Petroleum news

page 4 Parnell backs OCS development, revenue sharing for affected areas

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Nabors 27E at Point Thomson

COURTESY EXXONMOBIL

The Nabors 27E rig drilled the surface section of the second well at the Point Thomson central pad. See story on page 9.

Quebec on verge of breakthrough; Utica shale up to 9,000 feet thick

Get ready to add Quebec to the list of Canada's hydrocarbon producing provinces and the list of shale gas regions.

A study by Texas-based reservoir engineering firm Netherland, Sewell & Associates has bolstered the potential of the Utica shale in the St. Lawrence Lowlands to 150 billion cubic feet per square mile, 66 percent greater than any previous numbers.

Questerre Energy, a junior partner with Talisman Energy and Forest Oil in the area, said the report estimates its own prospective recoverable resources at 2.2 trillion-8 trillion cubic feet, with a best estimate of 4.28 tcf.

Questerre CEO Michael Binnion said the report is the first

see **QUEBEC** *page 23*

Exxon *not* named No. 1 green company; Profit must top $340 a barrel before ACES takes 75%

"FORBES NAMES EXXONMOBIL green company of the year." That, or something very similar, is a recent headline on thousands of Web sites and blogs.

Did we miss one of Forbes magazine's lists, I asked myself as I perused stories and comments via my Google Exxon alerts.

I couldn't find a green company list on Forbes' Web site. Or anywhere else.

What I *did* find was a cover story by Christopher Helman that was posted to Forbes' Web site on Aug. 5, and published in the Aug. 24 print edition of the magazine, titled "ExxonMobil: Green Company

see **INSIDER** *page 20*

EXPLORATION & PRODUCTION

Ready at Umiat

Renaissance says field development will depend on sustained oil prices

By ALAN BAILEY
Petroleum News

The Umiat oil field, adjacent to the Colville River on the eastern side of the National Petroleum Reserve-Alaska, has remained a tantalizing puzzle since the U.S. Navy discovered oil there in 1946 and subsequently abandoned as prohibitively expensive a scheme to pipe oil from the field to Fairbanks.

And despite being known to contain valuable light oil, the field's remote location, many miles from the Prudhoe Bay oil infrastructure and the trans-Alaska oil pipeline, has continued to preclude development of what could prove to be a useful addition to the inventory of producing fields in northern Alaska.

> *Now the company thinks that data from the 12 wells that the navy drilled years ago, together with the new seismic data, delineate the field sufficiently to enable a development decision that would lead the way straight into development drilling.*

Perhaps until now, that is.

Executives from oil independent Renaissance Alaska LLC, owner of two federal Bureau of Land Management leases and one state lease over the

see **UMIAT** *page 22*

FINANCE & ECONOMY

Pacific Energy IDs buyers

State of Alaska considers asset purchase but backs off, figuring to inherit property

By WESLEY LOY
For Petroleum News

The State of Alaska briefly considered buying some of the remaining Cook Inlet assets of imploding California oil and gas producer Pacific Energy Resources Ltd., but ultimately decided against it.

Kevin Banks, director of the state Division of Oil and Gas, said officials initially thought it might make sense to acquire the assets as a means of holding them together as a working unit, increasing their value.

But on reflection, officials decided much of the property would eventually land in state hands anyway should Pacific Energy abandon them, Banks said. Also, he said the state might be able to cooperate with private landowners such as Cook Inlet Region Inc. to find an interim operator for the assets.

"We're keeping our options open," Banks told Petroleum News on Sept. 9. All the landowners hosting Pacific Energy properties are "interested in seeing a successful outcome," he said.

For months, Pacific Energy has been looking to sell off its Cook Inlet oil and gas assets as part of its Chapter 11 bankruptcy proceedings in Delaware.

see **BUYERS** *page 21*

EXPLORATION & PRODUCTION

The planet's deepest well

Tiber among U.S. Gulf's biggest discoveries, but will require new technologies to develop

By RAY TYSON
For Petroleum News

BP's recent self-described "giant" oil discovery at the Tiber prospect in the U.S. Gulf of Mexico's Keathley Canyon, situated about 25 to 30 miles from Kaskida, another monster BP Lower Tertiary discovery, likely will require years of appraisal work and testing to bring into development, given the area's remoteness and technologi-

see **DEEPEST** *page 20*

COURTESY TRANSOCEAN

Transocean's deepwater Horizon rig, which drilled the Tiber discovery well.

BREAKING NEWS

3 No decisions yet on LNG: Future of Nikiski liquefied natural gas plant hinges on supply situation for Cook Inlet natural gas

5 Profits, costs, both to rebound: 24% drop in earnings for Canadian crude oil industry this year; prices expected to rise

12 Too soon to dismantle: Two more Cook Inlet platforms headed for mothballs; demolition crews not likely to show any time soon

contents

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● NATURAL GAS

No decisions yet on LNG

The future of the Nikiski LNG plant hinges on the supply situation for Cook Inlet natural gas

By ALAN BAILEY
Petroleum News

The owners of the LNG plant at Nikiski on Alaska's Kenai Peninsula are still evaluating whether to apply for renewal of the federal LNG export license that expires in March 2011, Dan Clark, manager of Cook Inlet assets for ConocoPhillips, told Petroleum News Sept. 4. Marathon Oil Co. and ConocoPhillips own the plant, with ConocoPhillips as operator.

Originally built in the heyday of Cook Inlet oil and gas development to provide a market for excess natural gas discovered during oil exploration, the plant went into operation in 1969, since when it has continuously exported LNG to Japan.

The original U.S. Department of Energy export license for the plant expired in 2009, and the plant owners' application for renewal of the license beyond that year met a barrage of questions regarding whether there was enough gas remaining in the Cook Inlet basin to support both the plant and the needs of local gas and power utilities. In the event, DOE extended the license through to 2011 while, under the terms of an agreement with the State of Alaska, the plant owners committed to drill some new Cook Inlet gas wells and to make some seismic and well data available to potential Cook Inlet oil and gas explorers.

But, with gas supplies from the Cook Inlet basin continuing to decline, what are the chances of LNG exports from Nikiski continuing beyond 2011?

No conclusion yet

"We haven't come to any conclusion yet as to whether to pursue more exports beyond March 2011," Clark said. "We think we still have time to get that (evaluation) done. So we still think it's very possible that it could happen."

The critical factor in any decision about whether to try to continue LNG production will be the question of how much gas will be flowing from the Cook Inlet gas wells, and whether that gas production will exceed the critical mass required to support the cost of renewing the export license and continuing to operate the plant, he said.

"It's not just dependent on ConocoPhillips and Marathon and what we're doing," Clark said. "It's dependent on other things that are happening in the basin."

Other ramifications

However, the ramifications of closing the Nikiski plant go well beyond the simple question of whether to continue the export of LNG from Alaska: As the only significant industrial consumer of natural gas in Southcentral Alaska, the plant performs a central role in the economics of the Southcentral gas industry. And, by on occasion diverting gas supplies earmarked for the plant, the plant owners can help bolster Southcentral utility gas deliverability, the rate of supply of gas to consumers, during peak demand during the most extreme cold of the winter — without this diversion of gas supplies, the Southcentral utilities would have run short of gas during a cold snap in January 2009, for example.

In addition, Enstar Natural Gas Co., the main Southcentral Alaska gas utility, has been discussing with the LNG plant owners the possibility of installing regasification equipment at the plant, to further increase gas deliverability during peak demand by converting LNG in the Nikiski storage tanks back to gas, as well as diverting the plant's gas supplies. A proposal to use the plant in this way, in effect as a gas storage facility to support "needle peaking" supplies, was included in a gas supply contract between ConocoPhillips and Enstar that the Regulatory Commission of Alaska rejected in 2008, Clark pointed out.


The LNG plant at Nikiski on Alaska's Kenai Peninsula

Deliverability risk

But, given the extreme swings in Southcentral Alaska utility gas demand between summer and winter, there's also a more fundamental problem associated with gas deliverability, were the LNG plant to close, Clark said.

The cessation of LNG exports after March 2011, a time of year at which the utility gas demand is starting to drop as the weather starts to warm, would likely result in the shut-in of gas wells, many of them quite old, that would otherwise have produced gas destined for the LNG plant, he said.

"That creates a lot of risk," Clark said. "You shut wells in and … you have risk of water encroachment. When that water comes into the well you potentially lose the well altogether."

Then, as gas demand soars during the following winter, the extra gas from those shut-in wells would not be immediately available or perhaps not available at all. At a minimum, time and money would have to be expended in restoring the gas production, and it is quite likely that production rates could not be fully restored to their previous values.

Incentive for development

In addition, the gas demand from the LNG plant provides economic incentives to drill new wells, to find and bring new gas reserves on line both for LNG exports and for local utility gas supplies. The local utility gas market, by itself, is very small in relation to the cost of exploring for and developing Cook Inlet gas.

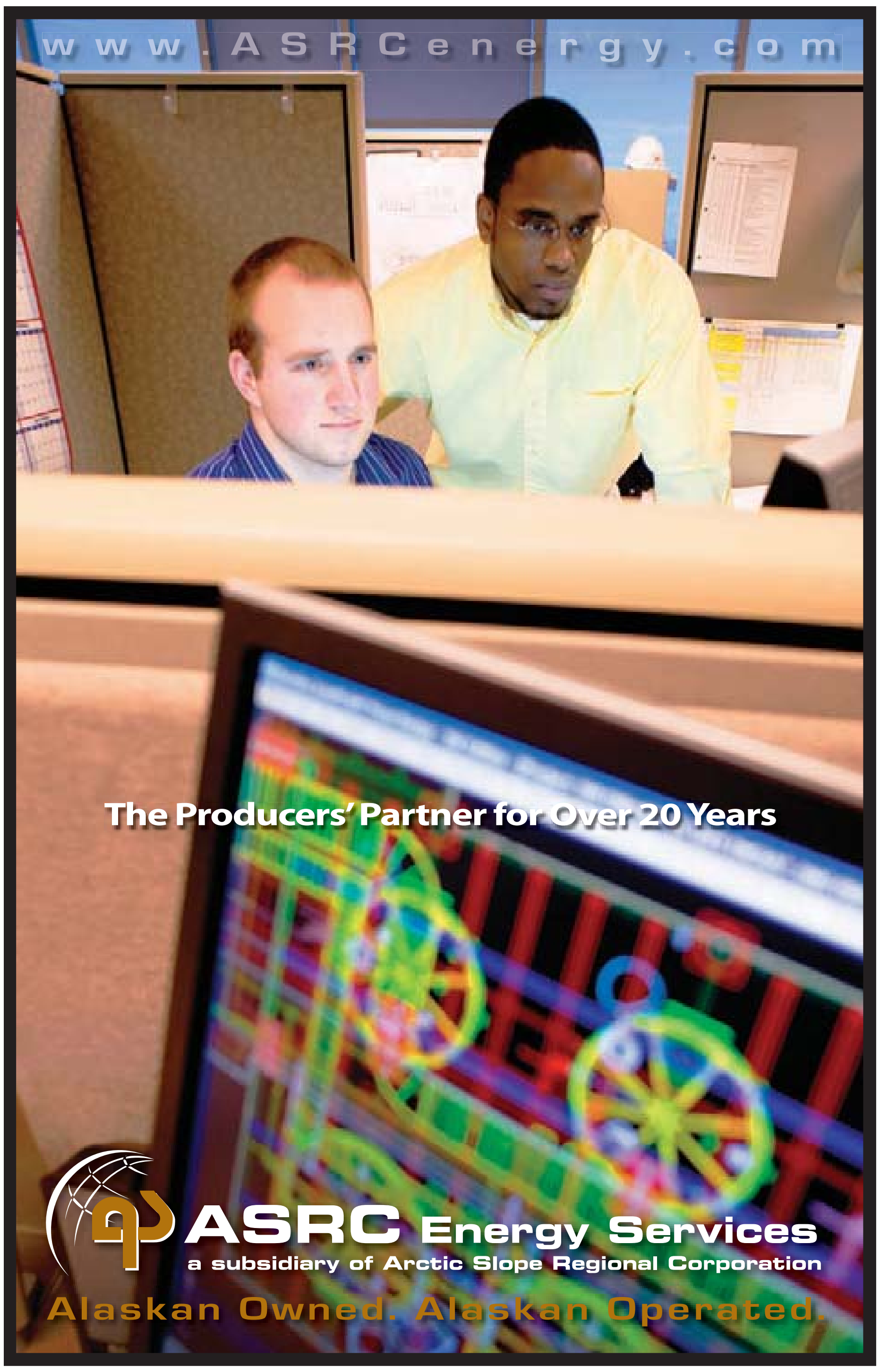
And that market situation adds to the challenges for Cook Inlet gas explorers.

"Just from my perspective it's already challenged because of the great amount of resistance that's encountered in terms of getting export (license) approval," Clark said. "We're only getting short-term extensions, like this last one which is two years. To justify spending the type of money that it takes to get wells on production here in the Cook Inlet, gas producers need some assurance that they're going to be able to flow their gas over a reasonable period of time. … It's pretty difficult to justify spending a lot of capital to develop wells that might deliver gas (for only) one or two months a year."

LNG imports?

One solution that people are considering to tackle a pending shortfall in Southcentral utility gas is the possibility of converting the Nikiski LNG plant to an LNG import terminal, to bring LNG from overseas into Southcentral Alaska. Essentially, the flow of LNG at the plant would be reversed, to transfer LNG into the plant storage tanks from incoming LNG carriers. Regasification equipment

see **LNG** *page 7*



EXPLORATION & PRODUCTION

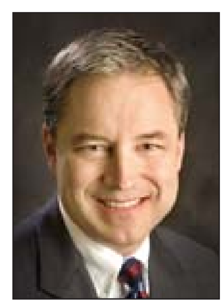
Parnell backs Alaska OCS development

Governor tells RDC state must fight for Alaska's outer continental shelf; says he continues to reach out to North Slope leaders

By KRISTEN NELSON
Petroleum News

Alaska Gov. Sean Parnell focused on development of Alaska's outer continental shelf in a Sept. 3 address to the Resource Development Council, calling it "one opportunity that we must fight for."

The meeting was the first at RDC's new meeting venue, the Dena'ina Civic and Convention Center, much larger than its previous location, allowing some 250 attendees to hear the governor pledge "a stable tax regime … a responsible budget" and "a consistent, clear regulatory regime."



GOV. SEAN PARNELL

"People and companies deserve to know — and have a right to know — the rules of the road, before they invest their money," he said.

The governor didn't exactly contrast the state's approach with that of the federal government, but he did say that while he has faith that Secretary of the Interior Ken Salazar will do the right thing and move ahead with OCS leasing, he remains concerned that "companies that have spent billions of dollars in the OCS really have nothing to show for it at this point and are stalled."

In a Sept. 3 letter to Salazar, containing the state's comments on Interior's proposed OCS 2010-15 five-year oil and gas leasing program, Parnell urged "a responsible OCS leasing program that makes available leases in Alaska's OCS for the exploration, development and production of oil and gas vitally important to Alaska and the nation."

Parnell told the secretary that the Joint Pipeline Office has said the trans-Alaska oil pipeline will have to begin addressing operational issues of low flow in the line between 2012 and 2018.

"We are quickly approaching the minimum throughput rate, beyond which the flow of oil cannot be maintained," he said, projecting that without new sources of oil the pipeline "could shut down within the next decade."

Alaska's OCS has the potential for 27 billion barrels of oil and 130 trillion cubic feet of natural gas, Parnell said, and for the oil pipeline to be maintained new sources of oil must be discovered now so that production can begin in time to sustain pipeline operations.

Parnell told RDC that he plans to meet with the secretary and has also requested meetings with the White House.

> *"To me the road to fiscal certainty runs right through AGIA."*
> **—Alaska Gov. Sean Parnell**

Culture, subsistence respected

He acknowledged the concern North Slope residents have about offshore oil and gas development.

"We have begun and will continue reaching out to North Slope community leaders as well to discuss OCS development concerns," Parnell said.

He said he has "spoken with whaling captains, coastal community leaders and other Alaskans who could be impacted by offshore exploration and development: I hear their frustration and I feel their very real fear."

Parnell said the state and its Native people "can work together to assure whale harvests and other subsistence activities will continue while offshore exploration and development is conducted safely."

"I will never trade one resource for another," the governor said.

He added that companies that want to work with Alaska to develop the state's resources "must respect and consult with our rural communities."

Whale migration can be protected by exempting certain areas from leasing and by seasonal drilling restrictions, he said.

"Cultural and traditional subsistence activities will be preserved and they can safely co-exist with the jobs and revenues from OCS exploration and development," Parnell said.

Revenue sharing

The governor said he supports federal legislation extending revenue sharing to Alaska communities, and called for a "comprehensive program for federal revenue sharing."

He called for Alaskans to be treated fairly in federal revenue sharing, and noted that the state's congressional delegation has long supported such legislation.

Asked at a Sept. 3 press availability why Alaskans should care about OCS development without revenue sharing, Parnell stressed the importance of keeping oil flowing through the trans-Alaska oil pipeline.

With more oil flowing through the line, he said, the tariff is lowered for all oil being shipped, "which means that more fields in Alaska get explored that can then access that pipeline."

"It means more jobs for residents of Alaska: that's what I'm focused on," the governor said.

see OCS page 7

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● FINANCE & ECONOMY

Profits to rebound, along with costs

By GARY PARK
For Petroleum News

Profits for Canada's crude oil industry will likely fall 24 percent this year from the record levels in 2008, but the pain should be short-lived as prices resume their long-term upswing in 2010, said a report by the Conference Board of Canada.

The independent think tank estimates pre-tax profits for Canadian producers will tumble to C$11.6 billion in 2009 from C$15.2 billion last year, while output will edge up only 1.8 percent because of the deferrals of nonconventional projects and the slump in conventional drilling.

"The Canadian oil industry has long been a boom or bust industry and that has been the case over the past year, but stimulus packages around the world will lead to improved performance starting in 2010," said board economist Todd Crawford.

"Accordingly, oil prices will resume their rise, eventually reaching US$103 a barrel by 2013 (after bottoming out at US$35)," he said. "Surging revenue growth related to higher prices will result in profits topping US$32 billion for the end of the forecast."

Crawford also predicts a resumption of delayed oil sands projects and production increases at existing plants, doubling volumes to 2.4 million barrels per day by 2013.

He wrote that the slowdown in production and investment will also slow the increase in total costs to 12.8 percent, compared with the 27 percent increase last year.

The report said the Canadian industry's revenues and costs are both expected to rise by an average 20 percent annually over the next four years, while profit margins will close in on their long-term average, settling at 15.3 percent in 2013.

Costs not expected to stay down

Crawford said the decline in drilling activity will keep cost growth to a minimum, but he doubts that the significant decrease in many key inputs will continue.

"Going forward, costs will resume their frantic pace of increase," he said. "Companies delayed projects in the hope that costs would come down … and they did. Unfortunately, costs will start to rise quickly again once prices return to profitable levels and construction begins in earnest industry wide."

The board does not expect the labor shortage in Western Canada will be solved any time soon and expects competition for workers will drive industry wage growth to 4.2 percent a year on average to 2013.

Capital costs will match the surge in investment and materials costs will rise at the same pace as revenues, reaching C$177 billion in 2012— up 150 percent over four years.

Crawford said oil prices over the near-term will be determined by a "mix of fundamental factors and the whims of the financial markets.

"Still, the recent narrowing of the contango (the difference between the spot price and the higher future price) would suggest that oil prices are not expected to take off in the next 12 months … and adequate supply to satisfy weak demand should help keep the appreciation of oil prices slow over the medium term," he said.

As a result, the board forecasts the WTI price will average $61.74 this year, rising to $76.89 by the end of 2010. ●

FINANCE & ECONOMY

Upgrader assets on auction block

The unraveling of once-promising plans to build a C$4 billion merchant upgrader in Alberta may be entering its final phase.

BA Energy, a unit of Value Creation, is ready to auction off the assets from its Heartland upgrader in a court-ordered disposal.

That comes a year after work was halted on what was seen by the Alberta government as a model of its efforts to keep more of the value-added end of oil sands production in the province.

The plant was originally designed to come on stream in three stages from 2009 to 2013, eventually processing 162,200 barrels per day of bitumen.

BA filed for bankruptcy earlier this year when faced with the prospect that the major lender to Value Creation was about to recall a US$507 million loan after BA was unable to repay a C$50 million loan.

Auction scheduled

An auction is now scheduled for Sept. 22 of more than 1,000 items.

At the same time a neighboring 900,000 barrel crude oil storage facility is being sold under a separate arrangement.

Also caught in BA's downward spiral is Aux Sable Canada, which had almost finished work on a C$45 million plant to process the off-gas from BA's upgrader.

The company said it is now looking for an alternative fuel source, confident that something will surface in time.

A spokesman for Alberta's Industrial Heartland, which is promoting the advantages of building upgraders and refineries in the Edmonton area, said it now appears the Heartland site will be empty for years, with no certainty that BA will ever resume work on the project.

Value, meanwhile, is pressing ahead with plans for its own oil sands project, aiming to launch two 40,000 bpd phases into production in 2011 at a break-even oil price of US$40 per barrel.

—GARY PARK

continued from page 4

OCS

OCS and gas line

OCS natural gas is also important, the governor said at the press availability, because it would add to the life of a gas pipeline.

Parnell said he thinks the gas line would be economic with known gas from Point Thomson, Prudhoe and Kuparuk, but with OCS gas the economic viability of a natural gas pipeline is extended.

"Having OCS natural gas available to plug into a natural gas pipeline means that instead of having a 30- or 40-year gas pipeline you can have a 40- to 60- or 80-year gas line."

The governor told the RDC audience that he believes the biggest obstacle to a gas line is "probably commercial negotiations between private parties." He said he was "heartened by the progress" so far as BP and ConocoPhillips came together to form Denali and ExxonMobil aligned with TransCanada.

What about tax changes, the governor was asked.

He said that having been a participant on the state side in the Murkowski-administration gas line negotiations, he had an opportunity to see what happens in those negotiations.

"And what I heard and what I saw demonstrated that the state cannot be in a position of negotiating with individual companies on a project."

The companies need to negotiate a project, he said, and once the companies have come together on a project, if they believe they need fiscal certainty then they should come to the state.

"I want the state to have a project telling the state what they need for fiscal certainty; that's what I'm looking for," Parnell said.

The road to fiscal certainty

The governor elaborated in response to gas line questions at the press availability.

"To me the road to fiscal certainty runs right through AGIA," the Alaska Gasline Inducement Act, he said.

In negotiations under the Murkowski administration, with the state talking to the proponents company by company, the state got "in the position of giving away value — company, by company, by company," he said.

While a request from one company for so many years of fiscal certainty sounded reasonable and constitutional, the next company wanted more years of certainty, and also tax changes.

"And any smart commercial negotiator knows that you negotiate with a partnership — you negotiate with a project — you don't negotiate with individual partners all the way along," he said.

This isn't the time for the state to talk, he said, because "nobody has a project yet."

Parnell said he is aware of where the companies are: The "Denali team wants to have their cost estimates done by the end of the year; the TransCanada-Exxon team wants to have their estimates done by the first quarter."

That is the setup for open seasons next year, because when they know the costs, they'll know the tariffs, he said.

AGIA is the state's framework for participating in the line: It establishes that the state is in for $500 million in exchange for terms that protect the state, he said.

Once the parties have "come together around and through that AGIA framework that they've already begun moving under then we can talk."

As for what the state will talk about, "I've already said I will consider anything that they can demonstrate is an economically valid argument, in other words anything that they can demonstrate is economically needed, I'll consider."

"… I'm in this to protect Alaskans' interests and for the jobs and revenue a pipeline can produce," Parnell said. ●

continued from page 3

LNG

would need to be installed, to convert the LNG into gas for supply into the Southcentral gas pipeline network.

Converting the plant in this way would require some investment but should be quite straightforward, Clark said.

"We've got a facility that's there," Clark said. "It's got a marine dock, tanks, equipment and piping, all in good condition."

Modifications would likely include alterations to the dock, to accommodate a variety of sizes of LNG carrier, he said.

North Slope gas

The other source being considered for future Southcentral utility gas is the North Slope, with gas delivered either through a "bullet line" direct from the Slope, or from a spur line off a main North Slope gas export line. Both of these North Slope gas options would require industrial gas demand in Southcentral Alaska, to drive sufficient pipeline throughput to achieve pipeline tariff levels that would result in feasible prices for utility gas. Could the Nikiski LNG plant become a prime driver in that future industrial demand?

"The LNG plant is an obvious candidate that could do that," Clark said.

If the plant were to cease its exports operations prior to North Slope gas being delivered into the Cook Inlet region, the plant could be mothballed or used for alternative purposes such as the importing of LNG. In part because of the low temperatures involved in LNG processing, but also because the plant has been well maintained, the plant is in excellent condition, with no corrosion, despite the plant's age, Clark said.

However, a long-term supply of gas from the North Slope would warrant investment in some upgrading of the plant, in particular the upgrading of the plant's 1960s era gas compressor technology.

"Probably the primary area where that (upgrade) would happen is in the gas compression turbines," Clark said.

However, this and all other decisions regarding the future of the plant remain in something of a state of limbo, waiting while the plant owners monitor the evolving Cook Inlet gas industry before the end-date for the current LNG export license starts to approach. ●

NATURAL GAS

Nova Scotia gas field poised for expansion

The dwindling reserves at Nova Scotia's offshore Sable natural gas project may be close to getting a lift from inclusion of the Chebucto field, which has proved plus probable reserves of about 160 billion cubic feet.

Sparton Resources, which has a 6 percent unitized interest in Chebucto, said Sable operator ExxonMobil Canada has served notice it is considering development of the field, which was discovered in 1984.

Although development plans are in the early stages, Sparton said the first gas could be produced in 2013, once the resource size and production expectations are confirmed along with estimated capital costs.

In addition to ExxonMobil, Royal Dutch Shell is a majority partner.

Chebucto is close to the existing Sable facilities, which supply gas to Atlantic Canada and the northeastern United States.

Although development plans are in the early stages, Sparton said the first gas could be produced in 2013, once the resource size and production expectations are confirmed along with estimated capital costs.

Sparton said earlier this year that Nova Scotia government leasing activity in the immediate area and the Sable Island region have shown a "renewed interest by both the government and industry in new exploration."

Two large exploration licenses were issued west and south of Chebucto last year for combined bids of C$120 million. The Canada-Nova Scotia Offshore Petroleum Board has rated the Chebucto field as the sixth largest in recoverable gas reserves of 24 known discovery areas in the region.

—GARY PARK

● NATURAL GAS

FirstEnergy believes gas could spike

By GARY PARK

For Petroleum News

Far from entering the prolonged slump most analysts are predicting, the natural gas business could soon enjoy a price spike if storage levels fall at a record pace this winter and liquefied natural gas imports continue to slow, said Calgary-based FirstEnergy Capital.

While sticking to its warning that Canadian prices could drop below C$1 per thousand cubic feet later in September and nudge US$2 per million British thermal units in the United States, FirstEnergy is offering the most upbeat industry predictions.

Analyst Martin King said forecasters are "far too conservative in estimating U.S. cumulative gas storage withdrawals for the upcoming heating season."

Analyst Martin King said forecasters are "far too conservative in estimating U.S. cumulative gas storage withdrawals for the upcoming heating season."

"Value factors such as falling supplies in the U.S. and Canada, improving demand, and slower LNG imports, contribute to our view for aggressive storage withdrawals," setting the stage for a sharp price rebound in early 2010 which could exceed FirstEnergy's current target of US$7 per million British thermal units.

The report noted that most storage forecasts call for U.S. levels to exit March 2010 at about 1.8 trillion cubic feet, pointing to a normal reduction of about 2 tcf.

But King said those are based on a belief that "slow industrial and commercial demand from a wounded U.S. economy and relatively slow declining domestic supply will keep storage withdrawals in check over the upcoming heating season."

Scenarios for early price recovery

King and FirstEnergy offered a number of theories that will spur an early price recovery.

They said Canadian supply losses will continue to grow to 1 billion cubic feet per day for 2009, double the previous estimate, meaning that Canadian storage will not remain full for long.

On LNG, First Energy believes U.S. imports will slide during 2010, while U.S. industrial demand could enter the first stages of a recovery by late 2009.

That recovery will "be better than the demand implosion that rocked the market" in the first half of 2009, FirstEnergy said.

King predicted that gas prices on the futures and physical markets will likely hit bottom in late September or early October, noting that forward pricing expectations are "reaching the point of maximum pessimism" as they hit seven-year lows.

"We expect that the last page of this sordid meltdown will be in a matter of days or weeks as producers are forced to shut-in production," he said.

Peters & Co. disagrees

Investment dealer Peters & Co. does not share the same near- to mid-term view as FirstEnergy, clinging to a "poor" outlook for winter prices that could result in 1.85 tcf of gas in storage entering the 2010 injection season as supply-and-demand balance is delayed until the second half of 2010.

But the firm said the North American situation could "swing sharply back in favor of higher natural gas prices in the second half of 2010 as we forecast that, even with flat year-over-year industrial and residential gas demand, U.S. gas storage will decrease to about 3.35 tcf for the beginning of the 2010-11 heating season."

Until then, Peters & Co. is not counting on a material gain in gas prices to about US$5 per thousand cubic feet until a year from now, although that timeframe could be shortened if U.S. industrial demand returns. ●

● EXPLORATION & PRODUCTION

Exxon sews up production well starts

Drilling kicks off $1.3 billion Point Thomson gas cycling project; key rulings expected in dispute between Alaska and companies

By WESLEY LOY
For Petroleum News

ExxonMobil announced Sept. 9 it has completed drilling and casing the surface section of the first production well in the company's billion-dollar project to produce hydrocarbon liquids from the Point Thomson field on Alaska's North Slope.

The Nabors 27E rig in August finished drilling the well to a target surface section depth of 4,875 feet, Exxon said. In May, the rig drilled a companion injector well to a similar depth.

Exxon said it plans to complete both wells to full depth by the end of 2010. The company couldn't drill deeper this summer, as state regulations forbid penetrating hydrocarbon-bearing rock between April 15 and Nov. 1.

The two wells are part of the first phase of Exxon's planned five-well, $1.3 billion natural gas cycling project at Point Thomson. The remote field straddles the Beaufort Sea coastline about 60 miles east of Prudhoe Bay.

Exxon has said it aims to produce 10,000 barrels of gas condensate per day for shipment down the trans-Alaska oil pipeline.

Other major Point Thomson owners participating in the drilling include BP and ConocoPhillips.

"We are progressing the development of Point Thomson consistent with the Alaska Department of Natural Resources Interim Decision of January 2009 and the Plan of Development submitted in February 2008," said Dale Pittman, Exxon's Alaska production manager. "We place the highest priority on safety and care of the environment. We are on schedule to begin production at Point Thomson by year-end 2014."

Backdrop of conflict

The drilling activity is the first at Point Thomson since 1983.

Lack of production from the field, which long has been known to contain rich reserves of natural gas as well as some oil, long has been a sore point for Exxon's landlord, the State of Alaska. In recent years, state officials have taken steps to prod the oil companies toward development, which means tax and royalty revenue plus jobs.

Those steps included terminating the Point Thomson unit and declaring that leases within the unit had expired.

Exxon, which for many years argued production from the remote Point Thomson field was uneconomic or impractical for lack of a North Slope natural gas pipeline, offered up the gas cycling project as part of a strategy to hang onto the Point Thomson acreage, which state officials had declared they were prepared to offer for lease to new owners.

After a five-day hearing to consider oil company appeals, state Natural Resources Commissioner Tom Irwin made a partial policy reversal, issuing a "conditional interim decision" on Jan. 27 reinstating two of the 31 leases (ADL 47559 and ADL 47571).

In exchange, Exxon would have to keep its pledge to drill a pair of wells on those leases right away.

That's just what Exxon set about doing, hiring dozens of contractors to carry out the work.

But the larger fight for control of the hugely valuable Point Thomson property is far from over.

Irwin has yet to issue his final decision on the status of Point Thomson leases.

Even more important, perhaps, is a forthcoming ruling from state Superior Court Judge Sharon Gleason. She is likely to decide by the end of the year whether the state was right — or wrong, as Exxon and other companies argue — in terminating the Point Thomson unit.

If the judge sides with Exxon, the effect of unitization is to extend leases that otherwise would have expired long ago.

However, Gleason isn't expected to have the last word, as the losing party is likely to appeal to the Alaska Supreme Court.

Huge costs, rich prize

Exxon says the partners are throwing down big money on Point Thomson. They

see **POINT THOMSON** *page 15*

COURTESY EXXONMOBIL

The Nabors 27E rig drilled the surface section of the second well at the Point Thomson central pad.

Norwegian fishermen disrupt seismic survey

Most data acquisition proceeded as planned but some areas were blocked by opponents of drilling in controversial Lofoten region

By SARAH HURST

For Petroleum News

The Norwegian Petroleum Directorate has been unable to complete all of its planned seismic data acquisition in the far north this summer because of protests by fishermen. The NPD failed to survey part of the Vesteralen waters in the Norwegian Sea north of Lofoten because the fishermen blocked a seismic vessel from operating in the area, according to the online news site E24.no.

Major hydrocarbon resources are believed to be located in the Vesteralen and Lofoten waters, but the fishing industry is opposed to drilling there. The NPD offered fishermen compensation this year to stay away while the seismic surveys were taking place. Approximately 120 fishermen accepted the compensation, the NPD said in a release Aug. 3.

"This gave us access and enabled us to do our job, as we were asked to do by the Storting (Norwegian parliament)," said Sissel Eriksen, the NPD's exploration director.

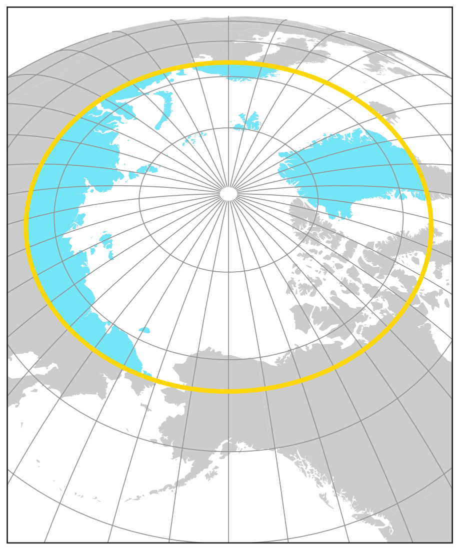
Data collected in Troms II area

Seismic data acquisition was successful in the Troms II area, northwest of Senja, with a total of 311 square miles of 3-D seismic being acquired, the NPD said. The NPD now believes the data basis for Troms II is adequate to provide the Storting with the necessary technical assessment of the possibility of petroleum in the area. The data will be processed and interpreted, and the results will be submitted to the Ministry of Petroleum and Energy in spring 2010. A revised management plan for the Barents Sea and the areas off Lofoten and Vesteralen will be presented to the Storting in 2010.

An environmental organization called Nature and Youth recently organized a training camp in Lofoten to train 260 young people from all over Norway on how to fight the oil industry in the region, the newspaper Aftenposten reported in early August. Part of the camp's program included training on civil disobedience against the oil industry, training in which the participants aged 13 to 24 put on survival suits and threw themselves into the water.

Nature and Youth is planning for people to jump in front of tankers and oil rigs.

Norwegians go to the polls Sept. 14 and the election results will determine whether or not the government will support drilling in Lofoten. ●



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Norway reduces Barents Sea resource estimate

The Norwegian Petroleum Directorate has updated its resource estimate for the Barents Sea, reducing estimated recoverable resources from 36.4 billion standard cubic feet of oil equivalents to 32.1 billion. In its Resource Report 2009, the NPD says that estimates of volumes of oil and gas in the ground have increased somewhat, but the recognition of poorer reservoir properties than expected, distance to the market and development costs have reduced expectations for the percentage of the resources that can be produced.

In 2010 the resource estimates for the North Sea and the Norwegian Sea will also be updated. Up-to-date resource figures for Nordland VII and Troms II will be released in connection with the revision of the comprehensive management plan for the Barents Sea and the waters off Lofoten.

The Resource Report, published every two years, also notes that companies on the Norwegian shelf are continuously working to improve oil recovery, with gas injection proving to be a very effective method.

"With today's adopted plans, about 54 percent of the oil will be left in the ground when production ceases," the report says. "The NPD believes that production can be increased beyond the planned level by using new methods to improve recovery. This can result in significant gains, but it will require extensive cooperation both among the oil companies and with the authorities in order to qualify and test new technologies on the fields."

—SARAH HURST

StatoilHydro replaces plant's heat exchangers

Norway's StatoilHydro shut down its Melkoya liquefied natural gas plant Aug. 15 for up to three months of scheduled upgrading and maintenance work, the company said in a release. The plant near Hammerfest processes natural gas from the Snohvit field in the Barents Sea.

From February this year the plant has produced at approximately full capacity, but to maintain this rate the plant has to be made more robust, the company said.

"We estimate about 510,000 labor-hours in connection with the stoppage, including preparations and the finishing process," said Geir Hopland, the plant's turnaround manager.

One of the big operations due to be undertaken will be the replacement of 15 heat exchangers which are at the core of the process that cools the Snohvit gas into a liquid state. All gas must be removed from the plant during the shutdown.

—SARAH HURST

Lukoil wants Nenets field to produce more oil

The Yuzhno-Khylchuyuskoye field in Russia's Nenets Autonomous Okrug is not yet producing as much oil as Lukoil had hoped, Leonid Fedun, a vice president of the company, said at a press conference Aug. 31. The field is operated by Lukoil subsidiary Naryanmarneftegaz, a joint venture with ConocoPhillips. Lukoil owns 70 percent of the company and ConocoPhillips 30 percent.

"The company is studying the field and the production peak will be reached, but I currently cannot say when that will happen," Fedun said. "Unfortunately, the first expectations were greater than what we have got," he added. The field is connected by pipeline to the Varandey terminal on the Pechora Sea coast.

The field produced 22.7 million barrels of oil in the first half of 2009, according to Naryanmarneftegaz.

China's Sinopec recently signed an agreement with Lukoil to purchase 21.4 million barrels of oil from the Yuzhno-Khylchuyuskoye field. The deal is valid from July 1, 2009, to June 30, 2010, or "until the contract is paid in full," Lukoil said. The oil will be shipped by Litasco, a trading arm of Lukoil.

—SARAH HURST

● EXPLORATION & PRODUCTION

Too soon to dismantle CI platforms

Two more offshore structures head for the mothballs but it will likely be a long time before the demolition crews arrive on the scene

By **ALAN BAILEY**
Petroleum News

As production slowly declines from the offshore oil and gas platforms in Alaska's Cook Inlet, inevitable questions arise regarding when the platforms will reach the end of their useful lives, and how and when the platforms will ultimately be removed and scrapped.

The wells on a platform will be shut-in at a point when oil or gas production from the platform drops below the level required for economic viability. But, although oil and gas leases typically require the removal of the field infrastructure from a defunct field, the fact that production from a platform has ceased does not necessarily trigger immediate removal of the platform. Instead, a shut-down platform may be mothballed, or "lighthoused" to use oil industry parlance, for several years, until a final decision can be made on any future use of the platform, and on how exactly the platform will be dismembered and removed.

So far, no offshore platforms have actually been removed from Cook Inlet. In fact, just two platforms, Chevron's Baker and Dillon platforms at the northern and southern ends of the Middle Ground Shoal field, have been lighthoused in response to the declining oil and gas production trend.

Two lighthoused

So far, no offshore platforms have actually been removed from Cook Inlet. In fact, just two platforms, Chevron's Baker and Dillon platforms at the northern and southern ends of the Middle Ground Shoal field, have been lighthoused in response to the declining oil and gas production trend. Dillon was shutdown in 2002 and Baker was shutdown in 2003, with both facilities being placed in lighthouse mode in 2003, Chevron spokeswoman Roxanne Sinz told Petroleum News. The wells drilled from the platform have not been plugged and abandoned, but remain shut in, with just one well on each platform producing natural gas to provide platform power and heat, Sinz said.

Marathon Oil Co. has proposed the lighthousing of two other platforms, the Spark and Spurr platforms in the North Trading Bay unit on the west side of the Inlet, Jonne Slemons, petroleum land manager in Alaska's Division of Oil and Gas, told Petroleum News Sept. 1. Production from these platforms has ceased and the company has started plugging and abandoning wells, Slemons said.

But a major factor in deciding when to eventually dismantle any platforms will likely be the economies of scale achievable from the removal of a series of platforms in a single large project — major costs such as that incurred in bringing from the Lower 48 the heavy equipment required to lift and haul out the massive components of a platform would be best spread across as many salvage exercises as possible.

"If you're looking at actual dismantlement and removal, then the economies of scale that can be realized by a shared rig become a huge issue and a huge help, if you can arrange it," Slemons said.

State requirements

And another critical factor in the dismantlement of the platforms will be the State of Alaska's specification of what exactly constitutes platform removal, a specification that DOG has yet to determine.

As more platforms become lighthoused and the day when platforms will need to be removed approaches, the state is considering the various removal options and what stipulations it will require.

"We're certainly coming up on this and the division is working it actively," Slemons said. "However, we have not reached any hard and fast conclusions about what state requirements might be, and what kind of input we would want from the companies and other stakeholders."

The division will determine some dismantlement options and then discuss these options with the oil companies, and with organizations such as the Cook Inlet Regional Citizens Advisory Council and Cook Inlet Keeper, to develop a final state position. The state anticipates a back-and-forth conversation on the requirements and, at the moment, it would be premature to speculate on what those requirements might be, Slemons said.

And, just to complicate the issue, the wide variety of platform designs in the Cook Inlet will drive a need to consider the requirements for each platform individually.

"How it would be accomplished in each case is always going to be individually treated by the state," Slemons said.

Future uses?

The other variable in the platform removal equation is the question of whether all possible use has been made of a platform, or whether the platform might serve some future role in the development of additional hydrocarbon resources.

"That's why we have purposely not required full-blown, detailed DR&R (dismantlement, removal and restoration) plans, because we wanted to leave some discretion to the (DNR) commissioner to decide at what point we wanted to move ahead with that," Slemons said.

Future platform roles could, for example, include exploration of new prospects either through directional drilling out from the platform, or by deep drilling below the exhausted reservoirs.

"We don't want to preclude that kind of activity from happening, especially given the gas situation in Cook Inlet," Slemons said.

So, the state is in no rush to insist on platform removal as long as the platforms remain in good structural condition. And the state checks on the condition of each platform annually, Slemons said. ●

● NATURAL GAS

ANGDA moving on propane, supply co-op

Authority board wants to meet with new governor, energy advisor; still working evaluation of route for gas line to Southcentral

By KRISTEN NELSON
Petroleum News

The Alaska Natural Gas Development Authority met Sept. 3 in Anchorage, heard from contractors on propane and supply co-op projects, but didn't resolve how it will tackle the role the Legislature assigned it at the end of this year's session — to be the public voice in picking a route for a gas line coming into Southcentral Alaska.

At a July meeting the board came up with a laundry list of factors to consider in making such a decision. Over the interim the staff found a product designed to analyze inputs from varied stakeholders, based on facilitated stakeholder meetings, and the board saw an overview of that product.

Work needed to support the board's route selection would be done by the contractor hired by Harry Noah, the governor's in-state gas coordinator, Deputy Revenue Commissioner Marcia Davis said at the July meeting. The Legislature provided funds earlier this year for in-state gas line work, funds which went to Noah, selected by former Gov. Sarah Palin early this year as project manager to get in-state gas to Southcentral. Palin's plan included aligning gas owners with potential gas buyers, applying for permits and rights of way, estimating the tariff, developing a business plan and choosing a private sector company to build and operate the pipeline.

What the governor wants was an issue raised in the July board meeting, which occurred after Palin announced her resignation but before then-Lt. Gov. Sean Parnell was sworn in as governor.

Board member Kate Lamal raised the issue in July and again at the September meeting, noting that the state was coming out of a "tumultuous time" and saying that she would like clarification on the views of the current governor and the new energy coordinator, Gene Therriault.

Board members agreed and member Dan Sullivan undertook to talk with the governor about meeting with the board.

How to evaluate

There was considerable discussion about evaluating the route for a line to Southcentral.

Board member Brian Rogers told Heinze he thought ANGDA staff had wasted six weeks in not communicating the list of criteria developed at the July meeting to Noah.

Heinze said the availability of commercial products, such as the one the board saw demonstrated at the meeting, would allow the board to understand the full range of risks and benefits, and would also provide a third-party contractor to take part of the load of that work off the board.

Davis said she thought the public would have more confidence in a professional evaluation done by a third party.

> **On the Web**
>
> See previous Petroleum News coverage:
>
> "October target for ROW applications," in Sept. 6, 2009, issue at www.petroleumnews.com/pnads/65699409.shtml
>
> "ANGDA works on route decision criteria for in-state pipeline," in July 26, 2009, issue at www.petroleumnews.com/pnads/547008286.shtml

Propane project moving

Mary Ann Pease, an ANGDA contractor, updated the board on the propane project, which could be up and running with deliveries in less than three years.

ANGDA is in the process of finalizing an agreement with an unnamed North Slope producer to provide natural gas for the propane project, something which would be done "inside the fence" at Prudhoe Bay.

Private industry would take over "outside the fence" and build and run a propane plant, a carbon dioxide scrubber, a line taking the CO2 back to the Central Compressor Plant at Prudhoe Bay, propane storage and propane loading facilities for trucks, ISO containers or barges for delivery to in-state consumers.

Pease and Heinze have met with potential partners interested in moving forward on the "outside the fence" relationship and discussions are continuing with the North Slope producer.

Heinze said his rough estimate is $100 million for the project — $25 million "inside the fence" at Prudhoe and $75 million outside the fence. A contractor is developing an independent cost evaluation.

For some financial firms $100 million isn't even on the radar, he said, but they are interested because they are interested in the North Slope; for others $100 million is of interest.

Pease said NANA WorleyParsons has completed a technical review and economic sustainability has been confirmed with base-load end users.

Propane would be a "bridge solution" which could be up and running in two years.

Heinze said the response from companies with Alaska operations has been strong and enthusiastic, with some interested in doing the entire project and some interested in parts.

ANGDA would be the facilitator for the project, but ultimate responsibility is with the private sector.

Inside the fence the project would have the capability of taking up to 1 billion cubic feet a day, sufficient to produce up to 10,000 barrels per day. But the startup projection is much smaller, and facilities inside the fence would be designed so they could go to 1 bcf a day, not built out, but easily and cheaply expendable to 1 bcf a day.

Outside the fence the project is planned for one propane plant, but could be expanded to three.

Natural Gas Supply Co.

ANGDA contractor Tony Izzo updated the board on the Natural Gas Supply Co., certified under Alaska's co-op statute earlier this year. The entity exists essentially on paper he said.

The co-op, which would provide a way for utilities to get together to purchase gas, something which can be a daunting prospect for utilities without in-house expertise, Izzo said.

Homer Electric Association and Matanuska Electric Association have joined, and discussions are ongoing with others. Izzo said another name or two could come onboard shortly.

> *ANGDA is in the process of finalizing an agreement with an unnamed North Slope producer to provide natural gas for the propane project, something which would be done "inside the fence" at Prudhoe Bay.*

The co-op is working to increase the economies of scale, based on models in the Lower 48, and is targeting near-term supply, in 2011 through 2014.

Heinze noted that the co-op is focused on electric utilities, which may have different short-term storage options than Enstar, and said the co-op has initiated discussions with Cook Inlet producers, pursuing the concept of a big tranche of gas to fill certain electric needs.

ANGDA is also working with the Alaska Energy Authority on gas supply concepts and continuing work on aggregating needs for an open season for the main line.

The TransCanada connection

Heinze said at the July board meeting that he had attempted to meet with TransCanada but was not satisfied he was making the right connections and talking

see ANGDA page 17

FINANCE & ECONOMY

Suncor gives exit passes to 1,000

The juggernaut everyone knew was coming showed up — ironically — just two days before the Labor Day weekend.

No one from the top down had tried to hide the inevitable round of layoffs that would follow Suncor Energy's takeover of Petro-Canada, which created a combined payroll of 12,886.

Mostly, the bleeding will occur in the head office, where there is the greatest overlap in information technology and administration. Engineers and geologists in the natural gas business will also take a hit.

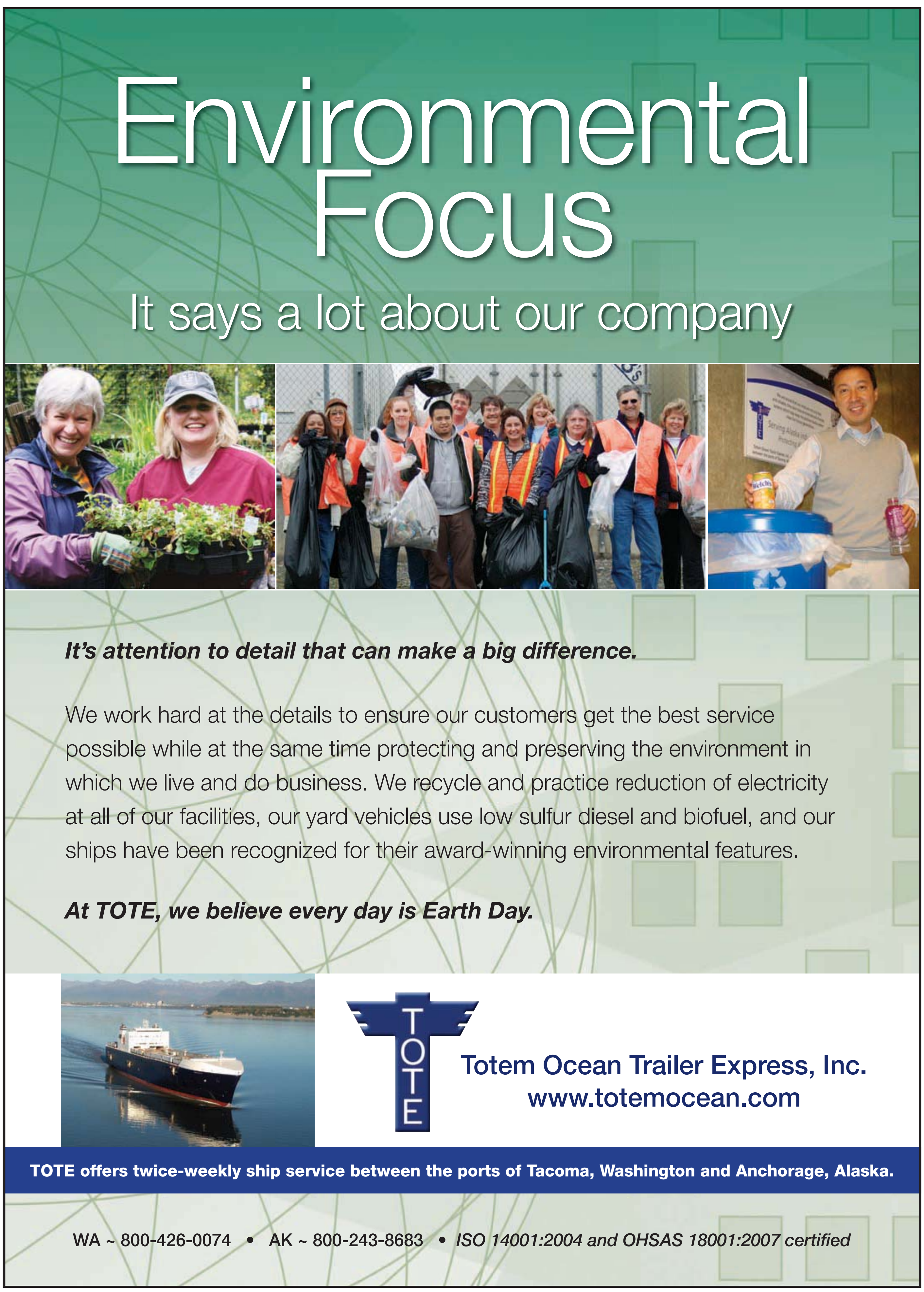
By the middle of October that number will be down by about 1,000 through a mix of outright layoffs, early retirements and eliminated job contracts.

Mostly, the bleeding will occur in the head office, where there is the greatest overlap in information technology and administration. Engineers and geologists in the natural gas business will also take a hit.

Suncor Chief Executive Officer Rick George, known for his ability to make the tough decisions, said "bringing two large businesses together has also meant that some of the efficiencies are necessarily through work force reductions."

"It's been difficult, but we've said from the start that this would be the case and worked hard to keep employees informed and to move quickly to build the new organization."

see **SUNCOR** *page 16*



● FINANCE & ECONOMY

OPEC leaves crude oil targets unchanged

By TAREK EL-TABLAWY
The Associated Press

OPEC on Sept. 10 decided to leave its production quotas unchanged, opting to take a cautious approach in a market awash in crude and a global economy still in the early stages of recovery.

The 12-nation Organization of Petroleum Exporting Countries said "market fundamentals have remained weak," even though current oil prices at about $71 are roughly double their level since December, when the group announced a record 4.2 million barrel per day cut from September 2008 levels.

The meeting's closing communique said "whilst there are signs that economic recovery is under way, there remains great concern about the magnitude and pace of this recovery," especially in the West. The group noted uncomfortably high crude and refined product levels, which reflect that refiners are not eager to churn out additional product.

"Since the market remains oversupplied and given the downside risks associated with the extremely fragile recovery, (OPEC) once again agreed to leave current production levels unchanged for the time being," the statement said.

The upswing in prices was a blessing for the bloc — supplier of roughly 35 percent of the world's crude — but OPEC ministers noted volatility remained in the market and a delicate touch was needed to ensure that the uptick does not derail global economic recovery efforts.

Decision a shift in policy

The decision, announced in the early hours of Sept. 10, came as little surprise, confirming earlier predictions by the group's oil chiefs.

But analysts said it also reflected a shift in policy for the group.

Whereas earlier this decade, OPEC "would have moved proactively, this time they chose not to," said David Kirsch of Washington-based consultancy PFC Energy. "The ministers all acknowledged downside risks to both demand and prices."

"The reason is pretty clear: Because of the current economic risks, OPEC is adopting a different approach," he said. "It's really hoping that the economy turns around and takes care of the current overhang in distillates somewhat naturally" instead of them intervening directly.

Coming into the meeting, Saudi Oil Minister Ali Naimi, whose country is OPEC's biggest producer and its de facto leader, had sounded an upbeat tone about current crude prices and ruled out any possibility that a cut was in the offing.

Focus on production targets

Other OPEC ministers indicated the focus would likely be on reining in overproduction, an effort key to sustaining prices in a market swimming in crude, grappling with fluctuations in the U.S. dollar, exposed to volatility linked to weak demand and set against the backdrop of a global economic recovery that has yet to firmly take root.

The group — excluding Iraq — has set a production target of slightly under 25 million barrels per day, but has been overshooting that mark by about 1 million barrels per day, according to analysts.

The increase in inventories is a major challenge for OPEC, especially as the U.S. driving season winds down and refiners gear up for the winter heating-oil season with refined product inventories also high.

"When we look at fundamentals, we see this overhang with great concern," OPEC Secretary General Abdulla Salem el-Badri said.

While the group was optimistic that the global recovery would help mop up the excess oil, el-Badri also took notice of the compliance issue, saying that "of course, when the conference takes a decision, we would like our members to adhere to the decision."

But he also stressed that the group was not ready to jeopardize the economic recovery efforts by pushing for steep cuts.

"We are working on a very thin line," he said. "We have to be very careful. We don't want to take action that will jeopardize the recovery."

see **TARGETS** *page 15*

continued from page 14

TARGETS

Volatility the norm

For the better part of a year, volatility in prices has been the norm as supply and demand fundamentals were often overshadowed by investors using crude as a hedge against fluctuations in the dollar.

OPEC members have railed against such speculation, with Kuwaiti Oil Minister Sheik Ahmed Al Abdullah Al Sabah telling reporters at the start of the meeting that oil was now more a financial instrument than a commodity.

The group's president, Angolan Oil Minister Jose Botelho de Vasoncelos, said while members were satisfied with current price levels, rampant speculation is still buffeting crude markets.

"We are concerned about the continuing price volatility, which — once again — is happening when there is plenty of crude in the market," Botelho de Vasoncelos said, at the meeting's opening.

Even so, "we are optimistic that the darkest days of financial turmoil and economic recession are behind us," he said.

With no control over currency fluctuations or crude demand, OPEC members could focus only on the one factor within their grasp — supply.

Compliance has waned

But the strong compliance with quotas has waned over the past four months, dropping to between 68 and 70 percent, according to el-Badri. That erosion came in tandem with rising prices as some members — starved for hard currency — upped production to generate more revenue.

In doing so, however, they not only risked credibility, but also could open the door for undermining the price of a commodity most in the bloc rely on for their livelihood and economic growth.

While Saudi Arabia had repeatedly indicated earlier that $75 per barrel was a fair price for both consumers and producers, other members have begun to raise the threshold.

Kuwait's Al Sabah said $80 per barrel was fair, and Iran's new oil minister, Masoud Mirkazemi, said that "what is good is the price that will give us a good incentive for more investment."

"At the current value of the dollar, and the fact that the dollar depreciated, it is questionable if that is the right price," he said, referring to the $70 per barrel threshold. "I think it has to go up given the fact that the dollar has depreciated so much."

But PFC Energy's Kirsch said the comments come in the broader context of a long-term sustainable price, versus a day-to-day level, which el-Badri said has averaged about $54 per barrel for the group so far this year.

"There is a recognition that you don't get that (sustainable price) without a healthy economy," said Kirsch. "And you have to put the healthy economy first." ●

continued from page 9

POINT THOMSON

committed $120 million to the drilling and development activities in 2008, and expect to invest an additional $250 million this year.

What's more, the Nabors 27E rig needed about $35 million in upgrades for drilling the brawny wells required to safely tap the high-pressure Thomson sands reservoir.

Point Thomson holds an estimated 8 trillion cubic feet of gas — about a quarter of all the known gas reserves on the North Slope — plus about 200 million barrels of condensate, Exxon said.

Point Thomson gas is considered a crucial component for a proposed multi-billion-dollar natural gas pipeline from the Slope into Canada.

"ExxonMobil will continue to bring innovative technology and world-class management expertise to the project," said the company's Sept. 9 press release on the Point Thomson drilling. "Field development will include a gas cycling plant designed to produce hydrocarbon liquids and re-inject natural gas back into the reservoir, making Point Thomson the highest-pressure gas cycling operation in the world. In addition to processing facilities, the development will include a pipeline tie-in to the Trans-Alaska Pipeline System (TAPS) and other ancillary facilities and infrastructure."

Through the year, Exxon has been building out a beachfront gravel work pad at Point Thomson, hauling more than 80 barge loads of equipment and material to the site since mid-July, Exxon said.

The company is suspending its barging activities at times when it could disturb Native hunts for bowhead whales in the Beaufort Sea. ●

SAFETY & ENVIRONMENT

USCG deploys drifting buoy in Arctic

As an initial exercise in a program to deploy a network of buoys for scientific research data collection in the Arctic, a U.S. Coast Guard C-130 aircraft based in Kodiak has dropped an ocean drifting buoy in the Arctic Ocean north of the Bering Sea, the Coast Guard said Aug. 19. Personnel from the Coast Guard International Ice Patrol, headquartered in New London, Conn, assisted with the buoy drop.

"This effort signals the beginning of airborne deployments by Coast Guard C-130 Hercules Arctic Domain Awareness flights in support of the buoy network," said Pablo Clemente-Colón, chief scientist of the National Ice Center and an oceanographer with the National Ocean and Atmospheric Administration.

The new Arctic Ocean buoy suspends a drogue system at a depth of 50 or 150 feet below the ocean surface, to track deep water currents that affect the movement of icebergs. The buoy also measures the temperature at the sea surface. Ground stations pick up the buoy data via satellite.

Ocean drifting buoys have been used for data collection in the north Atlantic for a number of years and the International Ice Patrol deploys 12 to 15 buoys each year in the Labrador Sea and North Atlantic region, the Coast Guard said.

The new Arctic Ocean buoy suspends a drogue system at a depth of 50 or 150 feet below the ocean surface, to track deep water currents that affect the movement

see **BUOY** *page 21*

continued from page 14

SUNCOR

International to Calgary

A Suncor spokesman would not say how many of the reductions applied to former Petro-Canada employees, emphasizing that "we're interested in getting the right organization with the right people with the right roles without regard to which company they came from."

Suncor also announced it would move the international and offshore units, which were part of Petro-Canada, to Calgary from London.

Suncor said it is on track to "meet or exceed" its anticipated operational savings of C$300 million a year and capital efficiencies of C$1 billion by eliminating "redundant spending and targeting capital budgets to high-return, near-term projects."

A priority list of major projects is expected to be released this fall.

Alberta Premier Ed Stelmach said the job losses are significant and a "great concern to us in government," but the merger will "make for a much stronger company, one that will attract investment" to the Alberta oil sands on both the production and refining side.

"We will get those (1,000) jobs back, plus many more," he said.

—GARY PARK

NATURAL GAS

RCA to hold conference on CI gas

The Regulatory Commission of Alaska is holding a technical conference on Cook Inlet natural gas pricing, to address issues that have arisen in recent years regarding RCA approval of utility gas supply contracts. The conference, targeted at entities involved in or interested in the Cook Inlet gas industry, will start at 9:30 a.m. on Sept. 16 in the commission's east hearing room.

Since 2001 the commission has only approved one Southcentral Alaska utility gas supply contract, with several contracts being rejected as containing, in the commission's view, gas pricing that was unacceptably high. The rejection of contracts has resulted in regulatory uncertainty regarding what contracts the commission may approve, in a situation where contract negotiation and approval may take a year or two to achieve, at great expense, at a time when Southcentral utility gas supplies are becoming extremely tight.

"The purpose of the technical conference is the voluntary exploration of regulatory approaches that will make the RCA review process for natural gas supply contracts more predictable and straightforward for utilities and producers," RCA Chairman Robert Pickett said in announcing the conference. "Participants are encouraged to be prepared to discuss natural gas pricing guidelines that would allow a predictable regulatory review process while also ensuring affordable prices for natural gas consumers."

Possible approaches to regulating gas prices include the adoption of a "safe harbor" pricing mechanism, the use of gas price indices to specify Cook Inlet gas prices, allowing seasonal adjustments to gas prices and allowing add-on prices for producer-operated gas storage.

Conference participants could also discuss potential changes to state statutes that govern the review of gas supply contracts, with one possibility being a request that legislators specify a gas pricing methodology for future RCA guidance, Pickett said.

—ALAN BAILEY

EXPLORATION & PRODUCTION

Newfoundland welcomes new field

The Newfoundland offshore has received a regulatory green light for another step-out field in its Hibernia oil project.

The Canada-Newfoundland and Labrador Offshore Petroleum Board approved development of the Hibernia AA field which holds an estimated 48 million barrels.

The plan involves the drilling of four new wells at a total cost of C$196 million, with oil expected to start flowing sometime next year.

Production from one block is expected to average 11,000 barrels per day and rise to 25,000 bpd when a second block is introduced. The production life is targeted at 2024.

Hibernia Management and Development Co. said there is an upside case pointing to as much as 70 million barrels in the field, which is consistent with previous low-ball Hibernia estimates.

Owners of the AA field are ExxonMobil Canada 33.13 percent, Chevron Canada 27.9 percent, Suncor Energy 20 percent, Canada Hibernia Holding (owned by the Canadian government) 8.5 percent, Murphy Oil 6.5 percent and Statoil Hydro Canada 5 percent.

—GARY PARK

GOVERNMENT

Parnell appoints members to state boards

Alaska Gov. Sean Parnell has made appointments to the Prince William Sound Oil Spill Recovery Institute Board and the Alaska Seismic Hazards Safety Commission, the governor's office said in a Sept. 4 press release.

The governor reappointed five members to the Prince William Sound Oil Spill Recovery Institute Board: Douglas Lentsch of Nikiski, general manager of Cook Inlet Spill & Prevention Inc. since 1995 and previously in the U.S. Coast Guard for 25 years; George Levasseur of Valdez, a commercial fisherman and charter boat captain, and retired state road and airport operations manager; William Lindow of Cordova, a commercial salmon gillnetter in the Copper River and Prince William Sound since 1978 and a halibut fisherman in the Gulf of Alaska since 1997; David Totemoff Sr. of Tatitlek, an Alaska Native of Aleut descent with 17 years of commercial fishing experience who has been employed with BP on the North Slope since 1976; and Glenn Ujioka of Cordova, a commercial salmon gillnetter in Copper River and Prince William Sound who has worked for an Alaska Native consortium that contracts with Alyeska's SERVS.

The institute was established by federal law in 1990 after the Exxon Valdez oil spill to identify and develop the best available techniques, equipment and materials to deal with cold-water marine oil spills, and to help federal and state officials document, access and understand the long-term effects of such spills.

Seismic Hazards Safety Commission

The governor appointed two new members to the Alaska Seismic Hazards Safety Commission: David Miller of Sitka, who has more than 20 years of experience as a public safety officer and is chief of the Sitka Fire Department; and Gayle White of Anchorage, who has worked for State Farm Insurance Co. since 1989 and is a chartered financial consultant and a chartered property and casualty insurance underwriter.

The governor also reappointed two members to the commission: John Aho of Anchorage, who has 35 years of experience in planning, designing and managing multidisciplinary facility building projects and recently retired as vice president and principal project manager for CH2M Hill; and Roger Hansen of Fairbanks, who has been state seismologist at the University of Alaska Fairbanks' Geophysical Institute since 1994.

The commission is responsible for advising the governor, the Legislature and private sectors on policies for seismic hazard mitigation and disaster preparedness, and on when to issue seismic hazard warnings.

—PETROLEUM NEWS

LAND & LEASING

Oct. 28 date for fall O&G lease sales

The Alaska Division of Oil and gas has set Oct. 28 as the date and the Dena'ina Civic and Convention Center as the location for its 2009 North Slope and North Slope Foothills areawide oil and gas lease sales.

Bid openings for the sales will begin at 9 a.m., the division said in a Sept. 8 notice of sale. Complete sale information is available on the division's Web site at www.dog.dnr.state.ak.us.

The 2009 Beaufort Sea areawide sale expected to be held with the other two sales has been postponed.

Division of Oil and Gas Director Kevin Banks told Petroleum News that a technical glitch caused the sale postponement.

The division is in the process of doing a new best interest finding for the Beaufort Sea sale area, required for areawide sales every 10 years, said Bruce Buzby, the division's leasing unit manager.

After comments were received on the preliminary best interest finding the division realized that while the request for comments was posted on the Department of Natural Resources Web page, mailed out and published, the requirement to run the request in a paper with statewide circulation had been missed.

The division has a lot of options for requesting comments, Buzby said, but is required to publish a notice in a paper with statewide distribution.

After the omission was discovered, the division ran a second request for public comments.

That request for comments closed Aug. 22 and Buzby said the division anticipates completing work on the second round of comments by the end of September.

But because of timing requirements — a final best interest finding must be published a minimum of 90 days prior to the sale — the Beaufort Sea sale couldn't be held at the same time as the North Slope and North Slope Foothills sales.

A Beaufort Sea sale could be scheduled early in the winter, rolled in with the May sales (Cook Inlet and Alaska Peninsula) or deferred until next fall.

—KRISTEN NELSON

continued from page 13

ANGDA

about the right things.

Since that meeting ANGDA had a visit from the TransCanada-ExxonMobil commercial team, based in Houston and Heinze said he's now "a big fan" of TransCanada and ExxonMobil.

The team came and had a conversation and it was exactly the conversation you want to have with a pipeline company six months out from open season, he said.

Heinze said ANGDA's goal is to participate in the open season as the smallest anchor tenant on the main line.

Davis said the TransCanada-ExxonMobil team got their pens out and started to take notes on the prospect of a spur line being pre-built from Cook Inlet to meet a main line and on the propane project.

A line pre-built from Cook Inlet, Davis said, would enable the main gas line to pretest compressor stations up line. And if the propane project is up and running, that could be a cost-reduction item for them, she said. ●

Petroleum news

Business Spotlight

Northwest Technical Services

FORREST CRANE

Bonnie Hayes, Personnel Specialist

Northwest Technical Services, a specialty recruiting firm, supplies temporary staff and project support to clients in aerospace and defense engineering, IT staffing and IT project support, working closely with companies in Alaska's petroleum industry. Northwest Technical Services meets a wide variety of professional and clerical staffing needs, and has a reputation with contract employees for providing a superior employment experience.

Bonnie Hayes has been working in the human resource profession for three years now, and finds it very rewarding. Prior to her current position, Hayes has been a corporate trainer, and also worked in the aviation industry. When she is not working on the challenges of personnel recruiting, she enjoys traveling, photography, reading and spending time with friends and family.

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

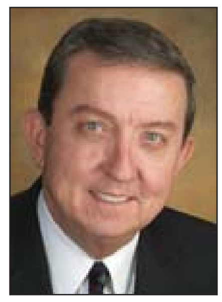
ADVERTISER — PAGE AD APPEARS

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

Petroleum news

Oil Patch Bits

CH2M Hill's Ralph R. Peterson passes away


RALPH PETERSON

CH2M Hill said Sept. 2 that its long-term former CEO and chairman, Ralph R. Peterson, passed away in his home after a long battle with cancer. Peterson joined CH2M Hill in 1965 as its 148th employee. From 1991 through 2008 he served as the firm's chief executive officer. "It is with great sadness, that I share the news that our dear friend Ralph Peterson has passed away," said CH2M Hill President and Chief Executive Officer Lee McIntire. "He was a great man and industry icon. His passion, dedication and leadership built CH2M Hill into the place that I am so proud of today. I will miss his passion and desire to help others succeed. Our thoughts are with his wife Betty, their family and many friends around the world."

AIC wins two Juneau area construction contracts

The company successfully bid for the principal civil and piping contract for the tailings facility at Coeur Alaska's Kensington Mine. Coeur awarded the contract on Aug. 21. AIC also won a $28.6 million contract to complete runway safety area improvements at Juneau International Airport on Aug. 10.

Alaska Interstate Construction LLC said Sept. 3 that it recently won two construction contracts in the Juneau area of Southeast Alaska. The company successfully bid for the principal civil and piping contract for the tailings facility at Coeur Alaska's Kensington Mine. Coeur awarded the contract on Aug. 21. AIC also won a $28.6 million contract to complete runway safety area improvements at Juneau International Airport on Aug. 10. The tailings facility at Lower Slate Lake is the only remaining construction left before the Kensington Mine can begin gold production. AIC's successful bid for the Juneau International Airport contract will extend the airport's runway at both ends, which requires extensive filling and dredging. AIC will also improve taxiways and lighting, realign an adjacent creek and trail, dredge the float plane pond and build float plane ramps. For more information visit www.aicllc.com.

Rain for Rent's Freeze Sentry heater product line

Rain for Rent said Sept. 2 that its latest innovation in liquid-handling solutions, the Freeze Sentry heater product line, prevents water and expensive liquids from freezing and maintains a constant temperature to protect equipment. The Freeze Sentry line is available in various configurations to cover pipe, manifolds, wellheads, pump volutes, barrels, boxes, frac tanks, upright tanks, water-truck valves and more, all while maintaining clear access to critical valves. For more information visit www.rainforrent.com.


COURTESY CROWLEY

Crowley's newest barge makes waves in Portland

Crowley Maritime Corp. said Sept. 1 that it has welcomed a new 400-foot by 105-foot heavy-lift deck barge to its fleet at the Gunderson Marine shipyard in Portland, Ore. The barge is the fourth heavy-lift deck barge christened by Crowley this year and the seventh in a series of heavy-lift deck barges slated to be built and put into service by 2013. Crowley's heavy-lift 455 series deck barges with 25-foot side shells provide both the capacity and deck strength needed to accommodate larger drilling and production units used for deepwater offshore energy exploration and development. For more information visit www.crowley.com.

Editor's note: All these news items — some in expanded form — will appear in the next Arctic Oil & Gas Directory, a full color magazine that serves as a marketing tool for Petroleum News' contracted advertisers. The next edition will be released in March.

continued from page 1

INSIDER

of the Year."

The story, which was very interesting, appears to be fact-based; its provocative headline likely the source of misunderstanding.

Still, a lot of journalists and Internet writers and bloggers didn't bother to verify whether there was a green company list with Exxon's name at the top.

And if they actually read Helman's article, they would know it was not about a list.

Forbes Editor William Baldwin's comments about the article (in a Forbes opinion piece that also did not mention a list) added fuel to the fire by calling Exxon chief Rex Tillerson a "hero," making for some very unhappy environmentalists.

You can read the article at www.forbes.com/forbes/2009/0824/energy-oil-exxonmobil-green-company-of-year.html. (It carries a link to Baldwin's comments.)

FYI—In a Sept. 10 phone conversation, Helman confirmed there was no list.

—KAY CASHMAN

Profit per barrel must top $340 before ACES takes 75%

A MID-AUGUST ARTICLE IN PETROLEUM NEWS contained a quote that said the State of Alaska's take under its new production tax could be as high as 80 percent of an oil company's net profits, depending on the price of oil at the time the tax was assessed.

The quote was from an oil company executive, but it was from the period of time just before Alaska's Clear and Equitable Share, commonly known as ACES, passed the Alaska Legislature in late 2007. The final tax bill was slightly different from the version the executive commented on, and although he is no longer working in Alaska, his firm's position on ACES remains negative.

Petroleum News had asked Cody Rice, a petroleum economist in the Alaska Department of Revenue's Tax Division, to comment on the quote but it was a last minute request, so his response didn't make it in time for the article.

Rice's e-mailed response, which arrived Aug. 27, after being cleared with his superiors for accuracy, said the "highest tax rate under ACES is 75 percent of net profits," but that rate can only be reached when the "net profit per barrel of oil is $342.50."

Tax rates under ACES depend on production rates, oil prices and the cost of production, Rice said.

"Depending on the level of expenditure necessary to develop a field, the company making the investment can see their total taxes either increase or decrease as a result of their investments," he said, using BP's offshore Liberty field, which sits in federal waters, as an example.

"A company developing a field on state land similar

see INSIDER *page 21*

continued from page 1

DEEPEST

cal challenges associated with this geologically deep emerging play.

In fact, majority owner and operator BP said the Tiber discovery well, at a total depth of 35,055 feet, including 4,132 feet of water, is the deepest well ever drilled on the face of the planet. Therefore, overcoming extreme pressures and temperatures at these depths alone promises to be difficult, even requiring new technologies, BP told Petroleum News.

BP holds a 62 percent stake in Tiber, followed by Brazil's Petrobras with 20 percent and U.S. major ConocoPhillips with 18 percent. The Tiber discovery well was drilled from Transocean's Deepwater Horizon, a dynamically positioned, ultra-deepwater semi-submersible rig under contract to BP.

Aside from future challenges, initial drilling results from Tiber, located on Keathley Canyon block 102 some 250 miles southeast of Houston, Texas, point to an immense reserve "in the same league" or "resource potential" as big U.S Gulf producers Thunder Horse, Atlantis and Mad Dog, BP spokesman Daren Beaudo said.

Did he say Thunder Horse? This Mississippi Canyon giant, with a facility capacity of 250,000 barrels of oil per day and 200 million cubic feet of natural gas per day, represents the largest discovery ever in the U.S. Gulf and stands second in productivity in the United States only to the BP-operated Prudhoe Bay field on Alaska's North Slope.

Kaskida estimated at 3 billion barrels of oil in place

Moreover, and perhaps more relevant, is BP's own comparison to other Lower Tertiary discoveries in the U.S. Gulf, including what is believed to be the largest — Kaskida. BP said Tiber's reserve potential could be as large as or larger than Kaskida's estimated 3 billion barrels of in-place oil.

"If you are talking about in the same league, that's kind of the neighborhood that it's in," Beaudo explained.

In 2006, positive results from the first Lower Tertiary production test, conducted on the Chevron-operated Jack prospect in Walker Ridge, elevated this emerging play to monumental importance in the U.S. Gulf. Also known as the deep Eocene or Wilcox trend, the Lower Tertiary play stretches several hundred miles from Walker Ridge westward through Keathley and Alaminos canyons, and is now believed to hold potentially billions of barrels of recoverable oil in untold dozens of individual prospects.

A glimpse at plans for Kaskida, BP's first Lower Tertiary discovery in the U.S. Gulf, sheds some light on what to expect at Tiber. Kaskida, discovered in 2006 with an astounding 800 net feet of hydrocarbon-bearing sands, is undergoing what BP calls a "measured appraisal," with one well currently drilling and another appraisal well scheduled for 2010. This would be followed by an "integrated completions" field trial, or field (production) test, in 2011.

"We need a step change basically in well production rates, and we need new completions technology to address higher temperatures, higher pressures," Beaudo said of Kaskida. "So we would be looking to advance the development of those technologies during that time."

Translated, BP evidently does not yet have all the technology needed to produce from the Lower Tertiary trend at Kaskida, located on Keathley Canyon block 292 at a vertical depth of around 32,500 feet, including 5,860 feet of water. Based on disclosed depths of the discovery wells, Tiber, after adjusting for water column depth, is nearly 4,300 feet deeper (below the ocean floor) than Kaskida, likely bringing to BP's design and engineering table a whole set of pressure and temperature problems unique to Tiber.

New technology for Thunder Horse

However, BP, the largest producer in the U.S. Gulf with more than 400,000 barrels of oil equivalent output per day, is no stranger to offshore challenges, including the development of Thunder Horse, which met with several delays and took nearly a decade to bring into production following its 1999 discovery.

"When we discovered Thunder Horse and acquired the leases … we didn't have the technology in place to deliver it," Beaudo noted. "We developed the technology that delivered it. It's the same thing with Kaskida."

Fortunately, Tiber partner Petrobras brings special Lower Tertiary expertise to the team as operator of the Cascade-Chinook development in Walker Ridge. This project, expected to come on-stream in the first quarter of 2010, will be the first in the U.S. Gulf to commercially produce from the Lower Tertiary, as well as the first to deploy a floating production, storage and offloading facility, in lieu of an export pipeline.

The next step for Tiber is to drill an appraisal well, although "we have not lined out the pace at which that happens, or how quickly we get on that," Beaudo said. "But it needs to be appraised. We've got the one well (and) it's very encouraging. We liken it to the resource potential of those big fields (in the U.S. Gulf). But we need to go through appraisal to determine its size and figure out what kind of development it will be." ●

continued from page 20

INSIDER

to Liberty would receive a minimum production tax deduction of 25 percent and a capital credit of 20 percent of all capital costs incurred to develop the field, regardless of whether production had yet begun from the Liberty-like field," Rice said.

The 45 percent credit, "an offset against tax liability," would "likely decrease a company's tax liability in the early years when investment is being made and production either has not begun or is just beginning from the new field," he said.

What's the least amount of its net profit on a barrel of oil that an oil company has to pay the State of Alaska under ACES?

"Ignoring the minimum tax for the purposes of this discussion, the lowest base tax rate under ACES is 25 percent of net profits, and this rate could be applicable when prices are $9 or $150, depending on the company's mix of oil and gas investments, and its cost to produce that oil or gas," Rice said.

—KAY CASHMAN

continued from page 15

BUOY

of icebergs. The buoy also measures the temperature at the sea surface. Ground stations pick up the buoy data via satellite.

The deployment of the buoy constitutes a contribution by the U.S. Interagency Arctic Buoy Program, a collaborative research program involving several U.S. government agencies and research programs, to the Arctic Observing Network and the International Arctic Buoy Program, the Coast Guard said.

"We are leaning forward to gain a thorough understanding of the cultural, environmental and operational challenges the Coast Guard faces in northern Alaska and the Arctic domain. As such, we need to project a persistent presence in these remote regions to expand our knowledge of the environment and protect U.S. sovereignty," said Capt. Robert Phillips, chief of the Incident Management Branch, 17th Coast Guard District. "In order to accomplish these goals we are partnering with the scientific community and other federal agencies, such as NOAA, to join us in collecting data for future operations and a successful road ahead in the Arctic."

—ALAN BAILEY

continued from page 1

BUYERS

Its effort to sell perhaps its most valuable producing asset — a minority stake in the Chevron-operated offshore Trading Bay unit and field — was unsuccessful and the company has abandoned the property.

Now Pacific Energy is concentrating on disposing of a grab bag of remaining properties.

The collection includes the Pacific Energy-operated West McArthur River field, the West Foreland field, and the Redoubt Shoal field with its Osprey offshore platform and Kustatan onshore facility. Also included are interests in the Three Mile Creek field, which Aurora Gas operates; some exploration properties; and a 50 percent stake in Cook Inlet Pipe Line Co.

Sale options

On Sept. 2, Pacific Energy filed a notice in the Delaware bankruptcy court identifying four potential buyers of the assets, one of them being the state.

The notice said the company had yet to select a buyer or work out a "definitive purchase and sale agreement" with anyone.

As of mid-day Sept. 10, no further notice had been filed in court saying any sale had been consummated.

Another court hearing was scheduled for 3 p.m. Eastern time Sept. 11 in Delaware.

The four potential buyers Pacific Energy listed include:

• New Alaska Energy, an Alaska limited liability company, offering $1.33 million plus assumption and payment of contract cure obligations and environmental liabilities.

• Cook Inlet Energy, another Alaska limited liability company, offering $500,000 plus assumption and payment of contract cure obligations and environmental liabilities.

• NTP Oil Corp., home base unknown, offering $500,000 plus assumption and payment of contract cure obligations.

• The State of Alaska, offering "nominal consideration" plus assumption and payment of contract cure obligations.

All four purchase offers excluded the Cook Inlet Pipe Line stock, according to the Pacific Energy court filing.

Lawyers for the state informed the court on Sept. 9 it would not be a buyer.

Pacific Energy, based in Long Beach, Calif., also filed papers seeking permission to abandon office leases in Anchorage and in Bakersfield, Calif., as company executives proceed with "winding down their business operations."

Pacific Energy's fall

Pacific Energy entered the Alaska scene in 2007, buying the assets of Forest Oil Corp. for $464 million.

The company filed for bankruptcy reorganization on March 9 citing the steep drop in oil prices toward the end of 2008. The Mount Redoubt volcano also hurt the company, with eruptions halting oil production earlier this year on the west side of Cook Inlet.

Faced with mounting losses on its Alaska holdings, Pacific Energy sought to sell its Alaska assets as well as its oil and gas properties in California. The California sale efforts are ongoing.

A big worry for the state is what happens to Cook Inlet wells, pipelines, shore-based production facilities and the Osprey platform should Pacific Energy simply abandon the properties. Lawyers for the state have cited the potential for pollution, saying it could cost the state tens of millions of dollars to safeguard or decommission the properties.

Pacific Energy has said it was carrying out a proper shut-in of the properties, and Banks told Petroleum News he believes most all the assets are now idle and not producing oil.

Even if abandoned, Banks said state officials believe many of the assets eventually will end up in state hands. For example, the state probably would inherit the Osprey platform because it represents an improvement to a state lease, he said.

Objections pending

Others are unhappy with the situation.

Chevron on Sept. 8 filed an objection saying Pacific Energy's proposed sale of the remaining assets "does not adequately protect" Chevron's rights.

Chevron wants assurance that any buyer has the financial strength, permits and insurance to properly abide by an existing facilities agreement to use of the Trading Bay air strip, barge landing, roadways and pipeline rights of way in support of the Pacific Energy properties.

Chevron also complains Pacific Energy hasn't provided a list of precisely which assets it aims to sell. The list is needed to make sure no Trading Bay assets are sold "inadvertently or otherwise," Chevron's lawyers argue.

Dan Donkel, who says he owns an overriding royalty interest in the Redoubt leases, also has filed an objection arguing, in part, that Pacific Energy didn't do an adequate job of marketing the properties. He wants assurance that his royalty interest is protected in the event of either a sale or abandonment.

In support of his objection, Donkel filed an affidavit from a former Alaska attorney general, Charlie Cole. The two-page affidavit says Cole is himself a long-time oil and gas investor, and that he believes the firm Pacific Energy hired to market its assets, Lazard Freres & Co., had made an "abysmal" effort, failing to "consult those individuals who routinely invest in the Alaskan oil and gas market." ●

continued from page 1

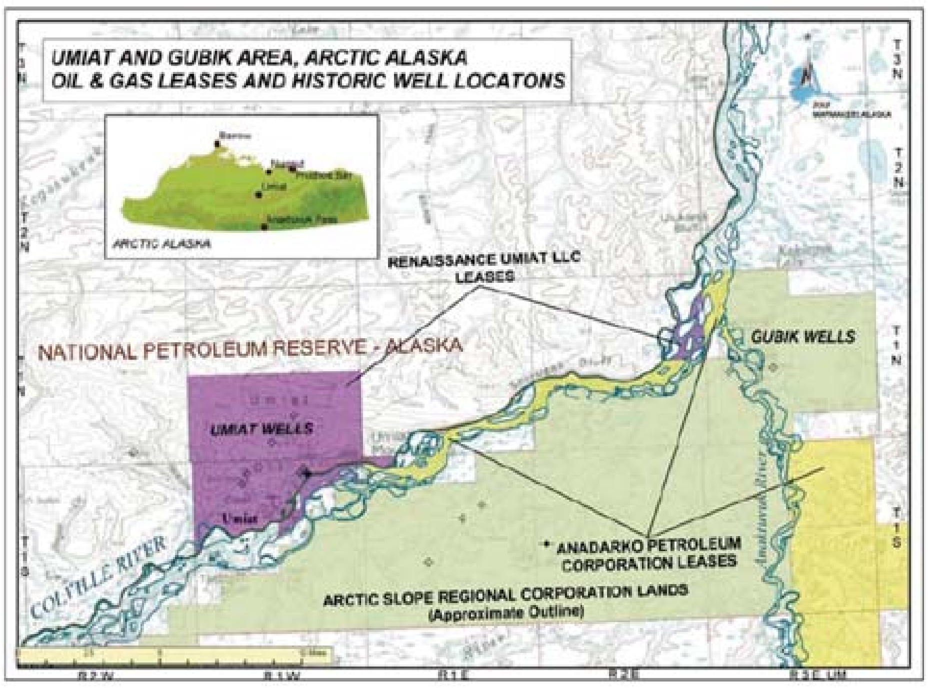
UMIAT

Umiat reservoir, told Petroleum News Sept. 4 that Renaissance has evaluated the field and is now waiting to see what happens to oil prices before deciding whether to proceed with development drilling. The company has recently renewed the core southerly BLM lease in the field, with the term of the lease now extending through to 2019.

"Umiat oil is light — about 37 API oil — and it's sweet, sweeter than anything else up on the Slope. We're excited in terms of the work we've done here in the past couple of years to de-risk the project," said Jim Watt, Renaissance president and CEO.

250 million barrels

Following a 2008 3-D seismic survey by PGS Onshore and a subsequent assessment of field reserves by Ryder Scott Co, Renaissance thinks that the main reservoir horizons in the field hold some 250 million barrels of economically recoverable oil, a figure substantially higher than an old U.S. Geological Survey assessment of 30 million to 100 million recoverable barrels. The USGS assessment assumed the use of vertical wells, rather than horizontal wells, and did not take into account modern secondary and enhanced oil recovery techniques, Watt said.



RENAISSANCE ALASKA LLC/MAPMAKERS ALASKA

Map showing Renaissance Alaska LLC's Umiat leases. Nearby natural gas exploration by Anadarko could lead to a cluster of developments in the Umiat area and an eventual development corridor into the National Petroleum Reserve-Alaska.

And independent evaluations of the field reservoir have given Renaissance confidence that modern drilling techniques, such as horizontal drilling, will result in viable oil-well flow rates.

"Given the reservoir characteristics, there's a high degree of confidence that these wells will perform," Watt said.

In fact, despite the very shallow nature of the Umiat field, with the deepest oil lying just 1,400 feet below the surface, the pay sands are well consolidated, rather than consisting of well-bore-plugging, loose sand, said Allen Huckabay, Renaissance executive vice president for exploration and development. Geologic studies have indicated that the sands were compacted when buried to depths of 6,000 to 7,000 feet, with subsequent uplift of the rock strata resulting in the current shallow depths, he said.

Several horizons

Huckabay explained that the Umiat field contains oil in several distinct rock horizons, all in the Nanushuk group, within the Brookian sequence, the youngest of the petroleum-bearing rock sequences in northern Alaska — the 7,500-acre Umiat oil field structure consists of a fold within the Brookian of the fold belt that lies along the northern side of the Brooks Range.

Two sandstone horizons, called the upper Grandstand and lower Grandstand, hold the oil reserves assessed for potential development, Huckabay said.

And comprehensive well core data from the wells drilled by the navy has indicated the presence of shales that seal the sand reservoirs, holding in the oil and potentially supporting the maintenance of the reservoir pressure that would be needed when producing the field.

Moreover, shallow sands associated with well-known surface oil seeps at Umiat and lying above the Grandstand horizons, could hold additional potential of 400 million barrels of oil in place. And, because the figure of 250 million barrels of recoverable reserves derives from an estimate of more than 700 million barrels of total oil in place in just the Grandstand horizons, there appears to be a large amount of oil in total at Umiat.

"All told it's over 1 billion barrels of oil in place," Huckabay said.

So, given the size of the field and the quality of the oil, why has no one considered developing Umiat until now?

The Umiat acreage was not offered for oil and gas leasing in the initial NPR-A lease sales held in the early 1980s and did not become available until a 1999 lease sale, said Mark Landt, Renaissance executive vice president of land and administration. But the drop of oil prices to around $10 per barrel in 1999 discouraged interest in Umiat at that time, he said.

New opportunity

Then, as oil prices started to climb a few years later, Renaissance saw Umiat as one of several Alaska opportunities.

"This one caught our eye when oil prices started to step up from the $30s into the $40s, and it's at that point in time that we started to pull together the funding to capture the leasehold," Watt said.

The company started buying into the Umiat leases in 2004, acquiring acreage from R3 Exploration and Arctic Falcon Exploration, the initial leaseholders. By 2007 Renaissance had pulled together an acreage position over the entire field.

see **UMIAT** *page 23*

continued from page 1

QUEBEC

confirmation of the significance of Questerre's discovery.

He said the calculations are supported by "significant and material data" and relate only to lands that "have geology validated by successful wells."

Binnion said the independent estimates are "materially higher than past industry figures, which we believe reflects the additional data, technical work and advancement on the learning curve."

Assessment being updated

Questerre said the assessment is being updated to include results from the recently completed St. Edouard No. 1 vertical well that tested in August at 2.6 million cubic feet per day with an average rate of 700,000 cubic feet per day on a one-inch choke.

The well has been shut-in to gather additional pressure data and a final report is due for release this fall.

Binnion said Questerre has now "confirmed effective

The Utica shale is present in Quebec, New York and Pennsylvania with thickness varying from 500 feet to 9,000 feet.

rock properties and encouraging stable gas rates" over a 60-mile area.

Questerre and operator Talisman are currently reviewing potential locations for horizontal wells adjacent to the vertical test wells.

The Utica shale is present in Quebec, New York and Pennsylvania with thickness varying from 500 feet to 9,000 feet.

Binnion had previously said that problems obtaining capital had slowed commercialization of Quebec's gas plays by 12 to 18 months; a pilot horizontal program is scheduled for 2010 and commercial development is targeted for 2011.

Infrastructure needed

A CanaccordAdams equity research report said the participation of Talisman and Forest improves the chances of Quebec's Utica shale becoming commercial "in the next few years," but doubts additional gathering, processing and transportation infrastructure will be in place until after 2012.

Preliminary results from the Netherland, Sewell study also estimate total prospective original gas in place volumes for Questerre's gross acreage at 82.7 tcf-180.5 tcf with a best estimate of 129.2 tcf.

Questerre is involved with Talisman in exploring 720,000 gross acres of the Utica shale. Subject to farm-in and participation arrangements, it could qualify for a 25 percent working interest.

Two other Quebec interests include a partnership with Forest Oil and Gastem on the 113,000-acre Yamaska block, where a gross overriding royalty is being converted to a 20 percent working interest, and a 56 percent working interest with Gastem on the 181,000-acre St. Jean block close to the United States border.

Questerre also has exploration interests in British Columbia's Greater Sierra and Horn River gas regions.

—GARY PARK

continued from page 22

UMIAT

In 2007 Texas-based Rutter and Wilbanks also became involved in the Renaissance Umiat venture, but pulled out of the project towards the end of that year.

And in February 2008 Renaissance deferred an initial plan to drill seven or eight appraisal wells in the Umiat structure, electing instead to "de-risk" field development with a 3-D seismic survey.

Now the company thinks that data from the 12 wells that the navy drilled years ago, together with the new seismic data, delineate the field sufficiently to enable a development decision that would lead the way straight into development drilling.

"At this point in time we're real comfortable with the data that we have," Watt said.

"Originally our plan was to drill these appraisal wells … and we now see these … wells would clearly be part of the ultimate development plan," said Huckabay.

Oil price the key

But confidence in oil prices remaining robust into the future will prove to be the key to Renaissance moving ahead at Umiat.

"Until that (confidence) comes, where you can start making large investments, I think everybody's probably going to step back and be a little more cautious in terms of how they proceed," Watt said.

Meantime, Renaissance has started to prepare a business plan for an Umiat development, having commissioned NANA WorleyParsons to estimate the costs of developing field facilities and well pads, and Arctic Slope Regional Corp. subsidiary, Houston Pipeline, to develop estimates for building an oil export pipeline from Umiat to pump station 2 of the trans-Alaska pipeline.

A team in the University of Alaska Fairbanks, funded by a U.S. Department of Energy grant, is further working with Renaissance on the geology, geophysics and reservoir engineering of the Umiat field.

Renaissance is also studying the challenges of producing cold oil — because of the shallow nature of the Umiat reservoir, the oil will be produced at temperatures in the range 28 to 32 F, temperatures that are much lower than those of a more conventional field in northern Alaska. And Renaissance is assessing pumping the oil, cold, down the export pipeline, rather than heating the oil up, Watt said.

"That's an area of study for us that we're going to be looking at here over the next few months," Watt said.

Multiple developments

A key issue that would impact the economics of an Umiat development is the question of what other companies are doing in the Umiat region. For example, Anadarko Petroleum is exploring for natural gas at a number of nearby locations, including the neighboring Gubik gas field — the use of a single pipeline right of way for more than one project, together with the sharing of activities such as conducting baseline environmental studies during project permitting, could significantly reduce project costs, Landt said.

Renaissance also hopes that the state will move ahead with its concept of building a gravel road from the Dalton Highway to Umiat, a road project that the company believes would have a major impact on the economics of the Umiat development by providing year-round surface access to the field location. And, by co-locating the road with an Umiat pipeline corridor, the road would speed up pipeline development. Renaissance thinks that the existence of a road would reduce the pipeline construction time from two years to one year, thus bringing oil to market earlier than would otherwise have been possible, Landt said.

Moreover, by reducing the need for ice-road construction by multiple companies for winter exploration and development, a state road would significantly reduce the state's tax credit liabilities, Landt said.

And a road and pipeline corridor to Umiat, supporting multiple developments in that area, could form the start of a bridgehead into eastern NPR-A, opening the way to future access to oil and gas resources in the reserve, in a somewhat analogous manner to ConocoPhillips' expansion of the oil and gas infrastructure to the west of the Colville River delta, into northeastern NPR-A, Landt said.

"The state could take a lead here in terms of access. That way there could be a corridor for development," he said. ●