution to oil prices; Shell chief says time to focus on difficult oil

By GEORGE JAHN
Associated Press Writer

Top oil executives and a senior EU official June 30 urged the world to pull together in the face of skyrocketing energy prices, while acknowledging that — even if it does — costly crude is here to stay for years.

The comments to the World Petroleum Congress by EU Energy Commissioner Andris Piebalgs and the heads of Shell, BP and Spanish Repsol reflected a key theme of the four-day meeting in Madrid, Spain — how to bring order into volatile and ever pricier oil and related energy markets.

Underlining their concerns, oil rose to a new record high above $143 a barrel June 30, as expectations of a weaker dollar spurred investors to buy dollar-denominated oil futures as a hedge. Light, sweet crude for August delivery was up US$3.31 to US$143.52 a barrel in electronic trading on the New York Mercantile Exchange, by midday in Europe. Earlier in the session, the contract rose to a new record high of US$143.67 before falling back slightly.

Oil's new peak underscored the somber tone of the conference's opening session. While speakers expressed hope that prices will stabilize after more than tripling over the past three years they agreed that they are unlikely to return to their 2005 levels.

> *"The era of cheap energy is probably over at least for the medium term."*
> **—BP Chief Executive Tony Hayward**

"We need a global effort to improve our resilience," Piebalgs told delegates packing a cavernous plenary hall, while acknowledging that "there is no silver bullet" to lower prices, ease concerns about supply and reduce speculative investments propelling markets upward.

BP CEO Tony Hayward warned against hopes that present high prices are a bubble that will burst the same way that they did in the 1970s, saying the supply and demand picture had changed since them.

"The era of cheap energy is probably over at least for the medium term," he said.

"The last time oil prices surged to this level, new production from the North Sea and Alaska helped bring prices down," but now there are no new sources of "easy oil" to compensate, he said. Instead, said Hayward, OPEC production fell by 350,000 barrels a day last year — although demand has grown for five consecutive years — and in Russia, "production has started to decline."

Shell: difficult oil remains

While agreeing with Hayward that there was enough crude in the ground, Shell chief Jerome van der Veer acknowledged it was time to focus more on "difficult oil" — unconventional methods of recovery that are costlier and more complicated than the normal drilling process — to meet growing demand.

"There is hardly any additional access to easy oil," he said. "Most of the new supplies will be difficult oil."

Producers and refiners in the Spanish capital will be struggling to find answers not only on how to ensure stable supply, but also on doing it in a way that minimizes emissions of the greenhouse gases believed to cause global warming.

Repsol's Antonio Brufau touched on the task facing energy producers, saying their challenge was "to produce more oil and to deliver ... products with stricter environmental standards." He and the others emphasized the importance of carbon trading and storage as strategies for the future.

Still, with oil bouncing from high to higher, the primary concern at the meeting was over availability and prices that are propelled higher by a potent mix of developments.

see COSTLY OIL page 17

FINANCE & ECONOMY

Canadian drillers try to regain luster

Schlumberger buying Saxon, but no takeover wave expected as Canada oversupplied with rigs; Precision, Ensign move rigs to U.S.

By GARY PARK
For Petroleum News

Emerging battered and bruised from the roughest ride in its recent history, Canada's service sector has reason to hope the worst is over as gas prices lock in above $10 per thousand cubic feet.

Whether they have a new cause to be nervous set off a debate following a takeover offer in May that has Saxon Energy Services headed for the Schlumberger fold for C$592 million — a price that had shareholders and analysts complaining.

The deal won't be concluded until July when the offer must be approved by two-thirds of Saxon shareholders.

So far all that is known is that Saxon managers and related shareholders who own about 14 percent of the 84.6 million shares have tendered to the offer from a private company called Sword Canada Acquisition, which is owned by Saxon management, Schlumberger and First Reserve Corp.

Depending on the circumstances, if the deal is rejected Sword would collect a termination fee of C$17.3 million. It also has the right to match any competing offer.

Saxon, which started life in 2005 with nine rigs in Ecuador, had a fleet of 56 rigs at the end of 2007, with major and intermediate clients among its customers in North and South America. It also runs joint ventures with Schlumberger, one of the world's largest service companies, in Ecuador and Colombia.

Chris Gindl, an analyst with Dundee Securities, is urging Saxon investors to tender to the offer, which he views as a "done deal," with no white knights on the horizon.

Precision Chief Executive Officer Kevin Neveu said Canada is oversupplied with rigs, prompting his company to move 17 rigs south of the 49th parallel over the last year and schedule the transfer of another five or six this quarter, while opening a new U.S. headquarters in Houston.

No support for upcoming wave

There is no support among analysts for any theory that more takeovers are at hand.

Mike Mazar, an analyst at BMO Capital Markets, said that if a wave of consolidation was in the works "it would have happened by now."

He said international companies are not anxious to enter the Canadian market, which is overloaded with capacity.

Brian Purdy, with National Bank Financial, said Canadian land drillers have a heavy emphasis on natural gas, while buyers are seeking exposure to oil.

He said companies that are active in the oil sands could have some appeal to foreign buyers, suggesting that would be a good way for companies with large worldwide operations, but no presence in Canada, to gain some presence.

If Canadian companies did find favor on a global scale, the betting among analysts is that Precision Drilling Trust, Ensign Energy Services and Savanna Energy Services would have appeal.

Precision moved rigs to U.S.

Precision, which owns about 30 percent of Canada's rigs, and Ensign have decided against tying their futures to Canada alone, with both making strong bids to enter the United States.

Precision Chief Executive Officer Kevin Neveu said Canada is oversupplied with rigs, prompting his company to move 17 rigs south of the 49th parallel over the last year and schedule the transfer of another five or six this quarter, while opening a new U.S. headquarters in Houston.

While noting that "there's a renewed level of optimism in our client base compared with the last quarter of 2007," he said gas producers are still trying to come to terms with Alberta's royalty increases and are not totally convinced about the sustainability of gas prices.

Although Canada will remain Precision's home, like all other drillers it has to deal with the winter-spring thaw that "means for much of May and June a lot of our rigs are sitting around. … The U.S. is far less weather-dependent," he said.

In the 11 months since Neveu took over the helm from Precision founder Hank Swartout he has been assembling the pieces of global expansion that could start in August with the expiry of a non-compete agreement with Weatherford International, which acquired Precision's international division in 2005.

He aims to build the trust from Canada's dominant land driller into a key player in the U.S., and a worldwide power, applying the efficiencies that are essential to succeed in Canada's 10-week peak drilling season.

Precision showed its intentions in mid-June with a spurned $2 billion takeout bid for Houston-based land driller Grey Wolf on the heels of Grey Wolf's moves to merge with Texas-based Basic Energy Services.

Beyond the U.S., Neveu sees strong prospects in the Middle East, north-central Africa and parts of Latin America.

Ensign doing more work abroad

Ensign Chairman Murray Edwards said his company expects to generate more cash outside of Canada in 2008 for the first time in its 20-year history, the bulk coming from the U.S., with Australia, the Middle East and South America also contributing.

He said the fact that Canada is still lagging, despite increases in commodity prices "is cause for concern. … Clearly the growth opportunities are in the U.S. and international."

Edwards said there is only enough work to keep 700 of Canada's 900 rigs at work.

Add to that list the name of Savanna Energy Services, which is expanding its well servicing business into North Dakota, with an initial commitment of six rigs, all of them newly manufactured and designed for the U.S. market.

The company has also secured long-term drilling contracts in Texas for five conventional double drilling rigs, with three of the rigs being transferred from the Canadian fleet.

The new contracts represent about 10 percent of Savanna's fleet. ●

continued from page 16

COSTLY OIL

There is the weakening U.S. dollar; each time it loses traders buy oil as a hedge; and dollar appears set to fall further with Europe possibly moving toward interest rate increases as low U.S. rates stand firm — trends that will see more investors abandon the American currency.

Rising demand, supply interruptions have contributed to price

Adding to oil's more than twofold price increase in the past year is rising demand, particularly in fast-growing economies such as China and India. Supply interruptions in the Middle East and Nigeria have also contributed, as has falling production in Mexico. And tensions over Iran, OPEC's second-largest producer, have added to volatility.

In Jeddah, Saudi Arabia, earlier in June, the kingdom said it would add 200,000 barrels per day in July to a 300,000 barrel per day production increase it first announced in May, raising total daily output to 9.7 million barrels. But that pledge disappointed the U.S. and other major consumers arguing that supply is not keeping up with demand, even as the Saudis and other OPEC members blame speculators and the swooning dollar.

Although the Saudi and other OPEC oil ministers are among the more than 3,000 registered participants they are not known to be carrying any solution to be presented while in Madrid. That has lowered expectations that any decisions here will soothe the market. ●

continued from page 1

MEDIATION

table earlier this year by BP and ConocoPhillips.

Sen. Lesil McGuire, R-Anchorage, responding to public testimony, suggested at Anchorage legislative hearings June 19 that the administration should call a halt to the AGIA license approval process and talk to all the parties. She said at public testimony the previous day one man was concerned "that we are not facilitating, we're not doing enough to facilitate bringing all the parties together to try and figure out what we can do as a team to move the gas line forward for Alaska."

She asked Commissioner of Revenue Pat Galvin if the administration would consider calling a halt to the AGIA process and using a mediator to try to bring the parties together.

McGuire said people in her district, who have worked for ConocoPhillips for 15-20 years or for BP for 30 years, have told her "they feel ... this vote is for them or against them. That's how they feel."

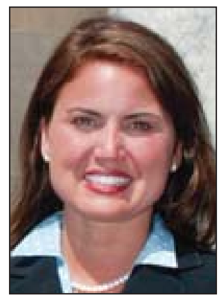
She said she believes the upcoming vote on AGIA "divides us."

McGuire compared granting the AGIA license to TransCanada to marriage.

"Once the license is locked in, we are, we're married. We're all married." Divorces can happen, she said, "but it's pretty expensive and it takes a lot of time and by the time a lot of people who are divorced look back over the time value of their life for 10 years, the same opportunities don't exist."

Concerns with AGIA

Some of the results of AGIA are good: "I like the pressure on the producers: I think it's good," McGuire said.



Sen. Lesil McGuire, R-Anchorage, said people in her district, who have worked for ConocoPhillips for 15-20 years or for BP for 30 years, have told her "they feel ... this vote is for them or against them. That's how they feel." She said she believes the upcoming vote on AGIA "divides us."

But, she said of the $500 million in matching funds: "We don't know if we need it or not. We don't know if that is the thing that we need to put into the equation to get it going. There might be other ways."

McGuire said she is concerned that the language in AGIA disallowing actions that could be construed as supporting another pipeline could get the state in legal difficulties. She said in spite of administration assurances that the statute was clear on the issue of what the state can and can't do in support of another project without being required to pay treble damages, "I have seen statutes interpreted in bizarre ways and I have seen judges agree with those bizarre interpretations. And I'm uncomfortable."

And approval of an AGIA license is "a political thing," she said, with 60 lawmakers, 50 running in the coming election, and "an incredibly popular governor: I mean, you cannot get in the way of this governor; she is very popular."

She also said she is concerned that some of the difficulties between industry and the Department of Natural Resources over termination of the Point Thomson unit have "gotten personal."

What about mediation

McGuire asked Commissioner of Revenue Pat Galvin if he would consider mediation.

Galvin told McGuire the issue she raised was the crux of the question of how the state gets from here to there.

The gas line is a commercial enterprise and the state is trying to "participate in a meaningful way," he said.

But it's difficult for a representational form of government to participate in the same way a business does, Galvin said.

"Frankly, we have to take a position; we have to make decisions on an ongoing basis in order to be able to ultimately succeed."

And the state can't do that "in a way that's very nimble and very real time, as you would hope to be able to do if you were in a purely commercial setting. And so we have to accept the fact that there's going to be a little bit more structure or separation between the decisions than what we would normally see as an optimal way to get from here to there."

Galvin said the state has to take a position. "We have to agree to it; we have to ... go through all the ... discussions, have all the pros and cons laid out and actually take a vote and you guys have to agree with the executive branch" in order for the process to go forward.

That's what AGIA does, he said. It sequences the decision making and allows the state to reach the goal, "so we have to do it in a certain manner."

Possible vs. not

One of the things that the state is establishing is "what's in the realm of the possible; what are the things the state's willing to do? But we're also establishing what's ... outside of the realm of the possible."

The state has been defining the possible vs. the not possible over the past few years, he said, calling it a fairly disjointed process which takes the state a long time.

"But we're doing that," Galvin said.

"We've established to a certain extent what's outside of the acceptable. And now we're trying to identify what is within the realm of the possible and we do that both in our decision making and our discussion of it."

It's difficult for a representational form of government to participate in (mediation) the same way a business does, Commissioner of Revenue Pat Galvin Galvin said. "Frankly, we have to take a position; we have to make decisions." …. He said it's critical for the Legislature and the executive branch, together, "to establish … the framework for further discussion.

He said it's critical for the Legislature and the executive branch, together, "to establish what is the framework for further discussion. And we do that by approving this license and saying these are the terms that Alaska wants to operate within."

If the state diverts from the process it is in — discussing and voting on an AGIA license — "it sets up an expectation that there is a whole realm of alternative possibilities and it expands the discussion beyond the ability for us to bring it back and actually find agreement ... get the parties to recognize what is the actual framework of the game, to reach consensus and conclusion and agreement within a relative period of time."

A decision on the license is a statement from Alaska on what the framework of the discussion will be, Galvin said.

Coming together

Galvin said he does not see the process "as erecting barriers in our ability to bring the parties together. In fact I think that it will be a major advancement in our ability to get the parties to come together because we will again shear off and eliminate what is ... now outside the realm of the discussion."

What remains is "the makings of our deal."

Could there be a possibility of an impasse in the future that might require mediation?

There is that possibility, Galvin said.

"We're not there yet. We're not at that point."

That's because the discussion hasn't been framed enough "to identify that we are at an impasse and we need to have somebody come in and help us see things differently."

He said the administration is not trying to drive a wedge between the producers and the state on the gas line.

"We're trying to advance this project" and getting TransCanada going on the project "provides the framework for the discussion" that can eventually bring about alignment, Galvin said.

"We believe that there is tremendous opportunity, once the license is issued, to bring the parties together" and identify a deal, Galvin said June 25 at a Senate Judiciary Committee hearing. "But until we get to that point, we don't have a foundation upon which to have that discussion that we believe is solid enough to actually engage in meaningful mediation or negotiation or whatever term you want to use."

He also said a sense of momentum has been created over the last year and if the Legislature doesn't make a decision, "we end up losing that momentum."

Galvin said he thinks "we have done what we need to do in order to create the atmosphere for resolution. And we need to hit that home by having the Legislature make a decision on this." ●

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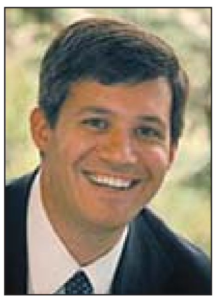
DEFINITION

July 9.

"In the interest of transparency and full disclosure from all parties, we seek to get more information on the table about your proposed alternative, so Alaskans can fully consider all options," the two said in a June 30 letter to Denali President Bud Fackrell.

BP and ConocoPhillips said Fackrell would respond.

ConocoPhillips Alaska spokeswoman Natalie Lowman told Petroleum News in a June 30 e-mail that ConocoPhillips understands that Fackrell, president of Denali — The Alaska Gas Pipeline LLC, "will be prepared to respond to the issues raised in the letter when he testifies before the Legislature in July."



BILL WIELECHOWSKI

BUD FACKRELL

BP sent a response from Fackrell in a July 1 e-mail:

"We are more than happy to talk about the Denali project. I will be testifying before the Legislature next week, and will be prepared to address the topics raised in the senators' letter," Fackrell said.

Questions based on AGIA

French and Wielechowski asked how Denali would meet the AGIA requirements met by TransCanada. They specifically asked if Denali would:

• Commit to hold an open season for firm shipping commitments within two to three years?

• Commit to a firm date for an application to the Federal Energy Regulatory Commission (Denali received FERC approval of a pre-filing request from FERC June 25)?

• Commit to financial provisions to keep the tariff low, including a debt-to-equity ratio on construction of not more than 70 percent debt to 30 percent equity?

• Commit to soliciting demand for a pipeline expansion at least every two years, to expanding when there is sufficient need and to using rolled-in rates for expansion costs up to 115 percent of initial rates?

• Commit to at least five delivery points in Alaska with distance-sensitive rates?

• Commit to capital cost overrun measures that protect the state and shippers from an unreasonably high tariff?

• Commit to hiring qualified Alaskans for construction and operation of the gas pipeline and to signing project labor agreements to ensure that as many Alaskans as possible help construct the gas line?

• Define the fiscal terms that would be requested from the state.

State offers 10 years

AGIA promises 10 years of fiscal stability to shippers committing gas at an initial open season, including 10 years of contractual stability on gas royalties and 10 years of statutory stability on gas production taxes following the beginning of gas shipments, French and Wielechowski wrote.

"If the license is issued to TransCanada, AGIA will prevent the Legislature from extending that fiscal stability, or any other preferential royalty or tax terms, to any other entity. Those provisions will make it difficult and expensive for the Legislature to ever grant fiscal stability to gas shipped through your proposed Denali pipeline," they said.

French and Wielechowski asked how Denali would meet the AGIA requirements met by TransCanada.

Producers have indicated that fiscal terms must be negotiated with the state before gas is shipped, but "there has not been a clear articulation of what those terms are. It is time for all parties interested in constructing a natural gas pipeline to be forthcoming and tell Alaskans what they are willing to do and on what terms," the two said. "To not be upfront about those terms risks misleading Alaskans about the costs and benefits of each of the proposals under consideration. We ask for your cooperation in helping to inform all Alaskans about the Denali proposal and the fiscal terms you will require. In short, it is time for you to put your cards on the table."

—KRISTEN NELSON

FINANCE & ECONOMY

SEC proposes new rules for oil reserves

The Securities and Exchange Commission proposed updated rules for energy companies June 26 that will require them to provide more detailed information to investors when reporting their oil and gas reserves.

Reserves are an oil company's most valuable asset and a critical indicator of its long-term financial prospects. Any reduction in their estimated size is a concern for investors. The SEC's current reporting rules for oil and natural gas reserves were adopted more than 25 years ago, and the proposed changes are intended to reflect technological changes in how oil companies determine their proven reserves.

The proposed changes will be opened to a 60-day public comment period and could be formally adopted some time afterward.

The SEC move comes at a time when global energy prices are spiking, gasoline in the United States is over $4 a gallon, and regulators are scrutinizing the role of speculators in world oil markets.

"The more that precise, firsthand information from oil and gas companies is available to investors and the marketplace, the less ... the marketplace is forced to rely solely upon information provided by speculators," the SEC said in a news release.

The proposed changes would: allow companies to use new technologies to determine proven oil and gas reserves provided the technologies have been shown to lead to reliable assessments; allow resources such as oil sands — now considered to be mining reserves — to be classified as oil and gas reserves; and require companies to certify the independence of petroleum auditors that audit their assessments of reserves.

In August 2004, the SEC fined Royal Dutch/Shell Group $120 million in connection with the overstatement of oil and gas reserves.

—THE ASSOCIATED PRESS

Business Spotlight

ASRC Energy Services


COURTESY PHOTO

Jens Beck, CFO

Jens Beck has been named chief financial officer at ASRC Energy Services. Employed by the ASRC family of companies since 1999, he has served as CFO of ASRC Construction Holding Co. and vice president of finance for SKW/Eskimos Inc. He was a senior auditor in public accounting for KPMG where he obtained his CPA certification for Alaska. Jens holds a degree in Business Administration from Phillips University, Marburg, Germany, a BBA in accounting and a BBA in international finance from UAA.

Jens has extensive experience in financial management and internal controls. His expertise includes strategic and financial planning, accounting, financial statement preparation and operating budget development. He serves on the PTO for the German Charter school, Rilke Schule Verein, and is a two-time iron man world finisher.

—PAULA EASLEY

Usibelli Coal Mine


COURTESY PHOTO

Rebecca Galasso, Assistant Controller

The Usibelli Coal Mine has supplied Interior Alaska with cost-effective fuel for heating and electricity production for more than 60 years. The company produces about 1.5 million tons of coal annually.

Rebecca Galasso joined the Usibelli team in Healy as assistant controller in November 2007 and is responsible for its accounting program and financial statements. She graduated from the University of Alaska Fairbanks and has more than 20 years of accounting and budget experience. Still learning, she is currently enrolled in the University of Wyoming MBA program. Rebecca has three children — a daughter living in Oregon, a son in the U.S. Air Force stationed in England, and her youngest daughter residing in Healy. Rebecca says she's excited to be back in Alaska and part of the Usibelli team.

—PAULA EASLEY

Companies involved in Alaska and northern Canada's oil and gas industry

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

EXPLORATION & PRODUCTION

June ANS production down 5.5 percent

Trans-Alaska oil pipeline down at end of month for planned maintenance; North Slope field maintenance scheduled for same time

By KRISTEN NELSON

Petroleum News

Alaska North Slope crude oil production averaged 666,873 barrels per day in June, a drop of 5.5 percent from a May average of 705,724 bpd.

With the exception of Northstar, all fields on the North Slope had reduced production in June, driven by a planned shutdown of the trans-Alaska oil pipeline at the end of the month and planned field maintenance.

Alyeska Pipeline Service Co. spokeswoman Michelle Egan told Petroleum News July 1 that planned maintenance occurred June 28 and 29. Egan said this was a full shutdown, scheduled for 30 hours, but the work was completed six hours ahead of schedule. Remote gate valve 72 near Fairbanks was replaced, she said, along with piping at Pump Station 9. Egan said some 100 people were involved in just the remote gate valve replacement.

Another maintenance shutdown is planned in August.

ANS production, which ran at more than 700,000 bpd for most of June, dropped to 586,847 barrels June 27 and to 250,001 barrels June 28 before turning upward June 29 and finishing out the month at 521,118 barrels.

Lisburne had largest June-over-May percentage drop in output

The largest percentage drop, 37 percent, was at the BP Exploration (Alaska)-operated Lisburne field, which averaged 21,951 bpd in June, down from an average of 34,849 bpd in May. Lisburne production includes Point McIntyre and Niakuk.

The Alaska Department of Revenue said there was planned maintenance at Lisburne beginning June 1. Production on that day dropped to 1,708 barrels, was at zero June 2-5, and rose to 713 barrels on June 6. The field did not reach the 30,000-bpd level until June 16, and dipped below that level June 28-29 due to the partial shutdown of the pipeline.

The second-highest percentage drop — 20.7 percent — was at BP's Milne Point field, where Revenue said maintenance was scheduled beginning June 28. Production at Milne averaged 28,251 bpd in June, down from an average of 35,644 bpd in May. Production slowed to 1,539 barrels June 27 and was at zero June 28-29, reaching 10,513 barrels on June 30 as the field began to come back online.

Production at the BP-operated Endicott field averaged 40,682 bpd in June, down 15.7 percent from a May average of 48,242. Revenue's figures for Endicott include some 33,000 bpd of Prudhoe Bay Flow Station 2 oil, rerouted into the Endicott line as BP rebuilds flow lines.

Kuparuk down 4.7 percent

Production at the ConocoPhillips Alaska-operated Kuparuk River field was down 4.7 percent from May, with June production averaging 142,547 bpd compared to 149,640 bpd in May. Production at the field stayed above 150,000 bpd for most of the month, dropping below 100,000 bpd beginning June 26 and continuing through June 29, before closing out the month at 122,609 barrels June 30. Kuparuk includes satellite production at Tabasco, Tarn and Meltwater, as well as West Sak heavy oil.

The Alpine field, also operated by ConocoPhillips, averaged 112,036 bpd in June, down 2.7 percent from a May average of 115,152. Alpine production includes satellites Fiord and Nanuq.

Prudhoe Bay production averaged 285,765 bpd in June, down 2.5 percent from a May average of 293,161 bpd. Production at the BP-operated field includes satellite production from Aurora, Borealis, Midnight Sun, Orion and Polaris.

The BP-operated Northstar field averaged 35,641 bpd in June, up 22.8 percent from a May average of 29,036 bpd. Northstar had reduced production earlier in the year due to planned maintenance and its production is returning to pre-maintenance levels.

Cook Inlet production averaged 13,111 bpd in June, up 2 percent from a May level of 12,839 bpd.

The temperature at Pump Station 1 on the North Slope averaged 45.4 degrees Fahrenheit in June, compared to 29.9 degrees F in May. ●

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ECON ONE

view from the Palin administration and a positive one from the Alaska Gasline Port Authority. Looking for another opinion, the Legislature charged Pulliam with comparing the netbacks of a potential LNG project with an Alaska Highway pipeline.

Using data from the state and modeling work from the Port Authority, Pulliam compared four configurations for marketing North Slope natural gas: two potential LNG projects and two potential highway lines.

Pulliam broke each down by volume, using the 2.7 billion-cubic-foot-per-day project proposed by the Port Authority and the 4.5 bcf project proposed by Sinopec for LNG, while using the 3.5 bcf pipeline that TransCanada proposed as the minimum viable option and the 4.5 bcf pipeline that TransCanada prefers for a highway route.

LNG wins with expensive oil

Looking at those four options, the benefits of an LNG project compared with an overland pipeline depend on which crystal ball you rub.

A vision of the future featuring high worldwide oil prices, a strong gas-to-oil price ratio in Asia paired with a weak price ratio in the United States and a delay that pushes the start of a highway pipeline to 2026 favors a project that can ship a lot of LNG to Asia.

But that scenario requires an export license, and no one is entirely sure whether the license secured by Yukon Pacific Corp. nearly 20 years ago will be any good today.

In light of the troubled history of exporting Alaska oil and recent political winds touting energy independence, Pulliam remains "skeptical" that the federal government would allow large shipments of American LNG to Asia unless the price fell considerably.

"You need to focus on this particular risk issue pretty hard," Pulliam said.

Without an export license, the next most likely market for Alaska LNG would be the West Coast of the United States, which means losing the price advantage of shipping to those hungry markets in East Asia, Pulliam said.

"There's virtually no reasonable price scenario that would make that attractive relative to a pipeline project," Pulliam said about shipping to the West Coast.

But uncertainty shouldn't be a deal-breaker, according to Bill Walker, project manager with the Alaska Gasline Port Authority, because every project contains risks.

"Let's not stop trying to build an all-Alaska line because we think we might not be able to keep what has already been awarded," Walker told lawmakers. "That doesn't seem to make sense to us."

Walker pointed to potential permitting challenges facing any company that proceeds with a highway line through Canada.

High volume means competition

Even with an export license to ship to Asia, though, the most productive LNG option faces challenges as it steps into the forecasted future, Pulliam said.

Today, Japan, South Korea and Taiwan use around 60 percent of the 21.8 bcf of LNG consumed globally every day, but that region of East Asian has little to no gas production, Pulliam said, quoting the 2008 BP Statistical Review of World Energy.

Gauging the rising demand through 2020, the estimated start of an Alaska pipeline, those three countries alone are expected to use around 19 bcf per day. At that rate, a smaller 2.7 bcf LNG project from Alaska would cover around 14 percent of East Asian demand, while the 4.5 bcf project would cover around 24 percent.

But, Pulliam said, the large volume that makes the project more productive in the long run might be too large: Alaska would have to compete for demand.

"If prices remain high, suppliers are going to fight for that," Pulliam said. "If you try to put that kind of volume into that market, I would suspect you would weaken the price considerably."

Price guesses favor highway

Looking more cautiously into the crystal ball, the "more likely" price forecasts give a big overland pipeline higher netbacks than LNG over the long run.

In a world where oil prices remain eight times higher than gas prices, Pulliam found that a 3.5 bcf highway pipeline would earn netbacks of $6.11 per million British thermal units in 2008 dollars and total netbacks of $229.5 billion in 2008 dollars.

By comparison, under the Port Authority model, Pulliam found that a 2.7 bcf LNG project would earn netbacks of $5.22 per million Btu in 2008 dollars and total netbacks of $145.1 billion in 2008 dollars.

Looking at the other end of the volume spectrum shows a similar outcome.

Keeping the eight-to-one oil-to-gas ratio, Pulliam found that a 4.5 bcf highway pipeline would earn netbacks of $6.31 per million Btu in 2008 dollars and total netbacks of $304.6 billion in 2008 dollars.

By comparison, Pulliam found that using the Port Authority pricing data for a 4.5 bcf LNG project would earn netbacks of $5.63 per million Btu in 2008 dollars and total netbacks of $271.8 billion in 2008 dollars.

Keep LNG option available

Although the Econ One report contained a mix of sobering and upbeat news about an LNG project, Walker praised it as a collaborative success.

"He didn't agree with everything we presented, and we didn't agree with everything he presented, but we had an opportunity to communicate," Walker said, referring to the modeling information Port Authority gave to Econ One for the report.

Walker pointed out that LNG does provide the highest netbacks under several scenarios, and used the hearing as an opportunity to announce a one-year deal between the Port Authority and Mitsubishi Corp. to develop a "Y-line," which would combine a highway route with an LNG spur.

But Walker said the Port Authority's primary concern is timing. Walker still believes the Port Authority can get gas to market and to Alaskans quicker than any other option.

Walker asked lawmakers not to "close the door on the LNG option."

Offering similar advice from the other side, Pulliam told lawmakers to "Ask the question: Is there a reason the state has to choose between (a highway line and an LNG project)? In the end, a market-based outcome is the most favorable. ... I don't see any reason to preclude one or another, but I don't see a reason in the economics to try and intervene to make LNG happen at the expense of the pipeline." ●

Contact Eric Lidji at 907-770-3505 or elidji@petroleumnews.com

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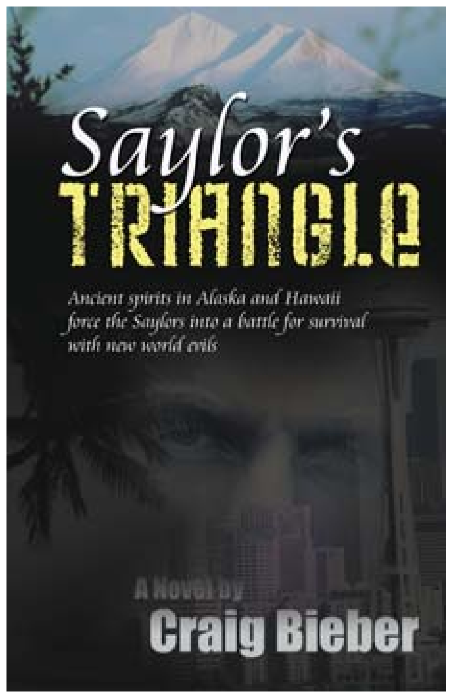
INSIDER

Craig Bieber's novel 'Saylor's Triangle' makes Anchorage debut

FORMER M-I SWACO ALASKA MANAGER and Petroleum Club of Anchorage President Craig Bieber hosted a book signing at the club on June 19 for his new novel, "Saylor's Triangle." Bieber was surrounded by family and colleagues and the evening appeared to be a success, giving him not just an opportunity to sell books, but a chance to get some feedback and catch up with old friends.

Saylor's Triangle is an adult action drama that takes place in Alaska, Hawaii, and Washington.



Nick Saylor is a wealthy man when he semi-retires on the island of Maui, leaving his sister Beth in Seattle as president of Saylor Industries and Beth's flawed ex-husband Devon as the company's Alaska manager in Anchorage.

Devon quickly heads Saylor Industries down a path of destruction with his affinity for criminals, loose women and dirty money.

Nick is drawn back into the business by the mystical warnings of a new kapuna friend in Maui, and an Alaska Native spiritual leader. Beth and Nick contend with Mexican drug cartel members, deranged killers-for-hire, would-be terrorists, law-enforcement agents, and a drug dealer as they scramble to save themselves, their company and a slice of humanity.

"Saylor's Triangle" has been selected to be part of the Tucson Festival of Books in March 2009 at the University of Arizona, where authors from all over the United States will participate. The event draws 50,000 visitors over a three-day period.

Bieber's novel also has a five star rating from Amazon Books, including the following review from Richard E. Kelly, author of Growing Up in Mama's Club: "I just completed reading "Saylor's Triangle," and I am still out of breath. …The book is well-written and difficult to put down. …Be prepared to be tantalized and surprised by the unexpected. …Bieber is a great storyteller, and this book is a must read."

Bieber was born, raised, and educated in South Dakota, at a time when he says "imagination, dreams, and literature were the windows to the world." After nearly 40 adventurous years in Alaska, he wrote "Saylor's Triangle." He now spends summers in Anchorage, winters in Tucson, and is working on a new novel.

If you missed the signing you can find information about his book at www.saylorstriangle.com or you can purchase the book online from Amazon.com or pick up a copy in Anchorage at Title Wave or Borders book stores.

—AMY SPITTLER

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ACMP

coastal districts consist of coastal municipalities.

The coastal districts can develop their own coastal management programs for inclusion in the statewide ACMP.

The 2003 changes to ACMP statutes attempted to minimize duplication between state and municipal regulation and to streamline the ACMP process. But some aspects of the changes have resulted in appeals, lawsuits and some level of confusion about how the ACMP is being implemented, Bates said.

A key component of the 2003 changes was a requirement that district enforceable policies cannot duplicate state or federal regulations. In addition, a so-called "DEC carve out" provision removed any permitting done by the Alaska Department of Environmental Conservation from the ACMP process, thus in effect eliminated the regulation of air, water and land quality from the program.

Districts excluded?

Although the changes significantly reduced duplication and overlap in the permitting roles of the regulating authorities, the changes also left the coastal districts with a sense that they had been all but excluded from the ACMP process.

"The coastal districts want to be able to write policies to effect change to projects … and the way the state has implemented the plan, the districts have very little room to write enforceable policies," Bates said. "… They (also) want to be able to view what DEC is doing in the context of the project, and right now they're not able to do that because of the DEC carve out. … ACMP used to coordinate the entirety of a (permitting) project."

The 2003 changes also required the coastal districts to bring their enforceable policies into compliance with the new statutes and regulations.

But according to a report on the ACMP issued in June by the National Oceanic and Atmospheric Administration, the federal agency that oversees the implementation of the Coastal Zone Management Act, five of the Alaska coastal districts ceased implementing their own coastal plans as a result of the new requirements. And 14 districts, including the North Slope Borough, the Northwest Arctic Borough, the Kenai Peninsula Borough and the Aleutians East Borough, have yet to complete revisions to their plans.

So how does DCOM intend to address the questions that people have raised about the ACMP?

Comment period

Following a meeting of ACMP stakeholders in June to discuss the reevaluation, DCOM announced on July 1 the start of a public comment period that will last until Aug. 15. During that period, as well as being able to submit comments on the ACMP to the division, members of the public will be able to participate in three scheduled teleconferences.

The division anticipates spending a month compiling and analyzing the comments received, before working with ACMP stakeholders on any proposed changes to statutes and regulations. There will be a comment period on the proposed changes, in time to present the proposals to the governor, prior to submission of a package of requested statute changes to the Alaska State Legislature at the beginning of the 2009 legislative session.

Following any changes to the statutes enacted by the Legislature, DCOM anticipates completing any necessary changes to regulations by about the end of August 2009. The changes would then require federal review and approval, a process that would likely take until around July 2010, Bates said.

Incremental change

However, Bates expects the reevaluation to result in incremental improvements to ACMP, rather than a wholesale rewrite. And although the division recognizes the issues associated with ACMP in its current form, Bates is anxious to hear peoples' views on the strengths of the current program, as well as the program's weaknesses.

Some of the changes made in 2003 were appropriate and necessary, Bates said. And industries such as mining and oil want a stable regulatory environment, he said.

"We've got a lot of work to do to make sure everybody's on the same page, understands what the rules are and that everyone participates effectively," Bates said. "… We're absolutely interested in evaluating those (2003) changes. … We're committed to evaluating the need to change to figure out 'how do we make all legs of this stool stable?'" ●