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Week of February 1, 2009 • $2

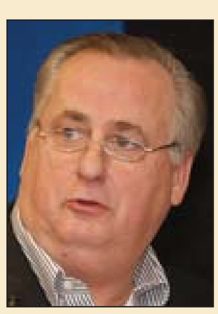
page 16 Conoco hopes to drill Chukchi in '11; wants gas pipeline and fiscal stability

NABORS ALASKA DRILLING

Nabors Rig 105E is a mobile exploration rig that uses AC power, computer-based controls and can be rapidly broken down into modules for transportation in remote locations. The rig is fully winterized for Arctic conditions.

Rigs to meet Arctic challenges; Parker, Nabors show innovations

Amid the technical wonders of steerable drilling bits, ultra extended reach drilling and measurement-while-drilling techniques, it's easy to overlook the humble drilling rig that makes the whole drilling operation happen. But at the Alaska Support Industry Alliance Meet Alaska conference on Jan. 23 Nabors Alaska Drilling and Parker Drilling Co. sought to set the record straight by describing some of the innovations in rig design that have dramatically broadened the range of drilling possibilities in recent years.



JUDY PATRICK

DON KORACH

Between 2005 and 2009 Nabors is spending about $250 million dollars on new rigs and rig upgrades for Alaska, Don Korach, engineering manager for Nabors Alaska Drilling, told the conference attendees. And that marks the latest phase in a program of rig innovation that Nabors has pursued since the company started operating in Alaska in 1962.

For example, Nabors modified a couple of rigs for operation in the limited space of BP's Northstar Island and Pioneers Natural Resource's Oooguruk Island in the Beaufort Sea, Korach said.

"We have a unique moving system that can move these rigs fully loaded with pipe and drilling fluids, saving hours at a time in rig moves and fluid handling, and reducing the chance of a spill," Korach said.

AC rigs

But one of the biggest rig efficiency improvements in recent years has been the introduction of alternating current, or AC, electrical power for rig drives, Korach said.

In the 1970s most rigs used an engine to drive the rig machinery through a mechanical transmission. Then came SCR rigs in which a silicon controlled rectifier (or SCR) converts diesel generated AC electricity into direct current, or

see **RIG TECHNOLOGY** page 21

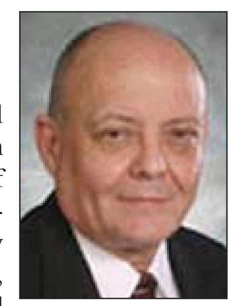
LAND & LEASING

Thomson drilling a go

Irwin authorizes ice road permit, drilling; requires AFEs for facilities

By KRISTEN NELSON

Petroleum News



TOM IRWIN

Alaska Department of Natural Resources Commissioner Tom Irwin has authorized processing of permits, including an ice road permit, and drilling on two "conditionally reinstated" leases at Point Thomson, allowing ExxonMobil to move forward with drilling this winter.

Irwin issued a conditional interim decision Jan. 27 in pending lease termination appeals for the Point Thomson area.

For the conditional reinstatement of the two leases to become final, however, Irwin is requiring unconditional funding commitments for drilling the two wells for which conductor has been set and for production facilities necessary for "sustained commercial production and transportation of hydrocarbons from these two wells on these two leases to market by 2014."

Documentation of that funding is required within two weeks.

There are a number of appeals, administrative and judicial, over Point Thomson, a unit formed on the eastern side of the North Slope in 1977 and terminated by Irwin last year for lack of development, a decision which is under appeal in Superior Court.

Irwin's Jan. 27 decision is on an appeal by the Point Thomson leaseholders of the August termi-

see **DRILLING** page 21

NATURAL GAS

Gas for Alaska by 2014?

From Palin to lawmakers to industry, in-state gas is a focus for the coming year

By ERIC LIDJI

Petroleum News

HAROLD HEINZE

SEN. HOLLIS FRENCH

The new rallying cry in Alaska is first gas in five years.

Throughout much of last year, high heating oil prices in Fairbanks and dwindling natural gas reserves in Anchorage created public outcry for a new in-state supply of natural gas.

Now, as state lawmakers reconvene in Juneau, the issue is suddenly a high priority item.

In the first three days of the new session, a Senate committee heard testimony from three groups hoping to build smaller gas pipelines, Gov. Sarah Palin pledged to get gas flowing in five years and a Fairbanks task force gave recommendations for meeting that deadline.

Meanwhile, the Alaska Gasline Port Authority told lawmakers that a weak Lower 48 natural gas market means Alaska should keep the liquefied natural gas option alive.

Can ANGDA and Enstar partner?

The Alaska Natural Gas Development Authority, a public corporation, and Enstar Natural Gas, a private utility, continue to pursue separate projects for bringing gas to Alaskans.

see **IN-STATE GAS** page 22

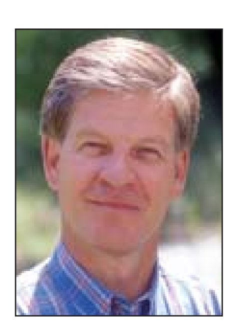
FINANCE & ECONOMY

Telling it like it is

Oil sands pioneer Suncor takes axe to spending program, freezes C$20.6B project

By GARY PARK

For Petroleum News



Suncor Energy Chief Executive Officer Rick George

The Canadian petroleum industry may have passed the point where it will bother to camouflage how tough times are, with oil sands pioneer Suncor Energy making the most drastic disclosure yet.

The world's second-largest producer of synthetic crude after Syncrude Canada, Suncor has slashed its 2009 capital budget to C$3 billion, down 50 percent from its forecast last October and 70 percent from an earlier projection in 2008.

In reporting its first quarterly loss in 16 years, Suncor has indefinitely shelved its C$20.6 billion Voyageur expansion project and plans for Stages 3 through 6 of its Firebag thermal operation, which were designed to boost design production to 550,000 barrels per day by 2013 from 350,000 bpd. To date, C$7 billion has been invested.

At the same time, Chief Executive Officer Rick George disclosed that discussions have taken place "with other people in terms of either a long-term processing deal or even ownership of upgrading

see **SUNCOR** page 23

BREAKING NEWS

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

Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Prudhoe Bay MPF-96	BP
Sky Top Brewster NE-12	15 (SCR/TD)	Kuparuk 3H-33	ConocoPhillips
Dreco 1000 UE	16 (SCR/TD)	Prudhoe Bay DS 11-09	BP
Dreco D2000 UEBD	19 (SCR/TD)	Alpine CD3-305	ConocoPhillips
OIME 2000	141 (SCR/TD)	Kuparuk CD7-48	ConocoPhillips
TSM 7000	Arctic Fox #1	Stacked in Yard	Pioneer Natural Resources
	Arctic Wolf #2	Subcontracted for exploration	UltraStar Exploration
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Stacked, Prudhoe Bay	Available
Dreco 1000 UE	2-ES	Prudhoe Bay DS 07-08B	BP
Mid-Continental U36A	3-S	Milne Point MPG-12	BP
Oilwell 700 E	4-ES (SCR)	Prudhoe Bay PBU R-24	BP
Dreco 1000 UE	7-ES (SCR/TD)	Prudhoe Bay F-33A	BP
Dreco 1000 UE	9-ES (SCR/TD)	Polaris M-19B	BP
Oilwell 2000 Hercules	14-E (SCR)	Stacked	Available
Oilwell 2000 Hercules	16-E (SCR/TD)	Being fitted out for drilling this winter	Brooks Range Petroleum
Oilwell 2000	17-E (SCR/TD)	Stacked, Point McIntyre	Available
Emsco Electro-hoist -2	18-E (SCR)	Stacked, Deadhorse	Available
Emsco Electro-hoist Varco TDS3	22-E (SCR/TD)	Stacked, Milne Point	Available
Emsco Electro-hoist	28-E (SCR)	Stacked, Deadhorse	Available
Emsco Electro-hoist Canrig 1050E	27-E (SCR-TD)	Under modification	ExxonMobil
Academy AC electric Canrig	105-E (SCR-TD)	Stacked on ice pad at Chandler #1	Anadarko
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Prudhoe Bay Drill Site E-36a	BP
Superior 700 UE	2 (SCR/CTD)	Milne Point Well Drill Site MP C-43	BP
Ideco 900	3 (SCR/TD)	Kuparuk Well 3G-03	ConocoPhillips

North Slope - Offshore

Nabors Alaska Drilling			
OIME 1000	19-E (SCR)	Oooguruk ODSN-31	Pioneer Natural Resources
OIME 2000	245-E	Nikaitchuq OP26-P02	ENI
Oilwell 2000	33-E	Northstar NS-33A	BP

Cook Inlet Basin – Onshore

Aurora Well Service			
Franks 300 Srs. Explorer III	AWS 1	Lone Creek 4, rigging down Will stack west side of Cook Inlet	Aurora Gas
Marathon Oil Co. (Inlet Drilling Alaska labor contractor)			
Taylor	Glacier 1	Drillng BC-18	Marathon
Nabors Alaska Drilling			
Continental Emsco E3000	273	Stacked, Kenai	Available
Franks	26	Stacked	Available
IDECO 2100 E	429E (SCR)	Stacked, removed from Osprey platform	Available
Rigmaster 850	129	Kenai IRU 11-06	Chevron
Academy AC electric Heli-Rig	106-E (SCR/TD)	Muskoxen 36 7-8	Chevron
Rowan Companies			
AC Electric	68AC (SCR/TD)	On site at Cosmopolitan	Pioneer Natural Resources

Cook Inlet Basin – Offshore

Chevron (Nabors Alaska Drilling labor contract)			
	428	M-18 Steelhead platform	Chevron
XTO Energy			
National 1320	A	Platform A no drilling or workovers at present	XTO
National 110	C (TD)	Idle	XTO
Kuukpik	5	Tyonek platform A-16 Completion	ConocoPhillips

Mackenzie Rig Status

Canadian Beaufort Sea

SDC Drilling Inc.			
SSDC CANMAR Island Rig #2	SDC	Set down at Roland Bay	Available

Mackenzie Delta-Onshore

AKITA Equtak			
Modified National 370	64 (TD)	Drilling at South Ellice J-27	MGM Energy Group

Central Mackenzie Valley

Akita/SAHTU			
Oilwell 500	51	Racked in Norman Wells, NT	BG Canada

The Alaska - Mackenzie Rig Report as of January 29, 2009. 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 Marti Reeve


JUDY PATRICK

Baker Hughes North America rotary rig counts*

	January 23	January 16	Year Ago
US	1,515	1,568	1,747
Canada	426	438	582
Gulf	61	64	56

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

● NATURAL GAS

Natural gas price part of global crisis

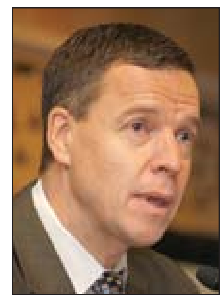
BP, Wood Mackenzie tell Alliance supply, demand out of balance; Alaska gas needed, but recession may have pushed out date

By KRISTEN NELSON
Petroleum News

Natural gas demand in the Lower 48 is down — and supply is up. That doesn't sound good for a proposed Alaska natural gas pipeline which would deliver some 4 billion cubic feet a day into Lower 48 markets.

Brian Frank, president of BP Energy Co., BP's commercial arm, and Ed Kelly, vice president, North American Gas and Power for energy consultant Wood Mackenzie, talked about the situation at the Alaska Support Industry Alliance annual "Meet Alaska" conference Jan. 23.

Both were of the opinion that the market situation for natural gas would correct in time. And with its earliest in-service date appearing to be at least 10 years out, time is one thing an Alaska gas pipeline project has on its side. The U.S. Department of Energy's Energy Information Administration is showing Alaska North Slope gas coming into Lower 48 markets in about 2020; Kelly said Wood Mackenzie is showing 2021.


JUDY PATRICK
BRIAN FRANK

Frank said the role of BP Energy in the Alaska gas pipeline would be as a shipper. BP Energy will be looking for the project that "represents the least risk, the best value and the highest netback to BP production on the slope."

But he's not concerned about the ability of the North American market to absorb Alaska gas. The "U.S. market is the largest market in the world — so that's underlying — it will always be there," he said.

"Right now we're seeing incredible weakness in demand and that's having an impact on price," but commodities are cyclical and while "I can't remember in my career ever seeing the dramatic decline that we've seen in demand and prices as we've seen over the last six months," that just "underscores the risk around price, which is the key variable for anybody who is looking at underpinning" such a huge project.

"But the U.S. economy will respond and ... the underlying demand will always be there," Frank said.

North American market

Frank said the North American natural gas market, "which is the largest market, the most liquid market, the most transparent market, the market with more storage than anywhere else in the world — that market is going through a rather dramatic change."

The cost of the Alaska gas project was estimated at $20 billion to Chicago in 2001, he said, with a tariff to Chicago of "roughly $2.40 for about a ... 4 billion cubic-feet-a-day pipeline," compared to estimates today of $30 billion to $40 billion, "and therefore the tariff (to Chicago) is approaching $5 at the upper end of that range," more than the current price of natural gas.

That highlights the commodity risk, he said, a risk carried by the shippers and a risk that would ultimately be reflected in the netback to the producers on the North Slope.

What's happening in the North American natural gas market today is "massive demand destruction" due to what's happening in financial and credit markets and the current economic recession, he said.

Added to that is what happened to gas supplies in 2008 with development of shale gas in the Lower 48. "We have seen shale gas supply increase by about 2 to 3 bcf a day year-on-year," he said. That caught the market by surprise in mid-2008, "and turned what was a very bullish market in the first half of the year into a very bearish market."

Then there is the existence in the United States of 12 billion to 13 billion cubic feet per day of regasification capacity, most of which did not exist five years ago. While only about 1 bcf of that capacity is in use today, "there is enormous potential for LNG to come into the U.S. market, up to 12-13 bcf a day. And that's equivalent to roughly three Alaska gas pipeline projects," Frank said.

Gas drilling down

The supply-side response to the drop in demand has been a reduction in drilling.

> *"We have seen shale gas supply increase by about 2 to 3 bcf a day year-on-year." That caught the market by surprise in mid-2008, "and turned what was a very bullish market in the first half of the year into a very bearish market."*
> **—Brian Frank, president, BP Energy Co.**

Frank said rigs drilling for natural gas peaked at some 1,600 midyear and have now dropped to about 1,200, "so you've seen about 25 percent of the rigs laid down in the last six months."

Natural gas inventories, which are normally drawn down during the winter months due to heating demand, have not been; because of the demand decrease inventory usage this winter is dropping.

"And again, that's attributable to weak demand and relatively strong supply."

The natural gas market is also less liquid because of the financial crisis and the economic recession, and "liquidity, the ability to trade in the forward years and into the future is reduced."

Alaska gas prospects

Frank said that the current supply and demand for an Alaska gas pipeline is "not a pretty story right now in terms of North American gas markets, and the signals are very bearish and the demand destruction that we're seeing and growth of supply in the face of demand destruction is certainly suggesting that we will see weaker prices here in the short- to medium-term."

But Frank said he is "a big believer in the market," and the balance of supply and demand: "Low prices will send signals to suppliers to develop less and they'll send signals to consumers to consume more."

And the Alaska gas pipeline is at least 10 years out. We don't know what gas prices will be 10 years from now, he said, noting that 10 years ago they were $2, have since peaked at rates approaching $15 and "the futures market is telling us that gas prices over the next five to six years" will be in the $6 to $8 range.

Among the risks of an Alaska gas project is that Alaska gas "will have to compete at the margins with unconventional supplies" including shale gas and the potential for LNG imports considerably above today's rates.

Frank said BP Energy, as a potential shipper on an Alaska gas pipeline, is focused on "reducing risk and increasing certainty" and believes that "stakeholder alignment is critical for the project to go forward."

see GAS DEMAND page 18

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● GOVERNMENT

Glimmers of light in the Canadian North

After 12 years deficit-free, Ottawa plans shortfalls of C$85B over 5 years; changes in project regulatory requirements possible

By GARY PARK

For Petroleum News

In getting to grips with what it calls a "deepening economic crisis," the Canadian government is ending 12 years of deficit-free budgets and running up shortfalls of C$85 billion over the next five years, with a heavy emphasis on infrastructure spending.

For Canada's North there were some reasons for hope in the economic stimulus budget unveiled by Finance Minister Jim Flaherty on Jan. 27, including measures that could speed up regulatory approval of the Mackenzie Gas Project.

The government has earmarked C$37.6 million for the 2009-10 fiscal year to support the regulatory and environmental assessment processes related to the proposed Mackenzie Valley gas pipeline.

Northwest Territories Industry Minister Bob McLeod told Petroleum News he welcomes word that a federal offer was presented to the MGP partners earlier in January and views the budget allocations as evidence that the government is "serious about the pipeline" by putting the necessary funding in place for various federal departments and preparing for aboriginal consultation.

In addition, Infrastructure Minister John Baird said before the budget was unveiled that Ottawa plans to remove some of the environmental roadblocks that slow progress on major resource development, but there was no indication these changes would come in time to benefit the MGP.

Economic development agency

Coming just three months after Prime Minister Stephen Harper insisted Canada would not allow a return to budget deficits, the economic stimulus package is also Harper's attempt to cling to power.

The New Democratic Party and Bloc Quebecois will vote against the budget, while Liberals — who control the balance of power — will support the budget provided Harper's Conservative administration agrees to table regular updates on its budget spending commitments.

Among its other provisions for the Arctic region, the government has allocated C$50 million over five years to establish a new economic development agency for the Northwest Territories, Yukon and Nunavut.

That delivered on a promise Harper made last September when he announced the government would set up a standalone agency to promote economic investment in the Arctic region along with a northern satellite office to deal with federal regulations governing major resource projects and improve regulations for northern natural resource projects by simplifying processes and reducing administrative costs.

The government said at the time that "development and regulatory structures in the North are overly complex and often are major barriers to growth."

Mac regulatory costs

No one is better aware of the costs and delays associated with current regulatory process than the Mackenzie Gas project consortium, which has been bogged down in environmental and socio-economic hearings that have delayed the potential startup date for deliveries of Arctic gas by five years to at least 2015.

Baird, on Jan. 26, said the Canadian government is also contemplating changes to legislation that currently requires separate federal and provincial environmental assessments for major resource projects.

Without disclosing the details of what action is planned, he said provincial governments have told him that while "it's essential to protect the environment, it's not essential to do two assessments for each and every project."

The budget also contained plans to upgrade key Arctic research facilities and study the feasibility of a proposed High Arctic research station, both part of Harper's push to reinforce Canada's claims to sovereignty over the area.

Targeting the generation of 190,000 jobs for Canada's population of 33 million, the government has earmarked C$12 billion for major infrastructure projects over the next two years, with the spending conditional on provincial, territorial and municipal governments adding C$9 billion.

An additional C$1 billion will be spent over five years on "green projects" such as sustainable energy, which the government believes will generate C$2.5 billion in new investment over the same period, and another C$1 billion for "clean energy" research development and demonstration projects, including carbon capture and storage.

Issues with MGP help

Meanwhile, there has been some unhappiness over the federal government's offer of financial help for the MGP, although the details of that proposal have yet to be released.

Kevin O'Reilly, a spokesman for Alternatives North, a Yellowknife-based social justice group, told the Canadian Broadcasting Corp. his group interpreted the offer as a "real contrast" to what Environment Minister Jim prentice said a year ago when he rejected the notion of government subsidies or an ownership position in the MGP.

Peggy Holroyd, Arctic program director with the Alberta-based environmental think tank Pembina Institute, said making an offer while MGP is still in the regulatory phase puts the government in a conflict-of-interest position and raises doubts about the federal administration's ability to make a "fair and objective decision" on the project.

Ian Doig, a leading analyst of frontier energy projects, said the federal offer poses problems for the federally appointed National Energy Board, which is entitled under its mandate to rule that MGP is not an economic undertaking. ●

NATURAL GAS

Canadian gas heads for trouble

Canadian natural gas exports to the United States edged up in the 2007-08 contract year that ended Oct. 31, reaching 3.71 trillion cubic feet and setting a new high for revenues of C$33.11 billion, the National Energy Board reported.

But, along with the impact of the economic downturn, surging output from U.S. shale plays is expected to take a major bite out of those numbers.

Compared with 2006-07, volumes were up about 1 billion cubic feet and revenues grew by C$5.24 billion. The previous record was C$33.09 billion set in 2004-05.

Average export prices for the sales year were C$8.27 per gigajoule, compared with C$6.98 in 2006-07 and C$7.85 in 2005-06.

For the 10 months of the 2008 calendar year through October revenues rose by C$5.2 billion to C$28.12 billion, while average prices climbed to C$8.69 from C$6.85.

Exports for the month were down 5.4 percent in the U.S. Midwest at 121.8 bcf and 6.3 percent in the U.S. Northeast at 93.1 bcf. For the 10 months of 2008, the Midwest shipments dipped to 1.255 tcf from 1.258 tcf and to the Northeast to 967 bcf from 1.085 tcf. But six straight months of declining volumes saw exports in the January-October period slip to just under 3.02 tcf from 3.11 tcf and October exports slumped 11 percent to 278.4 bcf.

The U.S. Energy Information Administration has forecast that Canada's share of U.S. supply will decline sharply over the short- and long-term period as domestic production grows, with unconventional production meeting most growth in demand, offsetting a drop in conventional production and imports.

—GARY PARK

● FINANCE & ECONOMY

ConocoPhillips earns $2.3B in Alaska

Despite crash in final quarter, earnings increase slightly, oil and gas production down, natural gas prices aligned with Lower 48

By ERIC LIDJI
Petroleum News

ConocoPhillips earned more than $2.3 billion in Alaska in 2008, up around 2.7 percent from the $2.2 billion earned in 2007, according to financial filings released on Jan. 28.

The company earned $456 million on exploration and production in Alaska in the fourth quarter of 2008, up slightly from the $448 million earned during the same period of 2007.

Those numbers show the unusual way ConocoPhillips finished out the last two years, as roughly even production yielded roughly even profits despite falling commodity prices.

In the final quarter of 2007, when ConocoPhillips sold Alaska oil on the West Coast for an average price of $87.88, the company paid some $234 million to comply with a revised tax code that went into effect in November and included retroactive elements.

In the final quarter of 2008, ConocoPhillips watched the delivered price of Alaska North Slope crude oil fall from a high of about $96 a barrel to a low of about $26 a barrel. The company reported an average sales price of $64.13 over that three-month stretch.

Even with that drop, ConocoPhillips saw higher oil prices on average year over year, selling a barrel of Alaska oil for an average of $69.75 in 2007 and $99.23 in 2008.

Companywide, ConocoPhillips lost $31.8 billion in the final three months of 2008 and some $17 billion for the year after a previously announced write down of assets.

ConocoPhillips plans to decrease spending and lay off some of its workforce this year.

Oil and gas production down

Higher average prices helped offset a continued decline in North Slope production.

After planned maintenance tempered oil production in the third quarter, ConocoPhillips produced 258,000 barrels of oil per day on average in Alaska in the fourth quarter of 2008, just slightly above the production levels over the same period in 2007.

But despite those steady fourth-quarter figures, ConocoPhillips saw a roughly 6.5 percent decline in oil and condensate production in Alaska between 2007 and 2008. The company produced 244,000 bpd of oil last year, down from 261,000 bpd in 2007.

ConocoPhillips produced 88 million cubic feet of natural gas per day in Alaska in the fourth quarter of 2008, down 13.7 percent from the 102 million cubic feet per day produced in the same period in 2007. For the year, ConocoPhillips produced 97 million cubic feet of gas per day in 2008, down 11.8 percent from the 110 million cubic feet per day produced in 2007.

ConocoPhillips saw prices increase for Alaska natural gas for the quarter and

The price ConocoPhillips received for Alaska natural gas was slightly higher than the Lower 48 average price of $4.76 per mcf ConocoPhillips saw in the fourth quarter of 2008. For decades, Alaska natural gas has typically been cheaper than the Lower 48 average.

the year. On average, the company sold Alaska natural gas for $4.90 per thousand cubic feet in the fourth quarter of 2008, up from a price of $4.12 per mcf over the same period of 2007.

That jump came as natural gas prices plummeted around the country. As a result, the price ConocoPhillips received for Alaska natural gas was slightly higher than the Lower 48 average price of $4.76 per mcf ConocoPhillips saw in the fourth quarter of 2008.

For decades, Alaska natural gas has typically been cheaper than the Lower 48 average.

For the year, ConocoPhillips sold Alaska natural gas for an average price of $4.38 per mcf in 2008, up from an average price of $3.68 per mcf in 2007, but still much lower than the average price of $7.71 per mcf seen across the Lower 48 in 2008.

In the fourth quarter in 2008, ConocoPhillips sold an average of 74 million cubic feet of liquefied natural gas per day from its export facility on the Kenai Peninsula, down from 78 million cubic feet per day sold during the fourth quarter of 2007. For the year, ConocoPhillips averaged 74 million cubic feet per day in LNG sales, down from 85 million cubic feet per day sold in 2007.

Average LNG prices rose from $6.21 per mcf in 2007 to $7.62 per mcf in 2008.

ConocoPhillips spent $45 million on exploration charges in Alaska in the fourth quarter of 2008, up from the $26 million spent over the same period in 2007. For the year, the company spent $100 million on exploration charges, down from $106 million in 2007. ●

Contact Eric Lidji at 907-522-9469 or elidji@petroleumnews.com

EXPLORATION & PRODUCTION

Endicott well may drain unknown pool

The Alaska Oil and Gas Conservation Commission has given BP Exploration (Alaska) permission to commingle production from a proposed well with production from the Eider, Ivishak, Alapah and Endicott oil pools.

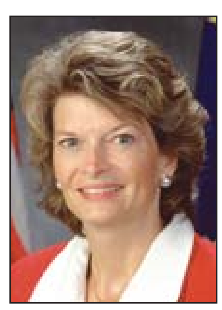
BP told the commission that based on seismic information the proposed well will not drain any of those identified oil pools.

The commission said BP requested approval to commingle production in November and said it has given the company a year after start of production to determine whether the well is in communication with any defined Endicott field oil pools and apply to include the well within an existing Endicott oil pool or within a new Endicott oil pool.

—PETROLEUM NEWS

GOVERNMENT

Murkowski gets high spot on Senate energy committee


SEN. LISA MURKOWSKI

Sen. Lisa Murkowski, R-Alaska, has been named the ranking Republican on the Senate Energy and Natural Resources Committee, her office said Jan. 27.

Murkowski has served six years on the committee, which will be responsible for shaping a new energy bill. Sen. Jeff Bingaman, D-N.M., chairs the committee.

"It's essential that we take a balanced approach to energy policy. While we need to improve energy efficiency and conservation, and expand development of renewable energy, we must also continue to support responsible development of traditional sources of energy," Murkowski said. "We cannot cut ourselves off from fossil fuels overnight, but we can, and should, begin the transition to a renewable, clean energy future."

—PETROLEUM NEWS

● FINANCE & ECONOMY

French giant Total makes oil sands grab

UTS Energy, junior partner in Petro-Canada's Fort Hills project, target of $617 million bid; Fort Hills UTS' main asset

By GARY PARK

For Petroleum News

Total has launched a surprise hostile bid to take out a junior partner in Petro-Canada's Fort Hills oil sands project just a month after speculation had the French super major planning a cash takeover offer for Nexen.

The company said its Canadian subsidiary is ready to pay C$617 million for UTS Energy, whose main asset is a 20 percent stake in the stalled Fort Hills venture.

The C$1.30 per-share offer was C47 cents a share above UTS's trading level when announced Jan. 27, is open for 60 days and is conditional on Total receiving at least 66.67 percent of UTS shares.

Total already has majority interests in the Joslyn oil sands project, after buying Deer Creek Energy for C$1.7 billion in 2005, and 60 percent of the Northern Lights project, following its acquisition of Synenco Energy last year for C$530 million, with the balance held by a subsidiary of China's Sinopec.

UTS conceded challenge

UTS has openly conceded it faces a severe financial challenge, compounded last October when it was disclosed that cost estimates for the Fort Hills mine and upgrader had soared to C$25 billion, forcing the junior, which has no cash flow, to raise billions of dollars to cover its share of development costs.

> *William Lacey, an analyst at FirstEnergy Capital, told reporters he was surprised by what he called Total's "opportunistic" bid, suggesting the company was "trying to capitalize on a very weak market (by) paying almost nothing for an enormous resource."*

Although Fort Hills has effectively been mothballed, Total said a final decision to resume work on the project is expected in 2010, with production starting as early as 2013.

In addition to its Fort Hills holding, UTS has a 50 percent working interest in more than 300,000 acres of prospective leases and holds an estimated 2.1 billion barrels of bitumen resources.

Fort Hills third partner is mining giant Teck Cominco which faces its own struggle after acquiring Fording Canadian Coal Trust's assets last year for US$14 billion — a deal completed just as commodity prices were collapsing — adding US$9.8 billion to its debt load and prompting a credit rating downgrade.

Teck said in early January it was cutting 1,400 jobs and warned more might follow.

It took an initial 15 percent stake in Fort Hills in 2005 for C$475 million, but analysts have questioned whether it can remain in the oil sands given the magnitude of its other challenges.

Analyst surprised

William Lacey, an analyst at FirstEnergy Capital, told reporters he was surprised by what he called Total's "opportunistic" bid, suggesting the company was "trying to capitalize on a very weak market (by) paying almost nothing for an enormous resource."

He said Total appears to be taking a long-term view of the oil sands, given its takeover of Synenco, but suggested counter bids for UTS are likely, including a possible offer from Petro-Canada.

Randy Ollenberger, a BMO Nesbitt Burns analyst, said it is clear that Total expects Fort Hills to go ahead and may also be counting on synergies between Fort Hills and its separate plans to build a bitumen upgrader capable of processing 200,000 bpd, given that the Fort Hills partners are wavering on their own upgrader plans.

UTS Chief Executive Officer Will Roach said there had been no prior discussions with Total, but the offer would receive "full and fair consideration."

A spokesman for Petro-Canada said that having a major international company as a partner would only be beneficial, but he could not say whether Total's presence would speed up corporate approval of Fort Hills. ●

● PIPELINES & DOWNSTREAM

Enbridge Alberta-Gulf pipeline shelved

Project would have moved Western Canadian crude to Gulf, reversed direction of flow; lacked support from potential shippers

By GARY PARK

For Petroleum News

Canadian pipeline company Enbridge has added to the postponement of oil sands-related projects by shelving indefinitely plans for a US$350 million scheme that would have moved Western Canadian crude to the U.S. Gulf Coast via tanker by mid-2010.

The Trailbreaker project offered 130,000 barrels per day of capacity to the Gulf through the Portland pipeline by reversing the flow from Montreal to Portland, Maine, as well as 70,000 bpd to Montreal refiners.

It had already failed to get backing from the Canadian Association of Petroleum Producers, which said it did not offer sufficiently attractive returns for producers.

CAPP said the project would be put on hold until shippers and CAPP renewed interest in the project.

In a letter to Enbridge filed with the National Energy Board, Montreal Pipe Line — which owns the Canadian segment of the existing 18-inch Portland-Montreal pipeline — said an open season which closed Dec. 30 did not generate the level of firm volume commitments from Canadian producers and U.S. and Canadian refiners required to proceed with the project at this time.

The letter said that although several prospective shippers showed strong interest in moving their crude for loading onto marine tankers and accessing new markets on the North American East Coast, the Gulf and possibly offshore they said the timing was not right for them to make shipping commitments.

It said the dramatic change in economic conditions over recent months and the outlook for supply and demand of Western Canadian crude is less certain.

The open season could be reopened along with related negotiations with shippers as soon as market conditions warrant, the letter said.

The Trailbreaker route, which was to have been operating by 2010, was designed as a temporary export route until such time as demand resumed for a 400,000 bpd overland pipeline from Alberta, once targeted for startup in 2012. But Enbridge said last summer it doubted there would be enough oil sands production to justify the line before 2014.

An Enbridge-BP partnership had proposed spending up to US$2 billion to expand existing pipelines and build new connections to deliver up to 250,000 bpd to refiners on the Gulf Coast.

In the midst of such general gloom, even small developments in the oil sands are warmly greeted.

Connacher resumes output

In a speedy about turn, Connacher Oil and Gas said it is resuming full output from its Great Divide project, less than a month after cutting output almost in half to 5,000 bpd.

The junior producer said it expects to reach 9,000 bpd by the end of February because returns from extra-heavy crude have improved and should yield improved bitumen prices and netbacks during the next six months, with "further improvements possible as more normal commodity and capital markets re-emerge and the economic outlook brightens."

Connacher had been the first notable oil sands producer to cut production when oil prices slipped below US$40 per barrel.

However, the company's plans for a 10,000 bpd expansion remain on hold, other than completion of a plant site, well pad sites and the construction of key equipment.

It said a resumption of activity will need "a thaw in and improvement of capital markets and improvement in the

see PIPELINE page 9

● SAFETY & ENVIRONMENT

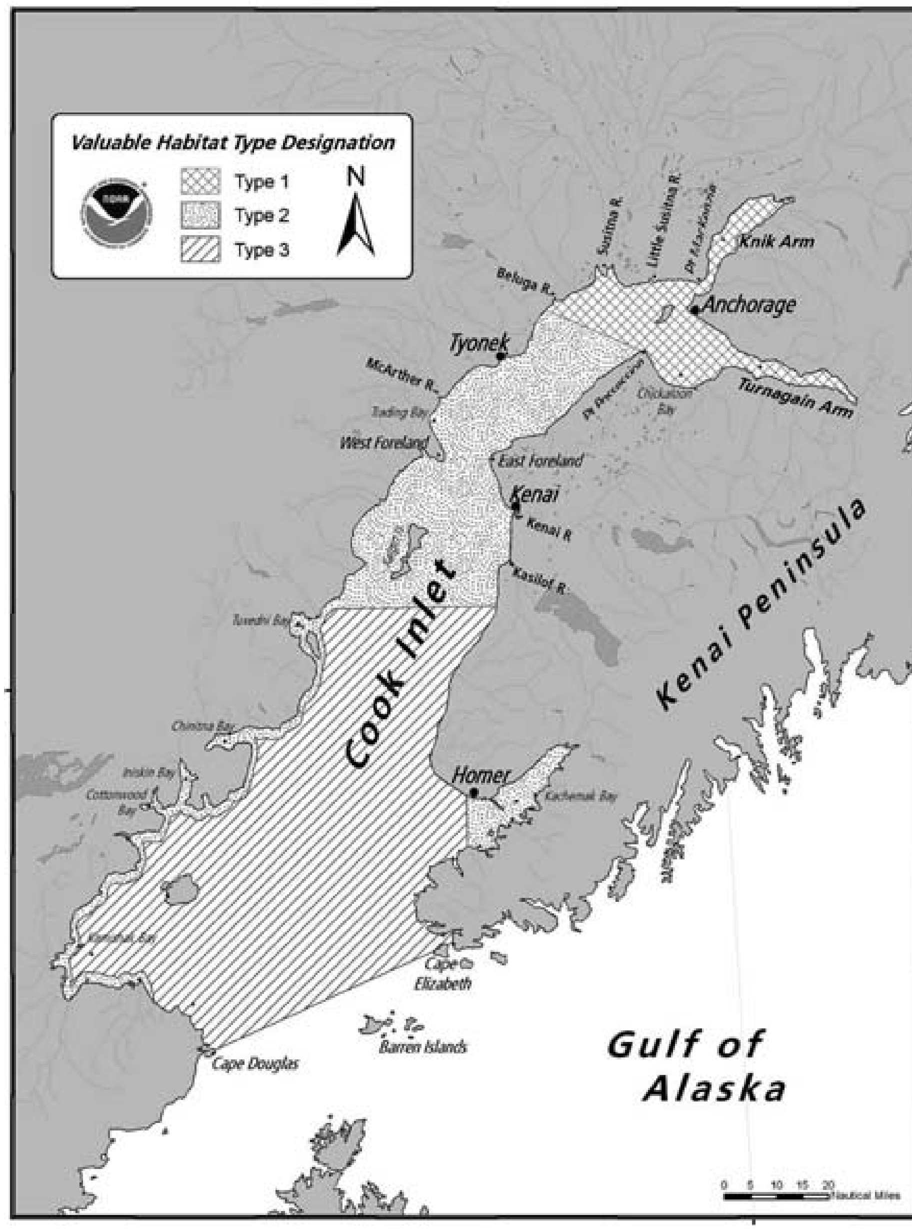
Next steps for the Cook Inlet beluga

NMFS starts ESA consulting and moves towards completion of a recovery outline, while wastewater utility takes stock of its position

By ALAN BAILEY
Petroleum News

While the elusive beluga whales of Alaska's Cook Inlet overwinter in the inlet's grey and murky waters, oblivious to the war of words surrounding their future well being, the U.S. National Marine Fisheries Service has started applying the various procedures that result from the whales becoming listed under the Endangered Species Act.

The October decision by NMFS to list the whales as endangered fueled an intense debate, with some people supporting the listing and others saying that it was premature. And on Jan. 14 the State of Alaska announced that it would sue to challenge the listing, expressing concerns about economic impacts and saying that the listing was not necessary.



NATIONAL MARINE FISHERIES SERVICE

A beluga whale habitat map from the National Marine Fisheries Service beluga whale conservation plan may point to candidate locations for critical habitat designation under the Endangered Species Act. However, the designation will require the identification of specific physical and biological habitat features and will be subject to an economic evaluation.

Consultations started

Brad Smith, Anchorage office supervisor for the NMFS protected resources division, told the Alaska Association of Environmental Professionals in Anchorage on Jan. 21 that his office had already started beluga whale consultations with other federal agencies — under the terms of section 7 of the ESA any federal agency involved in an action or funding an action that might impact the whales must consult with NMFS to determine how to avoid jeopardizing the whales' survival.

"Basically it encourages us and the (other) federal agencies to work together and try to come up with ways to mitigate a plan so that it doesn't result in a take," Smith said. A "take" is generally prohibited for an animal with an endangered status and includes harassment or harming of an animal, as well as more lethal actions such as hunting or shooting.

Consultation generally starts informally, to determine whether a take is likely to occur during the planned action. If a take is unavoidable, a formal consultation would ensue to develop a biological opinion on whether an incidental take could be allowed. And the consultation needs to take into account both the direct and indirect consequences of the action, Smith said.

However, despite the NMFS view that the future of the Cook Inlet beluga whales is already in jeopardy, Smith sought to dispel concerns that NMFS would seek to prohibit all activity in Cook Inlet.

"We're not going to contest the listing." **—Brett Jokela, assistant general manager of Anchorage Water and Wastewater Utility**

"That's not the case and we certainly aren't going into the consultation process from the position that nothing further can go on in the Cook Inlet," Smith said. The focus will be on identifying those actions that would increase the risk to the whales.

And, given the size of the emerging consultation workload, the Anchorage office is having to prioritize what consultation to do first, Smith said.

Critical habitat

Also under the terms of the ESA, by October 2009 NMFS has to designate the beluga whales' critical habitat. Federal agencies are then required to avoid adverse modifications to that habitat.

The critical habitat consists of those parts of the animals' range where there are physical and biological features that are essential to the conservation of the species and which may require management, Smith explained.

"This has been tested in court and the operative phrase … is 'essential features'," Smith said. "It's not enough to draw a circle around an area and say that this is critical habitat because this is where the whales are. Rather we have to be able to identify and describe those physical and biological features."

Smith said that NMFS does not yet know where the Cook Inlet whale critical habitat would be — the range of the whales encompasses the whole of Cook Inlet. However, he showed a couple of maps that provide clues as to where critical habitat might exist.

One map consisted of a habitat model based essentially on the marine substrate, the water depth and the proximity of drainage basins. The habitat areas in this map occur in discrete locations around the Cook Inlet coast and appear to correspond quite closely with high densities of whale observations from NMFS annual beluga whale surveys.

The other map, from an NMFS Cook Inlet whale conservation plan, showed three levels of habitat importance, with the most important habitat occurring in the upper Cook Inlet near Anchorage, and in the Knik and Turnagain arms.

However, the ESA does require NMFS to take into account the economic impact of designating critical habitat.

"That's no small endeavor and we're working with our regional economist right now as he begins to get his hands around this," Smith said.

An area can be removed from the critical habitat if the economic benefit of removing it exceeds the benefit of including it. That tends to lead to an "apples and oranges" type of comparison, in which the agency may have to drop an area from the critical habitat because of cost and then come up "with something on the other side of the ledger," Smith said.

Recovery plan

NMFS also has to prepare a recovery plan for the Cook Inlet beluga whales and anticipates using a conservation plan that it had already developed as a starting point.

"We've already prepared a conservation plan that looks and acts a lot like a recovery plan, so we've got a leg up on the process," Smith said.

However, NMFS developed the conservation plan in house and anticipates involving a wider participation in the development of the recovery plan. So, to formulate the recovery plan, the agency expects to form a recovery team that

see **BELUGAS** *page 9*

continued from page 8

BELUGAS

includes a range of stakeholders in the beluga whale conservation issue.

"I would anticipate that we will need a recovery team for the purpose, just because of the visibility and controversy that surrounds the listing and probably because of some of the actions that are going to be necessary to hopefully begin the recovery process," Smith said.

The purpose of the plan will be to identify the threats to the whales, specify conservation actions and determine the criteria for downlisting the species. The plan also requires a time and cost estimate for recovery of the whales.

However, since it may take four or five years to develop the recovery plan, NFMS is in the process of completing what it terms a "recovery outline" to specify interim steps to take while the recovery plan is being developed, Smith said.

Sizing up

Meantime, people in Anchorage and on the Kenai Peninsula are sizing up the potential impacts on their activities of the beluga whale listing decision. Effluent discharges from the Anchorage sewage system, for example, have been mentioned as something that requires study in relation to beluga whale conservation.

Brett Jokela, assistant general manager of Anchorage Water and Wastewater Utility, told the AAEP meeting that he is confident that Anchorage sewage is not polluting the waters of the Cook Inlet and that AWWU will support efforts to restore the beluga whale population.

"We're not going to contest the listing," Jokela said. Fighting the listing would be a waste of AWWU resources and the utility respects the science that NMFS carries out, he said.

AWWU has three sewage treatment plants. Two small plants treat sewage from Eagle River and Girdwood. The main plant, which treats Anchorage sewage, is the John Asplund plant at Point Woronzof, on the Cook Inlet coast. The three AWWU plants fully meet the requirements of the Clean Water Act, Jokela said.

There are relatively few industrial discharges into the Anchorage sewage system and any industrial discharges in the city are subject to a rigorous permitting process, with limitations on what can be discharged, Jokela said.

On the Web

See previous Petroleum News coverage:

"CI belugas on the endangered list," in Oct. 26, 2008, issue at www.petroleumnews.com/pnads/36334619.shtml

"Beluga whales hold steady in Cook Inlet," in Oct. 5, 2008, issue at www.petroleumnews.com/pnads/516446932.shtml

"Cook Inlet belugas: decline or not?" in May 13, 2007, issue at www.petroleumnews.com/pnads/191458333.shtml

"Beluga ESA listing prompts debate," in April 29, 2007, issue at www.petroleumnews.com/pnads/140159294.shtml

"We have a very vigorous program for industrial pre-treatment," Jokela said.

And because the city has low levels of contaminants in its wastewater, the Asplund plant operates under the terms of a waiver under section 301(h) of the Clean Water Act. That waiver enables the plant to operate without secondary biological treatment or tertiary nutrient treatment — essentially, the plant filters the wastewater and then puts the water in clearing ponds, to remove solids and scum. However, the effluent is sterilized using chlorine before being discharged through a diffuser located about 800 feet offshore.

The strong Cook Inlet tidal currents sweep the discharges from the plant more than 20 miles up Knik Arm or down the inlet in a single day, Jokela said.

And AWWU's comprehensive monitoring of potential contamination both around the Asplund plant outfall and in the tidelands of Knik Arm and elsewhere indicate that the sewage plant is not causing any environmental harm, Jokela said. In addition, there is no sedimentation around the outfall, he said.

"The results show that we don't have any distinct differences between the biota that exist near our outfall and the biota that exist far away," he said. "… We have no water quality standard issues."

Permit renewal

However, the Environmental Protection Agency wastewater discharge permit required to operate the Asplund plant runs on a five-year cycle and AWWU is currently in the process of renewing the permit. And, because EPA is retaining federal administration of 301(h) waivers, the permitting of the plant will not move to the State of Alaska as part of the state's takeover of permitting under the National Pollutant Discharge Elimination System.

Smith was adamant that the various criticisms of the listing are unfounded. The listing decision came after a more that 20 year investigation of the Cook Inlet beluga whale issue and was based on sound science, he said. NMFS has determined the Cook Inlet belugas are genetically and physically isolated from other beluga populations. And the Cook Inlet beluga whales are subject to some well-documented threats, he said.

The consequence of all of this is that EPA and NMFS have already started informal ESA section 7 consultations regarding the Asplund plant permit application, as a consequence of the beluga whale listing. A determination that the plant could have an effect on the beluga whales would trigger a formal consultation, Jokela said.

And the stakes are high. The loss of the 301(h) waiver would trigger the need for a plant rebuild at a cost in the range of $500 million to $800 million, Jokela said.

There's also the possibility that some as yet unknown contaminant from the plant is causing a problem.

"Advanced waste treatment, which could be necessary in order to get at some specific contaminants that might be identified at some point as being significant, could run into the billions," Jokela said. "However, at this point the benefit of providing any higher level of treatment is really questionable."

And Jokela urged the need to focus on determining whether there are any specific contaminants that need to be investigated, rather than conducting a blanket search for every possible item of information.

"Our approach and our philosophy towards the assistance with recovery are going to be open and pragmatic," Jokela said. "We have 56,000 customers that depend on us to provide efficient wastewater service and the cost of that wastewater service is large."

But what of the controversy surrounding the Beluga whale listing and the state's lawsuit against it?

Smith was adamant that the various criticisms of the listing are unfounded. The listing decision came after a more than 20 year investigation of the Cook Inlet beluga whale issue and was based on sound science, he said. NMFS has determined the Cook Inlet belugas are genetically and physically isolated from other beluga populations. And the Cook Inlet beluga whales are subject to some well-documented threats, he said.

"Our scientists have accomplished four status reviews since 1988," Smith said. "Those have looked at the viability of the population, some of the threats associated with it and some of the science that we felt was necessary to understand the ecology of these whales and to hopefully bring about their recovery." ●

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PIPELINE

general economic conditions in North America" – all factors it puts in the unknown category as far as timing is concerned.

Long Lake production begins

Meanwhile, Nexen, with partner OPTI Canada, has reported the first production of synthetic crude from the initial phase of its C$6.6 billion Long Lake operation.

The main process units at the upgrader have successfully been brought on line and should allow full capacity of 60,000 bpd to be reached within 12 to 18 months, Nexen said.

Nexen Chief Executive Officer Marvin Romanow said the milestone is proof that the innovative technology — incorporating a gasification process in the upgrader to reduce the consumption of natural gas at the thermal operation — is working.

OPTI said Long Lake is expected to yield the highest quality synthetic crude to come from the oil sands with low operating costs. ●

● ALTERNATIVE ENERGY

Fire Island wind farm work this year

Cook Inlet Region Inc. hopeful state's first major wind far will be running in late 2010; Corps of Engineers doing public review

By GEORGE BRYSON
Anchorage Daily News

Construction crews should be busy on Fire Island near the western tip of Anchorage this summer, and the state's first major wind farm could be up and running there late next year.

So say officials with Cook Inlet Region Inc., the Native corporation that plans to develop land it owns on the mostly barren isle into a wind-driven source of power for thousands of Railbelt households.

"We're moving forward with the project," CIRI spokesman Jim Jager said the week of Jan. 19.

Significant hurdles still remain, including determining which electric companies will buy the power and approval of all permits, Jager said.

"Of course any of this can be thrown sideways by about a thousand different things. But our anticipation is that there aren't any show stoppers ... and there will be power coming off the island late next year — in 2010."

The announcement came as the Army Corps of Engineers launched a month-long public review of the proposal filed by Wind Energy Alaska, a business owned by CIRI and enXco Inc., a U.S. company that develops and runs wind energy projects.

The plan calls for erecting 20 wind turbines, each capable of generating 1.5 megawatts of power. A three-mile-long cable would carry the electricity to Point Campbell on the mainland and into the existing power grid that runs from Homer to Fairbanks.

Earlier proposal was larger

Earlier versions of the project — first explored about 10 years ago by one of its potential customers, the Chugach Electric Association — called for 33 wind turbines and up to 100 mw of power.

But the towering 3-mw wind turbines required to do so would be less efficient in Anchorage's cold temperatures and sometimes moderate winds than the smaller 1.5-mw turbines, Jager said. That trimmed the project down to a 50-mw wind farm.

And its developers decided to cut the proposal to 20 turbines and 30 megawatts to satisfy concerns raised last year by the Federal Aviation Administration, which maintains an aircraft navigation signal on the island.

The wind power will supply a small fraction of the overall electricity consumed along the Railbelt, where utilities primarily rely on power generated by gas, hydro and fuel oil. The American Wind Energy Association says 30 megawatts of wind power equals the annual electricity needs of about 9,000 households.

Legislature approved some monies

Last year the Alaska Legislature appro-

The plan calls for erecting 20 wind turbines, each capable of generating 1.5 megawatts of power. A three-mile-long cable would carry the electricity to Point Campbell on the mainland and into the existing power grid that runs from Homer to Fairbanks.

priated $25 million to construct the seabed transmission line to carry that power into the electricity grid. But before the cable can be laid, the developers will need to get at least a few of the utilities involved to sign power-purchase agreements.

Anchorage Municipal Light & Power, Homer Electric and Golden Valley in Fairbanks have each expressed interest in the power, and Chugach has said it's willing to transport it to the grid, Jager said.

Chugach is also a prospective buyer of Fire Island wind power, Chugach spokesman Phil Steyer said Jan. 23. The company is studying how the fluctuating power from a wind farm can be integrated into the Railbelt grid without causing load problems.

The utilities are also waiting for Wind Energy Alaska to tell them exactly how much the electricity will cost per kilowatt, Steyer said.

That's a number that's partly dependent on construction bids that are just now forthcoming, Jager said.

In the short run, the wind power will probably be more expensive than electricity generated from natural gas, since its expense is all upfront in the cost of building the farm, he said. But in the long-run, wind power costs are stable, since its fuel source is free, whereas the cost of gas-fired electricity may well continue to climb.

"That makes wind more attractive, because while the price may be slightly higher now, you have rate certainty for the next 15 or 20 years," Jager said.

Environmental issues

The project will also have to satisfy concerns about its effect on the environment. Wind farms can kill birds. But the newer, larger turbines pose less of a threat, because the blades move more slowly, Jager said.

Audubon Alaska senior scientist John Schoen said his organization hasn't yet taken a position on the Fire Island wind farm.

"In general we support wind energy," Schoen said. "But we still need to do our homework. ... We might have questions about the siting."

Specifics on the precise placement of the turbines, as well as the make and model, haven't yet been decided, Jager said. But enXco engineers are presently favoring a 1.5-mw wind turbine manufactured by the General Electric Co. that they have in stock.

The G.E. turbine has a flexible tower height with a hub that can vary between 215 feet and 265 feet — taller than a 20-story building — and a three-blade rotor that would whirl around a circle 252 feet in diameter.

The Army Corps of Engineers, meanwhile, will focus its own attention on the effects the project might have on the marine environment, including both the seabed transmission line and the impact that barge traffic carrying workers and materials may have on the intertidal zone. The Corps is accepting public comments on the project through Feb. 19. ●

EXPLORATION & PRODUCTION

Upping the limit for the Oooguruk field

Amid the current financial doom and gloom, it's helpful to at least find some good news in the oil patch.

And a recent application by Pioneer Natural Resources for an increase to the oil spill response planning standard for the Beaufort Sea Oooguruk field strikes a positive note. Pioneer has applied to the Alaska Department of Environmental Conservation to increase the planning standard from 2,500 barrels per day to 5,000 barrels per day for the Oooguruk oil discharge prevention and contingency plan.

"One of Oooguruk's initial Kuparuk (oil pool) wells is performing better than we anticipated when applying for our initial C-plan and therefore we are seeking to amend the plan accordingly," Pioneer spokesman Tadd Owens told Petroleum News Jan. 27.

Owens said that although the well performance has been exceeding expectations, that particular well was just one of the more than 30 wells planned for the field.

"At this time we have not adjusted any of our resource or production estimates for the unit," Owens said.

But Pioneer's 2008 report on proved reserves and finding costs hinted that the Oooguruk field may be exceeding Pioneer's expectations.

"Results from our Oooguruk drilling are better than anticipated," said Scott Sheffield, Pioneer's chairman and CEO in announcing the report.

Oooguruk, the first producing North Slope oil field to be operated by an independent oil company, went online in June 2008. A continuing program of development drilling is targeted at the field reaching peak production in 2010.

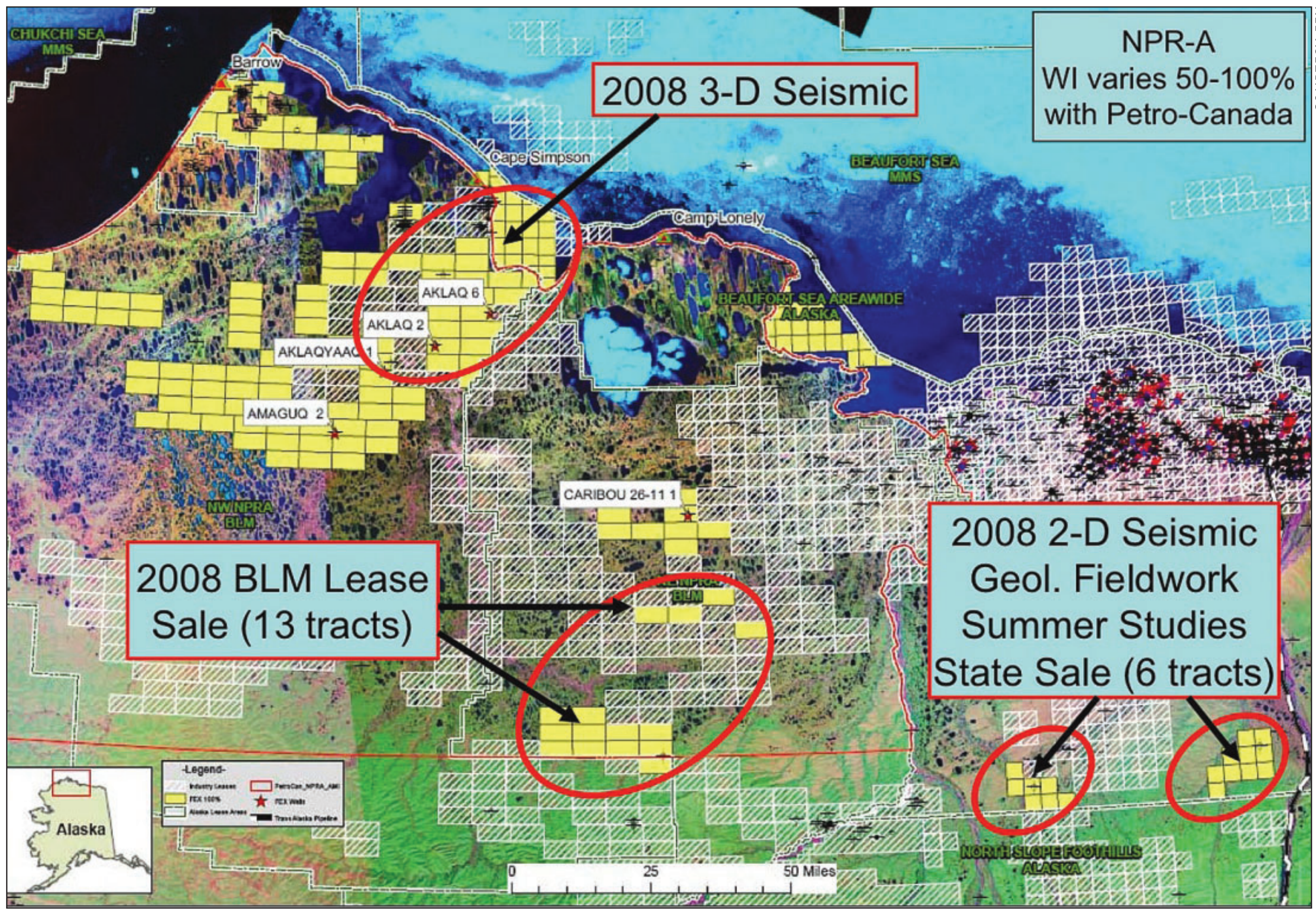
—ALAN BAILEY

● EXPLORATION & PRODUCTION

FEX won't drill until at least 2011

Company says it needs time to process 3-D seismic shot last year; says Alaska must compete for investment worldwide in tight times

By ERIC LIDJI
Petroleum News



FEX holds around 1.1 million net acres spread over 178 state and federal leases, most owned in partnership with Petro-Canada.

Talisman Energy won't drill in the National Petroleum Reserve-Alaska this winter or next, a company executive told the Alaska Support Industry Alliance on Jan. 23.

Last fall, the Calgary-based independent, which operates in Alaska through a subsidiary called FEX, suggested it might resume its Alaska exploration program next winter.

Although FEX didn't drill in Alaska last year, the company shot a major 3-D seismic survey. Processing and interpreting the information from that shoot "takes quite a while," according to John 't Hart, executive vice president of global exploration for Talisman.

"As a result we won't expect to be drilling either in 2009 or in 2010," 't Hart said.

Last fall, FEX officials said the company was studying seismic data, and hoped to start mobilizing a drilling team early in 2009 in preparation for resuming exploration in 2010.

Benefits and challenges

In January, Talisman unveiled a $4 billion spending plan for 2009 focused on "bigger prospects, which can renew the company," as President and CEO John Manzoni put it.

With positive seismic results, the NPR-A could fit that description, 't Hart said.

"The Alaska North Slope has a lot of oil and gas to be found. The only problem is it's hard to find commercial quality reservoirs," 't Hart said, adding, "It's a super charged system, and if you can find the right reservoir, this is a great place to be."

He said Alaska is attractive because vast swaths of land remain unexplored; emerging technologies make exploring it less risky; the state provides tax credits for exploration work and technical cooperation; and the oil pipeline has plenty of spare capacity.

"So these are all good reasons to be here," 't Hart said.

But there are significant challenges to working in Alaska as well, he said.

Companies working in frontier regions of Alaska, like NPR-A, run into short drilling seasons, a scarcity of infrastructure, long lead times and high project costs, 't Hart said.

Alaska is more expensive than other parts of the Arctic, he said, adding that Talisman operations in the Northwest Territories cost around 60 percent less than those in Alaska.

FEX is exploring difficult reservoirs in NPR-A, and "for new companies entering Alaska for the first time, the data challenge is time consuming and expensive," 't Hart said.

He also pointed to a series of recent changes to the state fiscal system, saying it added uncertainty to the economics of long-term projects. But as a company working mostly on federal land, FEX wouldn't pay state royalties or many state taxes once it produces oil.

Despite an expansion of the tax credit program in Alaska, 't Hart said the state doesn't give special incentives for remote exploration, like those offered in the Gulf of Mexico.

Alaska is a very high-risk environment with the possibility of high rewards, but "the differential really needs to be better to remain competitive on a global basis," he said.

> *"The Alaska North Slope has a lot of oil and gas to be found. The only problem is it's hard to find commercial quality reservoirs."*
> **—John 't Hart, executive vice president of global exploration, Talisman Energy**

Looking at a tight budget

Like many independent oil companies, Talisman crafted a restrained budget this year in response to low oil prices and tight credit markets. The company plans to spend only the revenues it earns from existing operations, a figure projected to be around $4 billion.

Over the past five years, FEX has been responsible for some of the most remote wildcats in Alaska, some more than 100 miles beyond the existing North Slope infrastructure grid.

But after completing its fifth Alaska well in 2007, FEX put its exploration program on hold while it considered where to drill next. Last year, the company spent $25 million shooting seismic over the area of land near Smith Bay, northwest of Teshekpuk Lake.

During that time, Talisman underwent significant changes. In September 2007, John Manzoni took over as president and CEO of the company. In May, he unveiled a new corporate strategy centered on "fewer, more material assets." Alaska remained a priority.

Unveiling the 2009 capital budget, Manzoni said spending would be limited to revenue earned from existing operations. The company based its budget on $40-a-barrel oil prices and $5-per-million British-thermal-unit natural gas prices, slightly above current prices.

> *One of the largest leaseholders in northern Alaska, FEX holds some 1.1 million net acres spread over 178 state and federal leases, most owned with Petro-Canada.*

One of the largest leaseholders in northern Alaska, FEX holds some 1.1 million net acres spread over 178 state and federal leases, most owned with Petro-Canada. ●

Contact Eric Lidji at 907-522-9469 or elidji@petroleumnews.com

● EXPLORATION & PRODUCTION

BRPC adds to exploration program

Company plans to drill at West Shore if time permits, now drilling three prospects in Gwydyr Bay this winter, gets AOGCC permit

By ERIC LIDJI
Petroleum News

A four-company joint venture is adding two proposed wells to an already busy North Slope exploration program this winter in the Gwydyr Bay area north of Prudhoe Bay.

Project operator Brooks Range Petroleum Corp., the local arm of Kansas-based Alaska Venture Capital Group, is permitting a well and a sidetrack at the West Shore prospect.

With the additional wells, BRPC is now looking at drilling three prospects this winter in the hopes of proving up enough possible reserves to justify development in the region.

With the additional wells, BRPC is now looking at drilling three prospects this winter in the hopes of proving up enough possible reserves to justify developing the region.

In the fall, the company announced plans to explore two prospects this winter.

First, the company will drill North Shore No. 3 from an existing ice pad used to drill North Shore No. 1, an exploration well BRPC drilled in 2007 and re-entered last winter.

North Shore No. 1 tested at a day rate of 2,092 barrels of oil from the Ivishak formation, but a mechanical problem compromised testing of the shallower Sag River formation.

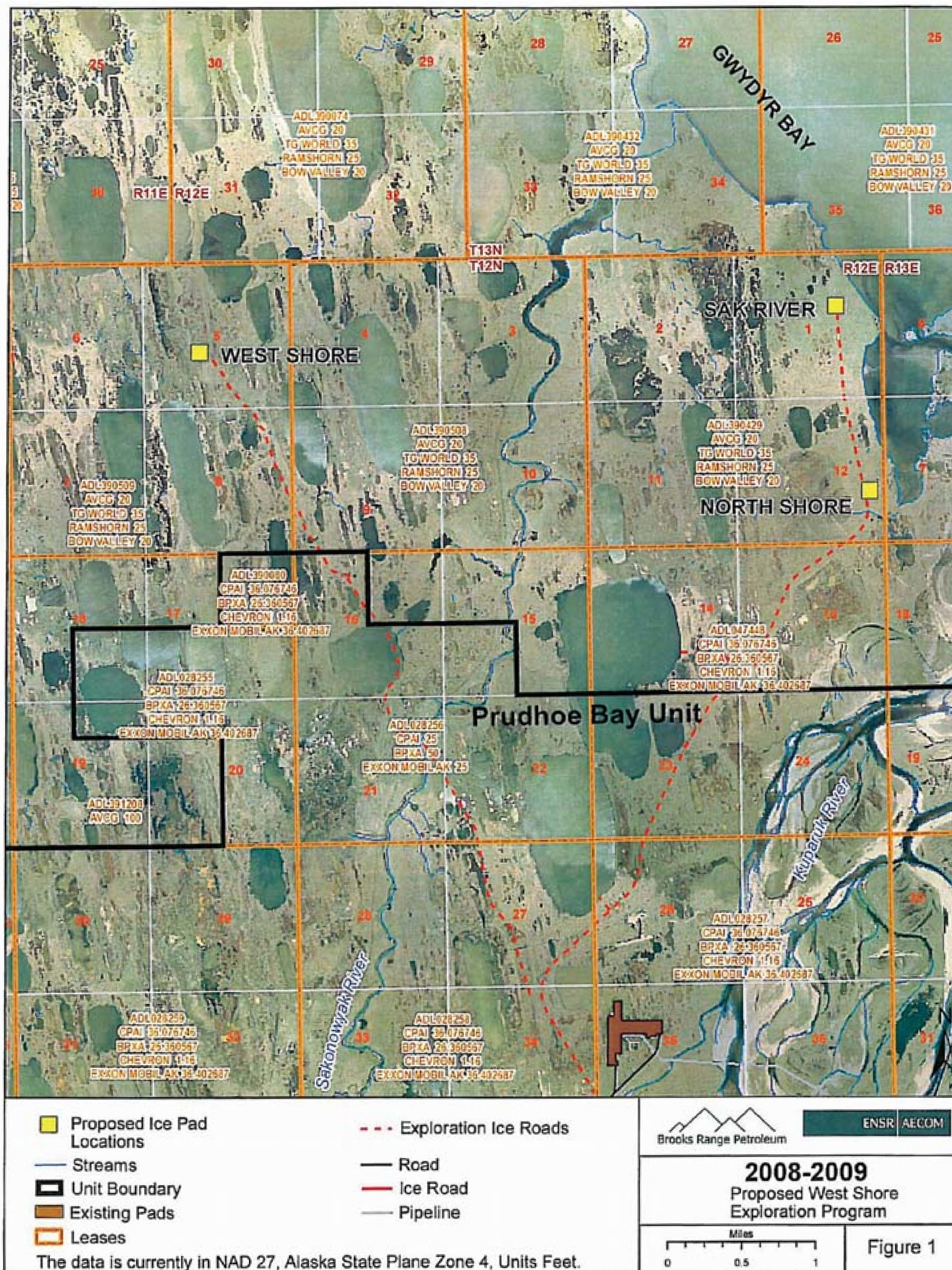
North Shore 3 permitted

On Jan. 23, the Alaska Oil and Gas Conservation Commission approved a permit for BRPC to drill North Shore No. 3, the first drilling permit issued to the company this year.

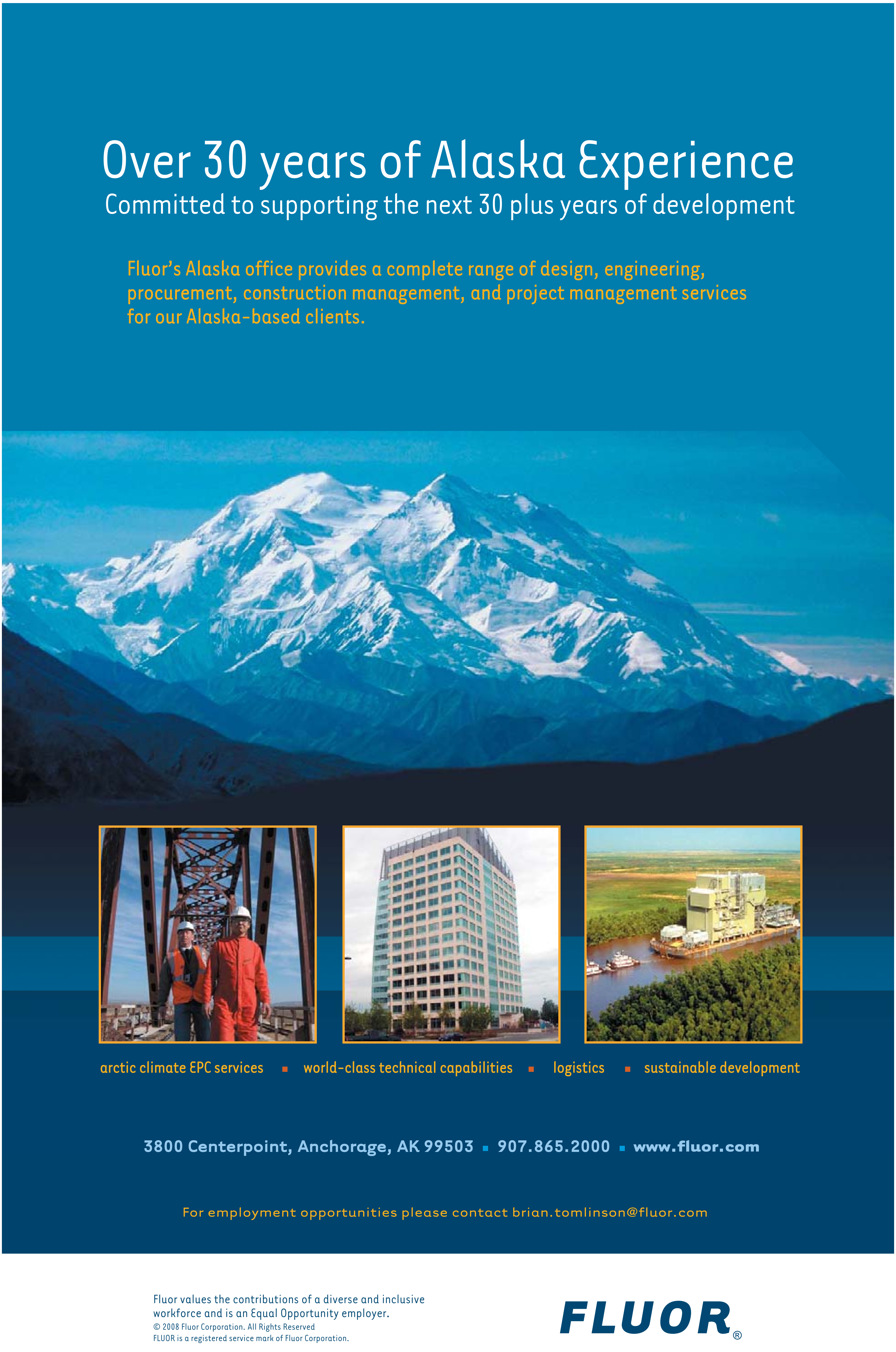
According to a timetable given to the state in October, BRPC hopes to drill for some 45 days at North Shore, finishing work before the end of February.

Next, BRPC plans to move a mile to the north to drill Sak River No. 1A, a sidetrack to a dry hole the company drilled in 2007. If successful, the company could drill a sidetrack.

see WEST SHORE page 14



COURTESY BRPC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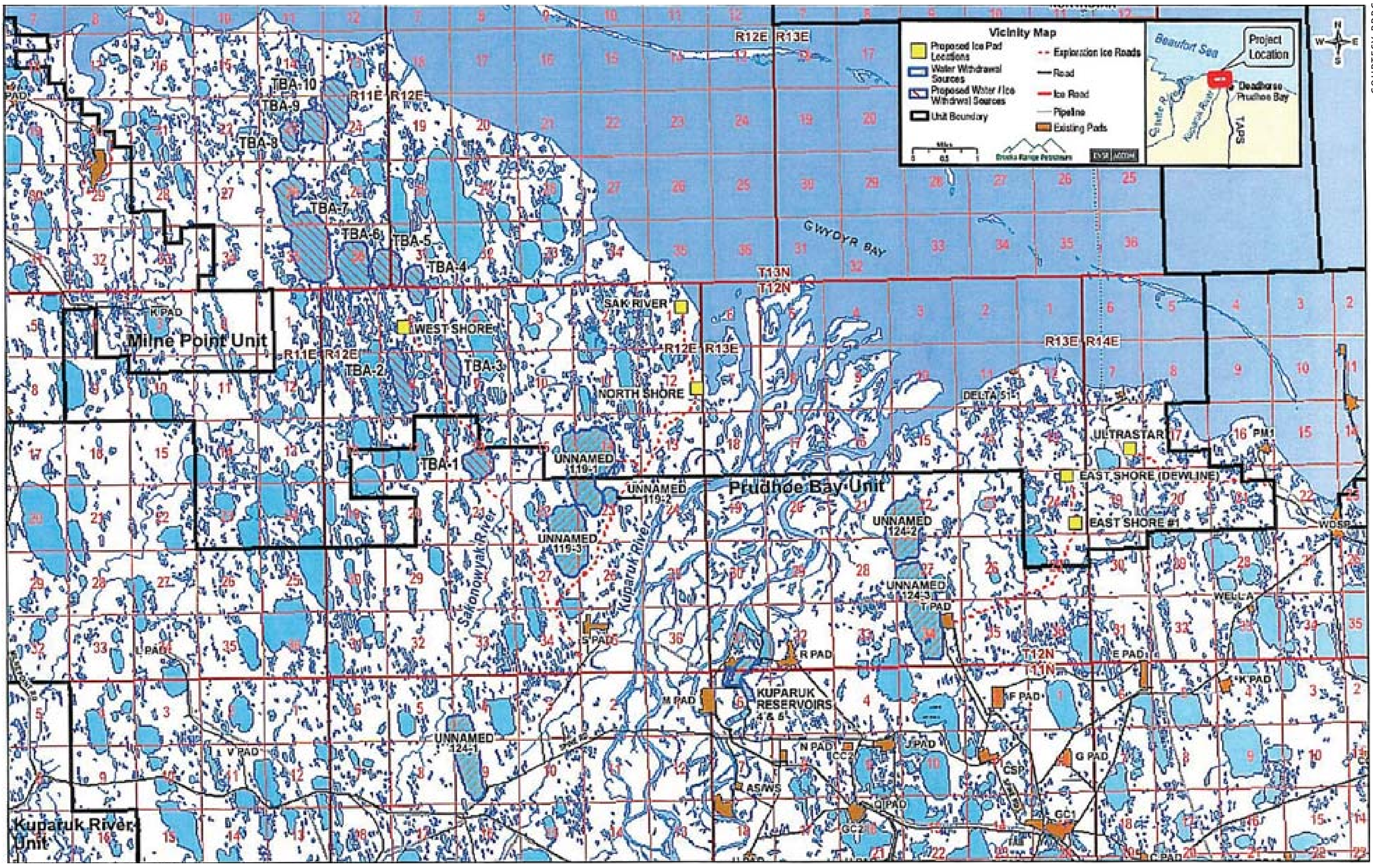


COURTESY BRPC

continued from page 12

WEST SHORE

The company expects to spend two months at Sak River, finishing at the end of March.

If time permits, BRPC would then move four miles to the west to drill West Shore No. 1 before the end of April. The company could also drill a sidetrack and conduct a flow test.

To explore West Shore, the company needs to build five miles of ice road and an ice pad.

The company plans to drill all three prospects using Nabors rig 16-E.

BRPC is operating the Gwydyr Bay exploration program on behalf of TG World Energy Corp., Bow Valley Alaska Corp. and Nabors subsidiary Ramshorn Investments Inc.

BRPC is currently engaged in a legal battle with TG World, after the Calgary-based independent decided not to participate in drilling and development programs this winter. ●

Contact Eric Lidji at 907-522-9469 or elidji@petroleumnews.com

● NATURAL GAS

FERC taking on oversight at Kenai LNG plant

By KRISTEN NELSON
Petroleum News

On Jan. 15 the Federal Energy Regulatory Commission notified ConocoPhillips and Marathon that the agency was taking on oversight of the Nikiski liquefied natural gas facility the companies built and have operated since 1969.

FERC said that in the 1960s it was determined that the facility was not subject to FERC oversight because it was not on the U.S. border with another country.

FERC said the scope of its authority over LNG terminal and storage authorities has since been clarified and it "currently exercises its jurisdiction over the siting, construction, operation and maintenance of LNG terminals to impose reporting and inspection requirements that serve to ensure the safety and security of such facilities."

The Kenai facility is subject to and must comply with FERC's reporting and inspection requirements, the agency said.

"FERC's recent order states that its purpose is to clarify that the Kenai LNG facility is subject to the Commission's reporting and inspection requirements," ConocoPhillips told Petroleum News in an e-mail.

"ConocoPhillips, in consultation with its co-venturer, is evaluating the order," the company said, and added that it has operated the Kenai LNG export facility safely since 1969.

Design review

FERC said that to ensure the Kenai LNG facility conforms to the requirements met by other such facilities, it "will be subject to a cryogenic design and technical review of the facility's design, operation and maintenance," and ConocoPhillips and Marathon were directed to provide specific information included in applications for LNG projects.

After the information is reviewed, "staff may recommend modifications to be made to the facilities and operations of the LNG terminal and storage facilities," FERC said in its order.

After the initial review, the Kenai LNG facility will be subject to at least annual technical reviews and site inspections. Semiannual operational reports are also required and the companies must report significant nonscheduled events to FERC staff.

ConocoPhillips and Marathon are required to provide information identified in the order within 90 days. ●

NATURAL GAS

OFC to have Alaska office at JPO

The Office of the Federal Coordinator will have a temporary office at the Joint Pipeline Office in Anchorage beginning in February, Federal Coordinator Drue Pearce said Jan. 23 at the Alaska Support Industry's annual "Meet Alaska" conference.

A search is under way for permanent space, she said.

Pearce also said the OFC has hired its first employee for the Alaska office, an environmental engineer who will work in the permit, schedule and compliance division of OFC; that employee will begin work Feb. 17.

The Office of the Federal Coordinator coordinates the 22 federal agencies that have permitting roles in an Alaska gas pipeline project.

—PETROLEUM NEWS

ASSOCIATIONS

'Meet Alaska' draws more than 500

The Alaska Support Industry Alliance's annual conference, "Meet Alaska," drew 517 attendees Jan. 23 in Anchorage. Alliance General Manager Paul Laird told Petroleum News Jan. 28 that while it wasn't an all-time record, "I can say with a high degree of confidence that it's the highest in the past decade."

—PETROLEUM NEWS

FINANCE & ECONOMY

Arctic research funding applications due

Industry Technology Facilitator, a not-for-profit organization based in Aberdeen, Scotland, is inviting proposals from organizations seeking sponsorship for research, development and/or field trial projects that fall under the general theme of "Arctic challenge." Proposals must address technology for dealing with one or more of four Arctic issues: the harshness of the Arctic climate; the impact of ice; the sensitivity of the environment; and the remoteness of the location.

Projects must be innovative, demonstrate a clear business case to justify support and have a clear path to commercialization and implementation.

ITF says that it is "a recognized champion for innovation within the global oil and gas sector," with access to funds from major oil and gas operating and service companies that comprise its membership. Since 1999 the organization has supported 131 projects worth in excess of $38 million by delivering finance to help develop new initiatives for oil and gas technologies, ITF says.

Further information about ITF and the call for proposals, together with project application materials, can be found on the ITF Web site at www.oil-itf.com. Applications are due by March 16.

—ALAN BAILEY

UAF pushing to fast-track energy center

The University of Alaska Fairbanks wants to fast-track plans for building a $30 million center that can be used for energy research.

The university wants to build a 31,000-square-foot facility dedicated to studying the use of wind, hydrogen and even coal fired energy.

It would serve as the home to the 1-year-old Alaska Center for Energy and Power. The building sits on a short list of construction projects offered by the board of regents.

UAF Chancellor Brian Rogers said a new building with an energy technology-driven mission would follow up on pledges to assist the state's efforts in significantly expanding its use of renewable energy.

Just recently Gov. Sarah Palin accentuated that goal when she announced her wish for half of the state's electricity to come from renewable sources by 2025.

"Energy issues were already there, (as was) the need for more space" for research and testing, Rogers said of the school's decision last year to create the Center for Energy and Power. "I think it became more acute as energy issues came to the fore."

The plan calls for the university to sell bonds to finance half of the cost and secure the rest of the money from a state grant.

The board would also like to land a five-year grant that would link the energy center with the state-operated Alaska Energy Authority on state-backed research projects.

Researchers at the energy center already work in cramped quarters tucked away in a modular building not far from the campus' coal power plant.

The center is used to research and develop energy projects for statewide use. That includes analyzing hybrid wind-diesel power systems that could cut back rural communities' reliance on diesel.

The university's proposed construction budget has already been submitted to the Alaska Legislature for review.

—THE ASSOCIATED PRESS

● GOVERNMENT

Canada steps up Arctic OCS mapping

By GARY PARK

For Petroleum News

With only four years left in the race to lay claim to the Arctic Ocean seabed, Canada is gearing up for six months of mapping work by a team of federal scientists to determine how far the continental shelf extends into Canada basin, located north of the Beaufort Sea.

The activities are expected to start about mid-March and continue virtually non-stop until the start of fall, Jacob Verhoef, from Natural Resources Canada, told the Canadian Broadcasting Corp.

The leader of the Canadian effort, which is backed by C$109 million of federal government money, said a gradual buildup over the last two or three years will accelerate to maximum effort this year.

Under the United Nations Convention on the Law of the Sea, Canada has until 2013 to make its sovereignty claims, including control of vast areas rich in resources, such as minerals, oil and natural gas.

Although the United States has yet to ratify the United Nations treaty, it has collaborated with Canada on mapping work.

Canada signed the international treaty in 2003 and has been working with Denmark to map the Lomonosov Ridge near Ellesmere Island.

Three joint projects

That joint effort will now include three projects: one to map the seabed north of Ward Hunt Island; one to map an area in the Labrador Sea; and an aerial survey near Alert in Nunavut Territory.

In the process, scientists will test an autonomous underwater vehicle off Alert in April and hope to use two underwater vehicles in 2010 to map remote parts of the Arctic seabed.

The effort will also provide an opportunity to test new techniques that are evolving from satellite imagery.

Although the United States has yet to ratify the United Nations treaty, it has collaborated with Canada on mapping work.

About 200 researchers and coast guard personnel participated in that work last year aboard a Canadian icebreaker and U.S. Coast Guard cutter as they try to prove that their continental shelves extend beyond the 200 nautical-mile economic zone.

They fired more than 85,000 seismic pulses into the ocean and, according to Verhoef, gathered data "in areas we've never been before," reaching latitudes as far as 83 degrees north.

He said the preliminary data has yielded encouraging support for Canada's claims.

The two countries are now considering another joint mapping project north of Banks Island to focus on an underwater mountain chain called Alpha Ridge. ●

● EXPLORATION & PRODUCTION

Conoco hopes to drill Chukchi in 2011

Company bid on federal leases last year, now facing technical and environmental challenges, wants gas pipeline and fiscal stability

By ERIC LIDJI

Petroleum News

ConocoPhillips could start drilling exploration wells on its leases in the Chukchi Sea as early as two years from now, according to a senior executive with the company.

"We are gathering data. We hope to be able to drill in 2011," John Carrig, president and chief operating officer of ConocoPhillips, said at the Meet Alaska conference on Jan. 23.

JOHN CARRIG

In a federal lease sale last February, ConocoPhillips acquired a major land position in the waters off the northwest coast of Alaska, spending around $500 million for 98 tracts. The company ran two vessels through the region last summer to conduct early fieldwork.

The Chukchi Sea is considered to be among the most promising undrilled acreage in the world, but any explorer in the region faces both technical and environmental challenges.

The Chukchi Sea is remote, icy and hundreds of miles from existing processing facilities.

Previous wells in the Chukchi suggest tremendous gas potential, but any gas reserves remain somewhat stranded without a gas pipeline running from Alaska to the Lower 48.

"We all know that there are obstacles to exploration that are emerging. And, depending upon what's down there, it could all depend on the development of the (Alaska North Slope) gas pipeline, for it to be commercially viable."

—John Carrig, president and COO, ConocoPhillips

"We all know that there are obstacles to exploration that are emerging," Carrig said. "And, depending upon what's down there, it could all depend on the development of the (Alaska North Slope) gas pipeline, for it to be commercially viable."

Through a joint venture with BP, ConocoPhillips is trying to build a gas pipeline from Prudhoe Bay into Alberta. TransCanada is pursuing a similar project with state backing.

A large natural gas pipeline would alleviate the pressure to find oil, making explorers "somewhat indifferent to the product that they located in a hydrocarbon basin," Carrig noted. But even so, the added expense associated with the extremity of the Chukchi Sea guarantees that "the minimum economic field size… is quite large," Carrig said.

Other mounting obstacles

There are nontechnical challenges to drilling in the Chukchi Sea as well.

The region is a focal point of many environmental groups that worry about the impact drilling might have on polar bears in the region. Last year, the U.S. Department of the Interior listed the polar bear as a threatened species under the Endangered Species Act.

"Climate change is a risk for any oil and gas opportunities here in Alaska," Carrig said.

Carrig repeated a concern about fiscal stability. Investment in the Chukchi wouldn't yield returns for "at least 10 years," he said. ConocoPhillips doesn't want "things that were in your control," presumably taxes, "to change the day after the project is up and running."

Carrig also acknowledged a growing concern in Alaska: a weak Lower 48 gas market.

Carrig also acknowledged a growing concern in Alaska: a weak Lower 48 gas market.

"Some consider the Lower 48 to be a market of limitless demand. Well that's just not the case," Carrig said, pointing to increased drilling for unconventional gas last year. "That, I would say, is an unexpected supply injection into the Lower 48 oil and gas picture."

ConocoPhillips recently said it would reduce spending 20 percent and lay off around 4 percent of its global workforce in response to global economic conditions and low prices.

The company is drilling two wells in the National Petroleum Reserve-Alaska this winter. ●

Contact Eric Lidji at 907-522-9469 or elidji@petroleumnews.com

● GOVERNMENT

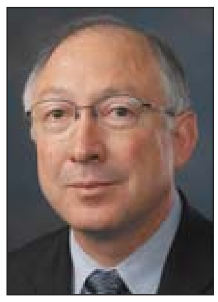
Salazar: Limits needed on OCS drilling

By DINA CAPPIELLO & H. JOSEF HEBERT

Associated Press Writers

Interior Secretary Ken Salazar said Jan. 27 the expansion of offshore oil drilling should be worked out with Congress as part of a broad energy blueprint and not independent action by his department.

In an interview with The Associated Press, Salazar indicated the drilling plan left on his desk by the Bush administration likely will be scrapped. It would open the entire Atlantic and Pacific coasts for drilling.


Interior Secretary Ken Salazar

Salazar declined to single out any waters considered automatically off limits to oil exploration.

"There are places that are appropriate for exploration and development and there are place that are not," Salazar said in an interview in his spacious and historic office, with a fire roaring in the fireplace beneath a full-length painting of George Washington.

Salazar, who resigned as Colorado senator to join President Barack Obama's Cabinet, said he wants to work closely with Congress on "a plan that makes sense" for offshore oil and gas development, but that any expansion of drilling should be part of a comprehensive energy plan.

Congress last year failed to renew the long-standing moratorium on oil and gas exploration across 85 percent of the nation's Outer Continental Shelf, leaving all waters potentially open to drilling. Congressional Republicans and energy lobbyists have argued against even a partial reimposition by Congress of an offshore drilling ban.

Bush administration left draft

Four days before leaving office, officials in the Bush administration issued a draft of a five-year drilling plan that calls for energy leases to be made available in both the Atlantic and Pacific waters, including vast areas that until recently had been off limits for a quarter century.

But Salazar indicated that plan is all but dead.

"It seems to me the appropriate place to address the OCS and issues like royalty reform would be in the context of an energy bill," said Salazar, referring to Outer Continental Shelf development and an overhaul of the way his department collects royalties from drilling in federal waters.

On other subjects during the interview, Salazar:

— Made clear that investigations into the gift and conflict-of-interest scandals at the Minerals Management Service that led to the firing of several people and disciplinary action against others is not yet resolved. He promised further reviews to determine if the investigations "led to the right actions."

— Cautioned against pushing too fast on oil shale development in Colorado, Wyoming and Utah until more is known about the impact on water resources and climate changed.

Oil shale extraction requires a lot of water that could strain the resources of the Colorado River and huge amounts of electric power that could impact climate change, he said. "We're going to have to be very thoughtful in the way it's going to be developed."

— Promised to review at least 10 "midnight regulatory actions" by the outgoing Bush administration, citing as examples regulations to limit the reach of the Endangered Species Act, oil shale permitting, and oil and gas permits issued near two national parks in Utah.

"I'm troubled by many of the midnight actions by the (Bush) administration. We'll take a look at them one at a time and make the right decision going forward," said Salazar.

Salazar, 53, who was among a group of Cabinet nominations confirmed unanimously on the day of Obama's inauguration, has been quick to make his presence known at the Interior Department. He addressed employees on Jan. 22 and the next day made a trip to the Statue of Liberty in New York City, a monument managed by the U.S. Park Service. On Jan. 27, he conducted separate interviews with a number of news organizations. ●

● FINANCE & ECONOMY

Eni CEO: Oil price bumps unprecedented

By DONNA ABU-NASR

Associated Press Writer

The head of the Italian oil company Eni SpA said Jan. 25 that the turbulence in oil prices is unprecedented and is "extremely bad news" for the industry.

Paolo Scaroni, CEO of Eni, told a panel at the Global Competitiveness Forum that the time is ripe for the oil industry to look for ways to ensure more stability.

"Our sector is no stranger to cycles," Scaroni said. "But the turbulence we are currently experiencing — with oil doubling in the nine months to July 2008 and then losing two-thirds of its value in the following six months — is unprecedented."

"It is also extremely bad news for an industry like ours, where a five-year view counts as short term," he added.

Oil prices reached highs of nearly $150 per barrel in mid-July before plummeting around 70 percent due to economic woes and shrinking demand. Three production cuts totaling 4.2 million barrels by the Organization of the Petroleum Exporting Countries have failed to provide lasting support to prices, which on Jan. 23 settled at $46.47 after a particularly volatile trading day.

Transparent reporting needed

Scaroni said that increasing stability requires several issues to be addressed. He said there should be a rapid, precise and transparent global reporting system for production, consumption and inventories.

"That will form the basis for authoritative forecasting and help prevent groundless alarmism from spooking the market," Scaroni said. OPEC officials had repeatedly attributed last year's run-up in crude prices to speculation, saying that they did not reflect supply and demand fundamentals.

"We also need to cooperate, in the interest of a price stability, which will benefit producers and consumers alike," he added.

In an interview with The Associated Press after the panel discussion, Scaroni said some complex projects in very deep waters and in difficult areas of the world "might be jeopardized at this level of oil price."

He said, however, that Eni and other companies are forecasting a long-term price of around $50, a level that he said is "certainly viable for conventional oil projects."

"Since projects develop their profitability in five, six or seven years, it's not really important what is the price of oil today. What is important is what is your forecast for the long-term," he said.

Concern over investment

Some analysts and oil officials have argued that the current low price of crude could undercut investment in projects, which may result in tight supply once demand rebounds.

see **OIL PRICES** *page 18*

continued from page 4

GAS DEMAND

Frank was involved in the first attempt to move Alaska North Slope gas in the 1980s and said in one way or another he's been involved in the project for 25 years and to him the "outstanding issue is stakeholder alignment and without it it's difficult to visualize this project going forward."

Role of gas shifting

Wood Mackenzie's Ed Kelly said he thinks the long-term position of natural gas in the energy marketplace is "shifting under our feet, really, right now," and expects demand for natural gas to grow more slowly than was once expected.

Kelly's presentation was entitled "demand deferred — long-term implications of economic recession on North American energy markets," and he said power-generation load growth plateaued at about 18 billion to 19 billion cubic feet, but the next plateau in natural gas use hasn't been reached "and we're probably going to take a couple of steps back as far as the use of natural gas ... before we take a step forward."

2018-19 is going to be about what 2012-13 was expected to be, with power demand growing and the U.S. forced "to bid into oil-linked world markets for marginal supply at about the time we might wish we had marginal supplies."
—Ed Kelly, vice president, Wood Mackenzie

A few coal plants are being completed and power use is down due to the weak economy.

And as the use of renewable sources of energy grows, "renewables are actually going to impact the level of gas," he said, absorbing some of the share that was assumed to belong to natural gas.

What will happen when we come out of the recession?

Gross domestic product growth rates in the United States have dropped from 2.9 percent in 2006 to 1.4 percent in 2008 and are expected to go negative, a minus 1.7 percent this year, before edging up in 2010 to 0.8 percent, 1.8 percent in 2011 and 2.5 percent in 2012.

"When and if we come out of this phase ... and normal economic growth rates do resume at some point and we get growth again ... let's say 2010, 2011 and things return to a more or less normal cycle of economic growth and investment, what then?" Kelly asked.

It will take longer than that for natural gas demand to pick back up.

Demand will pick up

While there have been reductions in natural gas drilling, Kelly said those reductions are in areas other than shale. Drilling in shales may not ramp up as quickly, he said, but shales are lower-cost to develop than other areas, so the 30 percent reduction in drilling expected in 2009 will be "from less productive areas into lower-cost and more productive areas such as the shales."

Shale production declines very quickly but has a long tail, so there is an extended plateau for unconventional Lower 48 production into 2018-19, he said, and "that's when demand is expected to pick up for natural gas."

Kelly said there will be a collision of an expected supply plateau "with demand growth resuming or accelerating for natural gas," assuming the economy grows at normal rates.

While natural gas isn't expected to be produced at potential rates until 2016-17, that is about when demand "might resume growing at a quick rate, about when LNG might not be so available on the world market ... (and) about then we start to need gas in a more significant way."

2018-19 is going to be about what 2012-13 was expected to be, he said, with power demand growing and the U.S. forced "to bid into oil-linked world markets for marginal supply at about the time we might wish we had marginal supplies."

There will come "a time at which the natural gas market grows again," Kelly said.

"But I'll tell you one thing: It doesn't grow as fast as it could have grown. Those renewables do make inroads."

While the place of natural gas in the long-term energy market in North America is more uncertain than a few years ago, in 2017-18 the U.S. "begins to need to bid into world markets, and whose world markets are oil-linked."

By 2017, Kelly said, competition for renewed growth in the natural gas market will be between marginal domestic supplies, imported LNG and "potentially frontier supplies" such as Alaska North Slope gas. ●

continued from page 17

OIL PRICES

But the Eni chief said it was difficult to anticipate whether that would indeed happen.

Asked about Libyan leader Moammar Gadhafi's comments earlier in January on the possibility of nationalizing the oil sector in response to low prices, Scaroni played down the prospect.

"We are always concerned when a country where we operate is talking about nationalization. I have the impression, just an impression, that this ... doesn't look like being a decision or a plan or something like that."

Some analysts said the remarks were just Gadhafi's unique way of calling attention to the difficulties producers face because of the global economic meltdown.

On Iraq, where Eni has recently submitted a bid to develop the Nasiriyah oil field, Scaroni said that country has the potential to produce 6 million barrels a day, up from current production of about 2.4 million barrels per day of crude.

Scaroni said his company's operations in Iran are proceeding normally despite U.S. efforts to tighten sanctions on that country to pressure it over its nuclear program.

"We are performing two contracts which we were assigned in 2001, much before any sanctions whatsoever," he said. "Since we've been awarded the contract we have to fulfill our obligations and nobody's been asking us not to do it, including the U.S. government." ●

Petroleum news

Oil Patch Bits

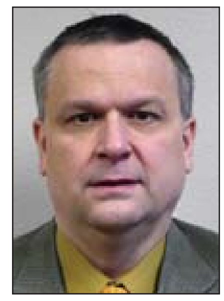
COURTESY UNIQUE MACHINE

Unique Machine builds new facility

Unique Machine is moving to a new location off King Street in Anchorage, where it is erecting three buildings on 13.6 acres to accommodate its operations, as well as to provide office space for lease. The development will be marketed as the "Alaska Technology Center," said Pat Hanley, Unique Machine's general manager. The largest of the three buildings will contain its general machine shop, office space and various CNC lathes and mills. The second will hold Unique Machine's full length threading plant, including a new Okuma LOC650 22-inch CNC lathe. The third building will be used for storage and material handling. A rail spur will be completed in the spring. Unique Machine, which operates 24/7, will begin phasing into the plant in March.

—See full story in the January 2009 Arctic Oil & Gas Directory

NAC names David Karp CEO



DAVID KARP

Anchorage-based Northern Air Cargo said Jan. 13 that David W. Karp has been named president and chief executive officer. Karp has served as the company's chief operating officer for the past three years. This represents the final step in a transition plan that has been in place since the purchase of NAC by Saltchuk in 2006. Karp will be responsible for the oversight of NAC and its subsidiaries which have about 320 employees in Alaska.

CGGVeritas awarded two new BP seismic contracts

CGGVeritas said Jan. 23 that it has been awarded two long-term seismic acquisition contracts by BP to undertake multiple high-end marine 3-D, wide-azimuth and 4-D seismic surveys. The first contract encompasses an Arctic Ocean exploration 3-D survey in the Canadian Beaufort Sea. This project is expected to commence in the summer of 2009. The second long-term contract comprises multiple wide-azimuth and 4-D reservoir management surveys in the Gulf of Mexico and is expected to start in early 2009. The total of these new contracts with BP is expected to reach $130 million. CGGVeritas is a leading international pure-lay geophysical company delivering a wide range of technologies, mainly to the oil and gas industry. For more information visit www.cggveritas.com.

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

continued from page 1

DRILLING

nation of 31 unit leases by DNR Division of Oil and Gas Director Kevin Banks. The companies appealed the decision to Irwin; there was a hearing Jan. 12-16.

Irwin said in his decision that the appellants — ExxonMobil was the operator at Point Thomson prior to termination of the unit; other major owners include BP, Chevron and ConocoPhillips — "offered at the hearing that they have unconditionally committed to drilling two wells on two leases, including initiating actual drilling this winter season," completing two wells by 2010 and beginning production from those wells by 2014.

He said he wasn't ruling on the other leases and issues in the appeal because the proceedings were not yet complete.

Irwin said in a Jan. 27 statement that he issued the interim conditional decision in response to testimony at the mid-January hearing "that if DNR issued the ice road permit by the end of this month," ExxonMobil and the other owners "would proceed with their drilling commitments during this winter season."

He said it was in the public interest to issue the ice road permit and process other necessary permits at this time, and said he was holding ExxonMobil to its "unconditional commitment, made under oath, to drill and produce from these wells." Failure to abide by those commitments "will result in the automatic termination of these leases according to the lease terms," he said.

ExxonMobil reviewing decision

ExxonMobil spokeswoman Margaret Ross told Petroleum News in a Jan. 27 e-mail that the company has received the decision and is reviewing it "and will respond accordingly."

"However, we are encouraged that the DNR has progressed the decision regarding Point Thomson leases and will grant the ice road permits allowing mobilization of the drilling rig," Ross said.

She said ExxonMobil also appreciates that DNR has indicated to other agencies that drilling will be permitted.

"This decision clears the way for construction of nearly 50 miles of ice roads needed to transport the drilling rig and associated equipment, materials, camps and personnel to the Point Thomson site," Ross said, calling it "good news for Alaska and especially for the 50 Alaskan companies and more than 200 people working at Point Thomson today."

She said ExxonMobil is "committed and ready to move forward with the Point Thomson Project."

Ice road permit to be issued

Kurt Gibson, deputy director of the Division of Oil and Gas, told Petroleum News late in the day Jan. 27 after the decision was issued that the ice road permit was prepared and would be issued the next morning.

The division will have to approve a plan of operations for drilling, but assuming Exxon is willing and able to comply with the decisions set out in the interim decision, that shouldn't be a problem, Gibson said.

"At this point the ball is kind of in Exxon's court," he said.

"They indicated if the ice road permit could be issued before the end of this month ... they could proceed with their winter drilling program," he said.

The final agency decision on the appeal of the lease terminations will be made after the hearing record has been closed. The hearing was continued to Feb. 12 to allow Irwin the opportunity to question witnesses who did not appear at the January hearing but presented testimony in writing.

Not a done deal

Irwin's conditional decision definitely has conditions.

"If Appellants provide the documents listed below, the record will be adequate to support reinstatement of the two leases and issuance of permits to authorize drilling of these two wells," he said in the decision.

Irwin said that if the companies can provide the listed documentation, he finds that ADL 47559 and ADL 47571 "have been extended by the drilling operations savings clause" because of the unconditional commitment to initiation of drilling this winter season, "including drilling a well out of the conductors with a rig capable of drilling through the Thomson Sands on that lease, and completing the drilling of two wells on these two leases, both penetrating the Thomson Sands reservoir, by 2010."

In addition, Irwin said in his decision, the companies mobilized equipment and materials to the North Slope to support their operations and "unconditionally committed to bring these two wells on the two leases into production by 2014."

ExxonMobil argued at the January hearing that Point Thomson unit leases were held by drilling operations work it initiated within 90 days of the termination of the unit last year, per the terms of the leases. That work included rig preparation, drill site preparation and installation of conductors through which the first two wells would be drilled.

Irwin said he directed that the ice road permit be issued and all permits pending before DNR necessary for drilling be processed. Local, state and federal agencies will be notified that Exxon is authorized to drill the two wells on the two leases, he said.

Requirements for reinstatement

When he terminated the Point Thomson unit last year Irwin said that given the history of the unit he did not trust the companies to go ahead with proposed work.

In the conditional interim decision he asks for financial commitments from the participants for work up to and including production and transportation facilities to meet the 2014 production date.

Irwin said that to make the conditional reinstatement of the two leases permanent, the companies must complete the two wells by 2010 and begin "sustained commercial production and transportation of hydrocarbons from these two wells on these two leases to market by 2014."

Agency approvals must be obtained for all of the work.

And answers and documentation requested during the January hearing must be provided within two weeks, "including the precise well locations, drilling dates and production dates for each well."

Irwin is also requiring, within two weeks, "a drill rig contract for each well, unconditional AFEs (authorizations for expenditure) for each well signed by all parties, an AFE for the production infrastructure, and affidavits from each Appellant stating its willingness to pay its share of the costs for each well and for the production infrastructure."

The companies told Irwin at the mid-January hearing that funds were authorized for 2009 work and said money would be available when needed for additional wells and facilities work.

The commissioner wants those commitments formalized now. ●

Petroleum News Oil Patch Bits

Duoline promotes Tim Stewart to FRP supervisor


TIM STEWART

Duoline Technologies, an industry leader in solving oilfield corrosion problems through innovative products and services, said Jan. 22 that Tim Stewart has been promoted to FRP supervisor. Stewart, initially hired as a material handler, later worked as an engineering technician and will now fill the role of FRP supervisor. Prior to joining Duoline, Stewart attended Tarleton State University and served in the United States Army; he has more than 15 years' experience in retail management and warehouse distribution. For more information about Duoline products or services visit ww.duoline.com.

CH2M Hill provides water to United Arab Emirates

CH2M Hill, a global full-service engineering, procurement, construction and operations firm said Jan. 19 that it had delivered design, construction and commission services to the Sharjah Electricity and Water Authority for two seawater reverse osmosis or, SWRO, desalination plants in the United Arab Emirates. A third desalination plant for the authority is currently under construction and is expected to be online by mid-2009. CH2M Hill has provided all of the engineering, procurement, and construction services for the three new plants, which will provide more than 16 million gallons per day of high-quality desalinated water to the people of Sharjah. The firm, a leading employer, was named one of the 100 best companies to work for and one of America's most admired companies by Fortune magazine 2008. For more information visit www.ch2mhill.com.

Editor's note: Expanded versions of these news items will appear in the next Arctic Oil & Gas Directory, which will be released in July. The one exception is the Unique Machine brief. It appeared in the January 2009 directory.

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RIG TECHNOLOGY

DC, to power and control a DC electric motor drive.

"It was a new way to distribute and manage power in a rig more efficiently," Korach said. "For years SCR rigs were the backbone of the drilling industry and they still are today."

But with advances in microprocessing and computers, AC drive technology has started to come into use. An AC motor is much less susceptible to sparking than a DC motor, Korach said.

And, unlike a DC motor, an AC motor can be stalled or locked without burning out.

"This key difference opens up a whole new world for drilling with new features," Korach said.

The motor can now be used as a drilling brake. Then by inputting parameters such as pipe weight, mud pressure, mud flow and safety limits to a computer that is hooked up to the motor, the drillers can exert a heightened level of control over the drilling operation.

"Nabors started developing this technology in the mid-'90s … and in early 2000s started doing it for the (rig) drawworks," Korach said. "… Nabors was the first to introduce AC technology to Alaska with (Rig) 19AC."

Mobile exploration rigs

In 2007, Nabors designed and built two mobile AC exploration rigs — Rigs 105 and 106, Korach said. Anadarko has been using Rig 105 to explore in the Brooks Range foothills, while Chevron has been using Rig 106 for its White Hills exploration south of Prudhoe Bay.

"These rigs are equipped with the latest AC technology top drives and are fully winterized for high Arctic conditions," Korach said. "These rigs are designed to rig down to 35,000-pound loads and are re-assembled in the minimum of time."

The rig modules can be carried by hel-

see RIG TECHNOLOGY page 24

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IN-STATE GAS

"I think the competition on the in-state side is great," Harold Heinze, chief executive officer of ANGDA, told members of the Senate Resources Committee on Jan. 21.

ANGDA is working on a pipeline between the Beluga power system, west of Anchorage, and Fairbanks. The line would ideally connect to larger pipeline headed to the Lower 48.

The project is in competition with a bullet line promoted by Enstar that would run from the Gubik gas field in the north through Fairbanks and down to the Beluga power plant.

Last summer, Palin announced a partnership between the two groups. Heinze said he thinks a public-private partnership is the best way to advance the project, but admitted that the two sides have failed to work together in the months since the announcement.

Enstar believes the circumstances have changed since summer. In its ongoing search for supplies, the company is finding it harder to get long-term contracts, according to George Schreiber, president and CEO of Continental Energy Systems, Enstar's parent company.

"Our thinking has changed dramatically. We're going to have to get gas from the north to bring south because gas in the inlet is just not there," Schreiber told the committee.

Enstar is pushing forward on a "bullet line" that would connect a northern gas supply, like the Gubik field near Umiat, directly to markets in Fairbanks and around Anchorage.

Enstar believes it has funding for the $4 billion project. But while Enstar isn't asking the state for financial help, Schreiber said the company needs "a governmental framework that promotes private sector investment" and "predictable and fair market prices for natural gas." For years, Enstar has battled with state regulators over natural gas prices in Alaska.


JUDY PATRICK
GOV. SARAH PALIN


SARAH HURST
REP. JAY RAMRAS

Although confident, Enstar still isn't completely sure that the natural gas reserves at Gubik can support the project. And even if the supply is proven, Enstar would need large industrial anchors to moderate shipping rates and make the gas affordable for customers.

Those anchors include the Agrium fertilizer plant coming back into operation, the Kenai liquefied natural gas facility exporting at capacity and the natural gas grid in Fairbanks being fully expanded, thereby nearly doubling residential gas demand along the Railbelt.

A push for gas by 2014

Thinking along similar lines, Rep. Jay Ramras, a Fairbanks Republican, sponsored four interconnected resolutions designed to get a bullet line sanctioned by November 2010.

The resolutions ask the governor to work toward getting a supply commitment of 180 billion cubic feet per year, reopening the Agrium plant and expanding the LNG facility.

In her annual State of the State address on Jan. 22, Palin said she would introduce legislation in February to facilitate "a smaller, in-state gas line" that could deliver 460 million cubic feet per day of natural gas to markets in Alaska within the next five years.

Palin did not offer further details and several questions remain outstanding, including the source of natural gas for the pipeline, the entities responsible for building and operating the pipeline, how the pipeline will be funded and the route it would take through the state.

Under the terms of the Alaska Gasline Inducement Act, the state cannot give funding or preferential tax and royalty treatment to a pipeline carrying more than 500 million cubic feet per day.

TransCanada and Denali, the sponsors of competing proposals to build a gas pipeline from Prudhoe into Alberta, both told lawmakers recently they plan to complete separate studies of the natural gas needs of Alaska, a required document for any major pipeline.

Worries persist in Fairbanks

An in-state gas pipeline would solve different problems in different parts of the state.

In Anchorage, a pipeline would offset declining Cook Inlet fields, but in Fairbanks it would offer an alternative to diesel fuel, which strained household budgets this summer when oil prices spiked, and would also help the city meet federal air quality standards.

A task force in Fairbanks came together last year to assess the options on the table.

In a draft of its findings released on Jan. 23, the group calls the ANGDA spur "fatally flawed," saying there isn't enough gas in Cook Inlet to ship north and Fairbanks can't wait for a pipeline from the North Slope to join up with the spur sometime around 2018.

The task force also expressed concern about the Enstar line. In addition to questions about sufficient supply and adequate demand, the report worries about the route.

First, any pipeline running along the Parks Highway, as preferred by Enstar, would need permission to pass through several parks, including Denali National Park and Preserve.

Second, the task force worries about Enstar's plan to run its pipeline 40 miles west of Fairbanks and connect to the city with a lateral line, which could increase the cost of gas.

Return of the All-Alaska line

A recurring theme over the first week of the session has been the growing concern over weakening natural gas markets in the Lower 48, as a recession crimps demand for fuel after a year of increasing production and the future promising more unconventional gas.

On the back of that emerging dynamic, the Alaska Gasline Port Authority testified before a Senate committee about liquefying North Slope natural gas and shipping it overseas.

As gas prices topped $13 per thousand cubic feet last summer, companies took interest in unconventional gas plays, like the Marcellus Shale running from West Virginia to New York, said Bill Walker, general counsel and project manager for the Port Authority.

"We're glad that Alaska has multiple options," Walker told members of the Senate Resources Committee on Jan 21. "We think that LNG makes an abundance of sense."

The Port Authority wants an All-Alaska line running from Prudhoe Bay to Valdez, where gas would be liquefied and shipped overseas, or possibly domestic markets in the future.

The LNG facility on the Kenai Peninsula is the only export facility in North America.

Sen. Hollis French, D-Anchorage, said the "hang-up" facing the LNG option in the past has been getting permission from the federal government to ship American gas overseas.

> *"Our thinking has changed dramatically. We're going to have to get gas from the north to bring south because gas in the inlet is just not there."*
> **—George Schreiber, president and CEO of Continental Energy Systems**

"But now I'm sitting here wondering whether the recent discoveries of large volumes of natural gas in the Lower 48, while they seem to be an impediment to our big line to the Midwest, may not provide an opportunity for us to revisit the political difficulty of shipping our gas overseas," French said.

Walker said the concern behind exporting is whether American need is being met by its supply. If the shale estimates turn out to be accurate, that would no longer be a problem.

Plus, Walker said, LNG contracts can be designed to be "interruptible," meaning a tanker setting out for Asia could be diverted back to America in the case of an emergency.

LNG obstacles

But LNG still faces many obstacles.

First, the high prices that drove companies to explore shale last summer have fallen.

"The question is: How will that effect the shale gas?" Walker said.

Another problem is competition. A planned LNG import facility in Kitimat, British Columbia, is now planning to export instead to serve markets along the Pacific Rim.

During a special session last summer, the liquefied natural gas option seemed dead, as legislative economists said it wouldn't yield returns as high as those on a highway route.

But before summer ended, the Port Authority got several breaks.

First, lawmakers mentioned the LNG option in legislative intent passed alongside AGIA. Then, Palin issued an order promoting the LNG option. Finally, TransCanada said it would pursue an LNG project if enough shippers preferred it to a highway route.

Those measures allowed the Port Authority to progress partnerships with Mitsubishi Corp., a major supplier to Asia, and Sempra, which owns an import terminal.

Since the summer, the Port Authority has been in talks with the Office of Hawaiian Affairs, a Native group, about possible shipments to Hawaii, and continues to work on cost estimates of its All-Alaska pipeline in preparation for possible open seasons in 2010. ●

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SUNCOR

assets.”

That represents the previously unthinkable for a company that, 40 years ago, led Canada into the age of commercial oil sands production and has taken great pride in what it has accomplished through growth, technological innovation and reduction of its greenhouse gas emissions, while building an impressive reputation for its treatment of employees.

George, who never hesitates to deliver a clear, unequivocal message in conference calls with analysts and investors, was more direct than usual on Jan. 20 in painting a picture of what he called a “very tumultuous time.”

“We just don’t know how long this (price) trough will last, when we’ll see the commodity cycle start moving back and when we’ll see oil prices, for example, move back up.

“We do know it will occur. We just don’t know when. For prudence, we decided to cut to a C$3 billion budget.”

Bracing for $40 oil

Chief Financial Officer Ken Alley said Suncor is bracing itself for oil prices of about US$40 per barrel.

George was emphatic that the Voyageur and Firebag projects will be built, adding “it’s just a matter of when.”

But he also made it clear the strategy will be different when work resumes.

“What you can expect from us is that we’ll no longer talk about Voyageur as a big, C$20 billion project. When we restart these, we’ll restart them one project at a time,” he said.

That, he said, will be a “time when we feel we have better control of our costs and when we can fund it without doing any stress to our balance sheet.”

The surprise for analysts was George’s disclosure that Suncor is “open for business,” by trading an equity stake in the Voyageur upgrader for investment and is talking to other companies about processing their bitumen for a fee.

What Suncor won’t consider is selling any of its oil sands reserves.

“There is so much value in owning reserves,” he said. “That is the core of why Suncor exists today and we’re not giving up on them.”

Focus on two things in ‘09

In retreating from its original spending program and allocating only C$1 billion this year on growth projects and C$2 billion on sustaining work, Suncor will concentrate on two things in 2009, rather than bemoaning the low crude oil price environment, George said.

Taking a glass-is-half-full approach will see Suncor work on: operational excellence, which “is getting the most out of the assets we have on the ground” by hiking production this year to 300,000 bpd from the oil sands, from last year’s 228,000 bpd, which was constrained by planned and unplanned maintenance; and cutting costs.

“This is a time of great uncertainty,” he said. “It’s also a time of opportunity. For us, it’s a time to focus on costs … and we’ll get our entire workforce engaged.

“We will face a period where we have much less competition for human resources, internally and externally.

“And I think the industry in general will find growth on a go-forward basis will be much easier to manage, with much more predictability.

“For the first time in almost a half a dozen years, we have the opportunity to go out and gain significant control over our costs — both on an operating basis and a construction basis,” he said, adding there have already been signs that contractors and suppliers are open to reviewing costs.

> *“What you can expect from us is that we’ll no longer talk about Voyageur as a big, C$20 billion project. When we restart these, we’ll restart them one project at a time.”*
> **—Suncor Energy CEO Rick George**

Hughes leaves Husky

Another telling announcement got much less attention, when Husky Energy lost the head of its oil sands operation after less than two years on the job, raising speculation that its C$10 billion, 200,000 bpd Sunrise project (part of a joint venture with BP) could be destined for the shelf.

Catherine Hughes, who joined Husky in 2005 after running Schlumberger’s Canadian operation and was later promoted to vice president of oil sands, took her leave after the company consolidated its oil sands and heavy oil business units.

Husky has already announced spending on Sunrise this year will be cut by 78 percent to C$65 million, but is not expected to disclose the future of the project until its fourth-quarter results are released Feb. 4.

In the meantime, the company will say only that Hughes left of her own accord to “pursue other options.”

Trickle-down effect

The trickle-down effect of Suncor’s budget contraction is turning into a cascade for some Canadian companies.

Two Alberta-based companies alone figure their revenues will be cut by C$180 million.

Flint Energy Services, which provides production services, field construction, process equipment design and manufacturing, expects to lose C$100 million to C$150 million in 2009 cash flow, resulting in immediate layoffs of construction workers at Firebag 3, with more to come later.

Edmonton-based Lockerbie & Hole said Suncor’s pullback will defer C$35 million in revenues it anticipated in 2010.

Flint said it will continue working on other oil sands projects, including the Shell Albian Sands’ expansion, Suncor’s Firebag sulfur plant and StatoilHydro’s Leismer project, noting its facility infrastructure division had an C$800 million backlog of work at the end of 2008.

Flint President Bill Lingard said his company hopes “this is a short run postponement” of Suncor’s projects, adding “We are confident that oil sands development will continue, albeit at a reduced pace.”

Although not directly tied to Suncor, steelmaker Evraz Group confirmed it is laying off 400 employees across Western Canada — 295 in Alberta — because of the slumping demand for steel plates and tubes, largely for the oil and gas sector.

Drop in drilling forecast

Calgary-based investment dealer Peters & Co. captured the difficult year ahead for the service sector by forecasting that only 14,500 wells will be drilled in the Western Canada Sedimentary basin and only C$15 billion will be spent on drilling, casing and completion work.

Because of the struggle with restricted access to credit and low commodity prices, Peters & Co. said the majority of operators it covers have planned 2009 capital programs that match their declining cash flow.

As a result, strong balance sheets, proven management teams and exposure to resource plays will be crucial to the survival of service companies, it said.

Gil McGowan, president of the Alberta Federation of Labor, said that although a number of projects are still on the go, the big concern is what will happen when they are finished.

“At this point there is absolutely nothing on the horizon to replace what’s currently under construction,” he told the Globe and Mail. “We’re currently in what I would describe as the afterglow of the boom. The boom itself is over, but the day of reckoning has yet to arrive.”

The Construction Owners Association of Alberta forecast last October that by the second quarter of 2010, 43,000 workers would be needed for 70 projects each carrying a price tag of more than C$100 million. The spending cuts since then have halved that number.

An association spokesman said the message should be a “very sobering” one for industry and government as they face a sharp decline in demand for heavy industrial labor.

Trickledown of 5 to 1

The Canadian Energy Research Institute has calculated that every dollar spent on major oil projects results in $2.50 of trickledown spending in Alberta and another $2.50 in the rest of Canada. Thus, every $10 billion decline in direct energy spending translates into about $60 billion of lost economic activity across Canada.

John Tasdemir, an oilfield service analyst at Tristone Capital, said he expects companies will see earnings decline this year by 50 percent to 80 percent from 2008, leading to bankruptcies.

Compounding his assessment is the fact that shallow drilling that was once Canada’s bread and butter is drying up and disappearing as the industry turns more to horizontal drilling and selective multiple fracture stimulation — wells that are much more expensive to drill and take much longer to drill.

The average time needed to complete a well in Western Canada is up 22 percent since 2002 and 10 percent since 2006, a Peters & Co. report noted.

Even if crude oil prices rebound, the firm believes additional funding will be diverted to international properties.

Andrew Bradford, head of Canadian energy research at Raymond James, is less pessimistic, but still expects earnings to drop 25-30 percent for larger, more mature companies, while noting that 2008 “wasn’t any great shakes either.”

What hasn’t been widely anticipated is just how sharply field activity has already slumped, he told the Financial Post.

An irony in the midst of this gloom occurred during a mid-January weekend when 20 environmental activists and residents from the Athabasca Chipewyan First Nation of northern Alberta, which blames the oil sands for high cancer rates and the destruction of wildlife and fish, took lessons in how to create a human blockade to block oil sands development.

It was one of several seminars being offered as part of a conference hosted by organizations such as Greenpeace, the Sierra Club of Canada and the nationalist Council of Canadians. ●

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RIG TECHNOLOGY

icopter, Rolligon or truck, but the rig can also be moved in larger pieces for rapid transit where there is an appropriate road infrastructure.

"They can get out earlier than the standard rig and can leave later in the drilling season," Korach said.

The rig operator works inside an air-conditioned cab with a clear view of the rig floor. The operator controls the drilling operation using a joy stick connected to the computer-based control system.

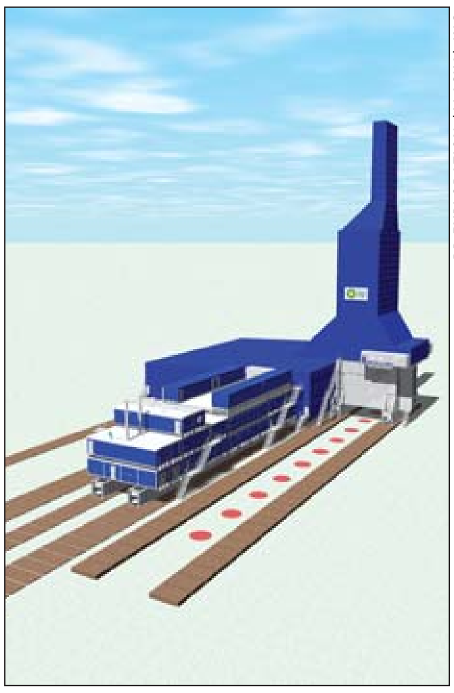
"The computer assists and limits the driller from operating the rig beyond its design specifications, (thus) decreasing down time and accidents," Korach said.

CDR2

Nabors is about to transport to Alaska a new AC powered rig, the CDR2 rig, for coiled tubing drilling and conventional drilling. Coiled tubing drilling, which is typically used to drill sidetrack wells from existing well bores, uses a long length of flexible tubing rather than conventional drill pipe.

"Our experience with AC technology and coiled tubing really allowed us to design and build a new lightweight, state-of-the-art AC hybrid coiled tubing rig for Alaska," Korach said. "We have worked closely with ConocoPhillips to incorporate new innovations."

And for the drilling that ExxonMobil plans in the Point Thomson field, Nabors has modified its Rig 27E to meet the demands of deep drilling into the hot and exceptionally high-pressure Point Thomson gas and condensate reservoir.



BP EXPLORATION (ALASKA) INC.

Parker Drilling Co.'s massive rig for BP's Liberty project will enable the drilling of record-breaking ultra extended reach wells. A specialized AC powered 1,250-ton top drive will deliver the massive torque required to turn several miles of drill string.

Fabrication for the upgrade started in June 2008 with an eventual cost of $40 million, Korach said.

"We are happy to report that we will be ready to mobilize the rig as required this Wednesday," he said.

The rig is rated at 9,600 horsepower, as compared with the 3,000 horsepower of a typical Prudhoe Bay rig, while the hoisting capacity, mud capacity and blowout preventer rating of the rig are all around double their more usual values.

Growth opportunities

Joey Husband, Alaska general manager for Parker Drilling Co., talked about how new drilling rig technologies are providing new growth opportunities for Arctic oil and gas drilling. Parker Drilling is returning to Alaska after a 10-year absence.

New technologies reduce drilling costs, thus enabling new drilling possibilities, Husband said.

"The technology today actually allows us to drill the same or more footage with less rig," Husband said. And the reduction of the drilling footprint as a consequence of directional drilling from a single rig at a single drill site reduces the environmental footprint.

But new drilling opportunities involve an increasing number of stakeholders. For example, Parker Drilling hires where it works, to develop the local workforce, Husband said.

"The community is a stakeholder in what we do," Husband said.

And then drilling success trickles through to increased economic activity and jobs for many people.

Alaska origin

Much Arctic drilling rig technology originated in Alaska in the late 1960s during exploration on the North Slope, Husband said.

"A lot of the technology was focused on mobilizing rigs from remote locations," Husband said.

Technologies for air lifting rigs to the slope were developed, for example.

Subsequently people developed wheel or other move systems to reduce rig move times. Then came techniques such as the use of offshore gravel islands.

While rig development continued in Alaska, Arctic rig technology such as rig winterization migrated from Alaska to regions like the Caspian Sea and Siberia.

Oil developments on Russia's Sakhalin Island then saw a wave of new rig innovations, including rigs that could withstand earthquakes and new offshore platform designs. And innovations in places like Alaska and Sakhalin have led to a worldwide network of new drilling rig technical knowledge.

Liberty rig

Parker Drilling has been able to use its Sakhalin experience to migrate new extended-reach drilling rig technology back to Alaska to build a rig for BP's Liberty project, Husband said. BP is planning to use record-breaking extended-reach wells to develop the Beaufort Sea Liberty field from an existing drilling island at the Endicott field.

The massive Liberty drilling rig requires huge quantities of drilling pipe, extreme drilling torques and the capacity to move vast quantities of drilling fluids, Husband said.

To avoid the need for an unrealistically large rig substructure, the rig design will enable the horizontal assembly and storage of stands of drill pipe, offline from the drilling operation. A specialized 1,250-ton top drive will deliver the required torque to the drill string from a 239-foot mast. Four 2,200-horsepower mud pumps will handle the hydraulics. All equipment is AC powered.

Parker Drilling is also building two new specialized Prudhoe Bay three-module infield rigs, called Alaska Arctic drilling units, for use by BP. The new design pays special attention to rapid rig moves, efficient pipe handling and dealing offline with activities such as blowout preventer handling, Husband said.

The rigs will use AC powered equipment. Specially designed wheel arrays will distribute the module weights at fast move speeds, and cantilevered blowout preventer and riser systems will eliminate the need to remove well houses. The command unit for each rig will be onboard, thus eliminating the need to wire up a separate control unit and minimizing the rig's footprint on the drilling pad. Stands of drill pipe can be assembled offline.

"We believe that with this technology and the right crews we will be able to improve on what is a very good performance today … on the slope," Husband said.

In both its Liberty and Prudhoe Bay rigs Parker Drilling has taken a fresh look at drilling hazards, Husband said. By engineering hazards out of the rig operation, the company can improve its safety performance, he said. For example, remote controlled derrick handling eliminates the need for someone to work at height within the drilling derrick.

Arctic Learning Center

And to develop personnel resources Parker Drilling is commissioning an Arctic Learning Center in Anchorage, Husband said. The center will provide operational support for Parker Drilling's customers, will provide training, including safety training, and will act as a repository for information about drilling technology.

"We also have equipment commissioned … to simulate critical safety equipment … and the drilling equipment on the rigs themselves," Husband said. "… Instead of people having to go out for the first time and run equipment on a rig that's been built for the first time in the industry, we get them on simulators."

Parker Drilling also plans to open up the center for general use by industry in Alaska, Husband said.

"This is Parker's commitment to its return to Alaska," he said.

—ALAN BAILEY