Petroleum news

page 14 Slaiby fills new general manager position for Shell's Alaska operations

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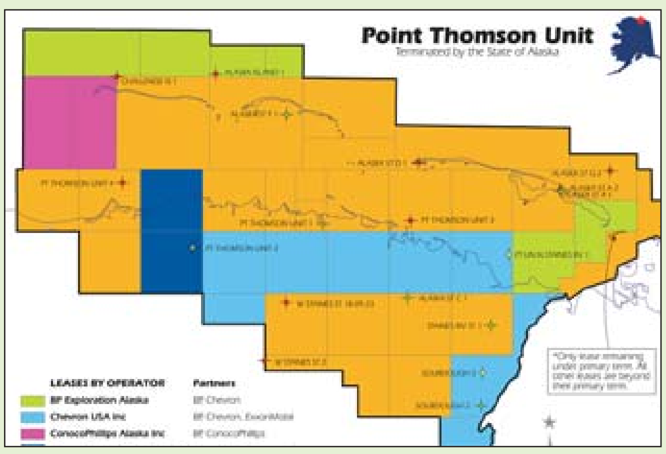


Point Thomson leases a mixed bag: Can Exxon drill? What about a new lease sale?

Although the Alaska Department of Natural Resources has terminated the Point Thomson unit, the erstwhile unit owners are clearly bent on moving ahead with drilling on leases that formed part of the unit.

"Despite the DNR's decision, we are continuing plans to begin drilling this coming winter," Margaret Ross, media advisor for ExxonMobil corporate public affairs, told Petroleum News June 11. "We have the right to conduct

see **LEASES** page 18

Hosie: Point Thomson litigation likely to take 16-18 months

The impasse between the Point Thomson unit owners and the State of Alaska is heading down a road clearly signposted toward litigation. And that being the case, the legal title to at least some of the Point Thomson leases is likely to stay in limbo for quite some time.

So, just how long might it be before the state can schedule a Point Thomson lease sale, assuming that the state prevails in its position that the Point Thomson unit, together with its underlying leases, passed into oblivion following Department of Natural Resources Commissioner Tom Irwin's decision to

see **LITIGATION** page 17

MGM, Gwich'in sign Canadian Arctic exploration agreement

MGM Energy, a junior explorer in the Canadian Arctic, has blazed another fresh trail by taking the first step toward a commercial relationship with a northern aboriginal organization.

Under a memorandum of understanding, MGM and the Gwich'in Tribal Council, which represents communities that signed a land claim settlement in 1992, have opened the way to evaluation of the resource potential underlying tribal lands

see **DEAL** page 15

BREAKING NEWS

PIPELINES & DOWNSTREAM

FERC lowers tariff

Commission upholds '07 TAPS ruling; outlines basis for reasonable rates

By ROSE RAGSDALE
For Petroleum News

The Federal Energy Regulatory Commission June 19 affirmed a May 2007 administrative law judge ruling that interstate rates charged on the Trans-Alaska Pipeline System in 2005 and 2006 were not just and reasonable and ordered limited refunds to shippers who had overpaid. The order, which the five-member commission approved without comment, establishes the basis for new just and reasonable rates that will go into effect on a prospective basis.

FERC said the order affirms, clarifies and modifies an initial decision that Judge Carmen A. Cintron issued May 17, 2007, regarding the pipeline carriers' 2005 and 2006 interstate rate filings. The order affirms Cintron's finding that pipeline owners BP Exploration (Alaska) Inc., ConocoPhillips Alaska, ExxonMobil Production

> *The order affirms Cintron's finding that pipeline owners BP Exploration (Alaska) Inc., ConocoPhillips Alaska, ExxonMobil Production Co, Unocal Pipeline Co. and Koch Alaska Pipeline Co. LLC failed to prove the proposed rate increases in their 2005 and 2006 tariffs were just and reasonable, and ordered limited refunds to all trans-Alaska oil pipeline shippers.*

see **TARIFF** page 15

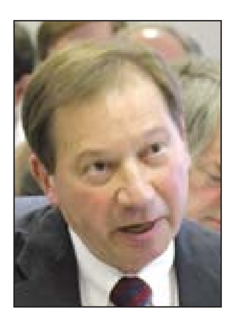
NATURAL GAS

Two lines to Southcentral

Enstar, ANGDA argue the merits of small pipelines projects for in state gas

By ERIC LIDJI
Petroleum News

On the natural gas fight card this year, the main event is clearly the big pipeline: Denali, created by BP and ConocoPhillips, squaring off against TransCanada, backed by the state and looking for legislative approval.


HAROLD HEINZE


CURTIS THAYER

That's undoubtedly the heavyweight match, but there is a highly competitive undercard as well: two smaller proposals for bringing northern gas to markets in Southcentral Alaska.

The Alaska Natural Gas Development Authority, or ANGDA, wants to build a spur line connecting the mainline to Anchorage, while Enstar Natural Gas Co. wants to build a "bullet line" connecting gas fields in the foothills of the Brooks Range to Anchorage.

The two projects hope to solve the same problem: declining production in Cook Inlet threatens to cause a shortage of natural gas supplies in Southcentral Alaska. According one forecast, that shortage could start to be felt as soon as 2014.

see **TWO LINES** page 17

EXPLORATION & PRODUCTION

PTU not another Alpine

BP, Chevron, Exxon dispute state's Point Thomson analysis, say gas main resource

By KRISTEN NELSON
Petroleum News

The oil at Point Thomson is not the equivalent of another Alpine field, ExxonMobil and Chevron told Alaska legislators June 17. The loss of Point Thomson oil if gas were produced first as described in a Department of Natural Resources report is based on erroneous assumptions about how much oil could be recovered from the field under any scenario, they said.

Gas is the primary resource at Point Thomson, not oil, and Point Thomson gas is necessary for a successful gas pipeline, the companies said.

BP did not testify, but delivered a similar message in a June 16 letter to legislators.

Up until three weeks ago, everyone believed Point Thomson gas was necessary for a gas pipeline, said Craig Haymes, ExxonMobil Alaska production manager, adding that the Point Thomson leaseholders don't understand how that

> *"It's not that the work is wrong," but it doesn't take into consideration economics or factors like location and type of wells, and "reaches a conclusion that is very optimistic, both in the original hydrocarbons that are in place but particularly in the recoverable hydrocarbons."*
>
> —Vince LeMieux, Chevron's manager of Alaska new ventures

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contents

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

● NATURAL GAS

NEB filing designed to keep tolls low

TransCanada's application to the National Energy Board designed to make Alberta System more commercially attractive to North Slope, Mackenzie and B.C. natural gas shippers

By KAY CASHMAN
Petroleum News

TransCanada said June 17 that its subsidiary TransCanada PipeLines Ltd. filed an application with Canada's National Energy Board, or NEB, to establish federal regulation for TransCanada's Alberta System, an action designed to provide more competitive transportation rates for the company's natural gas customers outside of Alberta, including Alaska, British Columbia and Mackenzie shippers.

Currently TransCanada's Alberta System is regulated by the provincial government, and Alberta legislation precludes TransCanada from acquiring, constructing or operating facilities that transport gas across Alberta borders — i.e. extending the system outside Alberta, although it is not precluded from bringing gas to the system.

Being regulated by NEB would allow the Alberta System to expand lines to hot new natural gas producing areas, allowing for more attractive service offerings to Alberta, British Columbia, Alaska and Mackenzie gas producers.

TransCanada's plans would also bring the Alberta System closer to TransCanada's proposed gas line from Alaska's North Slope by extending a pipeline across Alberta's border to Fort Nelson in northeast British Columbia along the Alaska Highway.

"Under the current regulatory environment we would have to deliver North Slope gas into the Alberta System at the Alberta border," TransCanada Vice President of Commercial West Canadian Pipelines Steve Clark told Petroleum News June 17. "In our AGIA (Alaska Gasline Inducement Act) proposal we have identified Fort Nelson as a receiving point. This jurisdictional change sets the stage to do that."

If NEB turns down TransCanada's request, a two-step process that is expected to take about 18 months, it won't prevent TransCanada from delivering Alaska gas into its Alberta system, Clark said.

"Nothing prevents Alaska gas coming to Alberta and hooking in, but by extending the Alberta System it makes it even more commercial," he said.

'Win-win' for TC, Alberta, gas producers

Clark doesn't think NEB will turn down TransCanada's application, as the company has spent a lot of time talking to its shippers and the provincial government, which has made no secret about its concerns that Alberta's gas fields are maturing and producing less and less gas. "It's a very remote possibility," he said.

"The way we have structured our application we are confident that we have a solid application. It's just a matter of getting through the process itself. … It's a win-win for everybody because if we can extend the system by adding gas from outside Alberta it drives down the tolls," which Clark said meets the province of Alberta's goal of keeping the Alberta Hub and related economy as competitive and robust as possible.

Increased throughput from locations outside Alberta will benefit Alberta by increasing the physical and commercial flow of gas within and from the Alberta Hub, "making it a more transparent and liquid environment for natural gas buyers and sellers and increasing natural gas liquids supply to straddle plants and petro-chemical infrastructure located in Alberta," the company said.

Hal Kvisle, TransCanada's president and CEO

"We want a larger commercial hub here," Clark said, describing "liquid" as "lots of buyers and sellers" and "transparent" as "good price discovery."

Currently, 11-12 billion cubic feet of natural gas per day is run through the Alberta Hub, but "each molecule is bought and sold five or six times in the hub," Clark said. "More gas through the system drops tolls (tariffs) for everybody."

TransCanada expects feedback on its application from NEB, he said. The second part of the process is to apply for certificates to operate the system.

In the meantime, it will be business as usual for the Alberta System.

"We anticipate business as usual for the Alberta System during and following the regulatory approvals process," Hal Kvisle, TransCanada's president and chief executive officer, said. "This includes the continued processing of significant Alberta System matters by the Alberta Utilities Commission while the jurisdiction application is considered by the National Energy Board."

In May, Kvisle told an Anchorage audience TransCanada is working with Canadian regulators to speed up the regulatory processes there and will work with Federal Energy Regulatory Commission, or FERC, to speed up the regulatory process for the Alaska side of the project.

Keystone, then Mackenzie, then Alaska line

The Keystone project, which will be TransCanada's "major construction project focus over the next four years," will be complete by late 2011, early 2012, Kvisle said. At the same time, TransCanada will be investing $2 billion in large-diameter gas pipeline additions in Alberta. ConocoPhillips is TransCanada's partner in Keystone.

Then will come the Mackenzie Valley project, he said.

Over that five to six year period, "we are going to develop a lot of young people with exceptional capabilities in both technical design and also project management, and we think all of that will position us very well — no better way to get ready to build the Alaska pipeline than to build a lot of other pipelines in the meantime."

> *"Nothing prevents Alaska gas coming to Alberta and hooking in, but by extending the Alberta System it makes it even more commercial."* **— Steve Clark, TransCanada vice president of commercial west Canadian pipelines**

TransCanada's partners in the Mackenzie Valley project are ConocoPhillips, ExxonMobil and Shell. BP is an explorer in the region, not a pipeline owner.

"And we're moving that project forward. We haven't quite resolved all the issues but it's a much smaller project than the Alaska one," Kvisle said.

Mackenzie is 700-plus miles of 30-inch-diameter pipe expected to move some 1 billion cubic feet a day to market, compared to 1,700 miles of 48-inch pipe (North Slope to Alberta) moving 4-4.5 bcf a day for the Alaska Highway gas pipeline.

He said they've come up with "a structure for the Mackenzie. While we haven't got that new structure formally sanctioned yet, we're optimistic that it will work for both the Mackenzie producers and the government of Canada."

TransCanada's network of wholly owned pipelines extends more than 36,500 miles (59,000 kilometers), tapping into virtually all major gas supply basins in North America.

The company is one of the continent's largest providers of gas storage and related services with approximately 355 billion cubic feet of storage capacity.

A growing independent power producer, TransCanada owns, controls or is developing approximately 8,300 megawatts of power generation.

The company's common shares trade on the Toronto and New York stock exchanges under the symbol TRP. ●

EXPLORATION & PRODUCTION

Alberta lags behind neighbors in permits

Improved natural gas prices have yet to work their way down to the Alberta industry, which remains a spectator as British Columbia, Saskatchewan and Manitoba revel in the new environment.

For the first five months of 2008, the three smaller provinces all posted substantial gains in new well licenses, while the Energy Resources Conservation Board in Alberta issued 6,851 permits, off 6 percent from a year earlier and the poorest showing in six years.

The regulator approved 853 licenses in May, down 68 from last year, with conventional gas-targeted permits slipping to 2,831 from 3,096. Oil and bitumen permits tapered off to 1,382 from 1,502. Only coalbed methane activity posted an increase at 607 from 549.

Saskatchewan continued its strong progress, approving 268 oil licenses in May, pushing its oil total for the first five months to 1,187, while gas permits totaled 507 wells, up 23 from May 2007. On the oil front, both the May and year-to-date numbers were the highest this decade, while gas was far short of the May 2005 benchmark of 945.

In gas-prone British Columbia, the five-month tally of 338 was up a mere four wells from 2007, although May surged to 90 permits from 65 last year.

Manitoba recorded 134 permits in the January-May period, an increase of 37 from 2007.

EnCana easily held its leading spot among operators, with 1,493 licenses, although that was down 90 from last year. Canadian Natural Resources climbed to 512 wells from 345 a year earlier.

—GARY PARK

CORRECTION

In the June 8 issue of Petroleum News we published a story about the Bureau of Land Management bumping National Petroleum Reserve-Alaska recoverable crude reserves up to 17 billion barrels. The article was about a recent inventory of oil and gas resources on federal lands. In fact, the 17 billion-barrel number included Arctic National Wildlife Refuge crude reserve estimates, not just NPR-A. The BLM inventory figures were essentially derived from U.S. Geological Survey assessments of northern Alaska and did not represent a new assessment.

We have corrected the online version of the article. Here is a link to the revised text version: www.petroleumnews.com/pnads/216890658.shtml.

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● NATURAL GAS

EnCana talks up shale gas plays

Horn River, B.C., Haynesville Shale in Louisiana and Texas compared in size to Barnett shale of north-central Texas, says EnCana CEO

By GARY PARK
For Petroleum News

EnCana, North America's leading natural gas producer, has cranked the continent's shale gas plays up another notch, without disclosing hard numbers from its activities in the Horn River area of northeastern British Columbia.

The big independent announced June 16 that it is building a dominant land and resource position in both Horn River and the Haynesville Shale in Louisiana and Texas, reporting that a "series of exploration wells has shown strong potential to deliver commercial volumes of natural gas."

Chief Executive Officer Randy Eresman said wells drilled by EnCana, its partners and other companies "indicate these two resource plays hold the potential to eventually become amongst the largest in North America."

He told a Canadian Association of Petroleum Producers investment symposium that Horn River and Haynesville are being compared in size and scope to the Barnett shale of north-central Texas, which currently produces 3 billion cubic feet per day and is still growing.

Eresman said EnCana, since discovering Horn River in 2003, has established a leading land and technology position, including 220,000 net acres, while its stake in Haynesville is now a net 325,000 acres.

He said each play has the potential to ultimately reach a net 1 bcf per day, comparable to what the company has announced at its more-established plays at Montney in British Columbia and Deep Bossier in East Texas.

Eresman said EnCana's success in finding and unlocking the potential of some of the largest new unconventional plays in North America can significantly accelerate its growth rate "to an even higher sustainable level," once Horn River and Haynesville are incorporated in its portfolio.

He said strong production from across EnCana's resource plays and higher-than-budgeted cash flow due to more robust gas prices should allow the company to increase drilling and continue expanding its shale play land holdings.

But, for now, EnCana is disclosing only preliminary results from the four production wells it drilled in partnership with Apache at Horn River.

Eresman said two of the four wells have just started to flow, with early results pointing to strong production potential.

Speaking at the same symposium, ARC Energy Trust said its exploration in the Dawson area of the Montney play points to gas-in-place of 10 bcf to 100 bcf for every 640 acres, with an average recovery factor of 20 to 40 percent or 5 bcf per well.

It said an independent reserves evaluator has suggested that recovery factors may ultimately reach 60 to 70 percent, but that will depend on drilling density, completion technology and reservoir response.

Currently producing 44 million cubic feet per day at Dawson, ARC said the use of isolated, multi-frac horizontal completions have seen its average well costs drop from C$7.5 million for its first four wells, to C$6 million for its next six. It is now budgeting for C$5.5 million per well this year.

A presentation by Canadian Natural Resources said it has ultimate drilling activity of 360 wells in Montney and 800 wells in British Columbia's Muskwa Shale, with an additional 275 wells in the Doig Shale of Alberta, compared with a combined current prospect inventory of 109 wells for the three plays. ●

● EXPLORATION & PRODUCTION

BP preps gas cap injections for Lisburne

Three-year pilot project follows Prudhoe Bay effort, goal to lower gas-to-oil ratio at North Slope field and increase oil production

By ERIC LIDJI
Petroleum News

Looking to enhance oil recovery, BP Exploration (Alaska) is implementing a new pilot project at the Lisburne oil pool on the North Slope.

The process involves injecting seawater into the gas cap of the reservoir to increase pressure and produce more oil. The company estimates the process will help produce 500,000 additional barrels of oil over the next three years.

If successful, the pilot project could be expanded into a full program lasting 20 years, which BP estimates could add 10 million barrels of oil from Lisburne.

The Alaska Oil and Gas Conservation Commission approved the three-year pilot project on June 4, requiring BP to report annually on the progress of the program.

Lisburne production on steep decline

Lisburne is in the northeast corner of the Prudhoe Bay unit, part of a group of fields collectively known as the Greater Point McIntyre Area.

These fields have seen steady production declines every year for the past decade.

In filings with the state, BP said Lisburne alone produced an average of 10,222 barrels per day of oil in 2007, along with 1,457 bpd of natural gas liquids.

The state calculates Lisburne production along with several other fields. Through the first five months of this year, those fields produced an average of 36,400 bpd of oil. By comparison, the fields produced an average of 84,500 bpd through the first five months of 2001.

Some of the drop can be attributed to high gas-to-oil ratios at the field. The Lisburne Production Center can only handle so much gas.

As the facility began processing fluids from the nearby Point McIntyre and Niakuk oil pools in 1994, the operators began shutting in Lisburne wells with low oil ratios. Between 1997 and 2007, fewer than 41 of the 79 wells in the Lisburne oil pool have been active in any given month, according to BP filings.

Similar projects done at Prudhoe

The Lisburne field went into full production in 1987 and the operators at the time tried a two-year "pilot waterflood test," but canceled the project after "Water breakthrough was much faster than expected."

In 2002, BP implemented a much larger-scale version of the gas cap injection pilot project at Prudhoe Bay. According to filings, "There have been some early favorable results."

Using models of Lisburne, BP predicts the injection "may act as a blocking agent" effectively keeping the gas in the reservoir from moving toward the production wells, thereby lowering the gas-to-oil ratio from the field.

BP doesn't expect the project to decrease eventual gas production at the field and suggested it may even lead to slight increases in future gas recovery. ●

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● NATURAL GAS

Denali president outlines firm's priorities

By ERIC LIDJI
Petroleum News

The newly appointed president of a producer-backed natural gas pipeline company in Alaska said the workload for 2008 would mix administrative chores and major spending.

As reported in last week's issue of Petroleum News, Bud E. Fackrell is the first president of "Denali-The Alaska Gas Pipeline," a joint venture between BP and ConocoPhillips created in April and charged with the task of building a natural gas pipeline from the North Slope to markets in the Lower 48.

Denali has three main priorities this year: completing a season of fieldwork, finding permanent office space and assembling an executive team, Fackrell told Petroleum News in a June 13 interview.

Denali plans to spend $40 million this summer on fieldwork, as part of a $600 million effort to prepare for an open season by 2010.

"That's extremely important that we don't lose the summer," Fackrell said.

Denali has 50 people working in the field this summer and 50 people working in Anchorage. The company is temporarily based out of existing office space in the BP and ConocoPhillips buildings, but is looking for a more permanent location.


BUD FACKRELL

One of the first tasks before Fackrell is putting together an executive team from a list of nominees being compiled by BP and ConocoPhillips. Fackrell said that team should come together "over the next few weeks" and will likely include people currently in Alaska, as well as people from Outside.

"We are looking companywide," Fackrell said. "We want the best candidates available. But obviously people in Alaska have a lot of the skills were looking for."

Fackrell would not comment on a possible partnership with TransCanada, saying that would be the decision of his "owners," BP and ConocoPhillips.

However, when asked whether Denali would proceed regardless of whether state lawmakers awarded TransCanada a license to build a pipeline under the Alaska Gasline Inducement Act, or AGIA, Fackrell said, "Denali's plans are independent of AGIA. We are moving forward on this project."

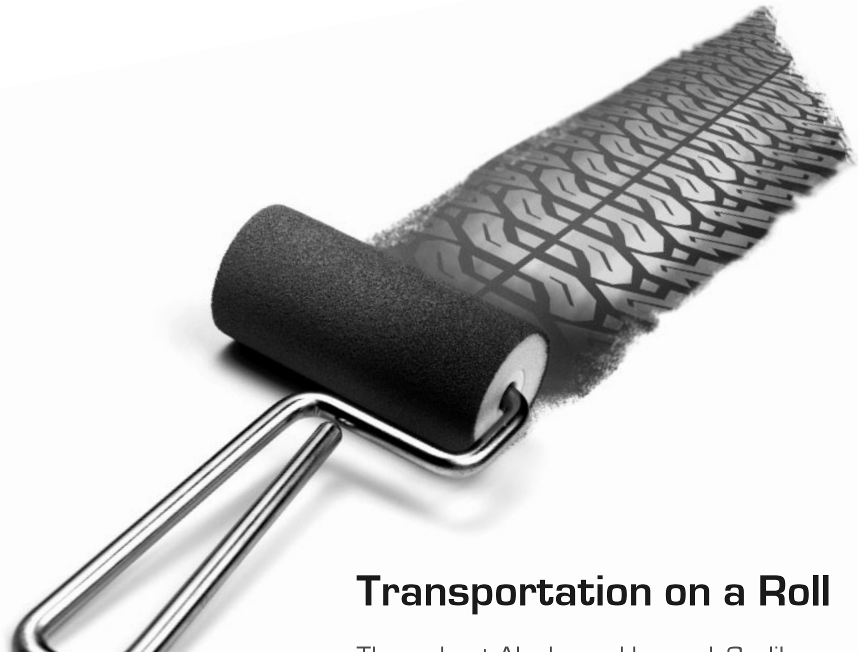
At a legislative hearing on June 16, the Federal Energy Regulatory Commission confirmed that BP and ConocoPhillips planned to apply for a license with the federal agency.

Denali is still in its infancy.

While registered as a Delaware corporation, "Denali-The Alaska Gas Pipeline" was still only a reserved name in the Alaska corporation database as of June 16. BP and ConocoPhillips are in the process of filing final paperwork for an Alaska business license, according to BP spokesman Steve Rinehart.

Fackrell came to Alaska in August 2006 to become the senior vice president for BP's Alaska Consolidated Team, which covers all North Slope operations except Prudhoe Bay.

Fackrell said he has spent more than half of his 33 years in the oil and gas industry managing joint ventures around the world, including the Abu Dhabi Marine Operating Co. He said joint ventures like Denali are "very common in our industry." especially "for a project of this size." ●



FINANCE & ECONOMY

OECD lectures Alberta to manage revenues

Tells Canada province to restrain spending, pump more oil and gas revenues into heritage fund; recommends Norway's example

By GARY PARK
For Petroleum News

The Organization for Economic Cooperation and Development, representing 30 of the world's richest nations, is urging the Canadian and Alberta governments to establish a fund for windfall oil and gas revenues to combat the negative impact of a rising Canadian dollar and the emerging threat of inflation.

It has accused the two governments of not prudently managing revenues from their natural resources and suggested they should take a leaf out of Norway's book, which uses its resource wealth to keep its own currency from rising and eroding the international competitiveness of domestic manufacturers.

A Norwegian fund is worth almost US$400 billion and is expected to double in size over the next 10 years, making it a major global investor. Alberta's Heritage Savings Trust Fund, which was allowed to languish for several years but now collects one-third of the province's unbudgeted surpluses, is currently valued at about C$17 billion. Canada has no such fund.

In a wide-ranging report on Canada's economy, the OECD has also warned that oil sands development is endangering environmental goals, with Secretary-General Angel Gurria recommending that Canada pursue a combination of carbon taxes, a cap-and-trade system and technological advances to reduce greenhouse gas emissions.

Spending constraints urged

Finally, the report was critical of the Alberta government's lack of overall spending restraints and the absence of a firm policy for its heritage fund.

"Alberta should implement allocation and withdrawal rules for its heritage fund; preferably it should save all its oil revenues in a foreign asset fund, as Norway does," it said.

"The federal government should consider doing likewise for revenues resulting from transitory terms-of-trade gains."

It said that applying the Norwegian model by investing in foreign currencies would take the upward pressure off a strong Canadian dollar, which is being driven higher by the resource boom, and prevent the weakening international competitiveness of its manufacturing sector.

The OECD said the Alberta government should more systematically increase contributions to its heritage fund.

"Fiscal policy in Alberta should be more prudent," the 160-page report said, adding that other countries have shown "much more restraint and foresight in managing their resource revenues to mitigate boom and bust cycles."

Federal fund recommended

On the federal side, the OECD said a fund would provide a cushion against a fall in prices or future depletion of the resources.

"The general justification for such funds is that some share of government revenues derived from the exploitation of non-renewable resources should be put aside for the future," it said.

Gurria, a former Mexican finance minister, said it is something his country "should have done, but didn't."

"Canadians know what to do; all we have to do is remind them what is happening in other places," he said.

Gurria said Alberta could become a major investor on the world stage at a time when major projects are desperate for money from sovereign wealth funds.

The organization said energy revenues have filtered through the Canadian economy in the past to benefit all regions, but clearer policies are now required.

"With the gathering U.S. recession and depreciating U.S. dollar, the balance has been shifting," it said. "This is straining the fiscal federal equilibrium (in Canada) and increasing demands for subsidies and transfers." (There is already a rising demand in

Quebec for a fairer distribution of resource revenues.)

Alberta defends spending

Alberta Finance Minister Iris Evans defended her province's use of oil and gas revenues to keep taxes low while spending interest from the fund.

She said Alberta has no choice but to improve its infrastructure and get the capital in place to support a population that grew by 103,000 last year.

"Managing the pressures of a robust economy comes with a price tag," she said.

Andrew Plourde, head of the University of Alberta's economics department, and Frank Atkins, an economist at the University of Calgary, both suggested the OECD seemed unaware that under Canada's constitution natural resources are owned by the provinces.

However, Plourde said there is building pressure in Alberta for the government to take a more serious view of the ideas floated by the OECD, adding he would not be surprised to hear the theme echoed by the provincial government.

Federal Finance Minister Jim Flaherty, whose officials reviewed the OECD report before it was released and had a chance to comment, said the OECD recommendations were largely consistent with the "direction our government is taking."

Specific OECD recommendations

The OECD recommended that:

• Canada's central bank should consider lowering interest rates in the short term to stimulate the Canadian economy, but be prepared to raise them in 2009 when growth is back on track.

• Government budget surpluses risk turning into deficits if energy prices decline, so governments should rein in their spending.

• Energy production is bumping up against supply constraints, so more labor and resources should be made available by eliminating employment insurance incentives that keep workers in high-unemployment regions and by eliminating inter-provincial trade barriers.

• Governments need to devise and quickly implement a market-based system to control carbon emissions. ●

PIPELINES & DOWNSTREAM

Flint denied price break on royalty oil

High costs and low margins have led owners of Alaska's largest oil refinery to seek price breaks on North Slope royalty oil purchased from the state, but Department of Natural Resources Commissioner Tom Irwin said he is unwilling to negotiate until Flint Hills provides financial information to justify the need for a lower price Flint has denied that request, Irwin told the Fairbanks Daily News-Miner.

The fate of the North Pole refinery remains uncertain following a May announcement that Flint would reevaluate the plant. A decision is expected by year-end.

Flint President Brad Razook told employees by email in May that three options were being considered: reconfiguring the plant; investing in upgrades to increase volume and lower costs; and selling the operation.

Flint has asked for state help several times, starting less than a year after Flint purchased the refinery from Williams, Irwin said.

"We understand how critical that plant is to Fairbanks. … But they need to show me their numbers," he said.

If Irwin lowers the price, his decision must be approved by the Alaska Royalty Oil and Gas Development Advisory Board and the Alaska Legislature.

—THE ASSOCIATED PRESS

EXPLORATION & PRODUCTION

BRPC, partners prep North Shore strategy

The four-company joint venture will meet to discuss how to develop the Gwydyr Bay prospect; also plan winter seismic and drilling

By ERIC LIDJI

Petroleum News

A group of independents exploring Alaska's North Slope is discussing strategies for how best to develop a series of Gwydyr Bay oil prospects, according to a partner in the joint venture.

The four-company partnership lead by the Brooks Range Petroleum Corp., or BRPC, plans to meet in Calgary in July to talk about the different ways of developing the field and satellites of the North Shore prospect, should they ultimately vote to sanction the project, according to Clifford James, president and CEO of TG World Energy Corp.

Speaking at the company's annual meeting in Calgary on June 18, James said he believes the joint venture could sanction development later this year, citing encouraging test results from recent winter exploration at North Shore, the high price of oil and BRPC's generally "bullish" nature. If the companies decide to move forward on North Shore, James said the prospect could be online as early as the second quarter of 2010.

"That would be the soonest," James said.

In addition to TG World and BRPC, the joint venture includes Bow Valley Alaska Corp. and Nabors subsidiary Ramshorn Investments Inc. TG World's share ranges from 25 percent to 35 percent of the joint venture's holdings.

Another busy winter on the horizon

The joint venture was one of the busiest on the North Slope this past winter, drilling two wells and two sidetracks, as well as acquiring a portfolio of 3-D seismic data.

The North Shore No. 1 exploration well in Gwydyr Bay, a re-drilling effort carried over from the previous winter, yielded a flow test of 2,092 barrels of oil per day from the Ivishak formation.

However, a piece of coil tubing lodged in the well prevented the companies from completely testing the Sag River formation. The damaged well flowed at an average rate of 50 bpd. TG World believes the actual rate would have been 10 to 20 times higher.

Earlier in June, the companies announced the acquisition of additional leases in the Gwydyr Bay area, including the Pete's Wicked prospect discovered by BP in 1997.

> *"We bit the bullet last year and we raised more money than we knew we needed."*
> —Clifford James, president and CEO of TG World Energy

This coming winter is shaping up to be another busy one for the joint venture.

James expects the companies to focus on Gwydyr Bay for exploration activities with the goal of "establishing a threshold" and sanctioning the development of the North Shore prospects.

Establishing that threshold means justifying the project by finding a way to prove up and develop satellites together with the main North Shore prospect.

James said the companies are considering several options, like using the existing North Shore No. 1 pad to test two nearby satellites or even drilling a 20,000-foot well to reach the Ivishak oil reserve of Pete's Wicked.

Or, the companies could lump the North Shore satellites together and attack Pete's Wicked separately from the east along with the Arcturus prospect, essentially creating two production areas, one on each side of a river cutting through the area.

James also mentioned using the Sak River No. 1 exploration well, a dry hole the companies drilled in the winter of 2006 and 2007, to test the Kuparuk Stratigraphic Trap a potential reserve just north of North Shore No. 1.

To get a complete test of the Sag River formation, James expects BRPC to propose using "lateral completion," similar to tests BP is conducting nearby at Prudhoe Bay.

Another stab at Slugger seismic survey

Next March or April, the joint venture plans to shoot a 130-square-mile 3-D seismic survey over the Slugger prospect south of Point Thomson on the eastern edge of the central North Slope, James said. The companies picked up those leases in October 2007.

"It's crying for seismic to firm up some of these prospects," James said.

The joint venture originally planned to shoot that survey this past January, but had to cancel after mid-winter storms blew away snow cover in the area, keeping the fragile tundra closed to off-road travel longer than expected.

In addition to the flow test at the North Shore No. 1 well this past winter, the companies discovered oil at the Tofkat No. 1 well in March.

The companies acquired a 210-square-mile 3-D seismic survey of Tofkat this winter, and expect to process that information by the end of the year. The results will determine whether or not they decide to return to Tofkat this coming winter.

The joint venture owns 329,645 acres of state lands across the North Slope, of which 29,631, or 9 percent, are set to expire this year.

Recent tax changes have benefited TG World

As the smallest explorers to find oil on the North Slope in recent years, the four companies in the joint venture will be test subjects for some of the recent tax changes enacted by state lawmakers last year.

TG World has benefited greatly from an expansion of the tax credit program designed to promote exploration. Even without oil production to pay taxes on, the company has already earned $3.8 million by reimbursing these credits. The state is processing a second claim for $4.9 million and TG World plans to make a third claim for $8.3 million.

Altogether, James said these credits helped TG World pay ultimately only 35 cents for every dollar of exploration costs.

"It's significantly reduces what we're paying," James said of the credits.

TG World and the other companies in the joint venture will see a different side of the tax if they bring a field online in coming years and start paying taxes, but, "Overall, it's not a bad tax system given the comparison to other jurisdictions," James said.

Even with the tax credits, though, the ambitious program taking shape will cost TG World and the other companies a lot of money, especially as drilling and exploration costs rise.

Preparing for the long haul, James said TG World raised enough money to cover two drilling seasons. The company raised $25 million through the end of last November, mainly for the work planned for Alaska. The company had $21.1 million in cash and cash equivalents at the end of March.

"We bit the bullet last year and we raised more money than we knew we needed," James said.

TG World gearing up for lawsuit

In recent securities filings with the Canadian government, TG World Energy said that an un-named third party filed a claim "alleging entitlement to 2.5 percent gross overriding ownership interest for all leases on the Alaska North Slope."

For helping to negotiate that joint venture, TG World paid the "third party" a $100,000 bonus in March and April, and gave it shares of the company, according to TG World.

As part of the deal, the "third party" also received a "2 percent overriding royalty interest share" of oil and gas produced from an initial slate of TG World leases, as well as a 1.25 percent overriding royalty from any future leases, according to TG World.

TG World officials declined to name the third party, to speculate on the basis of the claim, to say where the suit had been filed or to elaborate on the status of the suit.

In addition to work in Alaska, TG World also maintains operations in Niger. ●

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● NATURAL GAS

FERC ready; Denali applies to pre-file

Office of Energy Projects officials ready to process application; will work with all comers, let market decide what project built

By KRISTEN NELSON
Petroleum News

Mark Robinson and Jeff Wright, director and deputy director of the Federal Energy Regulatory Commission's Office of Energy Projects, told Alaska legislators June 16 they are ready to process an application for an Alaska gas pipeline. The FERC's process for certificating natural gas pipelines is in place and all aspects of the process have been challenged and tested.

"We are ready and our process works," Robinson said.

Since 2000 some 12,000 miles of large-diameter natural gas pipelines have been completed: "We do get gas pipeline in the ground and our process works to do that," he said.

The pre-filing process has been in use at FERC since 1995, Robinson said: "We developed it and we invented it" and it is now used at the state level and has been mandated by Congress for liquefied natural gas projects.

Pre-filing requires all stakeholders to get involved early, he said.

It's the opposite of "bring me a rock" where an agency says bring me an application and then tells the applicant it's not the application needed. The solution is to get all agencies involved at the beginning — not in the acceptance of an application, but in making sure that the application meets agency needs, Robinson said.

He said they are not advocates for projects, but are working instead on getting the best application possible, for the best project possible.

Once an application is accepted then the application is evaluated on a public policy basis.

Issues solved early

National Environmental Policy Act issues are also scoped as the application is developed. Robinson said one goal of the pre-application process is getting issues addressed when they come up, rather than having them become imbedded in an agency's data storage, to resurface at every point along the way.

That way when the application is accepted, issues that can be solved along the way have been taken care of, and the five FERC commissioners, who are appointed by the president, can deal with major policy issues.

The pre-application process requires that agencies get together and work through issues that can be solved early on.

Robinson said FERC's timeline is dependent on pre-filing; the critical path starts with pre-filing. To get an Alaska gas pipeline into service in 2018, he said, pre-filing should happen in June, allowing the commission to be ready to act in August 2011.

He said he knew there was a lot of concern in Alaska about open season issues, but said from the commission's perspective the most crucial thing was to start the pre-filing process so that issues can be aired and solved.

Pre-applications begun

Robinson said they expected to see a pre-application from Denali — The Alaska Gas Pipeline, the joint venture established earlier in the year by BP and ConocoPhillips.

In a letter dated June 15, newly named Denali President Bud Fackrell applied for approval to use the FERC's pre-filing procedures.

Fackrell said the request was being submitted earlier in the process than normal because of the scope of the project. He said it "will require a much longer time period" than typical and specified 36 months.

He said the pre-filing request was suggested by FERC staff during an initial visit so that Denali and FERC can "exchange information and coordinate planning and activities to insure a timely and efficient application development and review process."

The project will include transportation lines to take gas to the Denali system, a standalone gas treatment plant on the North Slope and "a 48- to 52-inch pipe capable of transporting approximately 4.0 bcf/d of gas at approximately 2,500 psi," Fackrell said. The line will "generally follow the Dalton Highway south to Fairbanks where it will follow the Alaska Highway southeast to the Canadian border."

TransCanada Alaska, the project being evaluated for an Alaska Gasline Inducement Act license, has not yet applied for pre-filing.

Robinson said expansion is an issue that is 10 years out.

It will be 10 years before we have Alaska gas flowing, he said, and while the commission has had expansions during construction that has happened because the market changes. With the Alaska project Robinson said he expects to get through the process and get the pipeline in place before it is expanded.

How long would it take to get an expansion through? During the California energy crisis expansion was authorized in about six weeks, including miles of looping, he said.

The important first step, he said, is to create an environment where someone will come in and spend the first dollar.

You can't expand without a pipeline to expand, Wright added.

Multiple certificates possible

The history of the commission has been to certificate more than one project where there are multiple applicants; the market will pick the one that is most efficient, Robinson said.

Asked about a situation where there were two applications for different pipeline sizes — a 36-inch line fully compressed which would close the basin to any new explorers, vs. a 48-inch line which would open the basin, Robinson said the commission could consider that in looking at the applications.

Wright said the commission generally doesn't regulate gas treatment facilities — those are upstream of transmission — and its authority probably starts at the tail-end of the GTP.

But Robinson said that given the unique nature of the Alaska gas pipeline, the GTP could be presented to the commission if it might be used to limit production of gas. ●

Jack-up rig progresses at glacial pace

The Zvezdochka shipyard in northwest Russia's Arkhangelsk Oblast has completed one of the most complicated technological parts of its Arkticheskaya floating jack-up drilling rig. The lower parts of the platform support pillars were submerged to a depth of 66 feet, and the platform unit was placed on top of them, the shipyard said in May 28.

The Arkticheskaya rig has been under construction for more than 10 years and it is not clear when it will be completed. The 289-foot long and 216-foot-wide platform is intended for use in the Barents and Pechora seas, and its maximum drilling depth is 21,320 feet. The rig can accommodate 90 workers.

—SARAH HURST

COURTESY INTEGRA GROUP

The Ekaterina drilling rig is the first of 11 that Integra Group will supply to Gazprom for its Yamal Peninsula field.

Gazprom happy with rig for Yamal field

Uralmash-VNIIBT, a subsidiary of Moscow-based oilfield service company and drilling rig manufacturer Integra Group, has completed the construction of its BU 4200/250 drilling rig for Gazprom's Bovanenkovskoe gas field on the Yamal Peninsula. The rig has been named Ekaterina, after the city of Ekaterinburg in central Russia where it was built. Uralmash-VNIIBT will supply a total of 11 rigs to Bovanenkovskoe under the contract.

"As a customer we are completely satisfied with the work done by Uralmash," said Andrei Rossinsky, managing director of Gazprom's drilling subsidiary Burgaz. "Before we started our cooperation we conducted a detailed review of the design, engineering and production capabilities of the project team and were entirely satisfied. We have a positive impression from joint work with this contractor, product quality and time of delivery, which is currently ahead of schedule," he added.

—SARAH HURST

Gazprom pioneers permafrost construction

Russia's state-owned Gazprom has completed the main construction stage of a crossing over the Yuribey River floodplain as part of its preparations for the Bovanenkovskoe gas field development on the Yamal Peninsula, the company said June 10. The crossing will be part of the Obskaya-Bovanenkovo railroad. In total almost two miles of the crossing (78 percent of the total planned length) have

see **PERMAFROST** *page 11*

Varandey Arctic oil terminal starts up

Lukoil sends tanker to Newfoundland, ConocoPhillips head praises new technology and points to benefits of Alaska experience

By SARAH HURST
For Petroleum News

Lukoil has loaded the first ice-class tanker at its new Varandey oil export terminal on the Pechora Sea coast, the company said June 9. The 70,000-ton Vasily Dinkov was headed for the Canadian port Come By Chance in Newfoundland. Varandey has the capacity to export up to 240,000 barrels of oil per day, much of which will come from the Yuzhno-Khylchuyuskoye field.

Varandey "represents a significant advance in technology," Jim Mulva, chairman and CEO of ConocoPhillips, said at the St. Petersburg International Economic Forum June 7. ConocoPhillips is a partner with Lukoil in developing the Yuzhno-Khylchuyuskoye field. "Our joint venture has also worked with Sovcomflot to develop three new Russian-flagged ice-breaking tankers to transport the oil," Mulva added.

Yuzhno-Khylchuyuskoye "has been a predominantly Lukoil-style development," Mulva said. "But it has been supplemented in key areas by the experience that ConocoPhillips gained on Alaska's North Slope. These insights have, for example, helped reduce the number of drilling pads needed from the originally planned 10 to only three. They also enabled us to double peak production capacity, reduce the environmental impact and improve the development economics. Overall, this blending of expertise has resulted in more than $500 million in savings."

Fixed ice-resistant terminal with mooring 14 miles offshore

The Varandey facility consists of an onshore tank farm with a total rated capacity of 325,000 cubic meters (11.5 million cubic feet); a fixed ice-resistant oil terminal 14 miles offshore, with a height of over 160 feet and a weight of over 11,000 metric tons, including living quarters and a mooring cargo handling system with a jib and a helicopter platform; two underwater pipelines, 32 inches in diameter, connecting the onshore tank battery and the offshore oil terminal; and an oil metering station, auxiliary tanks, pumping station and power supply facilities.

COURTESY LUKOIL

Lukoil's Vasily Dinkov was the first tanker to load up with oil at the new Varandey terminal in the Russian Arctic.

An auxiliary icebreaker and an ice-breaking tug will be on duty in the vicinity of the terminal, according to Lukoil. The environmental safety system at Varandey has three levels of security and is fully automated. The terminal has been designed to operate with zero discharge, which means that all industrial and domestic waste is collected in special containers and transported onshore.

"Our company has created a unique sea export system which makes it possible to transport large quantities of oil to polar regions; it is unrivaled in the world," said Vagit Alekperov, Lukoil's president and CEO. "This new Russian transportation corridor exports oil at a minimum cost, while preserving its quality, via the shortest sea route to the European and North American markets. In addition, the infrastructure we have been able to establish helps develop new fields in the Timan Pechora oil and gas province," he added. ●

● EXPLORATION & PRODUCTION

BP's Thunder Horse oil field goes online

U.S. Gulf's largest discovery producing after delays; just one well online; commissioning will be after steady state production

By RAY TYSON

For Petroleum News

The BP-operated Thunder Horse field, the largest-ever oil discovery in the U.S. Gulf of Mexico, is finally onstream and headed toward higher production following repeated startup delays dating back to 2005. First oil was achieved June 14 from a single well, BP confirmed.

"We have a lot yet to do as we prepare other wells for production and continue to drill and complete other wells," BP spokesman Ronnie Chappell told Petroleum News June 17.

The Thunder Horse platform, on a multitract development in the vicinity of Mississippi Canyon Block 822 in water depths of up to 6,050 feet, is capable of producing 250,000 barrels of oil per day and 200 million cubic feet of gas per day.

"We are making good progress. First oil is an important milestone on the way to startup of the Thunder Horse field. We will be ramping up production in the coming months." —BP spokesman Ronnie Chappell

However, Thunder Horse's actual "production profile" hinges on "well performance" and "how fast we are able to drill and connect new wells," Chappell cautioned.

"We are making good progress," he added. "First oil is an important milestone on the way to startup of the Thunder Horse field. We will be ramping up production in the coming months."

Formal startup later

BP will announce the formal startup of Thunder Horse when field "commissioning" is finished and "we … achieve steady state operations," Chappell said.

The Thunder Horse field was discovered in 1999, and was designed to use the largest production drilling semisubmersible platform in the world. The platform weighs more than 50,000 tons and will produce from some of the highest temperature and highest-pressure wells in the Gulf of Mexico.

Thunder Horse and its estimated 1 billion barrels of recoverable oil became the development centerpiece for a massive pipeline system serving Thunder Horse and other large BP discoveries in the deepwater U.S. Gulf, including Atlantis and Mad Dog.

However, Thunder Horse development has been plagued with problems over the years, causing not only startup delays for Thunder Horse, but also for Atlantis due to concerns over the integrity of subsea equipment.

COURTESY BP

At 50,000 tons, Thunder Horse is among the largest production drilling semi-submersible platforms in the world.

BP's headaches began in 2003 when development drilling was temporarily suspended after a marine riser separated between a drilling rig and a production well about 6,000 feet below the ocean surface. The Transocean rig was drilling BP's ninth development well at Thunder Horse when the riser separated in what industry experts said was a rare occurrence.

Initial startup set for '05

Thunder Horse missed its initial 2005 startup when Hurricane Dennis swept through the U.S. Gulf, purportedly causing damage to the platform and causing it to list 20 to 30 degrees, according to BP. However, the U.S. Minerals Management Service all but dismissed Dennis and its high winds as the cause of the listing. Nevertheless, BP postponed Thunder Horse production into 2006.

Later BP told analysts in a conference call that leaks in the manifold system would delay first production from late 2006 into early 2007, but didn't specify the cause of the damage. The manifold, built by Houston-based FMC Technologies, is a massive subsea structure designed to send oil and gas from individual wells up toward the production platform. Reportedly, the structure could have been damaged during Hurricane Dennis.

One industry analyst theorized that the leaks might have come from "hydrogen embrittlement" of the welds, with the hydrogen coming from seawater that seeped in through cracks in the insulation. The insulation then may have been damaged as the manifolds, insulated in 2004, sat unused for an extended period on the sea floor.

Startup again was delayed when a series of tests revealed "metallurgical failure" in components of the field's subsea system. As a precaution, BP said it would retrieve and replace all the subsea components it believed could be at risk. The company said the work would be done over the next year but did not expect first production from Thunder Horse before the middle of 2008. Analysts believed the fix would add tens of millions of dollars to the project. The production facility alone cost more than $1 billion.

Just a week after announcing its final startup target for Thunder Horse, BP announced postponement of first production from Atlantis, from year-end 2006 to the first quarter of 2007. Because the Atlantis project was at an earlier stage of subsea installation than Thunder Horse, BP said it had already taken the opportunity to retrieve and make precautionary modifications to the Atlantis manifolds. Production was actually brought online in October 2007 from a facility designed to process 200,000 barrels of oil per day and 180 million cubic feet of gas per day.

BP owns 75 percent of Thunder Horse and ExxonMobil 25 percent, while BP owns 56 percent of Atlantis and Australia's BHP Billiton owns 44 percent. ●

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PERMAFROST

been built, including 88 bridge arms and 87 spans.

Most of the work could only be done during the winter and construction took place on a round-the-clock basis for 235 days. More than 1,300 people were employed at the construction site. "The crossing is unparalleled in the world's bridge construction practice both in terms of design and the climatic and permafrost conditions of construction and operation," Gazprom said. "In particular, the crossing is being constructed without the traditional deposition of soil, which makes it possible to preserve the river floodplain's ecosystem." Wells 66-131 feet deep were drilled to stabilize crossing arms under permafrost conditions.

Some sections of the Obskaya-Bovanenkovo railroad are already in operation, and 15 station sidings, 37 river crossings and 262 culverts have been constructed so far. The railroad is expected to be complete by late 2009.

—SARAH HURST

On the Web

See previous Petroleum News coverage:

"Blowdown a loss: State — producing Point Thomson gas first would mean 500M fewer barrels," in June 15, 2008, issue at: www.petroleumnews.com/pnads/551121043.shtml

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

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

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

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ANALYSIS

can have changed so rapidly, since the field contains 25 percent of known North Slope natural gas.

John Zager, Chevron's Alaska general manager, agreed: Reserves to back a 4.5 billion-cubic-foot-a-day line are insufficient, "in fact there's insufficient reserves to back a 3.5 bcf-a-day pipeline" — and that's with Point Thomson included, he said, referring to the total gas that would be needed over the life of the line.


JUDY PATRICK
JOHN ZAGER

The state has said the gas pipeline would be economic without Point Thomson gas, although the tariff would be higher for a 3.5 bcf line than for 4.5 bcf.

Zager said it's not just throughput but also the reserves behind the line, and asked if anyone would commit to firm transportation on a line that didn't have enough resources to back it.

"People talk about this yet-to-be-found gas like it's a bankable commodity; it's not," he said.

Without Point Thomson, needed gas resources to back a gas pipeline are "significantly" larger, Zager said.

And then there's the issue of blowing down Prudhoe Bay. If Prudhoe is providing the only gas, and earlier than with Point Thomson gas, there could be a loss of otherwise producible Prudhoe oil, he said.

ExxonMobil is the largest leaseholder at Point Thomson and the unit operator. Chevron and BP also hold large acreage positions; ConocoPhillips holds a smaller stake and there are more than 20 minority interest holders. DNR terminated the unit for lack of production in late 2006, a decision confirmed by current DNR Commissioner Tom Irwin earlier in June.

Oil recovery issue

Haymes said ExxonMobil has not seen the PetroTel report done for DNR, the source of the assertion that the oil at Point Thomson is the equivalent of another Alpine, just DNR's summary; he said they'd asked for a copy of the actual report.

The summary, published as part of the Alaska Gasline Inducement Act decision document, "appears to be based on very selective and limited data," he said. It also isn't based on the companies' most recent data, since data sharing between the Point Thomson leaseholders and DNR has been stalled over the last three years by litigation, Haymes said.

PetroTel estimated gas in place at Point Thomson at 8.5 trillion to 10.4 trillion cubic feet, with associated condensate of 490 million to 600 million barrels and a potential oil rim of 580 million to 950 million barrels.

"The report provides an estimate of recoverable liquids and gas, but it does not consider that fundamental necessary technical work that has yet to be done," Haymes said.

"Based on our review of that summary report, no sound technical conclusions could be made on the producible resource," he said.

PetroTel estimated a recovery factor of up to 50 percent from the oil rim, Haymes said.

But "the oil rim is thin, discontinuous and heavy oil — molasses," he said.

PetroTel assumed horizontal wells would be used to develop the reservoir. "We're not aware of anywhere in the world that anybody has drilled horizontal wells in this pressure reservoir with this deviation. And we did research last week to confirm that," he said.

The issue, Haymes said, is that today's technology doesn't allow drilling of horizontal wells at the pressure encountered in Point Thomson and at the required deviation.

The Point Thomson owners "don't believe the recovery of this heavy oil will be more than 5 percent — nowhere near 50."

Point Thomson is a high-pressure, 10,200 psi, retrograde condensate field that straddles the coast 60 miles east of Prudhoe Bay.

Gas sales recovers 90 percent

Work done by the owners concluded that "90 percent of the resource will be recovered through gas sales development. So the cycling project and the oil delineation will chase 10 percent of the resource," Haymes said. That 90 percent includes gas and oil, and the condensate that falls out of the gas when temperature and pressure are reduced, he said.

The Point Thomson owners proposed a 23rd plan of development in February to meet state demands for unit development. Wells would test cycling — producing gas, stripping condensate and reinjecting the gas — and also the deeper oil rim and shallower Brookian oil accumulations. The initial phase would produce 10,000 barrels per day.

Haymes said the risk with the cycling project, rejected by DNR earlier in June, is that the reservoir may not be homogeneous and the gas may not flow between injector and production wells.

Wells at the field will cost $60 million to $100 million for the most complex wells, compared to current Prudhoe Bay costs of $6-$8 million per well, he said, and will take 90 to 120 days to drill, compared to a current average of 20 days at Prudhoe Bay.

The flank wells — those targeting the oil rim — can test communication in the reservoir, Haymes said. If those wells are in communication with the more central wells, they can be used for injection and production could be doubled or tripled quickly.

Results from earlier drilling are conflicting, with variation in reservoir size, he said, and drilling won't tell us much; what is needed is production.

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● FINANCE & ECONOMY

New Shell general manager for Alaska

Pete Slaiby takes over management of Shell's Alaska operations, wants local and state governments get share of OCS revenues

By ALAN BAILEY
Petroleum News

Shell has appointed a new general manager, Pete Slaiby, to head the company's Alaska business. Slaiby was previously Shell's Brunei asset manager.

The general manager for Alaska has in the past been located in Houston, Slaiby told Petroleum News on June 17. The appointment of a general manager located in Alaska marks Shell's growing presence in the state, he said.

PETE SLAIBY

"I think Anchorage is always the right place for the GM to be. Alaska is a very unique business environment," Slaiby said, noting the state is very important to Shell.

"The Chukchi and the $2.1 billion lease bonus really put us into another league and with that we really wanted to match our organization … with the size of the business opportunity," Slaiby said. "… We are very, very serious about Alaska."

Rick Fox, Shell's Alaska asset manager who has been Shell's point man on site in Alaska, will retain his current position, Slaiby said. Fox will deal mainly with operational issues, while Slaiby will manage the entire Alaska operation and particularly focus on stakeholder relations.

"Rick … (has) done a tremendous job. … He knows everybody," Slaiby said.

Arctic Alaska's challenges

Slaiby commented on the challenges that Shell faces in Alaska, especially the concerns about the possible environmental impacts of offshore oil and gas development. There are different opinions on offshore, he said, noting that Alaska Native corporations are fairly bullish on the opportunities the oil industry presents while the Northwest Arctic and North Slope boroughs have expressed reservations.

Slaiby believes listening to people's concerns is critical: "The last thing in the world that we are going to do is to come in and tell everyone 'we're Shell, we know what's the right thing to do and this is the way to do it."

Slaiby's background in the oil industry is in offshore operations.

"For me this really is something I have done and am very comfortable doing, but we have to recognize there's a whole group of people who aren't as comfortable as we are." Solutions, he said, need to be acceptable to both Shell and the various stakeholders in the region.

"We think we'll be able to put together a pretty good value proposition for Alaskans, with job opportunities and revenue opportunities, but it will take a lot of engagement and a lot of listening," Slaiby said. "… We really have to be premier corporate citizens."

In the past Shell has drilled in both the Beaufort and Chukchi seas without causing environmental problems, he said.

"Success is really measured in the fact that people don't remember we've been here. That for me is a critical performance indicator. … Shell does have a fairly strong technical edge and an excellent track record of protecting the environment — it's hugely important to us."

The development footprints in the Beaufort and Chukchi seas will be very small, Slaiby said. "We are not an open pit mine. We will not have the footprint that you see on the slope … It is going to be an operation with modern technology, with extended reach wells, smart components built into the wells, modern platform construction."

That approach fits well with the wishes of the North Slope and Northwest Arctic communities, he said.

And when it comes to working with those communities to address concerns about the potential impacts on subsistence hunting, Shell is building a portfolio of studies into baseline environmental data.

Meshes well with subsistence

Slaiby also said that work schedules for people who want jobs in an offshore industry would mesh well with the subsistence way of life.

"I think there are enough safeguards and I think there's enough protection where we … can operate offshore and have a subsistence way of life," he said. "For certain people it could be a real boon."

The outer continental shelf, or OCS, is under federal control, so oil and gas revenues go to the federal government. Shell wants local and state governments to get a share.

"I really do think that's hugely important," Slaiby said. "We've got communities that I believe could benefit from that." ●

LAND & LEASING

State of Alaska extends exploration license comment period by 30 days

The public will get another month to comment on proposals by two companies hoping to explore undeveloped oil and gas basins in Alaska.

The extension runs through July 14.

The two companies filed their proposals in April 2007 in the hopes of obtaining state exploration licenses, a rarely utilized option for companies hoping to explore parts of the state not included in the state's areawide competitive lease sales.

BGI North America LLC is requesting an oil and gas exploration license covering around 72,443 acres in the Crooked Creek-Circle basin, east of the community of Central and south of the community of Circle.

LAPP Resources Inc. is requesting a natural gas exploration license covering around 21,080 acres near Houston and Willow, north and east of the Parks Highway.

The state Division of Oil and Gas announced the proposals in December and began asking for public comments in April.

In the exploration license process, public comments are used to help create a best interest finding, which in turn is released for another round of public comments.

The state has already received some public comments, but had requests to keep the record open longer, according to Kathy Means, with the state Division of Oil and Gas.

"We wanted to make sure and accommodate those requests," Means said.

—ERIC LIDJI

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ANALYSIS

Haymes said some information would come quickly from the work proposed in the 23rd plan of development.

By monitoring reservoir pressure from the flank wells, "within six weeks of production we will know whether we have a small tank (connected reservoir) at Point Thomson or not. And if we have a small tank, we've all got a problem. But in six weeks we'll know that after turning on production," he said.

Strictly theoretical

Vince LeMieux, Chevron's manager of Alaska new ventures, told legislators he looked at DNR's summary of the PetroTel report, and "the work that was done there was strictly theoretical."

"It's not that the work is wrong," he said, but it doesn't take into consideration economics or factors like location and type of wells, and "reaches a conclusion that is very optimistic, both in the original hydrocarbons that are in place but particularly in the recoverable hydrocarbons."

What the report doesn't address, he said is "the practical recoverable reserve that you could get to."

As for another Alpine at Point Thomson, LeMieux said "incremental recoverable liquids at Point Thomson are substantially less than 500 million barrels," and if you accelerate Prudhoe Bay gas because Point Thomson has been taken off the table, "you may actually end up with less oil produced on the slope as a result of this."

There has also been reference to seismic data providing evidence of field continuity, he said. "What you're really worried about in the continuity of the field is how the rocks are put together — the stratigraphy, the actual detail within the reservoir. And you can't access that from seismic.

"You can learn more about the structure; you can learn something about the faulting, but you're not going to — in this case — learn about the stratigraphy, which is absolutely critical to understanding how this field will be developed." ●

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TARIFF

Co, Unocal Pipeline Co. and Koch Alaska Pipeline Co. LLC failed to prove the proposed rate increases in their 2005 and 2006 tariffs were just and reasonable, and ordered limited refunds to all trans-Alaska oil pipeline shippers.

The order also clarifies provisions in Cintron's order regarding the appropriate dismantlement, removal and restoration expenses and modifies the return on equity component of the capital structure, consistent with FERC's new policy on proxy groups for pipelines.

The new rate, based on FERC Opinion No. 154-B methodology, is prospective, and will be determined after the TAPS carriers make a compliance filing. The refunds for 2005 and 2006 are limited to the difference between the 2005-06 proposed rates and the 2004 rate, the commission said.

FERC decision culminates prolonged dispute

The Commission's order had not been released to the public by press time June 19.

But news of the decision comes more than a year after Cintron's ruling and three and a half years after both sides began arguing the case. Over time, proposed 2006 and 2007 tariffs were added to the case, along with numerous ancillary questions.

Initially, the shippers challenged the carriers' 2005 interstate tariffs, but every conceivable aspect of the issue was soon drawn into the proceedings.

The State of Alaska protested the 2005 interstate tariffs, charging discrimination based on provisions of the Interstate Commerce Act, after the Regulatory Commission of Alaska reduced in-state tariffs for the pipeline by more than 50 percent.

The carriers countered with a defense that relied on the strength of a settlement agreement reached with the State of Alaska in 1985 that established a method for calculating tariffs for the pipeline. They also asked FERC to overturn the RCA ruling, claiming the lower in-state rates and subsequent attempts to block increases in interstate tariffs contradicted terms of the 1985 pact and violated provisions of the ICA.

Law judge: Tariffs were 'excessive'

The FERC law judge concluded that Anadarko Petroleum Corp., Tesoro Alaska Co. and the State of Alaska, essentially got it right when they argued the tariffs were "excessive."

The judge outlined her reasoning in more than 250 separate points, starting with which side must prove its case and ending with whether RCA's lower rates violated the Interstate Commerce Act.

"The crux of the matter," wrote Cintron, "is that the carriers must recognize the previous recoveries of their investment, otherwise there will be an unjust and unreasonable double recovery," she wrote. "The carriers have presented no fact in the case that calls for an opposite conclusion."

She noted that there was considerable difference between the pipeline owners' $1,751.18 million revenue requirement for computing the tariffs and Anadarko-Tesoro's revenue requirement of $647.32 million.

The judge further endorsed the argument of FERC's trial staff that "just and reasonable rates cannot result where any double recovery is allowed," calling the reasoning "commonsensical" and impossible to ignore.

Cintron found that actual amounts collected by the carriers must be used to calculate the tariffs, saying the approach is consistent with a FERC precedent that disallows double recovery of investment.

The new rate, based on FERC Opinion No. 154-B methodology, is prospective, and will be determined after the TAPS carriers make a compliance filing. The refunds for 2005 and 2006 are limited to the difference between the 2005-06 proposed rates and the 2004 rate, the commission said.

She said Anadarko and Tesoro's calculations would be the basis for her ruling, with minor variations in return on equity and tax.

Decision will bring refunds to state coffers

Reaction to Cintron's ruling in May 2007 was favorable from the shippers and Alaska officials. They have hailed Cintron's decision to lower tariffs for the trans-Alaska oil pipeline as "important" and beneficial.

Gov. Sarah Palin praised the law judge's ruling, saying it "reaffirms the need to ensure low tariffs on oil and gas lines."

"This is why we spent a great deal of time working on structuring the Alaska Gasline Inducement Act to maximize value for the state and ensure low tariffs. We're pleased with the FERC decision, and we look forward to continued progress on this issue," Palin said.

The Division of Tax at the Alaska Department of Revenue estimated that the State will collect about $500 million in refunds and some $100 million in interest based on final resolution of the case in 2010. ●

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DEAL

on the Mackenzie Delta.

The Gwich'in have agreed to make five parcels of land available to MGM for geological and geophysical work.

If the results indicate the land is prospective, it is expected seismic work will take place and eventually wells will be drilled to establish the resource.

The memorandum contemplates further agreements being negotiated in upcoming weeks.

Tribal council President Fred Carmichael said "this is a true partnership" that commits MGM and the Gwich'in to cooperate in creating job opportunities.

The Gwich'in did not give up or reduce any of their rights under the comprehensive land claims agreement.

MGM is required to negotiate benefits and access agreements and the Gwich'in will be entitled to royalties on any hydrocarbons produced from lands they own.

After farming-in on a Chevron-BP license, MGM has completed a minimum exploratory drilling program of five wells and remains the operator.

—GARY PARK

Petroleum news

Business Spotlight

Cosco Fire Protection

Cosco Fire Protection, in business since 1959, offers full project design, installation, and complete inspection, repair and maintenance services on new construction projects. It also protects existing buildings with preventive maintenance contracts that include all appropriate inspections and emergency services, 24/7. Recent new construction projects include the Anchorage Civic & Convention Center, the F-22 Raptor Hangar on Elmendorf, the Anchorage and Wasilla Target stores and the new Cold Bay airport. Recent retrofits include remote high schools, the Carrs/Safeway Distribution Center and the Kenai Courthouse.


FORREST CRANE

Dave Milliman, service manager

Dave Milliman

Born in Anchorage, Dave Milliman attended West Anchorage High and the University of Alaska. He's a journeyman sprinklerfitter by trade and has been with Cosco two years. His trade has taken him to the North Slope, Southeast and Southwest Alaska and to oil platforms in Southcentral. Dave and his wife Kim have three children, Benjamin, Francesca and Isabella. He balances family activities with another passion, GOLF.


FORREST CRANE

Katrina Mejia, PMA, inspection sales

Katrina Mejia

Katrina Mejia earned a degree in languages from the University of Alaska Anchorage, and has worked for Cosco nearly two years as an inspection/preventive maintenance sales representative. She formerly spent 12 years in the customer services industry. Her hobbies are listening to live music and all things Alaskan — hiking, camping, biking and in winter, hockey (with the Consolidated Enterprises team). Katrina has two fabulous dogs, Bella and Andre, that also love the great outdoors.

— PAULA EASLEY

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

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

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LITIGATION

terminate the unit?

As in all things legal, that depends on what happens.

Complete the state lawsuit

The first step will necessarily be the completion of the current Point Thompson lawsuit in Alaska Superior Court, before Judge Sharon Gleason.

On Dec. 27, Gleason ruled that DNR acted properly when it rejected Exxon's 22nd plan of development for the Point Thomson unit. Rejection of that plan in 2005 led to the chain of events culminating in termination of the unit. However, Gleason directed DNR to give the Point Thomson owners one last chance to come up with an "appropriate remedy" as an alternative to termination by holding a DNR administrative hearing. DNR held the hearing and Commissioner Irwin re-affirmed the termination decision.

DNR will send the record on the hearing and decision back to Judge Gleason shortly, Nan Thompson, petroleum manager for DNR's Division of Oil and Gas, told Petroleum News June 16. Gleason will review the DNR decision and then make a final decision in the case. It's probable that, assuming Gleason finds in favor of the state, the oil companies would appeal the case to the Alaska Supreme Court.

And how long might it then take for the Supreme Court to decide on the case?

"A reasonable estimate for the Supreme Court is a couple of years after it gets to them," Thompson said.

Spencer Hosie, a senior partner and specialist in business law with the San Francisco firm of Hosie McArthur, told Petroleum News June 17 that the state's view of the timeframe may be a little pessimistic. Given the urgency of the situation, the court would likely expedite the case.

"It could be resolved in 16 to 18 months," Hosie said. "With any luck it shouldn't take a full two years."

Federal court?

On the other hand, if the case were to end up in federal court rather than state court, the timeframe for resolution could extend considerably. But the state doesn't think that there is any valid federal claim.

"It's an issue we've looked at," Thompson said. "This is an issue about state management of its resources."

Hosie agrees.

There's probably no federal case to answer, he said. But if the lease owners wanted to make a federal case they'd probably claim that a federal constitutional due process violation had occurred. They would file a new case in a federal court and that court would decide whether there was a valid federal case. Of course, the lease owners could then appeal that court decision.

But Hosie thinks that the whole Point Thomson question comes down to a requirement that the lease owners tell the state whether they view Point Thomson as being economic for development.

"What the state is entitled to here is a straight answer. Is it economic or not?" Hosie said.

The owners have not answered that question, he said.

—ALAN BAILEY

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TWO LINES

But the two projects differ in philosophy. By definition, a spur line requires a mainline and a bullet line doesn't. That distinction could determine how fast gas gets to Anchorage, and how much it would cost once it got there.

The debate came up during legislative hearings in Fairbanks on June 12, as part of a day devoted to plans for bringing Alaska natural gas to Alaskans.

This summer, ANGDA is spending between $1.2 million and $2 million, by far the largest single expense in the five-year history of the public corporation, to study a 370-mile spur line corridor from Delta Junction to Beluga through Glennallen.

At the same time, Enstar is planning to spend at least $6 million this year on engineering work along the 690-mile route for a pipeline from the Gubik gas field near the village of Umiat to the utility's existing grid in Anchorage along the Parks Highway.

These projects have been under way in various forms for years. Until earlier this year, Enstar had been considering the Parks Highway for a spur line. In the past, ANGDA has mentioned a bullet line might be the last resort if progress stalled on a big pipeline.

"If they don't hurry up, we'll figure out a way to get all the way north," Harold Heinze, chief executive officer of ANGDA, told the Palmer Chamber of Commerce in late 2004, as reported by the Anchorage Daily News.

Both ANGDA and Enstar believe in that call to "hurry up," but as each company looks into the near future, it sees a different outcome on the horizon — one less optimistic than the other.

Enstar: Time is up

Enstar believes it can no longer afford to wait on a big pipeline. The company is expecting major shortages within six years. And whereas Enstar once enjoyed supply contracts lasting 15 years or longer, the most recent contract before state regulators would last only five years.

"We have a precipitous fall off over a period of time," said Andrew White, of Enstar, talking to lawmakers about natural gas supplies from Cook Inlet. "And in terms of where Enstar is right now, that's led us to not only thinking of gas contracts with ConocoPhillips and Marathon through 2013, but also looking elsewhere ... for a natural gas pipeline from the foothills to Southcentral Alaska with a spur into Fairbanks."

With a 20-inch bullet line, Enstar believes it can get gas to Southcentral five or six years sooner than it would by waiting for the mainline and building a spur.

The $3.3 billion bullet line could have gas flowing to Anchorage as soon as 2014, said Gene Dubay, senior vice president and chief operating officer of SEMCO, the Michigan utility that owns Enstar.

But two huge obstacles stand in the way: one with supply and another with demand.

The Enstar line only became possible because of recent exploration efforts at Gubik by Anadarko Petroleum. Taking gas from Gubik rather than the North Slope would shave more than 100 miles in the length of the pipeline.

But Anadarko doesn't know how much gas is at Gubik. The most recent reserve figures come from 1951, when a U.S. Geological Survey expedition estimated the field held 600 billion cubic feet of natural gas. Enstar needs 3.5 trillion cubic feet for its bullet line.

Enstar doesn't know how much more the bullet line would cost if it had to run all the way to Prudhoe Bay, White said. Nor has the company talked with North Slope producers about buying gas from Prudhoe Bay.

Enstar is meeting with Anadarko in mid-July to discuss the results of the exploration program at Gubik this past winter, Dubay said.

A lack of gas at Gubik would make the bullet line physically impossible, but failing to attract major industrial customers would make the bullet line economically impossible. If the cost of the project fell entirely on the shoulders of residential and small commercial customers along the Railbelt, the rates would probably be prohibitively high.

Enstar won't build the project without commitments from large industrial users, like an expansion of the Kenai liquefied natural gas plant or a revived Agrium fertilizer plant, Dubay said. He said Enstar is drafting a letter to Agrium, hoping to get a commitment about the future of the plant should the bullet line move forward.

Either way, Dubay remains hopeful.

"We're approaching this project with quite a bit of certainty that when it comes time for the industrial users to sign up for a capacity in this line that we're going to get commitments from the industrial users that are going to take capacity in the line," he said.

Enstar plans to decide whether to sanction the bullet line by June 2009.

ANGDA: approve TransCanada and let the market work

While Enstar no longer wants to wait for a pipeline, Heinze says it's not too late.

He believes the Alaska Gasline Inducement Act, or AGIA, prompted the producers to create Denali-The Alaska Gas Pipeline LLC and quickly prefile with the Federal Energy Regulatory Commission, an early first step toward permitting the 48-inch main pipeline.

Believing the entire timeline is now moving fast, Heinze wants lawmakers to approve the TransCanada application and let the company battle it out with Denali in the marketplace.

"Frankly, the only reason I can't start building tomorrow is that people don't know and aren't sure if a big project is going to be built," Heinze told lawmakers.

Even with pre-building, where work on a 20-inch spur line begins as soon as the main line gets final approval, the project could take longer to bring online than a bullet line.

Still, ANGDA sees its $1.25 billion project as the cheapest source of gas for Alaska, because local prices would be tied to an outside market, rather than competing with oil.

Heinze points to Fairbanks Natural Gas as the alternative. The natural gas utility of Fairbanks charges residential customers $23.35 per thousand cubic feet of gas, most likely the highest natural gas rate in the country.

But whether the price is high depends on the context. Compared by energy content, natural gas is still cheaper than fuel oil in Fairbanks, but it's also more than two and a half times more than what natural gas customers pay in Anchorage.

"You pay the competitive alternative price and you're locked into it," Heinz told lawmakers. "And that's one of the things you're trying to break by bringing a big pipeline down through the spine of the state."

Enstar disagrees.

"I don't think the size of the pipe is going to have an impact on the cost of the gas. I think it's going to be an index-based price whether it's a 48-inch pipe or a 20-inch pipe," Dubay said.

Enstar uses indexes now to price its natural gas supply from the Cook Inlet. In the new contracts before state regulators, Enstar pulls the middle price from a selection of indexes as a way to avoid unexpected cost swings in the market like those felt after Hurricane Katrina.

With these indexes, Anchorage would probably pay a little more to get natural gas from the bullet line than it currently does from Cook Inlet, while Fairbanks would probably pay a lot less than it does now to get that same Cook Inlet gas trucked north.

"We are paying market prices and we will continue to pay market prices," Enstar spokesman Curtis Thayer told Petroleum News.

ANGDA also believes the spur line is the best way to create a petrochemical industry in Alaska, using by-products from the gas stream on the North Slope.

Compatible vs. competitive

As the debate continues on the large pipeline, both Enstar and ANGDA want to avoid a provision within AGIA that keeps the state from supporting a competing project after awarding a license.

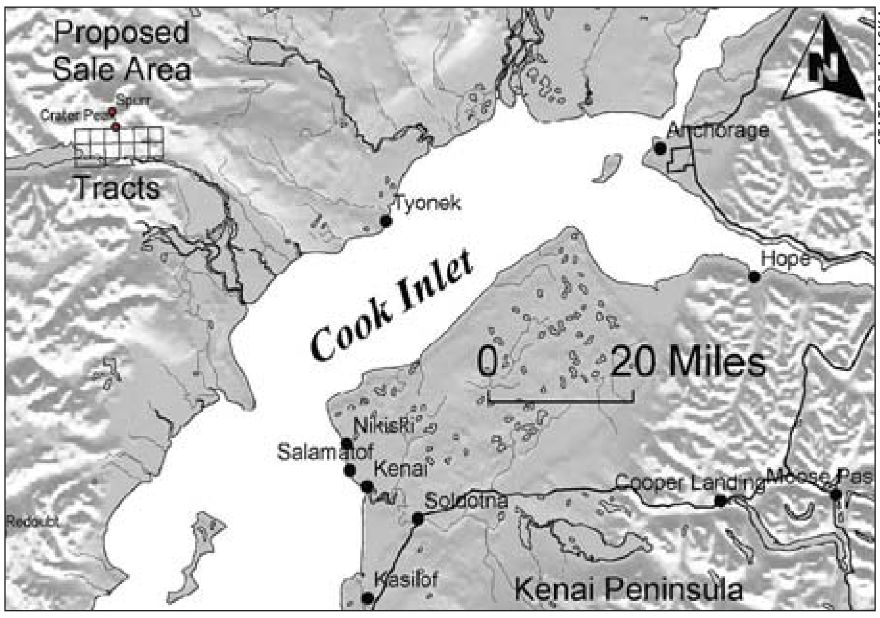
In fact, speaking to lawmakers, both companies said they planned to work with either TransCanada or Denali and both companies used almost identical language to defend their respective plans for bringing gas to Southcentral.

"We're not a competitive project. We're a compatible project," Heinze said.

"This is not a competing project and it's a complementary project," Dubay said. ●

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

LAND & LEASING



STATE OF ALASKA

State of Alaska issues final BIF for Mount Spurr, division says yes to lease sale

Alaska's Division of Oil and Gas has issued the final best interest finding for a geothermal lease sale on 16 tracts of state land on the southern flank of the Mount Spurr volcano, on the west side of the Cook Inlet.

"I conclude that the potential benefits of the Mount Spurr Geothermal Lease Sale No. 3, as conditioned, outweigh the possible adverse impacts, and that the sale will best serve the interests of the State of Alaska," said Kevin Banks, acting division director, in the final finding document. Tom Irwin, commissioner of the Department of Natural Resources concurred with Banks' conclusion.

As a consequence of comments received from the public the division has incorporated some changes to its preliminary findings document that it issued in December. Changes include some new stipulations for geothermal exploration and some new information about the region that may be impacted by the exploration.

Although the finding opens the way to hold a geothermal lease sale, there's no word yet on a sale date — the division told Petroleum News June 18 that it is working on the lease sale schedule following the decision in the best interest finding.

According to the best interest finding, the minimum bonus bids on sale tracts will be $1 per acre.

If geothermal exploration takes place following the lease sale field crews would likely do initial reconnaissance, with electrical and electromagnetic surveys being used to find prospective locations. Deep drilling at a prospect would be required to test for the presence of a geothermal water source.

Hot water from that source might then be sufficient to power an on-site project, perhaps by boiling a secondary, volatile fluid that can drive a turbine. A geothermal development at Mount Spurr would probably involve the construction of a power transmission line from the power plant to the nearest point on the Southcentral electricity grid, at Beluga on the northwest side of the Cook Inlet.

— ALAN BAILEY

ASSOCIATIONS

AOGA annual luncheon set June 30

The Alaska Oil and Gas Association will hold its annual luncheon on Monday, June 30, featuring the presentation of a new look at the role oil and gas plays in the economy of Alaska.

The luncheon will be at the Egan Center in Anchorage starting at 11:30 a.m. in conjunction with the Anchorage Chamber of Commerce "Make it Monday" forum.

The luncheon will feature a keynote presentation from Brian Rogers, the newly named interim chancellor of the University of Alaska Fairbanks.

Rogers also runs the economics and analysis firm Information Insights. He will unveil a comprehensive new Information Insights study on oil and gas in Alaska.

AOGA is requesting people reserve a seat no later than June 25 by calling (907) 272-2401, or visiting www.anchoragechamber.org. The luncheon costs $30 per person and $240 for a table of eight.

—PETROLEUM NEWS

FINANCE & ECONOMY

Compton bows to sales pressure

Compton Petroleum — a rare mid-sized Canadian oil and gas producer — has finally caved in to what many saw as the inevitable, putting itself up for sale just four months after saying it was "puzzled" by a demand from its largest shareholder to consider "strategic alternatives."

Carrying a market capitalization of C$1.65 billion and production of 33,000 barrels of oil equivalent per day (5,000 barrels of liquids and 170 million cubic feet of natural gas), Compton said it will now start looking for a buyer and hopes to conclude a deal by the fall.

However, the company said it will continue its C$410 million capital spending program and planned 350 wells during the transition period as well as the potential sale of non-core properties that produce 4,000-5,000 barrels of equivalent per day that could fetch C$200 million to C$300 million by the end of June.

"On the capital spending front, all efforts will be directed to maximizing shareholder value during the sale period," the company said.

Chad Friess, an analyst with UBS Securities Canada, said it is unlikely Compton can now achieve its 2008 target of 36,000-37,000 barrels of oil equivalent per day.

Compton shares have ranged over the last 52 weeks from C$13.45 to C$7.24 and recently hovered around C$12. UBC has a target price of C$15 and CIBC World Markets expects C$14.50.

The company lost more than 20 percent of its share value in 2007, punished by weak natural gas prices, but now that gas has almost tripled from its low point to US$12 per million British thermal units it seems to have decided this is an ideal time to test the market.

Compton was blasted earlier this year by New York-based hedge fund Centennial Energy Partners, which owns 20 percent of the shares, saying that it lacked a clear vision.

In a partial response, the company said it was revisiting its drilling program and capital budget for the balance of 2008 to make greater use of horizontal drilling and multi-stage frac technology.

—GARY PARK

continued from page 1

LEASES

such drilling under the terms of the leases, which have not yet expired."

And Craig Haymes, ExxonMobil's Alaska production manager, told a legislative hearing on June 17 that the company plans to drill at Point Thomson during the winter of 2008-09.

But do the companies have the legal right to conduct drilling operations on the Point Thomson land without an agreement with DNR? And what exactly is the legal status of the original leases that were combined into the unit?

A unit such as the one at Point Thomson is formed to enable lease owners to combine their efforts in developing an oil or gas field. A field often straddles multiple leased tracts, each of which typically has a different ownership configuration. Combining the leases into a single unit ensures consistent ownership interests across the entire field, thus enabling the field to be developed as a single entity.

Several categories of leases

There were 45 leases in the Point Thomson unit, Nan Thompson, petroleum manager for DNR's Division of Oil and Gas, told Petroleum New June 16. But the differing histories of those leases make it difficult to make any general statement about the lease status, she said.

"You have to look at it on a lease by lease basis. … In truth you could probably split the leases in the unit into five or six different categories, but you have to look at the facts of each particular lease to answer the 'what happens now?' question." **—Nan Thompson, petroleum manager for DNR's Division of Oil and Gas**

"You have to look at it on a lease by lease basis," Thompson said. "… In truth you could probably split the leases in the unit into five or six different categories, but you have to look at the facts of each particular lease to answer the 'what happens now?' question."

DNR issues leases with primary terms of seven or 10 years — a lease normally ceases to exist after the end of its primary term, Thomson said. And the primary terms have expired for all Point Thomson leases, she said.

But a lease can extend beyond its primary term if it becomes part of a unit, such as in Point Thomson. On the other hand, a lease that has exceeded its primary term but is part of a unit will generally cease to exist once the unit expires, she said.

However, the question of whether a lease or unit operator has drilled any wells within a lease complicates the lease termination situation. A lease continues to exist if it contains a well that is producing hydrocarbons or if it contains a well that has been certified as capable of producing hydrocarbons, Thompson said. On the other hand, the existence of a well that has been plugged and abandoned has no bearing on lease termination, she said.

And the existence of wells at Point Thompson has created that complex mix of different situations for the Point Thompson leases.

However, the situation is very clear for leases that formed an expansion to the original unit area, because the expansion agreement included drilling com-

see **LEASES** *page 19*

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LEASES

mitments, Thompson thinks.

"What that (unit expansion) agreement said was you have to drill these wells. … And if you don't the leases contract out of the unit and you have to pay the state a $20 million penalty. They paid that last summer," Thompson said. "… From the state's perspective the leases in the expansion area expired when the unit was terminated. … Those have gone."

Thompson also said that leases with no wells or with plugged and abandoned wells have clearly expired following unit termination.

Fuzzier if well suspended

Things become fuzzier where a well has been suspended, rather than plugged and abandoned. In principle these wells could be re-entered but, given that the Point Thomson wells were drilled in the late 1970s and 1980s, there's a question mark regarding whether it is now physically possible to achieve that re-entry.

"After a period of time you can't re-enter," Thompson said.

And the age of the wells is likely to give rise to litigation regarding the status of wells that were certified as capable of production many years ago, Thompson said. Certification is supposed to hold the status of a well until the well starts producing after a delay of perhaps a year or two, she said. Nothing has ever happened with the Point Thomson wells that were certified and there is a factual question of whether those wells are still capable of producing, she said.

"Wells don't last forever," Thompson said. "You have to do things to maintain them."

A DNR map of the Point Thomson leases depicts the wells in question as "decertified."

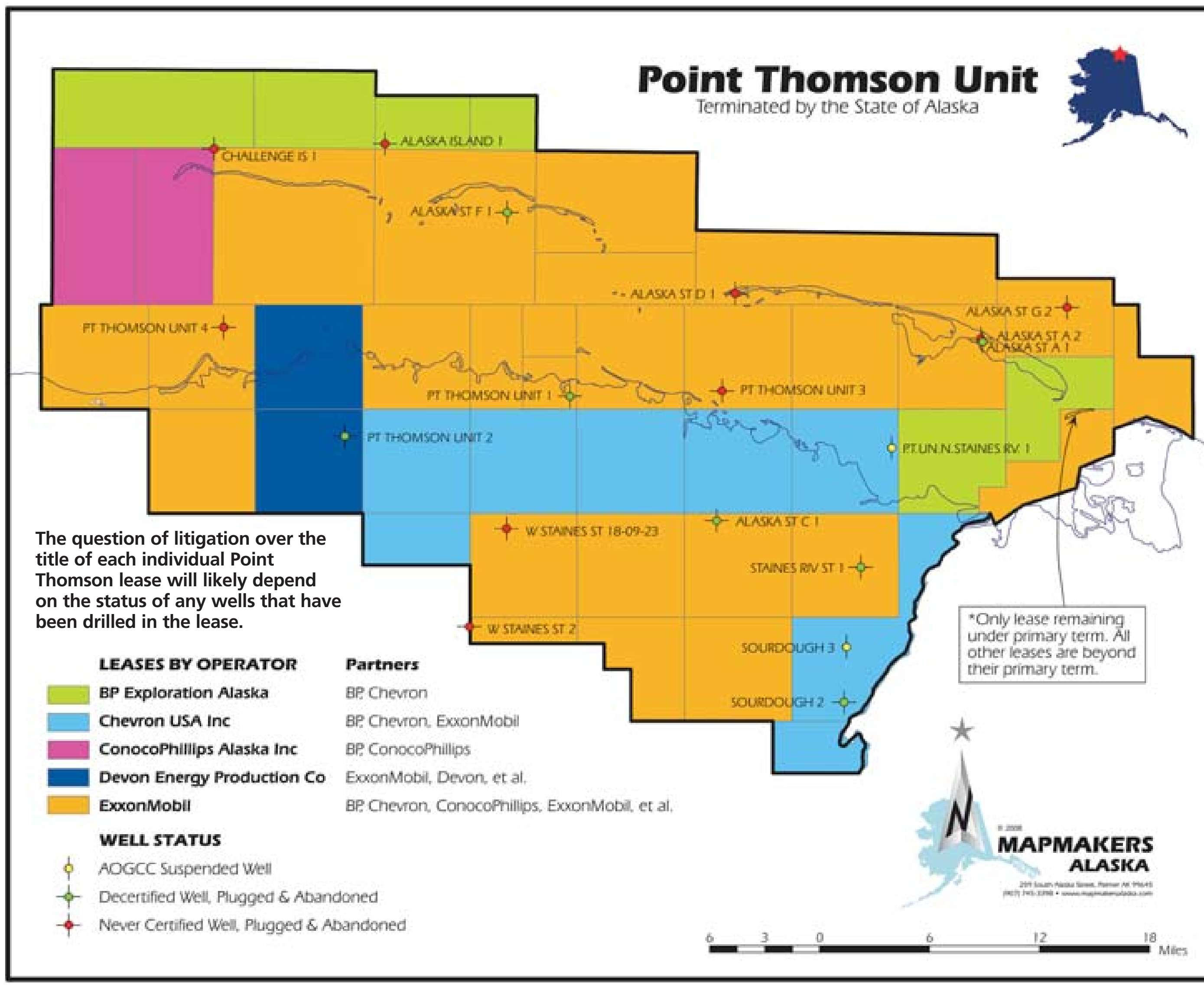
So, given that the question of the legal status of at least some of the Point Thomson leases looks to be heading into litigation, does Exxon have the right to drill?

Probably not, until there is clear title to the leases, Spencer Hosie, a senior partner and specialist in business law with the San Francisco firm of Hosie McArthur, told Petroleum News June 17.

But Hosie also commented that views of the situation are a matter of perspective.

"They (the lease owners) would say they have the right. The state would say they don't have the right," Hosie said.

—ALAN BAILEY



The question of litigation over the title of each individual Point Thomson lease will likely depend on the status of any wells that have been drilled in the lease.

Banks: New Point Thomson lease sale would be unique

If the State of Alaska prevails in litigation over title to the Point Thomson leases, how might the state offer the leases back on the market?

This would be a unique situation — lease sales normally involve unexplored land, rather than land where there's a known oil field, Nan Thompson, petroleum manager for DNR's Division of Oil and Gas, told Petroleum News June 16.

One possibility would be to offer the land as a unit rather than as separate tracts, said Kevin Banks, acting director of the Division of Oil and Gas. That would eliminate the inevitable need to unitize the leases at some time after the lease sale, he said.

Banks said that another possibility would be to include work commitments within the lease terms, rather than having just work commitments within plans of development submitted after the leases had been purchased.

"Under current law we also have the ability to impose work commitments," Banks said.

And the tracts offered for leasing wouldn't necessarily correspond exactly with the previous Point Thomson unit.

"We shouldn't assume that it's going to be offered in the same lease tracts as it was," Banks said. "We know more about this area than we do for a lot of the areas we commonly lease."

Partial sale?

But, assuming that some leases from the previous Point Thomson unit become embroiled in litigation over title, might the state offer for lease just those tracts of land where the title is clear? Or would it perhaps even be possible to offer leases for sale where the title was still in dispute?

"Certainly the legal status of a lease would impact its value, which is something the state would consider when we were deciding whether or not it goes into a lease sale," Thompson said. It's possible you could have a unit with some leases — other leases still subject to litigation might be added to the unit later.

It would be a question of weighing what is practical and what would be beneficial to the state, Banks said.

Spencer Hosie, a senior partner and specialist in business law with San Francisco's Hosie Frost Large & McArthur, is skeptical about the concept of piecemealing the future sale of Point Thomson leases. Pragmatically, there would be too many title questions involved, Hosie told Petroleum News.

But whatever the format of a future lease sale, new Point Thomson leases would be valuable assets. The likely size of the lease bonus bids would probably count some potential bidders out of the running, Banks said. On the other hand, there is no prohibition against several small companies submitting joint bids, he said.

And what if Exxon or any of the other previous owners were to bid for Point Thomson?

Any qualified bidder could participate in the sale, Thompson said.

"We don't have a blacklist," said Banks.

—ALAN BAILEY