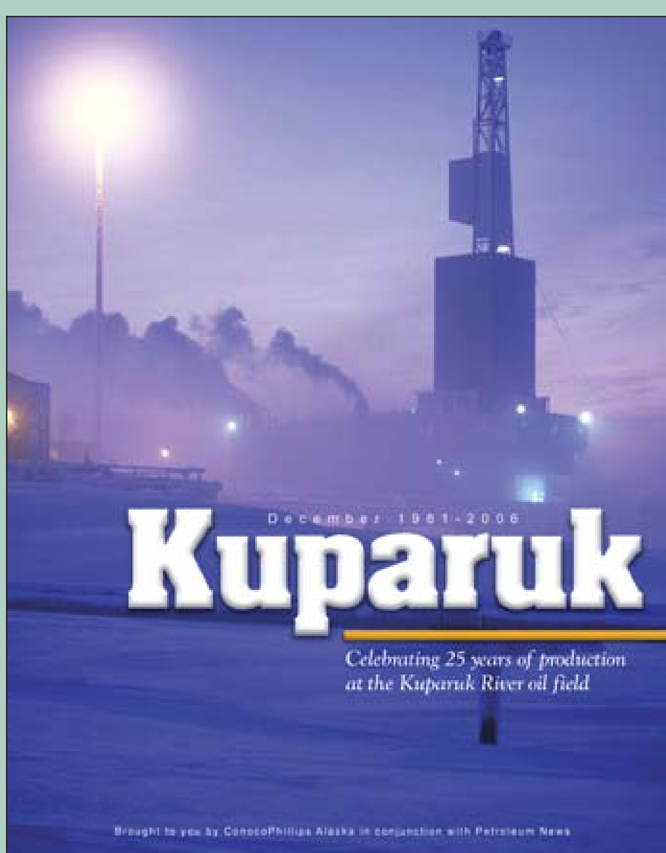
Petroleum news

Vol. 12, No. 3 • www.PetroleumNews.com — *A weekly oil & gas newspaper based in Anchorage, Alaska* — Week of January 21, 2007 • $1.50

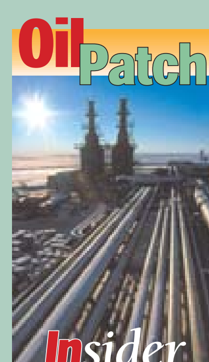
page 9 BP's Borowski says it's a challenge to get Alaskans to compete for jobs

Kuparuk unit celebrates 25 years



Inside is a special publication about the history of the Kuparuk River oil field on Alaska's North Slope, and the Meet Alaska magazine.

Husky turns into a lead dog



ONCE RATED THE POOCH of Canada's integrated oil companies (those who produce, refine and market), Husky Energy has been quietly asserting its pedigree over recent years as it has moved to the head of the pack in Alberta's oil sands and Canada's East Coast offshore.

Over the past year, its stock has remained a solid performer, ranging from a high of C$83 in August to a low of C$58 in May, currently keeping its nose above C$70.

In the process it has grown its market capitalization to more than C$30 billion, about C$9 billion ahead of Petro-Canada and nipping at the heels of its other peers, Shell Canada (C$35 billion), Imperial Oil (C$36 billion) and Suncor Energy (C$37 billion).

It enters 2007 with a solid endorsement from Merrill Lynch analyst Dennis Mark who said Husky is "the technically strongest big-cap energy name" on the Toronto Stock Exchange for this year.

Often accused in the past of hiding from public view, a habit that was attributed to its controlling owner Hong Kong billionaire Li Ka-shing, Husky now seems more willing to

see **INSIDER** *page 21*

BREAKING NEWS

5 API report: In 2006 oil and gas drilling in the United States hit a 21-year high; Alaska drilling flat, around 200 wells

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15 Shell flags intent to test winter seismic: To investigate feasibility of seismic acquisition from floating ice in Beaufort Sea

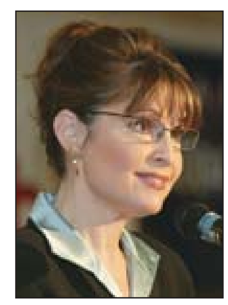
NATURAL GAS

Competition the key

Palin: new gas line bill's inducements will give Alaska 'skin in the game'

By KRISTEN NELSON

Petroleum News



JUDY PATRICK

GOV. SARAH PALIN

Alaska's new governor, Sarah Palin, says the state must ramp up resource development across Alaska, beef up oversight on the North Slope and end warehousing of the state's resources at Point Thomson.

But the resource focus of her first state-of-the-state address Jan. 17 was the gas pipeline bill her administration will introduce, a bill that will offer a competitive process with inducements to those building the line and to those who have leases with natural gas.

The gas pipeline is "the primary focus of our long-term energy plan," Palin said.

She said that while it is in Alaska and America's interest to get North Slope gas to market, "It won't happen with the snap of a governor's fingers."

There are "many entities with differing considerations" and the project needs to ensure that viable explorers and producers "can access the gas line on reasonable terms and we need a project that can be expanded when there's more gas found."

A gas line project is costly and risky, but "this is a sound, economic project," Palin said.

Alaskans learned a lot from the previous administration's attempt to develop the state's gas under the Alaska Stranded Gas Development Act. We

see **COMPETITION** *page 22*

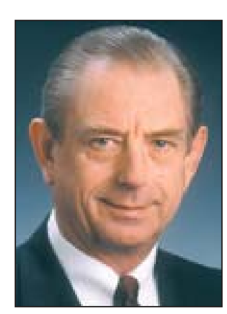
FINANCE & ECONOMY

Harbour slams RCA ruling

Questions impact of abandoning precedent to use Henry Hub pricing for Inlet gas

By ALAN BAILEY

Petroleum News



DAVE HARBOUR

On Jan. 10 Regulatory Commission of Alaska Commissioner Dave Harbour issued a second dissenting statement lambasting RCA's majority decision to reject the proposed Cook Inlet natural gas supply contract between Marathon and Enstar. Harbour thinks that the commission majority is bowing to popular demand to keep gas prices down, while discounting the risk of future gas supply shortages.

Enstar announced its new contract with Marathon in November 2005, saying that the contract would ensure adequate gas supplies through to 2016. The price that Enstar would pay for the gas would be based on a 12-month trailing average of the Lower 48 Henry Hub gas market futures.

RCA rejects contract

Following a lengthy public hearing, RCA issued an order on Sept. 28 rejecting the gas pricing in the contract. The order represented a majority decision, with commissioners Harbour and Mark Johnson dissenting.

see **HARBOUR** *page 23*

NATURAL GAS

Mac backers still believers

NWT minister: Mackenzie gas line economics strong; Imperial remains committed

By GARY PARK

For Petroleum News

Take a break from the relentless stream of doom and gloom.

Two of those most closely connected to the Mackenzie Gas Project are not ready to cut and run.

Northwest Territories Industry Minister Brendan Bell said the economics underpinning development of Mackenzie Delta gas are as strong as ever, not least because of an expected 1.1 percent annual rise in North American gas consumption over the 2003-2030 period.

"But we can't sit here and assume it will happen," he told Petroleum News.

Pius Rolheiser, a spokesman for Mackenzie

see **BELIEVERS** *page 19*

Bold new energy firm makes northern debut

A northern newcomer — at least in name — is full of bullish sentiment about prospects in the Northwest Territories, on the overriding condition that the Mackenzie Gas Project moves forward.

MGM Energy made its debut Jan. 11 as a spinout from Paramount Resources and has started trading on the Toronto Stock Exchange.

Its assets are dominated by 1.02 million gross acres in the Mackenzie Delta under a farm-in agreement with Chevron Canada

see **ENTRY** *page 19*

contents

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

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
Akita Drilling Ltd.			
Dreco 1250 UE	63 (SCR/TD)	Commissioning at Doyon Yard in Deadhorse	Anadarko
Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Milne Point MPF-99i	BP
Sky Top Brewster NE-12	15 (SCR/TD)	Kuparuk 1J-136	ConocoPhillips
Dreco 1000 UE	16 (SCR/TD)	Workover R Pad 15a	BP
Dreco D2000 UEBD	19 (SCR/TD)	Alpine CD3-107	ConocoPhillips
OIME 2000	141 (SCR/TD)	Kuparuk 1J-103	ConocoPhillips
TSM 7000	Arctic Fox #1	Stacked in Yard	Pioneer Natural Resources
	Arctic Wolf #2	Mobilizing to Amaguq #2	FEX
Kuukpik	5	Mobilizing to Noatak #1	ConocoPhillips
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Stacked, Prudhoe Bay	Available
Dreco 1000 UE	2-ES	A-05AI	BP
Mid-Continental U36A	3-S	PBD W-29	BP
Oilwell 700 E	4-ES (SCR)	DS 01-33	BP
Dreco 1000 UE	7-ES (SCR/TD)	W-204	BP
Dreco 1000 UE	9-ES (SCR/TD)	V-217	BP
Oilwell 2000 Hercules	14-E (SCR)	Stacked at Cape Simpson	FEX
Oilwell 2000 Hercules	16-E (SCR/TD)	Under contract for drilling at Gwydyr Bay	Brooks Range Petroleum
Oilwell 2000	17-E (SCR/TD)	Stacked, Point McIntyre	Available
Emsco Electro-hoist -2	18-E (SCR)	Stacked, Deadhorse	Available
OIME 1000	19-E (SCR)	Stacked, Deadhorse	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)	Rock Flour #2	ENI
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Moving to Prudhoe Bay well G-24a	BP
Superior 700 UE	2 (SCR/CTD)	Kuparuk 2Z-13	BP
Ideco 900	3 (SCR/TD)	Kuparuk 3K-32	ConocoPhillips

North Slope - Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Nabors Alaska Drilling			
Oilwell 2000	33-E	Northstar NS-34	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	Stacked at Nikiski	Available
Marathon Oil Co. (Inlet Drilling Alaska labor contractor)			
Taylor	Glacier 1	Grossum Oskolkoff #5	Marathon
Nabors Alaska Drilling			
National 110 UE	160 (SCR)	Stacked, Kenai	Available
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	Swanson River SRU 41-05	Chevron

Cook Inlet Basin – Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Unocal (Nabors Alaska Drilling labor contractor)			
Not Available			
XTO Energy			
National 1320	A	Platform A no drilling or workovers at present	XTO
National 110	C (TD)	Idle	XTO

Alaska Interior

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Cudd Pressure Control			
Cudd 340k Jack Unit		Workover Ahtna #1-19	Rutter and Wilbanks

Mackenzie Rig Status

Canadian Beaufort Sea

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Seatankers (AKITA Equtak labor contract)			
SSDC CANMAR Island Rig #2	SDC	Set down at Roland Bay	Devon ARL Corp.

Mackenzie Delta-Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
AKITA Equtak			
Dreco 1250 UE	62 (SCR/TD)	Stacked in Tuktoyaktuk, NT	EnCana
Modified National 370	64 (TD)	Moving to Inuvik, Mackenzie Delta	Chevron

The Alaska - Mackenzie Rig Report as of January 18, 2007.
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*

	Jan. 12	Jan. 5	Year Ago
US	1,717	1,695	1,467
Canada	586	417	674
Gulf	81	82	74

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

FINANCE & ECONOMY

Saudi minister says no need for more cuts

Saudi Arabia's oil minister said Jan. 16 there is no need for further production cuts by OPEC and called the situation in the global crude market "very healthy."

Ali Naimi's comments came amid speculation that the 12-nation Organization of Petroleum Exporting Countries could call an emergency meeting to discuss further cuts in production to keep global oil prices from falling further.

"There is no need now (for further cuts) on the basis of what market conditions are," the Dow Jones Newswires quoted Naimi as saying after arriving in New Delhi for an international conference organized by India's oil ministry.

The news pushed oil prices down by 88 cents to US$52.11 a barrel in New York, the Dow Jones Newswire said.

His comments came hours after Nigeria's Petroleum Minister Edmund Daukoru said OPEC members should wait until February before deciding on further cuts in their crude oil output.

OPEC members said late last year they would reduce their output by 1.2 million barrels a day and plan to cut production by another 500,000 barrels a day beginning sometime in February. The cuts are aimed at keeping oil prices from falling too much in the face of weak winter demand in the United States — the world's biggest oil consumer — increased production by non-OPEC countries.

Daukoru said it was too early to judge the impact of the cuts that have already been announced.

When asked if OPEC's output cuts, totaling 1.7 million barrels a day, would be sufficient to buoy prices, he said: "I don't know. February is not yet here. When we implement (the February cuts) ... we will see how the market is going to react."

Naimi insisted OPEC has succeeded in managing oil inventories well.

"The market is behaving the way it should, I think," he said. "The market is growing healthier by the day ... supply, demand and inventories are in equilibrium."

—THE ASSOCIATED PRESS

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● GOVERNMENT

The Terminator turns Agitator in Canada

New liberal leader takes lesson from Schwarzenegger's get-tough approach to 'dirty fuels,' applies to oil sands

By GARY PARK
For Petroleum News

It's just another of those troubling distant early warning calls that sends a nervous tremor through the oil sands, but it plays right into the hands of the man who could be Canada's next prime minister.

It begins with California Gov. Arnold Schwarzenegger who has announced a new fuel standard he hopes to introduce in 2008 that will require a 10 percent reduction by 2020 in the carbon content of all fuel sold in the state.

That means California would count all greenhouse gas emissions during the life cycle of a fuel from production to consumption — bad news for the oil sands which currently consume large volumes of natural gas to extract and refine raw bitumen, making them a leading source of greenhouse gases.

> *"If you do the right thing, you pay less; if you don't do it, you pay more."*
> **—Stephane Dion, new leader of the federal Liberal party**

Currently, very little oil sands production finds its way to California, but preliminary plans are taking shape for delivery connections from Alberta to California, including the possibility of 100,000 barrels per day or more being shipped by tanker from a northern British Columbia deepwater port.

"Let us blaze the way for the U.S., for China and for the rest of the world," Schwarzenegger said in his State of the State address Jan. 11. "Our cars have been running on dirty fuel for too long.

"California has the muscle to bring about such a change. I say use it."

And Schwarzenegger is not operating in a vacuum of his own making.

In the U.S. Northeast states such as New York, Connecticut, Massachusetts, New Jersey and Maryland are implementing greenhouse gas standards for electrical utilities, pointing to vehicle fuel standards as the next obvious move.

Traditionally, Oregon and Washington follow California's lead, while 37 states belong to an ethanol coalition, which could draw momentum from the new California standards.

Liberal party's Dion urging penalties

Canadian petroleum industry spokesmen gave a low-key response, regardless of the message Stephane Dion, new leader of the federal Liberal party, has been spreading across Canada as he tries to take advantage of the governing Conservative party's perceived weakness on the climate-change front.

Entering the lion's den of energy-producing Alberta on Jan. 11 and 12, he said Canada should impose penalties on energy companies that fail to reduce greenhouse gas emissions and water use, especially in the oil sands region.

"If you do the right thing, you pay less; if you don't do it, you pay more," was how Dion described his strategy.

Those who fail to act should be "penalized in the market where they need to be competitive," he said.

Dion suggested that if the government sets a target of a 10 percent cut in emissions and companies achieve a 15 percent reduction they should be able to sell the surplus to gain credits.

Prime Minister Stephen Harper has consistently rejected the idea of trading carbon credits on the international market.

But Dion continued to bear down on oil sands producers, arguing they should lose generous royalty incentives if they fail to meet emissions standards and continue to be a drain on fresh water.

He brushed off any concerns that harsh regulations would kill oil sands investment, arguing it was time for Canada to follow the example of European countries and some U.S. states.

Dion said his proposed environmental tax reforms would make the Alberta oil sands more sustainable for many years to come.

If he becomes prime minister, he promised to be the "best partner" the oil sands ever had in the federal government.

Making the sector sustainable by curbing greenhouse gases would allow Canada to export "our new technologies, our know-how and we will make megatons of money with it," he said.

Greg Stringham, vice president of the Canadian Association of Petroleum Producers, even welcomed Dion's proposed new incentive mechanism to promote technologies that could address environmental issues.

But Dion turned thumbs down on the use of nuclear power in the oil sands.

He said it is not a viable option because of lingering concerns over the disposal of spent fuel, although he conceded the ultimate decision rests with the Alberta government.

The hard-line stance came amid word that Husky Energy is studying the nuclear option to provide power for its future oil sands developments, while privately held Energy Alberta Corp. said it expects to unveil a plan within 90 days to build a nuclear power plant. ●

● EXPLORATION & PRODUCTION

U.S. 2006 drilling hits 21-year high

By KRISTEN NELSON

Petroleum News

U.S. oil and natural gas drilling activity "remains robust with nearly twice the level of activity recorded during the lows of the early to mid-1990s," the American Petroleum Institute said Jan. 16.

API said its fourth quarter 2006 well completion report shows a 21-year high, with an estimated 49,375 oil wells, natural gas wells and dry holes completed in the United States in 2006.

It said an estimated 12,439 completions in the fourth quarter was the highest since the first quarter of 1986.

Since this was a nationwide estimate, specifics weren't available for states.

"Basically, drilling is about the same in Alaska as it has been for the decade — around 200 wells annually favoring oil wells," API analyst Jeff Obermiller told Petroleum News.

Alaska Oil and Gas Conservation Commission records show, as of mid-January, 148 wells completed in 2006, vs. 198 wells in 2005 and 260 wells in 2004, an average of 202 per year. This compares to an average of 189 wells per year for a three-year period 10 years ago, 1994-96.

Natural gas remains the main driver of the U.S. E&P industry, API said, with an estimated all-time high of 29,356 natural gas wells completed in 2006, an estimated 7,482 of those in the fourth quarter, "an all-time quarter high for natural gas drilling activity in the U.S."

"Basically, drilling is about the same in Alaska as it has been for the decade — around 200 wells annually favoring oil wells," API analyst Jeff Obermiller told Petroleum News.

API said its estimates show that "the resurgence in oil well completion activity that began in 2000 continued into 2006." It estimates 15,345 oil wells were completed in 2006, an activity level that exceeds "every year in this decade and every year in the 1990s."

2006 also saw the fourth straight year of rising numbers of exploratory oil wells, with 932 a 20-year high. "The fourth quarter estimate of 301 wells was the highest since first quarter 1986."

Total estimated footage drilled in 2006 "was the highest in more than two decades," API said. It estimates some 289,959,000 feet was drilled in 2006 — 74,439,000 feet in the fourth quarter alone.

API is a national trade association that represents all aspects of America's oil and natural gas industry, including producers, refiners, suppliers, pipeline operators, marine transporters and service and supply companies.

The API Quarterly Well Completion Report is available from API as an annual subscription.

On the Net: www.api.org/Publications/.

Looking at drilling in Alaska over the period since the early 1990s, there are fewer grassroots wells being drilled — wells with an original well bore — and more sidetracks and laterals, where drilling begins from an existing central well bore.

Over a three-year period 10 years ago, 1994-96, grassroots wells represented 72 percent of wells drilled (1994), 61 percent (1995) and 59 percent (1996).

In 2004, only 48 percent of the wells drilled in Alaska were grassroots wells, 33 percent were sidetracks and 19 percent were laterals. Thereafter the number of grassroots wells dropped, to 42 percent in 2005 and 43 percent in 2006, with sidetracks staying about the same proportion — 32 percent in 2005 and 33 percent in 2006 — but laterals growing to 26 percent in 2005 and 24 percent in 2006.

The type of well permitted in Alaska — development, exploration, service — has also been shifting.

In 1994-96, about 85 percent of permits were for development wells and about 5 percent for exploration wells and some 10 percent for service or injection wells.

In the 2004-06 period, however, permits were up for both exploration and service wells, and down for development wells, which have been averaging some 65 percent of the permit mix, with exploration wells just under 10 percent and service wells at about 25 percent. ●

● NATURAL GAS

Two gas pipeline entities will work together

Alaska Gasline Port Authority, Alaska Natural Gas Development Authority, sign MOU; governor pleased with cooperation

By ANNE SUTTON

Associated Press Writer

The Alaska Gasline Port Authority and the Alaska Natural Gas Development Authority have signed a formal agreement to work cooperatively on developing a natural gas pipeline.

Officials with the two voter-approved entities announced Jan. 11 that they signed a memorandum of understanding Jan. 9.

"Alaskans working together is the best approach to developing a natural gas pipeline project," said AGPA chairman Jim Whitaker.

The cooperation does not mean the group will be picked to build a multibillion dollar natural gas pipeline.

Voters created AGPA in 1999 to build a natural gas pipeline through Alaska. The authority says it has secured rights to the right of way and permits necessary for a trans-Alaska pipeline from Prudhoe Bay to Valdez and associated liquid natural gas facilities.

Gov. Frank Murkowski snubbed the LNG project in favor of a deal with three major oil producers to build a gas pipeline to Alberta, Canada, and perhaps the Midwest.

Palin willing to consider all proposals

His successor, Gov. Sarah Palin, has said she is willing to consider all proposals for getting North Slope gas to market.

ANGDA was authorized by the Legislature to ensure the distribution of natural gas and propane within the state as well as to pursue a natural gas pipeline.

ANGDA director Harold Heinze said Jan. 11 that the formal agreement would allow two entities that share common interests to also share confidential information regarding proposed design and cost estimates.

"We can work together without this MOU, but what it does is allow that conversation to be in a much higher level of detail," Heinze said.

Heinze said the agreement does not bind either entity to a particular project or exclude similar agreements with other entities.

Palin said she was glad to see parties cooperating.

"I applaud any efforts by any potential applicants to join forces, including the three primary North Slope producers, in whatever manner they deem appropriate to eventually submit the most attractive and beneficial proposal for the administration's consideration under the new law," Palin said in an e-mail to The Associated Press.

Murkowski limited pipeline negotiations to the three largest North Slope producers, BP, ExxonMobil and ConocoPhillips, but was never able to get a contract put together that met with the approval of the Alaska Legislature.

The $20-25 billion pipeline is intended to take Alaska's North Slope gas to Midwestern markets.

Palin took office Dec. 4 and the next day reopened negotiations with anyone interested in building the pipeline. She met with 12 separate groups or companies that week.

She is expected to introduce legislation at the beginning of the session that will guide the process of developing a new gas pipeline deal with oil and gas producers. ●

● FINANCE & ECONOMY

Canadian trusts start making moves

By GARY PARK

For Petroleum News

Canadian income trusts are starting to make their moves as they come to terms with the end of their tax-free status in 2011.

But the scorecard so far offers no clarity on what direction trusts intend to take.

One trust has decided to bolt back to the corporate world; one is sticking with an announced merger; and one has abandoned a planned takeover.

The most decisive response has come from True Energy Trust, which is reverting back to a corporate structure only 14 months after leaving that environment for the trust sector.

A mid-sized operation, with 600 drilling locations spread across 780 square miles in Western Canada and production of 11,500 barrels of oil equivalent per day, True said Jan. 15 it sees a better future as a "growth oriented, dividend paying, intermediate exploration and production company."

Its initial dividend will be 2 cents per share, per month, paid on a quarterly basis. As a trust, it currently pays 12 cents per unit per month, which is only half what it was in September, before the Canadian government turned the trust world on its head by announcing trusts would be taxed at the same level as corporations.

True said a review of the long-term future facing trusts persuaded it that converting back to a corporation before the changes take effect in 2011 would be the "best opportunity to enhance unit and asset value over time."

For starters, it plans to hike its capital budget for 2007 to C$120 million, allowing it to build reserves and production.

Undeterred by the government changes, Crescent Point Energy Trust has resumed plans for a C$640 million merger with Mission Oil and Gas.

A scheduled December vote of investors was postponed pending the release of government guidelines governing the operation of trusts over the next four years.

Those rules essentially restrict trusts to doubling their size between now and 2011 without paying any penalties.

Crescent Point makes case for merger

But Crescent Point Chief Executive Officer Steve Saxberg said the trust will make a case for the merger to be excluded from the rules because the deal was announced Sept. 11, seven weeks before the government decided to put trusts on the same tax footing as corporations.

If the transaction is completed, Crescent Point will increase its production by about 6,000 barrels of oil equivalent per day to 26,500 boe per day.

FirstEnergy Capital analyst William Lacey told the Calgary Herald that Crescent Point should be entitled to the same treatment as Pengrowth Energy Trust, which got a federal green light to proceed with its C$1 billion purchase of ConocoPhillips Canada assets — a deal that also predated the tax change decision.

He said Crescent Point should be able to preserve its dry powder for other opportunities; otherwise it would be treated differently from Pengrowth.

So far, the only deal to collapse has been a C$496 million takeover by Shiningbank Energy Income Fund of Rider Resources, boosting the trust's output by 8,800 boe per day to 35,000 boe per day.

The two parties said there was no certainty on the timing or content of draft legislation to cover the tax changes. ●

● GOVERNMENT

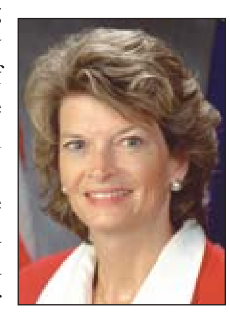
Alaska senator seeks to 'REFRESH' energy policy

U.S. Sen. Lisa Murkowski promotes bill in Congress to spur development of renewable fuels, cut carbon dioxide emissions

By ROSE RAGSDALE

For Petroleum News

U.S. Sen. Lisa Murkowski, R-Alaska, introduced legislation in Congress Jan. 16 aimed at improving energy efficiency and reducing greenhouse gas emissions, by developing additional forms of renewable energy and paving the way for better fuel consumption by vehicles.


Sen. Lisa Murkowski

S. 298, the Renewable Energy, Fuel Reduction and Economic Stabilization and enHancement Act of 2007, or REFRESH Act, would reduce carbon dioxide emissions from fossil fuel usage by about 530 million metric tons in the United States by 2025 — a 7 percent decrease from currently anticipated emissions levels that year.

"In Alaska, we have certainly seen firsthand the effects of a warming climate in recent years," said Murkowski. "It only makes sense that we take common-sense steps now to improve fuel efficiency, to promote the development of a wider range of alternative energy technologies and to encourage Americans to buy more fuel efficient vehicles. This bill includes vital measures we must take to reduce fuel usage and greenhouse gas emissions."

Murkowski is the ranking member of the Subcommittee on Energy for the Senate Committee on Energy and Natural Resources.

Her bill is being offered as a companion to S. 183, legislation introduced Jan. 4 by Alaska senior Sen. Ted Stevens to raise the nation's Corporate Average Fuel Economy, or CAFÉ, standards of automobiles to 40 miles per gallon within a decade.

$250 million in grants proposed

Murkowski's bill invests in alternative and renewable energy and promotes greater efficiency of energy use in the transportation sector. It would provide up to $100 million each in grants for the development of geothermal power, all forms of ocean energy and small hydro-electric plants, along with tax credits to spur that development.

It would extend to 2012 a tax credit; lift a cap on tax credits available to encourage the purchase of "hybrid" and advanced fuel-efficient vehicles; and authorize up to $100 million in research aid to help "plug-in" hybrids and storage battery development.

Additionally, the legislation provides up to $50 million in grants to states and local communities to encourage reductions in traffic congestion by helping states establish telecommuting and flexible-work programs that keep motorists off roadways during rush hours.

Together with Stevens' existing and proposed legislation, the bill seeks to cut U.S. oil consumption by nearly 5 million barrels per day and carbon dioxide emissions by about 530 million metric tons yearly by 2025.

Unlike current law, the bill also would require a "truth in advertising" provision for the CAFE standards to be based on the actual fuel economy that vehicles would achieve under real-world driving conditions. ●

● EXPLORATION & PRODUCTION

Savant Alaska holds off drilling Kupcake

Opstad: inability to secure rig reason for independent's decision to wait until next winter to test Liberty-area Beaufort prospect

By KAY CASHMAN

Petroleum News

On Jan. 16, Erik Opstad said Savant Alaska has postponed drilling its Beaufort Sea Kupcake No. 1 well until next winter. The independent, he told Petroleum News, was unable to secure a drilling rig for its exploration program, initially expected to start in February.

PATTERSON SHAW

Opstad, a consultant tasked with finding a drilling rig and putting together a group of contractors for Savant, said the "effort to close a rig sublease agreement for the current winter drilling season was unsuccessful." The delay, he said, will give the company "time to bring forward alternative drilling resources."

He said all permit applications for the project, "with exception of the AOGCC permit to drill, have been filed with the appropriate agencies" and that the exploration plan of operations filed with the Alaska Department of Natural Resources was not expected to change.

Savant, he said, was going to "continue to pursue and secure all necessary permits, approvals and authorizations related to the project" and had asked permitting agencies to issue permits that "reflect this change in schedule."

Savant Alaska, a closely held limited liability company that is an affiliate of Denver-based Shaw Resources and new to Alaska, was "fully capitalized to go forward" with exploration, Patterson Shaw told Petroleum News in April. Shaw, president of both companies, won the Beaufort Sea leases at the March 1 state areawide lease sale, later transferring them to Savant Alaska LLC. He bid a total of \$1.465 million for the seven leases in bids ranging from \$10.17 to \$207.35 per acre.

East of Prudhoe Bay, the Kupcake prospect is adjacent to the 130 million barrel offshore Liberty field operated by BP. Savant's leases extend east towards BP's offshore/onshore Badami oil field along the Mikkelsen Bay fault zone.

East of Prudhoe Bay, the Kupcake prospect is adjacent to the 130 million barrel offshore Liberty field operated by BP. Savant's leases extend east towards BP's offshore/onshore Badami oil field along the Mikkelsen Bay fault zone. Kupcake No. 1, Savant has said, is approximately 8,000 feet west of the Liberty No. 1 discovery well in Section 29, T11N, R18E, UM.

Although BP has not yet sanctioned development of Liberty, in January a company spokesman confirmed what BP has been saying for a number of months — that BP "is moving forward energetically … to see (Liberty) approved."

Hoping to recover 100 million barrels

According to True North Energy Corp., a publicly held independent out of Houston, Texas, that took an 8.4 percent working interest in Kupcake in late 2006 by pooling leases, Savant hopes to discover 200 million barrels of oil at Kupcake in the Kemik formation, with 100 million barrels of that recoverable.

Greg Vigil, a former BP Exploration (Alaska) employee who runs Savant's Alaska operations from Shaw's Denver headquarters, described Kupcake No. 1 as "a conventional exploration well targeting several hundred feet of Beaufortian age sediments located at a depth of approximately 10,600 feet."

" … based on interpretation of licensed 3-D seismic data, Savant suggests that Beaufortian sediments have filled an accommodation space between the NW-SE trending Mikkelsen Bay and Tigvariak faults adjacent to the discovery at Liberty," Vigil said.

Kupcake's name comes from "KUParuk zone-C and KEkiktuk equals KUPCAKE. The Kuparuk-C age Beaufortian sands are the sweet icing atop the Kekiktuk," Opstad said. ●

LAND & LEASING

Potential Alaska state and federal oil and gas lease sales

Agency	Sale and Area	Proposed Date
DNR	Alaska Peninsula Areawide	Feb. 28, 2007
DNR	North Slope Foothills Areawide	Feb. 28, 2007
MMS	Sale 202 Beaufort Sea	April 18, 2007
DNR	Cook Inlet Areawide	May 23, 2007
DNR	Beaufort Sea Areawide	October 2007
DNR	North Slope Areawide	October 2007
MMS	Chukchi Sea	November 2007
BLM	NE NPR-A	2007
BLM	NW NPR-A	2007
DNR	Alaska Peninsula Areawide	February 2008
DNR	North Slope Foothills Areawide	February 2008
DNR	Cook Inlet Areawide	May 2008
DNR	Beaufort Sea Areawide	October 2008
DNR	North Slope Areawide	October 2008
DNR	Alaska Peninsula Areawide	February 2009
DNR	North Slope Foothills Areawide	February 2009
DNR	Cook Inlet Areawide	May 2009
DNR	Beaufort Sea Areawide	October 2009
DNR	North Slope Areawide	October 2009
MMS	Sale 209 Beaufort Sea	2009
MMS	Sale 211 Cook Inlet	2009
DNR	Alaska Peninsula Areawide	February 2010
DNR	North Slope Foothills Areawide	February 2010
DNR	Cook Inlet Areawide	May 2010
DNR	Beaufort Sea Areawide	October 2010
DNR	North Slope Areawide	October 2010
MMS	Sale 212 Chukchi Sea	2010
MMS	Sale 217 Beaufort Sea	2011
MMS	Sale 219 Cook Inlet	2011
MMS	Sale 221 Chukchi Sea	2012

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

This week's lease sale chart sponsored by:

PGS Onshore, Inc.

● FINANCE & ECONOMY

Oil, gas prices down on warmer weather

EIA projects WTI average of $64.42 in '07, compared to $66.02 in '06; Henry Hub expected to rise, from $6.94 in '06 to $7.06

PETROLEUM NEWS

Warmer U.S. December weather led to a decline in crude oil and natural gas prices, the U.S. Department of Energy's Energy Information Administration said Jan. 9 in its short-term energy outlook.

During December the spot price for West Texas Intermediate fell from $63.48 per barrel to $60.85 and the Henry Hub natural gas spot price dropped from $8.67 per thousand cubic feet to $5.67 per mcf.

The agency projects the price of WTI crude oil, which averaged $66.02 per barrel in 2006, to average $64.42 per barrel in 2007 and $64.58 per barrel in 2008. Henry Hub natural gas prices, which averaged $6.94 per mcf in 2006, are projected to average $7.06 in 2007 and $7.72 in 2008.

The WTI average price stayed at about $60 per barrel in the fourth quarter because the Organization of Petroleum Exporting Countries cut output in the quarter, with OPEC production averaging 700,000 barrels per day lower in the fourth quarter than in the third. Saudi Arabia accounted for half of the reduction.

> *Net imports of natural gas are estimated to have fallen 5.5 percent in 2006 and are expected to fall by a further 1.1 percent in 2007, then increase by 7.8 percent in 2008, with decline pipeline imports from Canada tempered by increased liquefied natural gas imports.*

WTI $64-$65 barrel in '07

The agency expects "a fairly close match between non-OPEC supply growth and growth in global oil demand," with a modest increase in OPEC production capacity, keeping the market "fairly balanced and perhaps a little weaker in 2007."

EIA said if OPEC continues "to alter production to keep inventories near normal levels" it expects the price of WTI to average between $64 and $65 per barrel in 2007.

Global oil demand is expected to rise by 1.5 million bpd in 2007, the agency said, an increase of 700,000 bpd above 2006 growth.

Non-OPEC supply is expected to grow by 1.1 million bpd reflecting new projects in the Caspian Sea, Russia, Africa, Brazil and the United States.

EIA expects OPEC spare capacity to increase following recent cutbacks, and said if its "demand and supply projections materialize as expected, OPEC surplus capacity will average over 2 million barrels per day, the highest level since 2002."

The market will, however, still face short-term volatility due to weather, security-related disruptions or delays in non-OPEC supply growth, all of which could cause price increases.

Price decreases could occur if demand growth slows or "if Saudi Arabia decides to abandon production cuts in order to gain greater cooperation from other OPEC members."

U.S. crude production, natural gas

EIA expects 2006 U.S. production to be about 5.14 million bpd, close to 2005 production levels, with growth to 5.31 million bpd in 2007 and 5.45 million bpd in 2008 as recovery continues from the 2005 hurricanes in the Gulf of Mexico and as new deepwater production starts up.

Warm weather has kept natural gas prices from rising in December and with 16 percent fewer heating degree-days than normal, the December average Henry Hub price was $6.97 per mcf.

Remaining months of the winter are expected to be only slightly warmer than normal, and the Henry Hub spot price is expected to remain below $7 per mcf for the winter.

The agency said natural gas prices will be sensitive to periods of sustained cold weather during the remainder of the winter, particularly in the Northeast and Midwest. The Henry Hub natural gas price averaged $6.94 per mcf in 2006 and is expected to average $7.06 per mcf in 2007 and $7.72 per mcf in 2008.

After a 1.3 percent decline from 2005 to 2006, the EIA expects natural gas consumption to grow 2.4 percent from 2006 to 2007.

Domestic production of dry natural gas rose 2.4 percent in 2006; only 1.9 percent growth is expected in 2007.

Net imports of natural gas are estimated to have fallen 5.5 percent in 2006 and are expected to fall by a further 1.1 percent in 2007, then increase by 7.8 percent in 2008, with a decline in pipeline imports from Canada tempered by increased liquefied natural gas imports. LNG imports are expected to increase to 0.8 trillion cubic feet in 2007 and to 1.1 tcf in 2008.

As of Dec. 29, working gas in storage was 3.074 tcf, 433 billion cubic feet above a year ago and 408 bcf above the five-year average. The EIA said it expects current high inventory levels to slowly return to historical averages. ●

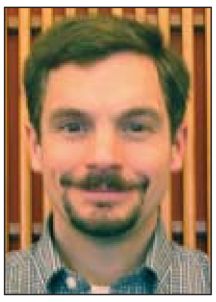
● WORKFORCE DEVELOPMENT

BP's perspective on present, future growth

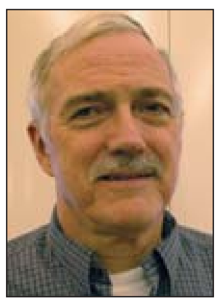
The work is there and so are the jobs, say BP's Borowski and Rees; the challenge is getting Alaskans to compete for them

By AMY SPITTLER
Petroleum News

A recent Petroleum News interview with BP Exploration (Alaska)'s Florian Borowski, human resource manager for resource planning, and Dave Rees, technical resourcing specialist, provided an inside look at the company's employment process and its perspective on the workforce situation in Alaska.



FLORIAN BOROWSKI



DAVE REES

AMY SPITTLER PHOTOS

BP has 300 more employees in Alaska than it did two years ago. According to Borowski the company's Alaska headquarters in midtown Anchorage is "busting at the seams." Parking is an issue; 22 weekly flights to the North Slope are full, and once you get there the beds are all occupied and the offices are packed.

Managing current growth while focusing on the future is BP's main concern.

"We at BP have been recognizing the need to not only believe we have a 50-year business, but act like we have a 50-year business. Growth is really about executing our 50-year plan; my position was actually created for that purpose," Borowski explained.

With projects large and small on the horizon, BP is on the lookout for promising new hires to complement that plan.

"Most of the positions right now are in discipline engineering, supporting our base business: mechanical, civil, construction and project engineers, and on the subsurface side, petroleum and reservoir engineers," Borowski said.

"We are hiring people right out of school, but right now we're really looking for experienced folks," added Rees. Corrosion engineers, for example, with the necessary experience are hard to find, he said.

To beef up its production while simultaneously addressing the workforce issue, BP developed three main focal points for increasing growth: "Re-establishing our ability to pursue our base business, production, integrity management and organizational capabilities; pursue major projects like Liberty and the western region development project, as well as brown-field type projects; and renewing our workforce — we lost 15 technicians last year, mainly to retirement, and we hired 80 new ones via transfer or external hire, " Borowski explained.

"Renewing the workforce also means renewing the equipment," Rees said. "We want to accelerate renewal and it takes people to do that, we need project managers to get these big projects started, but we also need people to maintain the facilities long-term."

Where BP looks and what it wants

Like all companies, BP has a process it goes through to find new people — a process Borowski said is concise, focused and comes with high expectations.

"Every time we have a job opening the job gets posted with the Alaska Department of Labor job service and with five Alaska newspapers; that's where it goes first and foremost every time," Borowski said. "The challenge is, if we can't fill it through those means, then we find ourselves recruiting from the Lower 48." Again, specialty areas are tough to fill; "there just aren't a lot of Alaskans with the necessary experience looking for work up here."

But Alaskans still have the best shot. In 2005, 83 percent of BP's employees in the state were Alaska residents, 71 percent receiving a permanent fund dividend.

"We've tripled the number of college hires that we're pursuing; graduates from UAA and UAF 4-year programs are preferred. We look for Alaskans who are going to school out of state; we want to get them back home. We pride ourselves on the progress we've made in that arena," Borowski said.

BP is first and foremost looking for Alaskans. But which ones do they want?

"Working for BP takes education, training and a positive attitude. You can have the education and training but if you don't have the right attitude you might not work for BP," Borowski said.

"We're looking for people who want to bring something extra to the job," Rees added.

Depending on the position, the education and training necessary for a job with BP can come from trade schools, colleges or working for a BP contractor.

Providing solutions and resources

Concern about finding enough qualified job applicants in Alaska has been raised at several meetings and forums over the last year. When asked about BP's proactive role in workforce development, Borowski said "BP has taken a leadership role in internship programs and process tech programs, utilizing internships more than any other company up here in terms of bringing folks in."

He explained that "we do that because not only are we giving people the opportunity to learn the skills and get some experience, it also allows us to develop a long-term interviewing process with them, which is extremely effective for us, and it contributes a lot to the community."

This past summer BP employed 16 interns from process tech programs and

see GROWTH page 18

● NATURAL GAS

U.S. imports of LNG drop for 2nd year

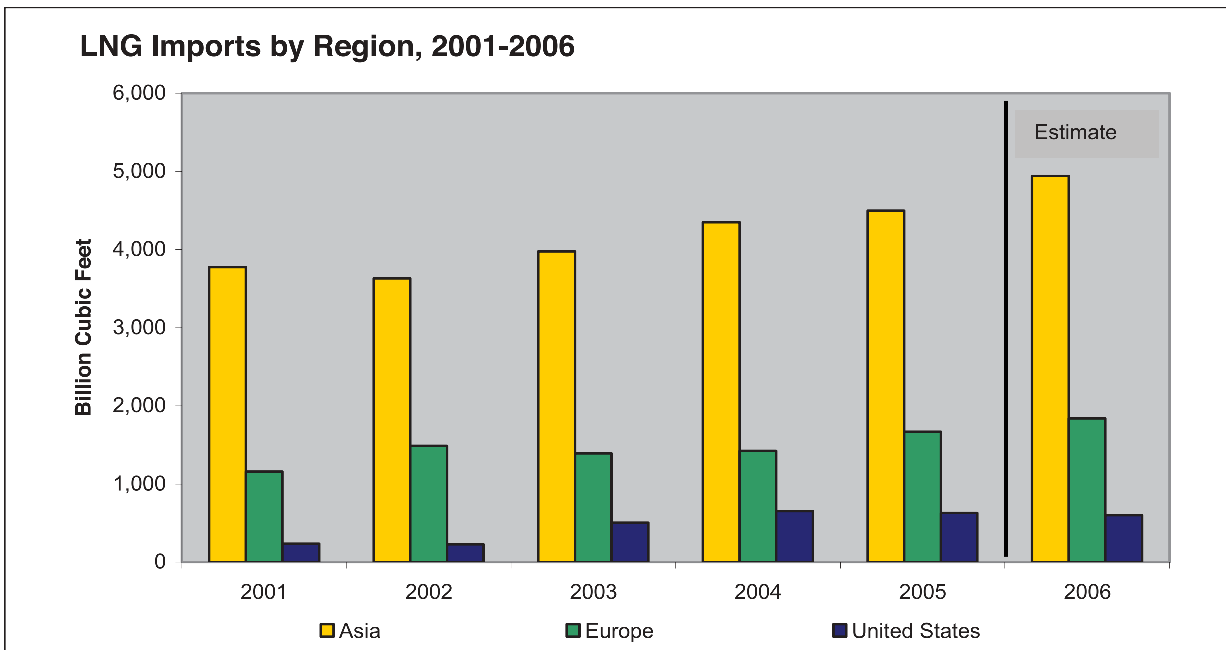
EIA analysts expect rebound this year, but shortages of feedstock gas and European competition for supplies are potential roadblocks

By **ALLEN BAKER**

For Petroleum News

Imports of liquefied natural gas into the United States declined in 2006 for the second straight year, as European customers outbid U.S. firms for the fuel. Those findings come in a new report from the U.S. Energy Information Administration.

With delays in several projects around the world, including Chevron's Gorgon and Gazprom's Sakhalin 2, LNG production may not grow as fast as projections — or worldwide demand. That could keep prices high and may divert LNG supplies away from the U.S. market.



Source: Energy Information Administration, *Natural Gas Monthly;* and FACTS Global Energy, Inc., *Gas Insights*.

High European prices

Last September, for example, netbacks to the big LNG operation in Trinidad and Tobago for shipments to Spain were $9.17 per million Btu. Shipments to the United Kingdom brought producers $5.32 per million Btu, still a big payday compared with the $3.71 netback for shipments to the U.S. terminal at Lake Charles, La.

Netbacks are the price that LNG producers get after subtracting transportation and other marketing costs. And a voyage to Spain or Scotland is far longer than a trip across the Caribbean and the Gulf of Mexico to Louisiana, so the prices at the consuming end in Europe were even more impressive.

"Competition has diverted much of the supply away from us," said Damien Gaul, one of the authors of this month's report, in a Petroleum News interview. "But this market has been the focus of a lot of LNG suppliers, so we think the supplies will get here."

Gaul's EIA report predicts imports of around 770 billion cubic feet this year, up 35 percent, and around 1.08 trillion cubic feet in 2008, a further increase of 39 percent.

Existing facilities can handle those amounts easily. U.S. import terminals in the Atlantic basin already can bring in 1.7 trillion cubic feet annually, and capacity will more than double by the end of 2008 with expansion of one terminal and the addition of three new Gulf Coast ports. The Sempra port in Baja California will also provide LNG import capacity for the West Coast market.

Slim pickings

But so far, U.S. prices haven't proved high enough to pull in even a quarter of the LNG available in the Atlantic basin market, as spot cargoes are being lured to Europe, which is consuming 88 percent of the available LNG in that market.

Last year, U.S. LNG imports slumped to an estimated 12.1 million tonnes of LNG (equivalent to 580 billion cubic feet of gas), less than 3 percent of the U.S natural gas market. The import figure was down 8 percent from 2005 and 11 percent below the peak of 652 bcf in 2004.

Still, Gaul figures new supply from Equatorial Guinea, Norway, and then Qatar and Yemen, will bring enough added LNG to the Atlantic basin market that more of it will end up in the United States. While Qatar and Yemen may ship their product mostly to Europe, their addition to the market, expected in 2008, should loosen the supply equation somewhat.

"It's difficult to discount the fact that there's lots of new supply," Gaul says. "In the next couple of years, there's going to be even more supply." Since the U.S. is by far the largest natural gas consumer in the world, "this market has been the focus of a lot of LNG producers, so we think the supplies will get here," he said.

Other analysts are more pessimistic, and some think the worldwide LNG supply squeeze could last until 2011 or longer.

High projections

Gaul admits that the EIA projections have been off the mark in the recent past.

"We've been expecting these LNG supplies to show up, but they didn't show up in the last year and a half," he notes.

As the EIA report indicates, expanded liquefaction capacity doesn't always result in as much new tonnage as anticipated.

While new capacity was added in Egypt, Trinidad and Tobago, and Nigeria since 2005, the report says "maintenance delays and lack of available feedstock gas caused LNG production in the Atlantic basin during 2006 to grow at a much lower rate."

Asian competition

LNG is a big part of the supply equation in Asia, notably in Korea and Japan, both of which have "demonstrated a consistent willingness to outbid U.S. importers," and both of which have locked in future supplies with contracts that are often a quarter of a century long, the report says.

South Korean LNG imports rose 20 percent in 2006 to the equivalent of 898 bcf. LNG imports by Asian countries altogether are estimated at 4.9 tcf, up 10 percent for the year and more than eight times the U.S. import figure.

Both South Korea and Japan rely on LNG for more than 90 percent of their natural gas supplies, and both use the gas extensively for power generation. So they have swallowed costs that quadrupled since 2002. Spain has a similar need for LNG to produce electricity.

The United States, conversely, has a diversity of supply in its various production basins, as well as in Canada. And this country has managed to deal with seasonal peaks by using extensive underground storage. The mild hurricane season and this year's mild winter have led to higher stockpiles than usual and a weaker U.S. market.

Delays and overruns

In the longer term, LNG supplies may not rise as quickly as the builders of the multi-billion-dollar liquefaction trains may hope. Costs for those facilities are rising at an alarming rate, and the plants are taking more like four years to build, instead of three.

A recent Bloomberg report quotes sources at Bechtel Inc., the big San Francisco engineering firm, as saying the cost of a liquefaction train has tripled since 2000, to $600 million for each million tonnes of annual LNG capacity. And the prolific fields that supply the huge projects may not be able to sustain such huge quantities if they are drained at a rapid rate.

Other factors go into the mix as well, as they do in the world oil market.

In Nigeria, rebel attacks have made things uncomfortable for Shell and other big oil companies operating there. Iran sits under a political cloud as well.

"Geopolitical developments likely will continue to play a major role in energy prices and supplies, as has been the case in Nigeria and elsewhere," the EIA report concludes. "Lastly, and perhaps most importantly, the degree of competition from other countries will be a crucial variable that determines the actual flow of LNG to the United States." ●

● NATURAL GAS

Bering Sea likely rich in hydrates

Cold war era acoustic research may have stumbled across vast quantities of methane trapped under 12,000 feet of water

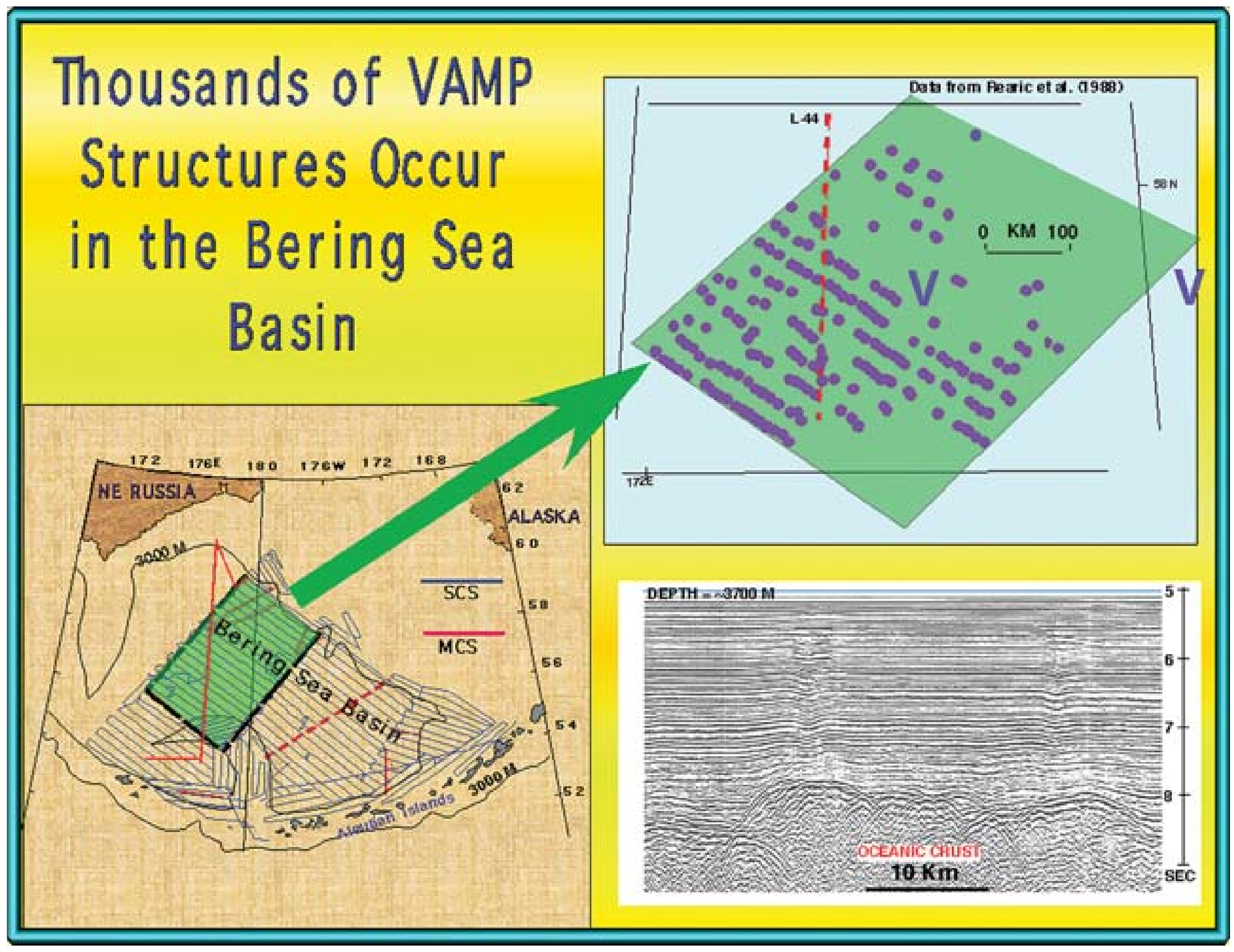
By ALAN BAILEY
Petroleum News

The remote Bering Sea seems an unlikely location for a major natural gas province. Yet the region may hold thousands of trillions of cubic feet of gas resources.

At a Jan. 11 meeting of the Geophysical Society of Alaska, U.S. Geological Survey Senior Research Geologist David Scholl described how what appear to be massive methane hydrate bodies pepper the south-central Bering Sea subsurface in a region that straddles the divide between the U.S. and Russian economic zones. The hydrates occur in a flat area of the abyssal plain, comparable in size to Nevada and Utah combined, Scholl said.

The hydrate bodies appear as strange looking features in seismic data collected during the Cold War.

"The reason we found these things was because of anti-submarine warfare," Scholl said. "… We were chasing submarines around and doing acoustic work."



DAVID SCHOLL

Trapped methane

Methane hydrate, often referred to as gas hydrate, consists of a crystalline substance in which a lattice of water molecules traps methane molecules (methane is the primary component of natural gas).

The hydrate crystals remain stable within a certain range of temperature and pressure, known as the methane hydrate stability zone. If moved outside the stability zone, the hydrate crystals decompose into water and methane gas. When decomposed the crystals yield about 170 times their volume in methane, Scholl said.

Hydrates can occur on the seafloor if the water temperature and pressure falls within the stability zone. Alternatively, the hydrates can occur underground, within rock formations that lie within the stability zone. Within rocks the hydrates may be dispersed in rock pores, or form nodules, layers or massive aggregations, Scholl said.

On Alaska's North Slope there are extensive gas hydrate deposits within underground rock formations around the base of the permafrost zone — a government and industry team is currently engaged in a multi-year project to determine whether it is possible to viably extract natural gas from these hydrates.

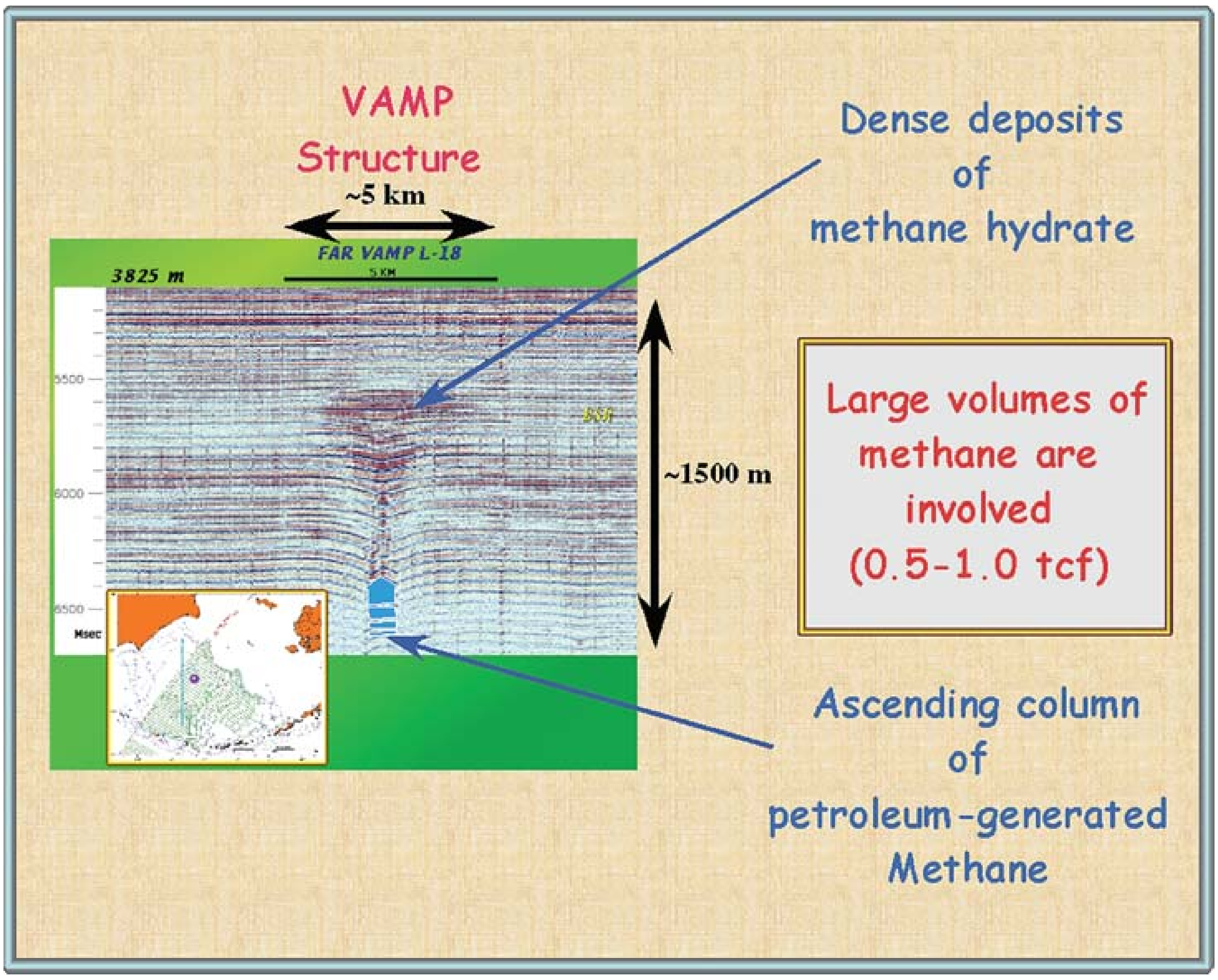
Seismic features

The scientists engaged in the Cold War era research

see **HYDRATES** *page 12*

continued from page 11

HYDRATES



DAVID SCHOLL

observed many strange-looking anomalies in the deep Bering Sea seismic sections. In profile, these anomalies looked like giant mushrooms, with the heads of the mushrooms typically about 1,200 feet below the seafloor and about 3 miles across. The stalks of the mushrooms would extend vertically downwards for several thousand feet to basement rocks that lie underneath the sediments that blanket the seafloor.

Typical water depths in the region where the structures were found are around 3,800 meters (12,500 feet).

Scholl explained that because no seismic line crossed the same structure twice, it was impossible to say whether in plain view a structure was circular or of a more elongated form.

The structures showed up on seismic profiles in part because they contained areas of heightened seismic signal amplitude, and in part because within the structures the reflections of rock strata would be deflected out of the horizontal.

In the head of the mushroom seismic reflections from otherwise horizontal rock strata would be deflected upwards, a phenomenon that geophysicists term "pull up," while in the stalks the reflections would bend down, a phenomenon known as "push down." Pull up is caused by material with relatively high sound velocity — the reflections of the seismic sound reach the surface seismic receivers more quickly than normal, thus making the reflections appear closer to the surface. Push down is the opposite effect, where a relatively low sound velocity slows down the seismic signals.

The scientists termed the Bering Sea structures VAMP structures, an abbreviation for velocity and amplitude anomaly.

"We didn't know what these things were," Scholl said.

But the scientists could see that the structures occurred in clusters of several hundred. And thousands of the structures dot the deepwater region of the south-central Bering Sea.

Evidence for hydrates

After the physics of methane hydrates became known in the early 1970s it became evident that the VAMP structures related to gas hydrates in the subsurface.

The hydrate has a relatively high sound velocity that would account for the pull-up effect in the head of the VAMP. Methane reduces the sound velocity, so that the push down in the mushroom stalk provides evidence of a gas chimney. Gas in the chimney would bubble upwards from deep within the seafloor rock strata and feed the hydrate accumulating in the head of the mushroom.

"A couple of percent gas (in the rock) and your (sound) velocity will drop 20 or 30 percent," Scholl said.

But how can the scientists be so sure that the seismic anomalies result from underground methane and methane hydrate?

It's mainly a question of the location of the methane hydrate stability zone. When you project the known temperature and pressure gradients downwards below the seafloor you find that these gradients cross the boundary of the hydrate stability zone at the bases of the VAMP heads. Go below the heads and gaseous methane would be stable. Go higher and methane hydrate is stable.

In fact a distinctive seismic reflection known as the bottom simulating reflector, or BSR, also depicts the seismic velocity contrast at the bottom of the region of presumed methane hydrate and generally runs parallel to the sea floor (apparently, the "BS" portion of BSR was originally coined from a driller's response to being asked to target the reflection. The phrase "bottom simulating" was later thought up as more polite terminology).

The push down effect in the stalks of the VAMP mushrooms increases with depth, presumably because of the cumulative velocity effect of sound passing to deeper and deeper levels through gas in the gas chimneys. That shows that the gas is flowing from great depth within the chimneys and, thus, indicates that the gas is thermogenic, Scholl said (thermogenic gas forms from the heating of organic material, as distinct from biogenic gas that results from bacterial decomposition of the material).

Geologic explanation

And there's a plausible geologic explanation for a gas hydrate kitchen under the deep Bering Sea.

The seismic sections show that near-horizontal sedimentary strata, anywhere from about 3,000 feet to 30,000 feet thick, blanket a pre-existing, mountainous rock basement with immense troughs and ridges. The VAMP structures tend to occur over the higher points in that basement.

Some drilling done in association with the acoustic survey work found that the sedimentary strata consist of two distinct sequences. The younger and shallower of these sequences consists of rocks called turbidites that are typically laid down from sediment flows in deep water. The Bering Sea turbidites started to form about 2.5 million years ago, Scholl said. Under the turbidites lies an older sequence of mudstones containing huge quantities of diatom remains — diatoms are tiny algae with silica cell walls. The older sequence of strata appears to extend back into the Miocene epoch that began around 26 million years ago.

The existence of diatoms in the mudstones indicates that in the geologic past the Bering Sea was organically productive, just as it is at present. And organic material from buried diatoms and other organisms would feed thermogenic gas production in the region.

Hot basin

But what about the necessary heat for the process?

The geologic setting of the Bering Sea results in an exceptionally high heat flow out through the Earth's crust in the region. The subsurface thermal gradient is about 60 C per kilometer, Scholl said.

"That means that in a couple of kilometers (6,000 feet) you're in the gas window," Scholl said.

Not only that, but the alteration of diatom-containing mud under the effects of temperature and pressure would likely release further heat, with the assemblage

see **HYDRATES** *page 13*

PIPELINES & DOWNSTREAM

Free Venezuelan oil finally reaching Alaska villages, 11,000 homes eligible

Alaska villages are finally receiving a much-criticized donation of heating fuel from Venezuelan oil company Citgo.

More than 11,000 homes in rural Alaska are eligible for 100 gallons each as part of Houston-based Citgo's pledge to donate 1 million gallons of heating fuel to poor Americans.

More than 150 Alaska villages took advantage of the offer and residents began receiving vouchers for the fuel late in late December. The vouchers can be redeemed at local fuel stores.

"It was a great way to start the new year," said Gambell resident Jennifer Apatiki, whose husband hauled home a 55-gallon drum of free heating oil shortly after Christmas.

Citgo's $5.2 million gift drew a barrage of criticism because of Venezuela President Hugo Chavez's combative attitude toward U.S. policy, particularly after he called George Bush the "devil" in a speech at the United Nations. Citgo is owned by the Venezuela government.

Because of Chavez's political views, Citgo's offer was refused by the Aleutian Pribilof Islands Association, a Native regional nonprofit corporation representing four eligible villages.

People in Gambell, a Yup'ik village of 660 on St. Lawrence Island, need the money more than they care about the politics, Apatiki said.

"Devil, angel, whoever gave it to us, we're grateful," she said.

Heating fuel costs $4.65 a gallon in Gambell. Apataki said she's spending more than $600 a month to heat her three-bedroom home despite relatively warm temperatures this winter.

Coordinators of the giveaway, led by the Alaska Inter-Tribal Council, had hoped vouchers would reach villages by Nov. 1. But Citgo needed paperwork verifying addresses and head of households for every home in more than 150 villages. That's an enormous undertaking in many remote areas, said Steve Sumida of the tribal council.

Native nonprofit corporations led the effort in their regions. In some areas volunteers went door-to-door verifying identification and addresses, Sumida said.

—THE ASSOCIATED PRESS

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HYDRATES

of sediments acting like a water laden and organic-rich blanket enveloping an already hot basement and effervescing methane gas.

The seismic data show little evidence of geologic faulting that might provide conduits for the methane to flow towards the surface. The scientists have instead proposed a theory involving the gas chimneys forming in fracture systems in the mudstones. Evidence from similar rocks in California shows that the original diatom-containing sediment shrinks and fractures as is solidifies — those fractures could form embryonic gas chimneys that would later become self-perpetuating, as hot gas flowed towards the surface.

The fact that the VAMP structures tend to occur over high points in the oceanic basement remains something of a mystery. One theory is that compaction of the sediments over these high points might have accelerated the fracturing and gas chimney formation.

Massive resource

Some simple calculations show that the Bering Sea VAMP structures may contain vast amounts of methane. Assuming that the structures are circular and assuming a minimum gas concentration in the chimneys, a typical vamp might contain anywhere from 0.5 trillion cubic feet to 1 tcf of methane. Multiply that by the potential number of VAMP structures and you arrive at some fairly mind-boggling numbers.

But before anyone gets too excited about developing this spectacular resource they might want to consider that the gas lies many miles from land under more than 12,000 feet of water in one of the world's harshest marine environments — economic extraction of the gas seems implausible in the foreseeable future.

And scientists would like much more information about the physics of the structures, their geometry and their distribution — among other things, that information would enable much more complete gas resource estimates.

"What we want very much to do is to get up and acoustically map both the horizontal and vertical characteristics of a number of VAMPs," Scholl said. "… No vessel has ever gone out there to take a look at one of these things using modern navigation equipment."

But, given the cost of vessel-based research, these investigations seem unlikely to occur for a number of years. Meantime the methane hydrate "mushrooms" of the Bering Sea remain a tantalizing feature of the region.

"The Bering Sea is really infected with these guys," Scholl said. ●

● EXPLORATION & PRODUCTION

Canada tallying wins and losses

Shallow gas, coalbed methane take chunk out of well licenses; oil posts highest completions in almost a decade, most finds in 21 years

By GARY PARK
For Petroleum News

Largely reflecting uncertainty over the fate of the Mackenzie Gas Project, drilling in Northern Canada is on the skids, with regulators issuing a meager five well permits in 2006, continuing a successive decline that started at an impressive 32 in 2003 and tumbled to 15 in 2004 and 12 in 2006.

The retreat has been accompanied by a series of court challenges and regulatory delays that have pushed the possible start-up date for the Mackenzie development from 2009 to 2012, creating doubt over whether the project will actually proceed to construction.

For the rest of Canada, it was a troubling year on the permit front, mostly because of back-pedaling by operators in the shallow natural gas plays of southern Alberta and Saskatchewan and rapidly shrinking popularity in the coalbed methane sector.

Regulatory agencies issued 29,901 licenses in 2006, off 3.2 percent from the 2005 record of 30,917 and, although still the second highest 12-month count on record (the 2004 count was 28,631), the trends contained disturbing elements.

On the upside, sturdy oil prices saw the industry log the most oil completions since 1987 and the most finds since 1985.

There was also a hint of hope for long-range gas prices, with exploration wells rising 7 percent to 3,997, although gas development wells continued their steady slide to 11,289 from 11,609 in 2005 and 11,941 in 2004.

Industry statistics showed 926 oil discoveries, the best since the 1,258 finds in 1985, including 434 in Alberta and 383 in Saskatchewan. Development oil wells gained 15 percent at 4,673.

The shift from shallow to deep gas drilling was clearly evident, with 667 deeper gas holes completed, up about 50 percent from 2005, while shallow wells declined 8 percent to 8,551.

Across the industry, well completions tallied 22,171, beating 2005 by 191 wells, although that number is distorted because of a delay in releasing well results from 2004.

Other data points to actual completions last year of 23,184, off 6 percent from the 2005 benchmark of 24,746.

A persistent drag on gas prices combined with an announced change in the tax status of income trusts did most of the damage to the well permit count through the second half of 2006 after the industry reached the year's mid-point with 15,576 well approvals, 12.6 percent ahead of the pace set in 2005.

By then, many companies had already started trimming their drilling programs and were pointing to further cuts in 2007, which are mirrored in the permit applications.

Had it not been for a rush to drill oil sands evaluation wells in northeastern Alberta there would have been little to cheer about last year.

Alberta has 3.5 percent decline

Alberta authorized 23,210 wells, a decline of 3.5 percent from 2005, with conventional gas permits sliding 13 percent to 12,604 and coalbed methane licenses tumbling 23 percent to 2,392.

The coalbed methane tally brought coalbed methane optimism to an abrupt halt after permit numbers surged from 577 in 2003 to 1,598 in 2004 and 3,106 in 2005, with forecasters aiming for 5,000 in 2006.

The turnaround places a cloud over coalbed methane predictions, notably a new study by the Canadian Energy Research Institute forecasting a rise in coalbed methane production from the current 500 million cubic feet per day to 1.4 billion -1.9 billion cubic feet per day from 2011 to 2017, backed by capital spending of C$9 billion over the 2006-2026 period.

Those hardest hit were southeastern Alberta (the focus of shallow gas and coalbed methane drilling), off 15 percent to 7,236, central Alberta down 29 percent at 3,217 and southwestern Saskatchewan, off 22 percent at 1,813.

Entering 2007, there have been some sharp revisions to that thinking. Don Herring, president of the Petroleum Services Association of Canada said anticipated gas prices of US$6 per thousands cubic feet for this year will not stimulate much activity in shallow gas and coalbed methane plays, while Greg Stringham, vice president of the Canadian Association of Petroleum Producers, said prices above $5 are needed to achieve a break-even point.

Many permits lapse or are cancelled

Permit approvals are not the final guide to actual drilling in Canada, since many operators cancel their licenses within the 12-month deadline.

In 2004, 2,212 licenses lapsed, while 2,249 were cancelled in 2005 and, so far, of last year's permits 494 have been cancelled.

The industry obtained 3,892 authorizations for oil sands test/evaluation wells last year, a gain of 84 percent from the previous year's 2,113, further evidence of the sizzling pace of activity in the region.

Topping the list of oil sands test holes were Suncor Energy at 384, Synenco Energy (60 percent operator with China's Sinopec as the minority partner in the Northern Light project) at 384, Deer Creek Energy (wholly owned by France's Total in the Joslyn project) at 1,763, Shell Canada (operator of the Athabasca project) at 245 and newcomer North American Oil Sands at 244.

Of the few areas to post permit increases, northeastern Alberta (center of the oil sands play) was up 48 percent to 5,054 and eastern Saskatchewan was up 35 percent at 1,285.

Those hardest hit were southeastern Alberta (the focus of shallow gas and coalbed methane drilling), off 15 percent to 7,236, central Alberta down 29 percent at 3,217 and southwestern Saskatchewan, off 22 percent at 1,813.

Overall, Saskatchewan posted only a slight decline of 139 permits to 4,522, despite a 23 percent drop in gas approvals to 1,656. Offsetting that, oil-targeted permits jumped 16 percent to 2,609.

British Columbia's gas-weighted industry reflected the commodity markets, sliding 10 percent to 1,673 new licenses, halting four successive years of gains.

Manitoba, bolstered by a new play, recorded a gain of 62 permits to 446, while Eastern Canada, led by offshore Newfoundland, had an impressive 81 percent increase to 184 wells.

Excluding oil sands test/evaluation approvals, EnCana retained its top spot in the list of operators at 3,637 licenses, despite a decline of 1,008 permits after heavy cuts to its 2006 and 2007 capital budgets.

It was trailed by Canadian Natural Resources at 1,763, Husky Energy at 1,470, EOG Resources at 1,177 and ConocoPhillips at 1,046. ●

LAND & LEASING

Alberta picks up where it left off

Alberta government land sales haven't missed a step as they start a new year, with oil sands parcels accounting for more than 70 percent of the initial bidding round in 2007.

Having dominated the bi-monthly auctions in 2006, the oil sands generated C$133.6 million for rights to 495,000 acres, with conventional sales contributing another C$54.2 million from 293,000 acres.

However, the combined total fell C$25 million short of the initial auction last year when 580,000 acres changed hands.

The average per-acre price took a 35 percent drop year-over-year, another indication of the downturn in drilling intentions and wilting oil and gas prices.

C$24.8 million bid tops sale

Topping the oil sands lease sale was a successful bid of C$24.8 million by broker Scott Land & Lease on behalf of an unidentified client, who paid an average C$1,632 per acre compared with the sale's average C$270 for oil sands rights.

Two nearby parcels were acquired by Windfall Resources and Canadian Coastal Resources for C$17.6 million and C$15.5 million at respective per-acre prices of C$1,157 and $2,047.

Major oil sands operators with rights in the area are UTS Energy, a partner with Petro-Canada and Teck Cominco in the Fort Hills project, and Shell Canada.

Petroland Services (1986) led the per acre average at a startling C$11,567 for a section in the Cadoette area of the Peace River region in northwestern Alberta close to where Shell has wells licensed.

—GARY PARK

● EXPLORATION & PRODUCTION

Shell flags intent to test winter seismic in Beaufort

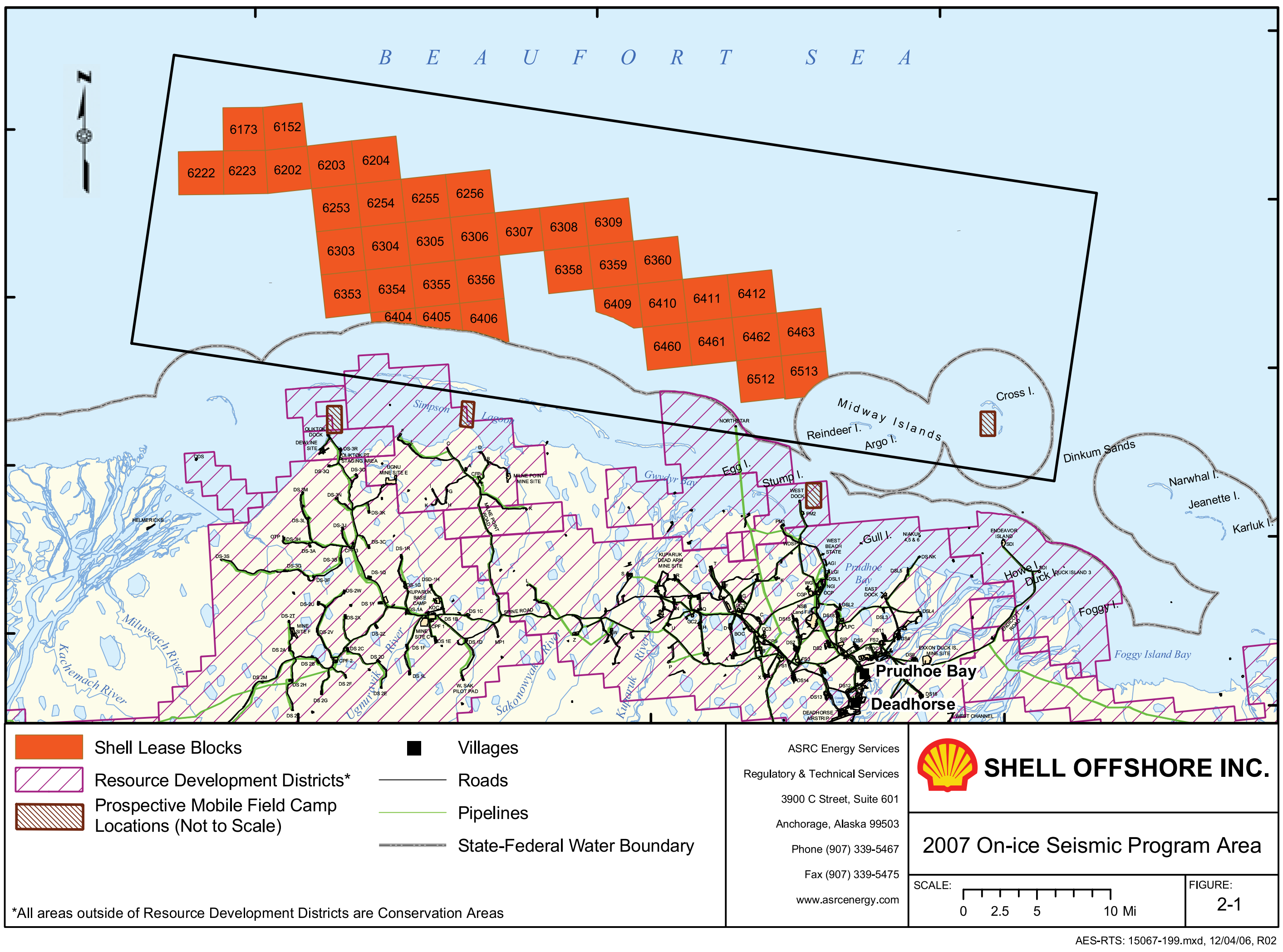
By ALAN BAILEY
Petroleum News

In a Jan. 12 letter to the Alaska Department of Natural Resources, Shell Exploration and Production Co. gave notice of its intent to carry out a research program, to investigate the feasibility of seismic data acquisition from floating ice in the Beaufort Sea. Shell plans to conduct the research between mid-March and mid-May 2007.

Although the company expects the research to take place entirely within the federal outer continental shelf, Shell has applied for a state geophysical permit, as a contingency against ice conditions forcing the work to be carried out closer to land.

In a fact sheet describing the program, Shell said that it wants to establish whether it can acquire seismic data from floating ice in the company's shallow water Beaufort Sea oil and gas leases — water depths in some of the leases are too shallow to permit the operation of a seismic vessel, the company said.

In October at the National Marine Fisheries Service Arctic Open Water Peer Review Meeting in Anchorage Shell also said that shooting offshore seismic from sea ice in the winter might provide a means of eliminating any possible conflicts between seismic operations and subsistence hunting by North Slope communities.



Forty-eight inch ice

In its letter to DNR, Shell said that the winter seismic testing would take place on ungrounded ice, at least 48 inches thick, in water less than 60 feet deep. Monitoring of potential sites would start in January, with the actual site being chosen using criteria such as the measured ice thickness.

A key research objective will be to find a seismic technique that can overcome problems associated with what is known as a "flex wave," the transmission of excessive seismic noise through the ice.

"Noise associated with the flex wave has been found to be up to a thousand times higher in amplitude than the desired seismic signal," Shell said in its fact sheet.

The survey crew will place seismic sources and receivers both above and below the ice in an area of 16 square kilometers, to test for source/receiver pairings that will best address the flex wave and other noise effects. In addition to receivers attached to the ice surface, some receivers will be sus-

see SHELL page 16

Report: BP ignored big safety issues

By JOHN PORRETTO

Associated Press Writer

British oil company BP failed to emphasize safety at its U.S. refineries before the 2005 Texas City explosion that dilled 15 people, according to a report released Jan. 16 by an independent panel led by former U.S. Secretary of State James A. Baker III.

The panel, in a statement summarizing its 300-plus page report on BP's operations, said the company had made strides in personal accident prevention but came up short on the bigger picture.

"The panel maintains a central theme that prior to the Texas City tragedy BP emphasized personal safety and had achieved significant improvements in personal injury rates, but the company did not emphasize process safety," the statement said. "BP mistakenly interpreted improving personal injury rates as an indication of acceptable process safety performance at its U.S. refineries."

The 11-member panel made 10 recommendations, including that an independent monitor report to the company's board of directors for five years.

Browne: 'BP gets it, and it get it too'

"BP gets it, and I get it too," BP CEO John Browne told reporters by video link from London. "I recognize the need for improvement."

Browne, who got the report from Baker Jan. 14, called the report a "hard-hitting and critical analysis that focused on deficiencies and negatives."

Browne defended the company's overall safety record, which the Baker report acknowledged was sufficient in terms of personal injury prevention and environmental safety.

But on so-called process safety, "it wasn't excellent enough," Browne said. "And the standard is excellence."

Browne said the company would implement the panel's recommendations, including the independent monitor. But he said the company needs to compare Baker's report with a companywide safety examination that began soon after the Texas City explosion; he gave no time frame for making the changes Baker's group suggested.

Baker has led the panel investigating corporate management at Houston-based BP Products North America following the March 2005 blast that killed 15 people and injured more than 170 others.

CSB urged BP to hire experts

The U.S. Chemical Safety and Hazard Investigation Board, known as the CSB, urged BP in August 2005 to hire outside experts to look at the company's oversight of safety management systems and make its findings public — similar to an investigation at NASA following the space shuttle Columbia tragedy.

The panel, announced in October 2005, has traveled to BP's five U.S. refineries and interviewed hundreds of employees.

"BP tended to have a short-term focus in its U.S. refining operations, and its decentralized management system and entrepreneurial culture delegated substantial discretion to U.S. refinery plant managers without clearly defining process safety expectations, responsibilities or accountabilities," the panel said in the report.

Baker, a senior partner at the Houston-based Baker Botts law firm, was White House chief of staff and treasury secretary in the Reagan administration and secretary of state in the first Bush administration. The release of the BP report was twice delayed because of his work with the Iraq Study Group, which made its recommendations to President Bush in December on how to revamp U.S. policy in Iraq.

The release of the report comes less than a week after London-based BP said that Browne, its chief executive, would step down by the end of July, more than a year ahead of schedule.John Manzoni, the company's head of refining and marketing, said Jan. 16 he had no plans to resign.

Company has paid out $2B

The 2005 explosion has so far cost the company around $2 billion in compensation payouts, repairs and lost profits. BP has settled hundreds of lawsuits related to the accident, putting aside $1.6 billion just to resolve legal disputes.

Based on its investigation, the CSB has criticized BP for its safety systems at Texas City, about 40 miles southeast of Houston, finding the company fostered bad management at the plant and failed to fix problems.

In September 2005, the U.S. Occupational Safety and Health Administration found BP committed more than 300 willful violations of its rules and fined the company $21.3 million.

BP's own December 2005 report blamed failures by management at the refinery, saying it didn't make safety a priority, tolerated risks and failed to communicate. But BP added it "found no evidence of anyone consciously or intentionally taking actions or decisions that put others at risk."

The CSB has credited BP for cooperating with its investigation, making sweeping changes in how it recognizes potential hazards and hiring the Baker panel. ●

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SHELL

pended in the water column and others will lie on the seafloor. Sources will include standard and lightweight vibrators; accelerated weight drop on the ice; and small-volume air gun arrays deployed through holes augured in the ice.

Veritas DGC Land Inc. will conduct the experimental survey, using a vehicle fleet that includes a variety of sizes of vibrators. A modified track vehicle will deploy sub-ice seismic sources. Seismic receiver deployment will involve 13 tracked vehicles.

A camp of about 120 people about a half-mile offshore the West Dock at Prudhoe Bay will require up to 35 sled trailers, including medical facilities; crew quarters; offices; kitchen and dining facilities; technical work spaces; generators; and fuel storage units. ●

● NATURAL GAS

Canada CBM leader on wobbly perch

Rumor has Trident Exploration, largest pure coalbed methane company, up for sale; EnCana, Nexen, Husky possible purchasers

By GARY PARK

For Petroleum News

The two-pronged dive in natural gas prices and rise in drilling costs over the last year, combined with a rising debt, could be about to topple a leader in Canada's coalbed methane sector.

Downtown Calgary is abuzz with rumors that Trident Exploration, a unit of Texas-based Trident Resources, is up for sale and could quickly disappear into the EnCana fold.

But the largest pure coalbed methane company in Canada has been floundering lately, weighed down by a US$700 million debt, sideswiped by the slump in gas prices and caught up in internal ructions that culminated in the departure of founding Chief Executive Officer Jon Baker, who remains CEO of the parent company.

A pioneer in Alberta's coalbed methane sector, Trident currently produces 95 million cubic feet per day, one-third from the emerging Manville formation in Alberta; has 865,000 acres of exploration holdings, of which 75 percent is awaiting development of more than 3,000 wells; and is the dominant landholder in the Corbett area, 100 miles northwest of Edmonton.

Minority shareholders working on restructuring debt

While minority shareholders have been spearheading a bid to restructure debt and possibly replace the executive team, Trident has reportedly negotiated emergency financing of US$270 million at premium rates from one of its bankers, Credit Suisse Securities.

In a new report, Michael Wang, an analyst at John S. Herold, estimated Trident's worth at US$900 million — US$300 million for proved reserves of 101 billion cubic feet and US$600 million for non-proved reserves.

Much of the company's financial woes have been linked to hopes that an initial public offering, since dashed, would generate the cash needed to tackle expansion of coalbed methane production in the Mannville and Horseshoe Canyon plays.

While minority shareholders have been spearheading a bid to restructure debt and possibly replace the executive team, Trident has reportedly negotiated emergency financing of US$270 million at premium rates from one of its bankers, Credit Suisse Securities.

Horseshoe Canyon is well-established as the main source of coalbed methane, having the advantage of dry coal seams, while Mannville, which could contain half of Canada's estimated 600 trillion cubic feet of coalbed methane potential, produces substantial quantities of saline water along with the gas, making the extraction process more challenging.

EnCana, Canada's largest coalbed methane producer at about 195 million cubic feet per day last year and targeting 270 million this year, is seen as an eager suitor, given that it spent C$160 million in 2005 for Mannville exploration lands.

The big independent has budgeted US$485 million for coalbed methane operating in 2007, including 915 wells.

Nexen, Husky possible suitors

Other logical suitors could include Nexen, a joint venture partner in a C$400 million project to launch the first commercial production from the Mannville formation, and Husky Energy, which struck a joint venture with Trident in 2004 to drill 120 coalbed methane wells over two years.

Nexen Chief Executive Officer Charlie Fischer said in December his company is poised to exercise its right to serve notice on any wells that Trident is unable to finance after the struggle Trident had to arrange its US$270 million loan.

For others, coalbed methane is a source of some concern. Bob Merkley, president of the Petroleum Services Association of Canada, cautioned that "some of the small, specialized companies (in the service sector) that have developed around CBM will have trouble" in 2007 unless gas prices rebound.

Speaking to the Canadian Society of Petroleum Geologists in November, Mike Finn, Trident's chief geologist, suggested smaller coalbed methane producers in Alberta should think about teaming up to assemble large land blocks and head off any moves by regulators to enforce more efficient removal of resources.

The high costs of shallow gas operations and the low returns have dramatically slowed the pace of coalbed methane drilling in southern Alberta over the past year, barely four years after Canada's first commercial coalbed methane production.

Coalbed methane well permits crashed 23 percent in 2006 to 2,392 from a 2005 record of 3,106, ending for now industry hopes of reaching the 5,000 level in the near future and undermining optimistic forecasts that coalbed methane cold grow from 2 percent of Canada's overall gas production to 27 percent as soon as 2014, according to one forecast by Ziff Energy Group. ●

Want to know more?

Go to PN archives at www.PetroleumNews.com to find the following:

- **Dec. 17**, 2006 Nexen ready to take control of CBM play
- **April 23**, 2006 CBM stumbles in Alberta

● FINANCE & ECONOMY

BP CEO Browne to retire at end of July

Departure spells 'end of an era' for London-based oil and gas giant; Browne joined BP in 1966 as an apprentice, took top job in 1995

THE ASSOCIATED PRESS

BP's chief executive is stepping down by the end of July — more than a year ahead of schedule — after a series of high-profile mishaps including a deadly refinery blast in Texas that tarnished the image of one of the world's largest oil companies.

BP said Jan. 12 that Chief Executive John Browne, 58, will be succeeded by Tony Hayward, the head of exploration and production, who will take over the difficult task of trying to repair the company's reputation with investors and the public.

JUDY PATRICK

During John Browne's tenure as CEO, BP said, the company saw a five-fold increase in its market capitalization to $202.7 billion.

Browne, whose future has been the subject of intense speculation, had announced in July that he would step down at the end of 2008.

"Last summer, John and I had agreed that he would stay as CEO until the end of 2008," said BP Chairman Peter Sutherland. "John decided that it would be in the company's interest to name a successor now in order to provide an orderly transition. Having made that decision, which the board fully supports, we came to the conclusion that a six-month handover would be more appropriate than 18 months."

Hayward, 49, who is currently in charge of the firm's exploration and production arm, will take over on Aug. 1. Analysts said Hayward's appointment was no surprise, but

BP said Jan. 12 that Chief Executive John Browne, 58, will be succeeded by Tony Hayward, the head of exploration and production, who will take over the difficult task of trying to repair the company's reputation with investors and the public.

that having a succession plan announced could help the company move forward.

"Tony's been standing in the wings for some time and he currently runs the largest division at BP, so the move is no surprise," said Brendan Wilders of Oriel Securities. He added that the appointment removes some uncertainty and "clears the air" but that Browne's departure will be "the end of an era."

Richard Hunter, head of U.K. equities at Hargreaves Lansdown stockbrokers, called 2006 "something of an annus horribilis for BP. … Whilst it was previously known that Lord Browne would be departing in 2008, clearly this move may allow BP to draw a line in the sand and concentrate on the various operational problems it is currently facing."

Browne first joined the company in 1966 as an apprentice and worked his way up, taking the top job in 1995. He oversaw BP's expansion into the United States, involving a number of takeovers, including the 1998 merger with Amoco and the subsequent acquisitions of ARCO and Castrol.

During Browne's tenure as CEO, BP said, the company saw a fivefold increase in its market capitalization to $202.7 billion.

But BP said in early January that production in the fourth quarter is unlikely to change compared with the previous three months, following more than a year of declining output.

First oil company CEO to acknowledge global warming

Browne's attempts to fashion BP as an environmentally friendly oil company — he was the first major oil company CEO to acknowledge global warming and masterminded BP's logo change from a shield to a flowerlike sunburst design with the slogan "Beyond Petroleum" — were undermined by the company's recent U.S. troubles.

It was forced to temporarily close some of its operations at the Prudhoe Bay oil field in Alaska because of a major pipeline spill and delayed the opening of its key Thunder Horse platform in the Gulf of Mexico. The 2005 explosion at its Texas refinery that killed 15 workers has so far cost the company around $2 billion in compensation payouts, repairs and lost profits. (See related story on page 16.)

"We clearly have important issues still to deal with which I am determined to address," Browne said in a statement. "I am pleased that Peter and I have been able to work together to develop a successor in Tony in whom I have every confidence."

Browne earned $6.5 million last year after his $2.9 million salary was boosted by bonuses. He's entitled to a pension of around $2 million each year, as well as share options. BP did not provide details on his retirement package. ●

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GROWTH

22 interns from colleges, Rees said.

When asked if BP was utilizing trade school graduates in Alaska, Rees explained that "most of our entry-level positions require a high skill level, so we're usually talking to experienced hires with five-to-10 years in the field."

True entry levels with the company can be filled by graduates from process tech programs, he said, noting that most of them have had the work experience and are top students with great employability skills.

Borowski recommended that people interested in a process tech position look into training offered by the Alaska Process Industries Careers Consortium.

Generally positions offered through BP directly require many hours of training, experience and certifications; individuals without this type of background may "certainly be good candidates for one of our contractors," he said.

"We need to get the word out on the jobs available and how people get into them." **—Florian Borowski**

Borowski also mentioned efforts being made by The Alliance to maintain a Web-based portal for its member organizations' employment contact details. He referred to the site as one-stop shopping: "If you're a welder and want to work on the slope, go to the Alliance Web site and get the information on all the companies that are hiring welders right now and make those contacts."

Motivating Alaskans to compete for BP jobs

"I think it's important that we really make an effort to demystify how to get into this business; I think APICC is providing a great resource to people trying to figure out what steps to take," Borowski said. "Our business isn't visible here in Anchorage; we don't have a big refinery down here that people drive by to see what it is we do to operate on a daily basis."

Borowski repeatedly stressed the importance of getting Alaskans to compete for BP jobs: "They're going to be filled, but how to get Alaskans to be prepared and capable and qualified to fill these jobs is the challenge. That's where PARW, Putting Alaska's Resources to Work, and other initiatives are playing an important role in getting the word out. We have a strong bias for getting Alaskans in these positions."

"It starts with the kids; getting them motivated," Rees said.

Although BP does not have trouble filling positions when forced to go outside Alaska to look for applicants, Borowski admitted being concerned about the workforce shortages some of its contractors are having.

"We're very dependent on those companies that are having a problem finding the right talent. We really want the service and supply companies that work with us and support our projects to be successful at getting the talent they need to get the work done."

Boom and bust image

But Borowski also recognized that people often view oil and gas as a boom and bust industry, which could prove a deterrent for people making long-term career plans.

Both men adamantly agreed that they want people to realize BP is always going to need its core people to keep the company operating.

Part of Borowski's job is to make sure the business evaluates itself and follows through with its obligations. "We take that very seriously, to grow in a thoughtful manner," he said. "How big should we be? How many positions should we have?"

BP has 1,600 employees in Alaska today. Sticking to its 50-year commitment means two more generations will have careers at BP Exploration (Alaska).

"That's roughly 3,000 people that will come to work for BP in the next 50 years," Rees said. "It could be 3,000 Alaskans."●

continued from page 1

BELIEVERS

lead partner Imperial Oil, said the company remains as committed to the project as it has from the outset.

"If we weren't we wouldn't be doing the work we are," he said in an interview.

Bell: imported LNG, Alaska line contribute to urgency

Bell said that contributing to a "growing sense of urgency" is the prospect of a rapid rise in imported liquefied natural gas and the chance that an Alaska gas pipeline could move ahead of the Mackenzie plans.

He conceded that a year ago he would have hoped "we could have been farther along," but it was not possible to foresee a court challenge from the Dene Tha First Nation over a connection from the Mackenzie Valley pipeline to the pipeline network in Alberta.

Topping his list of milestones that must be passed over the next year are final regulatory decisions allowing the project proponents to decide by mid-2008 whether to embark on construction.

He credited the National Energy Board, which concluded almost a year of hearings in mid-December, with doing a "wonderful job of making sure that everybody who wanted to be heard was heard from."

Although the Joint Review Panel, which is charged with weighing the environmental and socio-economic issues, has postponed the conclusion of its hearings from December to April, Bell said he hopes the panel will submit its report to affected cabinet ministers in time for them to react and the NEB to deliver an overall verdict by early 2008.

On the cost front, he is anxious to "get a better sense of what the project will cost," once Imperial Oil presents an updated budget to the NEB in February or March.

"Hopefully they will not face the cost overruns of the oil sands, but the project does not exist in a vacuum," meaning it has to overcome the challenges of hiring and retaining labor, Bell said.

Rolheiser: proponents exploring alternatives

Rolheiser said the proponents, in their efforts to bring costs under control, have constantly explored alternatives that could make the project "fundamentally different."

Those options have included conversion of Mackenzie gas into liquefied natural gas or building a lateral pipeline to connect in the Yukon with an overland Alaska pipeline.

Each time the partners have concluded that the original plan remains the best approach, he said.

But the search for cost-saving measures has raised the possibility of shortening the pipeline construction to two winter seasons from three — an idea Bell said would not encounter any opposition from the NWT government.

Whatever the options, Rolheiser said Imperial has felt from the outset that actual construction of the pipeline would be the "simplest part" of a project that would be "unprecedented in its complexity."

"It has been as complex as we expected ... and more," he said, drawing special attention to the challenge of building and maintaining a consensus among the stakeholders.

While focused on its internal issues, the proponents "absolutely need the regulatory decision (covering the conditions that must be met) and realistically we are looking for that in early 2008," he said.

Bell said that contributing to a "growing sense of urgency" is the prospect of a rapid rise in imported liquefied natural gas and the chance that an Alaska gas pipeline could move ahead of the Mackenzie plans.

Negotiated settlement possible with independents

On one of the messiest issues, Rolheiser is not ruling out hope of a negotiated settlement between the MGP partners and the Mackenzie Explorer Group of independent companies who want "fair and reasonable" access to the Delta gathering system for the 175 million cubic feet per day they currently estimate is available and to give them reason to step up exploration of the region.

Although the two sides appear to have reached an impasse, Rolheiser, without getting into confidential matters, said a negotiated resolution is still possible.

Bell said he is "not entirely sure" what stands in the way of a deal, but made it clear he would prefer the two sides come to terms rather than take the case to the NEB.

For the NWT government, access to the Mackenzie pipelines for producers outside the core gas owners' group is essential if the MGP is to be the catalyst for what Bell has described as "the next great oil and gas producing basin in Canada."

In his final testimony before the NEB, he made a forceful point that the MGP can be a basin-opening project only if it takes into account "more than the specific interests of the project proponents."

While there has been a drag on the regulatory process, Imperial quietly resumed talks with the Canadian government in October on royalty and tax terms for the MGP after calling a halt in mid-June, but Rolheiser said that until definitive project costs are available "it is difficult to have detailed discussions."

What emerges from any decisions on the fiscal regime is of special interest to the NWT government which is determined to see control over natural resources devolve from the Canadian government, although at this stage Bell said the NWT is prepared to hold back "until we have a better sense of what the project would cost." ●

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ENTRY

Resources and 1.48 million gross acres in the Colville Lake area of the Mackenzie Valley.

Both regions are bursting with potential, but ultimately held back until a pipeline network is built.

MGM's newly appointed President Henry Sykes, formerly president of ConocoPhillips Canada, told shareholders there is a "significant opportunity" beckoning in the NWT, where (other than a pocket of drilling in the Norman Wells area of the Central Mackenzie Valley) the region has logged only one well for every 260 square miles compared with an average one well for just under every square mile in the Western Canada Sedimentary Basin.

Two wells this winter

He said MGM is involved in two NWT wells this winter costing about C$40 million-$42 million — the Kumak I-25 targeting 5,400 feet to 6,560 feet in the lower Taglu formation and Unipkat M-45 targeting 2,460 feet to 4,900 feet in the Taglu formation. Drilling of the first well is expected before the end of January.

MGM is backed by some positive exploration successes in Colville Lake, where a partnership with Apache drilled and cased two wells in the Nogha prospect in 2003 and followed up with two delineation wells in 2004.

McDaniel and Associates, after independently reviewing the Nogha results, assigned possible raw gas reserves of 250 billion cubic feet to a 17,000 acre area.

Paramount has been active in gas hearings

Paramount, before handing over the controls to MGM, has also been an active participant in the regulatory hearings for the Mackenzie Gas Project.

Like other independent companies in the Mackenzie Explorer Group it has voiced concern about the inability so far to settle on the terms of gaining access to the proposed pipeline systems for companies outside those who own the Delta's three anchor fields — Imperial Oil, Shell Canada, ConocoPhillips Canada and ExxonMobil Canada.

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Under the Chevron/BP pact, MGM is committed to drill 11 wells over the next four years, including a drilling budget of C$80 million to complete four wells in 2008, Sykes said.

But he voiced a degree of unease over costs, expressing a hope that as MGM's northern activity increases there is both the challenge and the opportunity to reduce operating costs.

A report by investment dealer Peters & Co. said MGM's position is bolstered by a large undeveloped land holding and significant farm-in upside that provides exposure to vast gas exploration potential in the Mackenzie Valley and Delta.

Countering that, the risk of further delays in approval and construction of a Mackenzie pipeline raises near-term financing risks as MGM deals with a limited annual operating window in the NWT, slowing the pace of development.

But Sykes was emphatic that MGM's strategy is to build on its land interests in the Mackenzie Valley and central NWT, either directly or indirectly.

He said development of Canada's North is only a matter of time, meaning those who are in place first will be able to reap the rewards.

—GARY PARK

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

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Business Spotlight

FORREST CRANE

Kelly Dart, Anchorage Branch Manager

Alaska Tent & Tarp

Alaska Tent & Tarp maintains an extensive inventory of industrial fabrics and geomembrane liner and berm products at its main Fairbanks location or through the Anchorage branch for statewide distribution. The company's highly trained fabricators and creative design team have many years' experience producing equipment covers for arctic industrial applications. "We Cover Alaska" is its slogan, which reflects a strong background in environmental protection and containment.

Kelly Dart joined the company in 2001 and in 2003 moved to sales and service in Fairbanks. In 2006 she accepted the position of Anchorage branch manager. This single gal, who grew up on ranches and loves animals, finds adventure training and riding horses, skijoring (with horses), hunting, fishing and snow machining.

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INSIDER

step into the spotlight.

Chief Executive Officer John Lau provided a series of interviews Jan. 8, during which he said:

• The company needs another year to put all of the pieces in place for its oil sands strategy, including the hunt for a possible U.S. or offshore joint venture to upgrade and refine its production, which could include 30,000 barrels per day from the just-completed Tucker project and 200,000 bpd from the Sunrise project over the long haul.

Talks with Marathon Oil are progressing, but other candidates could include BP and possibly Lyondell, with whom Husky has explored a stake in a Texas refinery.

Lau said the failure to conclude negotiations in 2006 stemmed from Husky's uncertainty over construction costs if it decided to invest C$10 billion to C$15 billion to build upgrading capacity in Canada, and what technology will be used to power upstream oil sands operations in Alberta.

Those options, Lau said, include nuclear power, coal-fired power or bitumen residues, all designed to avoid the high cost of using natural gas.

Grappling with the Sunrise technology is likely to delay initial production from an initial 2010-2012 window to 2012-2015, Lau conceded.

• In laying the nuclear alternative on the table, Husky has joined France's Total in stoking a debate that is stirring interest in the Alberta and Canadian governments as one of the best methods of reducing greenhouse gas emissions.

Federal Natural Resources Minister Gary Lunn said recently it is just a matter of when, not if nuclear power will be deployed in the oil sands, suggesting it could "play a very significant role."

Lau acknowledges nuclear will make no headway without government endorsement.

A better current bet could be to burn some of the extracted bitumen, similar to a technology being applied by Nexen and OPTI Canada at their Long Lake project.

But the first real test of the nuclear alternative could be imminent.

Wayne Henuset, a founding partner with Energy Alberta Corp., told the Calgary Herald a proposal for a plant in the oil sands region is almost certain to be unveiled within 90 days.

Federal Natural Resources Minister Gary Lunn said recently it is just a matter of when, not if nuclear power will be deployed in the oil sands, suggesting it could "play a very significant role."

The privately held company has an agreement to commercialize Atomic Energy of Canada reactors and has been in talks with major oil sands producers, although Husky is not one of them.

It is widely anticipated that at least one scheme will result from a call for proposals by EnergyINet, a government-industry consortium that includes producers such as Nexen, Shell Canada, EnCana and Canadian Natural Resources.

• Lau said Husky has not closed the door to spinning off its oil sands operations as a separate unit, adding that option is still being explored.

• For the East Coast, Husky is seeking permission from the Newfoundland government to hike output at its White Rose project to at least 140,000 bpd from the current maximum average of 100,000 bpd, taking advantage of two new discoveries which could hold an additional 190 million barrels.

Husky also has several trillion cubic feet of gas reserves in the region, which Lau said could be developed with the province as an equity partner in return for some breaks on taxes and royalties.

• Husky's goal is to almost triple production by 2020 to 1 million bpd from the oil sands, the East Coast, the Northwest Territories and the South China Sea.

• Constantly fingered as a takeover target, some of that speculation has cooled off as Husky has more than doubled its share price over the past two years. Lau also noted that Li has said he has "no intention" of unloading the company at this time.

Besides, Lau asked, where could Li reinvest the proceeds from a Husky sale and gain a better return.

—GARY PARK

FINANCE & ECONOMY

Conoco disappoints Wall Street analysts

ConocoPhillips' announcement that it added three times as much oil and gas to its reserves as it produced last year did little to impress Wall Street analysts, largely because the gains occurred through acquisitions. At least three major brokerage houses — A.G. Edwards, Deutsche Bank and Citigroup — said Jan. 11 they were disappointed with Conoco's 2006 reserves replacement figures, released Jan. 10.

The company said it likely ended 2006 with the equivalent of 11.1 billion barrels of oil in proved reserves, up from 9.4 billion barrels in 2005. But the growth was largely tied to a $35.6 billion purchase of Burlington Resources last spring and Conoco's increased stake in Russian producer OAO Lukoil.

"With a low-profile exploration program that has offered little in the way of exploration success, (Conoco) has pursued acquisitions to bolster reserve additions that in this environment, we believe, will likely come with a high price tag and (put) further pressure on the balance sheet," Citigroup analyst Doug Leggate said Jan. 11.

Leggate, who maintained his "hold" rating on Conoco stock, estimated the company's organic reserves replacement has averaged only 73 percent in the past five years. Some analysts say a company's reserves replacement should average around 130 percent over a three-year period if it expects to grow production.

A.G. Edwards' Bruce Lanni said that Conoco reserves replacement likely amounted to only 10-15 percent last year excluding purchases, and 2006 marked the third straight year of reserves replacement below 100 percent. He also reiterated his hold rating on Conoco shares.

"In our opinion, this announcement, along with the company's dependence on acquisitions and joint ventures, further suggests that Conoco's future organic growth opportunities remain somewhat limited," the A.G. Edwards note said.

—THE ASSOCIATED PRESS

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COMPETITION

learned, she said, that "Alaska's gas isn't stranded."

We also learned a lot about the oil producers' terms, Palin said.

"We learned that under the old act, some producers will talk to us, and talk to us, and talk to us until we agree to their terms.

"Well, those terms were unacceptable. They demanded that, in a sense, we give up some fundamental rights as a state" because the deal would have removed the state's taxing, regulatory and judicial authority for decades.

It was no deal, Palin said. And it exceeded the administration's authority.

The producers didn't have to commit to preparing applications, "much less build a gas line," she said without naming her predecessor Frank Murkowski and the unsuccessful deal he put together with the three major North Slope oil producers, BP, ConocoPhillips and ExxonMobil.

Palin said it was time to leave the old act behind and "move forward with a new vehicle" for a gas pipeline, one that "builds on the knowledge and experience gained from a valiant — but futile — effort previously in a non-competitive process."

New vehicle for gas

Palin said it was time to leave the old act behind and "move forward with a new vehicle" for a gas pipeline, one that "builds on the knowledge and experience gained from a valiant — but futile — effort previously in a non-competitive process."

The new process will be embodied in the Alaska Gasline Inducement Act or AGIA.

"The centerpiece of this is to induce construction of the gas pipeline."

Palin said this would be a gas pipeline constructed on the state's terms, "without selling Alaska's sovereignty."

It "allows transparent and competitive processes," she said. "It jumpstarts progress with incentives, and it strikes the right balance on a project for the state, the nation, the project proponents and the producers.

"It will be good for all," she said.

The bill will be introduced in this session; currently the administration is "scrutinizing its legality … its strategy and its efficacy. We're doing that now with top experts. With legislation this important, really, it is more important that we do it right than do it fast," she said.

The review includes potential applicants. Palin said she and Lt. Gov. Sean Parnell began meeting with potential applicants the day after they took office, and are continuing to meet with them.

What's in the act

Palin said the act "offers inducements to those who will build the pipeline itself."

It might be the three major North Slope oil producers who build the line, she said, "it might be an independent oil or pipeline company; it might be a state or quasi-state entity" — or a combination of the above.

She said there will be pipeline construction incentives to encourage companies to compete for the right to build the line.

"We're currently developing such incentives as a substantial state capital contribution so bidders know that the state will have skin in the game, too. Alaska will have skin in the game."

The bill will also include "permit streamlining and state-funded training programs to ensure a qualified Alaskan workforce."

To be able to compete for the inducement package, "the applicant must agree to certain bedrock, must-have requirements of the state, such as gas for Alaskans and jobs for Alaskans and project benchmarks."

And competition and long-term exploration and development on the North Slope will be required. "This pipeline must be able to expand in step with the development of new reserves so North Slope gas energizes us not just for our lifetimes, but for the lifetimes of our children."

Inducements also extend to those who hold the leases and control the gas.

"Regardless of who builds the line, we need a mechanism to strongly encourage the leaseholders to commit their gas to the licensed project."

Palin said one of the most appealing differences between this bill and the stranded gas act, is that it "will contain clear, competitive criteria by which we can judge which projects best meet our long-term needs. That means that Alaskans will know why the state is making the choices that it is."

DNR will do energy audit

"Without increased oil development, forecasts show about $100 million reduction each year in available revenue," so responsible resource development must occur across the state, Palin said; development the state can encourage by providing "stability in regulations for our developers."

The responsible part is crucial, and to prove the state "can responsibly develop, we'll beef up oversight on the North Slope because we've seen some legal obligations ignored."

"Greater oversight ensures proper maintenance of the lines that carry our oil to market. And I won't tolerate corrosion eating through pipes while crippling our state economy with costly shutdowns," she said.

"I'll establish a dedicated state team to ensure rigorous inspections and line integrity analysis. Our oil must, and will, flow to help continue to fund our essential services."

The governor said she is struck by the "absurd situation" that Alaska is in, that with its abundant energy resources, so "many communities (are) facing threats to safety and wellbeing because of the high price and limited supply of energy."

The state needs to coordinate its energy programs, Palin said, "to find local sources, to help communities become self-sufficient."

"So, DNR will inventory potential sources of energy, all of those, including renewables like tidal and wind and hydro and geothermal. Taken together, new initiatives can finally provide new energy."

Resources must be developed

The governor said energy must also come from known resources, and said her administration would "aggressively defend" the state's obligations to develop those resources.

Palin cited the Point Thomson field on the North Slope. Huge reserves are known there, she said, but producers hold the leases in "iron-clad contracts. They're promises to develop the public's resources for mutual benefit — or give back the leases."

Without mentioning Point Thomson operator ExxonMobil by name, Palin referred to a "large producer" that has held the leases for 30 years with no development.

"Warehousing Alaska's resources is not an option anymore," she said. "We can't afford it."

Alaska is asking to have the 1002 area of the Arctic National Wildlife Refuge opened for drilling, but can't even get its own lands adjacent to ANWR developed, she said.

"I promise to vigorously defend Alaska's rights, as resource owners, to develop and receive appropriate value for our resources."

PPT not her preference

On the petroleum profits tax passed by the last Legislature, the governor said that she would have preferred to stick with a tax based on the gross value of oil and gas, rather than the net profits tax, but PPT is law, "so I've asked our Revenue commissioner to assess and adopt the necessary regulations to ensure PPT works as Alaskans were promised, and tighten up any loopholes."

She said her administration would watch carefully as the first tax returns come in to make sure there aren't any surprises.

"If so, let's try again and get our production tax right." ●

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HARBOUR

The commission did allow the supply of gas under the new contract, but only if the contract pricing reduces the average cost of gas to Enstar.

In support of its September decision, RCA said that gas pricing indexed to Henry Hub had not resulted in additional Cook Inlet exploration. The commission also said that Enstar had not demonstrated that the new contract would result in reliable gas supplies.

If the commission majority had been more reluctant to change the course of gas price precedents, it would "still mourn with me local, rising utility bill prices, while courageously recognizing that the price signal was our responsible effort to support sustained supplies," Harbour said in a partial dissent to the Sept. 28 order.

Following a flurry of filings questioning the commission's decision, the commission on Dec. 29 issued another order, with a majority decision partially reconsidering its September order. In this new order the commission majority withdrew its statement that Henry Hub gas pricing had not resulted in additional Cook Inlet exploration, but instead said that the pricing had not resulted in increased net Cook Inlet gas reserves. The majority held to its position that the pricing formula in the contract was too high and that, in reality, the contract did not guarantee gas supplies for Enstar.

Commissioners Harbour and Johnson partially dissented from the Dec. 29 order.

Delay shut the door

Harbour, in his Jan. 10 statement, criticized the delay to the end of the year in the majority issuing its latest order. That delay has shut the door on further consideration of options for resolving the issues relating to the Marathon/Enstar contract, Harbour said.

"The majority waited until the end of December, the eve of the extended time for reconsideration, to suggest belated remedies," Harbour said. "… The importance of this point is that with more time and options, the commission might have available to it an option which more responsibly supports public interest considerations."

Harbour said that further consideration of the majority order rejecting the contract would have confirmed flaws in the arguments against the pricing model in the contract. That could then have led to actions such as considering a proposal by Enstar for resolving the impasse over the contract.

"Had it (the commission majority) done that before Dec. 15, 2006, there would have been time by year-end to act on that expanded record," Harbour said. "The majority, having created this problem with its own delay, disingenuously laments this loss of options by reluctantly concluding we cannot further consider the tariff filing 'because the statutory timeline for this tariff filing has run.' … I can only hope that the majority's skill in reforming (while affirming) its position upon reconsideration finds Marathon and Enstar still willing and able to continue their efforts with us to finalize a long-term gas supply agreement."

Insulated from criticism

Harbour said that the commission majority has insulated itself from criticism because "the supply squeeze that could materialize in the wake of (the contract's) … rejection will not be fully realized for years." If on the other hand Marathon and Enstar agree on an amended contract, the majority will take credit for reducing the cost of Southcentral Alaska gas.

"The majority will then be able to proclaim to an appreciative populace that its action forced industry to provide gas to consumers at lower prices, and that admiring public will have no idea how close it came to losing a long-term, secure supply of natural gas," Harbour said.

Harbour also questioned the impact on the Alaska investment climate of tossing out an established precedent to use a Henry Hub gas price index.

"In its deviation from precedent, the majority also created the prospect that other regulated industries could begin to attach some additional risk premium to planned investments throughout Alaska requiring regulatory approvals based on the commission's precedent; though any of those lost investments, likewise, will remain forever unknown," Harbor said.

"I have great respect for the majority's ability to portray a popular result, but greater regret that I could not have more effectively communicated the flaws in that portrait and the virtue of supporting a secure gas supply along with the reliable precedent and healthier investment climate our predecessors passed on to us," Harbour concluded. ●

PIPELINES

Tesoro posts tug in Cook Inlet

Oil tankers navigating the treacherous bottleneck of ice in Cook Inlet can receive assistance this winter from a new tugboat that will be brought in by oil refiner Tesoro Alaska Co. Early last year, a 600-foot ship leased by the company, the Seabulk Pride, was pushed off its mooring at the Kenai Pipeline dock in Nikiski by an ice flow and set adrift. It ran aground a half-mile away.

In early January, the ship was unloading crude at a dock near the Tesoro refinery at Nikiski when some of the ropes and cables securing the vessel to the dock were strained by ice 6 inches thick and carried by a slow-moving tide against the ship. One cable snapped and four other lines at the bow were strained, causing winches to pay out to relieve the stress and slacken the lines.

No oil was spilled and there were no injuries or no serious damage to the ship.

Tesoro has contracted a tug called the Protector as a safety precaution. "It's certainly going to add another layer of protection to our marine operations," said Tesoro spokesman Kip Knudson, who said the tug was under contract only for this winter.

Coast Guard officers and oil industry watchdog groups say a tug posted in the region could help avert a catastrophic shipwreck or oil spill. Industry watchers called for a tug and an expansion of other safety measures after the incident in February.

The 5,500-horsepower tractor tug, operated by Crowley Maritime Corp., is coming up from Seattle and is due in Cook Inlet this week, said Coast Guard Capt. Mark DeVries. "We all can sleep a little bit easier knowing that if something goes wrong, we've got that extra asset down there."

Cook Inlet has tugs based in Anchorage and other ports, but this latest addition is much more powerful, DeVries said.

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