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page 5 USGS Greenland assessment adds to understanding of Arctic reserves

North Slope gets third operator

PIONEER NATURAL RESOURCES ALASKA

An August 2007 aerial view of Oooguruk Island, a six-acre gravel pad Pioneer Natural Resources built offshore Alaska in the Beaufort Sea. The company recently brought the Oooguruk unit online. See story on page 12 of this issue.

Icebreaker LNG carriers for Arctic Alaska gas an interesting but challenging concept

An April announcement by the American Bureau of Shipping about a joint initiative between the bureau and the Russian Marine Register of Shipping to jointly develop classification rules for Arctic LNG carriers raises an interesting question. Could emerging technologies for icebreaking LNG carriers provide an alternative to a pipeline for exporting gas from Arctic Alaska?

In November Petroleum News reported on a revolutionary new icebreaker design, known as a double-acting system, in which a vessel carves its way in reverse through pack ice, propelled by diesel-electric powered propellers mounted on rotatable pods under the stern. The propellers break up the ice, thus enabling the ship to move through the ice more efficiently astern than forward. In open water the stern pods rotate 180 degrees to

see **LNG CARRIERS** *page 24*

Reports that Gazprom is angling to join Alaska gas pipeline projects (as yet) unconfirmed

RUSSIAN NATURAL GAS MONOPOLY OAO Gazprom is angling for a role in a proposed Alaska gas pipeline, The Associated Press reported June 7.

AP quoted Gazprom Director Alexei Miller as saying Gazprom has made a proposal to BP and ConocoPhillips, which in April announced plans for a multibillion-dollar pipeline that would carry natural gas from Alaska's North Slope to the Lower 48.

see **INSIDER** *page 21*

BREAKING NEWS

EXPLORATION & PRODUCTION

Blowdown a loss

State: Producing Point Thomson gas first would mean 500M fewer barrels

By KRISTEN NELSON
Petroleum News

Everyone seems to expect that gas from Point Thomson will be part of what initially fills a gas pipeline taking North Slope natural gas to market.

But Point Thomson, some 60 miles east of Prudhoe Bay, has both oil and gas, and Point Thomson oil has never been produced.

Blowdown at Point Thomson — producing the gas without producing liquids first, the quickest way to get gas into a North-Slope-to-market line — could result in a loss of hundreds of millions of barrels of oil when compared to production with gas cycling.

That is the conclusion of a study commissioned by the Alaska Department of Natural Resources Division of Oil and Gas.

Chopra said geologic models indicate gas in place at Point Thomson is 8.5 trillion to 10.4 trillion cubic feet, with associated condensate of 490 million to 600 million barrels and a potential oil rim of 580 million to 950 million barrels. Point Thomson could be "the third-largest oil field" on the North Slope, after Prudhoe Bay and Kuparuk, he said.

"A gas blowdown scenario could recover over 500 million barrels less than a gas cycling

see **BLOWDOWN** *page 23*

LAND & LEASING

Thomson decision confirmed

Irwin sticks with April termination of PTU unit; Exxon still plans to drill

By KRISTEN NELSON
Petroleum News

DNR Commissioner Tom Irwin

Alaska Commissioner of Natural Resources Tom Irwin is standing by his April decision to terminate the Point Thomson unit and backing it up with a 25-page decision providing DNR's perspective for the benefit of a reviewing court.

The major owners at the former Point Thomson unit — Exxon Mobil Corp., BP Exploration (Alaska), ConocoPhillips Alaska Inc. and Chevron U.S.A., along with one of the minority owners, Leede Operating Co. — asked for reconsideration of Irwin's April 22 decision rejecting a proposed 23rd plan of development for Point Thomson.

The unit was terminated in late 2006, a decision upheld in Alaska Superior Court in early 2008, although Judge Sharon Gleason remanded the decision to the department so that the former unit owners would have an opportunity to suggest an appropriate remedy for their failure to submit an acceptable plan of development.

In February the owners proposed a 23rd plan of development as a remedy, including dates for drilling to begin on a small-scale gas cycling project to test the feasibility of such development and the department held a hearing on the proposed remedy.

The previous plan, the rejection of which led to

see **DECISION** *page 18*

LAND & LEASING

Canada's Beaufort wakens

Record bidding indicates majors turning to Arctic frontier; greens anger locals

By GARY PARK
For Petroleum News

Northwest Territories Premier Floyd Roland

As global oil giants ExxonMobil and BP jostle for position in the Canadian Arctic waters, pledging record amounts to lock up exploration rights, they also seem to be moving inexorably to a head-on clash with environmentalists.

Whether they have their sights set on oil or natural gas or both, the two companies have made record work commitments totaling almost C$1.8 billion — 25 percent of that already paid over in work deposits — to expand their presence in the Canadian portion of the Beaufort Sea, led by BP which made winning bids of C$1.18 billion for one 500,000-acre block, C$15.1 million for 507,000-acre parcel and C$1.1 million for rights to 503,000 acres.

The rush over the past two years into Canada's northern frontiers has stunned industry observers and awakened opposition in the environmental world.

Co-venturers Imperial Oil (69.6 percent owned by ExxonMobil) and ExxonMobil Canada brought the Beaufort out of its prolonged slumber in 2007 by risking C$585 million for 508,000 acres in the

see **CANADA'S BEAUFORT** *page 22*

contents

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

Alaska - Mackenzie Rig Report

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

Alaska Rig Status

North Slope - Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Akita Drilling Ltd.			
Dreco 1250 UE	63 (SCR/TD)	Moving to Alberta	Available
Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Prudhoe Bay C-19B	BP
Sky Top Brewster NE-12	15 (SCR/TD)	Kuparuk 3C-17	ConocoPhillips
Dreco 1000 UE	16 (SCR/TD)	Prudhoe Bay DS6-15	BP
Dreco D2000 UEBD	19 (SCR/TD)	Alpine CD2-464	ConocoPhillips
OIME 2000	141 (SCR/TD)	Kuparuk warm stack	ConocoPhillips
TSM 7000	Arctic Fox #1	Stacked in Yard	Pioneer Natural Resources
	Arctic Wolf #2	Stacked in yard	FEX
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Stacked, Prudhoe Bay	Available
Dreco 1000 UE	2-ES	Prudhoe Bay DS 02-08	BP
Mid-Continental U36A	3-S	Milne Point MPL-13	BP
Oilwell 700 E	4-ES (SCR)	Prudhoe Bay GPB A-13	BP
Dreco 1000 UE	7-ES (SCR/TD)	Prudhoe Bay PBU B-37	BP
Dreco 1000 UE	9-ES (SCR/TD)	Prudhoe L-205	BP
Oilwell 2000 Hercules	14-E (SCR)	Stacked	Available
Oilwell 2000 Hercules	16-E (SCR/TD)	Stacked	Available
Oilwell 2000	17-E (SCR/TD)	Stacked, Point McIntyre	Available
Emsco Electro-hoist -2	18-E (SCR)	Stacked, Deadhorse	Available
Emsco Electro-hoist Varco TDS3	22-E (SCR/TD)	Stacked, Milne Point	Available
Emsco Electro-hoist	28-E (SCR)	Stacked, Deadhorse	Available
OIME 2000	245-E	Oliktok Point OPi2	Anadarko
Emsco Electro-hoist Canrig 1050E	27-E (SCR-TD)	Stacked	Brooks Range Petroleum
Academy AC electric Canrig	105-E (SCR-TD)	Stacked on ice pad at Chandler #1	Anadarko
Academy AC electric Canrig	106-E (SCR/TD)	Stacked	Chevron
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Prudhoe Bay DS 15-18A	BP
Superior 700 UE	2 (SCR/CTD)	Kuparuk well 1D-04A	BP
Ideco 900	3 (SCR/TD)	Kuparuk well 1D-122	ConocoPhillips

North Slope - Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Nabors Alaska Drilling			
OIME 1000	19-E (SCR)	Oooguruk ODSN-40	Pioneer Natural Resources
Oilwell 2000	33-E	Stacked	BP
Kuukpik	5	Preparing to mobilize to Tyonek platform	ConocoPhillips

Cook Inlet Basin – Onshore

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

Cook Inlet Basin – Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Unocal (Nabors Alaska Drilling labor contractor)			
Not Available			
XTO Energy			
National 1320	A	Platform A no drilling or workovers at present	XTO
National 110	C (TD)	Idle	XTO
Chevron			
		Grayling Platform G-15RD	Chevron

Mackenzie Rig Status

Canadian Beaufort Sea

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

Mackenzie Delta-Onshore

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

Central Mackenzie Valley

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Akita/SAHTU			
Oilwell 500	51	Staged on Bear Island	Imperial oil

The Alaska - Mackenzie Rig Report as of June 12, 2008.
Active drilling companies only listed.

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

This rig report was prepared by Alan Bailey

JUDY PATRICK

Baker Hughes North America rotary rig counts*

	June 6	May 30	Year Ago
US	1,886	1,877	1,760
Canada	218	176	226
Gulf	64	65	78

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

● LAND & LEASING

BRPC picks up three Gwydyr Bay leases

Covers Pete's Wicked oil prospect discovered by BP in 1997, passed on by Pioneer Natural Resources, adjacent to other BRPC leases

By ERIC LIDJI
Petroleum News

Looking to expand its land holdings at Gwydyr Bay, Brooks Range Petroleum Corp. recently acquired 5,120 acres on three state leases on the coast of the North Slope.

On behalf of a four-company joint venture, BRPC acquired the land on June 6 from Pioneer Natural Resources, which owned a 100 percent working interest in the leases.

The three leases — ADL 390425, ADL 390426 and ADL 390427 — sit on the northern border of the Prudhoe Bay unit and expire on April 30, 2011.

The new acreage is adjacent to a 45,598-acre block of leases already owned by the joint venture, which includes TG World Energy, Bow Valley Alaska Corp. and the Nabors subsidiary Ramshorn Investments Inc. in addition to BRPC.

That joint venture was one of the busiest explorers on the North Slope this winter, re-drilling one well, spudding a second well and drilling a pair of sidetracks, in addition to commissioning a seismic survey.

The new leases sit due east of the North Shore No. 1 exploration well the company started last winter and re-drilled this winter. The new leases also cover an area of land included in a 3-D seismic survey the joint venture acquired last year.

The joint venture has talked in the past about drilling a North Shore No. 2 exploration well in the Gwydyr Bay region.

Leases near Pete's Wicked No. 1

The new leases sit over the bottom hole of the Pete's Wicked No 1 exploration well drilled by BP in 1997. Although BP discovered oil with the well, the company ultimately decided the prospect wasn't large enough to justify a conventional development scheme.

But Pioneer came to Alaska in 2002 specifically to develop prospects deemed "too small" by the bigger companies, a business model the company recently used to bring the Oooguruk unit online in the Beaufort Sea.

After acquiring the Gwydyr Bay acreage in the 2003 Beaufort Sea lease sale, Pioneer applied for permits to build a small gravel pad and a corridor running south to T Pad in the Prudhoe Bay unit. The company also announced plans to drill two exploration wells in the winter of 2005 and 2006.

But the company never followed through on either effort, choosing instead to focus on developing the Cosmopolitan unit in Cook Inlet and Oooguruk off of the North Slope.

Pioneer's decision to drop the Gwydyr Bay leases follows its announcement last September to suspend exploration efforts in Alaska following several unsuccessful wells. ●

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● NATURAL GAS

Fowler paving the way for Kircher CBM well

By ALAN BAILEY
Petroleum News

Fowler Oil & Gas Corp. announced June 5 that it has started to construct the access road and drilling pad for the Kircher No. 1 well. The well will test for coalbed methane in privately owned land in an area of forest and farmland between Palmer and Wasilla in Alaska's Matanuska-Susitna Borough.

Initial drilling activities will involve Tester Drilling Services using a small rig to core vertically to a depth of 2,500 feet. The coring operation will provide information about what is in the subsurface, Bob Fowler, CEO of Fowler Oil & Gas, told Petroleum News June 6. Fowler Oil & Gas will notify the Alaska Oil and Conservation Commission of the results of the coring, Fowler said.

The company obtained a permit to drill the Kircher well from AOGCC on May 14. The Matanuska-Susitna Borough approved a conditional use permit for the well in October.

But Fowler declined to speculate on exactly when the coring operation would start.

"We're going to take our time on this and do it right," Fowler said.

The company plans to produce coalbed methane from multiple horizontal wells sidetracked from a vertical well bore. By threading the horizontal wells through the subsurface coal seams, the company hopes to achieve viable gas production rates through the single surface well head of the vertical well — coalbed methane projects have become notorious in the past, in part because of the use of a multiplicity of wells.

The company also plans to inject produced water into an underground sandstone reservoir using a downhole separator and pump, thus eliminating the need to flow water to the surface. One objective of the coring operation is to locate a suitable sandstone reservoir for the water injection operation, Fowler said.

Assuming that the coring operation proves successful, Scientific Drilling Inc. will take over the drilling operation and use the Aurora Well Service No. 1 rig to ream out the initial coring well to the full diameter of the vertical production well.

"We'll go back into the same hole and ream it out to the same depth," Fowler said.

After completing the vertical well, Scientific Drilling will use the Aurora rig to drill the first set of horizontal wells — Scientific Drilling specializes in the type of horizontal drilling required for the Kircher well. Fowler Oil & Gas will then bring in its own Speedstar rig to enable Scientific Drilling to drill the remaining horizontal wells.

"The Speedstar 185 rig is custom built for our use," Fowler said.

Obtaining well casing and drill pipe is proving difficult but Fowler Oil & Gas hopes to bring the Kircher well into production in late September or early October, Fowler said.

"Casing and pipe are becoming harder to get in quantity," Fowler said.

The company plans to connect the well to a nearby Enstar pipeline without having to compress the Kircher gas. ●

● LAND & LEASING

USGS assessment adds to Greenland picture

West Greenland-East Canada Province estimated to have 7 billion barrels of oil, 52 tcf gas, 1billion barrels natural gas liquids

By GARY PARK

For Petroleum News

The U.S. Geological Survey has made another contribution to the understanding of oil and natural gas resources within the Arctic Circle by releasing an interim assessment of the offshore region between western Greenland and Canada's Baffin Island.

The so-called West Greenland-East Canada Province is estimated by the USGS to have a mean 7.275 billion barrels of oil, 51.816 trillion cubic feet of gas and 1.152 billion barrels of natural gas liquids.

The study said the estimates relate to "undiscovered technically recoverable conventional oil and gas resources" within five assessment units.

As part of the USGS evaluations of various provinces, a study released last year of the East Greenland Rift Basins Province, covering about 130,000 square miles, generated estimates of 9 billion barrels of oil, 86 tcf of gas and 8 billion barrels of gas liquids the USGS rated as technically recoverable in less than 1,640 feet of offshore water in the absence of sea ice.

The final overall results are due to be released this summer.

North of Arctic Circle

The USGS said the assessment units in the West Greenland-East Canada study cover only those portions that are north of the Arctic Circle, the latitude that defines the area of its ongoing Circum-Arctic oil and gas assessment.

The unit with the greatest potential is the Northwest Greenland Rifted Margin AU, with oil rated at 2.746 billion barrels, gas at 17.8 tcf and gas liquids at almost 400 million barrels.

The growing interest in Greenland gained added momentum earlier in June at a Reuters Global Energy Summit, when Bill Gammell, chief executive officer of Scottish-based Cairn Energy, said the Danish territory could have billions of barrels of oil, but the costs of development would be high, making production a distant prospect.

Cairns, which has stakes in six of the 10 leased blocks off western Greenland, is working on seismic this year and may start drilling in 2009. ExxonMobil, Chevron, Husky Energy and Sweden's PA Resources also have interests in the region.

Gammell believes exploration will eventually work its way to the east coast, but said "costs will be large, so the size of the prize needs to be big. … There will need to be a lot of wells drilled before you're successful."

USGS Director Mark Myers, in releasing the East Greenland findings last year, said that "knowing the potential resources of the Arctic — an area of tremendous resource potential, environmental sensitivity, technological risk and geological uncertainty — is critical to our understanding of future energy supplies to the United States and the world." ●

USGS Director Mark Myers … said that "knowing the potential resources of the Arctic — an area of tremendous resource potential, environmental sensitivity, technological risk and geological uncertainty — is critical to our understanding of future energy supplies to the United States and the world."

● NATURAL GAS

Rebuffed AGIA rival backs governor

Port authority board member Whitaker says he now supports TransCanada's proposal; expert says LNG project not competitive

THE ASSOCIATED PRESS

Jim Whitaker, mayor of the Fairbanks North Star Borough and a board member of the Alaska Gasline Port Authority, is supporting Gov. Sarah Palin's approach to building a natural gas pipeline and her decision to back Canadian pipeline builder TransCanada Corp.

The port authority submitted its own pipeline proposal last year and formally protested when the Palin administration rejected its application as incomplete and accepted TransCanada's.

Since then, the group has continued to pursue its own project, which involves a pipeline from the North Slope to Valdez and liquefied natural gas tankers.

Whitaker said June 10 that the administration, under the Alaska Gasline Inducement Act of 2007, made a "worthy effort" to move a pipeline project ahead and the process needs to continue.

JUDY PATRICK

Jim Whitaker said June 10 that the Palin administration made a "worthy effort" to move a gas pipeline project ahead and the AGIA process needs to continue.

Not all port authority officials concur

Other port authority officials were less willing to get behind their former competitor.

Scott Smith of Black & Veatch, which is doing research for the Palin administration, presented findings that an LNG project would cost billions more to build than a pipeline running into Canada and would result in shipping costs that were twice as high, reducing overall revenue for gas producers and the state.

Project manager Bill Walker said the port authority is deciding how to pursue its mission in the context of AGIA and is not ready to give up.

"What we're saying is our goal isn't to stop a TransCanada project or to stop the AGIA process," he said in Juneau. "Our goal is to continue to work on first available gas to Alaskans at the most economic price."

Board chairman Bert Cottle was openly critical of the Canadian pipeline builder.

"TransCanada's proposal does not take care of Alaska's needs," he said.

Cottle, mayor of Valdez, said the AGIA license would allow too much time for delay.

Whitaker said his position did not differ much from other port authority members.

Earlier in June, Whitaker hinted he would back TransCanada's proposal. The port authority has not fared well under the AGIA process or under the Stranded Gas Development Act used by former Gov. Frank Murkowski, he said at a meeting.

"Some of us think that our noses can only take so many punches, and mine's just about punched out," he said. "I've got to look at the broader and bigger picture."

The port authority will make a presentation Thursday, June 12 (as this edition of Petroleum News goes to press) to lawmakers during hearings in Fairbanks.

Expert says LNG project not competitive

In the second week of June, Lawmakers heard experts hired to comment on the economics and feasibility of liquefied natural gas projects.

Scott Smith of Black & Veatch, which is doing research for the Palin administration, presented findings that an LNG project would cost billions more to build than a pipeline running into Canada and would result in shipping costs that were twice as high, reducing overall revenue for gas producers and the state.

The findings conflict with estimates generated by the port authority, which has argued that a medium-sized LNG project could be completed sooner than a pipeline into Canada and could be more profitable for the state. ●

● EXPLORATION & PRODUCTION

Alberta crude, gas reserves in decline

By GARY PARK

For Petroleum News

Established reserves of conventional crude oil and natural gas continued their downward trend in Alberta last year, while bitumen was virtually unchanged, the province's Energy Resources Conservation Board reported.

Conventional crude, after production of 191 million barrels in 2007, was down a net 6.3 percent to 1.5 billion remaining barrels, putting them at less than one-fifth of the peak 7.7 billion barrels in 1969. However, the ultimate potential, which depends on technological advances and commodity prices, is rated at 19.7 billion barrels.

Natural gas slipped 3.7 percent to 3.9 trillion cubic feet after producing 4.8 tcf last year. Ultimate potential, excluding coalbed methane, is estimated at 223 tcf.

Bitumen output of 482 million barrels made scarcely a dent in the established bitumen reserves of 173 billion barrels, with ultimate potential calculated at 315 billion barrels.

Production from both mining and in-situ bitumen projects rose 5.2 percent in 2007 to 1.32 million barrels per day, while conventional crude was off almost 20,000 bpd at 523,000 bpd and gas volumes dropped about 265 million cubic feet per day to 13.15 billion cubic feet per day, according to the ERCB's annual report.

Bitumen now accounts for 72 percent of Alberta's crude oil and equivalent production and is forecast by the ERCB to reach 3.4 million bpd by 2017, when upgrading is expected to turn 70 percent into 2 million bpd of synthetic oil.

Last year 62 percent of all bitumen production was upgrading, yielding 688,000 bpd of synthetic crude.

Alberta had 8,900 producing in-situ bitumen wells last year compared with 2,300 in 1990, with production over the period rising to 500,000 bpd from 135,000 bpd.

Exploratory and development drilling for crude oil, along with enhanced recovery projects, added 130 million new barrels to the province's reserves last year, replacing only 68 percent of production, down from the previous year's 79 percent.

The report noted that the number of producing oil wells placed on production dropped 11 percent in 2007 to 1,745, while successful oil wells drilled were off 17 percent to 1,791.

Natural gas reserves from new drilling replaced only 51 percent of production, down from 68 percent in 2006.

Total gas output, including coalbed methane, fell 2.4 percent in 2007 and the ERCB is forecasting a 3.3 percent annual decline through 2016.

Output from coalbed methane wells was up 44 percent to 660 million cubic feet per day and is predicted to reach about 1.75 billion cubic feet per day by 2017, although those volumes could be higher if development of the wet Mannville coals is accelerated.

The ERCB forecasts WTI crude will average $105 per barrel this year and rise steadily to $138 per barrel in 2017, while Alberta plant gate gas prices are predicted to average C$8 per gigajoule this year and C$9.05 in 2017. ●

● FINANCE & ECONOMY

Report looks at 'why' behind high fuel

ISER study looks at 10 communities to see what drives high fuel prices in rural Alaska; full report to follow later this month

By ERIC LIDJI

Petroleum News

High oil prices combined with refining and transportation costs will always make fuel oil more expensive in rural parts of the state, but smaller, and possibly controllable, factors might also be at play, according to a new University of Alaska Anchorage report.

Obstacles like seasonally frozen rivers, undersized ports, limited storage facilities, distance from refineries, poor coordination and local sales tax all help to increase the cost of fuel oil, according to a study by the Institute of Social and Economic Research.

The news isn't shocking, but does provide a glimpse at the possible ways to pare down the fuel oil costs in parts of rural Alaska where households, businesses and governments pay several dollars more than the already expensive prices of urban Alaska.

"The research was to try and untangle the components of fuel cost. The second step is sort of the policy analysis," said Ginny Fay, one of the five authors of the report.

The Alaska Energy Authority requested the study, which fits together the various pieces responsible for the final price of a gallon of fuel oil in 10 small communities around the state. Together, these communities represent the diverse spectrum of transportation and storage issues facing the state.

The current information comes from a summary of a report due out by the end of June. The full report will take a more detailed look at world oil markets and refining costs, among other factors connected to fuel prices.

The report catalogues data from November 2007, when the price of crude oil was around $80 a barrel. At the time, crude oil and refining accounted for $2.31 per gallon of fuel oil.

Today, a barrel of crude oil costs around $130 a barrel. That run up in oil prices changes the components of a gallon of fuel oil, particularly because refining and transportation costs get more expensive, but the authors of the report said the higher prices don't change the facts on the ground.

Distance not always the main factor

Distance, for instance, isn't always the biggest factor in pricing. The type of transportation, whether by barge, plane or truck, often makes a larger impact, as well as how much fuel the community can store at any one time.

Of the communities surveyed, the cheapest prices were in False Pass, a village of 54 on the eastern end of the Aleutians. The village gets fuel oil barged in 850 miles from Anchorage to the village once a year, which locks in prices for better or worse. This trip and a 3 percent local sales tax account for 20 percent of the cost of fuel.

By comparison, the 250-mile truck ride from Anchorage to Chitna, a small road system community without a local sales tax, accounted for 32 percent of the $3.41 the community paid this past fall for a gallon of fuel oil.

The most expensive community was also the smallest: Lime Village, a community of 25 on the Stony River in the Kuskokwim Delta.

Fuel oil shipments to the village take a three-part journey, starting with an 1,800-mile barge from Anchorage to Bethel, followed by a second barge to Sleetmute and a flight to Lime Village, where the fuel is stored in a local 1,800-gallon tank. This trip helps account for 63 percent of the cost of fuel, which was $6.25 a gallon last November.

The authors note that public policy will never completely level the playing field between rural and urban Alaska, but do offer some suggestions for easing the price crunch for rural communities, like forming multi-village co-operatives, selling state royalty oil to refineries below market value and improving barge landings in smaller communities. ●

● NATURAL GAS

Another look at regulation for FNG

Lawmakers ask the RCA to consider rate regulation after Fairbanks' lone natural gas utility posts its first profitable year

By ERIC LIDJI
Petroleum News

Following a request from a bipartisan group of Alaska lawmakers, state regulators will consider reinstating economic regulations on the lone natural gas utility in Fairbanks.

Led by Rep. Jay Ramras, R-Fairbanks, the group of 12 representatives and two senators, including both Speaker of the House John Harris and Senate President Lyda Green, asked the Regulatory Commission of Alaska on May 5 to investigate whether or not to regulate the rates Fairbanks Natural Gas LLC charges nearly 1,100 customers in Fairbanks.

"Because of their position in the Fairbanks market, it seems that FNG has matured into a healthy profitable gas monopoly," the letter reads.

The lawmakers make that claim because Fairbanks Natural Gas had its first profitable year in 2007 after a decade in the red, and also greatly increased the salary of the company's president, Dan Britton, while raising rates for its customers.

Economic deregulation allows a company to adjust rates at will, without the lengthy and expensive process of dealing with state regulators, but still keeps company balance books in the public record.

The company said that while it made money last year, it made less than it could have under regulation, which would have set a rate of return designed to recuperate infrastructure investments over the past decade.

Fairbanks Natural Gas earned $621,362 in net income in 2007.

"Nor does mere profitability for one year justify a change in the current regulatory scheme," the company wrote in reply to the lawmakers' letter.

Company began under full regulation

Fairbanks Natural Gas began providing service in 1997, under full regulation.

From the start the company operated under an unusual business model for Alaska, buying Cook Inlet natural gas, liquefying it at a plant at Point McKenzie and trucking it 300 miles up the Parks Highway to Fairbanks.

The RCA decided to partially deregulate Fairbanks Natural Gas in 2003, allowing the company to change rates as long as it notified both the state and customers. This allowed Fairbanks Natural Gas to quickly adjust rates, both up and down, to keep pace with fuel oil, a completely deregulated market covered by several competing companies in Fairbanks, where it is the dominant home heating product.

But in the fall of 2006, Fairbanks Natural Gas came within a week of running out of gas after its supplier at the time, Aurora Resources, terminated its contract.

Through an emergency contract negotiated at the time, Fairbanks Natural Gas began buying its natural gas supply from Enstar. However, state regulators put a timeline on the arrangement and told Fairbanks Natural Gas to look for another supplier.

It was during the proceedings surrounding the emergency contract that Ramras first asked the RCA to consider once again regulating the rates of Fairbanks Natural Gas, citing the near loss of supply and the failure to notify customers as a major reason.

Ramras is a commercial customer of Fairbanks Natural Gas through his businesses.

SARAH HURST

Rep. Jay Ramras, R-Fairbanks

When the RCA closed the book on the emergency contract in late March 2007, it decided not to economically regulate Fairbanks Natural Gas, saying that competition with fuel oil provided enough incentive for the company to charge reasonable rates, although acknowledging that the competitive pressure eased during periods of high oil prices.

The RCA did, however, require Fairbanks Natural Gas to notify customers of any potential supply shortages in the future, to conduct regular financial audits and to maintain accounting records as though it were completely regulated.

Gas vs. oil in Fairbanks

Fairbanks Natural Gas says that while it may corner the natural gas market in Fairbanks, it is far from being the dominant energy supplier in the region. Fuel oil remains the leading heating source in Fairbanks by a wide margin.

Natural gas customers in Fairbanks most likely pay the highest natural gas rates in the country, but even so natural gas in Fairbanks has historically been priced below fuel oil by energy content, except for a brief period of time last year.

That remained true even as rates dramatically increased over the past six months.

By example, residential Fairbanks Natural Gas customers paid $8.56 per thousand cubic feet of natural gas in 2003. Today, that price has nearly tripled to $23.35 per mcf. But the equivalent amount of fuel oil by British thermal units, a measurement of energy, currently costs around $30.50 in Fairbanks, according to conversion rates from the U.S. Energy Information Administration.

Plans for new supply from North Slope

This past February, Fairbanks Natural Gas announced a 10-year contract to buy North Slope natural gas from Exxon, taking advantage of a new in-state tax rate for gas.

Under the new set-up, Fairbanks Natural Gas plans to build a liquefaction plant on the North Slope and truck the gas 550 miles down the Dalton Highway to Fairbanks. Although the trip will cost more than traveling up the Parks Highway, and will require a new multimillion-dollar plant, Fairbanks Natural Gas believes the operation will still be cheaper than trying to secure a guaranteed supply from the tight Cook Inlet market.

Ramras and the lawmakers questioned

see **FNG** page 8

● EXPLORATION & PRODUCTION

‘Dirty oil’ gets an airing

U.S.-Canada panel says U.S. reliance on oil sands feeds ‘destructive’ habit if refineries continue with expansions, conversions

By GARY PARK
For Petroleum News

United States refiners are ready to spend $53 billion to expand or convert their facilities to handle an extra 2 million barrels per day of oil sands-derived crude at the same time environmental groups are warning of “catastrophic” impacts from the growing reliance on the Alberta resource.

“This enormous (refinery) investment represents an entrenched commitment to perpetuating U.S. reliance on oil as our primary source of energy into the next generation and beyond,” said a joint study by the U.S.-based Environmental Integrity Project and Environmental Defense Canada.

The study said the reliance will be based on “Canadian tar sands (and perhaps U.S. shale oil) — even dirtier and more destructive sources of oil than conventional crude oil.”

Environmental Integrity Project Director Eric Schaeffer told a conference call “it is hard to imagine what else it is that the U.S. oil industry could do to go backwards further and faster than to rely on Canadian tar sands or similar resources in the United States.”

“Not only would this mean significantly more pollution overall, but it would substantially boost the greenhouse gas emissions linked to global warming,” he said.

“When we talk about, we’re talking about reducing reliance and moving away from it. We know that takes time.

“But those first steps start with an awareness of what it means to get your oil from the oil sands. This is a very intensely wasteful way of feeding the oil habit.”

However, Schaeffer conceded that attempting to halt oil sands production isn’t possible.

Matt Price of Environmental Defense Canada said carbon capture and storage could achieve significant reductions in greenhouse gas emissions, but he criticized the pace at which government and industry was moving that direction.

“The timelines for implementation are far, far too long,” he said.

Regulations being developed

The Canadian government is developing regulations requiring oil sands projects that come on-stream after 2012 to lower their GHGs by 2018 through technology, such as carbon capture and storage.

The joint study, relying on data from the U.S. Environmental Protection Agency permitting processes, estimated that of the 1.6 million bpd of increased refining capacity planned for the U.S., 1.1 million bpd of which is designed to handle oil sands output. Another 827,000 bpd of existing conventional capacity is being modified to handle crude from the oil sands.

Pierre Alvarez, president of the Canadian Association of Petroleum Producers, refused to get drawn into speculating on what the upcoming U.S. elections will mean for the oil sands, given the concerns expressed by Barack Obama about the growing role of the oil sands in the U.S. energy equation.

But Alvarez said there is no doubt the “global barrel is getting heavier.”

The impact of high oil prices has put energy back on the political radar after a long absence and Canada will figure in the debate “no question,” he said.

“I don’t think anybody denies that environmental performance needs to continue improving,” Alvarez said.

Before the study was released, he told a

see **AIRING** *page 9*

Aboriginals take legal route

Struggling to deal with rising costs, lengthier regulatory hearings, shortages of skilled workers and a rising tide of environmental opposition, the oil sands now face increasing legal challenges from Alberta aboriginal communities.

Two actions have been filed in Alberta Court of Queen’s Bench that could be more troublesome to the industry than any of the other issues.

There is no doubt it has the attention of the Alberta government, which created an Aboriginal Relations ministry in April and has just signed a protocol covering all First Nations in the province.

But that has not satisfied aboriginal leaders, who say they are tired of unfulfilled government promises to consult and have the backing of Canada’s highest court.

Earlier this decade, the Supreme Court of Canada ruled that federal and provincial governments are required to engage in meaningful consultation with First Nations before developments proceed on native lands.

That precedent underpins legal actions by the Chipewyan Prairie Dene First Nation and the Woodland Cree First Nation who have alleged a breach of Alberta’s constitutional duty to consult on two proposed oil sands projects.

The Chipewyan Prairie are trying to block further regulatory approvals for a project by MEG Energy, with China National Offshore Oil Corp., to expand its Christina Lake development.

Construction is under way on a 25,000 barrel per day project, approval is pending for a second phase of 35,000 bpd and MEG has plans to add another 160,000 bpd.

Meanwhile, the Woodland Cree have launched a similar action in an attempt to stall Shell Canada’s application to expand its Carmon Creek project in the Peace River area of northwestern Alberta to 100,000 bpd from 12,500 bpd.

Chipewyan Prairie Chief Vern Janvier said “our lakes, our land and the animals and fish we have relied on for thousands of years to support our way of life and cultural values are being destroyed by out-of-control oil sands developments.”

“Because our constitutionally protected rights are at risk in one of the few remaining places in our traditional territory where we can exercise them, we’ve asked the courts to step in before it’s too late.”

He said his community has warned the Alberta government for years about “the erosion of our rights through ever-increasing development and the lack of proper planning for resource development.

“If anything, Alberta has sped up the pace of its approvals,” Janvier said.

He said consultations take place after oil sands leases have been awarded and the legal responsibility for consultation is delegated to the oil and gas companies, he said.

As a result, the companies are in a conflict of interest and have no control over the cumulative impact of other projects that infringe on treaty and aboriginal rights, he said.

Attorney: consulting ‘broken’

Robert Freedman, an attorney acting for both the Chipewyan Prairie and Woodland Cree, said the Alberta government’s system for consulting for First Nations is “broken right now.”

He said the Woodland Cree lawsuit raises questions about whether the government can “continue to sell off lands (regarded as traditional territory by Natives) without talking to First Nations, without talking to the public.”

Freedman said the Chipewyan Prairie action is limited to the impact of the Christina Lake project on hunting, fishing and gathering rights, and involves no monetary compensation.

But he said there is an implied requirement for greater environmental protection in the oil sands region.

see **LEGAL** *page 9*

continued from page 7

FNG

the wisdom of building a new liquefaction plant at a time when the “potential” for a bullet line or spur line to ship North Slope natural gas to communities along the road system is “real” within the next “5-12 years.”

“Will the cost of an antiquated North Slope LNG facility be spread to FNG ratepayers over 30 years? The facility may become obsolete after a pipeline is built but survive as a burden on the FNG rate payers,” Ramras writes.

Fairbanks Natural Gas said it could no longer afford to wait.

“From a practical perspective, the ‘possibility’ of a pipeline to Fairbanks in ‘5-12 years’ does not allow FNG to ignore its customers’ present needs and their needs for the next 5-12 years,” the company wrote in response to the letter from lawmakers.

Instead of focusing on regulation, Fairbanks Natural Gas believes the RCA should worry about supply. With less than seven months to go, Fairbanks Natural Gas still does not have a supplier of natural gas for the three months between the end of the contract with Enstar and the beginning of the new one with Exxon.

“Unless FNG obtains a source of gas beginning January 1, 2009, there will likely be little utility service left to rate regulate,” the company wrote.

That might create some problems with the timeline of the current docket. The RCA asked the lawmakers to designate a spokesman by June 20, but gave itself until June 5, 2009, to issue a final ruling on the matter. ●

— Eric Lidji can be reached at 907-770-3505

continued from page 8

LEGAL

As a result, if the suit succeeds it could set a precedent for the way all oil sands leases and developments are approved, Freedman said.

The government, while unwilling to comment on specific cases before the courts, insists it takes seriously its dealings with aboriginal communities and by creating a new ministry is "going in the right direction."

Aboriginal Relations Minister Gene Zwozdesky said he is "trying to develop some new approaches and establish some mutual trust," describing the mood at several preliminary meetings as "very positive."

Chief Jim Boucher of the Fort MacKay First Nation in the heart of the Athabasca oil sands region said many leaders now believe their only recourse is through the courts, although not all have abandoned talks.

—GARY PARK

continued from page 8

AIRING

Reuters Global Energy Summit that carbon capture and storage, while important, is "only one of a number of things that have to be approached."

He said options such as nuclear and geothermal power have enter the debate, assuming carbon capture and storage can achieve its goal of reducing GHGs by 70 percent by 2050 in Canada.

Price said he expects the next U.S. administration will move to a "low carbon fuel standard" that could penalize oil sands imports.

"Regardless of who wins in November, there will be a major shift in the status quo," he said.

Brenda Kenny, the incoming director of the Canadian Energy Pipeline Association, doubts the U.S. election will see major changes on either side of the 49th parallel, with Canadian supplies remaining the center point of Canada-U.S. trade.

To suggest Washington might go cold turkey on Canadian oil is "far-fetched," she said.

Cindy Schild, refinery issues manager with the American Petroleum Institute, said the Canadian government has assured U.S. officials that the oil sands sector is serious about lowering its GHGs, which is consistent with petroleum industry support for climate-change legislation.

Total: crude supply concerns

The spreading unease over the oil sands was reflected in comments June 4 by Christophe de Margerie, chief executive officer of France's Total, who warned that tougher environmental measures for the resource would contribute to a global crude supply shortage.

Total has earmarked up to $15 billion in spending over the next 10 years to boost its oil sands production to 500,000 bpd, starting with the Joslyn project in 2013.

De Margerie said that although Alberta was "considered the most cowboyish" among oil producing regions in the past, that has changed now that Alberta and Canada have started to tighten environmental regulations.

Helge Lund, chief executive officer of Norway's StatoilHydro — like Total, a new arrival in the oil sands with big ambitions — told Reuters he believes the answer to tapping new, unconventional energy sources is to establish a common price for carbon dioxide emissions and "the market will find the most efficient solution quickly."

He said the question is not whether there will be exploitation of unconventional resources that are more energy-intensive to exploit but whether the industry can "develop them as efficiently as possible

Cost of cutting GHCs high

But the global cost of cutting GHGs in half by 2050 would add $45 trillion to energy bills, International Energy Agency analyst Peter Taylor told a climate conference in Germany June 4.

"It implies a completely different energy system," he said, suggesting hydropower and wind power would have to reach close to 50 percent of all power production, compared with 18 percent today.

The IEA identified 17 key technologies needed to attain the 2050 goal, including carbon capture and storage on the supply side and the adoption of little-tested hydrogen fuel cell technologies on the demand side.

However, even halving GHGs by mid-century would still leave carbon dioxide emissions above the safe level identified by the European Union and a United Nations panel of climate scientists. ●

U.S. refinery expansions, conversions

ADDITIONS TO EXISTING REFINERIES

Company	Location	Increased Capacity
Murphy Oil	Superior, Wis.	200,000 bpd
Marathon	Garyville, La.	180,000 bpd
ConocoPhillips	Wood River, Ill.; Borger, Texas	150,000 bpd
Sinclair Tulsa, Okla.	47,000 bpd	
BP/Husky	Toledo, Ohio	39,000 bpd
PROPOSED NEW REFINERIES		
Hyperion	Union, County, S.D.	400,000 bpd
Northwest	Northwestern, N.D.	50,000 bpd
CONVERSION FROM CONVENTIONAL CAPACITY:		
ConocoPhillips	Wood River, Ill.; Borger, Texas	345,000 bpd
BP	Whiting, Ind.	205,000 bpd
BP/Husky	Toledo, Ohio	131,000 bpd
Husky	Lima, Ohio	146,000 bpd
TOP US SOURCE OF OIL IMPORTS		
Canada	2.4 million bpd	
Saudi Arabia	1.7 million bpd	
Venezuela	1.4 million bpd	
Mexico	1.3 million bpd	
Nigeria	1.3 million bpd	

GOVERNMENT

Funds allotted for observing Alaska's seas

The National Oceanic and Atmospheric Administration is awarding $1.3 million to support ocean observing efforts in Alaska during fiscal year 2008. The funding will go to the Alaska Ocean Observing System through the Seward Association for the Advancement of Marine Science. The Alaska grant comes as part of $20.4 million in funding nationwide for NOAA's Integrated Ocean Observing System.

NOAA said that it is developing the observing system as a tool to track, predict, manage and adapt to changes in the nation's coastal environments. A network of people and technology is making ocean data and information from diverse sources accessible from one source for use by scientists and decision makers, thus enabling a "big picture" view of environmental change.

"This (funding) agreement represents another big step forward for the Integrated Coastal and Ocean Observing System, as called for in the President's Ocean Action Plan," said retired Navy Vice Admiral Conrad Lautenbacher, undersecretary of commerce for oceans and atmosphere and NOAA administrator. "This year's award is a great example of NOAA's dedication to our ocean and coastal observing capacity, as well as our commitment to work with our regional partners."

In Alaska Molly McCammon, executive director of the Alaska Ocean Observing System Regional Association, will lead a project "to plan, develop and manage observing systems in the three geographically, culturally and economically diverse large marine ecosystems of the Gulf of Alaska, Bering Sea and the Arctic Ocean," NOAA said.

"Regional partnerships are critical to the success of a national Integrated Ocean Observing System," said Zdenka Willis, NOAA Integrated Ocean Observing System director. "With increased understanding of our oceans and coasts comes an increased ability to keep our nation safe, our economy secure and our environment healthy and productive."

—ALAN BAILEY

NATURAL GAS

ANGDA worried about incurring damages

Public corporation hopes to avoid falling victim to 'non-compete clause' in AGIA; plans to work with any successful pipeline

By ERIC LIDJI

Petroleum News

The Alaska Natural Gas Development Authority is hoping to avoid becoming an unintended victim of a "non-compete clause" in the Alaska Gasline Inducement Act, or AGIA.

The state legislature is currently in special session to decide whether to give the Calgary pipeline company TransCanada a license to start work on a large-diameter natural gas pipeline from Alaska's North Slope via Canada to U.S. markets.

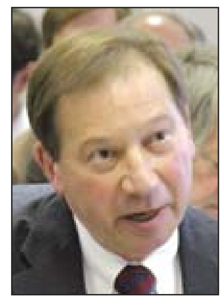
To protect the licensee, AGIA prohibits state money from being used to help a competing pipeline project, defined as any project able to carry more than 500 million cubic feet of North Slope natural gas to market each day.

If the state violates this clause, it is required to pay the AGIA licensee "treble damages," or three times what the company has already spent on its pipeline project.

As a public corporation of the state, ANGDA is run on state funds. But ANGDA is also charged with building a spur line to connect a large natural gas pipeline to markets in Southcentral Alaska. The corporation is also exploring a potential petrochemical operation under its state mandate.

Work with TransCanada

Those projects together could surpass the 500-mmcfpd limit stipulated by AGIA, according to Harold Heinze, chief executive officer of ANGDA.



FORREST CRANE

Harold Heinze hopes to sign a letter of understanding directly with TransCanada, should the company get the AGIA license. He said said both TransCanada and the Palin administration were "very receptive" to the idea.

"Do we trip into some sort of damage situation?" Heinze asked the ANGDA board of directors at a meeting on June 11.

ANGDA filed an application for AGIA, but unlike the other applicants, who all proposed ways to bring North Slope natural gas to market, the gas authority submitted an application for a spur line. That spur line was designed to be compatible with any mainline project, no competition was intended, Heinze said.

The issue could be resolved with an amendment to state statutes, but Heinze doesn't like that solution because "it just becomes a tool of the folks who are against" AGIA.

Instead, Heinze hopes to sign a letter of understanding directly with TransCanada, should the company get the AGIA license. The letter would make it clear that ANGDA is there to help and not compete.

The issue could be resolved with an amendment to state statutes, but Heinze doesn't like that solution because "it just becomes a tool of the folks who are against" AGIA.

"It seems like the most business-like resolution I could come up with to the problem," he said.

Heinze said both TransCanada and the Palin administration were "very receptive" to the idea. Nevertheless, ANGDA board member Kate Lamal asked Heinze to get an opinion from the state Department of Law to further guarantee that an letter of understanding would keep the gas authority from falling victim to the non-compete clause.

During upcoming legislative hearings, Heinze plans to make ANGDA's "whole case."

"What the case will be is that the in-state part of it, done through a spur line the way we're approaching it, is good for the big project," Heinze said. "And so there's

see ANGDA page 18

FINANCE & ECONOMY

BP chief calls for lower trade barriers

Governments should also cut taxes to boost global oil production, lower prices, Tony Hayward tells Kuala Lumpur conference

By EILEEN NG

Associated Press Writer

Governments should lower trade barriers and cut taxes for the oil and gas industry to boost production and help stabilize global oil prices, the chief of oil giant BP PLC said June 9.

Tony Hayward, Chief Executive of Europe's second-largest oil producer, said the world is not short of oil and gas resources but that high operating costs, rising taxes and lack of access are hampering investment in new production capacity.

The inadequate supply to meet rising demand has led global oil prices to reach records, he said.

TONY HAYWARD

"The problem is not below ground; the problem is above ground," Hayward told a two-day oil and gas conference in Kuala Lumpur, Malaysia.

"The taxes that governments take from the oil and gas industry have continued to increase across the world. I believe this is unsustainable and counterproductive. All it means is that we have less money to invest in new production," he said.

"Governments must also cooperate to lower trade barriers and tariffs. These are unproductive and run counter to the essential truth that a free and open energy market is just about the best possible guarantee to energy security," he said.

He criticized government use of subsidies to shield consumers from rising oil prices, saying it was unsustainable as it strained public finances and discouraged sensible fuel efficiency measures.

Crude futures made their biggest single-day leap ever June 6, soaring nearly $11 for the day to $138.54 a barrel but retreated below $136 in Asian trading June 9.

Some analysts predict prices could keep climbing amid strong demand in Asia and tight supplies in the Western Hemisphere.

Hayward said there were still 42 years of proven oil reserves and 60 years of natural gas left and vast quantities of other unproven resources and unconventional hydrocarbons such as heavy oil and oil sands.

"We need to invest in new technology, to invest in capability and in alternative energy. ... The key to new investment is to make the market work by getting the conditions right," he said.

IEA estimates $22 trillion needed

The International Energy Agency estimates that investments of $22 trillion are needed between now and 2030 to meet future energy demand, he said.

BP has raised its capital spending this year to $22 billion, up nearly 15 percent from 2007, to boost production, upgrade its refineries and investing in alternative forms of energy, Hayward said.

Investment in technology is crucial to boost production, he said. If the global recovery rate for oil reservoirs, which currently stands at 35 percent, is raised by just 5 percent, it could add around 170 billion barrels or five years of supply to world reserves, he added.

Hayward called for increase partnership between private oil companies and national oil firms, which hold 80 percent of world resources.

Hassan Marican, chief executive of Malaysian national oil company Petronas, also urged governments to gradually remove fuel subsidies which caused "unmitigated consumption and market distortions that are unmanageable in the long run."

Malaysia and India in early June became the two latest Asian nations to cut fuel subsidies, sparking protests nationwide as pump prices of gasoline and diesel rose sharply and inflation set to soar. ●

● EXPLORATION & PRODUCTION

May ANS production down 2% from April

By KRISTEN NELSON

Petroleum News

Alaska North Slope crude oil production averaged 705,724 barrels per day in May, down 1.7 percent from a 718,032 bpd average in April.

There was a substantial drop following a May 9 power outage at Prudhoe Bay, with production at that field falling from more than 320,000 bpd to less than 50,000 bpd May 9. Production levels began to come back up the next day, but didn't top the 300,000-bpd level until May 18.

Production from the BP Exploration (Alaska)-operated Prudhoe field, which averaged 305,860 bpd in April, averaged only 293,161 bpd in May.

Production from the BP Exploration (Alaska)-operated Prudhoe field, which averaged 305,860 bpd in April, averaged only 293,161 bpd in May. Prudhoe production includes western satellite production from Midnight Sun, Aurora, Polaris, Borealis and Orion; some Lisburne and Point McIntyre production also comes through Prudhoe.

Lisburne — part of Greater Prudhoe Bay — also had a substantial drop, down 11.9 percent from April, averaging just 34,849 bpd in May compared to 39,568 bpd in April. Lisburne production dropped below 20,000 bpd May 9, although it got back above 30,000 bpd May 11. Lisburne production includes Point McIntyre and Niakuk.

Greater Prudhoe Bay, which includes some 33,000 bpd of oil currently moving through the Endicott pipeline, averaged 361,010 bpd in May, down 4.6 percent from an April average of 378,408 bpd.

Other fields saw increases

Production from other North Slope fields was up in May compared to April.

The ConocoPhillips Alaska-operated Alpine field averaged 115,152 bpd in May, up 3.6 percent from an April average of 111,189 bpd. Alpine production includes satellite production from Fiord and Nanuq.

BP's Milne Point field averaged 35,644 bpd in May, up 1.7 percent from an April average of 35,048 bpd. Milne point includes Sag River and Schrader Bluff production.

The BP-operated Northstar field averaged 29,036 bpd in May, up 1 percent from an April average of 28,739 bpd.

The ConocoPhillips-operated Kuparuk River field averaged 149,640 bpd in May, up 0.1 percent from an April average of 149,441 bpd. Kuparuk includes satellite production from Tabasco, Tarn and Meltwater, as well as West Sak production.

The BP-operated Endicott field, which includes some 33,000 bpd of Prudhoe Bay Flow Station 2 crude, averaged 48,242 bpd in May, marginally above April production of 48,207 bpd. Endicott includes Sag Delta and Eider production.

The May temperature at Pump Station No. 1 on the North Slope averaged 29.9 degrees Fahrenheit, compared to 12.6 degrees F in April.

Cook Inlet crude oil production averaged 12,839 bpd in May, up 1.1 percent from an April average of 12,697 bpd.

ANS crude oil production peaked in 1988 at about 2 million barrels a day; Cook Inlet crude oil production peaked in 1970 at more than 227,000 bpd. ●

JUDY PATRICK

The Trans-Alaska oil pipeline stretches 800 miles from Prudhoe Bay to the Port of Valdez.

● EXPLORATION & PRODUCTION

Oooguruk unit produces first oil

Independent Pioneer is first company to join majors BP and ConocoPhillips as an operator of production in northern Alaska

By ERIC LIDJI
Petroleum News

In the biggest step yet taken by an oil company in northern Alaska that doesn't bear the name BP or ConocoPhillips, Pioneer Natural Resources has begun producing and selling oil from its offshore Oooguruk unit, the company announced on June 9.

The Dallas-based independent expects initial production of 2,000 to 3,000 barrels of oil per day from Oooguruk, developed from two pools, the shallower and smaller Kuparuk pool and the deeper and larger Nuiqsut pool. (See related story on page 15 of this issue.)

Oooguruk sits in the waters of the Beaufort Sea northwest of the Kuparuk River unit, operated by ConocoPhillips. Through an agreement reached between the two companies in February, Oooguruk oil will be processed at the Kuparuk facilities.


JUDY PATRICK
KEN SHEFFIELD

Pioneer won't have much time to build up momentum on the new project. Oooguruk will be suspended for around 45 days this summer while ConocoPhillips conducts maintenance on one of those shared facilities, called Central Processing Facility 3.

Pioneer anticipates peak gross production of 15,000 to 20,000 barrels of oil per day in 2010 from approximately 40 development wells drilled over the next three years at Oooguruk. Over the 25 to 30 year life of the field, Pioneer expects the unit to produce as much as 90 million barrels of oil.

Pioneer owns a 70 percent working interest in Oooguruk. The Italian super-major Eni Petroleum owns the remaining 30 percent.

The Dallas-based company is the first independent operator on the North Slope.

Pioneer promoted faster development

Pioneer came to Alaska as one of the independent oil companies coaxed north by Denver-based independent Armstrong Oil and Gas in the early part of the decade.

The two companies partnered on early exploration efforts at what later became Oooguruk, until Armstrong sold its share of the leases to Eni in August, 2005.

Although Pioneer is one of the largest independents in the country, it is small by the standards of the global super-majors like BP, ConocoPhillips and ExxonMobil.

From its early days in Alaska, Pioneer said its smaller size gave it agility unseen in northern Alaska. The company planned to explore and develop sizable fields considered too small by the standards of the super-majors.

Pioneer also promoted faster "cycle times" for development. From the creation of the unit in July 2003 to production this summer, the company brought Oooguruk online in just less than five years, among the fastest timeline of any unit in northern Alaska.

By comparison, ConocoPhillips needed six years to bring the large Alpine field online in the late 1990s and early part of this decade.

Shift to maturing basin

As the first smaller company to make the leap from exploration to development in northern Alaska, Pioneer also became a symbol of industry discontent with the state during and following the special legislative session this past fall to raise oil taxes.

Pioneer executives and others in the industry used Oooguruk to argue that tax increases would challenge the relatively smaller profit margins or smaller projects.

Company executives and industry advocates also noted how Pioneer started exploring under one tax structure, permitting under a second and developing under a third as proof of the lack of fiscal stability in the state.

Ken Sheffield, the head of Pioneer in Alaska, even appeared in a television commercial saying, "the pipeline is only one-third full and production is falling, requiring billions of dollars of new investment to keep Alaska's oil and gas industry going. Changing tax policy year after year is the wrong path to keep Alaska competitive."

The state argued that expanding the tax credit system would balance the impacts of the tax increase and promote exploration. Even without production in the state, Pioneer made $75 million for its Alaska operation in 2007 by selling and receiving reimbursement for those tax credits.

The recent run-up in oil prices also made Oooguruk more economic.

When Pioneer first began exploring the Oooguruk prospect back in 2002 and 2003, the delivered price of the Alaska North Slope crude oil was around $30 a barrel, compared with recent prices hovering around $130 a barrel.

It cost more than $500 million to bring the Oooguruk unit online, including the construction of a six-acre gravel island in the Beaufort Sea, making it the largest capital project ever undertaken by Pioneer.

The company also has projects in the Rockies, Texas, Tunisia and South Africa.

New revenue stream for the state

The move into production means a new revenue stream for the state.

In the fall 2007 revenue forecast, state economists expected to see early production from Oooguruk in fiscal year 2008. By the spring forecast a few months later, the state bumped first production to fiscal year 2009. The state fiscal year begins July 1.

However, even at the anticipated full production rate of 20,000 bpd, Oooguruk won't offset the expected declines from Prudhoe Bay and Kuparuk and the associated satellite fields, which have been dropping at a rate of 48,000 bpd over the past five years.

Completion of the gravel island and associated production facilities at Oooguruk contributed to a slight drop in construction spending anticipated on the North Slope this coming year, according to a forecast released in February by the University of Alaska's Institute of Social and Economic Research.

The researchers, though, expect other independents to make up some of that decline. ●

Contact Eric Lidji at 907-770-3505


PIONEER NATURAL RESOURCES ALASKA

An August 2007 aerial view of Oooguruk Island, a six-acre gravel pad Pioneer Natural Resources built in the Beaufort Sea. The company recently brought the Oooguruk unit online.

● NATURAL GAS

Wainwright CBM drilling under way

Permitting is complete, all equipment in Wainwright and DOI team has started drilling for a coalbed methane production test

By ALAN BAILEY

Petroleum News

Following a brief delay while permits were completed, a U.S. Department of the Interior-led team is now in the Chukchi Sea coast village of Wainwright drilling for coalbed methane.

"Equipment is all in Wainwright and we've started drilling on the first well," Art Clark, U.S. Geological Survey drilling project supervisor and co-project leader, told Petroleum News June 10.

As reported in the June 8 edition of Petroleum News, the team is drilling a delineation well and an array of wells for a production test, following successful results from a 2007 coalbed methane test well in Wainwright.

"There's enough gas contained within these coal seams (at Wainwright) to warrant the next phase of work. … These coals are fully saturated with gas," Clark said.

Equipment airlifted

The team airlifted all of the equipment to Wainwright from Prudhoe Bay, including a truck-mounted drilling rig for open-hole drilling.

But muddy ground conditions have resulted in a modification to the original drilling plan. Instead of starting by drilling a delineation well about two miles from the 2007 drill site, the team has decided to begin drilling the wells for the production test. The production test will take place in the vicinity of the 2007 well. The test will likely require four monitoring wells in addition to a production well.

The testing will enable an assessment of how easily gas and water can flow through the coal and will measure the amount of water produced for a given amount of gas. The testing will also involve monitoring pressure changes in the coal during gas production.

The delineation well that the team also plans to drill will run to a depth of 2,500 to 3,000 feet to test the lateral extent of the coal beds discovered in 2007, to look for additional coal beds and to look for a sand body in which to dispose produced water from coalbed methane production. The delineation well will also be used to obtain core from the coal seams, to enable additional testing of the coalbed methane resource.

The team plans to leave its equipment at Wainwright over the winter in preparation for a 2009 program, although no funding has yet been committed for 2009 work, Clark said.

USGS, the Interior's Bureau of Land Management, the North Slope Borough, Arctic Slope Regional Corp. and Olgoonik Corp, are all involved in the 2008 program, with the North Slope Borough being the primary funding agency.

Olgoonik is the village corporation for Wainwright. ●

On the Web

See previous Petroleum News coverage:

"More Wainwright coalbed methane drilling in works," in the June 8, 2008, edition at http://www.petroleumnews.com/pnads/30789112.shtml

"Wainwright test well finds gas," In the November 4, 2008, edition at http://www.petroleumnews.com/pnads/516981573.shtml

U.S. GEOLOGICAL SURVEY

Placing a coal core from the Wainwright well into a PVC desorption canister.

SAFETY & ENVIRONMENT

Two conservation groups plan to file lawsuit to protect polar bears

Two conservation groups plan to sue to protect polar bears from petroleum exploration and drilling off Alaska's coast.

The Center for Biological Diversity and Pacific Environment gave the federal government formal notice June 9 that they will sue under the Endangered Species Act to protect the bears, which were listed as threatened in May by Interior Secretary Dirk Kempthorne.

Polar bears are threatened — likely to become endangered — because their sea ice habitat has melted dramatically and computer models predict further losses, Kempthorne said. Polar bears use sea ice for mating, denning and hunting.

Kempthorne said the best scientific judgments did not conclude that polar bears were threatened by oil and gas development.

The conservation groups do not agree.

Whit Sheard, of Pacific Environment, said Bush administration officials have been so keen to grant offshore leases, they have not given proper consideration to the potential harm to polar bears.

"Instead of actively seeking to protect polar bears, they've been aggressively seeking to promote oil and gas development in polar bear habitat," Sheard said.

They are not seeking to shut down offshore drilling, he said, but will sue to ensure that the government follows requirements of the Endangered Species Act.

The act requires federal agencies to ensure that any action they carry out does not jeopardize a listed species, said Brendan Cummings, an attorney for the Center for Biological Diversity. All ongoing federally authorized offshore oil-industry actions affecting the polar bear, from exploration plans to seismic surveys, must be re-examined, Cummings said.

Boats, aircraft and drilling platforms will add to bears' stress by causing them to flee and expend more energy, Cummings said.

In 1993, the U.S. Fish and Wildlife Service began issuing incidental take permits — which allow incidental harm of species — for petroleum exploration. Since then, there has not been a single polar bear or walrus death attributable to oil and gas development, said Bruce Woods, a spokesman for the service.

Alaska has two populations of polar bears. The Chukchi and Bering sea population off the state's northwest coast is shared with Russia. The southern Beaufort Sea population off the state's north coast is shared with Canada.

A 60-day notice of intent to sue is required before a lawsuit can be filed.

—**DAN JOLING,** ASSOCIATED PRESS WRITER

● LAND & LEASING

Seeking balance at Teshekpuk Lake

Area north and east of NPR-A lake off the table – for now – but proximity to Barrow Arch explains industry's strong interest

By **ALAN BAILEY**
Petroleum News

In its supplemental final plan for the Northeast National Petroleum Reserve-Alaska, announced May 16, the U.S. Bureau of Land Management elected to defer leasing for 10 years in the environmentally sensitive area north and east of Teshekpuk Lake, believed to have the potential for discovery of as much as 2 billion barrels of oil and 3.5 trillion cubic feet of natural gas. (See story in May 25 edition of Petroleum News.)


JUDY PATRICK
HENRI BISSON

But a look through the public comments on BLM's draft plan reveals why the oil industry is anxious to explore the area.

In public testimony about the plan submitted in October Richard Garrard, geosciences manager for Talisman Energy subsidiary FEX in Alaska, explained his company's interest in the Teshekpuk Lake area.

Garrard pointed out that FEX has established a substantial acreage position in and offshore NPR-A and has drilled several exploration wells in NPR-A, with some of those wells encountering hydrocarbons. The area north of Teshekpuk Lake is a logical extension of the company's acreage position.

Barrow Arch

"The reason for the attractiveness of this area is the Barrow Arch, a geologically elevated area that has historically been the focus of oil and gas migration from the deeper basin areas ("source rock kitchens") to the north and south," Garrard said.

Traditional exploration plays in northern Alaska have tended to focus on the Barrow Arch that runs approximately along the Beaufort Sea coast. Fields like Prudhoe Bay and Endicott lie on the Arch.

The crest of the Barrow Arch lies just offshore Northeast NPR-A — the southern flank of the arch that lies under the Teshekpuk Lake area is considered to be one of the more attractive areas in Alaska for future exploration. Garrard said new high-resolution seismic data have revealed new exploration opportunities in the area.

FEX is "very aware of the environmental and cultural sensitivities of the onshore areas north of Teshekpuk Lake" and has demonstrated its ability to work in environmentally sensitive areas, he said.

BLM, in announcing the final plan, said that its deferral of oil and gas leasing in the area north and east of Teshekpuk Lake recognized the importance of the area for wildlife resources such as geese and caribou.

"The plan provides a balanced approach to energy development and wildlife protection, and forms a solid basis for the Bureau of Land Management to proceed with an oil and gas lease sale later this year," said Secretary of the Interior Dirk Kempthorne.

Bisson: appropriate decision

The area of leasing deferral probably holds the most significant wildlife resources on the North Slope — it is also an important area for subsistence hunting by several villages, Henri Bisson, BLM deputy director, told Petroleum News June 3. BLM weighed the potential activities onshore and offshore before making the deferral decision, he said.

"At this point we view it as an appropriate decision to make," he said.

Bisson said that everybody wants to see what unfolds in NPR-A, as oil and gas activities move ahead in areas that are open for leasing. In its decision, he noted, BLM reserved the right to lease the area in the future.

North Slope Borough

North Slope Borough Mayor Edward Itta lauded the deferral decision for the area north and east of Teshekpuk Lake. The borough was a cooperating govern-

see **BALANCE** page 16

● EXPLORATION & PRODUCTION

State lets Pioneer go with the flow

AOGCC allows Pioneer to use multiphase flow meters at Oooguruk, first application between two units with different operators

By ERIC LIDJI
Petroleum News

State regulators are allowing Pioneer Natural Resources to use a complex and powerful tool to measure oil production at the Oooguruk unit in the waters off the North Slope.

Through the end of October, the Dallas-based independent will be allowed to use multiphase flow meters to measure production of oil, gas and water from the offshore unit, which recently came into production. (See related story on page 12 of this issue.)

The temporary ruling from the Alaska Oil and Gas Conservation Commission allows Pioneer to begin production at Oooguruk while the commission tries to figure out the best way to monitor the complex program.

Flow meters are responsible for arguably the two most important parts of developing an oil field: testing the wells to keep the underground reservoir healthy, and divvying up the production among the various owners. In Alaska, that includes the state.

Traditionally, this process has been unwieldy, because wells produce gas, water and sediment along with oil. Reservoir engineers around the world measure production using large “gravity” separators, which spin this “multiphase” stream into its various components and measures each individually.

But for the past five years or so, improved technology has allowed companies to measure the entire messy stream at once using nuclear detectors. These “multiphase flow meters” are expensive, but pay off over the long haul because they require less space and maintenance that gravity separators.

Multiphase flow meters are becoming widespread across the industry, including Alaska, but some uncertainty exists about the accuracy of the machine under certain conditions, particularly heavier oil deposits and reservoirs with a high percentage of water.

A study commissioned by the companies and analyzed by the state suggested that viscous oil like that expected from Oooguruk, if not properly accounted for, could make the flow meter less accurate.

Oooguruk involves complex interests

Oooguruk is a complex field when it comes to ownership and operations.

As the first independent operator on the North Slope, and the first besides BP or ConocoPhillips to produce oil in northern Alaska, Pioneer has been looking for new ways to produce a small field large by North Slope standards.

One solution was to share facilities with the neighboring Kuparuk River unit, operated by ConocoPhillips. As a result, this will be the first time two North Slope operators use a multiphase flow meter to measure combined production.

An inaccurate reading could hurt either or both of the two companies, or the state, depending on whether the flow meter counts too much or too few barrels.

Pioneer Natural Resources will use the multiphase flow meters to determine the production rates at Oooguruk. That production will mix with the larger pool at the Kuparuk processing facilities. ConocoPhillips will measure that pool using more traditional techniques. By subtracting the Oooguruk production figures from the total measurements, ConocoPhillips will determine the production of Kuparuk.

As a result, the accuracy of the multiphase flow meters impacts production values from both Kuparuk, the second largest oil field in North America, and Oooguruk, the first new production in northern Alaska in years.

If it’s wrong, either the companies pay too much or the state gets too little, and the engineers tasked with monitoring wells to keep them online for as long as possible don’t have accurate information to make judgment calls.

AOGCC still trying to decide how to test meters

The AOGCC hasn’t decided how to handle all of these matters yet, but issued the temporary ruling to allow Pioneer to go ahead and start production at Oooguruk.

The companies question whether it is even possible to field test the multiphase flow meter without also installing a gravity separator for comparison, which would defeat the point of buying the smaller system.

A popular test, one completed by the two companies, involves attaching a multiphase flow meter to a loop of pipeline, which allows a small amount of fluid to test the accuracy of the machinery over a long period of time.

The state held a workshop in 2002 to discuss the practical application of multiphase flow meters and published a set of guidelines two years later.

BP and ConocoPhillips have since performed pilot tests on Prudhoe Bay and Kuparuk respectively. The AOGCC recently allowed BP to use multiphase flow meters at Milne Point, Endicott and Northstar, all single-unit applications.

But even a using the meters on two units operated by the same company can cause complications.

For instance, if BP decides to use multiphase flow meters at the offshore Liberty project and process the oil at the existing facilities at Endicott, the company would be mixing oil from state and federal lands, causing similar concerns to the ones currently being worked on at Oooguruk.

Both the state Department of Revenue and Division of Oil and Gas backed the AOGCC decision to allow the meters to be used at Oooguruk, but both governmental agencies also said Pioneer and ConocoPhillips should have to get a waiver to the state codes outlining where a company must measure its production.

In a letter from the Department of Revenue, Deputy Commissioner Marcia Davis wrote that having two companies with a “competing commercial interest” helped protect the state in this case.

The AOGCC is keeping the record open on the matter until July 7 to allow for additional technical reports and public comments to be included. ●

—Contact Eric Lidji at 907-770-3505

FINANCE & ECONOMY

EIA: $126 per barrel average through '09

The U.S. Department of Energy said June 11 that oil prices are expected to stay well above $100 a barrel and American motorists can expect gasoline prices around $4 a gallon through next year.

Guy Caruso, head of the department's Energy Information Administration, told a House of Representatives hearing that crude oil prices are likely to average $126 a barrel in 2009, four dollars higher than this year as oil supplies and demand are expected to remain tight.

Many Americans are fuming over high gas prices and lawmakers, many of whom face voters in the November election, are anxious to show they are trying to do something. Senate Republicans on July 10 blocked a proposal to tax the windfall profits of some of the biggest U.S. oil companies.

EIA, in a report, said that the high price of gasoline has reduced expected demand for this summer but not enough to dampen prices, largely because crude oil prices continue to climb on global supply concerns and weakness in the U.S. dollar prompting investors to bid up oil as a hedge. Oil prices are currently above $130 per barrel on the New York Mercantile Exchange.

Caruso testified that new auto fuel economy requirements and the increased use of ethanol and other alternative fuels is expected to produce "a substantial reduction" in oil use and oil imports over the next two decades.

Predicting future oil and gasoline prices is highly uncertain, Caruso acknowledged. EIA projects oil prices to decline to $86 a barrel in 2010 and then begin increasing to $107 by 2015.

Caruso's agency bases its gasoline projections on assumptions of future oil prices, expectations of demand and economic trends. It has revised its figures upward several times since last year — not having anticipated the huge surge in global oil costs.

A panel of energy experts, told the House hearing that people should not expect any quick fixes to energy problems.

They said one answer is more conservation and a shift to alternative fuels — transitions that would take time. Caruso told the lawmakers that new auto fuel economy requirements and the increased use of ethanol and other alternative fuels are expected to produce "a substantial reduction" in oil use and oil imports over the next two decades.

—THE ASSOCIATED PRESS

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BALANCE

ment agency in the Northeast NPR-A plan of development.

"BLM listened to local communities and made the plan better," Itta said. "The lease sale can proceed while one of the region's most sensitive wildlife habitats will be protected. It's a win-win."

North Slope Borough spokesman David Harding told Petroleum News June 11 that the borough is opposed to opening the area north and east of Teshekpuk Lake at any time in the future because the area is environmentally unique.

"If the deferral had been permanent we would have been much happier," Harding said. "Ten years is better than nothing."

ConocoPhillips

ConocoPhillips has major oil interests in the Colville River Delta immediately east of NPR-A and has continued to actively explore in the petroleum reserve. ConocoPhillips spokeswoman Natalie Knox Lowman told Petroleum News June 3 that the company understands the difficulty of addressing all stakeholder interests in the Teshekpuk Lake area.

"What we said was that 'we respect the process the BLM and the North Slope Borough went through to reach this point and recognize how important it is to balance the interests of all stakeholders," Lowman said. "We also believe that access to new acreage is important for development of the state's resources, and should be a priority in order to increase the availability of new energy supplies and lower energy prices in Alaska and the rest of the nation."

Lowman declined to comment on how the Teshekpuk Lake decision might impact ConocoPhillips' exploration plans. In 2007 the company, along with its partners Anadarko Petroleum and Pioneer Natural Resources, relinquished 300,000 leased acres in NPR-A, citing noncommercial finds and the cost of working far from infrastructure as the reason.

Unlike some past years, this past winter ConocoPhillips drilled wells close-in to existing Alpine infrastructure on the eastern edge of NPR-A versus venturing further into the petroleum reserve. ●

COURTESY DOYON

● SAFETY & ENVIRONMENT

FWS issues new Chukchi wildlife rule

New federal regulations regarding disturbance of walrus, polar bears for oil and gas explorers in Chukchi Sea go into effect

By ALAN BAILEY
Petroleum News

On June 11 the U.S. Fish and Wildlife Service issued a final rule authorizing unintentional, passive and short-term disturbance of polar bears and Pacific walrus in the Chukchi Sea and the adjacent coastline during oil and gas exploration. The rule specifies mitigation measures that operators need to take during various types of exploration activity, to ensure that disturbance to the animals remains below acceptable levels. Disturbance levels would not result in direct injury to an animal or have a negative effect on animal population, the Fish and Wildlife Service said.

Monitoring requirements associated with the regulations will provide information about the movements and activities of the animals, the service said.

Incidental take

In Alaska, the U.S. Fish and Wildlife Service manages the protection of polar bears, walruses and sea otters under the terms of the Marine Mammals Protection Act. Operators can avoid contravening the terms of the Marine Mammal Protection Act by applying for an authorization under the incidental take regulations. An authorization would include stipulations for mitigation measures that are spelled out in the regulations.

The regulations also require operators to develop a plan for interaction with polar bears and, if necessary, to develop employee educational materials about polar bears. Operators must also work with affected communities to limit any impacts on subsistence hunting and may have to develop a plan of cooperation to meet community concerns.

But the new rule is independent of the polar bear listing under the Endangered Species Act, the Fish and Wildlife Service said.

The regulations in the new rule "build on the experience and knowledge gained during more than 15 years of successfully managed coexistence between marine mammals and the oil and gas industry in Alaska," said Tom Melius, U.S. Fish and Wildlife Service Alaska regional director. "They require effective monitoring, reporting and mitigation of anticipated impacts and allow exploration operations to proceed in an environmentally sensitive manner."

The new final rule will remain in effect for five years and replaces previous authorizations. No lethal take of polar bear or walrus as a result of oil and gas activity has been reported while incidental take regulations have been in place in the Chukchi and Beaufort seas, the Fish and Wildlife Service said. ●

● NATURAL GAS

Legislative consultants: AGIA can't hurt

Juneau session with experts hired by LB&A includes some agreement by consultants, review of TransCanada's financial strength

By KRISTEN NELSON

Petroleum News

Consultants hired by the Legislative Budget and Audit Committee to evaluate the TransCanada proposal under AGIA, the Alaska Gasline Inducement Act, told members of the Alaska Legislature that they see no harm in approving the license.

Dan Dickinson, a former Tax Division head under the Murkowski administration, had been tasked with helping legislators examine the issues.

There have been five major reasons given to vote for a TransCanada license, Dickinson told legislators June 5, the second day of the special session: It provides enforceable commitments the state hasn't had before; it makes what has been described as a "dazzling" amount of money for everyone, so it seems logical, he said, that producers will sign on and the project will advance; it "guarantees" the state's must-haves for an "enhanced open-access pipeline" as opposed to the open access pipeline created by federal law; it is not in competition with a liquefied natural gas project — and in fact may be the best way of getting an LNG export project once the mainline is operating; and voting for the license is the best way of meeting in-state gas needs.

AL GRILLO

Granting an AGIA license to TransCanada "probably won't harm the prospects for a line and may strengthen them." We're on our own one- or two-yard line, he said, and while it's important to do it right, this won't be a touchdown play. He said he didn't see any huge downside in voting for the license. —Dan Dickinson

Dickinson said there is another reason: Granting an AGIA license to TransCanada "probably won't harm the prospects for a line and may strengthen them." We're on our own one- or two-yard line, he said, and while it's important to do it right, this won't be a touchdown play. He said he didn't see any huge downside in voting for the license.

Is this like chicken soup? It couldn't hurt? Sen. Con Bunde, R-Anchorage, asked all the LB&A consultants at the table — Barry Pulliam of Econ One Research, Lesa Adair of Muse Stancil, John Neri of Benjamin Schlesinger & Assoc. and Dickinson.

Dickinson reiterated that he didn't see any harm to granting the license. Pulliam said it won't hurt; Adair said talking about it helps; and Neri said "I see no harm."

What does vote cover?

An issue which came up during the LB&A presentations June 4-5 and was continued when the administration took the stand (June 6-10) was what exactly legislators were being asked to vote on.

Reps. Gabrielle LeDoux, R-Kodiak, and Mike Doogan, D-Anchorage, both had concerns about what the vote on AGIA covers.

Dickinson said there are three documents included: the AGIA statute; the request for applications; and the application from TransCanada — and questions to TransCanada and its responses.

The question came up again later in the hearings when the administration was on the stand. LB&A Chair Rep. Ralph Samuels, R-Anchorage, wanted to know if questions LB&A sent to TransCanada about the application, and the responses the company sent back, would also be considered?

This raised further questions from legislators about how whether committee hearings on the AGIA statute would be included.

This was not an issue that reached resolution in the discussion, but Commissioner of Revenue Pat Galvin told legislators it is not uncommon to have multiple-document agreements.

Issue of expandability

Sen. Joe Thomas, D-Fairbanks, asked what certainty there would be that if the producers built a line, rather than TransCanada, that it would be expandable.

Neri said if the capacity was all taken and the pipeline didn't want to expand, a producer with new gas could file for expansion with the Federal Energy Regulatory Commission and FERC would act. AGIA requires the pipeline to test the market every two years, to see if there is interest in expansion, Neri said; if there is interest then there is a standard procedure at FERC for expansions.

Thomas said his concern was what would happen outside of AGIA, if AGIA failed.

Neri said the Alaska Natural Gas Pipeline Act gives the ability to the new producer to go to FERC and file a protest; FERC would then decide, he said, whether they were going to force expansion. This is different, he said, under ANGPA than FERC's normal authority.

There have been concerns expressed about going to FERC for expansions and Dickinson said that while Congress has said FERC has the authority to force expansion, it is an untried process.

Evaluation of TransCanada

Muse Stancil's Adair provided an extensive financial evaluation of TransCanada and its capability to build an Alaska line. She said a project the size of the Alaska gas pipeline "dwarfs" the cumulative total of TransCanada's capital spending over the last five years. Taking on the project would likely require the company to raise additional equity.

The project does, however, complement the company's existing gas pipeline and storage assets,

As far as TransCanada's ability to handle Alaska gas, she said Muse Stancil is comfortable that TransCanada can handle all the gas through its Alberta hub. There is excess capacity before and after Alaska gas, she said, although there might be a small issue of capacity at startup. Adair said the Alberta gas supply forecast done by the National Energy Board is based on $7 gas and higher prices might produce more drilling, but based on NEB's reference case supply will exceed total demand and takeaway capacity by 300 million cubic feet a day in the first year of Alaska gas. Thereafter, the expected continuing decline in Alberta production is expected to provide more than enough capacity for Alaska gas. The demand-balance forecast bas based on Mackenzie gas going into production before Alaska.

Would TransCanada be on the list?

Doogan asked Adair whether TransCanada would be on the list if Alaska were looking to hire a pipeline company — and where on that list it would be ranked.

Adair said she wouldn't rank a list until she'd seen proposals, but TransCanada would be on the list based on existing assets and its ability to move gas to the Lower 48.

Rep. Mike Hawker, R-Anchorage, wanted to know whether TransCanada was the only entity with Canadian assets that could be used to move Alaska gas. Adair said the TransCanada portfolio, where you can get to from the company's Alberta system, is the best way. There are new-build options, she said, and you could move part of the gas other ways.

TransCanada is at the top of the list as far as existing facilities, Adair said.

Asked by Rep. David Guttenberg, D-Fairbanks, whether TransCanada is capable of pulling this off, Adair said whoever is in charge of the project will have to pull together the human capital to do the project. People with experience are hard to come by right now, but TransCanada has a lot of the core competencies to do the project, she said.

She said engineering and construction will be done by third parties, likely more than one construction company and maybe more than one engineering firm.

Adair said firm transportation commitments are necessary, and need to be made by producers with substantial assets to backstop those commitments.

Without firm transportation commitments, she said, there isn't even a valid reference case. Adair said she didn't believe the pipeline would be built without firm transportation commitments.

Sen. Bill Wielechowski, D-Anchorage, asked Adair why producers would be interested in building a pipeline when the returns are so low relative to other projects they have.

The pipeline is just the piece of equipment, Adair said: It's about getting the resource to market.

As to why producers would want to own the pipeline, she said when you turn over operatorship you don't always have your goals aligned and there may be more intangible things the producers would want to control. You eliminate possible issues if you operate, she said, especially at a time when every exploration and production company is trying to add reserves to its balance sheet. ●

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DECISION

the unit's termination, called for gas production for the proposed North-Slope-to-market gas pipeline. The rejected plan, the 22nd, said gas cycling, which would maintain reservoir pressure by reinjecting gas after stripping out the liquids, was not economic.

Irwin: no hydrocarbons to market from Thomson in 30 years

Irwin rejected the proposed 23rd plan of development as a remedy in an April 22 decision. The companies requested reconsideration May 12; partial reconsideration was granted May 22.

"My decision to terminate the Point Thomson Unit stands," Irwin said in the June 11 decision on reconsideration.

He said units are formed to facilitate development of the state's resources, but in more than 30 years since the Point Thomson unit was formed, "no oil or gas has been brought to market and none of the infrastructure for development has been built."

"This unit is terminated because the Point Thomson unit working interest owners failed to fulfill the commitments made in the unit agreement."

He listed a number of deficiencies in the request for reconsideration, and called it "flawed," but also said the request "on several issues merits a response so that a reviewing court has the benefit of DNR's perspective." The remand requires DNR to report back to the court on the outcome.

ExxonMobil will appeal

ExxonMobil is the largest Point Thomson acreage holder and the unit operator.

ExxonMobil spokeswoman Margaret Ross told Petroleum News June 11 in an e-mail that "ExxonMobil is extremely disappointed by the DNR decision." She said ExxonMobil's 23rd plan of development "is responsive to all of the DNR's requirements, including a commitment to bring Point Thomson on production."

"Thus, we plan to appeal this action and will pursue all alternatives to protect our rights to develop these resources," she said.

ExxonMobil believes Irwin "has no legal basis to terminate the unit and doing so will lead to further court appeals," Ross said, taking years to resolve and delaying Point Thomson development, and creating "tremendous uncertainty about the availability of Point Thomson gas for a gas pipeline project — gas that is essential to the success of such a project."

Ross said that prior to 2005 DNR approved plans of development for Point Thomson.

"Consistent with the instructions of the court, the owners believe the updated plan is an appropriate remedy for DNR rejection of plans of development that were submitted in 2005 and 2006," she said.

The owners have a "comprehensive technical understanding" of the Point Thomson reservoirs and have spent $800 million to date, she said, with $1.3 billion budgeted in the 23rd plan of development.

Plans for this year include drilling, Ross said, "and we have already hired Alaskans, secured a rig and ordered long-lead materials for this purpose. The plan would provide jobs for over 200 people this winter."

She also said the companies "are continuing plans to begin drilling this coming winter," despite DNR's decision. "We have the right to conduct such drilling under the terms of the leases, which have not yet expired," she said.

On the issue of commitment, Ross said: "The owners provided significant assurances that they would meet their commitments, including a provision for unit termination if we did not meet key milestones included in the plan of development."

On the Web

See previous Petroleum News coverage:

"DNR to reconsider Point Thomson decision," in May 25, 2008, issue at: www.petroleumnews.com/pnads/782233948.shtml

"Point Thomson nixed: Irwin not convinced ExxonMobil will carry through on field development," in April 27, 2008, issue at: www.petroleumnews.com/pnads/497969160.shtml

"A matter of trust: Companies testify on why DNR should accept a new Point Thomson plan," in March 16, 2008, issue at www.petroleumnews.com/pnads/220771379.shtml

"No off ramps: Exxon insists it will take Point Thomson to small-scale production by 2014," in March 9, 2008, issue at www.petroleumnews.com/pnads/320939019.shtml

"State wins lawsuit: Judge agrees with Alaska on 22nd Point Thomson plan; requires hearing on remedy," in Jan. 6, 2008, issue at: www.petroleumnews.com/pnads/485989934.shtml

DNR says it's not required to plan unit development

Irwin said he took issue with the claim in the request for reconsideration that if the department "found the 23rd POD deficient, it was obligated to disclose what it wanted Appellants to do to avoid termination." He said that claim misinterprets the remand proceeding "and constitutes an effort to put the responsibility for unit development on DNR."

The unit was terminated, he said, because of failure to submit an acceptable plan of development and "the failure to meet the obligation to develop oil and gas leases." The remand was to allow appellants to describe what they would do to remedy their failures, he said.

Irwin said the issue at hand was not a presentation by DNR of an acceptable plan of development under the unit agreement and the reasonably prudent operator standard. Judge Gleason found that DNR properly rejected the 22nd plan of development. The question, he said, is whether it is in the public interest for the unit to continue.

As for issue of whether the companies would carry out the 23rd plan if it were approved, Irwin said given "a unit with a history of broken promises and failures to meet work commitments, it is completely appropriate to query Appellants as to why I should believe they will carry out their work commitments and what assurances they can offer me that I can believe them."

Appellants' interests considered

The appellants contended that DNR "improperly focused on the public interest in terminating the unit and that the agency failed to adequately consider Appellants' interests. I disagree," the commissioner said.

DNR is required to consider the public interest, he said.

And if the "proposed remedy of 10,000 barrels per day of production" were accepted, Irwin said, it would take 40 years before Point Thomson gas was available because of the hundreds of millions of barrels of oil-rim oil and condensates that would have to be produced before gas production, unless the companies dramatically increased oil production or got permission from the Alaska Oil and Gas Conservation Commission to leave the oil in the reservoir and produce primarily gas.

Irwin said he carefully considered the rights of the companies when terminating the unit and said the unit history demonstrates the "close and generous consideration" DNR has given the companies for many years, allowing them many opportunities to conduct studies and refraining "from taking punitive action when Appellants repeatedly breached their various work commitments."

Irwin said the companies "ignore that their failure to submit an acceptable 22nd POD was the culmination of over thirty years of failure to develop."

DNR has struggled "for years" to get the unit into production, he said.

Issue of approved PODs

Irwin said the record doesn't support the "contention that DNR's approval of 21 PODs means that it approves the state of development." After the last well within the unit was drilled in 1983, "DNR has repeatedly requested or demanded that more wells be drilled to move the unit towards production," he said: Ten wells were promised between 1984 and 2001; not one was drilled.

"DNR approved most of the PODs, but it did not agree with the pace of unit exploration and development," Irwin said.

As for DNR's conclusions about whether the companies intend to perform legally enforceable contractual obligations, Irwin said the credibility of the companies matters because they "have asked DNR to trust that they will perform the commitments contained in the proposed 23rd POD. Credibility matters because they ask DNR to trust that they will expand production beyond the 10,000 barrels a day of gas condensate they plan to begin producing by the end of 2014 if their test results accumulated over the next six years are favorable and all permitting issues are resolved."

Credibility is also an issue, he said, because there is no commitment for production of the 8 trillion cubic feet of gas or the hundreds of millions of barrels of oil.

"Credibility matters because they are asking DNR to have faith that despite the long history of broken development commitments, they will eventually bring the state's oil and gas to market," he said.

Irwin said he would need to be certain that the companies would perform before he approved the 23rd plan of development.

He said testimony at the hearing and the companies' perspective on the unit's history convinced him that the companies "have a different view than I do on what honoring a commitment means."

He said he carefully considered credibility of witnesses at the hearing, as well as reviewing the history of the unit. "What I found was a pattern of broken promises and misleading communications by Appellants that did not result in any production of oil or gas." ●

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ANGDA

no way you can stretch us into a competitor if we're aiding their project."

But that goes for any big project, including the Denali pipeline, a competing project being pushed by BP and ConocoPhillips outside of the AGIA process. Heinze said ANGDA's willingness to work with whatever project goes forward could create a "tension point" with TransCanada.

"That's why they may want to sign an agreement," he said about TransCanada.

Wetlands work one-fifth done

The company hired to delineate the wetlands along the spur line route told the ANGDA board on June 11 that it is more than 20 percent finished with the work.

ANGDA hired Shaw Alaska to survey the 370-mile spur line route from Delta Junction to Beluga through Glennallen in order to get a wetlands permit from the U.S. Army Corps of Engineers.

At more than $1 million, the contract is the largest ever issued by the gas authority.

ANGDA has upcoming meetings planned in Fairbanks and Kenai. ●

GOVERNMENT

Energy assistance session date not set

Tension between call for action on short-term assistance, longer-term TransCanada AGIA decision; and it's an election year

By ANNE SUTTON
Associated Press Writer

Gov. Sarah Palin has promised state lawmakers they will be called upon this summer to address the immediate energy needs of Alaskans.

But it's still unclear when that will be and how broad a discussion it will entail.

Lawmakers have differing views on whether to address the issue in a separate special session or to expand the current debate on TransCanada Corp.'s application to build a natural gas pipeline from the North Slope to an Alberta, Canada, hub.

The Alaska Legislature is currently meeting to hear presentations on the Calgary-based company's proposed $26 billion pipeline that could supply Lower 48 markets with North Slope gas.

They are expected to vote on whether to grant the company an exclusive state license and $500 million in seed money next month after presentations are held in communities around the state.

Energy assistance plan proposed by Gov. Palin in mid-May

Meanwhile, Palin also wants lawmakers to consider her one-year $1.2 billion plan to help offset the high energy costs paid by the state's residents. The plan, as introduced in mid-May, would include energy debit cards for residents and grants for utility companies.

No date has been set yet and a formal call has not been issued though Palin has said she will present legislation by June 20.

"We are talking to legislators about what they would prefer and that will play into the ultimate timing," said Revenue Commissioner Pat Galvin.

The sooner, the better, said Rep. Mary Nelson, D-Bethel, regarding consideration of the governor's energy assistance plan. Rural communities need to put their orders in early for fuel barge shipments and winter is not so very far away, she warned.

Besides, Nelson said, it's appropriate to address the topics concurrently and to include both short and long term solutions for providing affordable energy to Alaska homes and businesses.

"It helps us remember that we can't develop this gas line without significant in-state use," said Nelson. "For as great as the oil pipeline was, there was a huge oversight in that we didn't secure enough in-state oil use. We can't afford to make that mistake again."

Public expected to weigh in on energy costs at hearings

Rep. John Coghill, R-North Pole, said in-state energy needs will most certainly be brought up in public testimony during the upcoming community hearings on the main gas line. And it's good to "ratchet up the discussion," he said.

Cash infusions and conservation incentives are simple ways of meeting Alaskans' immediate needs, he said, but more long term proposals like hydropower projects or in-state pipelines are complex and have broad ramifications that need to be thoroughly vetted.

Though many in his region are eager to see a small diameter 'bullet' line from the North Slope, Coghill said it won't provide near-term relief, and he is worried it will only detract from the immediate issue of whether to grant TransCanada a license.

The sooner, the better, said Rep. Mary Nelson, D-Bethel, regarding consideration of the governor's energy assistance plan. Rural communities need to put their orders in early for fuel barge shipments and winter is not so very far away, she warned.

"I would hate for us to get so focused on the near term that we kick out a good long term answer. So I think we have to be aware and cautious," said Coghill.

Concerns have been raised from Kenai lawmakers that a bullet line from the North Slope could affect the economics of expanding development of the Cook Inlet basin.

And Galvin said lawmakers also need to weigh the trade-offs.

Using the state's one-eighth share of royalty gas for in-state use would affect state tax and royalty revenues and Permanent Fund dividends.

But he said the administration plans to address the in-state bullet line in more detail during the current discussion, given the depth of interest among lawmakers.

Lawmakers added $300 million to weatherization programs

Sen. Kim Elton, D-Juneau, said discussion of energy needs should build on last session's accomplishments when lawmakers added $300 million to state weatherization programs and $50 million to begin study of renewable energy projects.

And while he welcomes debate on a range of possible solutions, an effort to nail down any policy decisions at this time "is so filled with what-ifs that it may not be productive."

He, too, is worried about drawing focus from the main pipeline.

"I don't know how combustible the special session gets if you add component A, the gas line, to component B, an energy plan," Elton said.

Palin has already carved out 60 days for lawmakers to consider the TransCanada license, 60 days required under the Alaska Gasline Incentive Act, and some balk at spending another 30 days in Juneau, especially with elections looming.

Rep. Carl Gatto, R-Palmer, who faces a challenger in the August primary, said Palin also needs to consider lawmakers' campaign and family needs when deciding the schedule. Legislators are barred from raising money while in session.

"It makes it hard for all the people here," Gatto said.

Palin's energy plan has two parts: grants totaling $475 million for utility companies operating in the state, to be used to lower customer bills and $100 monthly Energy Debit Cards for residents.

The cards would be authorized for purchases from Alaska energy vendors and total about $729 million. ●

Petroleum news

Business Spotlight

Tire Distribution Systems Inc.

Tire Distribution Systems, a full-service tire distributor, has served Alaska industry and consumers since 1976. With retail and Bandag retread facilities in Anchorage and Fairbanks, TDS maintains the right mix of new tire and retread knowledge to keep customers happy and services the smallest to the largest tires on the road. Visit www.tdstires.com for information about Bridgestone, Dayton, Firestone, Fuzion, Continental, Yokohama and Cooper tires and other services.


FORREST CRANE

Matt Ellis, Anchorage Store Manager

Matt Ellis

Matt Ellis started in the tire business with Denali Bandag 12 years ago as a tire stacker. Tire Distribution Systems purchased Denali Bandag in 1998, and Matt stayed on, working his way up the ladder to his present position. His introduction to Alaska included deplaning in Fairbanks at 62 degrees below zero wearing only a windbreaker, and then unloading a 45-foot container of furniture. Once thawed, he decided Alaska was home. The Ellises, Matt and Misty, have a boy and girl, ages two and four. Matt is proud to support Alaskans Against the Mining Shutdown.

Rod Jones

Quick-witted with an answer to every tire question, Rod Jones has 29 years in the business, 27 of that in Alaska representing Bridgestone/Firestone. He is an accused golfer with a driving and putting handicap. Rod is also a Kenai River guide and supports Trout Unlimited and the USGA. He and his wife Sandi have been married 36 years and have one daughter, Kristin, 29.


FORREST CRANE

Rod Jones, Commercial Salesman, Anchorage

— PAULA EASLEY

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

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

Oil Patch Bits

Marketing Solutions welcomes new account managers

Anchorage-based Marketing Solutions, an award-winning, full-service advertising and public relations agency, recently added three staff members to its client services team. As account managers, Lincoln Garrick, Blake Arrington and Michelle McMillan will represent several of the agency's most prominent clients.

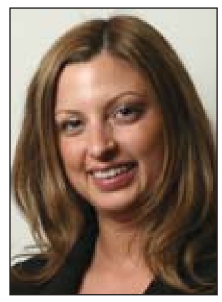
McMillan, a graduate of the University of Miami, brings "an effective combination of creative campaign strategy and dedication to excellence to her client relationships," the agency said in a June 11 press release.

LINCOLN GARRICK

As a former marketing professional for various Florida-based companies, McMillan represents Marketing Solution's clients in the telecommunications, education and tourism industries.

Garrick, an Illinois native, graduated from the University of Alaska Anchorage's School of Business and is currently earning his master's degree from Alaska Pacific University.

Garrick brings an extensive background in the education and nonprofit industries to the agency, where he works with clients in the healthcare and mining industries.



MICHELLE MCMILLAN

Arrington's extensive experience in the tourism and marketing industries "translate easily to his new role as account manager for several of MSI's tourism clients," Marketing Solutions said.

After serving in various roles for Hawaiian Vacations, including marketing manager, he works closely with the agency's clients in the tourism and transportation industries.

World records smashed for longest, highest ratio well

A Schlumberger team recently helped Maersk Oil Qatar break 10 world records with an extended reach offshore well.

Schlumberger said its technology has now contributed to six of the top seven extended reach directional projects. The latest, drilled in the Al Shaheen field offshore Qatar, broke the previous record length by 2,000 feet, reaching a total depth of 40,320 feet. Total step-out distance from the surface location was 35,770, the company said.

The eight and a half inch horizontal section was drilled in two runs with Schlumberger's PowerDrive X5 and PowerDrive Xceed RSS, and involved a company D&M team assigned to Maersk for more than a year.

Microseismic downhole monitoring goes live

In a May 30 press release Schlumberger said its microseismic monitoring "provides direct 4D information about stress changes in a reservoir by recording seismic waves generated during very small slip events."

Relatively new to the oil and gas industry, the technology can "map the path of fractures from the wellbore into the reservoir as they are created by hydraulic stimulations. When used with recently developed real-time monitoring technology, microseismic information helps engineers optimize production and mitigate risk throughout the life of the field by optimizing hydraulic fracturing jobs on the fly," Schlumberger said.

COURTESY SCHLUMBERGER

PS3 passive seismic sensing system and the Omega-Lok being readied for deployment.

Previously, microseismic data from a produced or stimulated well was acquired using a tool positioned in a separate well often drilled for that purpose. Today, "an innovative technology that reduces noise associated with fluid flow allows this data to be obtained in active treatment or production wells," the company said.

Used with the PS3 passive seismic sensing system, the Omega-Lok device couples geophones to the inside of casing as part of the well completion. It also decouples the sensors from the tubing, "minimizing completion noise passively while maximizing formation coupling. A hydraulically activated release mechanism is used to deploy the fit-for-purpose, low-noise-floor sensors," reducing the noise by a factor of 100 compared with other tubing-conveyed monitoring methods, enabling "long-term monitoring without the cost of drilling offset monitor wells and exploits the full value of microseismic information on a reservoir-wide scale."

Schlumberger acquires Integrated Exploration Systems

Schlumberger said June 8 it has acquired Integrated Exploration Systems, the Aachen, Germany-based supplier of advanced petroleum systems modeling software and services for the exploration and production industry.

IES specialized in the modeling of the generation, migration and entrapment of oil and gas using PetroMod software, which Schlumberger said is used to "estimate undiscovered hydrocarbons in frontier basins," mitigating exploration risks.

"The combination of IES expertise with WesternGeco and Schlumberger technology will … provide our customers with fully integrated exploration services," said Dalton Boutte, WesternGeco president and Schlumberger vice president.

IES's Aachen headquarters will become a Schlumberger Center of Excellence for Petroleum Systems Modeling.

Editor's note: See full stories in the next edition of the Petroleum Directory, a magazine that is published twice a year by Petroleum News.

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INSIDER

BarentsObserver.com reported that Miller's deputy, Aleksandr Medvedev, said Gazprom would also hold talks with TransCanada, a competing Alaska gas pipeline project that has been endorsed by the governor of Alaska under the Alaska Gasline Inducement Act.

AP said Miller told an international business forum in St. Petersburg, Russia: "Gazprom has unique experience, knowledge and modern technology and is the most advanced company in the world in the realm of gas transport in trunk pipelines. So, participation in such a large-scale project as the construction of a pipeline from Alaska is interesting for us."

Miller did not say whether there had been a response from BP and ConocoPhillips, AP said. The BP-ConocoPhillips proposal, dubbed Denali.

BP Exploration (Alaska) spokesman Steve Rinehart told Petroleum News that a number of companies have asked about joining the Denali gas pipeline project. Rinehart said while he couldn't comment about individual companies, "I can tell you they see this as a world-class project and that we have started already."

ConocoPhillips did not have a comment on the report.

TransCanada, which is awaiting approval of a license under AGIA by the Alaska Legislature, has not yet been contacted by Gazprom.

"We haven't seen a proposal from them or any other party," company spokeswoman Cecily Dobson told Petroleum News June 10.

AP said state-controlled Gazprom has been aggressively increasing its presence in Europe, drawing concerns of over-reliance on Russia for natural gas.

—Petroleum News and wire reports

Alyeska names new head of corporate communications

MICHELLE EGAN is joining Alyeska Pipeline Service Co. as director of corporate communications.

Alyeska said June 4 that Egan will begin work June 30; she will be responsible for the company's formal internal and external communications, including media relations, community relations, government relations and stakeholder relations.

Egan, raised in Kodiak, has nearly 20 years of professional experience in communications and has spent the past 10 years in the communications department at the Anchorage School District, where she managed internal and external communications.

Egan has also held communications positions with the Anchorage Economic Development Corp. and Junior Achievement of Alaska.

She has a B.A. from Boston College in psychology and holds Accredited in Public Relations certification.

—Petroleum News

Bristol Bay Native Corp. CEO retires

THE CHIEF OPERATING OFFICER of Bristol Bay Native Corp. has retired.

Tom Hawkins worked for the Anchorage-based Native corporation for 16 years before retiring May 30.

Company officials say that during Hawkins' tenure, the company gained 26 subsidiaries and many were launched or acquired with Hawkins' guidance.

The company also grew to more than $1 billion in revenue.

Before joining the company, Hawkins worked as a deputy commissioner at the Alaska Department of Natural Resources.

He also worked as chief executive officer of Choggiung Ltd., the village corporation in Dillingham.

The company appointed vice president April Ferguson as interim chief operating officer.

—The Associated Press

Editor's note: Insider news tips can be provided by email to Kay Cashman at publisher@petroleumnews.com, or delivered by phone to Eric Lidji at 907 770-3505.

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CANADA'S BEAUFORT

Beaufort, with another C$13.1 million coming from two other successful Beaufort bids.

In addition to its major bid, BP also landed two other Beaufort parcels totaling 1 million acres for C$16.2 million in work commitments; a partnership of MGM Energy 60 percent, ConocoPhillips Canada 27.5 percent and two units of Phillips Petroleum 12.5 percent pledged C$1.75 million for 507,000 acres; and ConocoPhillips made a solo winning bid of C$2.54 million for 486,000 acres.

Eastward extension of existing Imperial-ExxonMobil license

All four Beaufort parcels were an eastward extension of the Imperial-ExxonMobil license.

In addition to paying the 25 percent deposits, the companies have five years to drill an exploration or delineation well to earn a four-year extension on their license. If they discover enough hydrocarbons to allow sustained production they can qualify for a significant discovery license, which gives them indefinite tenure of the acreage.

"We are sick and tired of having out future economic wellbeing blind-sided by environmental organizations that poke their self-righteous noses into someone else's backyard without having the decency to consult with us or offer any realistic alternatives," said Nellie Cournoyea, CEO, Inuvialuit Regional Corp.

This revival of interest in the Beaufort comes on the heels of four low-key years for the Beaufort-Mackenzie Delta region, largely because of uncertainty associated with the protracted regulatory process for the Mackenzie Gas Project.

In the absence of any industry nominations there were no sales in 2003 and 2005.

Otherwise a joint-venture by Chevron Canada Resources and BP Canada Energy committed C$61.9 million for 138,500 acres in the Mackenzie Delta in 2004, while in 2006 there were two winning bids — C$1.2 million by EnCana 37.5 percent, Anadarko Canada 37.5 percent and ConocoPhillips Canada 25 percent for 140,000 acres and C$11.6 million by Shell Canada for 247,000 acres, both on the Delta.

> *Northwest Territories Premier Floyd Roland expressed "increasing frustration with southern-based advocacy groups promoting decisions which impact the lives and economic future of northerners." He said the NWT government will not be swayed by outside interference.*

Federal grants boosted Beaufort drilling in 1970s, 1980s

The Canadian Beaufort established its credentials in the 1970s and 1980s, when federal government grants covered up to 80 percent of wells drilled in frontier regions by companies more than 75 percent owned by Canadians, which racked up a host of significant discovery licenses.

The major find occurred in 1984 when Gulf Canada Resources (a predecessor company of ConocoPhillips) reported its Amauligak discovery believed to contain 350 million barrels of oil and 1.4 trillion cubic feet of gas.

But exploration took a dive when federal grants were withdrawn and a moratorium was imposed on the construction of a gas pipeline along the Mackenzie River Valley until aboriginal land claims were resolved.

When the Mackenzie Gasline Project came to life this decade there was a brief flurry of renewed activity in the Delta and Central Mackenzie Valley of the Northwest Territories and, in 2006, Devon Canada drilled the first wildcat in the Beaufort in 17 years, in hopes of a major gas strike to bolster its case for space on the proposed MGP pipelines. Instead, it struck an estimated 240 million barrels of recoverable oil and has shelved its exploration program.

The Beaufort comeback was partly explained by BP Canada spokeswoman Hejdi Feick, who said that expanding the company's holdings in the Beaufort — where its 1998 takeover of Amoco Canada gave it 15 significant discovery licenses and two exploration licenses covering 1 million acres in the an area where Canada and the United States are haggling over the boundary line — is "very much part of our ongoing business development activities to grow and add to our existing base."

She said the frontier play offers the chance to improve North American's energy supply and enhance security.

Subject to permits, Imperial-ExxonMobil plans 3-D seismic

Imperial Senior Vice President Randy Broiles last year said the Imperial-ExxonMobil acreage represents an opportunity to add to Imperial's Beaufort resource base and "is consistent with our continued interest in energy development for Canada."

The Imperial-ExxonMobil joint venture has contracted two ships and, pending approval from the National Energy Board and The Inuvialuit aboriginal community, plans to conduct 3-D seismic work this summer.

Feick said BP will develop an exploration plan after consulting with various stakeholders in the region, including aboriginals and environmentalists.

She said dealing with issues on wildlife and stakeholder benefits is not something that can happen overnight.

The identity of this year's other bidders was not disclosed, but Benoit Beauchamp, executive director of the Arctic Institute of North America, based at the University of Calgary, told the Calgary Herald he would have expected ExxonMobil to make a bold move to expand its real estate.

"Now that BP has arrived, that's a whole different game," he said. "It demonstrates what we've known for a couple of years … that the industry is looking north."

Beauchamp suggested it might need infrastructure spending from up to six companies to lower the risk to the point where the region can be opened up to petroleum development.

He said the changing patterns of world oil supplies and the shortage of opportunities for big conventional oil discoveries could mean the Arctic is last frontier.

In the run-up to the sale, ConocoPhillips Canada President Kevin Meyers made no secret of his company's interest in the properties, saying the blocks were "really significant postings in terms of acreage size."

To other observes the significant difference now from the 1970s and 1980s is that companies are putting their own money on the line and are not counting on Canadian government support.

Powerful environmental lobby

The other issue that has changed in the interim is the emergence of a powerful lobby by environmental organizations that are prepared to take legal action.

The World Wildlife Fund made a last

> *"Now that BP has arrived, that's a whole different game. It demonstrates what we've known for a couple of years … that the industry is looking north."*
>
> **— Benoit Beauchamp, executive director of the Arctic Institute of North America**

minute attempt to delay the June 2 deadline for this year's bidding round, arguing that awarding Beaufort licenses contravened Canada's Oceans Act, until the federal government completes a management plan to protect Beaufort habitats for polar bears and whales.

The WWF also argued there are no proven techniques for handling oil spills in "such dangerous iced waters."

A government spokesman said delaying the sale would be a "major setback to responsible economic development" in Canada's North and would undermine the confidence of companies thinking about investing in the region.

The successful bidding prompted federal Indian Affairs and Northern Development Minister Chuck Strahl to comment that issuing the exploration licenses gives momentum to the government's goal of promoting economic and social development in the North and bolstering Canada's Arctic sovereignty claims, while ensuring the "unique and delicate environment is protected for future generations."

Nellie Cournoyea, chief executive officer of the Inuvialuit Regional Corp., which plans a key role in economic development of the land claims covering the Western Arctic, said her community looks forwards to the economic benefits of reestablishing interest in Beaufort exploration.

She said the lead time needed to "identify and develop these resources" will ensure that the Canadian government, industry and Inuvialuit have an opportunity to advance parallel research and other initiatives to protect the Beaufort marine environment and its associated wildlife.

Earlier, Cournoyea had lashed out at WWF claims that there is no management regime for the Beaufort, saying that showed "total disrespect for the people who have continually tried to be good guardians of what the region represents."

"We are sick and tired of having out future economic wellbeing blindsided by environmental organizations that poke their self-righteous noses into someone else's backyard without having the decency to consult with us or offer any realistic alternatives," she said.

Northwest Territories Premier Floyd Roland expressed "increasing frustration with southern-based advocacy groups promoting decisions which impact the lives and economic future of northerners."

He said the NWT government supports "responsible and managed development" of its resource sector and will not be swayed by outside interference.

To date, the WWF has not indicated whether it will pursue legal options to challenge the auction process. ●

continued from page 1

BLOWDOWN

scenario,” the division said in a May 16 summary of the study. “This difference is larger than the expected ultimate recovery from the Alpine oil field.”

Petroleum geologist Julie Houle, with the division’s resource evaluation staff, introduced the study May 30 during the administration’s Alaska Gasline Inducement Act forum in Anchorage.

Houle said the division had a good in-house data set for Point Thomson, and began work with a 3-D geologic model, then contracted with PetroTel for help in understanding the geologic model and to do reservoir modeling.

She said the goal was to understand the Point Thomson reservoir, and when some of the conclusions reached were “surprising” the AGIA team was alerted because results indicated that Point Thomson gas might not be available for initial sales.

Feasible without Point Thomson?

Black & Veatch Corp., a global engineering, consulting and construction company working with the administration’s gas team, did an economic analysis. Deepa Poduval, a principal with the firm, said May 30 that the general perception had been that Point Thomson would have gas available at the beginning of gas sales. Was the project feasible without it?

The state’s conservative case was 4 billion cubic feet a day, compared to the 4.5 bcf base case, but they looked at a scenario — without Point Thomson gas — where a pipeline moved just 3.5 bcf a day, Poduval said.

What they found was that 3.5 bcf a day worked.

The project is “very feasible” without any Point Thomson gas, Poduval said, and would be profitable for both the state and the producers. The pipe would be the same in all three cases, 48-inch diameter, but fewer compressors would be needed for smaller volumes of gas.

The capital cost would drop, but with a lower volume over which to spread the cost, the tariff increases as the volume of gas drops, Poduval said.

Best recovery of liquids from condensate at 30 years

Plano, Texas-based PetroTel Inc., a consulting firm specializing in enhanced oil recovery, reservoir characterization and simulation, did the reservoir model study for the division.

The best oil condensate recovery from the field, according to model cases run by PetroTel, comes after 30 years with 30 wells, 22 producers and eight injectors: 86 percent of the liquids were recovered from the condensate and oil-rim recovery was close to 50 percent, 290-475 million barrels.

With the injectors converted to gas producers for a 30-well gas blowdown, up to 70 percent of remaining recycled gas would be recovered within 12 years after liquids production ended.

Point Thomson is a high-pressure condensate reservoir, with liquids suspended in the gas at pressures of more than 10,000 psi, much higher than encountered elsewhere on the North Slope. In gas cycling the condensate would be brought to the surface, the liquids removed and sold, and the gas re-pressured and reinjected to maintain reservoir pressure. Gas would be produced at the end of liquids production.

That was long the development plan for the reservoir, but a few years ago the Point Thomson owners (ownership at the unit is in litigation) decided gas cycling would not be economic, and proposed to produce the gas for sale in a proposed North-Slope-to-market gas pipeline.

The division objected and DNR concurred; ultimately the Point Thomson unit was terminated, a decision the former owners have appealed. Earlier this year the former owners proposed a small gas cycling project to test whether the reservoir would support a cycling project.

Point Thomson could be third largest oil field on North Slope

While Point Thomson has been characterized as a gas reservoir, specifically “it’s a retrograde gas condensate reservoir with an oil rim,” said Anil Chopra, founder of PetroTel.

He said at the May 30 presentation that gas and condensate have been tested but “consistent production tests” are lacking, in particular “consistent long-term production tests from the thin oil rim are missing.”

Chopra said geologic models indicate gas in place at Point Thomson is 8.5 trillion to 10.4 trillion cubic feet, with associated condensate of 490 million to 600 million barrels and a potential oil rim of 580 million to 950 million barrels.

Point Thomson could be “the third-largest oil field” on the North Slope, after Prudhoe Bay and Kuparuk, he said.

Primary depletion — blowdown — simplest for Point Thomson

Chopra said PetroTel ran more than 70 computer simulations, trying to establish the best way to produce Point Thomson. Primary depletion, blowdown of the gas, is easy, he said: “You go and punch holes in the ground and start producing gas.”

He said when blowdown was run in the model, with 22 wells 70 percent of the gas could be recovered in 12 to 15 years. While some of the condensate could be produced, 74 percent was left behind with blowdown, because as reservoir pressure is reduced, liquids drop out of the condensate.

Some 6-7 tcf of gas would be recovered with blowdown, but only 127-156 million barrels of liquids, about 26 percent of in-place volume.

In primary depletion — blowdown — oil-rim oil recovery varied from 3-16 percent (30-150 million barrels), depending on the number of wells drilled.

Pressure should be maintained

Gas cycling is required to maximize recovery, Chopra said.

Ideally you’d maintain reservoir pressure until all economically recoverable condensate and oil are produced.

If pressure is maintained through gas cycling for 10 years, 62 percent of the condensate is recovered (300-370 million barrels) along with 39 percent of the oil rim (225-370 million barrels).

Over a 20-year gas recycling project, 76 percent of the condensate is recovered (370-450 million barrels) along with 43 percent of the oil rim (250-400 million barrels).

Blowdown of the gas cap after 10 and 20 years of cycling recovers 57 percent and 56 percent, respectively (4.8-5.9 tcf) of the original gas in place.

The division’s report said “it became obvious that oil rim development had to be done during a gas cycling phase.” There is uncertainty about the quality of both the oil and reservoir rock in the oil rim, so reservoir pressure must be maintained “to preserve reservoir energy and sustain maximum oil producibility” from the oil rim.

The project is “very feasible” without any Point Thomson gas, Poduval said, and would be profitable for both the state and the producers. The pipe would be the same in all three cases, 48-inch diameter, but fewer compressors would be needed for smaller volumes of gas.

Injecting recycled gas into the oil rim would “help reduce the viscosity, improve swelling, mobilize and displace the oil.” Wells into the oil rim also help with recovery: increasing the number of wells into the oil rim during gas cycling development increases oil recovery. With 13 gas producers, 18 gas injectors and 20 oil-rim producers, recovery of oil-rim oil approached 50 percent after 30 years of cycling — three to 15 times better than oil-rim oil recovery during primary blowdown.

More gas could be used

The division said with production from the oil rim, voidage from the reservoir was increased. Looking at model cases with large-scale oil-rim development of 30 horizontal producers, reinjection of 90 percent of produced gas would not be sufficient to maintain reservoir pressure.

Gas from other fields could be imported and injected into the Thomson reservoir to help maintain reservoir pressure, and this gas could be in the form of carbon dioxide or inert gas such as nitrogen, methane or natural gas.

CO_2 is commonly removed from produced gas in a gas treatment plant and if enough CO_2 were available for pressure maintenance, it could allow sale of some Point Thomson gas prior to blowdown. The division also said that “CO_2 should be fully miscible with the Thomson oil and thus reduce the viscosity and further increase recovery.”

Because CO_2 is a greenhouse gas there could be government tax incentives for storing it in a reservoir.

Importation of CO_2 would require construction of a gas line to Point Thomson, but, the division pointed out, once blowdown began that line would be available for gas sales.●

On the Web

See previous Petroleum News coverage:

“Thomson gas cycling gets lots of study” In affidavit, Craig Haymes, Exxon’s Alaska manager, reviews history of working interest owners’ work on condensate production,” in April 6, 2008, issue at www.petroleumnews.com/pnads/753393422.shtml

“Exxon submits PTU plan: New development plan calls for condensate, oil to be produced before natural gas,” in Feb. 24, 2008, issue at www.petroleumnews.com/pnads/369341493.shtml

“DNR calls for briefing on Point Thomson plan of development,” in Jan. 13, 2008, issue at www.petroleumnews.com/pnads/534884139.shtml

“State wins lawsuit: Judge agrees with Alaska on 22nd Point Thomson plan; requires hearing on remedy,” in Jan. 6, 2008, issue at www.petroleumnews.com/pnads/485989934.shtml

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LNG CARRIERS

drive the boat forward in a conventional manner.

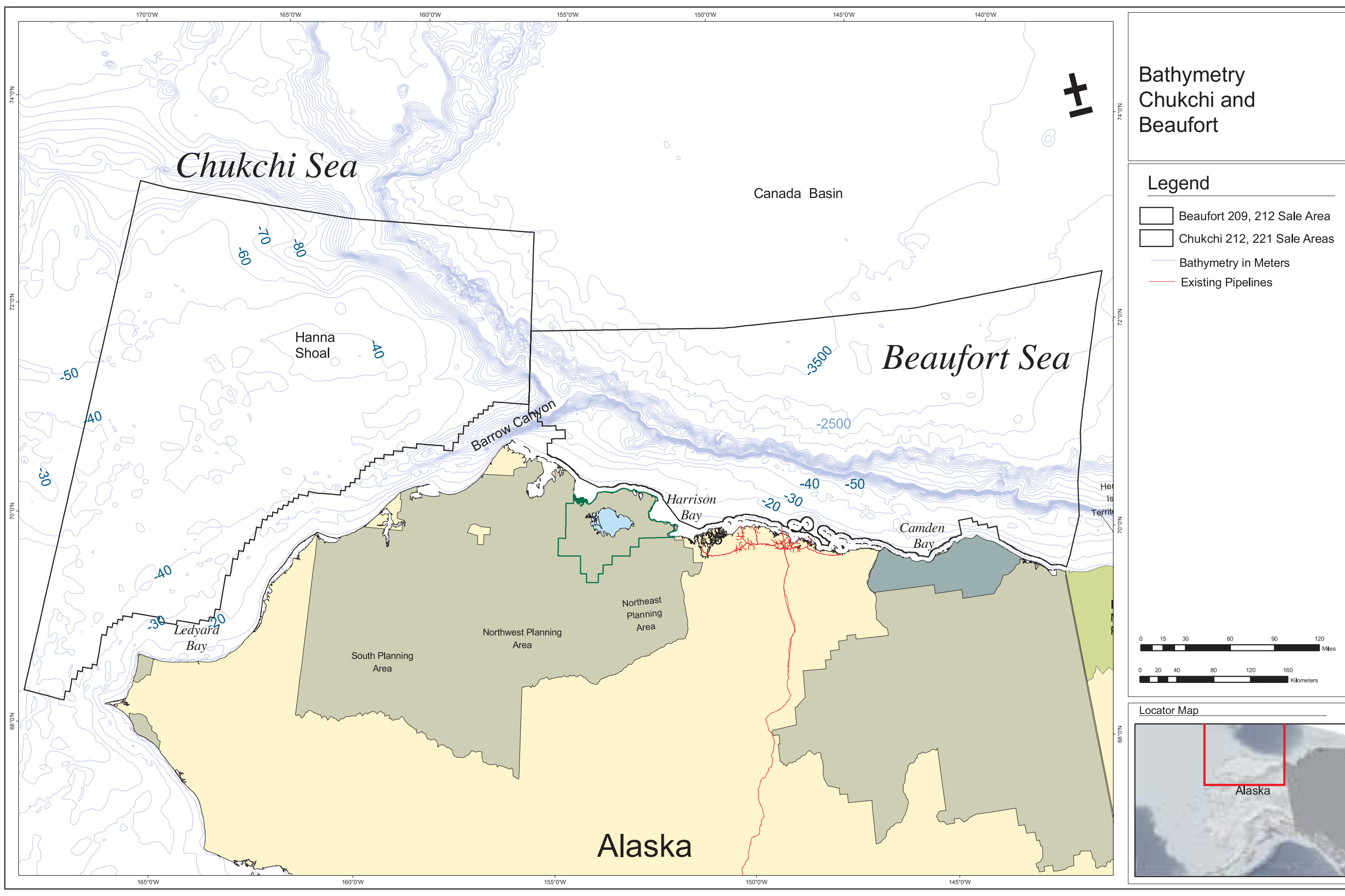
Container ship

An icebreaking container ship using this technology was successfully tested offshore northern Russia in 2006. Aker Arctic Technology, a leading Finnish icebreaker design and consulting company, has said that it is in the process of designing a double acting LNG carrier for use in Russia's Yamal field in the Kara Sea, north of Siberia. And in May the American Bureau of Shipping said that it has teamed with BMT Fleet Technology and Hyundai Heavy Industries to investigate the structural integrity of various cargo containment systems under different ice impact scenarios.

According to an April report in MarineNorway, Russia plans to use as many as 25 LNG carriers to ship LNG from the giant Shtokman gas field in the ice-laden Barents Sea.

But the American Bureau of Shipping has said that there is no service history for the use of LNG carriers in ice-breaking conditions.

So, could the use of LNG carriers really be a feasible option for shipping gas from Alaska's North Slope or, perhaps, from a future gas field in the Beaufort or Chukchi seas? Before anyone grabs a phone to call Governor Palin about postponing decisions on AGIA and a North Slope gas line, they might want to consider some of the many pitfalls facing an LNG project on the northern coast of Alaska.



A bathymetry map of the Beaufort and Chukchi seas depicts shallow water around the coastline. Water depths are in meters (approximately 3 feet).

Shallow water

The biggest hurdle facing anyone wanting to ship LNG from the Beaufort Sea or Chukchi Sea coast would likely prove to be the water depths — the water remains shallow for a long way offshore around the Arctic coastline of Alaska.

A typical LNG tanker draws about 39 feet when loaded, Jim Craig, U.S. Minerals Management Service geologist and economic evaluator, told Petroleum News. Allowing normal safety margins for clearing the seafloor would require water depth of 78 feet in a dock and a channel depth of 117 to 156 feet for transiting to and from the LNG facility.

These requirements "would be an impediment for much of the Beaufort and Chukchi coastlines where these depths would not occur within five miles of land," Craig said.

And then there's the question of what to do with the LNG shipped from, say, the North Slope, which the federal government wants to see brought to the United States, not shipped to foreign markets.

Shipments to the U.S. West Coast would be limited by LNG terminal capacity — the only operational terminal on the West Coast is in Mexico's Baja California and that terminal has fully contracted supplies according to reports on its May 2008 opening.

"No new terminals are under construction on the U.S. West Coast and any deliveries to future terminals would require Jones Act ships," Craig said.

The Jones Act mandates that only U.S.-flagged vessels with U.S. crews may carry goods between domestic ports.

"There are no Jones Act LNG ships operating today and no LNG ships have been built to operate in ice-infested waters," Craig said.

Export license

Exporting LNG overseas, say to Japan or one of the other Pacific Rim countries, would require an export license from the U.S. Department of Energy. A DOE export license can be denied if DOE determines that the export of the gas would not be in the public interest, perhaps as a consequence of domestic U.S. need for the gas.

The export of gas that originates from the U.S. outer continental shelf, perhaps from a future gas field in the Chukchi or Beaufort seas, would currently be prohibited under federal law and would require an exemption from Congress and the president.

Having said all of that, the Russians seem intent on using LNG carriers in ice-infested waters and anything may be possible using new technologies and exemptions from laws such as the Jones Act. But anyone wishing to export LNG by sea from Alaska's Arctic coastline would surely face some formidable challenges. ●

On the Web

See previous Petroleum News coverage:

"Breaking through the ice," in Nov. 25, 2007, edition at: www.petroleum-news.com/pnads/230239803.shtml

"Study reports on LNG carrier designs for the Arctic," in May 11, 2008, edition at: www.petroleumnews.com/pnads/935248596.shtml

FINANCE & ECONOMY

BP exec named first president of newly formed Denali gas pipeline firm

A senior executive with BP has been appointed the first president of a new company recently created to build a natural gas pipeline from the North Slope of Alaska to markets in the Lower 48.

BUD FACKRELL

Bud E. Fackrell will become the president of Denali — The Alaska Gas Pipeline LLC, formed by BP and ConocoPhillips in early April.

Fackrell comes to the position after serving as the senior vice president of BP's Alaska Consolidated Team, where he was responsible for all BP operations on the North Slope except Prudhoe Bay. He took the position in August 2006.

Before coming to Alaska, Fackrell was the chief executive officer and general manager of the Abu Dhabi Marine Operating Co. He previously worked for BP in the Rockies and in Egypt. He has more than 33 years of experience in the oil and gas industry.

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