Petroleum news

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page 3 Thomas wants targeted North Slope incentives, in-state line and hydro

October Mining News inside

The October issue of North of 60 Mining News is enclosed.

Repsol applies for 98,852-acre Qugruk unit; 4 wells this winter

Repsol E&P USA Inc. has applied to the Alaska Department of Natural Resources for formation of the 98,852-acre Qugruk on the North Slope.

Repsol, 70 & 148 LLC and GMT Exploration Co. LLC jointly proposed formation of the unit. The three together hold 91.5 percent of the working interest within the proposed unit area.

Other leaseholders in the proposed unit are: Pioneer Natural Resources Alaska Inc., Anadarko Petroleum Co., ConocoPhillips Alaska Inc., Paul L. Craig and Peter G. Zamarello. The unit agreement has been executed by Repsol, 70 & 148 and GMT. Repsol said it has offered the other lease-

see **UNIT APPLICATION** *page 18*

Environmental, Native groups appeal Discoverer air permits

It came as no surprise, but on Oct. 24 two petitions challenging Shell's air quality permits for the use of the Noble Discoverer drillship in the Arctic outer continental shelf landed in the inbox of the Environmental Appeals Board, the panel of judges with final authority over Environmental Protection Agency decisions. One petition came from the Native Village of Point Hope and a group of 10 environmental organizations; the other from the Inupiat Community of the Arctic Slope and the Alaska Eskimo Whaling Commission.

EPA had issued the Shell permits on Sept. 25 — the permits cover Shell's use of the Noble Discoverer for drilling the Chukchi and Beaufort Seas, starting in the summer open water season of 2012. The permits came in the wake of a previous appeal to the EAB over earlier permits, with EPA having taken

see **PERMIT APPEAL** *page 19*

NATURAL GAS

Through to 2015?

New Cook Inlet gas producers help stretch supplies for another few years

By ALAN BAILEY
Petroleum News

With temperatures in Southcentral Alaska dropping as winter approaches, local gas and power utilities are gearing up for another nail biting few months, trying to ensure that severe cold or an equipment malfunction will not trigger power outages as utility gas supplies from the Cook Inlet basin tighten. And on Oct. 21 four utilities — Enstar Natural Gas Co., Chugach Electric Association, Municipal Light & Power and Matanuska Electric Association — provided the Anchorage Mayor's Energy Task Force with overview of the current gas supply status.

In summary, the utilities said that the storage of summer produced gas for use in the winter has become a critical factor in the battle to ensure the availability of sufficient gas to meet peak winter demand; new Cook Inlet gas producers are starting to have an impact in the gas supply situation; and utilities will probably have enough gas to meet total annual demand until 2015, from which point the import of liquefied natural gas may be necessary to bolster local gas supplies.

> *Without new discoveries leading to 50 million to 80 million cubic feet per day of production "we're nowhere out of this box."*
> **—James Posey, ML&P general manager**

see **GAS SUPPLIES** *page 20*

EXPLORATION & PRODUCTION

One more step for Shell

EPA issues Shell's air permit for the Kulluk to drill in Beaufort Sea in 2012

By ALAN BAILEY
Petroleum News

The U.S. Environmental Protection Agency has issued a final air permit for Shell's planned use of its Kulluk floating drilling platform for exploration drilling in the Beaufort Sea starting in July 2012. The permit comes about a month after the issue of similar permits for the use of the drillship Noble Discoverer in both the Chukchi and Beaufort Seas.

"EPA's final permit significantly reduces the potential air pollution from Shell's drilling operations and protects the National Ambient Air

see **AIR PERMIT** *page 19*

SHELL EXPLORATION AND PRODUCTION

Shell's floating drilling platform, the Kulluk.

NATURAL GAS

Shell steps up LNG plans

Addition of Kitimat marine terminal adds weight to company's feasibility study

By GARY PARK
For Petroleum News

Shell Canada, backed by three of Asia's largest energy companies, is sending out clear signals that it is serious about joining the lineup to export LNG from North America.

The company is paying an undisclosed amount to Cenovus Energy for a marine terminal in Douglas Channel near the deepwater port at Kitimat for possible use in liquefying natural gas from British Columbia and Alberta.

Shell Canada confirmed it is now in the "early stages" of exploring the potential for an LNG export terminal at the site, with Korea Gas Corp., Mitsubishi and China National Petroleum Corp. as partners, one of a flurry of recent LNG developments.

Industry speculation has the partnership turning 1.8 to 2 billion cubic feet per day into LNG, exceeding the 1.4 bcf per day that the Apache-operated Kitimat LNG project is authorized to export.

> *Industry speculation has the partnership turning 1.8 to 2 billion cubic feet per day into LNG, exceeding the 1.4 bcf per day that the Apache-operated Kitimat LNG project is authorized to export.*

see **LNG PLANS** *page 18*

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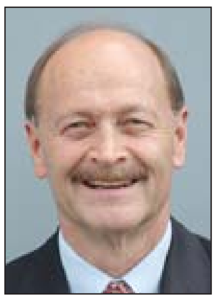
GOVERNMENT

Joe Thomas takes the long view

Fairbanks Senator wants targeted North Slope incentives, calls for aggressive approach on in-state gas line and Susitna River hydro

By STEFAN MILKOWSKI
For Petroleum News


JOE THOMAS

Sen. Joe Thomas of Fairbanks joined the Alaska Senate in 2009, landing a spot on the Finance Committee as a freshman legislator. He continues to hold that seat while also serving as co-chair of the Senate Education Committee.

Thomas, a Democrat and retired union leader and laborer, has made energy policy a focus. An early proponent of a Susitna River hydroelectric project, he helped win legislative support for dusting off old studies and moving the project forward.

This summer, Thomas was one of a dozen lawmakers traveling to Norway for a weeklong policy tour. At home in Fairbanks, he's been preparing for another legislative session likely to be dominated by oil and gas issues. Thomas is no fan of Gov. Sean Parnell's oil tax proposal, but says he is open to new incentives that reflect the changing nature of the North Slope development.

Petroleum News spoke with Thomas on Oct. 24.

Q AND A

Petroleum News: I gather you've been studying oil and gas markets around the world. What are you learning?

Thomas: I like to take a look at them. I don't claim to be an expert on any of it. What concerns me is the changing nature of things, particularly the price of oil from the North Slope and its relationship to WTI changing somewhat dramatically around the beginning of the year. We've been about $20 over them, and we used to be fairly equal or a little below. And I really don't quite understand what's caused that change.

Petroleum News: That means Alaska ends up with more tax revenue, but it's harder for producers to sell their oil?

Thomas: Well, I think they kind of control the market on the West Coast. It does mean more revenue for the state, but it might also be considered an artificial price. If we were down where we were before, we would be almost in that range where most people agree progressivity and the oil tax is not that big a problem. We'd be in the $80-$85 barrel range, where the progressivity is a little lower.

We need to be looking at the situation and be cognizant of where we're headed and that everybody would like to make a little more money when the prices are high.

Petroleum News: Is there anything the state can do?

Thomas: I think people are focusing on the problem. I'm happy to see that BP, ConocoPhillips, and Exxon are all becoming a little more available for comment on what would take place. The real critical thing to me is what would happen with a lowering of the tax. What projects are there — since we have so much discussion about throughput — that were on the books that may not be on the books now? What projects would they be following through with that would actually increase throughput?

Petroleum News: You're getting a better sense of that now from companies?

Thomas: Actually, at the Alliance meeting in Fairbanks about a month ago, (BP's) Claire Fitzpatrick actually mentioned some projects that were potentials, and I think that's productive to the conversation. The idea that you just lower the tax and hope for the best is not a sound business decision.

Petroleum News: What are your thoughts on the governor's tax proposal?

Thomas: I'm not a real big proponent. I think we need to focus more on what the industry actually plans to do. Most people agree the credits are pretty good for exploration, but they may not necessarily be for things like heavy oil — and that's 16 billion barrels of oil.

There's another 7 billion barrels of light oil, and the extraction of that heavy oil is

see THOMAS Q&A page 17

NATURAL GAS

Parnell wants gas to Pacific Rim as LNG

Alaska Gov. Sean Parnell told the Alaska Oil and Gas Association annual luncheon Oct. 27 that there needs to be greater alignment among shippers of gas and said that alignment should be for a line going to tidewater, with natural gas going to the Pacific Rim as liquefied natural gas.


JUDY PATRICK

GOV. SEAN PARNELL

Negotiations with shippers by TransCanada and ExxonMobil under the Alaska Gasline Inducement Act don't appear to be moving forward, Parnell said: There is no commercial alignment.

Negotiations with shippers by TransCanada and ExxonMobil under the Alaska Gasline Inducement Act don't appear to be moving forward, Parnell said: There is no commercial alignment.

The problem may be that the market for natural gas has shifted since AGIA was passed, due to the glut of natural gas in the Lower 48, "the devastating tsunami in Japan and that nation's subsequent shift away from nuclear power, and other market forces in the Pacific Rim."

"It all means that a better market for Alaska gas could very well be in Pacific Rim countries," he said.

And AGIA allows for reassessment of market conditions, he said.

Recent conversations

Parnell said that recently he has talked with TransCanada, ExxonMobil, BP, ConocoPhillips and the Alaska Gasline Development Corp.

He said he told them there appears to be an impasse on a line to the Lower 48 and "I asked them to move forward on a large-diameter LNG pipeline to tidewater in Alaska."

If market demand has shifted to the Pacific Rim, Alaska needs to shift, too, he said.

And, he said, a greater alignment leads to fiscal terms, a reference to statements he had made in the past that he won't negotiate separately with the players, but only with a project.

He said it's time to unleash Alaska's resources with meaningful tax changes, resolution of the Point Thomson issues and a new direction for the gas pipeline.

—KRISTEN NELSON

CORRECTIONS

Oooguruk water supply corrections

A pair of articles in the Aug. 14 and Sept. 18 issues of Petroleum News — "Pioneer production falls year over year" and "AOGCC investigating shortage of injection water at Oooguruk field" — misattributed a quote about the causes of reduced oil production at the Oooguruk unit to Pioneer Natural Resources Inc. CEO Scott Sheffield. The quote should have been attributed to COO Tim Dove. The articles also noted that Pioneer lost between 2,500 and 3,000 barrels of oil per day of production this year because of "third-party water injection supply shortages," but company executives recently told the Alaska Oil and Gas Conservation Commission that the figure is closer to 1,000 bpd. The 2,500 to 3,000 bpd figure, taken from a second quarter presentation available on Pioneer's website, referred to reductions from several Pioneer assets, not just Alaska.

Petroleum News regrets the errors.

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● PIPELINES & DOWNSTREAM

Northern Gateway facing a filibuster

Testimony at regulatory hearings on pipeline could last 650 hours, with more than 4,000 groups, individuals registered to speak

By GARY PARK
For Petroleum News

The battle lines are taking shape in the regulatory showdown over Enbridge's Northern Gateway pipeline, the essential link between the Alberta oil sands and markets in Asia and the U.S. Pacific Coast.

What they represent at this stage is an unprecedented public hearing, starting in January, before a Joint Review Panel of the National Energy Board and the Canadian Environmental Assessment Agency.

If each of the more than 4,000 registrants — individuals and groups — takes their allocated 10 minutes to speak, that phase of the hearings would take at least 650 hours.

That mirrors the level and extent of the opposition to the C$5.5 billion project to export 525,000 barrels per day of oil sands crude and import 193,000 bpd of condensate on a parallel pipeline to dilute the raw bitumen and allow it to flow through the pipeline.

Enbridge has little doubt that the hearing process is being orchestrated by environmental watchdogs who are trying to overwhelm the procedure.

Company spokesman Paul Stanway said the intent has already been divulged by Victoria-based Dogwood Initiative's registration drive, under the label "Mob the Mic!"

"That tells you pretty much all you need to know," he said.

But Dogwood spokesman Eric Swanson said his group simply wants the voices of British Columbia residents — 75 percent of whom are opposed to the project, according to four polls commissioned by Dogwood since 2005 — to be heard.

He said a single spill from a tanker could wipe out a coastal economy.

Jolan Bailey, speaking for the environmental group ForestEthics, said it is clear the project has "struck a public nerve. This is really a wall of public opposition."

Stanway said Enbridge welcomes public input, but is increasingly concerned that a startup date for Northern Gateway, which is already eight to 12 months behind schedule, could be pushed beyond 2017.

Concern over international groups

In addition, Enbridge is troubled that local people ate being manipulated by international groups that hope to turn Northern Gateway into an anti-oil sands battleground similar to TransCanada's Keystone XL pipeline.

Stanway said there is no question that well-financed groups are focused on both projects. "What would be a concern is if this is a strategy being employed by political activists to try and undermine the regulatory process," he said.

Concern has been raised that U.S.-based charitable foundations are making large financial contributions to so-called grassroots protests taking place in Western Canada.

A Vancouver researcher Vivian Kruse told Vancouver Sun columnist Barbara Yaffe she has determined over the past five years that "millions of dollars in foreign funding have given the Canadian environmental movement a level of influence that it would not otherwise have had."

Kruse said funds from U.S. charitable foundations, in the name of protecting the environment, could be intended to protect U.S. market and trade interests.

She said an assortment of foundations working against Northern Gateway could be setting up an "ingenious trade barrier to block exports of Canadian oil to Asia."

Enbridge Chief Executive Officer Pat Daniel, while confident the pipeline will be approved, said that "doesn't mean to say it's going to be easy."

But he argued the two main criteria facing the Joint Review Panel are: Is the project in the national best interest ("not too many will argue against that") and can it be built in an environmentally sound and effective way ("if Canadians can't do it, who can?")?

Daniel said that if U.S. opponents can "bring their big foundations up to Canada and fund First Nations opposition" they may find out that "most people think it's more important to have security of supply and alternative markets." ●

Contact Gary Park through publisher@petroleumnews.com

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● NATURAL GAS

Is LNG the answer for Alaska gas?

Senate Resources Committee hears proposal to truck Cook Inlet LNG throughout Alaska as a way to expand the local natural gas market

By ERIC LIDJI
For Petroleum News

An independent Cook Inlet explorer and an Outside liquefied natural gas industry executive are hoping to use LNG to expand the natural gas market in Alaska.

LNG Alaska, a partnership between Buccaneer Alaska LLC and LNG Central, believes it can increase the market reach of Alaska natural gas by connecting Fairbanks utilities and the Alaska Marine Highway System to the existing LNG facility in Nikiski (and also by potentially restarting exports from that soon-to-be-mothballed facility in the future).

"It's going to take several groups coming together to say: We want to do this plan," Keith Meyer, CEO of LNG Central, told members of the Senate Resources Committee at an interim hearing in Kenai on Oct. 21. "If we come together. It's actual very competitive."

Although he didn't offer any details about LNG Central, Meyer said he has 30 years of experience in the energy industry, including a stint as president of Cheniere LNG Inc., chairman at the floating liquefaction company Flex LNG and time at other companies.

Buccaneer expects to become the newest Cook Inlet producer this year, but the local subsidiary of Australian independent Buccaneer Energy Ltd is concerned its long-term plans for the basin could be stymied by limitations in the local market. When news broke that ConocoPhillips and Marathon planned to shut down the Kenai LNG plant it "sent a cold chill through our corporate offices," COO Jim Watt recently told lawmakers. (See sidebar this page.)

While the Southcentral supply crisis of recent years isn't resolved, the basin is busier than it's been in many years and regional utilities have all or most of the natural gas supplies they need for the near term. That is leading potential producers to worry that after all the commotion about flagging production the market won't be able to handle additional supplies.

The Cook Inlet has a "bad reputation," Meyer said, and policymakers are using the declines in the basin to justify energy projects ranging from an in-state natural gas pipeline to a major hydroelectric project on the Susitna River. "If people think there's no gas in Cook Inlet, then demand is not going to be there. If demand is not there, producers are not going to want to be there," he said, adding, "Virtually every producer in the inlet that I've talked to is willing to be supportive of a market growth initiative."

Fairbanks and Southeast

To convert a generic demand for energy into a specific demand for natural gas, LNG Alaska wants to convert the Alaska Marine Highway System to run on gas, ship volumes to the Interior power utility Golden Valley Electric Association and the Flint Hills Resources refinery, and restart regular exports of LNG to markets outside of the state.

With those volumes, Meyer said, Alaska could produce LNG for around $10 per million Btu before transportation. Without exports, though, the cost jumps to just more than $12 per million Btu and without GVEA and Flint Hills it jumps to around $18 per million Btu.

"The more volume we can get, the cheaper it is for all," he said, noting that rural villages could also be connected to the system through regional re-vaporization hubs.

The Alaska Marine Highway System is the best place to begin, Meyer said, because as ships in the aging fleet retire, they could be replaced with dual-fuel ships that run on natural gas, as well as diesel. "The Alaska Marine Highway System would be an ideal demand because of its large load and scheduled route. With the Alaska Marine Highway, we know where the ships are going to be and when they are going to be there," he said.

The pipeline problem

As with any large-scale energy plan, though, obstacles abound.

If an in-state natural gas pipeline option is available before an in-state LNG project comes online, the pipeline could probably provide lower cost fuel, Meyer acknowledged, but an LNG project could act as a "rubber pipeline," or a road and rail option used to justify infrastructure build outs in communities that would support a pipeline in the future. "I believe long term you're going to have a pipeline solution here," Meyer said. "I don't think it's going to happen in the next 10 years, and it's not forecasted to."

The LNG Alaska proposal would be cheaper and more reliable than a GVEA and Flint Hills project to truck LNG from the North Slope, Meyer said, because LNG coming from south to north can take advantage of numerous transportation options, both road and rail.

The LNG Alaska proposal is completely conceptual at the moment.

While Meyer said he brought the idea to ConocoPhillips, now the sole owner of the Kenai LNG facility, he said the meeting was "not a formal discussion." He called the plant "an ideal facility," but said it isn't crucial to the success of the plan. He hasn't presented the idea to GVEA, Flint Hills Resources or the Alaska Marine Highway System. ●

Contact Eric Lidji at ericlidji@mac.com

Buccaneer plans to be busy in 2012

Buccaneer Alaska LLC plans to be busy over the coming year.

The local subsidiary of Australian independent Buccaneer Energy Ltd. expects to become a producer at its Kenai Loop prospect this December, drill wells at its two offshore prospects next summer, and possibly drill wells at two other onshore prospects in 2012 or 2013, President and COO Jim Watt told the Senate Resources Committee on Oct. 21.

"We feel like the basin is underexplored and very attractive," he said, pointing to recent studies showing the undiscovered potential of the region, and to the exploration tax credits in the Alaska's Clear and Equitable Share, or ACES, fiscal system.

Buccaneer is not a "Big E" company, Watt said, meaning it doesn't take on major exploration projects. "Companies like Apache can take the risk of shooting such large surveys," he said. "We're more interested in well control, existing seismic and combined phases or stacked opportunities, and that's what we're pursing here in the Cook Inlet."

The company managed to find five prospects in Alaska that fit those requirements: the onshore Kenai Loop field north of the city of Kenai, the onshore West Eagle prospect on the southern Kenai Peninsula north of the city of Homer and the onshore West Nicolai prospect on the west side of Cook Inlet near Nicolai Creek, as well as the offshore Southern Cross unit and the offshore Northwest Cook Inlet unit in the upper Cook Inlet.

Under its current development plan, Buccaneer expects to bring Kenai Loop online late this year or early next year, begin production from West Eagle and West Nicolai in late 2013 and begin production from Southern Cross and Northwest Cook Inlet in late 2014.

Three onshore prospects

When it comes to onshore exploration, Buccaneer is looking for natural gas.

Buccaneer is currently building a pipeline at the roughly 9,000-acre Kenai Loop field in preparation to bring the field online in December. Through a contract with Enstar Natural Gas Co., Buccaneer will begin delivering 5 million cubic feet per day starting in April and is contracted to deliver as much as 15 million cubic feet per day depending on drilling results.

At 49,808 acres, the West Eagle prospect is the largest in the Buccaneer Alaska portfolio.

see **BUCCANEER** *page 6*

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● GOVERNMENT

Van Meurs critical of ACES, HB 110

Global oil expert outlines flaws in current production tax, says governor's bill won't fix problems; finds ANS gas noncompetitive

By STEFAN MILKOWSKI
For Petroleum News

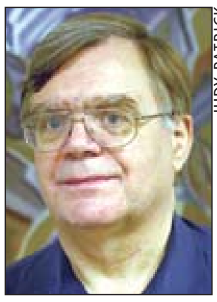
When state lawmakers resume discussions of oil and gas policy this winter, they'll have one tool they didn't have last year — a suite of reports by global oil expert Pedro van Meurs.

Van Meurs, who advised former Gov. Frank Murkowski, is compiling six hefty reports on oil and gas jurisdictions around the world with help from PFC Energy and Rodgers Oil & Gas Consulting. Alaska is discussed in the third report, which covers oil and gas jurisdictions in the Arctic. The sixth report, a summary report, is due out early next year.

The Legislative Budget and Audit Committee purchased the reports, along with a database compiled by the energy research firm Wood Mackenzie, in late 2010. The Van Meurs Corp. has granted limited-time access to its reports to news organizations, including Petroleum News.

Van Meurs finds ACES, HB 110 flawed

Van Meurs is critical both of the current tax, dubbed Alaska's Clear and Equitable Share, and of Gov. Sean Parnell's proposal to fix it.


JUDY PATRICK
PEDRO VAN MEURS

Van Meurs describes Alaska as one of a few Arctic jurisdictions that combine high taxes with generous incentives. (Other jurisdictions tax at a lower rate, but offer less support up front.) Among the 37 Arctic oil tax regimes van Meurs considers, Alaska is grouped in the middle, given three stars out of five in terms of attractiveness from an investor standpoint.

But van Meurs contends that Alaska's system is too extreme. The highly progressive tax limits companies' returns at high oil prices and, combined with high tax credits, can result in state support for developments nearing or even exceeding 100 percent, giving companies little incentive to reduce costs.

Despite the generous credits, van Meurs argues that Alaska doesn't do enough to incentivize the two commodities that could boost state revenues and ensure a long-term future for the North Slope: heavy oil and natural gas.

He adds that setting the progressivity surcharge based on the combined price of oil and gas (on a barrel-of-oil equivalent basis) will likely result in paltry or even negative incremental revenue for the state when North Slope gas is developed. Van Meurs advocates separating the tax on gas from that on oil — "decoupling" — but adds that the tax rate for gas would then have to be reduced.

Van Meurs writes that Gov. Sean Parnell's HB 110, a modified version of which passed the House last session, and HB 17 by Rep. Mike Hawker, would indeed increase returns for producers, but would not address the flaws in the current tax.

The governor's proposal to offer a lower rate for new fields could actually be counterproductive because it would force those developments to be taxed separately — to be "ringfenced" — while other developments can be written off existing production elsewhere in the state.

DOR defends plans

Deputy Commissioner of Revenue Bruce Tangeman agreed with much of van Meurs' analysis in an interview Oct. 26. He agreed that additional incentives might be needed for natural gas and heavy oil, and that taxes on gas and oil should probably be separated. "I think he makes a convincing argument," Tangeman said of decoupling.

But Tangeman also defended the governor's legislation. He said HB 110 was meant as an immediate fix for an immediate problem, and he disagreed with van Meurs' claim that Alaska's credits are excessive, saying tax credits have successfully generated interest in Alaska.

"We're reevaluating everything, taking the van Meurs report into account, plus Wood Mackenzie and anybody else," Tangeman said. "But I think the goal of HB 110 is still sound."

Tangeman, Chief Economist Cherie Nienhuis, and three other DOR officials attended a five-day workshop put on by van Meurs earlier in October in Houston. Tangeman said the state has more information than ever before and has done additional economic modeling.

Lawmakers offer mixed response

Rep. Mike Hawker, chair of the Legislative Budget and Audit Committee, also agreed with van Meurs' big-picture analysis and criticism of HB 110 and HB 17. "My bill was never intended to be a global fix," Hawker said.

Hawker agreed that lawmakers should address gas taxes now, but he said they state should wait on heavy oil to get a better sense of what incentives are needed.

Sen. Bill Wielechowski, a critic of tax changes, argued Alaska's tax credits have worked "exactly as planned," and questioned van Meurs' call for heavy oil incentives. He said ACES, as a profits-based tax, was designed to support projects with wide-ranging economic profiles — lower per-barrel profits result in a lower tax rate. "His position on heavy oil is pretty baffling to me," Wielechowski said.

Senate Finance Co-chair Bert Stedman agreed with van Meurs that the state should reconsider its credits. He said he personally supports tax changes, but that some of his colleagues don't. "You can't get the votes until you do the analysis and understand what you're doing," he said.

Van Meurs brainstorms gas project

Van Meurs' Arctic report contains an analysis of natural gas projects on the North Slope and on the Yamal Peninsula in Russia, which van Meurs presents as Alaska's competitor for the East Asian gas market.

The Alaska project is so handicapped compared to Yamal that Alaska would have to offer a long-term tax holiday or completely waive royalties to make it competitive, he writes. Alternatively, developers could use ice-breaking liquefied natural gas tankers to move gas off the slope, van Meurs proposes, acknowledging that he knows little about the technology.

Lawmakers seemed receptive to the idea. "With what's happening on the North Slope, (in the) Beaufort and Chukchi, I don't think it's an unreasonable suggestion," said Wielechowski. ●

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continued from page 5

BUCCANEER

Although West Eagle was still fairly remote when Buccaneer acquired the acreage in early 2010, the prospect is now only six miles from the regional distribution grid thanks to the work Armstrong Cook Inlet did to bring its North Fork unit online this year.

Buccaneer is reprocessing 2-D seismic over the region, and plans to apply to form a unit at West Eagle in April that will include a commitment to drill by September, Watt said.

The region is thought to be prospective for both natural gas and oil.

Finally, Buccaneer plans to drill at the 4,952-acre West Nicolai prospect once it acquires seismic over the region. Watt noted that Apache is shooting seismic over West Nicolai, and added, somewhat jokingly, "I'm sure they'll be very open to a reasonable deal."

Buccaneer expects to drill at West Nicolai in 2013, but could drill as quickly as next year, Watt said. The prospect is only three miles southwest of Aurora Gas' Nicolai Creek unit.

Jack-up getting closer to Alaska

The big activity for Buccaneer in 2012 will likely be offshore, though.

Buccaneer currently has a contract to buy a jack-up rig — previously known as the Transocean Adriatic XI but now called Endeavour-The Spirit of Independence — and recently hired Archer Drilling LLC to mobilize the rig, operate it for Buccaneer next summer and market it to other operators in the Cook Inlet as well as the Chukchi Sea.

Buccaneer hopes to have that rig in an Asian shipyard for modifications for sub-Arctic and Arctic Alaska by November in order to begin drilling in Cook Inlet next summer.

The company plans to drill first at Southern Cross and then at Northwest Cook Inlet.

Although both units are believed to contain oil and gas, Southern Cross is believed to be oil prone and Northwest Cook Inlet is also thought to contain deep oil deposits.

—ERIC LIDJI

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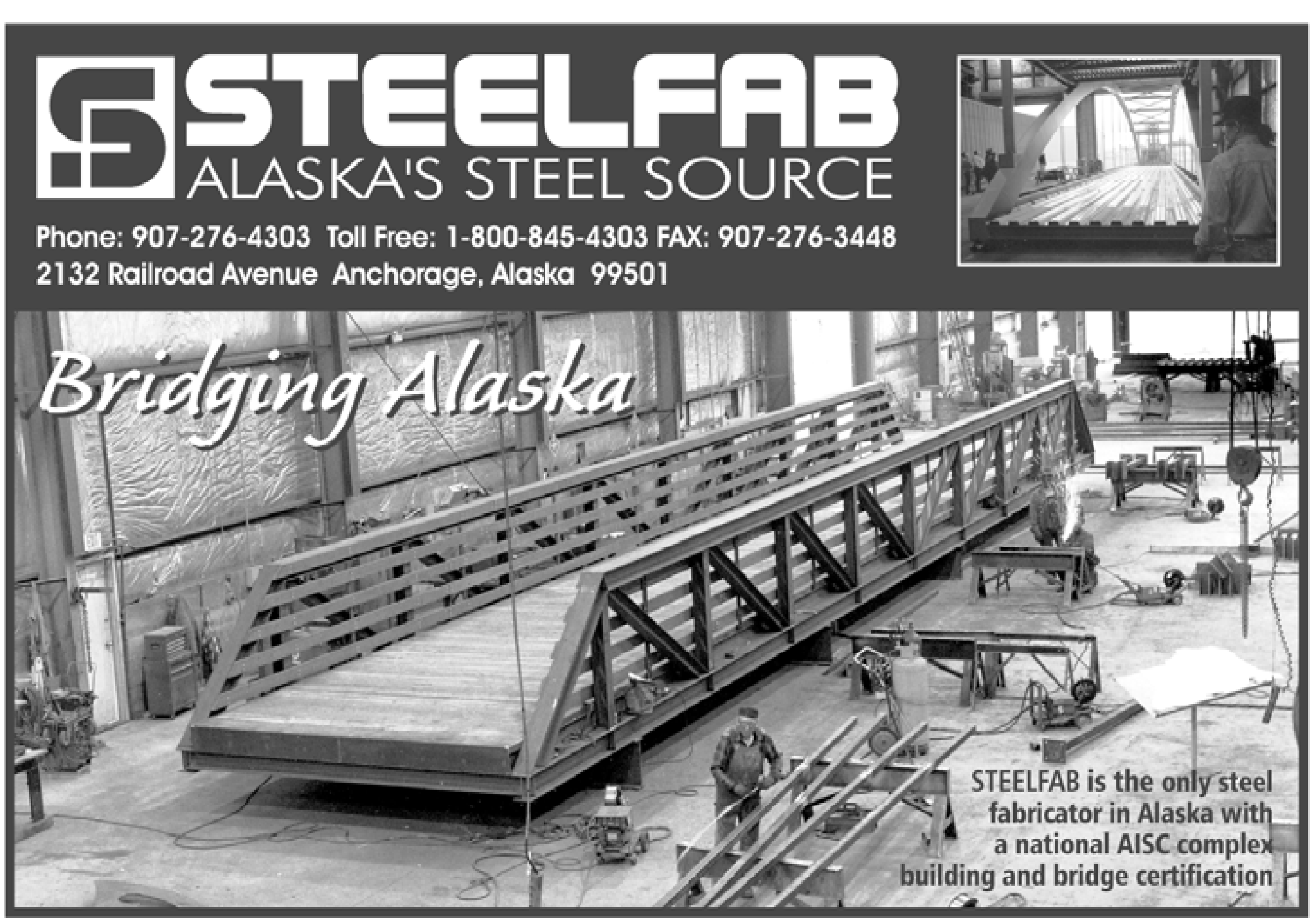

● EXPLORATION & PRODUCTION

Escopeta lays out development options

Company prefers outrigger caisson or three-deck platform for Kitchen Lights unit depending on whether it discovers oil, gas or both

By ERIC LIDJI
For Petroleum News

Escopeta needs to find about 150 billion cubic feet of natural gas and/or 50 million to 100 million barrels of oil to justify its development, Katic said. The company is considering four development options and already favors two potential schemes.

Escopeta Oil Co. believes it could produce natural gas from its offshore Kitchen Lights unit as soon as 18 months after making a discovery, if the company faces no interference.

"This is just full steam ahead," Vladimir Katic, the Alaska project manager for the Houston-based independent, told the Senate Resources Committee on Oct. 20.

Earlier this year, Escopeta became the first company to start drilling an exploration well in Cook Inlet using a jack-up rig in nearly 20 years, but the company won't know its future as a potential developer in the state until it finishes drilling Kitchen Lights Unit No. 1.

"We're quite confident that we will find oil and gas," Katic said.

Escopeta needs to find about 150 billion cubic feet of natural gas and/or 50 million to 100 million barrels of oil to justify its development, Katic said. The company is considering four development options and already favors two potential schemes.

Prefers outrigger caisson

Should the company produce only natural gas at Kitchen Lights, it favors a six-well campaign using an outrigger caisson platform, or a 14-foot diameter post, similar to one leg of Osprey platform, Katic said, filled with conductors going down to the sea floor.

Simultaneously, Escopeta would build a pipeline either to ConocoPhillips' Tyonek platform to the north or to the onshore East Foreland production facilities to the south.

The module could be built in Anchorage, or even in Kenai, Katic said, but he also noted that this precise development option has never been tried in Cook Inlet before. That said, by going "full steam ahead" the caisson option could deliver natural gas to the grid within 18 months from discovery and is "by far" the cheapest option, according to Katic.

"I certainly hope that does happen," House Speaker Mike Chenault said about the fast development plan free of interference, "but we're kidding ourselves if we think it will."

Escopeta could also use a subsea completion strategy at Kitchen Lights, constructing a wellhead on the sea floor surrounded by a cage to protect against drifting objects.

That option is more expensive and more complicated than a caisson, untried in Cook Inlet and problematic for repairs or emergency response during the ice season, Katic said.

Different plans for oil

Should Escopeta discover both oil and natural gas at Kitchen Lights, Katic said the company favors either a two-deck platform similar to the one in place at Osprey, or a three-deck platform similar to the one at Steelhead, depending on production volumes.

Escopeta is favoring the three-deck platform, Katic said, because the two-deck platform requires special installation considerations for the water depths at the Kitchen Lights unit and is limited to a 28-well capacity, which might not work for a larger discovery.

The three-deck platform can handle 32 wells and deeper waters, but requires a heavy lift barge for installation and is more expensive than the two-deck platform, Katic said.

Those platform options would take more than 30 months to bring online, Katic said.

Escopeta is currently estimating production of 50 million cubic feet of natural gas and 12,000 barrels per day of oil, requiring a 10-inch natural gas pipeline and an 8-inch oil pipeline to either the East Foreland production facilities or new onshore facilities.

Hopes to drill later

Escopeta halted drilling the KLU No. 1 at 4,933 feet earlier in October at the request of Alaska Department of Natural Resources officials concerned about safety issues, but recently got the go-ahead to continue toward its ultimate target in the Jurassic zone.

While the company currently is required to stop drilling by the end of October, Escopeta Vice President Bruce Webb said Escopeta is meeting with state officials and hopes to get an extension because of predictions the ice season will begin late this year.

Once drilling is done for the season, Escopeta plans to move the rig to either Port Graham or Seward, according to Webb, but the company would prefer to bring the rig to Port Graham because it keeps the giant machine out of the harsher waters of the Gulf of Alaska.

The company is also working to lower a $15 million fine from the U.S. Department of Homeland Security for allegedly violating the federal Jones Act. Webb said the company plans to argue the need for natural gas in Southcentral, including at military installations, and noted that the fine is an automatic amount based on the value of the rig.

The company has 60 days to appeal the fine. ●

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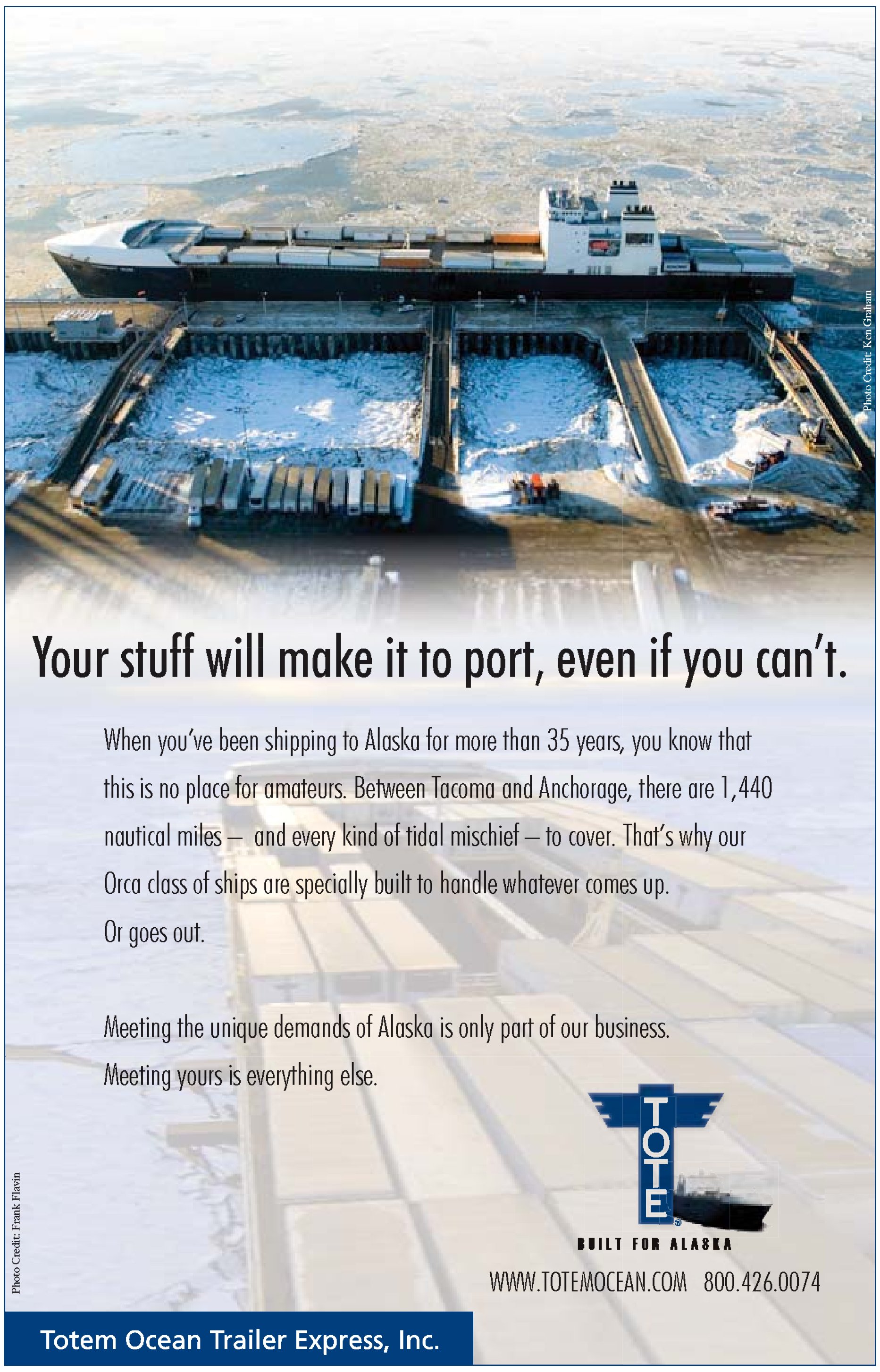
"The world needs more energy to lift millions out of poverty. Norway has both the resources and the expertise required to help make this happen and to ensure that energy production is as environmentally friendly as possible. That is a responsibility which I take seriously,"
— Ola Borten Moe.

Mr. Ola Borten Moe studied agronomy, political science, and history at Skjetlein Agricultural School and the Norwegian University of Science and Technology. Currently, Mr. Borten Moe is Minister of Petroleum and Energy and vice chair of the Centre Party. In 1995 he became a member of the Trondheim city council, and served there for three consecutive periods. In 2001 he became a member of the Norwegian Parliament, representing Sør-Trøndelag County. He has been a member of the Standing Committee on Energy and the Environment from 2005-2007. He was chair of the Standing Committee on Business and Industry from 2007-2009 and First Vice Chair in the Standing Committee on Scrutiny and Constitutional Affairs from 2009-2011. He was also vice chair of the parliamentary group steering committee.



● NATURAL GAS

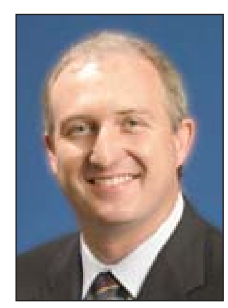
Marathon manager: ASAP challenges Cook Inlet projects

Hutchings says bullet line could tie up un-contracted future gas market, putting local developments at risk

By KRISTEN NELSON
Petroleum News

Tax reforms and process improvements within the Regulatory Commission of Alaska are positive improvements in the Cook Inlet oil and gas investment environment, Marathon Oil's Cook Inlet business unit manager, Wade Hutchings, told Senate Resources Oct. 20.

But the possibility of a bullet line bringing in North Slope natural gas, or other projects to address the upcoming shortage of Cook Inlet natural gas, create uncertainties for future investment, he said.


WADE HUTCHINGS

On the positive side, "The tax reforms have allowed us to make our projects more competitive on a global scale and to continue to ask for investment dollars from the corporation," Hutchings said.

And process improvements at the RCA "have created a lot better stakeholder alignment and timeliness of decisions," and has been critical to helping Marathon plan its business better, he said.

He thanked legislators, noting that most of those changes came from legislation or legislative support.

Hutchings said Marathon is also pleased by the work the Department of Natural Resources is undertaking to look at streaming the regulatory process. He said Marathon supports those efforts, "because at the end of the day, a predictable transparent regulatory and fiscal regime is critical to continue to attract investment dollars to the state and to the Cook Inlet."

Hutchings said that in 2010 Marathon averaged natural gas sales of 104 million cubic feet per day, roughly 34 percent of total Cook Inlet gas sales.

Marathon sees a "crossover point in the Cook Inlet, where supply is below demand on an annual basis, sometime in the next two to three years."

Investments in maintenance and new equipment are necessary for the company to meet its current and anticipated future contractual commitments, Hutchings said.

He said Marathon recognizes opportunities to develop additional resources and capture incremental gas sales, and said the company's "capital investment plans reflect a pace that is fairly in line with our recent investment history."

Investments will include: new wells to go after deeper or new targets; additional development wells within the fields the company operates; and "trying to add additional productive capacity within the well base that we currently have."

ASAP implications

Hutchings said Marathon has some concerns about the in-state bullet line proposal, ASAP (the Alaska Stand Alone Gas Pipeline) being developed by the state under the Alaska Gasline Development Corp.

He said the state needs to strike a balance between meeting natural gas demands in Southcentral Alaska and "encouraging a vibrant Cook Inlet E&P environment."

> *Projects like ASAP introduce new uncertainties because of the possibility that significant long-term contracts required to make ASAP viable could possibly "tie up all the un-contracted future local market in the inlet."*
> **—Wade Hutchings, Cook Inlet business unit manager, Marathon Oil**

The two objectives are not mutually exclusive, "but care will need to be taken to balance between and achieve both."

The concern, he said, is that in addition to the potential for resources and regulatory and fiscal certainties, "investment in exploration and development requires a high degree of market certainty."

"Simply put, we often ask the question, will there be a market for new gas production within the inlet?"

Historically there has been a lot of gas under production in the inlet and a limited market, a combination that "inhibited robust natural gas exploration and development," he said.

Contractual issues

Projects like ASAP introduce new uncertainties because of the possibility that significant long-term contracts required to make ASAP viable could possibly "tie up all the un-contracted future local market in the inlet," Hutchings said.

He said the local consumption market in Cook Inlet is estimated at 90 billion cubic feet a year, and ASAP would have a capacity of roughly 180 bcf a year, 500 million cubic feet a day.

Marathon questions if that volume will be sufficient on a seasonally adjusted basis to "sustain or create industrial consumption centers" similar to those that have existed in the past. Hutchings said Marathon also questions the impact of a project like ASAP on the market price of natural gas within the inlet.

"A lack of certainty in these areas creates uncertainty for long-term gas exploration and production projects," he said.

If ASAP — or a project like it — creates a situation where there is very little industrial gas consumption and all of the local market is tied up in long-term contracts, "then there is low incentive for future inlet gas exploration and development."

Hutchings said Marathon thinks there is a solution which can meet both objectives — gas supply for Cook Inlet and a healthy oil and gas industry in the basin.

ASAP hasn't been a significant part of day-to-day discussions, Hutchings said, but is an issue of "longer-term uncertainty for us, for bigger-picture investment projects in the inlet." ●

Contact Kristen Nelson at knelson@petroleumnews.com

● NATURAL GAS

Alaska gas hydrate well nears key test

ConocoPhillips, DOE partner on project to unlock 'fire in the ice' bonanza through exchange of carbon dioxide, methane molecules

By WESLEY LOY
For Petroleum News

ConocoPhillips Alaska Inc. is seeking permission for a key test of its exploratory well targeting natural gas hydrates at Prudhoe Bay.

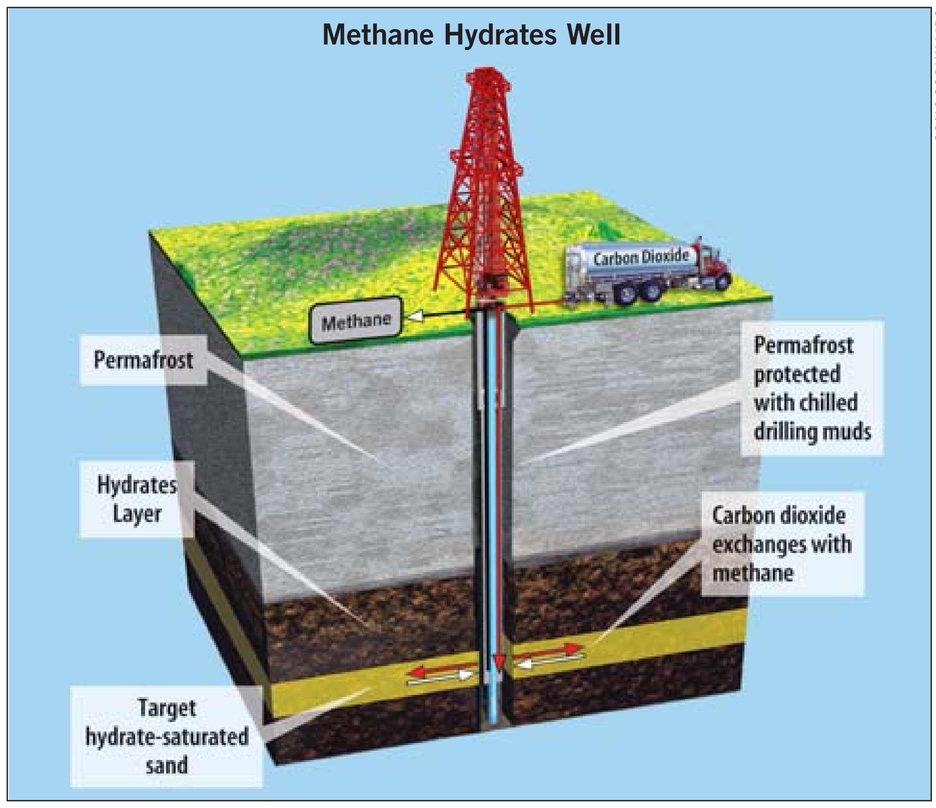
Hydrates are a solid, crystalline form of gas, usually methane, mixed in sandstone and water. A combination of cold and pressure keeps the gas as a solid.

The test will involve injecting tons of carbon dioxide down the well in an effort to free methane from hydrate-saturated sandstone.

The process involves exchanging CO2 molecules for methane molecules within the hydrate. The aim is to produce methane gas, leaving the CO2 sequestered inside the hydrate structure.

Laboratory studies have indicated this exchange will work, but it hasn't been tried in the field.

ConocoPhillips on Oct. 17 submitted an application for the CO2 injection to the Alaska Oil and Gas Conservation Commission, which regulates drilling activity.



CONOCOPHILLIPS

DOE partnership

Gas hydrate represents a potentially huge new energy resource, with vast deposits in the Gulf of Mexico, off the Pacific and Atlantic coasts, and on Alaska's North Slope.

The U.S. Geological Survey has estimated 85 trillion cubic feet of undiscovered, technically recoverable gas resources exist within hydrates in northern Alaska. That compares to the 35 tcf of known conventional gas in Prudhoe Bay and other North Slope fields.

The Ignik Sikumi No. 1 exploratory well is the result of a partnership between ConocoPhillips and the U.S. Department of Energy's National Energy Technology Laboratory. The well's name is Inupiaq for "fire in the ice."

ConocoPhillips spudded the well on April 5 and reached total depth of 2,597 feet on April 16, an AOGCC well completion report shows.

It was drilled on an ice pad adjacent to the BP-operated Prudhoe Bay unit L-pad and temporarily suspended.

The plan now is to re-enter the well during the upcoming winter drilling season and run the production test, an online DOE project overview says.

"The production testing program will consist of CO2 injection and shut-in for exchange with methane to be followed by stepwise depressurization and flowback," the overview says. "Once the exchange test objectives are met, the intent is to use the wellbore for continued production testing, including extended depressurization, potentially through the end of that winter season."

First-time test

Planned total funding for the project includes a DOE contribution of $20.9 million, with ConocoPhillips contributing $5.3 million. The upcoming production field trial is the most expensive phase of the project.

DOE and ConocoPhillips have said the Ignik Sikumi project will test, for the first time outside a lab, patented production technology for exchanging CO2 and methane molecules.

A joint DOE-ConocoPhillips data sheet said: "The trial will answer two basic questions: First, does the laboratory-proven exchange mechanism work in the field, with minimal sand and water production? Secondly, what kind of rates and exchange efficiency is demonstrated?"

The company's application to the AOGCC for an "enhanced recovery injection order" offers additional details about the well and the planned experiment.

ConocoPhillips plans to inject a mixture of CO2 and nitrogen, with a total injection volume of about 20 tons.

"The source of the liquid CO2 is storage tanks and trucking from Fairbanks via Air Liquide to a CO2-approved ground vessel at the wellsite," says the AOGCC application submitted by David Schoderbek, gas hydrates director for ConocoPhillips Alaska. "Nitrogen and carbon dioxide will be mixed on-site in a gas mixing skid. The maximum amount pumped daily will vary with formation permeability but 10 tons or 2356.2 gallons (56.1 barrels) is the maximum volume estimated. The gas is predicted to exchange with the methane molecules and stay in zone in the formation."

The injection will go into the hydrate-saturated Sagavanirktok Upper C Sand, with proposed well perforations for injection at 2,243 to 2,273 feet.

No commercial development

The targeted injection zone is between the overlying permafrost and the underlying Ugnu formation.

Plans don't include hydraulic fracturing, so downhole pressures will be monitored to manage injection rates and avoid exceeding the strength of the rock, the AOGCC application says.

No underground sources of drinking water exist beneath the permafrost in the Ignik Sikumi No. 1 area, the application says.

The CO2 is expected to reach less than 15 feet into the Sagavanirktok Upper C Sand.

The Ignik Sikumi No. 1 site was carefully chosen to avoid any "hydrate dissociation" caused by the historic production of hot conventional fluids through nearby L-pad wells.

"Following a 10-14 day injection period, draw down will commence and produced fluids, including methane, will be flowed through surface well testing equipment where the produced gas will be heated, separated and measured," the AOGCC application says. "Produced methane will be vented/flared onsite."

The well likely will be abandoned once the CO2 pilot project is complete.

"No plans for future experimentation or commercial development exist at this time," the application says. ●

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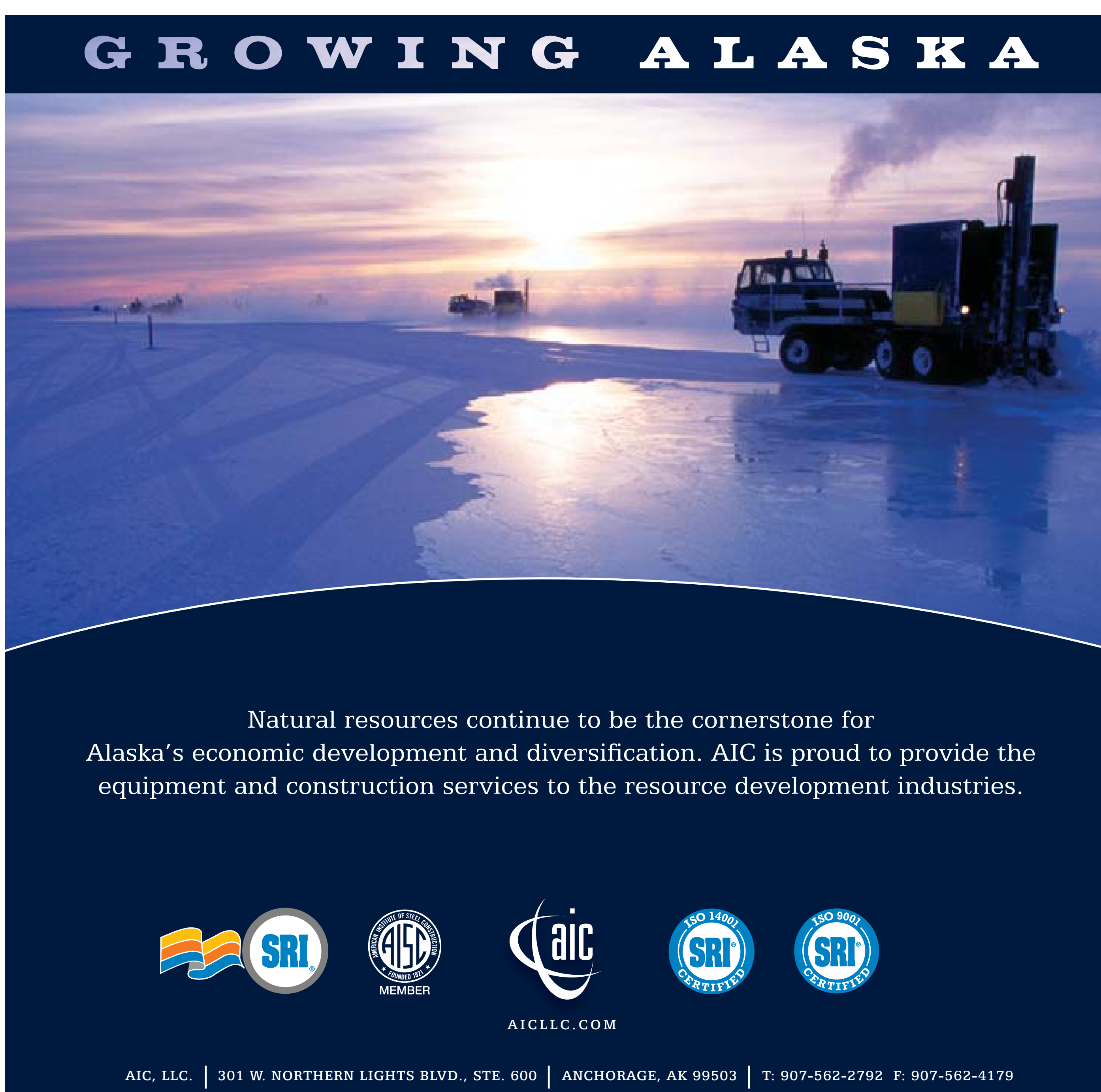

GOVERNMENT

Canada-EU lock horns

Canadian and Alberta government leaders have mounted a global defense of the oil sands, with newly elected Alberta Premier Alison Redford pledging to be "more aggressive, more proactive, more strategic."

Her self-described "very bold" stance coincided with threats by federal Natural Resources Minister Joe Oliver, delivered directly to officials from five European countries, that Canada would take the European Union to the World Trade Organization if it adopts a proposed fuel standard that labels oil sands crude as highly polluting.

"What they are doing is illogical," he told a conference call. "In fact, it is perverse because they are penalizing oil that they are not importing and they are giving a free pass to oil that they are importing."

Alberta joined that last-ditch campaign with a letter to the EU suggesting the measure "has been deliberately crafted in such a way as to discriminate specifically and uniquely against oil sands derived fuels."

The European Parliament has three months to adopt or reject the fuel quality directive, drafted by officials in the European Commission. If rejected, the commission can submit a revised proposal.

Alberta said the current directive "would be incompatible with the EU's international trade obligations."

Free trade talks threatened

The Canadian government has gone one step further, warning it is ready to abandon current Canada-EU free trade talks if the measure is adopted on grounds of "unjustified discrimination."

Under the proposed standard, which aims to reduce greenhouse gas emissions in the European transportation sector by 6 percent over a decade, the oil sands would be assigned a value of 107 grams of carbon dioxide per megajoule of energy, while most other crudes would be lumped into a common basket at 87.5 grams. Two other unconventional fuel sources have higher values than the oil sands — oil shale at 131.3 and coal-to-liquids at 172 — based on estimated lifecycle emissions.

The EU also has a wider target to reduce carbon emissions within its borders by 20 percent by 2020.

Oliver said in Paris the EU would be hypocritical if it singled out oil sands crude, but ignored carbon-heavy crudes from Saudi Arabia, Russia and Nigeria.

He said Canada supports efforts to reduce greenhouse gas emissions, but objects to moves that have "no scientific justification."

—GARY PARK

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● ENVIRONMENT & SAFETY

Council seeks report on Gulf disaster

Alaska industry watchdog group believes 'lessons learned' from Deepwater Horizon can aid its mission in Prince William Sound

By WESLEY LOY
For Petroleum News

The Prince William Sound Regional Citizens' Advisory Council is looking to hire a contractor to write a report on "lessons learned" from the Deepwater Horizon blowout and oil spill in the Gulf of Mexico.

The nonprofit organization says it believes the report could help support its congressional mandate of promoting environmentally safe operations at Valdez, where tankers load Alaska North Slope crude at the Alyeska terminal.

Formed after the Exxon Valdez oil spill in 1989, the council has 19 member organizations including local governments plus commercial fishing, environmental, Native, and recreation and tourism groups. The council operates with $2.9 million it receives annually under a contract with Alyeska Pipeline Service Co., the energy company consortium that runs the 800-mile trans-Alaska pipeline and the terminal.

The council intends to award a contract for the Gulf lessons learned report by Nov. 30. The contractor will be expected to complete a final report by March 31, 2012, the RFP says.

Focus areas

The Deepwater Horizon rig exploded offshore Louisiana on April 20, 2010, while working on a BP well, killing 11 workers and unleashing the nation's largest oil spill at an estimated 4.9 million barrels.

The council, in its RFP, says it is "interested in reviewing industry and regulatory changes" in the wake of Deepwater Horizon, and understanding how these changes might affect Prince William Sound tanker and terminal operations.

The council wants its contractor to summarize regulatory changes resulting from the Gulf spill, and identify lessons learned that might be applied to the prevention and response system in Prince William Sound.

Some specific subjects of interest from the Gulf disaster include daily oil recovery capacity, the use of dispersants and in-situ burning, the role of citizen oversight, and post-disaster mental health issues, the council RFP says.

It doesn't specify a value for the Gulf contract.

Second study on escort tugs

The council also is looking to hire a contractor to assess escort tugs and tethering systems in Prince William Sound.

Oil-laden tankers departing the Valdez terminal are required to have the escort of two powerful tugs to assist in case the tanker encounters engine or other trouble. The tugs can tow a disabled ship, with one actually tethered to the stern of the tanker to enable a quick "save."

The council, according to an RFP, is inviting proposals for a contractor to "conduct an analysis of escort tugboat tethering systems used in Prince William Sound. This project will focus on the towing winches and towlines currently used in these systems and will identify potential alternatives that could be adopted."

The final work product will be a report "detailing the consultant's professional opinion regarding what would constitute the best available technology" for escort tug tethering systems, the RFP says. ●

Contact Wesley Loy at wloy@petroleumnews.com

LAND & LEASING

BRPC keeping some Greater Bullen leases

Despite surrendering a significant chunk of acreage in the region, a joint venture led by Brooks Range Petroleum Corp. is not giving up entirely on the eastern North Slope.

The local operating arm of Kansas-based independent Alaska Venture Capital Group kept the leases in the northernmost of the six proposed exploration blocks at its proposed Greater Bullen unit and plans to apply for a unit of that acreage this coming January, vice president for land and external affairs Jim Winegarner recently told Petroleum News.

The 106,540 acres and 45 tracts that Brooks Range Petroleum is not retaining will be included in the State of Alaska lease sale planned for the North Slope this December.

The company kept the nine leases in the "N" block, also known as the Telemark prospect located between the Badami and Point Thomson units, as well as 16 other leases spread across the remainder of the proposed unit area that are set to expire on July 31, 2012.

Telemark would target a Brookian-age reservoir in the Flaxman sand, the company said.

Brooks Range Petroleum applied to form the 200,058-acre Greater Bullen unit in late June over 68 State of Alaska leases on the eastern North Slope, but recently withdrew the unit application and surrendered slightly more than half of its acreage in the area.

Winegarner declined to comment on the reason for the move.

The 106,540 acres and 45 tracts that Brooks Range Petroleum is not retaining will be included in the State of Alaska lease sale planned for the North Slope this December.

—ERIC LIDJI

● NATURAL GAS

Market will determine fate of LNG plant

By KRISTEN NELSON

Petroleum News

ConocoPhillips is exploring potential opportunities for the Kenai liquefied natural gas plant, currently expected to ship out its last tanker of LNG in November. The plant could be used to handle imported LNG or refurbished as an export facility. ConocoPhillips believes such opportunities exist, but "we cannot speculate on which outcome is more likely," Darren Meznarich, manager of ConocoPhillips Alaska's Cook Inlet assets, told the Senate Resources Committee Oct. 20.

ConocoPhillips' purchase of Marathon's 30 percent of the facility in late September, "demonstrates that we believe there are future opportunities for the facility," he said.

A decline in market conditions led to the announcement last February that the plant would likely be shut down in April or May, but the Japanese tsunami in March and "our success in marketing LNG to new customers" have kept the plant open, Meznarich said, adding that it is "expected to operate into November, prior to being shut down and preserved for an interim period for potential future use."

Possible future uses

Conversion to an import facility is one such option.

Cook Inlet utilities have testified that a likely shortage of natural gas in Cook Inlet over the next several years will result in LNG imports and regasification, Meznarich said.

In this short-term import scenario, "the plant, its dock and its LNG tanks could serve a role in the interim solution where LNG is imported and regasified to supply natural gas to the Southcentral utilities and users," he said.

Longer term, if North Slope natural gas becomes available in Southcentral or if there is a significant Cook Inlet natural gas discovery, "the plant could be refurbished and serve as an LNG export facility."

If no future opportunities materialize, "we will permanently shut down our plant operation," Meznarich said.

Changes to plant

Meznarich said that in an import scenario, the plant's dock would be used to receive ships and LNG would be offloaded to the existing LNG tanks. A regasification facility would be required to heat the LNG, turning it back into gas before it is compressed and sent into the pipeline.

"You would have the liquid LNG coming in and you'd have something like steam on the other side of a heat exchange heating it up," with some natural gas used for the steam conversion, he said.

Regasification would require new facilities, "but the dock and the LNG tanks could be used again and those are real valuable in that process."

He said the cost of such a conversion is confidential and while it is material it's nothing like the cost of the proposed bullet line.

Any expansion of the plant to handle more export capacity — if gas were available from the North Slope, for example — would be something developers of the gas would look at, Meznarich said, "but it would depend on the price and the commercial and fiscal terms." ●

Contact Kristen Nelson at knelson@petroleumnews.com

● EXPLORATION & PRODUCTION

Apache working 800,000 Cook Inlet acres

By KRISTEN NELSON

Petroleum News

Apache Corp., the largest oil and gas lease acreage holder in Cook Inlet, is targeting oil in the basin, and has begun an extensive 3-D seismic program.

While the company holds more than 800,000 acres in the Cook Inlet basin, only a portion of that is state acreage so the state's 500,000-acre limit doesn't apply, Paul Abokhair, senior commercial advisor with Apache, told the Senate Resources Committee Oct. 20 at a Kenai hearing.

The majority of the company's acreage, he said, is land held through Cook Inlet Region Inc. or the Tyonek Native Corp. (Editor's note: The Division of Oil and Gas shows current Apache state acreage at some 240,000 acres.)

"We are here for oil, and we believe the Cook Inlet has a lot of potential that has not been tapped yet," Abokhair said.

Shooting 3-D now

There is very limited 3-D seismic in Cook Inlet, so over the next three years Apache will be shooting an extensive 3-D program in the Cook Inlet basin.

Abokhair said the 3-D program covers both onshore and offshore acreage.

> *"We're going to operate here for many, many years — we're on a 25- to 30-year plan for the Cook Inlet."*
>
> **—Apache senior commercial advisor Paul Abokhair**

"We're going to operate here for many, many years — we're on a 25- to 30-year plan for the Cook Inlet," he said.

The three-year seismic shoot is being done with a wireless nodal system. Nodes are set out by people or machines, whichever is easiest, he said.

The onshore nodes weigh about five pounds each and a man with a backpack can carry eight of these nodes, which are laid out use GPS on a grid system.

Abokhair said the onshore hole shots will have a minimum impact, with 1-inch holes drilled to about 35 feet using small helicopter transported drills and compressors. When the shot is complete, the hole is filled. Offshore air guns will be used, although Abokhair said that for some shallow areas Apache will be using onshore detonations.

No transmitters

The nodes, onshore and offshore, are GPS-located, and have no transmitters, they are just listening devices, Abokhair said.

After the onshore explosive is shot off — or air guns for offshore work — the nodes are collected, the information is downloaded and the nodes are put back out again.

He said Apache estimates 6,000 node positions for the onshore work and about 2,000 offshore.

Apache has been going through the permitting process. The company has been in Cook Inlet for about a year, and started seismic operations about a month ago, Abokhair said.

"And the way our plan is set up, our president has already announced that we will do some exploratory drilling in 2012 and so I can't tell you where, but we are anticipating that we will be doing some exploratory drilling in 2012," Abokhair said.

Steven Ferris, Apache's chief executive officer, said in an Aug. 4 conference call that Apache planned to begin a 3-D seismic campaign in Cook Inlet this year, and said the company hoped to have enough of that seismic shot by December, and first-pass processing done, "and hope to drill a well in 2012." ●

Contact Kristen Nelson at knelson@petroleumnews.com

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GOVERNMENT

Kip Knudson to replace Katz in DC

Kip Knudson has been named director of state and federal relations in the governor's Washington, D.C., office.

Knudson, of Anchorage, is currently external affairs manager for Tesoro Alaska.

He replaces John Katz, who has served as the governor's director of state and federal relations for more than 30 years, and is retiring at the end of the year.

KIP KNUDSON

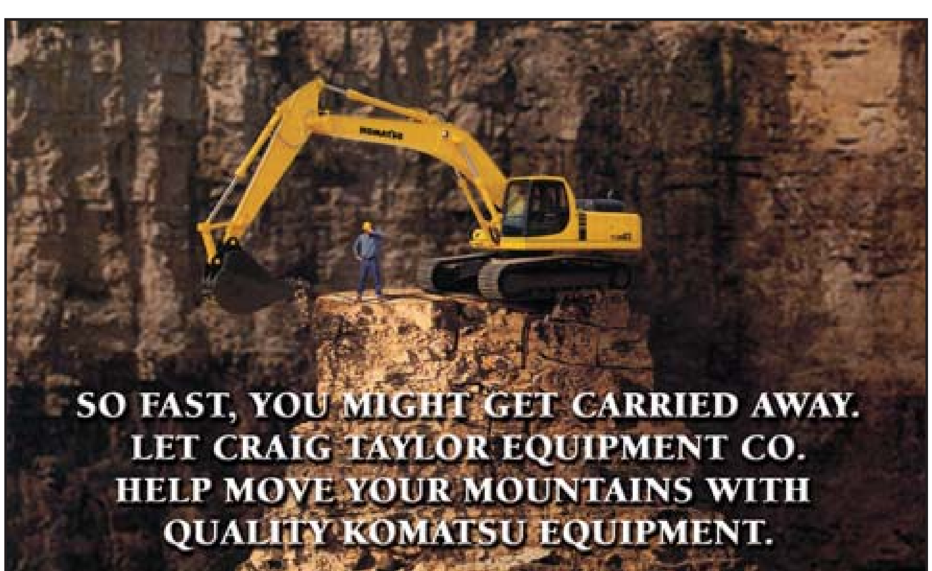
"I am pleased to appoint Kip to this vital post — he will be a strong advocate for Alaska," Parnell said in an Oct. 26 statement. "Kip is familiar with the issues facing our state. He has a strong background with the State of Alaska, the Legislature, and work in the private sector. Because Alaska is so dependent upon effective interaction with the federal government, it is extremely important to have someone as qualified as Kip advocating on Alaska's behalf."

Knudson, 47, served as deputy commissioner for aviation with the Alaska Department of Transportation and Public Facilities from 2003-05. He was the director of marketing for Era Aviation from 1998-2003, and also served as a legislative aide to Representatives Mark Hanley and Loren Leman.

"I am honored to serve the governor and Alaska in our nation's capital, humbled to follow in John Katz's footsteps, and excited to advocate in D.C. on behalf of Alaskans," Knudson said.

Knudson received a Bachelor of Science in foreign service from Georgetown University. He is active in numerous nonprofit and trade organizations including Hospice of Anchorage, Salvation Army, Alaska Oil and Gas Association, Resource Development Council for Alaska and the Alaska State Chamber of Commerce.

—PETROLEUM NEWS



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● PIPELINES & DOWNSTREAM

Court clash set on Exxon Valdez case reopener

At stake is $92 million government demand over lingering oil from 1989 spill; activist says this could be 'bitter end' of epic case

By WESLEY LOY

For Petroleum News

Government and ExxonMobil lawyers are set to meet in a federal courtroom on Nov. 15 to argue the latest chapter of a case spanning more than two decades.

At stake is $92 million the federal and state governments have demanded of the oil giant in connection with the Exxon Valdez oil spill in Prince William Sound.

The governments have said the money could be used to remove lingering oil from Alaska beaches.

ExxonMobil, however, is seeking to disqualify the government demand.

U.S. District Judge H. Russel Holland, who has long presided over court action stemming from the 1989 oil spill, has scheduled a hearing for 1:30 p.m. Nov. 15 in his Anchorage courtroom on ExxonMobil's motion opposing the government demand. The judge has given each side 15 minutes to talk.

Unanticipated injury

The governments made the $92 million demand pursuant to a "reopener" clause in a $900 million civil settlement reached with Exxon in 1991.

The clause allowed the governments to request up to $100 million more from the company to deal with unanticipated injury to habitat or species.

The governments said they made the $92 million demand after new information emerged that relatively unweathered oil remained in the subsurface of beaches in Prince William Sound and the Gulf of Alaska, and that the toxic oil was degrading at a far slower rate than was anticipated at the time of the 1991 settlement.

Although the governments requested the money years ago, in 2006, ExxonMobil hasn't paid and the governments haven't sued to collect. The governments say they won't sue until certain studies are complete. One study focuses on the feasibility of bioremediation to rid the beaches of oil.

ExxonMobil's attorneys argue the governments failed to propose a proper restoration plan, and therefore the $92 million demand is invalid.

'Running for cover'

The upcoming hearing appears to be a product of the efforts of Rick Steiner, a well-known oil industry critic and former University of Alaska professor.

Last December, Steiner began a court campaign seeking to force ExxonMobil to pay. Steiner contends the governments have been remiss in not pursing the money more aggressively.

He believes the Nov. 15 hearing could be pivotal.

"Should be interesting," Steiner told Petroleum News in an Oct. 21 email. "This could be the bitter end of 22 years of litigation over Exxon Valdez."

Recently, Steiner again asked the judge to order ExxonMobil to pay the $92 million plus interest. But Holland on Oct. 20 denied Steiner's motion.

Holland also reiterated something he has said previously — that it's up to the governments, not the court, to press a reopener claim.

"The court was previously and is now concerned that it might prejudice the parties by injecting itself into their business," Holland wrote in his Oct. 20 order.

Steiner is unhappy with the situation.

"Exxon does not want to pay a dime, the governments say they want to 'study it some more,' knowing they have no case, and the Court, that approved the provision 20 years ago, says now it has no hand here," Steiner said in an Oct. 24 email to Petroleum News. "Everyone is running for cover on this — the court, the State of Alaska, the U.S., and Exxon — a real insult to the public interest." ●

Contact Wesley Loy at wloy@petroleumnews.com

FINANCE & ECONOMY

Apache taps Hendrix to manage Alaska ops

Apache Corp. said Oct. 24 that John Hendrix has been appointed general manager of the company's Alaska operations and will be based in Anchorage.

Hendrix, who grew up in Homer, Alaska, has been general manager of Apache's Qarun Petroleum Co. joint venture in Egypt since 2006. He joined Apache in 2005 as production engineering manager of the Gulf Coast region.

"John brings a range of onshore, offshore, arctic and deepwater experience as well as deep Alaska roots; he will help Apache establish a new operating base in the Cook Inlet," John Bedingfield, Apache's vice president of worldwide exploration and new ventures, said in a statement. "Apache has built a base of 900,000 gross acres in Cook Inlet, a proven hydrocarbon basin, and we look forward to using modern 3-D seismic technology to help unlock its untapped potential," Bedingfield said.

Apache has begun a multiyear Cook Inlet seismic acquisition program with initial operations on the basin's west side.

Hendrix started his oil and gas industry career with Schlumberger in Alaska. He held a range of positions with BP in Alaska and several international assignments before joining Apache. He holds a bachelor's degree in civil engineering from the University of Tennessee.

—PETROLEUM NEWS

● ALTERNATIVE ENERGY

Ormat still optimistic on Mount Spurr

Geothermal drilling in 2011 proved disappointing but company is working with the state to prepare a revised exploration plan

By ALAN BAILEY
Petroleum News

Anxious to dispel recent rumors about Ormat Technologies' Mount Spurr geothermal project being a bust, on Oct. 20 Paul Thomsen, Ormat's director of policy and business development, assured the Alaska Senate Resources Committee that the project is still alive and well.

"We're still very excited about the Mount Spurr project," Thomsen said. "We think this can offer a source of clean, reliable, field-proven, base-load power to the (Alaska) Railbelt."

Ormat thinks that geothermal energy at Mount Spurr, an active volcano about 75 miles west of Anchorage, might support a 50 to 100 megawatt power plant.

Multiyear program

In 2008 the company leased 36,000 acres of state land for geothermal exploration on the flanks of the volcano. In the summer of 2009 the company embarked on an exploration program, initially involving various forms of aerial survey, coupled with surface gravity and electromagnetic measurements. In the summer of 2010 the program progressed into the drilling of two core holes to depths of 1,000 feet, seeking evidence of underground heat and water that might support the generation of electrical power.

With the drilling in 2010 having produced some very promising results, Ormat proceeded to the drilling of a deeper well in the summer of 2011. That well, drilled to a depth of 4,000 feet, proved disappointing: The downhole temperature was only about half of the minimum level of 350 F needed for a viable geothermal system, said Rahm Orenstein, Ormat director of business development and project leader for the Mount Spurr project.

Apparently the well unexpectedly encountered a type of rock called a conglomerate, formed from detritus of various sizes, including sand, stones and pebbles. This is a type of rock that does not hold heat particularly well and there may have been mixing of warm geothermal fluid with cold glacial water from the surface, Orenstein explained.

"We are at the stage now of analyzing that work … and updating our 3-D geological model," Thomsen said.

New plan

Thomsen said that Ormat is working with state geologists to come up with a new exploration plan, taking account of the results from the 4,000-foot well. The prime focus is to drill into some more suitable rock, changing location or drilling deeper to penetrate the base of the conglomerate. One possibility under consideration is to bring in a heavy-duty rig in 2012 to drill a much deeper well.

"We are … working with the state and we think some of the best talent in Alaska to make this project happen," Thomsen said.

The lack of success in locating a geothermal source with the 2011 well has caused Ormat to extend the time frame for the exploration phase of the Mount Spurr project, with the planned geothermal resource confirmation phase of the project now moving from 2012 to 2013. However, Ormat still hopes to be able to bring a geothermal system on line in 2016, Thomsen said.

After having spent $3.5 million dollars in acquiring its Mount Spurr leases, Ormat is paying about $100,000 per year in lease rent and has so far spent about $3 million on its exploration efforts, Thomsen said. The state has so far contributed $2 million to the exploration.

The state has appropriated another $12.5 million for the 2012 financial year for the Mount Spurr project and there is a $2 million Alaska Energy Authority grant still to be used. Ormat is working closely with the Alaska Department of Natural Resources and AEA on updating the scope of work for the project, Thomsen said.

Ice road

Orenstein said that bringing in a larger rig for deep drilling would probably require the construction of an ice road to the drilling site. The total cost of the drilling operation, including ice road construction, would likely to run to about $11 million. However, since Ormat had already planned on using a heavy duty rig to drill production and injection wells for the geothermal power plant, the ultimate impact of deeper exploration drilling on the overall project economics is uncertain, Orenstein said.

Commercial geothermal plants typically involve geothermal sources at depths ranging from 3,000 to 5,000 feet, and Ormat has developed systems with sources as deep as 8,000 feet, Orenstein said. However, the economics and viability of a specific geothermal system depend on both the depth and temperature of the source — the deeper the source the hotter it needs to be, he said.

Discussions with utilities

Ormat has projected a cost of 12 cents per kilowatt hour for Mount Spurr power and is still in discussion with Railbelt power utilities, trying to achieve an agreement on power sales. That projected power cost is higher than the avoided cost of five to 10 cents per kilowatt hour of the power that the Mount Spurr power would replace. However, while those avoided costs will likely rise over time, the cost of the geothermal power would remain constant, Thomsen said. And, being stable, base-load power, the geothermal power would not incur the power grid integration costs associated with some other forms of renewable energy, he said.

Geothermal energy development requires high up-front capital expenditure and involves risks in finding workable resources, Thomsen said. Worldwide there have been many successful geothermal projects but all have involved support from government policies, he said. In Alaska, Ormat appreciates state support through royalty legislation and grants, Thomsen said. And there has been great community support from the village of Tyonek, the Kenai Peninsula Borough and Anchorage, as well as from the Railbelt utilities, he said. ●

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PIPELINES & DOWNSTREAM

Exxon's new Alaska tankers described

More details are emerging about the pair of new double-hull tankers ExxonMobil's shipping affiliate, SeaRiver Maritime Inc., has ordered to carry Alaska North Slope crude oil.

The tankers will be driven by a single diesel engine, says an article in the September newsletter from the Prince William Sound Regional Citizens' Advisory Council, a Valdez-based industry watchdog organization.

"While the ships will not be constructed with double propellers, engines, or rudders, a SeaRiver representative indicated the design does include other navigational and propulsion redundancies," The Observer newsletter article says. "Specifically, SeaRiver has tried to eliminate the possibility of single points of failure leading to loss of power or navigational failure. This will include items like the inclusion of redundant engine cooling water, installation of additional low fuel level alarms and increasing the reliability of things like fuel flow meters."

The new tankers will be designed to operate in the North Pacific for a minimum of 25 years without suffering hull metal fatigue.

The newsletter article also says the ships will be among the first U.S. oil tankers built to meet specifications under "common structural rules" the major ship classification societies issued in 2006.

2014 delivery

ExxonMobil is the last of the major North Slope oil producers to build new double-hull tankers. BP and ConocoPhillips already have launched double-hull fleets.

On Sept. 29, ExxonMobil announced that SeaRiver had signed a $400 million deal with Aker Philadelphia Shipyard for the two new tankers.

Construction of the 820-foot, 115,000 deadweight ton tankers is expected to begin by mid-2012. The vessels are scheduled for delivery in 2014.

Each will have a carrying capacity of 730,000 barrels of crude.

That's about 12 percent less than the capacity of the two SeaRiver tankers to be replaced, the Kodiak and the Sierra.

While the Kodiak and Sierra are double-hulled, they are old, built in the late 1970s.

—WESLEY LOY

FINANCE & ECONOMY

CPAI earnings up, production down

ConocoPhillips earned $501 million in Alaska in the third quarter of the year, a 39 percent increase over the third quarter of 2010, because of increased oil prices.

Those prices masked a dubious milestone for the largest producer in the state: for perhaps the first time, its quarterly production fell below 200,000 barrels of liquids per day.

ConocoPhillips produced 199,000 bpd in Alaska in the third quarter, down from 223,000 bpd in the second quarter of the year and 215,000 bpd in the third quarter of last year.

The company reported an average sales price of $107.26 per barrel from Alaska liquids, compared to $72.30 per barrel for the Lower 48.

The company cited unplanned downtime for the higher than normal decline.

The longstanding decline in Alaska oil production, though, comes as ConocoPhillips is increasing its presence in Lower 48 shale oil plays, creating the likelihood that the company will soon produce more oil from the Lower 48 than it does in Alaska.

ConocoPhillips produced 174,000 bpd of liquids in the Lower 48 during the third quarter.

Higher Alaska commodity prices

However, the company continues to earn more from its operations in Alaska for now, primarily because of commodity prices. The company reported an average sales price of $107.26 per barrel from Alaska liquids, compared to $72.30 per barrel for the Lower 48.

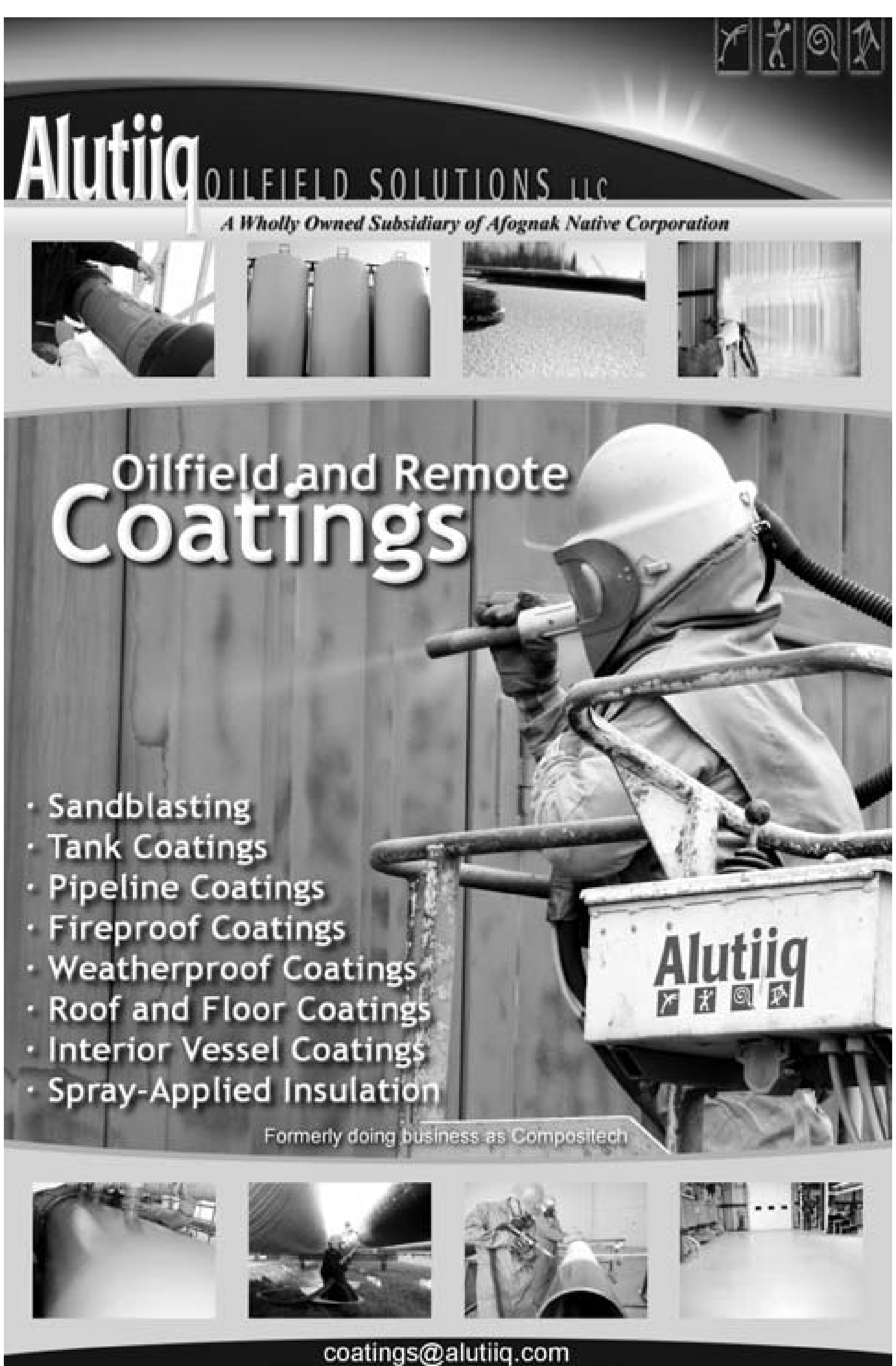
ConocoPhillips produced 56 million cubic feet of natural gas in Alaska in the quarter, down from 62 million cubic feet per day in the second quarter and 82 million in the third quarter of 2010. By comparison, the company produced 1.5 billion cubic feet per day of gas from its Lower 48 assets, down slightly quarter-over-quarter and year-over-year.

The company reported a realized price of $5.04 per thousand cubic feet for its Alaska natural gas, compared to an average of $4.15 per mcf for its natural gas in the Lower 48.

After selling just 18 million cubic feet per day of liquefied natural gas in the second quarter, ConocoPhillips sold 45 million cubic feet per day in the third quarter, the result of an unexpected shipment from the soon-to-be-mothballed export terminal in Nikiski.

Companywide, ConocoPhillips earned $2.6 billion in the third quarter.

—ERIC LIDJI



● GOVERNMENT

AOGCC hearing looks at Oooguruk water injection issues

Concerned about less-than-expected rates of water injection, impart on field's production, mentioned by Pioneer in earnings call

By KRISTEN NELSON
Petroleum News

The Alaska Oil and Gas Conservation Commission is concerned about the impact on Oooguruk development of differences between planned and actual water injection rates by Pioneer Natural Resources. It held a hearing Oct. 25 and had asked both Pioneer and ConocoPhillips Alaska, which as operator of the Kuparuk River field is the third-party water supplier, to present testimony.

Pioneer raised the issue in an Aug. 4 second-quarter earnings conference call when it noted that various issues at Lower 48 fields and at Oooguruk had caused an annual production loss estimated at 2,500 to 3,000 barrels of oil equivalent a day.

A story in Petroleum News reported the water injection supply shortage, but mistakenly attributed the overall volume of 2,500 to 3,000 boed to Oooguruk alone.

Asked about the situation in Alaska in the question and answer session of the August earnings call, Pioneer President and COO Timothy Dove said the figure for Alaska for the first half of the year was about 1,000 barrels per day.

Dove said Pioneer needed 15,700 bpd of water for injection and said, as reported in a transcript of the earnings call, "we're significantly short of that in terms of what we're being supplied, something like 6,000 barrels a day."

He went on to say that Pioneer hadn't thought water, used for sweeping oil from the reservoir, would be a problem and said the company is working on internal fixes.

"So, our production would be higher in this year, other than for the fact that we're losing production related to this lack of water, probably 1,000 barrels a day at least in the first half of the year."

No blame to ConocoPhillips

Pat Foley, Pioneer Natural Resources Alaska manager of land and external affairs, told the commission the Kuparuk River unit seawater supply for Oooguruk has been less than estimated by Pioneer.

But, he said, Pioneer contracted for water and ConocoPhillips has met all its obligations to deliver water on an "as available" basis. He said Pioneer places no blame on ConocoPhillips.

Foley said while water injection has been less than planned, Pioneer does not believe waste has occurred; deferred production is not lost production; and Pioneer believes ultimate recovery has not been impacted.

He disputed the numbers cited by Petroleum News — as well as who spoke to water supply issues at the Aug. 4 earnings call, incorrectly reported by Petroleum News as CEO Scott Sheffield — and said that according to a transcript of the Q&A, Dove had said production was down by roughly 1,000 bpd at Oooguruk in the first half of 2011 due to the water shortage.

Foley said Pioneer believes that ultimate recovery from the field will not be impacted and that no waste has occurred. Whether adequacy of water supply for enhanced oil recovery injection may lead to waste was an issue in the commission's public hearing notice.

Water from Kuparuk

Greg McDuffie, commercial activities supervisor for ConocoPhillips Alaska, told the commission at the Oct. 25 hearing that as Kuparuk River unit operator, ConocoPhillips Alaska's first goal with seawater is to maximize oil recovery from the Kuparuk River field. He said when KRU seawater deliverability exceeds KRU demand, seawater is available to third parties.

McDuffie said the seawater delivery rate is variable, and any weak link in the chain, such as maintenance or weather, will impact the water delivery rate to Oooguruk.

More than 8 million cumulative barrels have been delivered to Oooguruk since injection started in April 2009, he said, and more than 1 million barrels of water has been produced at Oooguruk since startup.

Commissioner John Norman asked if any other third parties received seawater from Kuparuk. McDuffie said the Colville River unit has been a third-party user of KRU seawater since 2000.

Norman asked how water was apportioned and McDuffie said it was not straightforward because there could be shortages in different parts of the system.

Asked by Commissioner Cathy Foerster about priorities in water delivery, McDuffie said that the first priority is the Kuparuk River unit, followed by the Colville River unit which has had an agreement for seawater delivery since 1998. CRU is the first third-party seawater user and has priority over any subsequent third party, McDuffie said.

Follow-up requested

Asked about any plans to increase water supply, Foley said Pioneer has had conversations with ConocoPhillips about increasing capacity. He said Pioneer has considered other ways to get water supply but hasn't found an alternative more cost effective than bringing in seawater from the Kuparuk River unit.

Forester said the hearing was not an attempt to find fault with Pioneer's development work at Oooguruk, but to see if there were issues the commission needed to understand better.

Norman said he echoed those remarks, but also said the question of water supply for injection has been raised and the commission will be keeping an eye on what is done on voidage replacement at Oooguruk.

Norman invited Pioneer to communicate with the commission's engineers on the company's plans for dealing with the water injection issue, or, he said, the commission could hold another hearing in six months. ●

Contact Kristen Nelson at knelson@petroleumnews.com

FINANCE & ECONOMY

Oil above $92 after Europe debt plan

Oil prices jumped above $92 a barrel Oct. 27 in Asia after European leaders agreed on a plan to reduce Greece's debt burden.

Benchmark crude for December delivery was up $1.89 at $92.09 a barrel at late afternoon Singapore time in electronic trading on the New York Mercantile Exchange. The contract fell $2.97, or 3.2 percent, to settle at $90.20 in New York on Oct. 26.

Brent crude was up $1.27 at $110.18 a barrel on the ICE Futures Exchange in London.

EU President Herman Van Rompuy said early Oct. 27 that policymakers struck a deal that will reduce Greece's debt to 120 percent of its GDP in 2020. The plan calls on banks to accept 50 percent losses on their Greek bonds.

Van Rompuy also said nations that use the euro common currency and the International Monetary Fund will give Greece another euro100 billion ($140 billion).

Investors cheered the accord as a first step toward containing Europe's sovereign debt crisis. The Dow Jones industrial average gained 1.4 percent on Oct. 26 and stock markets in Asia and Europe rose Oct. 27.

"This could be a turning point for the eurozone debt crisis," said Victor Shum, an analyst with energy consultancy Purvin & Gertz in Singapore. "It's a significant development that private investors have agreed to take a 50 percent haircut on Greece."

Crude has jumped about 21 percent from $75 on Oct. 4 amid growing investor optimism that the U.S. economy will avoid a recession this year. Shum said he expects oil to trade near $100 by the end of the year.

In other Nymex trading, heating oil rose 2.8 cents to $3.05 per gallon and gasoline futures gained 3.9 cents at $2.66 per gallon. Natural gas fell 1.0 cents at $3.58 per 1,000 cubic feet.

—ASSOCIATED PRESS

LAND & LEASING

State adds 200,000 acres to fall sales

The Alaska Department of Natural Resources said Oct. 25 that it has added a significant amount of previously leased acreage to the state's North Slope areawide oil and gas lease sale in December.

An increased 200,000 acres will be available for lease in the vicinity of Point Thomson and in the Beaufort Sea due to lease expirations and other administrative actions.

"We expect interest in these areas and hope that exploration will soon follow," Bill Barron, director of DNR's Division of Oil and Gas, said in a statement.

Thirty tracts are being added in the Point Thomson area, eight tracts formerly part of the Point Thomson unit and 22 tracts previously deferred due to their proximity to the unit, a combined 72,000 acres.

Forty-five tracts previously included in the proposed Great Bullen unit west of Point Thomson will also be available, a combined 106,540 acres.

Five leases from the previously proposed Donkel Oil and Gas unit in the Beaufort Sea north of the Arctic National Wildlife Refuge have expired, an addition of 14,403 acres.

The fall areawide oil and gas lease sales in the Beaufort Sea, North Slope and North Slope Foothills encompass some 14.7 million acres. Bids will be received on Dec. 5; the bid opening is scheduled for Dec. 7.

—PETROLEUM NEWS

GOVERNMENT

BSEE issues work safety rule guidance

As part of ongoing efforts to help operators comply with new safety rules for outer continental shelf oil and gas operations, the Bureau of Safety and Environmental Enforcement has issued guidance on a workplace safety rule mandated after the Deepwater Horizon disaster in the Gulf of Mexico. In a notice to lessees issued on Oct. 24 the agency has provided the guidance by consolidating information and rule clarifications gleaned over the past year from workshops and discussions with industry and interest groups. Operators have to implement the new rule by Nov. 15.

The rule applies to all OCS operations under BSEE jurisdiction, including drilling; oil and gas production; well workovers; well completions; well servicing; and pipeline activities.

The rule applies to all OCS operations under BSEE jurisdiction, including drilling; oil and gas production; well workovers; well completions; well servicing; and pipeline activities. And the rule requires the use of the use of safety and environmental management systems, designed to reduce the human and organizational errors that can lead to work related accidents and oil spills.

"Operators that develop and maintain a robust workplace safety program can help to achieve dramatic improvements in the overall safety of their operations for their workers while at the same time enhancing protection of the environment," said BSEE Director Michael Bromwich when announcing the issue of the guidelines. "If these programs are implemented conscientiously, we expect a decrease in the frequency and severity of offshore accidents. Based on my meetings with individual operators, I am confident that the vast majority of operators will be ready with their SEMS programs by the November 15 compliance date. Today's guidance should help address any lingering questions."

—ALAN BAILEY

● ENVIRONMENT & SAFETY

No environmental risk from WWII ship

THE ASSOCIATED PRESS

A torpedoed tanker that has sat on the seafloor off the central California coast since 1941 poses no environmental risk because very little of the 3 million gallons of crude it was believed to be carrying remains aboard, officials said after a survey of the 70-year-old wreck.

The announcement came Oct. 20 following an investigation led by the U.S. Coast Guard and California Department of Fish and Game to see if any oil remained in the hold of the 440-foot S.S. Montebello.

Following the ecological disaster from last year's Gulf of Mexico oil spill, state and federal authorities wanted to determine how they might prevent crude from leaking and marring the celebrated and environmentally sensitive stretch of California coast.

"There's probably a little oil on the ship," said Andrew Hughan, a spokesman with California's Fish and Game Department. "We can't say there's no oil but there's no significant oil, which is fantastic news."

The mystery remains as to just what happened to the millions of gallons of crude that was reportedly on the ship when it went down in 900 feet of water. Scientists concluded that it may have leaked out in the hours, days and weeks after the sinking.

"There are a number of unknowns associated with this release; therefore, we will probably never know exactly what happened to the oil," said Jordan Stout, with the National Oceanic and Atmospheric Administration.

The ship was hauling the crude from California to a refinery in Canada when it was torpedoed by a Japanese submarine in the early weeks of World War II and sank six miles off the coast of Cambria near Hearst Castle. All 38 people aboard the ship survived.

Concerns about the cargo of crude date to 1996, when a scientific survey located the wreck and discovered it was sitting upright and mostly intact — particularly the cargo holds. The presumption that oil was still inside led to worries of an eventual leak and environmental disaster. But the depth made recovery of any oil unlikely.

Earlier in October, investigators using a remotely operated underwater vehicle began assessing the ship. Officials had video and photos from previous dives but this was the first time technological advancements allowed them to determine if oil remained on the ship.

Officials assessed cargo and fuel tanks and collected ocean floor sediment samples using the underwater vehicle. The samples are being sent out for further analysis.

About $5 million was budgeted for the operation, money that came out of a fund that oil companies pay into for such measures. ●

Oil Patch Bits

Era Alaska pilot helps locate missing North Slope man

Era Alaska said one of its pilots, Eric Greener, flying a Caravan out of Barrow en route to Atqasuk on Oct. 18, heard a faint radio signal transmission. The signal, weak and garbled, prompted Greener to call back to acquire a stronger signal.

At the same time, in another part of the area, the North Slope Borough Rescue Service was actively searching for a man who had been out of contact for more than three days.

While on the radio, Greener discovered the man he was communicating with on the ground was the very person being searched for by the NSBRS. He continued talking with him and by activating his airplane lights and maintaining contact, was able to locate him.

Greener then contacted borough officials, and provided accurate coordinates to assist them in locating the missing man.

After being picked up by helicopter, the man was then transported to the Barrow hospital, where officials say he was rescued in the nick of time.

Arctic Slope Corp. declares dividend of $34.31

Arctic Slope Regional Corp. said Oct. 18 that it declared a fall dividend of $34.31 per share to be issued in early December. The average ASRC shareholder owns 100 shares of ASRC stock and will receive $3,431. This dividend brings the total dollars distributed since incorporation, in the form of dividends, to approximately $542.5 million.

"During these uncertain economic times, we recognize how important these dividends are to our shareholders," said Jacob Adams Sr., ASRC board chairman. "As we near our 40th anniversary, it's gratifying to see the difference the corporation and its employees have made to our North Slope communities."

The ASRC board of directors typically authorizes two dividend distributions, one in the fall based on preliminary year-end financial performance estimates with a typical "true-up" dividend in the spring, based on final financial results.

ConocoPhillips unit approved for voluntary program

The State of Alaska Department of Labor and Workforce Development said in a press release Oct. 20 that Commissioner Click Bishop has approved the ConocoPhillips Beluga unit for the Alaska Occupational Safety and Health Voluntary Protection Program at the "Star" level to signify a tremendous achievement in occupational safety and health.

The VPP recognizes and promotes effective workplace safety and health management through a cooperative program between a company's management, employees and AKOSH.

As a VPP Star recipient ConocoPhillips Beluga unit won't be subject to random enforce-

see **OIL PATCH BITS** *page 17*

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THOMAS Q&A

related to the light oil. (BP) has a plant up there and it is producing and I guess it's even had a little more success than they expected. But if they plan to mix that oil (with light oil) to raise it and transport it, the sooner we get a handle on that, the more heavy oil we will produce more easily. So if there is an opportunity to help with that, then I think that might be worthy of tax credits as well.

Petroleum News: Pedro van Meurs says Alaska's tax credits are too high, and that the state doesn't do enough to incentivize heavy oil and natural gas. Do you agree?

Thomas: Yeah, I think so. The Senate wanted to take a thorough look at it. They thought it was a little hasty to just rush through a tax bill (hoping) everything would get better. I think we need to take a serious look at it, and some of the discussion, the idea of comparing Alaska to North Dakota and stuff like that — it's such a different situation that it's a little unfair to do that. You're comparing us to a state where there's relatively flat terrain, railroads crisscrossing the countryside, oil and gas and product pipelines.

You have several new players at Prudhoe Bay, which I think will be helpful. As we look at development at Prudhoe Bay, and what the new folks are doing, and the smaller fields coming online — even the big three admit that those smaller companies are better suited to that kind of development.

Even though Pioneer, Repsol, and ENI are big companies, they're still relatively small. But I think those people will be the developers that hit those smaller pockets.

Petroleum News: Do you have ideas for incentives for heavy oil?

Thomas: I wish we'd put more money towards the development of the process in an Arctic climate. There's lots of heavy oil around the world, but in many places, they're steaming it, and that's probably not practical at Prudhoe Bay.

There are other things I think about, but I'm not sure how practical they are. I'd rather listen to the (industry) experts and see the projects that Conoco, BP, and Exxon would like to move forward with.

Petroleum News: Do you think the tax rate is too high?

Thomas: I don't know that it's necessarily too high because there are a lot of other places in the world where the taxes are similar. The credits do make quite a difference.

They do a lot of upfront investment in Norway. They do seismic, which is helpful, and then they stay invested. I think it would be better for us to be more of a partner with the industry. If we're simply a regulator and a recipient of royalties and taxes, then I think we don't have as close a tie to the industry and the resource as we should have.

Petroleum News: That sounds like what Sen. Hollis French was talking about – state direct financial investment?

Thomas: Yeah, I think that's important. In (Norway's) case, with their partnering with other people and having their own oil industry, they're injected in the process from beginning to end. It doesn't mean they cast environmental issues aside, but they know what they're doing and they move forward.

Petroleum News: At the Alaska Stand Alone Pipeline meeting this month in Fairbanks, you seemed worried that a gas find in Cook Inlet would leave Fairbanks without a gas supply. What's your concern there?

Thomas: I'm concerned that if the purpose of a gas line is more to make sure Southcentral has a supply of gas, and if the jack-up rigs coming in to Cook Inlet find gas, will there be the same emphasis put on building a gas line from the North Slope to Southcentral? (If not), that should be part of the discussion. It would be a horrible thing to wait until 2015 or 2016 to find that out that's the case, and, oh, now we're not going to build this line.

Fairbanks and other parts of the state are waiting for cheap energy, which that gas could supply, (with) Anchorage saying, That's fine, we've got our gas, why do we want to build an $8, $9, or $10 billion pipeline now?

I see it as an infrastructure project. It's for the state of Alaska, plus export — probably a great deal of it to begin with and then slowly that demand would be soaked up in the state as you build a gas-to-liquids plant or you fired up more electrical production or sold gas to the mining and resource development folks.

I see it as an extremely important project either way. If the big line's not going to be built because it's challenged by gas outside Alaska, then we certainly need an in-state line that provides cheap space heat and power.

Petroleum News: It sounds like you want a commitment to go ahead with a gas line even if gas is found in Cook Inlet.

Thomas: That's right. I would like to see that made based on a market, and I think we are not really looking for a market. There's talk of coming from the East Coast of the United States to Japan. That's three times further than from Valdez or Nikiski.

Petroleum News: Do you think the TransCanada/Exxon Mobil line under the Alaska Gasline Inducement Act (AGIA) has a chance?

Thomas: I think that one's really in tough shape. There's shale gas in Indiana, Michigan — everywhere surrounding that market.

Petroleum News: They did say they would go to Valdez if shippers wanted.

Thomas: I think ultimately it would have been good to change AGIA's focus and get with TransCanada and have serious negotiations about building the pipeline to Valdez or Southcentral.

If we're prepared to spend $8, $9, or $10 billion on a 24-inch in-state line, why not have those serious discussions with TransCanada and Exxon about building the line there?

Petroleum News: You've been a champion of a Susitna River hydro project. How's the state doing there?

Thomas: I think they're moving forward well. They did hire a project manager. I think that's a big step forward. I encouraged that. They do need to hire up some expertise — the Alaska Energy Authority is a relatively small organization.

I hope they can speed up the timeline a little bit. I think they can, particularly if they get people in place that are focusing on that project.

Petroleum News: How would that project affect the economics of a gas line? Wouldn't demand for gas drop considerably, making tariffs higher?

Thomas: I think the two almost complement each other. I see (Susitna) as the producer of electricity, because hydro is so much more efficient. We should use our gas for residential and commercial and industrial development, resource extraction.

I don't think anybody's going to do it for us. I think we have to take the bull by the horns and say, OK, we're going to build these two projects. This is going to move us dramatically forward. ●

Contact Stefan Milkowski at stefanmilkowski@gmail.com

> *"I think it would be better for us to be more of a partner with the industry. If we're simply a regulator and a recipient of royalties and taxes, then I think we don't have as close a tie to the industry and the resource as we should have."* **—Sen. Joe Thomas, D-Fairbanks**

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OIL PATCH BITS

ment inspections for five years. Enforcement regulations remain in effect, however, and cases of employee complaints, accident investigations or other significant incidents will result in an enforcement inspection. Participation in the program is voluntary.

"My congratulations to our Beluga Operations for their recertification as a VPP Star site," said ConocoPhillips Vice President of Commercial Assets Bijan Agarwal. "Being a VPP Star site directly aligns with our ConocoPhillips core safety values and our ultimate goal of attaining an 'Incident-Free Culture.' The Beluga River asset is truly a premier site for protecting worker safety and health."

There are 16 sites in Alaska with the AKOSH VPP designation.

Editor's note: All of 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.

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LNG PLANS

Shell's Canadian President Lorraine Mitchelmore has been forthright about her desire to pursue LNG shipments from Canada, noting that the gas market has "really changed over the last few years with shale gas."

She said Royal Dutch Shell, as the world's largest LNG producer, is ready to consider all options, hinting that a Canadian project could be "significant" because of Western Canada's gas resources and Canada's proximity to the "obvious" market in Asia.

Reserves of shale gas

Shell, like most producers in Western Canada, is stuck with large undeveloped reserves of shale gas, compounded by its C$5 billion takeover of Duvernay Oil in 2008, in what most observers now rate as a hefty premium.

Mitchelmore has warned that unless Canada moves swiftly to clear the way for export projects it will lose the chance to meet Asia's search for diversified supply sources and to exploit some of North America's largest gas deposits, including the estimated 700 trillion cubic feet in British Columbia's Horn River basin.

"This should be a great opportunity for Canada, but it isn't — or at least not yet," she said. "We need to expand our customer base for energy products and create access to global markets."

The Kitimat partnership — Apache with a 40 percent stake and Encana and EOG Resources with 30 percent each — showed no signs of unease over Shell Canada's first major public move into the LNG field.

Encana Chief Executive officer Randy Eresman said his company has "broadly stated we would welcome as many LNG export facilities as can be constructed in North America.

"We look forward to hearing other ones as well. There's plenty of room for additional projects on the West Coast, so we're supporters," he told analysts.

Eresman noted that there is a current "imbalance (in North America) between our ability to import natural gas with no ability to export."

Like Shell Canada, Encana holds vast amounts of stranded gas and is hunting for a joint-venture partner to fast track development of its British Columbia and Alberta properties.

The largest Canadian gas producer said it hopes to lock up a deal later this year for 50 percent of its Cutbank Ridge assets in British Columbia as it tries to partially recover from the failed joint-venture deal with PetroChina.

Eresman said the "interest level has been very high" from a broad group of industry players who have been invited to submit bids.

He said the assets identified for a joint venture are plays where drilling inventories are "viewed in decades."

Eresman has said Encana will confine itself in this round of joint-venture talks to "just" undeveloped resources, avoiding a repetition of PetroChina's insistence on establishing a complete business unit that embraced producing assets, undeveloped land and infrastructure.

Formerly an import facility

The Douglas Channel terminal, with capacity of 42,000 barrels per day, was acquired a year ago by Cenovus for C$38 million from methanol producer Methanex under an agreement with Cenovus's predecessor company Encana.

The facility has been used to import condensate for blending with oil sands bitumen to facilitate pipeline transportation.

A Cenovus spokeswoman said it was never the company's intention to retain the terminal and discussions had been held with several prospective buyers.

Enbridge, traditionally a crude oil carrier, has joined the LNG action by acquiring a large gas processing plant in northeastern British Columbia, which could handle gas for eventual export.

It is paying C$220 million to Encana for a 57.6 percent interest in the Cabin gas plant near Fort Nelson and said it plans to spend C$900 million increasing capacity to 800 million cubic feet per day, doubling phase 1 which is 70 percent complete.

Capacity for both phases has already been fully taken up by Horn River producers, who include the three Kitimat partners.

Al Monaco, Enbridge's president of pipelines, said the investment is a "substantial initial step in the execution of our strategy to establish a strong position in the Canadian midstream business, focusing on growing unconventional gas production in B.C. and Alberta."

Company officials had previously said Enbridge wanted to form partnerships with any of Canada's three proposed LNG terminals as an outlet for Horn River gas, or build support for a new one. ●

Contact Gary Park through publisher@petroleumnews.com

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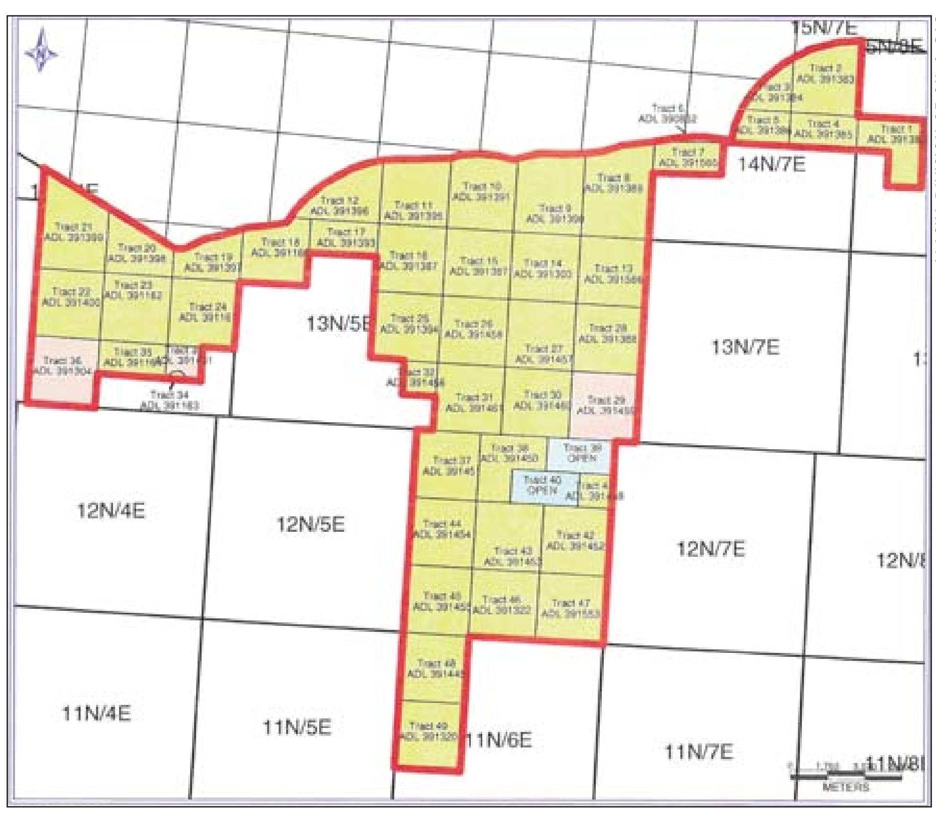
UNIT APPLICATION

holders the right to join the unit and is awaiting their response.

The proposed unit, in somewhat of a "T" shape, is between the Colville River unit to the south and west, the Oooguruk unit to the south and east and the proposed Placer and South Miluveach units to the south. The northern limit of the proposed unit is the boundary between state waters and the federal outer continental shelf.



Prospective intervals to be tested by the exploration program include — but are not limited to — the Cervelo, Judy Creek, Nechelik, Nuiqsut and Alpine sandstones within the Jurassic Kingak shale, and the Cretaceous Kuparuk C sandstone (Kup "C"), Torok formation and Nanushuk Group.

One-year plan

The initial plan of exploration is for one year and includes four wells. Repsol proposed a bond payable to DNR to ensure that work begins, with DNR to release the bond to Repsol when the first exploration well spuds. Repsol said the unit working interest owners agree to having the unit terminate if the first well is not drilled during the 2011-12 drilling season.

Prospective intervals to be tested by the exploration program include — but are not limited to — the Cervelo, Judy Creek, Nechelik, Nuiqsut and Alpine sandstones within the Jurassic Kingak shale, and the Cretaceous Kuparuk C sandstone (Kup "C"), Torok formation and Nanushuk Group.

The four planned wells are the Qugruk 1 in section 28 of township 13 north, range 6 east, Umiat Meridian, with a proposed true vertical depth of 7,100; the Qugruk 2, in section 25 of township 13 north, range 6 east, UM, with a proposed TVD of 7,000 feet; Qugruk 3, in section 31, township 12 north, range 6 east, UM, with a proposed TVD of 7,150 feet; and Qugruk 4, in section 15 of township 13 north, range 4 east, UM, with a proposed TVD of 8,300 feet.

Repsol said the sequence in which the wells are drilled may be changed and the location and drilling depth of subsequent wells may be adjusted following drilling of prior wells.

In its permitting paperwork Repsol has indicated that it may drill one vertical well and as many as two sidetracks at each location. It is also permitting the Kachemach exploration well farther south — outside of the proposed unit area — and just east of the Meltwater participating area of the Kuparuk River unit.

Kingak, Kup "C", Nanushuk group

There have been many exploration wells drilled in the area surrounding the proposed unit, including six wells within the proposed unit, beginning in 1966 and extending through to 2008, Repsol said in its unit application.

Primary objectives for the proposed unit are "sands within the upper portion of the Jurassic Kingak Shale, the Cretaceous Kup 'C' sand and several sands within the Cretaceous Nanushuk Group." Two sands in the J-2 interval of the Kingak shale are informally termed the Cervelo and Judy Creek sands, the Nechelik sand, the Nuiqsut sand and the Alpine "A" and "C" sands. Within the Nanushuk group the sands are the Nanushuk 3, Nanushuk 2 or Qannik sand, Nanushuk 6 and Nanushuk 7.

There is both 2-D and 3-D seismic over the area of the proposed unit, Repsol said.

While proprietary 3-D seismic exists over most of the proposed unit, Repsol said the primary 3-D seismic it has licensed over the proposed unit are the 2000 Fiord 3-D, the 1997 Kalubik 3-D and the 2007 Big Island 3-D. The company said that variably spaced 2-D lines (half a mile to 2-mile spacing) acquired from the 1970s to the 1990s were used in areas with no 3-D coverage.

Existing seismic "allows detailed mapping of fault patterns, truncation of individual Jurassic sands by the Lower Cretaceous Uncomformity (LCU), and amplitude anomalies associated with sands," the company said.

Productive

Because of production in adjacent areas, Repsol provided DNR with an extensive analysis of what it considers to be analogous production.

The Nuiqsut sand is productive in the Oooguruk unit to the east of the proposed Qugruk unit, Repsol said, while the Nechelik, Alpine "A" and Alpine "C" sands are producing in the Colville River unit to the west of the proposed unit.

"All the zones are being developed by horizontal laterals with alternating produc-

"Structure at the Kup 'C' level consists of an extremely large, roughly circular, four-way closure known as the Colville High," Repsol said, and the lands proposed for the Qugruk unit are "on the northwest flank of the structure but are still nearly entirely within the area of closure.

ing and injection wells."

The Kup "C" sand is a major North Slope reservoir and is produced most notably from the Kuparuk River field southeast of the proposed unit, Repsol said.

"Structure at the Kup 'C' level consists of an extremely large, roughly circular, four-way closure known as the Colville High," Repsol said, and the lands proposed for the Qugruk unit are "on the northwest flank of the structure but are still nearly entirely within the area of closure."

The Nanushuk group is divided into nine zones within the area proposed for the unit, including the Nanushuk 2, equivalent to the Qannik sand that is being developed within the Colville River unit, where Qannik sand production is south of the proposed Qugruk unit. There are six producing Qannik wells and three injection wells, with oil ranging from 27 to 32 degrees API gravity.

"To date the Qannik sand is the only sand that has been tested within the Nanushuk Group, however reservoir properties for the other Nanushuk sands are anticipated to be similar."

Madrid-based Repsol took a position in state acreage when it picked up a 70 percent working interest in 494,211 acres assembled by Armstrong Oil and Gas of Denver (bidding as 70 & 148 LLC) and northern Alaska acreage held by GMT Exploration LLC.

Under the deal, announced in early March, the remaining 30 percent is split 75:25 between Armstrong and GMT.

Repsol's previous interests in Alaska were in federal outer continental shelf acreage in the Beaufort and Chukchi seas.

—KRISTEN NELSON

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AIR PERMIT

Quality Standards," EPA said on Oct. 21 when announcing its issuance of the permit for the Kulluk. "Strict pollution controls in the permit include selective catalytic reduction units and catalytic oxidation reduction units on some engines, use of low-sulfur diesel fuel fleet-wide, and limits on operational hours."

Public appeals for review of the permit must be received by the Environmental Appeals Board by Nov. 28, EPA said. The agency published a draft version of the permit in July and after a public review period made a number of technical changes before issuing the final version.

"Shell has been in pursuit of a usable air permit for nearly five years," said Shell spokesman Curtis Smith in response to the issue of the permit. "We appreciate that EPA Region 10 has thoroughly evaluated our program and issued a final permit for the Kulluk that is technically and scientifically sound. Shell has gone to great lengths to meet the goal of having no measurable impact on coastal villages, including a retro-fit of the Discoverer's catalytic exhaust system and ongoing, multi-million dollar modifications to the Kulluk."

Drilling decision?

With the issue of the air permit for the Kulluk Shell now has all of the air permits that it needs to carry out its planned drilling in the Beaufort and Chukchi seas — the company wants to drill up to four wells in the Beaufort Sea and up to six wells in the Chukchi Sea, starting in 2012. However, on Oct. 24 some Native groups and environmental organizations appealed the Noble Discoverer permits issued a month ago and Shell has yet to announce any final decision on its planned 2012 drilling. Shell has said that it needs to make a decision in late October on whether to start activating its drilling operations and that the company's decision will depend on the status of all of the various permits that the company needs.

"Going forward, we will continue to advance our drilling plans and evaluate investment decisions that would allow us to commence with a 2012 drilling season," Smith told Petroleum News Oct. 21.

The terms of the new Kulluk air quality permit appear to be very similar to those of the Noble Discoverer. The permit considers the Kulluk to be a stationary emissions source requiring an air permit when it is moored at a drill site by at least one anchor. And the emissions from any vessel in the Kulluk's support fleet are also regulated under the terms of the permit when that vessel is within 25 miles of the Kulluk during a drilling operation. The support fleet includes icebreakers, anchor handlers and vessels that are part of Shell's oil spill response assets.

Shell has to notify EPA by April 1 each year of any drill sites where the company plans to drill during that year. The Kulluk cannot operate as a stationary source for more than 120 days in any drilling season, with drilling operations limited to a maximum of 1,632 hours in a season.

Other challenges

Although Shell now has its air permits, the company still faces several challenges to its drilling plans, in addition to appeals against the air permits themselves.

In August the Bureau of Ocean Energy Management, Regulation and Enforcement announced conditional approval of Shell's Beaufort Sea exploration plan. However, on Sept. 29 the Native Village of Point Hope and 12 environmental organizations appealed the BOEMRE decision in the U.S. Court of Appeals for the 9th Circuit. The court has set a deadline of Dec. 19 for submission of the petitioners' opening brief, with respondents answering briefs due by Jan. 17, 2012.

Shell submitted its plan for its Chukchi Sea drilling to BOEMRE in May. However, the agency placed its review of the plan on hold because of an unresolved appeal in the U.S. District Court in Alaska challenging the validity of the 2008 Chukchi Sea lease sale in which Shell purchased its leases. On Oct. 3 BOEMRE's successor agency, the Bureau of Ocean Energy Management, published a new supplementary environmental impact statement and record of decision for the lease sale. That new record of decision affirmed the sale, thus paving the way for the review of Shell's plan to proceed.

On Oct. 18 Michael Bromwich, director of the Bureau of Safety and Environmental Enforcement, told a U.S. Senate committee that the Department of the Interior is doing everything it can to complete a review of Shell's Chukchi Sea plan. And on Oct. 26 the District Court confirmed that BOEM can proceed with the exploration plan review. ●

Contact Alan Bailey at abailey@petroleumnews.com

Court allows exploration plan review

On Oct. 26 the U.S. District Court in Alaska lifted its injunction against lease related activities in the Chukchi Sea, so that the Bureau of Ocean Energy Management can proceed with its review of Shell's Chukchi Sea exploration plan. The court imposed the injunction in 2010 as part of a ruling in an appeal against the environmental impact statement for the 2008 Chukchi Sea lease sale in which Shell purchased its leases. Shell wants to drill up to six wells in the Chukchi Sea, starting in the summer open water season of 2012 and submitted an exploration plan to the Bureau of Ocean Energy Management, Regulation and Enforcement, predecessor agency to BOEM, in May for approval. BOEMRE had placed its review of the plan on hold because of the court injunction.

On Oct. 3 BOEM submitted to the court a new supplementary environment statement and an accompanying record of decision affirming the 2008 lease sale — the court had ordered the Department of the Interior to correct three deficiencies in the original lease sale EIS, with the injunction to remain in place pending a new lease sale record of decision.

"The three concerns (about the EIS) previously expressed by the court appear to have been addressed," wrote District Judge Ralph Beistline in the Oct. 26 court order. "Therefore, federal defendants are now permitted to act upon the proposed exploration plans pending before them and the injunction is hereby lifted."

However, the appeal over the lease sale is not yet over, since the plaintiffs in the case can still challenge the new SEIS. Any new complaint is to be filed on Nov. 16, with responses to be filed by Dec. 21.

—ALAN BAILEY

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PERMIT APPEAL

account of EAB directives from that earlier appeal when developing the new permits.

Nitrogen dioxide

The group involving the Native Village of Point Hope claims that the Shell permits will allow the emission of nitrogen dioxide in quantities that will cause degradation of air quality beyond permitted limits. The group also claims that EPA allowed Shell to use incorrect calculations to demonstrate nitrogen dioxide emissions compliance. And the group says that the permits' stipulations that ambient air standards only apply outside a 500-meter zone around the drillship contravenes EPA's definition of ambient air. For an onshore industrial facility, ambient air standards only apply outside the facility's fence — EPA has said that the equivalent to the "fence" for Shell's offshore drillship will be a U.S. Coast Guard imposed 500-meter public safety zone around the ship.

The Inupiat Community of the Arctic Slope and the Alaska Eskimo Whaling Commission have claimed that the public review period for the draft air quality permits was in effect only half of the legally required 30 days because of the demands on the public of overlapping review periods for multiple air quality permits — between July 6 and July 22 EPA had initiated public review periods for three Shell permits and two versions of a ConocoPhillips permit. The organizations also claim that EPA's definition of the time periods during which the drillship becomes a regulated emissions source is inadequate; the groups claim that Shell's limits on greenhouse gas emissions during drilling operations are unenforceable; and the groups claim that EPA has not adequately assessed the impact of the drillship emissions on local Native communities.

The Inupiat Community of the Arctic Slope has recently said that a vote conducted on Oct. 4 among Inupiat tribal members in eight Arctic coastal communities showed that nearly 60 percent of the people polled oppose oil and gas development in the Chukchi and Beaufort Seas.

—ALAN BAILEY

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GAS SUPPLIES

More gas needed

James Posey, ML&P general manager, told the task force that recent Cook Inlet gas discoveries have not been sufficient to avert the LNG import option. Without new discoveries leading to 50 million to 80 million cubic feet per day of production "we're nowhere out of this box," he said.

And Colleen Starring, president of Enstar, told the task force that, with the utilities still determining the cost parameters for LNG imports, it is too early to comment on the specifics of import options. Posey said that the utilities anticipated having more information to impart some time in 2012.

Starring said that Enstar continues to negotiate long-term gas supply contracts with local gas producers. However, starting in January 2011 the company has had to tender for daily volumes of "bid gas" from qualified producers, to supplement gas obtained under the terms of contracts for guaranteed gas supplies. The future gas supply situation depends on discoveries by companies currently exploring in Cook Inlet — there has been significant investment in this exploration in the past couple of years, Starring said.

New contracts with new producers are already appearing in Enstar's contract list for future supplies, she said.

Growing gap

Enstar sees a significant and growing gap between its current contracted gas supplies and gas demand from 2013 onwards. However, the company hopes that new Cook Inlet gas coming on line will delay any need to import LNG until 2015, Starring said. Enstar is also keeping an eye on gas pipeline options for obtaining gas from the North Slope, she said.

Meantime, Cook Inlet Natural Gas Storage Alaska, Enstar's sister company, is forging ahead with its new gas storage facility on the south side of Kenai, on the Kenai Peninsula. CINGSA plans to start accepting gas for storage in the spring of 2012, to support the delivery of utility gas in the winter of 2012-13. At the CINGSA site the buildings have been constructed, one well has been completed, a second well is ahead of schedule and the drilling of a third well will start soon, Starring said.

At the beginning of 2011 Enstar moved to a quarterly gas cost adjustment for its customers, thus enabling the company to pass on the higher cost of winter gas, Starring said. The Enstar gas cost adjustment ranged from $7.12 per thousand cubic feet in the first quarter of 2011 to $5.74 in the third quarter.

"We're trying to send the right price signals to customers," Starring said.

Bid gas

Enstar now has seven companies signed up to potentially supply bid gas during the coming winter, with the company expecting bid gas to account for about 3 percent of its overall supplies. Buccaneer Energy, one of the companies that have a contract for bid gas, also has a contract to supply gas to Enstar for storage in the CINGSA facility, starting in the spring, Starring said.

It is not possible to say how much bid gas might be available to Enstar on any particular day, but on one especially cold day during the last winter the company was able to obtain all of the bid gas that it needed, Starring said.

Phil Steyer, CEA's director of government relations and corporate communications, said that CEA uses natural gas as a fuel to meet 90 percent of its power generation needs. The company has gas supply contracts to meet its needs through 2013, possibly through 2014, with increasing unmet needs thereafter, he said. Meantime, the tightening gas supply situation has led to increasing complexity in the delivery of gas to power plants, although modifications to the pipeline infrastructure will improve the flexibility with which gas can be transported. And starting in 2012 the company will be storing some of its winter gas supplies in CINGSA's new facility. Along with other Southcentral utilities, CEA is considering the option of importing LNG to fill gaps in future gas supplies.

CEA is working with ML&P to build a jointly owned, state-of-the-art, combined cycle gas-fired power plant in Anchorage. That plant is scheduled to go into operation by Dec. 1, 2012, and its use will greatly increase the efficiency of the two utilities' power generation, thus reducing their gas demand from the beginning of 2013, Steyer said. And CEA's overall retail power load has remained fairly flat, with customers power usage actually dropping in recent years, thanks primarily to improved efficiency in people's use of energy.

Multifaceted approach

Although CEA expects to remain a gas fueled utility for some time to come, the utility is taking a multifaceted approach to meeting its long-term energy needs, Steyer said. Increments to the power capacities of the Bradley Lake and Cooper Lake hydropower systems on the Kenai Peninsula are planned, although increased power output from Bradley Lake is contingent on some transmission line upgrades on the Kenai Peninsula. Increasing the capacities of the transmission lines running north and south out of Anchorage would also allow greater flexibility in power generation. Looking further into the future, there is also the proposed major hydropower system at Watana on the Susitna River.

Posey said that, in addition to investing with CEA in the new Anchorage power plant, ML&P has been improving its own power plant, replacing turbines and some pipe work. The utility is investing in upgrades, including a new well and compressors, in the Beluga gas field, the field that it part owns with ConocoPhillips and Chevron and that forms its primary source of gas.

Turning point

ML&P expects its gas needs to drop as its power generation efficiency improves, but gas output from the Beluga field is also declining.

"Our turning point is 2018, when we will turn the corner of having to buy more and more gas each year," Posey said.

Joe Griffith, general manager of MEA, told the task force that MEA is moving ahead with a new 135-megawatt power station that the utility has been planning to build at Eklutna, at the base of the Chugach Mountains. The utility has the necessary air permit for the plant but is still seeking fuel supplies for the power generation. The plan is to use natural gas as fuel, but the generators will be also be able to operate with other fuels — MEA plans to keep diesel fuel on site as a backup but is investigating the potential use of propane.

MEA is making improvements to the utility's transmission and distribution networks, including the rebuild of some very old substations, Griffith said. ●

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