Petroleum news

Vol. 14, No. 10 • www.PetroleumNews.com

A weekly oil & gas newspaper based in Anchorage, Alaska

Week of March 8, 2009 • $2

page 7 Kim Elton named director of Alaska affairs at Department of the Interior

Thomson rig: Nabors 27E

COURTESY OF EXXONMOBIL

ExxonMobil is using Nabors rig 27E to drill at Point Thomson. The rig has been extensively refurbished to drill the deep, high-pressure reservoir.

Conoco cuts 80 Alaska jobs

Conoco Phillips is eliminating 80 jobs in Alaska as the company tightens spending in response to the steep decline from last year's record oil prices, a company spokesman announced today.

Charlie Rowton, a spokesman at Conoco's corporate headquarters in Houston, said 40 Alaska employees are being laid off and being given severance packages and another 40 are being transferred out of Alaska. He wouldn't elaborate on

see **CONOCO** *page 19*

Mackenzie two years away, says possible equity partner in line

If it ever proceeds, the start of construction on the Mackenzie Gas Project is at least two years away, says one of the possible equity partners in a Mackenzie Valley pipeline.

"Gas won't be flowing any time soon, nor will the significant long-term benefits" start reaching aboriginal owners, Bob Reid, president of the Aboriginal Pipeline Group told a Calgary conference March 4.

see **MAC LINE** *page 18*

BREAKING NEWS

3 State lays out bullet line plan: 'Action plan,' pair of bills coordinate efforts toward construction of $4B gas line into Southcentral

4 B.C. plugs on, Alberta caves in: Provinces chart different routes through tough times; Alberta answers call to stem drilling decline

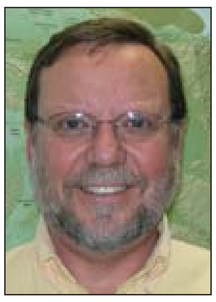
14 UltraStar preps to drill Dewline: Despite weak credit market, lower oil prices, company set for drilling after 4 years of trying

EXPLORATION & PRODUCTION

Slowing Nikaitchuq

Low oil prices and weak economy believed to be behind Eni's decision

By ERIC LIDJI
Petroleum News



KEVIN BANKS

Eni Petroleum is "slowing down" the pace of development at the Nikaitchuq unit in the nearshore waters off the North Slope, according to a top state oil and gas official.

Division of Oil and Gas Director Kevin Banks told Petroleum News that the American subsidiary of the Italian oil giant planned to move the project from the "fast track" to a "normal pace," which could delay startup of the oil field by six months to a year.

Management at ASRC Energy Services, a major North Slope contractor, reportedly told employees in late February that Eni planned to defer, but not cancel, its operations at Nikaitchuq, in the face of lower oil prices and the global economic environment.

An Eni representative in Anchorage declined to comment about plans for the unit, and an Eni spokeswoman in Houston was out of town and could not be reached for comment.

Eni sanctioned the $1.45 billion Nikaitchuq project in January 2008, announcing plans to develop the field from both onshore and offshore, and to build new processing facilities.

An Eni official last fall spoke about producing first oil from onshore pads at Nikaitchuq in late

see **NIKAITCHUQ** *page 18*

NATURAL GAS

One-stop shopping in Canada

NEB decision to place TransCanada's Alberta pipeline network under federal jurisdiction smoothes way for B.C. and Arctic producers

By GARY PARK
For Petroleum News

TransCanada has put two key building blocks in place to lock up a lead role in carrying gas from the British Columbia tight and shale plays and, if the projects go ahead, gas from Alaska and Mackenzie Delta.

In one of its most significant pipeline rulings, Canada's National Energy Board has placed TransCanada's Alberta network under federal jurisdiction, removing a major roadblock in the way of getting new gas to Alberta's AECO hub, the largest trading point in North America.

The result is that the NEB will regulate 23,500 kilometers of pipeline in Alberta that, until now, have been under the control of the Alberta Energy Resources Conservation Board.

The immediate initial benefit will be felt in northeastern British Columbia's fast-emerging Montney-Groundbirch tight gas and Horn River shale gas basins.

Rolled-in tolls an issue

Under federal regulation, TransCanada will be able to apply to the NEB for permission to extend its Nova Gas Transmission system (acquired by TransCanada in 1998) across the Alberta border into

see **SHOPPING** *page 19*

GOVERNMENT

A call for peace in CI

Giard wants to clarify utility gas pricing to end the 'Cook Inlet Gas War'

By ALAN BAILEY
Petroleum News

KATE GIARD

In December Petroleum News referred to the Regulatory Commission of Alaska's December decision to allow Enstar Natural Gas Company to obtain gas for a year under new contracts with two Cook Inlet gas producers as the closing of a chapter in a long regulatory process, with the book remaining open.

"Those in gas supply have a less literary description of the situation; they call it the 'Cook Inlet Gas War,'" said RCA Commissioner Kate Giard in a statement accompanying an RCA Feb. 27 order closing the docket in which Enstar had requested approval of its new gas supply contracts with Marathon Oil Co. and ConocoPhillips.

The standoff that Giard characterizes as a war reflects two opposing views of "equitable" Cook Inlet gas pricing: The producers have said that gas prices need to reflect Lower 48 pricing, to attract capital investments in new exploration and development in the expensive Cook Inlet gas basin, while consumer advocates have claimed that this type of pricing is channeling excessive profits to the producers at the consumers' expense.

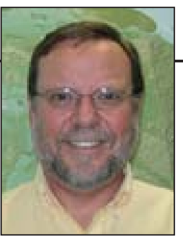
For many years Cook Inlet utility gas consumers enjoyed an abundance of cheap gas from Cook Inlet oil and gas fields discovered several decades ago. But

see **PEACE** *page 17*

contents

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

ON THE COVER



Slowing Nikaitchuq

Low oil prices and weak economy believed to be behind Eni's decision

One-stop shopping in Canada

NEB decision to place TransCanada's Alberta pipeline network under federal jurisdiction helps B.C., Arctic producers

A call for peace in CI

Giard wants to clarify utility gas pricing, to end the 'Cook Inlet Gas War'

SIDEBAR, Page 17: Agrium and the Cook Inlet gas market

Conoco cuts 80 Alaska jobs

Mackenzie two years away, says possible equity partner in line

EXPLORATION & PRODUCTION

6 **Upstream heads downhill**

Western Canada reeling as drilling, well permits, land sales crumble in the face of tight financial markets, cratering gas prices

12 ANS February production up 4.9%

14 **UltraStar preparing to drill Dewline**

Despite weak credit market and lower oil prices, tiny UltraStar is set for drilling on the North Slope after four years of trying

FINANCE & ECONOMY

4 **B.C. plugs on, Alberta caves in**

Provinces chart different routes through tough times; Alberta answers call to stem drilling decline, save jobs; could cost C$1.5B

8 Nova's star about to fade

GOVERNMENT

7 Elton named to Alaska slot at Interior

15 Lisankie takes Johnson's place at RCA

INTERNATIONAL

11 **Foreign legion in retreat**

Canadian-based companies experience more downs than ups in overseas plays; can't negotiate financing to develop strong prospects

LAND & LEASING

7 **One expansion approved, one deferred**

Prudhoe Bay unit expanded by 1,000 acres; expansion of Orion participating area deferred pending well data to prove up resource

15 MMS extends draft EIS comment period

NATURAL GAS

3 **State lays out plan for bullet line**

'Action plan' and a pair of bills would coordinate efforts toward construction of $4B gas pipeline into Southcentral

OUR ARCTIC NEIGHBORS

OUR ARCTIC NEIGHBORS

13 **Norwegian regulator keeps eye on Arctic**

Petroleum Safety Authority wants closer cooperation with Russia in Barents Sea, higher safety standards

13 Murmansk oil company sinking into hole

13 Europeans win Shtokman design contract

13 Gazprom expands geological facilities

SAFETY & ENVIRONMENT

5 Following up on the pipeline rupture

10 The shrinking Beaufort Sea coastline

14 Panel marks 20th EVOS anniversary

15 Obama reinstates species reviews

● NATURAL GAS

State lays out plan for bullet line

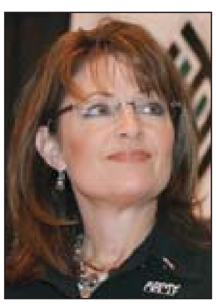
'Action plan' and a pair of bills would coordinate efforts toward construction of $4 billion gas pipeline into Southcentral; greatest state involvement in 'bullet line' efforts to this point

By ERIC LIDJI
Petroleum News

The Palin administration is taking a more active role in the construction of a $4 billion pipeline to deliver northern natural gas to communities along the Alaska road system.

Gov. Sarah Palin introduced two bills on Feb. 27 designed to "jump start" construction of an in-state pipeline, and on March 3 outlined an "action plan" to get gas flowing by 2015.

One bill expands the role of the Alaska Natural Gas Development Authority. The other tries to alleviate the risk for companies that want to build or ship gas through a pipeline.


JUDY PATRICK
GOV. SARAH PALIN

Under the action plan, the state will try to align potential gas owners with potential gas buyers, apply for permits and rights of way, estimate the tariff, develop a business plan and eventually choose a private sector company to build and operate the pipeline.

The state hopes to have enough commitments and information to be able to make that decision by June 2011, according to Project Manager Harry Noah, executive director of the Trust Land Office and former commissioner of the Department of Natural Resources.

Once the state hands the project over to a builder, Noah estimated costs between $600 million and $900 million for detailed engineering work, furthering permitting and buying long lead-time materials. Construction would begin in 2012 and finish in late 2014.

"This schedule is very ambitious," Noah said, but added that he thought it would be easier to slow down a fast timeline than be forced to speed up a slower timeline later.

Bullet line is still large

Although dwarfed by a large-diameter natural gas pipeline being planned to run from the North Slope into Canada, this "bullet line" is still a massive project by industry standards.

The state envisions a 24-inch pipeline moving 500 million cubic feet of natural gas per day some 800 miles from the North Slope to Southcentral Alaska at a cost of $4 billion.

Combined, the five longest gas pipelines completed in the Lower 48 in 2007 run 789 miles, but cost only $1.7 billion and move 3.4 billion cubic feet of natural gas daily, according to the most recent information from the Energy Information Administration.

The proposed bullet line is half as large and just as long as the trans-Alaska oil pipeline.

This bullet line idea is not new. Enstar Natural Gas is pursuing a nearly identical pipeline running from the Gubik Complex being explored by Anadarko Petroleum in the Brooks Range foothills to the Southcentral distribution grid with a connection to Fairbanks.

"The difference here," Palin said, "is that you have a state commitment and you have a project manager to see this project come to fruition. I think that's been one of the missing pieces of the puzzle."


HAROLD HEINZE


CURTIS THAYER

The puzzle is how to replace dwindling gas supplies in the Cook Inlet and volatile fuel oil supplies in the Interior. Current ideas include the bullet line, a spur line plan under way by ANGDA, efforts to increase exploration in the Cook Inlet and even importing supplies.

Additional puzzles

The bullet line faces additional puzzles.

One is how to coordinate enough industrial demand to keep transportation costs low on the pipeline, while keeping total volumes below 500 million cubic feet per day, the self-imposed limit for state involvement. Getting that demand requires not only coordinating the Railbelt utilities, but also restarting the mothballed Agrium fertilizer plant in Nikiski.

Another puzzle is finding an agreeable price for the commodity. Currently, producers and regulators have been unable to agree on how to price remaining gas supplies in Cook Inlet, and the stalemate could easily follow a bullet line back up to North Slope supplies.

Another is finding a supply of natural gas. Prudhoe Bay is proven, but far away. Gubik is closer, but Anadarko doesn't expect to have reserve estimates until 2016. The Nenana basin is closer still, but the least proven source. A group hopes to drill there this summer.

Noah acknowledged those challenges, but said, "If you're going to try and put together a project and you wait for everything to fall in place, you're always going to be behind the curve. This is something that we can control right now and move forward with. And we'll know more in two years than we know now. But if we don't start, we won't."

Evolving involvement on plan

The new plan furthers the evolution of the state's involvement with in-state natural gas.

Originally, the Palin administration expected the takeoff points from a large-diameter pipeline heading to the Lower 48 would meet the demand for natural gas within Alaska.

By May 2008, when the state awarded TransCanada a license to build that pipeline, dwindling supplies of Cook Inlet gas prompted Enstar to begin looking at a bullet line.

The administration did not become involved with the bullet line at the time, saying only that it would not challenge either the economics or the feasibility of the larger pipeline.

As oil prices peaked last July, Palin became more involved, announcing a public-private partnership between Enstar and ANDGA to build a bullet line from Cook Inlet to Fairbanks by 2013, or to the North Slope by 2014. That partnership failed to materialize.

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

Bills designed for certainty

The legislation consists of two bills.

The first, paired as SB 135 and HB 163, would expand the responsibilities of ANGDA, guaranteeing the public corporation could work on a wider variety of natural gas projects.

Under the proposed legislation, ANGDA could work on a natural gas pipeline connecting production basins anywhere in the state, such as the Nenana basin or the Copper River basin, with markets anywhere in the state, including the Interior region or

see **BULLET LINE** page 15

● FINANCE & ECONOMY

B.C. plugs on, Alberta caves in

Provinces chart different routes through tough times; Alberta answers call to stem drilling decline, save jobs; could cost C$1.5B

By GARY PARK

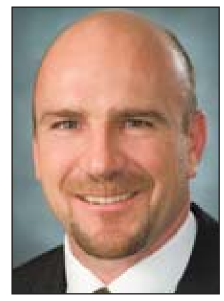
For Petroleum News

British Columbia keeps resolutely pressing ahead with its efforts to disperse gathering storm clouds, while neighboring Alberta has decided to step out from under its umbrella.

Faced with "economic instability," British Columbia has decided to expand its royalty credit program to "support and encourage economic activity that will continue to provide jobs (in British Columbia's) oil and gas industry," Energy Minister Blair Lekstrom said March 2.

The next day Alberta Energy Minister Mel Knight, facing relentless industry criticism that has reached unprecedented levels in what was once the ultimate haven for the oil and gas sector, made the fourth "tweak" to his province's controversial royalty regime.

For British Columbia, the aid will cost only a few million dollars more per year, while the latest stimulus plan in Alberta is potentially worth up to C$1.5 billion, meaning the province has handed back more than C$4.3 billion to the industry in the last year since rolling out its new royalty framework.



BLAIR LEKSTROM

If nothing else, the contrasting approaches to head off a collapse in drilling and save jobs reinforce what many analysts view as Alberta's misguided overhaul of its royalty regime.

B.C. looks to improve position

Lekstrom said that boosting British Columbia's infrastructure development program introduced in 2004 will "improve our competitive position for attracting investment and contribute to the ongoing growth and development of our oil and gas industry."

The program is designed to help companies build roads and pipelines into emerging gas plays, such as the Montney and Horn River tight and shale gas basins, and support year-round operations by improving access to areas that don't normally support heavy equipment outside of winter freeze-up.

The changes will see royalty credits boosted to C$120 million this year from C$100 million in 2008 and C$90 million in 2007.

Since 2004, the credit program has allocated C$316 million to companies, resulting in 72 new road-based projects and 53 new pipeline projects, representing total capital investment of more than C$632 million.

The government estimates it gets a return on investment of 2.5 for every dollar invested.

Greg Stringham, vice president of the Canadian Association of Petroleum Producers, told the Financial Post that by bringing down the cost of development in new areas, the British Columbia government is making another competitive move that Alberta should notice.

Alberta withstands demands

But the Alberta government has withstood demands to make structural changes to its royalty framework, despite warnings that companies have insufficient cash flow after royalties and costs to invest in exploration and development programs.

Even the latest incentives are a reaction to the global economic crisis and not a correction to the new royalty regime, Knight told a news conference.

The plan will reduce royalties on new conventional oil and gas wells to 5 percent or less for at least a year, to help free up cash flow and give the industry access to capital. But the new royalty rate is limited to only the first 50,000 barrels of oil, or 500 million cubic feet of gas.

In addition, a drilling royalty credit for new conventional wells will offer a C$200-per-meter-drilled royalty credit to companies on a sliding scale based on their production levels in 2008. It is aimed primarily at small- and medium-sized producers and aims to provide a capital infusion for those companies.

Finally, Alberta will establish a C$30 million fund to abandon and reclaim old well sites, thus reducing the industry's environmental footprint.

The new well incentive program could take a C$1.04 billion bite out of royalties and the drilling credit program will cost an estimated C$466 million.

"This has nothing to do with splashing money around," Knight said.

"It's relative to the economic situation, not relative to where we were a year or two ago (when the new royalty framework was being unveiled). The time to act aggressively is now."

He said it follows consultation with the industry and financial community about the "current impediments to new investment in Alberta."

Analysts still not happy

There is no doubt among analysts about the source of those "impediments" and they are no longer taking a subtle approach to tearing strips off the Alberta government.

In the days prior to the release of the stimulus plan, Paul Ziff, chief executive officer of Ziff Energy Group, said Alberta generated its own models for finding and development costs during its royalty review in 2007 by "conveniently leaving out dry holes … so the (estimated costs) were a lot lower than for the real industry situation and led to improper conclusions" that leave a lingering gap in understanding between the industry and government.

Randy Ollenberger, with BMO Capital Markets, said tight credit markets have restricted most Alberta companies to reinvesting internally generated cash flow, which is constrained by low commodity prices.

"It seems to me that the Alberta government still doesn't get this," he said.

Without changes to labor costs or the fiscal framework, the advantage that Alberta once enjoyed is 'definitely gone … and we have to fix that," he said.

Industry: Not complete fix

While welcoming the incentives offered, industry leaders were not prepared to suggest the plan will fix all of Alberta's ills.

Dave Collyer, president of the Canadian Association of Petroleum Producers, said "it's a positive step … but it does not deal with some of the more fundamental competitive issues that Alberta is facing."

However, he said the industry is confident that Alberta's on-going study of its competitive standing against similar jurisdictions will take a serious look at the "broader competitiveness."

see PROVINCES page 5

Petroleum news

www.PetroleumNews.com

Kay Cashman	PUBLISHER & EXECUTIVE EDITOR
Mary Mack	CHIEF FINANCIAL OFFICER
Kristen Nelson	EDITOR-IN-CHIEF
Susan Crane	ADVERTISING DIRECTOR
Theresa Collins	MARKETING DIRECTOR
Bonnie Yonker	AK / NATL ADVERTISING SPECIALIST
Heather Yates	BOOKKEEPER
Shane Lasley	IT CHIEF
Clint Lasley	GM & CIRCULATION DIRECTOR
Marti Reeve	SPECIAL PUBLICATIONS DIRECTOR
Steven Merritt	PRODUCTION DIRECTOR
Tim Kikta	COPY EDITOR
Alan Bailey	SENIOR STAFF WRITER
Eric Lidji	STAFF WRITER
Gary Park	CONTRIBUTING WRITER (CANADA)
Rose Ragsdale	CONTRIBUTING WRITER
Ray Tyson	CONTRIBUTING WRITER
John Lasley	STAFF WRITER
Allen Baker	CONTRIBUTING WRITER
Sarah Hurst	CONTRIBUTING WRITER
Paula Easley	DIRECTORY PROFILES/SPOTLIGHTS
Judy Patrick Photography	CONTRACT PHOTOGRAPHER
Mapmakers Alaska	CARTOGRAPHY
Forrest Crane	CONTRACT PHOTOGRAPHER
Tom Kearney	ADVERTISING DESIGN MANAGER
Amy Spittler	MARKETING CONSULTANT
Dee Cashman	CIRCULATION REPRESENTATIVE

ADDRESS
P.O. Box 231647
Anchorage, AK 99523-1647

NEWS
907.522.9469
publisher@petroleumnews.com
or Elidji@petroleumnews.com

CIRCULATION
907.522.9469
circulation@petroleumnews.com

ADVERTISING
Susan Crane • 907.770.5592
scrane@petroleumnews.com

Bonnie Yonker • 425.483.9705
byonker@petroleumnews.com

FAX FOR ALL DEPARTMENTS
907.522.9583

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

OWNER: Petroleum Newspapers of Alaska LLC (PNA)
Petroleum News (ISSN 1544-3612) • Vol. 14, No. 10 • Week of March 8, 2009
Published weekly. Address: 5441 Old Seward, #3, Anchorage, AK 99518
(Please mail ALL correspondence to:
P.O. Box 231647 Anchorage, AK 99523-1647)
Subscription prices in U.S. — $98.00 1 year, $176.00 2 years, $249.00 3 years
Canada — $185.95 1 year, $334.95 2 years, $473.95 3 years
Overseas (sent air mail) — $220.00 1 year, $396.00 2 years, $561.00 3 years
"Periodicals postage paid at Anchorage, AK 99502-9986."
POSTMASTER: Send address changes to Petroleum News, P.O. Box 231647 Anchorage, AK 99523-1647.

● SAFETY & ENVIRONMENT

Following up on the pipeline rupture

PSIO asks BP for more comprehensive reporting on its actions resulting from the Prudhoe Bay artificial lift gas pipeline break

By ALAN BAILEY
Petroleum News

On Sept. 29 a high-pressure artificial-lift gas pipeline on Y-Pad in the BP-operated Prudhoe Bay oil field on Alaska's North Slope blew apart, sending a piece of steel pipe flying through the air.

Subsequent investigations both by BP, and by state and federal regulators, quickly determined that external corrosion of the pipeline had caused the rupture of the line. And in the wake of the incident, BP has undertaken a series of follow-up actions.

Alaska's Petroleum Systems Integrity Office, the state's watchdog organization for overseeing oilfield facility maintenance, has been monitoring the progress of the incident investigation. And on Feb. 20 PSIO issued an investigation status report in the form of a letter from PSIO Coordinator Allison Iverson to BP.

"All parties agree this was a very serious incident — had the high pressure gas pipeline failure occurred under slightly different circumstances, the results would have been catastrophic, potentially with loss of life," Iverson said. "Ultimately the root cause of this incident was corrosion under (pipeline) insulation."

Insulation removed

Iverson said that in 1998 BP had removed a portion of the insulation from the pipeline to evaluate pipeline anchor welds. But the company did not re-install the removed insulation nor seal the remaining insulation, to protect the pipeline from moisture.

"These practices were in accordance with BPXA's approved practices for pipelines at that time," Iverson said.

Then, when BP examined the pipeline for corrosion again in 2003, the company did not inspect the section of pipeline that subsequently failed, because snow drifts had covered that pipeline section at the time of inspection. There was no follow-up on the missed inspection.

Iverson said that, through meetings between PSIO officials and BP following the pipeline rupture, BP had shown to PSIO multiple areas of improvement in its management of its Alaska operations.

"The PSIO applauds BPXA for its efforts to date," Iverson said.

However, Iverson also said that PSIO is "deeply concerned with the timeliness and depth of the incident investigation," saying that BP had not published its incident review summary until Jan. 13 and that the company had also stated that the investigation report was still being finalized.

Lengthy investigation

According to Iverson's letter, BP told PSIO in November that the company's investigation was taking a long time because the investigation team was looking into the question of whether, prior to the incident, company employees had expressed concern about exposed gas pipelines.

"Regardless of the reasons for the lengthy investigation, the PSIO sees a need for timely completion of BPXA's root cause analyses," Iverson said. "Indeed, the PSIO has reviewed similar incident reports from other Alaskan operators and found a much shorter response time (two weeks for the preliminary reports delivered to the state)."

Iverson also said that although the incident review that BP provided to PSIO correctly identified the cause of the incident — "moisture wicking under the insulation, causing external corrosion and ultimately rupture of the pipeline" — the review did not discuss contributory factors such as the lack of procedures either for re-insulating pipelines or for flagging the follow-up on missed inspections.

The corrective actions that BP listed in its incident review do not have assigned dates and there is no indication that accountability for the actions has been assigned to a level of management with appropriate authority, Iverson said.

"Due to the serious nature of the incident, the PSIO requests that BPXA completes all of the corrective action items by May 15, 2009," Iverson said.

Regularly informed

BP spokesman Steve Rinehart told Petroleum News March 2 that after the Y-Pad incident BP had moved ahead with its investigation "with deliberate speed" and had regularly kept PSIO informed of the company's findings and subsequent actions.

"We shared preliminary findings with PSIO and others in October and November of last year," Rinehart said.

And although the root cause of the incident was external corrosion of the pipeline, BP had determined that a contributing cause was the lack of a mechanism for tracking missed inspections, Rinehart said. Since the incident, BP has put in place a procedure to deal with the missed inspection problem, he said.

In fact, BP had already been in the process of upgrading its maintenance procedures at the time of the September incident, Rinehart said.

And within days of the pipeline rupture BP ensured that appropriate inspections had been carried out at 76 other sites on 26 high-pressure gas lines, he said.

BP is also in the process of developing new engineering standards for the sealing and re-insulating of pipelines, Rinehart said.

Corrective actions

Rinehart said that in its investigation report BP has clearly identified a set of recommended actions and that corrective actions resulting from the September incident have been assigned to senior management. Specific timeframes have been specified for carrying out the actions.

"Top managers are accountable to make sure this is done," Rinehart said.

Iverson confirmed to Petroleum News March 2 that following the September incident there had been communication between BP and PSIO regarding the status of the incident investigation and follow-up actions. The purpose of PSIO's Feb. 20 status report was to formally let BP know PSIO's remaining questions regarding the incident, with a view to achieving closure to the incident investigation, Iverson said.

"We didn't want it to be a never ending process for all involved," Iverson said.

Iverson said that PSIO officials had met with BP to discuss the PSIO status report and that at that meeting BP had reviewed in detail the actions it was taking. BP showed PSIO its internal incident report and explained what it is doing, Iverson said.

Iverson said that PSIO is in frequent contact with BP and will be following up on the company's actions by May 15. ●

continued from page 4

PROVINCES

For now, Collyer said the stimulus package should help correct some of the dramatic decline in drilling levels this year.

Gary Leach, executive director of the Small Explorers and Producers Association of Canada, said his member companies will respond and "stem the decline in drilling … (by) drilling more wells than they otherwise would have."

Although the industry leaders would not put a number on the additional wells, Knight said he hopes the plan will reverse the latest forecast of a 27 percent drop in drilling.

Roger Soucy, president of the Petroleum Services Association of Canada, said that without the incentives one quarter of the service sector workforce would have been laid off by the end of April.

"We believe this program will help stem the decrease in activity and potentially even stimulate new activity," he said.

Investment dealer Peters & Co. said the incentives should benefit companies that have chosen to keep capital spending at "reasonably high levels, while financially challenged entities will not benefit significantly because of their limited spending capabilities and low well count."

Tristone Capital shared a similar view, saying that for cash-strapped juniors "staring down the barrel of the banker's gun, the incentives put in place are just out of reach, and, by extension, so is their multiplier effect on the Alberta economy.

"We are skeptical to the degree to which the producers will cycle incremental cash from the incentive program back into the ground for two reasons: One, we are long on supply in North America and adding productive capacity today is not desirable, and, two, we believe the margin of cash that is retained by the incentives will predominantly focus on debt reduction."

Tristone research director Chris Theal said the fact that Alberta is working on a competitiveness study may dissuade the investment community from injecting more money into drilling "because things are subject to change." ●

● EXPLORATION & PRODUCTION

Upstream heads downhill

Western Canada reeling as drilling, well permits, land sales crumble in the face of tight financial markets, cratering gas prices

By GARY PARK
For Petroleum News

Even with land at basement-price levels, the major operators are turning their backs on government auctions in Western Canada, with returns for the three leading provinces totaling C$73.36 million for the first two months compared with C$393.42 million last year.

It's small comfort to Alberta, which has been clobbered since unveiling its royalty increases, but Saskatchewan and British Columbia, which have been a major drain on upstream spending in Alberta, are reeling from this year's land sale results.

The downturn is being accompanied by wave after wave of negative forecasts for the natural gas sector, on top of the slide in conventional oil and oil sands activity.

Statistics compiled from provincial government regulators show operators released rigs on 1,400 wells in January, off 28 percent from a year earlier and barely half the benchmark performance in 2006, while licenses issued for new wells totaled 1,867, down 49 percent from January 2008, with Alberta slumping to 1,613 permits from 3,177 a year ago and a record 3,569 in the first month of 2006.

Those numbers have forced the Canadian Association of Oilwell Drilling Contractors to downsize its 2009 forecast to 11,176 well completions, 22 percent or 3,100 wells below its original forecast issued four months ago and only half the completions in 2005 and 2006.

That is the first time in more than 20 years that CAODC has revised its projections in the middle of the peak winter drilling season.

CAODC President Don Herring said in a statement that the industry's best hope now is for a recovery in the second half of 2009.

The association expects an average 333 rigs from a fleet of 860 will be active in the first quarter for a 39 percent utilization rate, compared with 497 of an available 887 rigs in the same period last year.

The last time the utilization rate dropped below 40 percent was in 1992, when it nosedived to 32 percent, its lowest level in 30 years.

CAODC predicts the second quarter utilization rate will drop to 10 percent from 17 percent last year, with the average number of working rigs dropping to 86 — a level last seen in 1992 — then climb back to 31 percent in the third quarter and 42 percent in the final quarter, compared with 46 percent and 40 percent, respectively, in 2008.

For all of 2009, CAODC is counting on an average 262 rigs remaining busy for a rate of 30 percent, down from 351 rigs and 40 percent in 2008.

Based on $50 WTI

Its outlook is based on average commodity prices of $50 per barrel for WTI crude and C$7 for thousand cubic feet for gas.

The Petroleum Services Association of Canada updated its forecast in late January, projecting 13,500 well completions, off 21 percent from its final tally for 2008.

> *"If you look at the last three to four years, the average company is making hardly any return on gas spending."*
> **—Paul Ziff, of Ziff Energy Group**

Well completions for January were the lowest since 1999, with Alberta declining by 30 percent and Saskatchewan 4 percent, but British Columbia, driven by its shale and tight gas prospects, rose 6 percent to 164 wells.

Operators reported 204 exploratory wells, down 50 percent from January 2008, while development wells fell 19 percent to 1,196.

Of the licenses granted by the Alberta Energy Resources Conservation Board conventional crude permits plunged to 67 from 235 in January 2008 and conventional gas declined to 525 from 1,077, leaving oil sands activity to make up the balance.

British Columbia approved 71 well applications, off seven from a year ago, and Saskatchewan was off 224 wells at 151.

Of the leading operators, EnCana dropped to 350 permits from 650 and Canadian Natural Resources was down 41 licenses at 106.

Land sales down

Further mirroring the grim mood, the Alberta government's three land sales in January and February totaled C$42.35 million at the year's first three auctions, compared with C$86.05 million last year, while average per-hectare prices dropped to C$127 from C$299.

Saskatchewan's single sale in the first two months fetched a dismal C$6.3 million, in sharp contrast to its C$197 million in the first auction of 2008.

Energy and Resources Minister Bill Boyd said the results were "not entirely unexpected," pinning most of the blame on the 75 percent drop in spot oil prices over the past seven months and tighter financial markets.

British Columbia, easily the pacesetter in Canadian land sales last year, has also made an undistinguished start to the year, taking in C$24.71 million from two auctions compared with C$125.48 million to the end of February 2008.

The only bidding of note came from Progress Energy, which acquired 16,620 hectares of Montney prospective lease rights at an average C$792 per hectare, while BP Canada Energy paid about C$12.208 per hectare for portions of land northeast of Tumbler Ridge.

Progress Chief Executive Officer Michael Culbert said the Montney results have been so encouraging his company intends to keep building its position in the region.

BMO Capital markets analyst Mark Leggett said Progress is taking advantage of cheap land that is influenced by low gas prices and a shortage of capital.

Gas outlook dismal

The outlook for gas is dismal according to assessments by leading analysts in late February.

Chris Theal, managing director of energy research at Tristone Capital, told a conference that the North American market will shut in 750 billion cubic feet during the upcoming injection season because of oversupply and depressed prices.

Tristone is targeting average prices for this year of $4.25 per million British thermal units at Nymex and $6.75 in 2010.

The firm is forecasting U.S. storage will reach 3 trillion cubic feet in late July and 4 billion to 6 billion cubic feet per day of shut-in in September and October, with fall prices below $3 per million British thermal units.

He said rig counts in Western Canada are at lows not seen in many years, with British Columbia and Saskatchewan within five-year ranges and Alberta bleeding, which Theal predicts will cause a 5 percent drop in gas supply to 14.5 bcf per day this year.

He said the last three major recessions suggest industrial utilization will take 15 to 18 months to regain pre-recession levels.

Gas operating costs up

Calgary oil and gas consultant Paul Ziff, of Ziff Energy Group, said only 10 percent of 80 North American gas plays are economic at current prices, but the study did not identify those plays.

Finding and development costs in 25 supply basins average all-inclusive costs for new gas of $7 per thousand cubic feet.

He said new gas has not been "particularly economic," adding that either lower costs or incentives are needed to boost activity.

"If you look at the last three to four years, the average company is making hardly any return on gas spending," Ziff told the Economics Society of Calgary.

Operating costs for new gas in Western Canada soared 147 percent in the 2000-07 period, while costs for oil rose 156 percent.

The study listed the Canadian Foothills as the most expensive of the 25 supply basins.

The most encouraging news comes from the shale gas plays, which Ziff said are among the most economic when "they are up and running," especially for producers who made early purchases of land in Haynesville in Texas and Louisiana.

He predicted that by 2015 more than 25 percent of Canadian gas will come from unconventional plays, including tight sands, coalbed methane and gas shales and by 2017 60 percent of Canada's conventional gas reserves will be produced out.

Ziff does not expect any easing in oilfield service costs until the spring thaw "when the bottom will fall out … we'll see moderate costs decreases through spring breakup and then it's a whole new world." ●

● GOVERNMENT

Elton named to Alaska slot at Interior

By KRISTEN NELSON

Petroleum News

An Alaskan is going to Washington, D.C., in a key role — for the state — in the administration of President Barak Obama.

Sen. Kim Elton, D-Juneau, has been named director of Alaska affairs for the Department of the Interior, which manages the federal government's immense holdings in Alaska.

Elton submitted his resignation as a member of the Alaska Senate effective 5 p.m. March 2. He reports for duty in Washington, D.C., March 16.

Interior Secretary Ken Salazar said in a statement that Elton "not only has a broad background in state issues but also a record of bringing competing interests together for collaborative and constructive decision making. This is a record that will serve the state and the country well."

"The decision to leave our home, the community, and the state was difficult for Marylou and me," Elton said in a statement, "but this is a new way to serve Alaska and the nation."

KIM ELTON

"The Department of the Interior's mission is fundamental to Alaska's future and I look forward to helping the secretary and the administration make progress both on stewardship of Alaska's resources and on the economy of the state and the nation at this critical juncture in our history."

Elton said on the floor of the Senate March 2 that he did not seek the job, but was approached shortly after the first of the year about coming to Washington to work for the new administration.

He said his initial answer was that he might be interested, "but it would have to be Alaska connected and it would have to be a job that I felt I could actually do."

Elton said he talked with members of Salazar's leadership team when he was in D.C. for the inauguration.

"I felt very good about the leadership team that I had met and felt very good about what they described as their vision," Elton told the Senate.

"They're interested not just in stewardship but also in economic progress."

After the lengthy vetting process, the offer was finalized at the end of February. "I've discussed the job with both of our U.S. senators, with Congressman Young and twice with the governor's office," Elton told the Senate.

19 years in elective office

His resignation ends 19 years in elective office. He was elected twice to the City and Borough of Juneau Assembly, twice to the Alaska House and three times to the Alaska Senate.

He also served as executive director of the Alaska Seafood Marketing Institute, assistant state ombudsman and senior staff to Lt. Gov. Terry Miller in the administration of Gov. Jay Hammond.

He began his professional career as a newspaper reporter in Fairbanks during the oil pipeline construction years, was city editor in Anchorage and editor of his hometown newspaper, the Juneau Empire.

The governor has 30 days to nominate a replacement for Elton; her nominee must be accepted by the remaining nine Senate Democrats.

Another former member of the Alaska Senate, Drue Pearce, was senior advisor to the secretary for Alaska Affairs from 2001 until named in June 2006 by President Bush to be federal coordinator of an Alaska natural gas pipeline project. Henri Bisson, Alaska director of the Bureau of Land Management from 2001-06, was named acting senior advisor for Alaska affairs in June 2007.

The Department of the Interior manages more than 200 million acres of land in Alaska. Interior agencies include the Bureau of Indian Affairs, the Fish and Wildlife Service, the National Park Service and BLM. ●

● LAND & LEASING

One expansion approved, one deferred

Prudhoe Bay unit expanded by 1,000 acres; expansion of Orion participating area deferred pending well data to prove up resource

By KRISTEN NELSON

Petroleum News

As drilling moves to the northwest in the Orion accumulation in the northwest corner of the Prudhoe Bay unit on Alaska's North Slope, BP Exploration (Alaska) has applied to expand the unit, and the Orion participating area, to accommodate planned drilling close to the boundary of the expansion area.

The Alaska Division of Oil and Gas approved expansion of the unit Feb. 18 — subject to a well being spud by September — but declined to expand the participating area until BP presents well data showing that the proposed PA-expansion area is capable of producing in paying quantities.

The expansion area is 1,000 acres within ADL 390067.

Participating areas are the portions of units from which production is occurring.

The division said BP originally applied for the expansions in May 2004, but did not respond to a request for additional information.

BP submitted an updated application to expand the Orion participating area and the Prudhoe Bay unit in August 2008.

The Orion PA, formed Feb. 1, 2004, includes portions of 14 leases, a total of approximately 18,842 acres. It is being developed from L, V and Z pads. Production from Orion is commingled with Prudhoe Bay initial participating area and Borealis production and processed at Gathering Center 2.

No wells have been drilled in the expansion area.

The division said it has approved Prudhoe Bay unit expansion subject to a well being spud within ADL 390067 by Sept. 1, 2009. If a well is not spud by that date the expansion area will automatically contract out of the unit.

The division will consider expansion of the Orion PA once data from the proposed L-223i well is submitted. The portion of ADL 390067 not committed to the unit is severed and the segregated portion assigned ADL 391462, effective March 1.

ADL 390067 was issued Sept. 1, 2002, for a seven-year primary term and 16.667 percent royalty; ownership is 26.36 percent BP Exploration (Alaska), 36.08 percent ConocoPhillips Alaska Inc., 36.4 percent ExxonMobil and 1.16 percent Chevron.

In November BP advised the division that it was considering drilling an injection well on ADL 390067 prior to drilling the proposed multilateral L-203 production well adjacent to ADL 390067. It is data from the injection well that the division is requesting prior to approving expansion of the Orion PA.

Schrader Bluff accumulation

The Orion PA is in the northwest corner of the Prudhoe Bay unit and the acreage being added to the unit — and potentially to the PA — is on the northern edge of the unit. Thirty-eight wells have been drilled in the Orion PA: 11 oil wells, 25 injection wells and two wells suspended as of July 2008, the division said.

Other development wells targeting the deeper Ivishak and Kuparuk formations also provide geologic data on the Orion oil pool.

BP has drilled producing wells with two-to-six multilateral completions to access more individual sands and improve recovery efficiency, the division said, with multilateral wells "performing significantly better than earlier vertical or slanted wells in the Schrader Bluff formation."

The division said initial rates of production from multilateral wells are generally higher and the production is sustained over a longer period.

The Schrader Bluff formation at Orion, known as the West Sak formation in the adjacent Kuparuk River unit, is composed of several sandstones in the Orion PA, some of which pinch out or are truncated based on current well spacing, the division said.

At a pool rules hearing before the Alaska Oil and Gas Conservation Commission in 2004, BP estimated original oil in place at Orion to be 1.07 billion to 1.785 billion barrels. The division said production from the Orion PA to date is 14.1 million barrels of oil or about 1 percent of the original oil in place.

BP told the AOGCC that primary recovery was expected to be 5-10 percent

see **ORION** page 8

● FINANCE & ECONOMY

Nova's star about to fade

Struggling core of Alberta's petrochemical sector accepts takeover bid by Abu Dhabi company; deal still needs approvals

By GARY PARK
For Petroleum News

Once the bedrock of Alberta's treasured dreams of a world-scale petrochemicals industry, once forecast to see its share values top C$100, once a company that seemed to have a role in every corner of Calgary society, Nova Chemicals is now on the brink of disappearing forever, maybe into the fold of an Abu Dhabi government-owned company.

Trapped between its own cash squeeze and desperate for financing, Nova has finally given up a year-long fight to keep acquisitors at bay.

The offer on the table of US$2.33 billion — $499 million or $6 per share and the assumption of debts — comes from International Petroleum Investment Co. and hinges on ratification by the Canadian government and two-thirds of Nova shareholders.

If the deal goes through, it represent only a fraction of Nova's estimated real worth.

Chief Executive Officer Jeff Lipton told a conference call Feb. 23 that replacing his firm's assets would actually cost up to $11 billion, including $5 billion for the ethylene and polyethylene complex in central Alberta which has a payroll of 760.

It produces 4.8 billion pounds a year of ethylene, 2.2 billion pounds of polyethylene plastic and may add another 1 billion pounds of polyethylene.

"We looked at a wide range of things: private equity, trying to deal with our current balance sheet and moving forward with current borrowing; we looked at the probability of bond markets opening up," he said.

Offer 'best alternative'

At the end of the day, the IPIC offer was "clearly the best alternative."

"We couldn't find the wherewithal to continue the kind of growth internally that I would have liked to have seen us be able to do and to me that's the biggest disappointment," Lipton said.

But the clock was running down on Nova, which needed to raise $100 million by the end of February to meet its financing obligations.

Under the offer, IPIC, which has a portfolio of assets valued at $14 billion, has agreed to provide a $250 million credit backstop to give Nova sufficient liquidity going forward.

Lipton also said the deal gives Nova "both stability and long-term growth," by preserving its independence as a chemicals and plastic company and retaining current senior management.

IPIC Managing Director Khadem Al Qubaisi said the acquisition will "provide enhanced balance sheet strength for Nova Chemicals and facilitate Nova Chemicals' growth internationally."

The $6 a share offer was a 348 percent premium over Nova's closing stock price on Feb. 20.

Split from TransCanada

It revives nostalgic and bitter memories for some of Nova's emergence as a publicly traded company in 1998, after splitting from TransCanada, when its stock was worth $31.75, climbed to an all-time high in 2005 of $63.77 (well short of the $105 forecast for 2001 by TD Securities) then started its downward spiral, bottoming out at $1.38 in early February.

But the homegrown affection for Nova disappeared a decade ago when the corporate headquarters were moved to Pittsburgh — a decision that still makes little sense for a company that had its core operations in Alberta and Ontario.

Regardless of its location, Nova was criticized for its strategy. Jeffrey Zekauskas, an analyst at JP Morgan Chase, said in a report that it was unique among its petrochemical peers by not paying down debt "during the past few years of above-normal industry profitability."

IPIC has already established a formidable base in Alberta and through an Alberta-based company. In 2007, one of its affiliates, TAQA, bought North Sea assets from Talisman Energy, swallowed Northrock Resources for C$2 billion in cash, scooped up PrimeWest Energy Trust for C$4.6 billion and paid C$540 million for the Canadian unit of Pioneer Natural Resources.

Next step government

Short of an unexpected counter-offer from any other companies in the troubled petrochemical sector, or a private equity firm, attention now turns to the Canadian government, which will review the IPIC offer under its recently introduced Investment Canada Act, which requires that the transfer of Canadian assets to foreign-controlled interests must be of net benefit to Canada.

That will matter to any of the proliferating state-owned companies eying a move into Canada's natural resource world to buy themselves some added energy security. TAQA itself has declared its goal of establishing Canadian operations worth C$20 billion over the next five years. ●

continued from page 7

ORION

and that waterflood could increase recovery to 20-25 percent of original oil in place. The division said estimates for recovery from miscible gas injection have not been provided. Waterflood operations began in January 2004 and miscible gas injection began in October 2006, with 12.3 million barrels of water and 3.6 billion cubic feet of miscible gas injected to date.

Stage 2 drilling

The division said BP has completed stage-one drilling and is well into stage two, which consists of additional drilling from L, V and W pads in the western area at Prudhoe Bay. I pad, northwest of L pad, is still under evaluation.

The division said no wells have been drilled in ADL 390067 and limited Orion PA drilling has been done adjacent to ADL 390067, but confidential data provided by BP "is sufficient to support a finding that the expansion area encompasses the minimum area that may contain a potential hydrocarbon accumulation."

Since available data is insufficient to support a finding that the area is capable of producing or contributing to paying quantities, Orion PA expansion is not supported. The division said BP's commitment to spud a well in ADL 390067 by Sept. 1, 2009, supports expansion of the Prudhoe Bay unit.

"Well data from a well drilled in ADL 390067 will identify the downdip extent of hydrocarbons in the area and determine the potential extent of the PA," the division said. ●

● SAFETY & ENVIRONMENT

The shrinking Beaufort Sea coastline

A USGS team is assessing changes along the North Slope coastline using historical and contemporary maps and aerial surveys

By ALAN BAILEY
Petroleum News

A recent paper published by geologists from the U.S. Geological Survey reported accelerating rates of Beaufort Sea coastal erosion along a 37-mile section of shoreline bluffs, north of Teshekpuk Lake, at the northeastern edge of the National Petroleum Reserve-Alaska. The geologists said that erosion rates have increased from 6.8 meters per year pre-1979 to 13.6 meters per year in the period 2002 to 2007, with as much as 25 meters of erosion occurring in some places in 2007.

"Concurrent Arctic changes potentially responsible for this shift in the rate and pattern of land loss include declining sea ice extent, increasing summertime sea surface temperature, rising sea level, and increases in storm power and corresponding wave action," the geologists said. "Taken together these factors may be leading to a new regime of ocean-land interactions that are repositioning and reshaping the Arctic coastline."

Major concern

But how do the rates of erosion discovered in the relatively short stretch of coastline investigated in this particular study compare with rates elsewhere along the Beaufort Sea coast? Shoreline erosion has become a major concern for coastal communities in northern Alaska and could perhaps impact the oilfield facilities of the central North Slope at some point in the future.


U.S. GEOLOGICAL SURVEY

A well pad and pipelines near the shore on the west side of Prudhoe Bay, photographed during a 2006 U.S. Geological Survey coastline aerial survey. Although erosion along the Beaufort Sea coast has been accelerating, rates of erosion at Prudhoe Bay appear to be quite low.

A USGS team is engaged in a study of shoreline change along the entire U.S. Beaufort Sea coast, as part of a multiyear assessment of land erosion and accretion around the entire U.S. coastline, USGS geologist Bruce Richmond told Petroleum News Feb. 25.

"Coastal land loss is an issue all around the country and it looks like rates are accelerating," Richmond said.

The coastline project, involving cooperation in Alaska between various government agencies including USGS, the U.S. Bureau of Land Management, the U.S. Fish and Wildlife Service and the Alaska Department of Natural Resources, is collecting data from a variety of sources and assembling that data in a consistent format. The idea is to develop an historic archive and then update the data every five years or so, without having to keep re-investigating earlier data, Richmond said.

"The USGS is trying to come up with some consistent-methodology datasets so that we can look at one part of the United States in the same way as we look at somewhere else with respect to coastal erosion," said USGS geologist Ann Gibbs.

And the USGS team started studying the Beaufort Sea coast around 2006.

"We actually collected oblique aerial photography and video … along the coast from a small floatplane," Gibbs said.

Since then the team has been using more of an office-based approach, by tracking down and compiling historical data, from sources such as National Oceanic and Atmospheric Administration maps dating back as far as the 1940s, and then digitizing the data in an appropriate format.

The coastline project, involving cooperation in Alaska between various government agencies including USGS, the U.S. Bureau of Land Management, the U.S. Fish and Wildlife Service and the Alaska Department of Natural Resources, is collecting data from a variety of sources and assembling that data in a consistent format.

"BP and ConocoPhillips have (also) provided us some of their imagery to use for our analysis," Gibbs said.

Part completed

The team is using the shoreline data to make transects every 50 meters along the coast, west from the Canadian border, including the Beaufort Sea barrier islands but excluding major sea inlets, Richmond said.

"We're probably about one-third of the way finished with the analysis of the historical information," Gibbs said.

And in the summer of 2009 the team plans to conduct an airborne Light Detection and Ranging, or LIDAR, survey along the coast to document the location of the modern shoreline and obtain accurate land elevation data. The LIDAR data will enable the team to compile an up-to-date time history of erosion along the cost by comparing the position of the current shoreline with the historic data.

A LIDAR survey uses a laser system mounted in an aircraft to make precision measurements of landforms. It has 15 to 20 centimeter vertical accuracy, Richmond said.

Although the analysis of historic data is still a work in progress and remains subject to technical review, preliminary results suggest that erosion in the Prudhoe Bay area has been accelerating but that it is occurring at a much slower rate than the erosion found north of Teshekpuk Lake. In the period between 1981 and 2000, even those places with the highest erosion rates around Prudhoe Bay appear to have been losing less than 2 meters of land per year to the encroaching sea, Gibbs said.

Reasons for variation

However, the variation in erosion rates along the coast raises some interesting questions about why rates are higher in some places and lower in others. That is a question that the USGS geologists have yet to address, although Richmond speculated that the grain size of the land material may prove to be an important factor — the bluffs north of Teshekpuk Lake tend to be composed of finer grained material than the more sand-rich material found at Prudhoe Bay.

After completing its analysis of the shoreline changes, the USGS team hopes to use its video of the coastline to classify different shoreline types and then link those types to the erosion rates, Gibbs said.

"After we come up with the (erosion) rates there's a whole other level of the research project to try to reason it all out," she said. ●

● INTERNATIONAL

Foreign legion in retreat

Canadian-based companies experience more downs than ups in overseas plays; can't negotiate financing to develop strong prospects

By GARY PARK
For Petroleum News

Whether they have been looking for a way to hedge their bets, or using the Maple Leaf as a flag of convenience, Canadian-based companies operating outside of North America have found their foreign adventures less than rewarding in recent months.

Some of the choppiest waters have been in the North Sea, where low oil prices and financing problems have been the undoing of Oilexco and Bow Valley Energy.

Backed by proved plus probable reserves of 66 million barrels of oil equivalent and hopes of attaining 45,000 boe per day of production, Oilexco, faced with delisting by the Toronto Stock Exchange, ran afoul of its lenders.

Its assets have been placed under the control of Ernst & Young after its lenders, led by the beleaguered Royal Bank of Scotland, refused to advance any more funding.

Oilexco — the No. 1 drilling company in the North Sea for the past five years and a one-time market darling — has a portfolio that includes the Huntington field, one of the region's biggest oil discoveries.

But that wasn't enough to fend off insolvency for the company's North Sea unit, whose assets and shares are expected to be sold in the second quarter, although Oilexco said it has no way of predicting who the ultimate buyer or buyers will be, nor the value that could be realized through a sale process.

BG Group, Talisman Energy, Nexen and Petro-Canada have all been mentioned as possible contenders.

It is shaping up as a sad exit for a company whose share values have ranged from a 52-week high of C$19.50 to under 7 cents.

Bow Valley finds buyer

Bow Valley, with production of about 3,700 boe per day, found a buyer in mid-February, when Dana Petroleum, an independent United Kingdom oil and gas exploration and production company, negotiated a takeover for C$240 million, including the assumption of net debt and other obligations totaling C$197 million.

The deal is worth 50 cents in cash per common share, a 53 percent premium to the weighted average trading price for the 20 previous trading days, but almost C$6 lower than the 52-week high.

None has traveled a rockier road than Oilexco, whose once-lucrative North Sea interests were pumping 17,000 bpd, but the deepening credit crunch and the absence of any other source of financing prevented it from financing exploration activities.

In late 2008, the Royal Bank of Scotland demanded Oilexco's North Sea subsidiary immediately pay back US$547.5 million and 100 million pounds sterling to the bank and other lenders, forcing the company's board of directors to put the assets in play.

When a suitable purchaser failed to surface, the company entered creditor protection to the detriment of its parent company, shareholders, the bank and creditors.

Scrambling in T&T

Life hasn't been any easier across the Atlantic Ocean in the warmer waters of Trinidad and Tobago, where Canadian Superior and Challenger Energy have been scrambling to keep their heads above water

None has traveled a rockier road than Oilexco, whose once-lucrative North Sea interests were pumping 17,000 bpd, but the deepening credit crunch and the absence of any other source of financing prevented it from financing exploration activities.

on the highly rated offshore Intrepid block, where three natural gas discoveries have been reported by the two companies along with their third partner BG International, a subsidiary of British producer BG Group.

Canadian Superior said in February it was prepared to sell 25 percent or more of its interest in the block, while facing a demand from Canadian Western Bank for immediate repayment of its C$37.5 million credit line. That deadline was extended from Feb. 27 to March 12 after being reduced with a payment of C$9 million.

Meanwhile, Challenger has obtained an order from an Alberta court for bankruptcy protection from creditors, thus permitting the junior oil and gas company to keep control of its exploration property and evaluate strategic options, including outright sale of the company.

In mid-February, BG obtained an Alberta court order appointing Deloitte and Touche receiver of Canadian Superior's position as operator of Intrepid.

The order also allows the receiver to charge Canadian Superior's stake in the block up to US$47 million to pay for its share of costs under the operating agreement.

Canadian Superior said it will continue to monetize its interest in the block, applying the proceeds to its share of the costs, questioning the "motives of BG" in the process.

Others

Other ups and downs on the global scene include:

• A C$499 million takeover by state-owned China National Petroleum Corp. of Verenex Energy (42 percent owned by Vermilion Energy Trust), which has a 50 percent stake in Libya's Area 47, which is estimated to contain upwards of 2.15 billion barrels of oil and is scheduled to start production in 2011.

• In mid-December, Tanganyika Oil became a wholly owned subsidiary of China's state-owned Sinopec in a C$2.07 billion transaction that secured oil and gas assets in Syria. Tanganyika, a unit of Sweden's Lundin Group, has production-sharing agreements with Syria that produced a gross 16,670 bpd in the first half of 2008 and an estimated 5.5 billion barrels of

see RETREAT page 12

● EXPLORATION & PRODUCTION

ANS February production up 4.9%

By KRISTEN NELSON

Petroleum News

Alaska North Slope production averaged 738,318 barrels per day in February, up 4.91 percent from a January average of 703,745 bpd. There were weather-related delays in Valdez tanker loadings in the early part of January which dropped average production in that month almost 4 percent from December, as production was cut back when storage at Valdez neared capacity.

Unlike January, with the steep decline early in the month due to the tanker loading delay, February ANS production held fairly level all month.

Prudhoe Bay had the largest month-to-month increase, averaging 366,406 bpd in February, up 6.39 percent from a January average of 344,392 bpd. Prudhoe Bay, operated by BP Exploration (Alaska), includes satellite production from Aurora, Borealis, Midnight Sun, Orion and Polaris.

The BP-operated Lisburne field, part of greater Prudhoe Bay, averaged 37,211 bpd in February, up from 35,140 bpd in January, an increase of 5.89 percent. Lisburne production includes Point McIntyre and Niakuk.

Kuparuk includes Oooguruk

The ConocoPhillips Alaska-operated Kuparuk River field averaged 156,415 bpd in February, up 4.69 percent from a January average of 149,411 bpd. Kuparuk includes production from Tabasco, Tarn, Meltwater and West Sak, as well as from the Pioneer Natural Resources-operated Oooguruk field. Oooguruk production is only available on a month-delay basis from the Alaska Oil and Gas Conservation Commission which showed January production of 183,983 barrels, an average of 5,935 bpd.

Alpine, also operated by ConocoPhillips, averaged 110,428 bpd in February, up 3.11 percent from 107,098 bpd in January; Alpine includes satellite production from Fiord, Nanuq and Qannik,

BP's Milne Point field averaged 30,509 bpd in February, up 0.97 percent from a January average of 30,217 bpd. Milne Point includes Sag River and Schrader Bluff production.

The BP-operated Endicott field averaged 13,866 bpd in February, up 0.59 percent from a January average of 13,784 bpd.

The BP-operated Northstar field averaged 23,483 bpd in February, down 0.9 percent from a January average of 23,704 bpd.

The temperature at Pump Station 1 on the North Slope averaged minus 12.8 degrees Fahrenheit in February, compared to minus 14.9 degrees F in February.

Cook Inlet production averaged 11,712 bpd in February, down 4 percent from a January average of 12,200 bpd. ●

Note: The Alaska Department of Revenue corrected January production figures March 3, so there are differences between some of the numbers reported above and those reported by Petroleum News in a March 2 news bulletin and in the paper in February.

continued from page 11

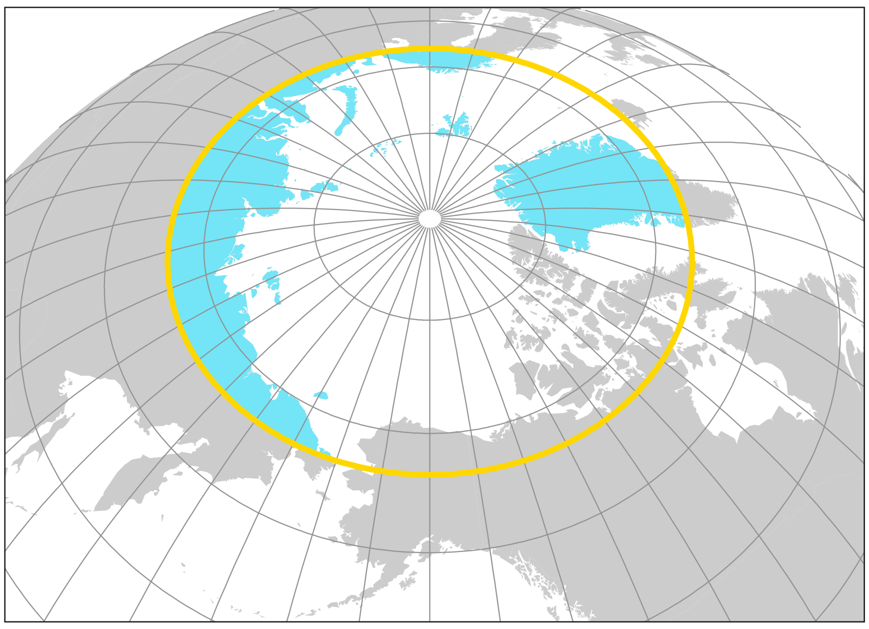
RETREAT

oil in place in various fields.

• Sherritt International, which produces nickel and oil in Cuba, is now immersed in pivotal negotiations with the Cuban government, which stopped paying for the oil in mid-2008, apparently because of its difficulties sourcing U.S. dollars. In late January, Sherritt struck a surprise deal with state-run Pebercan, its joint-venture partner, to terminate a production-sharing contract covering 4,500 bpd. Sherritt will receive US$60 million and the oil wells will revert to the government. What isn't clear is the future of its other Cuban oil production, which is not tied to Pebercan, and the company's status in Cuba.

• Heritage Oil, in partnership with Anglo-Irish explorer Tullow Oil, has unlocked a 400 million-barrel oil and gas find in Uganda's Alberta basin. Two of 16 exploration and appraisal wells have tested at more than 13,000 bpd and initial production of 4,000 bpd is set for the second half of 2009. Heritage is also operator of the first exploration well to be drilled on the highly prospective Miran license in the Kurdistan region of northern Iraq. The well is targeting three principal proven reservoir formations and is expected to be completed by late March. The Miran structures are estimated to contain billions of barrels of oil. Heritage has also received a license from the Tanzanian government to acquire stakes in four exploration licenses covering onshore and deepwater areas, carrying rights to earn 29.5 percent to 70 percent.

• Also active on the African continent, Addax Petroleum has boosted its stake in an offshore Gabon license to 68.75 percent from 50 percent, committing itself to drill two wells by the end of November. It holds stakes in two nearby licenses. As well, Abbax has reported a "significant" onshore oil find in Nigeria, where it already produces 6,000 bpd. It has a 100 percent working interest in the discovery under a production-sharing contract. ●



Murmansk oil company sinking into hole

A Russian state-owned oil company, Arktikmorneftegazrazvedka, AMNGR, based in Murmansk, is in financial hardship and laying off workers, BarentsObserver reported Feb. 26. The company's two jack-up rigs, Kolskaya and Murmanskaya, are both standing idle in port, leading to a loss of 83 billion rubles ($2.3 billion) in income per month.

The Kolskaya was leased by an unspecified foreign company to work in the North Sea, but by order of Russia's Federal Property Management Agency, the contract was canceled. The rig is now at port in Murmansk. The Murmanskaya is at port in Singapore, having been leased to a Norwegian company that breached the contract before its term ended out of fear that a court would force the rig back to base in February.

In addition to the layoffs, 500 employees have been restricted to part-time work and salary arrears have increased. The workforce is in a pre-strike position, according to Murmansk TV company TV21.

AMNGR's CEO, Oleg Mnatsakanyan, has said that the company will not go bankrupt because it is a so-called strategic federal enterprise, meaning that the Russian government will continue to back it. Local authorities will be cooperating with trade unions and the regional branch of the party United Russia to try to keep qualified personnel from leaving AMNGR.

—SARAH HURST

Europeans win Shtokman design contract

Shtokman Development Co. has awarded a contract to a consortium comprising Norway's Aker Solutions, Technip France and the Netherlands' SBM Offshore. The contract is for the concept definition and front-end engineering design or FEED for the floating production unit for the Shtokman gas and condensate field phase I project. The contract value is 25 million euros ($31.7 million).

The scope of the work includes design, floating production unit concept definition and FEED design for the hull, turret and mooring system and topsides, Aker Solutions said in a release Feb. 24. The work will be performed by an integrated team involving the three partners of the consortium, with Aker Solutions as leader. It will start immediately and be carried out over the next 12 months. The consortium will also tender for the full engineering, procurement, supply, construction and commissioning contract in 2010.

"We are very pleased to be part of the initial phases of the development of the world's largest offshore gas field," said Simen Lieungh, Aker Solutions' president and CEO. "Equally important for us is the establishment of the partnership with Technip and SBM. We build on each other's expertise and capabilities and are able to take on more assignments than what we could do alone."

—SARAH HURST

Gazprom expands geological facilities

Russia's state-owned energy giant Gazprom has opened a new geological center that will provide assistance to projects in the Arctic, the company said in a release Feb. 26. The Research Center for Reservoir Systems and core storage facility are located in the settlement of Razvilka in Moscow Oblast, and will be part of VNIIGAZ — Gazprom's research, development, technology and engineering affiliate.

Vlada Rusakova, the head of Gazprom's strategic development department, noted that the company's access to new strategic areas of gas production, including the Yamal Peninsula, Eastern Siberia, the Far East and the Arctic offshore, would demand considerable geological exploration to be followed by intensified studies of rock samples.

"The inauguration of the Research Center for Reservoir Systems will allow Gazprom to further increase the effectiveness of geological exploration, the quality of design approaches to field development and the efficiency of hydrocarbon production," Rusakova said. "Additionally, the creation of the corporate core storage facility will make it possible to integrate the activities related to storage of formation samples extracted from wells."

The first phase of the corporate core storage facility with a capacity of 76,000 linear meters (249,344 feet) is intended for centralized storage of Gazprom's core material. When the second phase of the storage facility is opened, scheduled for fall 2009, total storage capacity will increase to 184,000 linear meters (603,674 feet).

—SARAH HURST

● OUR ARCTIC NEIGHBORS

Norwegian regulator keeps eye on Arctic

Petroleum Safety Authority wants closer cooperation with Russia in Barents Sea, higher safety standards and use of new technology

By SARAH HURST
For Petroleum News

The Norwegian government is working to develop petroleum industry health, safety and environmental standards which will apply to both the Norwegian and the Russian sectors of the Barents Sea, the country's Petroleum Safety Authority says in its annual report. Published in February, the report is titled "Safety — Status and Signals."

Official regulations for petroleum operations differ in the Norwegian and Russian parts of the Barents Sea, but cross-border cooperation is being pursued, the report said.

"Safety levels must be at least on a par with those in the North Sea, while also taking account of the demanding conditions found in the far north," it said.

"Safety systems depend on ensuring that equipment like hydraulics or firefighting gear doesn't ice up," principal engineer Per Endresen, who is working for PSA on process safety in Arctic regions, said in the report. "Some process technology adaptations are also needed, such as fuels and lubricants which can cope with lower temperatures. Extensive areas of mobile units or fixed installations must be enclosed to protect personnel and hardware against climatic extremes. And heating will play a more central role. Weather conditions in these waters also call for better planning of maintenance and supplies."

The report notes that the Melkoya liquefied natural gas plant for the Snohvit project in the Barents Sea is one of eight land-based petroleum plants that the PSA has responsibility for.

"Both the construction of complex facilities and combined operation and development make big demands on safety. Supervising the land-based plants has therefore been both demanding and important," Ann Vatten, one of the PSA's two directors for supervisory activities, said in the report.

"To enhance robustness and output even further, a number of modification jobs are planned for Melkoya," the report said. "The PSA's attention in 2009 will be concentrated particularly on managing the risks of doing this work while production continues."

Growing integration between petroleum facilities offshore and on land means that activities at sea and on land have to be seen from a unified perspective, Vatten added.

"Increased transfer of experience between offshore personnel and people at facilities on land is one benefit of such tighter integration," she said. ●

SAFETY & ENVIRONMENT

Panel marks 20th EVOS anniversary

The National Oceanic and Atmospheric Administration is marking the 20th anniversary of the Exxon Valdez oil spill with a congressional panel on advances in spill response.

The March 24, 1989, oil spill, the largest ever in U.S. Waters, has produced a new environmental consciousness, NOAA said, with "two decades of new laws on container-ship construction, advances in spill cleanup technology and increased knowledge on how natural resources respond to human activities."

The NOAA-organized, U.S. Senate Commerce Committee-sponsored event will focus on progress made in spill preparedness, response and restoration at the federal and local level since the Exxon Valdez spill, "and the challenges facing the nation with increased energy exploration, climate change and the increase in marine transportation in the Arctic," NOAA said.

The NOAA-organized, U.S. Senate Commerce Committee-sponsored event will focus on progress made in spill preparedness, response and restoration at the federal and local level since the Exxon Valdez spill, "and the challenges facing the nation with increased energy exploration, climate change and the increase in marine transportation in the Arctic," NOAA said.

The March 13 panel will include Alaska Sens. Mark Begich and Lisa Murkowski; Patience Faulkner, president of the Prince William Sound Regional Citizens Advisory Council; senators from Washington and New Jersey; Coast Guard and NOAA officials; and state officials from Texas and New Jersey.

—PETROLEUM NEWS

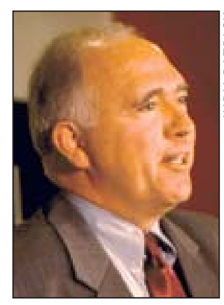
● EXPLORATION & PRODUCTION

UltraStar preparing to drill Dewline

Despite weak credit market and lower oil prices, tiny UltraStar is set for drilling on the North Slope after four years of trying

By ERIC LIDJI
Petroleum News

The prevailing wisdom right now says only the biggest ships can ride the biggest waves, but tiny independent UltraStar Exploration LLC is preparing to drill an exploration well this winter on the North Slope in the face of economic uncertainties and falling oil prices.



JUDY PATRICK

JIM WEEKS

Before the end of March, UltraStar expects to spud the Dewline No. 1 exploration well north of the Prudhoe Bay unit near Point Storkerson using the Akita-Doyon Arctic Wolf rig, Jim Weeks, managing member of UltraStar, told Petroleum News on Feb. 27.

A major reason the project is able to move ahead in the current economic climate is funding. UltraStar is backed by a group of about a dozen private investors, Weeks said.

"We've got individuals putting their personal money into the risk capital. There's no way you would get a bank to finance a risky well," Weeks said, adding, "It's easy to get money once you find oil."

Dewline No. 1 is permitted to 9,900 feet, deep enough to target a prospect in the Ivishak formation and "secondary targets" in the shallower Sag River and Kuparuk formations.

UltraStar recently submitted an application to the state to form the Dewline unit, which would include three leases UltraStar owns in the area, covering some 3,250 acres.

Under the proposed terms of the unit, the company would drill the Dewline No. 1 well by June 30, 2011, and a second well, North Dewline No. 1, by June 30, 2013. If the wells are successful, the proposal calls for filing an initial plan of development by Oct. 1, 2013.

Weeks said the proposed unit could contain additional prospects worth drilling.

"There are pleasant surprises in this business. You never know until you drill," he said.

Drilling permit issued

UltraStar is about to do just that at Dewline No. 1. Weeks said the company is fully permitted, including a drilling permit from the Alaska Oil and Gas Conservation Commission issued on Feb. 18. The drilling pad is complete, as is a two-mile ice road.

"We've got individuals putting their personal money into the risk capital. There's no way you would get a bank to finance a risky well."

—Jim Weeks, managing member of UltraStar Exploration

As of Feb. 27, Arctic Wolf was en route to the site, where it should take six days to erect.

Weeks said he expects crews will need 23 days to drill the well.

If Dewline No. 1 finds commercial quantities of oil, UltraStar plans to build a gravel road tying back to an existing road running from Point McIntyre down to Deadhorse, allowing the company to drill year round and possibly contract for cheaper rates on a drilling rig.

UltraStar also plans to eventually use a three-phase pipeline carrying oil, gas and water from Point McIntyre to the Lisburne production facilities in the Prudhoe Bay unit.

Weeks said UltraStar would most likely use multiphase metering technology, which measures the three-phase production stream without separating the mixture into its separate parts of oil, gas and water. Pioneer is currently testing the technology at the Oooguruk unit, which feeds into existing facilities at the Kuparuk River unit.

If the technology is successful and approved by regulators, it is expected to reduce the cost and complexity of gaining access to existing North Slope processing facilities.

With a large enough oil discovery, UltraStar might even be able to justify the cost of building new processing facilities at Dewline and connecting into the Northstar pipeline to the west that ships pipeline quality oil to Pump Station 1 on the trans-Alaska oil pipeline.

Trouble getting drilling rig

UltraStar began working on Dewline four years ago based on 3-D seismic acquired after sister company Winstar Petroleum drilled a dry well near Oliktok Point in 2003.

Dewline got its name because the area used to be a Distant Early Warning Line site, part of a broad system of radars set in the North American Arctic to detect Soviet attacks.

UltraStar originally planned to drill a directional well to hit Dewline Deep from the existing gravel pad at Point McIntyre, but failed to get access issues worked out.

The company next looked to drill along a road to Point McIntyre, looking to be as close as possible to the three-phase pipeline heading down to the Lisburne facilities.

But UltraStar had trouble getting a rig lined up. Because drilling rigs must be specially outfitted to operate in the harsh winter drilling season in Alaska, the rig market in northern Alaska can remain tight even when rig markets nationally start to loosen.

"Rigs are still in short supply on the North Slope," Weeks said.

see ULTRASTAR page 15

continued from page 3

BULLET LINE

the Bush.

ANGDA CEO Harold Heinze did not believe the current statutes restricted his group, but said the additional clarity would help when ANGDA goes for financing.

Concerning the action plan, which might overlap with ANGDA work, Heinze said, "The governor has set a direction that she wants to take. We're still a little bit in the dark trying to figure out exactly at what level of detail we can help Harry Noah and that effort."

The second bill, paired as SB 136 and HB 164, would amend the Pipeline Act and the Right of Way Leasing Act in the hope of offering more certainty to builders and shippers.

One way it tries to achieve that is by allowing shippers to make firm transportation commitments without fear of being prorated if new customers want space on the pipeline.

The provision is designed to get producers to commit long-term supplies to a pipeline.

Another is to allow the Regulatory Commission of Alaska to offer a pipeline builder a conditional certificate before the company gets financing or transportation commitments.

The administration believes this would bolster attempts to get investors and customers.

The bill also lays out expansion requirements on any in-state gas pipeline similar to those set up for an interstate pipeline under the terms of the Alaska Gasline Inducement Act.

The proposed bill would require a pipeline operator to solicit for new gas supplies every two years and expand the pipeline when necessary and commercially feasible.

Spokesman Curtis Thayer said Enstar was reviewing the bills, but planned to participate in the new action plan, saying, "Everything we have we will share with this state."

The bills have been referred to the respective energy committees in each body. ●

continued from page 14

ULTRASTAR

Then, last year, UltraStar learned the Arctic Wolf rig might be available. The rig is under contract to FEX, the local subsidiary of Canadian independent Talisman Energy. FEX previously used the rig for a multiyear frontier exploration program in the National Petroleum Reserve-Alaska in 2006, but recently decided not to drill in 2009 or 2010.

Dewline alone didn't justify a contract, so UltraStar partnered with Rampart Energy Co., the Denver independent planning to drill an exploration well in Nenana this summer.

The Arctic Wolf is a light-weight rig capable of drilling to a total depth of some 10,000 feet, about two-thirds the depth of the directional well UltraStar originally hoped to drill.

So UltraStar decided to drill Dewline vertically, reducing both the depth and the cost of the well, but requiring an ice pad and a two-mile ice road to connect back to the existing gravel road to Point McIntyre, essentially keeping the total cost of the project even.

Drilling vertically offers other benefits, such as reducing the risk of the well, Week said.

Above the Sag River formation sits a layer of shale known as the Kingak. Weeks said the Kingak would "slough and swell" in the presence of the freshwater drilling mud the company plans to use. A vertical well passes through less of the shale for less time.

Applying for ACES credits

Dewline No. 1 is a change of pace for Weeks, a former ARCO executive.

"It's been a real learning experience," he said, about trying to drill on the North Slope as a small independent, adding, "I used to just snap my fingers: Let's go drill over here."

UltraStar received tax credits under Alaska's Clear and Equitable Share, or ACES, for work completed in 2007 and recently applied for credits for work completed in 2008.

Echoing statements from state Department of Revenue officials, Weeks said he is still learning how the new tax system and the accompanying tax credits actually work.

"Everybody's learning the system. ACES is a very complicated piece of legislation," he said, adding, "I think on both sides, people are just trying to figure it out."

Asked about the different changes over the past five years, as he went from drilling a well under Winstar to preparing to drill under UltraStar, Weeks said he would like to see longer lease terms, which are down to five years from seven and previously 10 years.

"Five years is too short. I've been grinding on this for four," he said. ●

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

LAND & LEASING

MMS extends draft EIS comment period

The Minerals Management Service has extended the comment period for the draft environmental impact statement for Beaufort Sea and Chukchi Sea planning areas oil and gas lease sales 209, 212, 217 and 221.

Comments had been due March 16; MMS has extended the written comment period an additional two weeks, to March 30.

MMS announced the extension in the Federal Register March 4.

Also in the March 4 Federal Register was the official notice of the extension of the comment period on the draft proposed five-year 2010-15 outer continental shelf leasing program announced by Secretary of the Interior Ken Salazar Feb. 10.

Comments had been due March 23; the new closing date is Sept. 21.

—PETROLEUM NEWS

SAFETY & ENVIRONMENT

Obama reinstates species reviews

In a move that will subject a number of government projects to enhanced environmental and scientific scrutiny, President Obama is restoring a requirement that U.S. agencies consult with independent federal experts to determine whether their actions might harm threatened and endangered species.

The presidential memo issued March 3 will revive a decades-old practice under the Endangered Species Act that calls for agencies to consult with the Fish and Wildlife Service or the National Oceanic and Atmospheric Administration on whether their projects could affect imperiled species. On Dec. 16, the Bush administration let agencies waive such reviews if they decided, on their own, that the actions would not harm vulnerable plants and animals.

Obama said he had instructed Interior and Commerce Department officials to review the Bush rules. In the meantime, his memo said, officials should "follow the prior longstanding consultation and concurrence practices" that call for independent reviews.

—THE ASSOCIATED PRESS

GOVERNMENT

Lisankie takes Johnson's place at RCA

Paul Lisankie replaced Mark Johnson as a commissioner at the Regulatory Commission of Alaska at the beginning of March, the commission announced March 3. Johnson had reached the end of his six-year term in office. In February Governor Palin appointed Lisankie as Johnson's replacement.

Lisankie's term ends on Feb. 27, 2015.

RCA said that Lisankie is an economics graduate who also holds a law degree. He served for more than 20 years in Alaska state government, as an assistant attorney general in the Department of Law and in various positions in the Department of Labor and Workforce Development.

He served on the board of directors of Chugach Electric Association, a major Anchorage power utility, from 1987 to 1989, RCA said.

—ALAN BAILEY

Petroleum news

Business Spotlight

Delta Leasing LLC

Delta Leasing is Alaska's premier vehicle, equipment and remote modular facility provider, offering superior products and impeccable service to its North Slope and remote-site clients and customers. It offers all types of construction and oil- and gas-related equipment, from light plants, heaters and wheel loaders to cranes and boom trucks. The company's experienced professionals well understand the unique challenges of making a modular facility on the North Slope safe, functional and operationally efficient. A major current project is the Liberty Island modular living facility to support BPXA drilling/well operations.

FORREST CRANE

Lori Femiak, Sr. Executive Assistant

Lori Femiak

Ten years in triage call center management provided excellent training for Lori Femiak's current work at Delta Leasing. She provides admin support to the general manager and the sales and marketing staff, plus the office manager. When she joined Delta Leasing in 2006, the firm had only two employees; today it has grown to more than 20. Lori and her husband Brad, who's on active duty in the Air Force, love traveling and seeing the world.

Ed Gohr, Principal

FORREST CRANE

Ed Gohr, Principal, Sr. Project Manager

Ed was one of the founding partners in Delta Leasing and became its construction manager last year. Before that he spent 20 years in the Alaska oil and gas sector on both the owner and contractor sides. Ed and wife Birdie have three daughters — Caitlin, Gabi and Gracie. Marrying Birdie, he says, was the smartest thing he ever did, and his life goal is to equip the girls with the skills and knowledge to be successful in any endeavor they choose to pursue.

—PAULA EASLEY

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

ADVERTISER — PAGE AD APPEARS

A

ABB
ACS 20
Acuren USA 4
Advanced Supply Chain International (ASCI)
AECOM Environment (formerly ENSR)
Air Liquide
Air Logistics of Alaska
Airport Equipment
Alaska Air Cargo
Alaska Analytical Laboratory 18
Alaska Anvil 3
Alaska Computer Brokers
Alaska Coverall 14
Alaska Dreams
Alaska Frontier Constructors
Alaska Interstate Construction (AIC)
Alaska Marine Lines 10
Alaska Railroad Corp.
Alaska Regional Council of Carpenters (ARCC)
Alaska Rubber & Supply
Alaska Sales & Service
Alaska Steel Co.
Alaska Telecom
Alaska Tent & Tarp
Alaska Textiles
Alaska West Express 10
Alliance, The
Alta Air Logistics
American Marine 17
American Tire Corp.
Ameri-Tech Building Systems
Arctic Controls 12
Arctic Foundations
Arctic Slope Telephone Assoc. Co-op.
Arctic Structures
Arctic Wire Rope & Supply
ASRC Energy Services
Aurora Geosciences
Avalon Development

B-F

Badger Productions
Baker Hughes
Bombay Deluxe Restaurant
BP Exploration (Alaska)
Brooks Range Supply
Builders Choice Inc.
Calista Corp.
Canadian Mat Systems (Alaska)
Canrig Drilling Technologies 13
Carlile Transportation Services
CCI
CGGVeritas U.S. Land
CH2M HILL
Chiulista Camp Services 6
Colville
ConocoPhillips Alaska
Construction Machinery Industrial
Cosco Fire Protection
Crowley Alaska
Cruz Construction
Delta Leasing 19
Delta P Pump and Equipment
Denali-The Alaska Gas Pipeline
Dowland-Bach Corp.
Doyon Drilling
Doyon LTD
Doyon Universal Services
Duoline Technologies 9
EEIS Consulting Engineers
Egli Air Haul
Engineered Fire and Safety
Epoch Well Services (see Canrig Drilling Technologies)
Equipment Source Inc.
ERA Helicopters
ESS Support Services Worldwide
Evergreen Helicopters of Alaska
ExxonMobil
Flowline Alaska
Fluor
Foundex
Friends of Pets
Frontier Flying Service

G-M

GBR Equipment
Global Land Services 7
Global Offshore Divers 4
GPS Environmental
Hawk Consultants .... 17'
Holaday-Parks
Inspirations 15
Jackovich Industrial & Construction Supply
Judy Patrick Photography
Kenai Aviation
Kenworth Alaska
King Street Storage
Kuukpik Arctic Services
Kuukpik - LCMF
LaBodega
Lister Industries
Lounsbury & Associates
Lynden Air Cargo 10
Lynden Air Freight 10
Lynden Inc. 10
Lynden International 10
Lynden Logistics 10
Lynden Transport 10
MACTEC Engineering and Consulting
Mapmakers of Alaska
MAPPA Testlab
Maritime Helicopters 3
Marketing Solutions
Mayflower Catering 6
M-I Swaco
MRO Sales
MWH

N-P

Nabors Alaska Drilling 11
NANA WorleyParsons 18
Natco Canada
Nature Conservancy, The
NEI Fluid Technology
NMS Employee Leasing
Nordic Calista
North Slope Telecom 19
North Star Equipment Services (NSES)
North Star Terminal & Stevedore (NSTS)
Northern Air Cargo
Northern Transportation Co.
Northland Wood Products
Northrim Bank
Northwest Technical Services 15
Offshore Divers (see Global Offshore Divers)
Oilfield Improvements
Opti Staffing Group
P.A. Lawrence
PacWest Drilling Supply/Taiga Ventures
Panalpina
PDC Harris Group
Peak Civil Technologies
Peak Oilfield Service Co.
Penco 17
Petroleum Equipment & Services 5
Petrotechnical Resources of Alaska 2
PGS Onshore
Polar Supply
Price Gregory International
Princeton Tec 8
Prism Helicopters
PTI Group

Q-Z

QUADCO
Rain for Rent
Safety One
Salt + Light Creative
Schlumberger
Seekins Ford
Shaw Alaska 5
Spenard Builders Supply
STEELFAB
Stoel Rives
3M Alaska
Taiga Ventures/PacWest Drilling Supply
Tire Distribution Systems (TDS)
TOMCO Group of Companies
Total Safety U.S. Inc.
TOTE
Totem Equipment & Supply
TTT Environmental
Tubular Solutions Alaska
Tutka
Udelhoven Oilfield Systems Services
Umiaq
Unique Machine
Unitech of Alaska
Univar USA
URS Alaska 14
Usibelli
Weston Solutions
Western Towboat
XTO Energy

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

continued from page 1

PEACE

these fields have been running down, bringing supplies more into line with demand and reducing the Cook Inlet reserves-to-production ratio to a value similar to those found in the Lower 48 states. But, although tightening gas supplies argue for rising gas prices, the lack of a Cook Inlet spot market has made it impossible to establish equilibrium prices based on an open market.

Skeptical

Giard has long been skeptical about the producers' position on gas prices. And in her Feb. 27 statement she set out her perspectives on the series of regulatory battles that have engulfed Cook Inlet utility gas. She also proposed a route towards a truce.

"The Cook Inlet Gas War is a story of misrepresentation, a story of greed and a story of abdicating regulatory responsibility," Giard said. "All sides are equally guilty and there are no heroes."

In 2004 Enstar's gas consumers paid $66 million for 26.5 billion cubic feet of Cook Inlet gas, while in 2009 consumers are paying $228 million for the same volume of gas "with no major shifts in production, demand or supply," Giard said. And in the intervening period the Agrium fertilizer plant, a major natural gas user on the Kenai Peninsula, went out of business with the loss of 230 jobs.

"Chugach (Electric Association) is fighting tooth and nail not to have its ratepayers become the third casualty," Giard said, referring to Chugach's attempts to negotiate new gas supply contracts for its gas-fired power plants.

Started in 1994

Giard said that the gas war started in 1994 when Marathon refused to sell 400 billion cubic feet of gas to Enstar. Instead, Marathon exported that gas to Japan through the Nikiski liquefied natural gas terminal, she said.

The prolific nature of the Cook Inlet basin for gas production coupled with geographic and regulatory limits on LNG exports have tended to dampen Cook Inlet gas prices, when compared with prices elsewhere in North America, Giard said. At the same time substantial capital investments in new Cook Inlet gas production have only occurred in connection with applications to renew the export license for the LNG terminal, she said.

"The most recent field investment activity in Cook Inlet started around 2003 with the request for LNG extension filed in 2007," Giard said.

In 2001 RCA approved a new gas supply contract between Unocal and Enstar, with gas prices indexed to the Lower 48 Henry Hub gas market. This new contract would require Unocal to explore for new Cook Inlet gas rather than just using up existing reserves, Unocal and Enstar said at the time.

But the contract did not limit Unocal to just selling newly discovered gas, Giard said.

"Ratepayers were in danger of paying America's higher prices for gas from Cook Inlet's existing reserves," Giard said. "But Unocal promised RCA commissioners that much of its existing reserves were under contract to Agrium."

Approved by RCA

RCA approved the Unocal contract.

"Shortly thereafter, Unocal stopped supplying Agrium," Giard said. All of Unocal's existing gas production then became available to support the Enstar contract, she said.

And under that contract Enstar's consumers have paid Unocal $522 million for 72 billion cubic feet of gas between 2004 and 2009, while Marathon, under the terms of an earlier Enstar contract, received $336 million for the same volume of gas during the same period, Giard said. That price differential has resulted from the use of the Henry Hub price index, she said.

"Enstar's consumers have paid Unocal $184 million more, or about $850 per customer, under what was presented as an exploration contract," Giard said. But no one other than Unocal knows how much of the Unocal gas supplied to Enstar came from new gas field developments, as distinct from the draining down of established gas reserves, she said.

Marathon contract

In 2005 Enstar requested RCA approval for a new gas supply agreement with Marathon. The gas pricing in that contract would have been indexed to Henry Hub, in a similar manner to the 2001 Unocal contract. But the Marathon contract anticipated drawing gas production from existing reserves rather than from new gas fields, Giard said.

"Enstar told the commission that the extreme shortage of natural gas in Cook Inlet justified pricing all gas in Cook Inlet at American Henry Hub prices," Giard said.

But the commission rejected the Henry Hub pricing formula, saying that this would have resulted in gas prices that would be unacceptably high.

In a continuing attempt to plug an impending shortfall in its gas supplies, Enstar came back to the commission in 2008 asking for approval of the new Marathon and ConocoPhillips contracts that have recently gone into temporary play.

Tier pricing

The pricing formula that the producers originally wanted in these contracts, and which RCA rejected, would have set the base gas price to an index of North American market prices. Tier prices above that would then have applied to high levels of demand for gas in the winter.

"This time, the American index prices were used as a base, and they escalated up to 150 percent of the base during the coldest months of the year," Giard said. "This new methodology sent gas prices in Cook Inlet soaring even higher than the American Henry Hub prices in the Unocal contract."

And, according to information provided by electric utility Municipal Light and Power, part owner of the Beluga River gas field, the proposed pricing formula would have resulted in a 300 percent profit margin for the producers, were they to draw the gas from existing reserves, Giard said.

Extreme pressure

So, "under extreme pressure" following statements from Enstar about the possibility of having to cut supplies to as many as 400 businesses in early 2009, RCA imposed a price cap indexed to a basket of market prices from North American gas production basins, a series of price points that more accurately represents the Cook Inlet gas market than the more downstream (and higher priced) "city gate" markets that the producers wanted to use, the commission said.

But the Cook Inlet gas producers rejected the price cap and, to enable Enstar to meet all of its gas supply obligations, RCA allowed the new contracts to go into effect for one year with a weighted-average-cost-of-gas pricing formula.

"And thus the Cook Inlet Gas War is at a standoff," Giard said. "In a traditional old western standoff, neither side knows who

see **PEACE** *page 19*

Agrium and the Cook Inlet gas market

When Agrium Inc. bought the Nikiski fertilizer plant on Alaska's Kenai Peninsula from Unocal Corp. in 2000, Agrium expressed optimism that fertilizer production at Nikiski would enhance Agrium's position in the North American fertilizer market. And as part of the takeover deal, Agrium inherited a 1998 Unocal supply agreement for natural gas, the plant's main feedstock, from Unocal's erstwhile Alaska fertilizer subsidiary. That agreement was due to expire in 2009.

In 2001 the Regulatory Commission of Alaska approved a new gas supply contract between Unocal and Enstar Natural Gas Co., the main Southcentral Alaska gas utility. That contract involved gas pricing intended to encourage new Cook Inlet gas exploration, given that much of Unocal's existing gas reserves were dedicated to supplying Agrium, according to RCA records.

And in that same year Unocal announced a new $10 million gas exploration project on the Kenai Peninsula. The company also said that it was investing about $15 million in developing existing Cook Inlet gas fields in 2001.

But things had turned sour by early 2002 when Unocal announced that it had failed to discover commercial quantities of natural gas in a three-well drilling program in the southern Kenai Peninsula.

Litigation

Then, in the summer of 2002, litigation erupted between Unocal and Agrium over a dispute about the gas sales agreement for the fertilizer plant. According to Agrium the dispute, although financial in nature, hinged on issues relating to gas supplies from Unocal. And Unocal told Petroleum News at the time that, under the terms of the gas sale agreement, Unocal should be able to reduce its gas supplies to Agrium, to reflect a decline in Unocal's Cook Inlet gas reserves.

In May 2003 Agrium laid off 65 employees, in part, the company said, because of gas supply issues with Unocal. And a month later Agrium announced that Unocal had intimated further cuts in gas supplies. Agrium said that it was seeking alternative supplies from other producers.

In March 2004 Bill Boycott, general manager of Agrium's Kenai operations, told the Resource Development Council of Alaska that the fertilizer plant gas consumption of 53 billion cubic feet in 2001 had dropped to 40 bcf in 2004 and was expected to drop to 36 bcf in 2004.

Arbitration panel

And in July of that year an arbitration panel in the litigation between Agrium and Unocal awarded Agrium $38.5 million in damages plus interest for the under-delivery of gas. The panel accepted that the gas sales agreement involved delivery volumes linked to the levels of specific gas reserves dedicated to the agreement. However, Unocal's gas deliveries had not met required minimums, the panel said.

But in October 2004 Unocal said that it was unlikely to be able to deliver on-going gas volumes specified by the arbitration panel, despite the fact that "Unocal is in full-out production" from gas fields dedicated to the Agrium contract. And the company said that if it found new gas sources it was not obliged to divert that gas to meet

see **AGRIUM** *page 19*

continued from page 1

MAC LINE

The APG has rights to a one-third ownership stake in the pipeline on behalf of Native communities along the pipeline right of way provided it can secure volumes over and above those provided by the MGP anchor owners, Imperial Oil, Shell Canada, ConocoPhillips Canada and ExxonMobil Canada.

But he rated as "dismal and very disappointing" the length of time being taken by the Joint Review Panel, appointed to study the environmental and socioeconomic impacts of the project.

Because of the drawn-out process he said Canada's National Energy Board is unable to hear final arguments, while the co-venturers must apply for hundreds of land and water permits.

However, Reid underscored the importance of the MGP, noting that the 6 trillion cubic feet of Mackenzie Delta gas owned by the proponents "could serve every residential home in Canada for a period of 10 years."

Build before Alaska line

Like all other backers of the MGP and the Canadian government, Reid said it is vital the MGP is built before any pipeline from Alaska to the Lower 48.

Otherwise, he said it would be cheaper for Arctic producers to expand the capacity of an Alaska pipeline if that project was completed first than it would be to build an entirely new Mackenzie pipeline.

If Alaska is out of the blocks first, "Mackenzie will be put on the shelf for a very long time," Reid said.

Alberta Premier Ed Stelmach told the same Arctic gas conference that the northern resources will be in high demand once the economy recovers.

"As the various stimulus programs we keep hearing about begin to kick in, energy demand will grow," he said. "Prices will rise and the need for new supply will become stronger.

"Massive reserves like Arctic gas and Alberta's oil sands will be more important than ever before," Stelmach said.

He also said Alberta's gas hub has enough capacity to handle gas from Alaska and the Mackenzie Delta and deliver that production to the heart of the U.S. market.

In addition, he said Arctic gas will also provide feedstock for Alberta's petrochemical sector, which is "important to Alberta's future and really to Canada's future."

—GARY PARK

continued from page 1

NIKAITCHUQ

2009, and bringing offshore pads at the unit into production starting in late 2010.

As of early January, Eni had completed at least one development well from Oliktok Point, according to records from the Alaska Oil and Gas Conservation Commission. The company previously announced plans to drill seven producer wells from the onshore pad.

Spending with an eye on costs

Eni does not appear to be on a cost cutting spree.

Presenting 2008 year-end results and laying out a four-year strategic plan on Feb. 13, Eni executives said they planned to spend 14.1 billion euros (around $18 billion) in capital expenses this year, part of a 48.8 billion euro (around $62 billion) four-year capital expenditure program, down only 1 billion euros from the budget for 2008 through 2011.

In the strategic plan for 2009 through 2012, Eni still lists the North Slope as a "key area" of exploration for the company, and slated Nikaitchuq to come into operation for 2010, peaking at 26,000 barrels per day of oil. The company previously announced plans to build onshore processing facilities capable of handling 40,000 bpd.

In a question and answer session following the presentation, Paolo Scaroni, chief executive officer of Eni S.p.A., offered nuanced thoughts about the company's strategy for expensive and unconventional exploration ventures in the current economic climate.

Scaroni said a January 2007 decision not to enter the Canadian oil sands was "one of the wisest decisions I've ever taken in my life," but added that the company's unconventional oil prospects in Venezuela and the Congo should remain viable even at lower oil prices, saying, "Our unconventional oil is much better than some other unconventional oil."

Scaroni also said Eni likes its position in the Gulf of Mexico and hopes to remain a presence there, but added, "Other areas of the world might be under scrutiny to make sure that either they are material, or we have enough perspectives in order to make them material one day." He did not elaborate or mention any specific areas under review.

Royalties change economics

Eni is projecting oil prices to average $43 a barrel this year and $55 a barrel in 2010, and said a "vast amount" of its international portfolio would break even at $35-a-barrel prices.

Of the 525,000 barrels of oil equivalent in new production Eni hopes to bring online by 2012, some 57 percent would break even at an oil price of $35 a barrel; some 76 percent would break even at $40 a barrel; and 100 percent would break even at $60 a barrel.

Eni is presumably, though not explicitly, including Alaska somewhere in those figures.

Eni sanctioned Nikaitchuq after the state modified its royalty structure on several leases at the unit, allowing Eni to pay lower royalty rates to the state if oil prices began to fall.

Under the agreement, the royalty rate on oil produced from those leases rises and falls on a sliding scale connected to the delivered price of Alaska North Slope crude oil.

Up to an inflation-adjusted price of $42.54 per barrel, Eni pays 5 percent royalties to the state. As oil prices increase, so does the royalty rate, topping out at 16.667 percent, the original royalty rate attached to most leases in the unit. The scale is based on a Minerals Management Service program for deepwater federal leases in the Gulf of Mexico.

When the state changed the royalty structure in December 2007, those lower oil prices looked unlikely in the near future. Alaska North Slope crude traded at about $90 a barrel at the time, on its way to nearly $150. But oil prices dropped more than $100 a barrel in the fall.

Since the start of 2009, oil prices have moved between $32 and $48 a barrel.

In requesting a change to the existing royalty structure back in October 2007, Eni said the economics of Nikaitchuq would otherwise be only "marginal" at low oil prices. The state agreed to the changes on the condition that Eni sanction development by Feb. 28, 2008, and meet spending commitments: $822 million by 2014 and nearly $1.4 billion by 2019.

The royalty modification remains in place for 25 years after sustained production begins.

The royalty modification only covers oil produced from the Nikaitchuq Schrader Bluff OA reservoir, a shallower pool believed to contain heavier oil. The Nikaitchuq prospect also contains a deeper reservoir in the Sag River formation believed to bear light oil.

Heavy oil is often harder and more expensive to produce than light oil, but because the Sag River formation is "plagued with poor quality reservoir rock," development of it is "marginal at best unless there are significant advances in stimulation or enhanced oil recovery technology," state oil and gas officials wrote in the decision to modify royalties.

Eni estimates Nikaitchuq contains 180 million barrels of recoverable oil.

Sole owner at Nikaitchuq

Nikaitchuq has changed hands numerous times over the past decade.

Eni picked up a minority interest in the unit in 2005 and assumed the rest in 2007.

Banks speculated that might have something to do with the company decision to slow development, saying Eni would have more leeway to change timelines at Nikaitchuq than it would at projects around the world where it is partnering with other producers.

One of those projects is the Oooguruk unit, which neighbors Nikaitchuq in the nearshore waters of the Beaufort Sea. Pioneer Natural Resources brought the unit into production last summer and holds a 70 percent working interest. Eni holds the remaining 30 percent.

Nikaitchuq comes from an Inupiat word meaning "to persevere." ●

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

continued from page 1

SHOPPING

British Columbia with rolled-in tolls.

Stephen Clark, a TransCanada vice president responsible for Western Canadian pipelines, told reporters the NEB ruling allows his company to integrate pipelines from new production growth areas into the Alberta network, which in turn connects with TransCanada's main lines to Eastern Canada and the United States.

Eventually that could include a Mackenzie Valley pipeline, for which TransCanada has claimed the primary transportation rights, and an overland pipeline from Alaska, which has TransCanada and the Denali partners BP and ConocoPhillips, in competition to secure producer backing.

Clark said the big change under the new regulatory regime will allow TransCanada to go directly to producers with offers of rolled-in tolls — something not currently permitted under Alberta legislation — reducing the "economic hurdles producers face to get to the Alberta hub."

He said tolls for all shippers will be reduced by allowing more gas into the Alberta network, where current volumes are about 10.6 billion cubic feet per day, but have been declining as production has started to shrink in the Alberta portion of the Western Canada Sedimentary basin, and by feeding gas into other downstream pipelines, many of which have unused capacity.

Clark said that keeping pipelines operating closer to capacity will see the benefits ripple through the whole grid across North America.

Kvisle: increases likelihood of future Alaska integration

TransCanada Chief Executive Officer Hal Kvisle said in a statement the jurisdictional shift increases the likelihood that northern gas from the Northwest Territories and Alaska could integrate directly with the Alberta hub.

The NEB concurred with TransCanada's argument, made in hearings last year, that the Alberta and Foothills systems along with the TransCanada mainline are effectively a single operation to deliver gas to markets in Canada and the United States.

The federal regulator said there is clear evidence that these systems are functionally integrated and share common management, control and direction.

While TransCanada became owner of Nova gas Transmission after its merger with Nova, the Alberta system continued to function under the Alberta energy regulator based on the original charter which prohibited the network from operating outside Alberta,.

But the growth of production in British Columbia now means that 7.5 percent of gas carried on the Alberta system originates outside the province.

The NEB ruling also includes the operation of projects approved, but not yet constructed, including the C$923 million North Central Connector in Alberta.

Pipeline landowner associates had raised concerns at the NEB hearings about how their members would be affected by a jurisdictional shift, but the NEB decided the consultation program promised by TransCanada was adequate.

B.C. binding agreements

The verdict coincided with the latest binding agreement between TransCanada and British Columbia shippers.

This time TransCanada said it has secured backing for 378 million cubic feet per day from Horn River, which includes a 90-mile pipeline costing C$340 million and scheduled to start service by mid-2011.

Earlier in February, TransCanada obtained commitments from shippers for 1.1 billion cubic feet per day by 2014 from the Montney-Groundbirch region, with the C$250 million pipeline targeting an in-service date of 2010.

Kvisle said the "positive commercial response" to the binding open seasons sets the stage to add "future capacity … as the right opportunities present themselves."

The Alberta Energy Resources Conservation Board, which will continue to regulate 400,000 kilometers of pipelines in Alberta, has no plans to appeal the NEB decision so long as it is satisfied that "every aspect of the operation is regulated … and there are no regulatory gaps." ●

continued from page 1

CONOCO

what types of jobs are involved. Employees involved were notified today, the company said.

The company has about 1,200 employees in Alaska.

The Alaska layoffs come as part of Conoco's plan to cut its global work force of 33,800 employees by 4 percent.

In announcing the planned cuts in January, Conoco chief executive Jim Mulva said the company was deferring or slowing some capital spending projects because of lower oil prices.

"We are positioning ourselves in the current business environment to live within our means in order to maintain financial strength," he said.

Conoco is Alaska's top oil and gas producer. It holds a large stake in Prudhoe Bay, the nation's largest oil field, and it runs two other major North Slope oil fields, Kuparuk and Alpine.

Prices for North Slope crude delivered to West Coast ports crested above $140 a barrel last year, then plunged to below $26 in December and on Tuesday closed at $44.65. Now companies operating in Alaska are moderating their spending plans to account for the decline.

Last week, the Italian oil company Eni told state officials it's curtailing development of its new Nikaitchuq oil field on the Slope. The action is expected to result in job losses at contracting companies building the field.

—**WESLEY LOY,** ANCHORAGE DAILY NEWS

continued from page 17

AGRIUM

Agrium's needs.

In December 2004 Agrium and Unocal settled their litigation with an agreement that involved the termination of gas supplies on Oct. 31, 2005, and a payment of $25 million in compensation to Agrium for the cessation of supplies prior to the June 2009 date in the original gas supply agreement.

Agrium continued to seek new gas supplies at prices that would be viable for fertilizer production. The company even investigated converting the Nikiski plant to use coal gasification rather than natural gas. But, with annual gas supplies to the plant dwindling to 10 billion cubic feet, the plant finally closed its doors in late 2007.

—**ALAN BAILEY**

continued from page 17

PEACE

will pull the trigger first or who will end the day in a pine box. … Unocal has operated under a contract that was fully vetted and approved by the RCA. Marathon and ConocoPhillips reasonably expected parity for their contracts. … (But) somewhere in all of these hundreds upon hundreds of millions of dollars someone was supposed to protect the consumers."

Food for thought

But, although Giard continues to question the gas producers' claims of a Cook Inlet gas shortage, given the U.S. Department of Energy's 2008 extension of the license for the export of LNG from the Kenai Peninsula LNG terminal, a recent event has given her food for thought.

A few months ago she was listening to Don Page, Unocal's commercial manager, talking about his experience of keeping the utility gas flowing during an especially cold winter night.

"Mr. Page told a tale of a night of lost sleep and personal terror that the Southcentral pilot lights would be extinguished on his watch," Giard said. "… He told it so convincingly; it was as if I were there watching as he drove to his office and worked dispatch, side-by-side with his people all night, pulling gas from wherever he could find gas and pushing it to Enstar's system to ensure that my children and perhaps his own would sleep warm through the night."

It seems reasonable that producers should be compensated for pushing gas on those frigid days "when all of Alaska shivers," Giard said.

On the other hand, the cost of the base utility gas that flows every day of the year should also be reasonable, she said.

"It must not subsidize the export of LNG to Asia," Giard said. "It must reflect the abundance of gas supply that exists in Cook Inlet which supports the export of excess supply to Asia."

Giard said that she is going to propose regulations that would clarify future Cook Inlet gas pricing.

Perhaps in the past everyone has made mistakes in the gas pricing battles, she said.

"Perhaps as a commissioner I have tried too hard to 'unring the bell' and put ratepayers back into the time before the Henry Hub invaded Alaska under a cloak of darkness," Giard said. "… Maybe we just need to find a different bell to ring, one that recognizes Cook Inlet as a vibrant basin and also recognizes that our Cook Inlet producers do more than supply gas. They push gas at 20 degrees below zero to keep us warm." ●