Petroleum news

page 4 Apache Alaska spuds first Alaska exploration well, near Tyonek

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Inside: PN Bakken, Mining News

Enclosed this week find the latest issues of Petroleum News Bakken and Mining News as well as the debut of the first Bakken Oil & Gas Directory magazine

Shell's drilling fleet departs the Arctic as drilling season ends

Following the cessation of drilling operations at the end of October, Shell's Alaska drilling fleet is heading south out of the Arctic, Shell spokesman Curtis Smith told Petroleum News in a Nov. 13 email. The drillship Noble Discover, which had been drilling at the Burger prospect in the Chukchi Sea, will dock initially in Seward on the Kenai Peninsula, from where it will likely sail to a West Coast shipyard for routine maintenance, Smith said. The Kulluk, the floating drilling platform that Shell was using at its Sivulliq prospect in the Beaufort Sea, is heading for Dutch Harbor in the Aleutian Islands — it is possible that Shell may later also move the Kulluk to the West Coast for maintenance work.

"The Kulluk and its support fleet are well past Point Barrow and sailing to Dutch Harbor at roughly four knots," Smith said.

see **SHELL DRILLING** *page 19*

Linc building snow road to Umiat, prepping for January drilling

Work is under way at Umiat.

In preparation for a drilling campaign scheduled for January, Linc Energy Inc. recently began building a snow road to the North Slope oil field, the company said Nov. 12.

The 100-mile snow road will begin at the Dalton Highway, near Pump Station 2, and continue to Umiat, located on the boundary of the National Petroleum Reserve-Alaska.

Linc is currently pre-packing the road and expects the development to take 30 days.

With the road complete, Linc expects to begin mobilization in mid-December. The mobilization effort involves moving a camp, drilling rig and equipment to the field.

During the mobilization, Linc plans to build in-field ice roads and ice pads.

Between January and April, Linc plans to drill at least four wells at Umiat, starting with Umiat DS No. 1, a Class II disposal well the company plans to spud around Jan. 18.

Four-well program

Using the Kuukpik No. 5 rig, Linc would move uphill, to the

see **LINC ACTIVITY** *page 18*

EXPLORATION & PRODUCTION

1 step forward, 2 back

Conoco goes ahead with CD-5; BP halts heavy oil trials, won't increase viscous

By KRISTEN NELSON
Petroleum News

JUDY PATRICK PHOTOS

NICK OLDS

JOHN MINGE

BP Exploration (Alaska) and ConocoPhillips Alaska, the North Slope's major operators, delivered similar messages to the Resource Development Council's annual conference Nov. 14 in Anchorage: The state's oil and gas tax system needs to be changed.

It's not a new message, but Nick Olds, ConocoPhillips Alaska's new vice president, North Slope operations and development, said a better business climate in Alaska is necessary to draw the investment needed for continued development of legacy fields, including high-risk satellite opportunities.

John Minge, president of BP Exploration (Alaska), called ACES — Alaska's Clear and Equitable Share — a good short-term fiscal policy for the state, but said because it's short-term, BP will have to "adjust our plans and our strategy to shorter term, to fit within the ACES policies."

Minge said if the state wants to see a long-term sustainable oil industry, and a gas pipeline, it needs to consider a policy to encourage long-term investment.

see **RDC CONFERENCE** *page 20*

FINANCE & ECONOMY

BP Alaska to pay $255M

Arbitrators award state damages for production shortfalls following 2006 spills

By WESLEY LOY
For Petroleum News

Two leaks from major oil pipelines in the giant Prudhoe Bay field in 2006 ignited big trouble for operator BP Exploration (Alaska) Inc.

The leaks caused a partial field shutdown that rattled world oil markets, and drew scrutiny from federal regulators and members of Congress who criticized the company's upkeep of pipelines infested with corrosion.

BPXA ultimately was placed on probation for three years and fined $20 million after pleading guilty to a federal pollution misdemeanor.

But that wasn't the end of it. The state filed an aggressive civil suit against BPXA in 2009, seeking to recover back taxes, royalties and other damages for the leaks and the production shortfalls resulting from shut-ins and extensive pipeline repairs.

The arbitrators put the state's royalty loss at 30,344,971 barrels of oil and NGLs, and said the production won't be recovered until the end of field life.

At the time the suit was filed, a state lawyer said the damages could exceed $1 billion.

The state won't collect that much. But it has succeeded in winning a very substantial sum, more

see **BP PAYOUT** *page 19*

EXPLORATION & PRODUCTION

Oil sands output to rise

250 percent increase in Canadian sands production by 2035, IEA says

By GARY PARK
For Petroleum News

The next 23 years will see Canadian oil production rise steadily as oil sands volumes grow by 250 percent to 4.3 million barrels per day, more than enough to offset shrinkage in conventional output, the International Energy Agency predicts.

If the projection is accurate, based on assumptions that environmental opposition will be overcome and more crude will be delivered to the United States and Asia, Canada's oil production will grow to 6.3 million bpd by 2035.

But the report emphasizes that "extraordinary growth" in oil and natural gas production in the

Without new export capacity, the IEA said Western Canadian oil production will exceed regional consumption and current export capacity before 2016 ...

U.S. will mean a global sea change, with the U.S. becoming a net exporter of gas and almost self-sufficient in net energy terms over the forecast period.

From Canada's standpoint, the IEA said the outlook has become clouded by U.S. delays in approving TransCanada's Keystone XL pipeline to deliver Alberta oil sands crude and Bakken light/tight oil to the Texas Gulf Coast and by oppo-

see **SANDS OUTPUT** *page 18*

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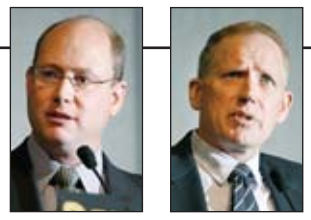

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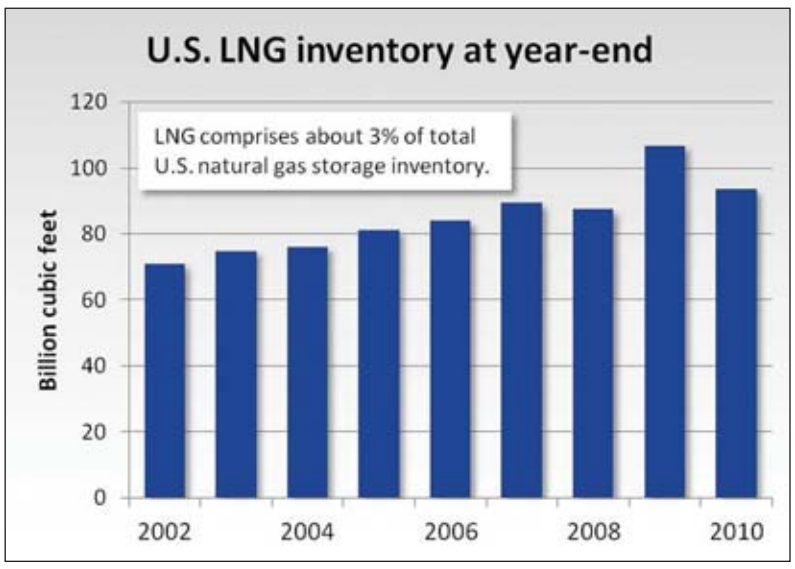

PIPELINES & DOWNSTREAM

Alaska - Mackenzie Rig Report

Alaska Rig Status

North Slope - Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Prudhoe Bay E-20 workover	BP
Dreco 1000 UE	16 (SCR/TD)	Milne Point MPE-03	BP
Dreco D2000 UEBD	19 (SCR/TD)	Alpine CD1-01	ConocoPhillips
AC Mobile	25	Prudhoe Bay Z-10A	BP
OIME 2000	141 (SCR/TD)	Kuparuk 3Q-06	ConocoPhillips
Kuukpik	5	Stacked in Deadhorse	Linc Energy Operations Inc. Umiat Job
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Prudhoe Bay	Stacked
AC Coil Hybrid	CDR-2	Kuparuk 2F-19	ConocoPhillips
Dreco 1000 UE	2-ES	Prudhoe Bay Stacked out	Available
Mid-Continental U36A	3-S	Prudhoe Bay Stacked out	Available
Oilwell 700 E	4-ES (SCR)	Deadhorse	Available
Dreco 1000 UE	7-ES (SCR/TD)	Prudhoe Bay	Available
Dreco 1000 UE	9-ES (SCR/TD)	Prudhoe Bay	Available
Oilwell 2000 Hercules	14-E (SCR)	Prudhoe Bay	Available
Oilwell 2000 Hercules	16-E (SCR/TD)	Prudhoe Bay	Available
Oilwell 2000	17-E (SCR/TD)	Prudhoe Bay	Stacked
Emsco Electro-hoist -2	18-E (SCR)	Prudhoe Bay	Stacked
Emsco Electro-hoist Varco TDS3	22-E (SCR/TD)	Prudhoe Bay	Stacked
Emsco Electro-hoist	28-E (SCR)	Prudhoe Bay	Stacked
Emsco Electro-hoist Canrig 1050E	27-E (SCR-TD)	Prudhoe Bay*	Available
Oilwell 2000	33-E	Prudhoe Bay	Available
Academy AC electric Canrig	105-E (SCR-TD)	Warm Stack	Great Bear Petroleum
*Pioneer winter work			
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Prudhoe Bay Drill Site D-29A	BP
Superior 700 UE	2 (SCR/CTD)	Prudhoe Bay Well Drill Site W-02	BP
Ideco 900	3 (SCR/TD)	Kuparuk Well 3M-13	ConocoPhillips
Parker Drilling Arctic Operating Inc.			
NOV ADS-10SD	272	Prudhoe Bay final construction and commission	BP
NOV ADS-10SD	273	Started acceptance testing on Aug. 2, scheduled to complete Aug. 11	BP

North Slope - Offshore

BP			
Top drive, supersized	Liberty rig	Inactive	BP
Nabors Alaska Drilling			
OIME 1000	19-E (AC)	Oooguruk ODSN-29	Pioneer Natural Resources
OIME 2000	245-E	Oliktok Point	ENI
Doyon Drilling			
Sky Top Brewster NE-12	15 (SCR/TD)	Spy Island SP30-W1	ENI

Cook Inlet Basin – Onshore

Kenai Land Ventures LLC (All American Consultants, labor Contract)			
Taylor	Glacier 1	Kenai Loop Drilling Pad #1	Buccaneer Energy Ltd
Aurora Well Service			
Franks 300 Srs. Explorer III	AWS 1	Happy Valley drilling HV B-16	Hilcorp Alaska LLC
Cook Inlet Energy			
Atlas Copco RD20	34	Finalizing Otter Project west side of Beluga River Field	Cook Inlet Energy
Doyon Drilling			
TSM 7000	Arctic Fox #1	Swanson River SRU 23B-22	Hilcorp Alaska LLC
Nabors Alaska Drilling			
	99AC	North Fork 23-25	Armstrong Cook Inlet LLC
Continental Emsco E3000	273E	Kenai	Available
Franks	26	Kenai	Stacked
IDECO 2100 E	429E (SCR)	Stacked in Kenai	Available
Rigmaster 850	129	Kenai	Available
Academy AC electric Heli-Rig	106-E (SCR/TD)	Tiger Eye 1	NordAq

Cook Inlet Basin – Offshore

XTO Energy			
National 110	C (TD)	Idle	XTO
Spartan Drilling			
Baker Marine ILC-Skidoff, jack-up		Spartan 151 Upper Cook Inlet KLU#1	Furie
Cook Inlet Energy			
National 1320	35	Osprey Platform RU-1, workover	Cook Inlet Energy
Hilcorp Alaska LLC (Kuukpik, labor contract)			
		Steelhead Platform Well M-16, workover	Hilcorp Alaska LLC
	428	Anna Platform, Replacing rig's turbine Generator	Hilcorp Alaska LLC

Mackenzie Rig Status

Canadian Beaufort Sea

SDC Drilling Inc.			
SSDC CANMAR Island Rig #2	SDC	Set down at Roland Bay	Available

Central Mackenzie Valley

Akita/SAHTU			
Oilwell 500	51	Still out of the NWT, but is again available	Available

The Alaska - Mackenzie Rig Report as of November 15, 2012. Active drilling companies only listed.

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

This rig report was prepared by Marti Reeve

JUDY PATRICK

Baker Hughes North America rotary rig counts*

	Nov. 9	Nov. 2	Year Ago
US	1,806	1,800	2,016
Canada	370	383	500
Gulf	47	48	36

Highest/Lowest		
US/Highest	4530	December 1981
US/Lowest	488	April 1999
Canada/Highest	558	January 2000
Canada/Lowest	29	April 1992

*Issued by Baker Hughes since 1944

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• EXPLORATION & PRODUCTION

Cook Inlet explorers take next steps

Apache spuds its first well in the basin while Buccaneer plans to move jack-up rig from Homer for winter drilling at Cosmopolitan

By ALAN BAILEY
Petroleum News


JOHN HENDRIX


MARK LANDT

Two companies, both new to the Cook Inlet basin, are taking the next steps in their ventures to find and develop new oil and gas in the basin, company executives told the Resource Development Council's annual Alaska Resources Conference on Nov. 14.

Apache Alaska Inc., the company that has been conducting a major 3-D seismic survey program across broad areas of the basin, has spud its first exploration well in the basin, near Tyonek, on the west side of the inlet, John Hendrix, general manager of Apache Alaska, told the conference.

"We spud our first well this morning at 7:44 in the morning — our first Apache Alaska drilling operation," Hendrix said. Apache is primarily looking for oil in the basin, although the company also expects to find natural gas in the course of its exploration drilling.

Pushing oil production up to, say, 50,000 or 100,000 barrels per day would revolutionize the Cook Inlet, Hendrix said.

Apache's well, the Kaldachabuna No. 2, is being drilled in Cook Inlet Region Inc. subsurface land by the Patterson Rig 191. This is a reservoir play that Apache wants to investigate, to assess whether this type of play is replicated in other prospects that Apache's seismic reveals, Hendrix said.

Mark Landt, vice president, land and business development for Buccaneer Alaska, a subsidiary of Australian independent Buccaneer Energy, said that this winter Buccaneer is going to use the Endeavour jack-up rig that it has brought to the inlet to drill at Cosmopolitan, a known oil pool offshore Anchor Point in the southern Kenai Peninsula. There are estimated to be around 90 billion cubic feet of natural gas at Cosmopolitan, in addition to an estimated 44 million barrels of oil, Landt said.

The Endeavour rig is currently positioned at Homer in Kachemak Bay, undergoing some unanticipated repairs before being ready for service. Buccaneer anticipates moving the rig from Homer in about two weeks for drilling at Cosmopolitan, Landt said.

Buccaneer is in the process of drilling the no. 4 well in its producing Kenai Loop field at the City of Kenai and plans a further two to three wells there in 2013, Landt said. In 2013 Buccaneer also plans to drill an exploration well in each of its offshore Northwest Cook Inlet and Southern Cross units, and to shoot 3-D seismic and drill a well in its West Eagle prospect in the southern Kenai Peninsula. All told, the company anticipates drilling three to four onshore wells and three offshore wells in 2013, Landt said.

Apart from oil potential at Cosmopolitan and Southern Cross, Buccaneer's current exploration interest is focused on natural gas, Landt said.

Landt said for funding its capital requirements Buccaneer has entered into a $30 million revolving credit facility. In addition, since entering the Cook Inlet gas business Buccaneer has raised $66 million in capital on the Australian stock exchange, he said. ●

Contact Alan Bailey
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CORRECTION

Smith Bay

A story about the state's Nov. 7 oil and gas lease sales in the Nov. 11 issue contained an error.

The leases which NordAq Energy acquired in the Beaufort Sea areawide sale surround existing NordAq acreage in Smith Bay, not Harrison Bay as stated in the story.

Petroleum News apologizes for the error.

● EXPLORATION & PRODUCTION

Canada goes conservative

Service sector 'cautiously optimistic' about 2013 drilling, based on technology impact on well count; capital spending could drop 10%

By GARY PARK
For Petroleum News

The Petroleum Services Association of Canada has unveiled what would normally be seen as a dismal drilling forecast for 2013, but not in the current upstream environment.

"We are cautiously optimistic about 2013's drilling activity levels," said PSAC President Mark Salkeld in targeting 11,400 well completions for next year, up a mere 150 from this year's anticipated tally, partly reflecting the significant increase in drilling and completion spending on longer, more complex wellbores.

Mike Edmonds, chairman of PSAC's board of directors, noted that the total measured depth of the 2013 wells will be 22 million meters, about the same as was drilled in 2008 by 17,000 wells.

He said current estimates point to horizontal wells accounting for 70 percent of next year's wells, noting that technology advances allow for directional drilling at greater depths than ever before.

Salkeld said the first quarter of the new year will see a "typical ramp up of activity," then a slowing down during the spring melt, shifting to a solid second half as larger producers continue with their plans and mid-sized companies gain access to the capital they need.

He said oil wells are expected to account for 87 percent of the completions, with gas wells only being drilled as needed.

Lucas Mezzano, PSAC's first vice chairman, said "access to cash flow and capital depending programs of our customers will also contribute to drilling-activity trends in the new year."

Based on WTI of US$95

PSAC is basing its forecast on average gas prices of C$3.25 per gigajoule at the AECO hub in Alberta and West Texas Intermediate prices of US$95 per barrel.

Salkeld said that "ongoing suppressed gas prices" will see well completions in gas-weighted British Columbia drop 11 percent from 2012 to 385, lagging far behind the other three Western Canadian provinces.

Alberta is forecast to drill 7,045 wells, up 3 percent from this year; Saskatchewan 3,199 wells, down 1 percent; and Manitoba 750 wells, an increase of 5 percent.

Roger Serin, managing director and head of energy research at TD Securities, said capital spending in Western Canada will likely "pull back a little" in 2013 despite a tight recovery in gas prices, but oil sands investment will increase, reflecting "both the economics and the long lead times" needed in that sector.

Serin is targeting a 10 percent rise in oil sands cap-ex, following this year's anticipated 25 percent increase over 2011.

"On the conventional basis, we think spending will fall by 5 to 10 percent after about a 10-15 percent drop this year. If anything we're probably conservative on that number," he said.

Serin is targeting a New York Mercantile Exchange gas price in 2013 of US$4 per million British thermal units, noting the AECO price is usually 50 cents lower than Nymex.

Gas exports down

He noted that Canadian gas exports will fall to 55 percent of Canadian production this year, down from the historic level of 65 percent and "over the next couple of years it's going to fall even more because Marcellus production is not only g0ing to grow for the northeast U.S., but we recently started importing Marcellus gas into Canada to the tune of 500 million cubic feet per day and that will probably grow to 1 billion cubic feet per day."

Serin said that trend underscores the urgent need for Canada to move ahead with LNG exports to Asia — a message that does not seem to be resonating, given a forecast by Wood Mackenzie that the first shipments from Western Canada are not likely to occur until 2019.

"LNG matters, even if you're not with a company that's exporting LNG," he said. "The reason it matters is it will significantly drive activity in the Western Canada Sedimentary Basin and unless we get an export opportunity — whether to new markets in the U.S. or Japan, Korea and China in the form of LNG — we're going to be awash in gas for some time."

That will confine netbacks on long-term LNG contracts to US$4-US$5, Serin said.

But he welcomed the return of supermajors to Canada's non-oil sands sector, especially ExxonMobil's offer to take over Celtic Exploration and start drilling in the Duvernay formation, where wells cost C$10 million to C$15 million.

Serin also expects significant capital spending in the Montney liquids-rich play which straddles the northeastern British Columbia and west-central Alberta border, the Cardium tight oil play and the emerging Duvernay liquids-weighted shale play.

He said the industry has spent about C$4.5 billion acquiring Duvernay land in the last two years and expects capital sending in the formation to top C$1 billion in 2013.

Drilling days down

The latest statistics for 2012 covering the first nine months show member companies of the Canadian Association of Oilwell Drilling Contractors logged 82,295 operating days, compared with 95,084 in the same period of 2011, with total meters drilled declining to 15.86 million meters from 16.19 million meters, although wells averaged 1,938 meters up from 1,753 meters a year earlier.

Operators across Canada drilled 8,163 wells during the January-September period, off 11 percent from 9,178 wells in the first three quarters of last year.

Manitoba was the only province to report a gain, drilling 463 wells, up almost 35 percent, while British Columbia was at the other end of the spectrum, down 27 percent at 347 wells.

Alberta logged 3,682 oil or bitumen wells, off 62 from a year earlier, while wells targeting gas or coalbed methane slumped to 813 from 1,507.

A similar pattern prevailed in Saskatchewan, where 2,218 oil wells were drilled compared with 2,350 in the same period of 201. Gas wells in that province dropped to nine from 32. ●

Contact Gary Park through publisher@petroleumnews.com

● FINANCE & ECONOMY

Feds move to have Furie lawsuit tossed

DOJ says company acted prematurely in going to court to try to kill $15 million fine for illegal transport of drilling rig to Alaska

By WESLEY LOY
For Petroleum News

Federal officials are asking a court to dismiss a lawsuit an Alaska explorer filed in an effort to kill a $15 million fine for an alleged violation of the Jones Act.

Furie Operating Alaska LLC sued federal authorities, including Homeland Security Secretary Janet Napolitano, on Aug. 7 in U.S. District Court in Anchorage.

The suit concerns the ocean transport of a jack-up drilling rig in 2011 from Texas to Alaska's Cook Inlet, where Furie is exploring for natural gas.

Federal authorities determined Furie didn't have clearance under the Jones Act to use a foreign ship to haul the rig. U.S. Customs and Border Protection, an agency within the Department of Homeland Security, assessed a fine of $15 million, which corresponds to the agency's determination of the rig's value.

In its lawsuit, Furie seeks a judgment that the fine is "null and void." The company argues the fine is arbitrary and capricious, and unconstitutionally excessive. Furie also argues that the rig was not "merchandise" as defined in the law, and therefore no Jones Act violation occurred.

Only a court has the authority to compel payment, the motion says. And so far, federal authorities haven't sued to enforce and collect the Jones Act penalty assessed against Furie.

On Nov. 9, Department of Justice lawyers representing Homeland Security answered Furie's suit with a motion asking the court to throw out the case, arguing Furie sued prematurely.

Waiver inconsistency?

The Jones Act requires that cargo transported between domestic ports be done with U.S.-made ships, owned and crewed by American citizens.

A foreign-flag, heavy-lift vessel, the M/V Kang Sheng Kou, hauled the Spartan 151 rig from a Texas port to Vancouver, British Columbia. From there, U.S.-flag tugs towed the rig to Cook Inlet, arriving on Aug. 11, 2011.

Escopeta Oil Company LLC originally arranged the rig transport, but Furie acquired Escopeta on June 29, 2011.

Furie's suit says the Kang Sheng Kou was used because the U.S.-flag Jones Act fleet had no ship capable of safely carrying the rig around South America, which was necessary because the rig was too big to pass through the Panama Canal.

Furie argues that, in 2006, Homeland Security granted a Jones Act waiver, although it was for a different jack-up rig and a different foreign transport vessel.

Problems developed with that rig, and it was never transported to Alaska.

In 2010, Furie asked Napolitano to reconfirm the 2006 waiver, saying the basis for the original waiver had not changed — a looming natural gas shortage in Southcentral Alaska, home to a major military base and the Anchorage international airport.

But Homeland Security officials told the company the 2006 waiver was no longer in effect and that it would need to seek a new waiver or face penalties, the government's Nov. 9 motion says.

On March 7, 2011, Napolitano denied Furie's request for a waiver.

"Nonetheless, Furie assumed that a Jones Act waiver would be granted," the motion says, and the Kang Sheng Kou departed Texas with the Spartan 151 rig.

As the long voyage unfolded, Furie continued talks with federal officials, who at one point said initiating the rig transport after Napolitano had denied the waiver would be viewed as an "aggravating factor" in a Jones Act violation.

Customs and Border Protection officials also said the violation was committed for commercial expediency. They noted that Furie could be eligible for millions of dollars in state drilling tax credits as a result of transporting the rig in violation of the Jones Act.

Furie feared Homeland Security officials might seize the rig, but that didn't happen.

No need to pay

Justice Department lawyers argue Furie's suit is premature, as assessment of the $15 million penalty does not constitute a "final agency action."

Furie has not paid any portion of the fine. And although Customs and Border Protection officials have hit Furie with demand letters and threats to forward the matter for "collection action," a violator is "under no compulsion" to pay a penalty that has been merely assessed, the government's motion says.

Only a court has the authority to compel payment, the motion says. And so far, federal authorities haven't sued to enforce and collect the Jones Act penalty assessed against Furie.

If and when the government files suit, Furie would have an opportunity at that juncture to defend against the penalty, the motion says.

And so Furie's lawsuit should be dismissed, the Justice Department argues. ●

Contact Wesley Loy at wloy@petroleumnews.com

EXPLORATION & PRODUCTION

Cook Inlet Energy plans more gas wells

Anchorage-based firm to spud exploratory well soon at Olsen Creek prospect; fracking operation conducted at neighboring Otter

By WESLEY LOY
For Petroleum News

Cook Inlet Energy LLC is aiming to spud an exploratory well by mid-December at its Olsen Creek natural gas prospect on the inlet's west side.

David Hall, chief executive of the Anchorage-based company, said the Olsen Creek gas structure has "strong potential."


DAVID HALL

In recent months, the company has been upgrading and extending the road system to the prospect, and hopes to start construction soon on the well pad, Hall said.

He made the comments during an Oct. 30 conference call for investors in Miller Energy Resources Inc., the Tennessee-based parent company of Cook Inlet Energy.

Potential 84 bcf field

Olsen Creek is among a number of shallow gas prospects Cook Inlet Energy has on the west side. The Olsen Creek prospect is west of the ConocoPhillips-operated Beluga River gas field.

The initial well will evaluate the Olsen Creek structure, Hall said.

"If successful, we see the potential for 24 wells on our leases," he said.

The company estimates a potential for each well of up to 3.5 billion cubic feet of gas, with a potential reservoir size for the field of about 84 bcf, Hall said.

Olsen Creek's oil potential also is being evaluated, he said.

The company is using its own rig 34 to drill the gas prospects. The truck-mounted Atlas Copco RD20 rig was brought up from Tennessee and extensively modified for work in Alaska.

The Otter prospect

About seven miles northeast of Olsen Creek is the Otter prospect, where Cook Inlet Energy this year drilled the Otter No. 1 exploratory well.

Olsen Creek is among a number of shallow gas prospects Cook Inlet Energy has on the west side. The Olsen Creek prospect is west of the ConocoPhillips-operated Beluga River gas field.

Recently the company conducted a hydraulic fracturing operation on Otter No. 1, using more than 800 barrels of proppant, Hall said.

Now the trick is removing the fracking fluid, which is believed to be keeping the formation gas from entering the wellbore, he said.

"Currently, we are recovering portions of the frack fluid as the well releases it," Hall said. "We have recovered 150 barrels to date. We're still very optimistic about Otter and will continue trying to bring it online once we recover the frack fluids."

Hall noted that while drilling Otter, mud pump problems forced a halt to the drilling at about 5,600 feet on a well planned for a depth of 7,000 feet, Hall said.

As a result, only a short section of the Beluga formation and none of the Tyonek formation were evaluated, he said.

New, more robust mud pumps have been purchased for installation on rig 34, and the company is planning a second Otter well to a minimum depth of 7,500 feet, which should yield more potential gas pay zones for evaluation, Hall said.

Cook Inlet Energy also operates the West McArthur River oil field and the offshore Redoubt unit with the Osprey platform.

During the Miller Energy investor conference call, executives said the company's total Alaska oil production was running between 1,400 and 1,450 barrels a day. ●

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GOVERNMENT

Agencies extend habitat rule comment

The U.S. Fish and Wildlife Service and the National Marine Fisheries Service have re-opened the public comment period for a proposal to simplify the process for identifying the critical habitat of species listed under the Endangered Species Act. The original 60-day public comment period closed on Oct. 23 but, following public interest in the proposal and multiple requests for more time for comments, the agencies are extending the comment period by an additional 90 days. The extended comment period will end on Feb. 6.

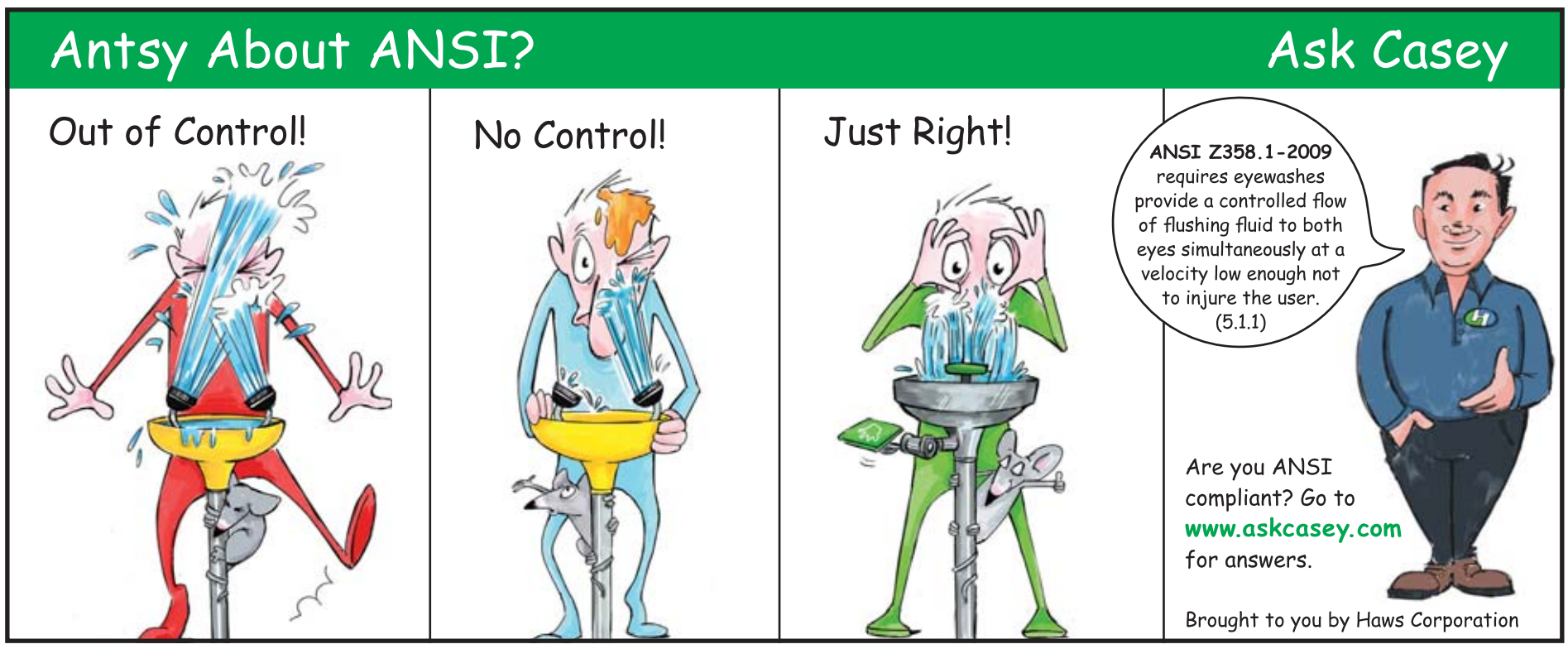
When an animal is listed for protection under the Endangered Species Act, the agency making the listing has to specify a critical habitat for the animal. But the act requires an economic evaluation of the critical habitat designation, with the potential for excluding areas of critical habitat from designation if the economic downside of designation outweighs the upside of habitat protection.

Fish and Wildlife and the Fisheries Service propose changing their Endangered Species Act regulations to require publication of preliminary estimates of the economic impacts along with a proposed habitat designation — the agencies have in the past completed the draft economic analysis at some time after the proposed habitat designation has been published for public review.

"Completion of the draft economic analyses at the time of (habitat) proposal would allow the agencies to refine habitat proposals earlier in the process, and provide the public with additional information to help them understand and comment on those proposals," the agencies said in a Nov. 7 press release.

The proposal is part of a general effort to find improved ways to conserve imperiled species while also being consistent with an executive order by the president to identify regulatory changes that will achieve regulatory objectives more efficiently and effectively, the agencies said.

—ALAN BAILEY



● GOVERNMENT

US limits Rockies oil-shale development

Obama administration scales back to a third of area proposed by George W. Bush administration; wilderness-quality lands off table

By PAUL FOY
Associated Press

The U.S. Department of the Interior scaled back a Bush administration plan Nov. 9 to lease Western range lands for development of oil shale and tar sands, the unconventional sources of oil found in pockets of the Rocky Mountains.

Federal officials said they were set to authorize 1,250 square miles of public land for commercial leasing in Colorado, Utah and Wyoming. That's a third of the range lands that President George W. Bush planned to offer, and the new administration said it was taking wilderness-quality lands off the table.

On paper, the Rocky Mountain oil shale deposits could yield a great abundance of oil — more than 1 trillion barrels — but environmental groups say it would involve ripping up public lands and depleting scarce sources of water. Political leaders in Arizona and Nevada and farmers worry about a diversion of Colorado River water. Big-game hunters oppose the intrusion of mining. Thousands of pages of comments have been filed on the plans.

The U.S. Bureau of Land Management said it selected the best reserves for oil shale, a rock that contains fossilized algae, a primitive form of oil that never received enough heat or pressure to produce liquid crude. It's also a hard nut to crack — major oil companies are still experimenting with ways to make production economical, notably by baking rock in the ground to release fluids.

The federal government is making about 200 square miles of the federal lands available for tar sands mining in Utah, similar to one project already under way on the state's own trust lands. The BLM issued the decision Nov. 9 along with a 6,245-page environmental impact study.

Environmental groups applauded Interior Secretary Ken Salazar's caution. Utah politicians called it short-sighted.

"Once again, despite President Obama's calls for an 'all of the above' energy approach, his administration is moving to limit American energy production and the jobs that come with it," said Sen. Orrin Hatch, R-Utah.

Sen. Mark Udall, D-Colo., struck a measured response, saying he was concerned about the use of limited water supplies.

"Nonetheless, I look forward to seeing this technology explored further. We need an all-of-the-above energy policy," Udall said Nov. 9. "The Interior Department's decision ensures that we will not be out over the front of our skis with untested technology."

The federal government has yet to authorize widespread development, instead leasing 160-acre research plots to a handful of companies testing extraction methods. Rifle, Colo.-based American Shale Oil LLC is heating an underground zone by pumping a pool of oil down a well and blasting it with hot fuel gas.

The BLM said players must prove their research before winning larger commercial leases. It approved another two research leases Nov. 9, to ExxonMobil Exploration Co. and Natural Soda Holdings Inc. for in-ground development in Colorado's Piceance basin.

In Wyoming, the BLM said it was putting limits on development in areas where sage grouse gather. That was small comfort to the Laramie-based Biodiversity Conservation Alliance, however. The group said any kind of development can chase off sage grouse, the birds that puff themselves up in mating dances.

The U.S. Fish & Wildlife Agency is under court orders to determine by 2015 whether sage grouse deserve protection under the Endangered Species Act.

Also in Wyoming, the BLM pulled the Red Desert's Adobe Town from consideration, a 128-square-mile wilderness study area rich in fossils.

A host of Republican politicians sounded off Nov. 9.

"The Obama Administration should cancel this plan and work with Congress and governors on solutions that will create jobs and strengthen our energy security," said Sen. John Barrasso, R-Wyo.

Rep. Ed Whitfield, R-Ky., chairman of the House Energy and Power Subcommittee, said the Obama administration was "locking up" as much potential oil "as the rest of the world's proven reserves combined." ●

PIPELINES & DOWNSTREAM

Trans-Alaska pipeline upgrades continue

Alyeska progresses pump station electrification and installation of technology for dealing with low oil flow through line

ALASKA STATE PIPELINE COORDINATORS OFFICE

As oil throughput in the trans-Alaska pipeline declines, Alyeska Pipeline Service Co. continues to upgrade the line for low-flow conditions.

By ALAN BAILEY
Petroleum News

With oil production from Alaska's North Slope in continuous decline for many years, Alyeska Pipeline Service Co., the operator of the trans-Alaska oil pipeline, has been upgrading the line and taking other actions to accommodate the technical issues caused by declining pipeline throughput. And an overview of the latest status of Alyeska's efforts to deal with the slowing flow of oil forms a core component of the 2012 State Pipeline Coordinator's Annual Report, published in October by the Alaska Department of Natural Resources.

Pipeline throughput peaked at more than 2 million barrels per day in 1988 but had dropped to around 600,000 barrels per day in 2012, the report says. The State Pipeline Coordinator's Office oversees the construction and operation of pipelines, including the trans-Alaska pipeline, on state right-of-way leases.

Low flow

The key issue for the trans-Alaska pipeline is the speed at which oil flows down the line. Essentially, the pipeline has a fixed internal volume configured to handle peak oil throughput and, with less and less oil entering the upstream end of the line, oil filling the line takes longer and longer to travel from the North Slope to Valdez.

With the slowing oil flow, the original pipeline pump systems, designed to handle relatively high rates of oil throughput, became inefficient and unsuitable for flexibly handling the lower flow rates. And, with the oil taking longer to travel the pipeline's 800-mile length, the oil, warm as it exits the oil fields, becomes increasingly cold along the pipeline route, raising risks associated with the freezing of water carried along with the oil and potentially increasing the clogging of the pipeline walls with wax deposits.

Strategic reconfiguration

In the early 2000s, to address the increasing inefficiency of the pumping systems as oil volumes declined, Alyeska initiated what it termed "strategic reconfiguration," a massive project involving the replacement of the original turbine driven pumps by new state-of-the-art electrically powered pumps — variable frequency drives on the new pumps would enable the pumps to operate over a relatively wide range of pump speeds. And as part of strategic reconfiguration, Alyeska installed new remotely operated pipeline control and monitoring equipment, using modern digital technology.

Alyeska completed the electrification upgrades at pump stations 3, 4 and 9 in the years 2005 to 2009. Upgrade work started on pump station 1 in the 2000s but Alyeska subsequently put this upgrade on hold, the report says.

With fewer pump stations needed at lower oil throughputs, Alyeska shut in the remaining pump stations, apart from pump station 5, which acts a pressure relief station on the south downslope of the Brooks Range and does not pump oil.

Pump station 1

During the 2011 financial year, which ended on June 30 of that year, Alyeska restarted the upgrade at pump station 1 in a phase of strategic reconfiguration that the company called the electrification and automation project, or EA, the report says. The EA project involves the installation of three new mainline pumps, with electric motors and variable frequency drives; the installation of a 12-megawatt turbine-powered electrical generator; and the modification of two of the three booster pumps at the pump station for electrical service. The project also involves the construction of a power line and electrical substation, to enable the new pumps to use power from the Prudhoe Bay grid in the event of a shutdown of the new generator system.

As part of the project, by the end of June of this year Alyeska had installed about 200,000 feet of the 293,000 feet of new electrical cabling needed at pump station 1. The new electrical substation was completed in the spring of 2012 and

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PIPELINE UPGRADES

work on the pump station cabling is progressing around the clock, the report says. The EA project appears to be on target for completion in the summer of 2014, the report says.

Three events

From the perspective of falling oil temperatures, the report highlights three events that illustrate the vulnerability of the pipeline to low-flow problems. In November 2006 low flow resulting from reduced North Slope oil production, storms at sea and some tanker loading problems at Valdez caused the internal pipeline temperature to drop to 37 F. In 2008 delayed tanker loadings because of storms resulted in a temperature drop to below 40 F. And in January 2011 an oil leak at pump station 1 on the North Slope triggered an extended pipeline shutdown, with the oil temperature dipping to 26 F.

"While these events were cause for concern, none of them prevented the restart of TAPS," the report says. "A future event with a more extended shut down or lower flow rate might seriously affect the ability to restart flow."

ALASKA STATE PIPELINE COORDINATORS OFFICE

A staff member from the State Pipeline Coordinator's Office views pump station 12 modifications designed to facilitate a cold pipeline startup in the winter.

And the company has revised its procedures for a pipeline cold restart. Under new procedures, if the oil temperature drops below 40 F during a pipeline shutdown, a startup of the pump station recycling systems to warm the oil will precede the startup of oil flow through the pipeline. However, if the oil temperature drops below the normal operating temperature range in a situation where oil flow has stopped for an extended duration, it may be necessary to pump oil both north and south in the pipeline to prevent the oil in the line gelling, the report says.

And, to implement the new cold restart procedures, Alyeska has installed new 540-horsepower booster pumps at pump stations 7 and 9 and anticipates installing a 3,390-horsepower engine for the booster pump at pump station 12 in 2013, the report says.

The company is improving the recycling arrangements at pump station 5 by using a tank heater to add heat to the oil in the event of a cold restart.

Alyeska has accepted that the minimum safe oil temperature to maintain oil flow is 31 F but the company also says that the oil temperature should be maintained at or above 36 F, with this being the target minimum temperature to be maintained as a result of low flow mitigation projects, the report says.

Refinery changes

One particular issue that Alyeska now needs to contend with is a further drop in oil temperatures in the southern section of the pipeline as a consequence of the reduced temperature and lower volume of residue fluids entering the line from the oil refinery at North Pole, near Fairbanks. The refinery uses some oil from the pipeline as feedstock and returns the refinery residues back to the line. The heat from these residues has been an important factor in maintaining adequate

see **PIPELINE UPGRADES** *page 12*

Recycling

Since the January 2011 shutdown incident Alyeska has been recycling oil at pump stations 3, 4, 7 and 9 to warm the oil when oil temperatures in the pipeline drop, the report says. Recycling involves pumping some or all of the oil through pressure-reducing valves at the pump stations, with the pumps adding energy to the oil and the pressure reduction converting flow energy to heat.

However, Alyeska has encountered some snags with the recycling arrangements, including mechanical problems at pump stations 3 and 4, and flow-induced vibrations at pump station 7. The company is upgrading the recycling systems at these pump stations and anticipates the systems being fully operational by late 2012 or early 2013, the report says.

Alyeska has also sanctioned a project designed to further increase oil temperatures through the use of improved control valves for the recycling systems at pump stations 3 and 4, and through the use of new control valves at pump station 7, the report says.

The company is investigating the possibility of heating the pipeline oil flow at pump station 5 and is also considering other possibilities for mitigating the risks to winter pipeline operations. Those possibilities include injecting additives such as freeze-depressants or emulsifiers into the oil; removing water from the oil at pump station 1; and tightening the standards for the amount of water and sediment allowed in oil delivered to the pipeline.

The report also points out that another way of addressing the low flow issues would be to increase production from the North Slope oil fields.

Follow up

As a follow up to the January 2011 incident and in response to a safety order by the U.S. Department of Transportation, Alyeska has been replacing or removing some old piping at pump station 1; constructing an additional facility between pump stations 5 and 10 to launch and receive the torpedo-shaped "pigs" that are used to clean and inspect the inside of the line; researching the installation of increased pump station tank capacity; and staging equipment needed for cold temperature operations or a pipeline restart in cold conditions, the report says.

NATURAL GAS

Begich proposes benefits for in-state gas

Sen. Mark Begich said Nov. 12 that he is proposing legislation to apply one-stop permitting benefits to any Alaska natural gas transportation system — an in-state pipeline, trucking gas or any combination of transportation systems.

The legislation would amend the Alaska Natural Gas Pipeline Act of 2004, which created a federal office to coordinate with more than 20 federal agencies, the Canadian government, the State of Alaska, tribal governments and other stakeholders with the goal of seeing a natural gas pipeline constructed to move Alaska's natural gas to Lower 48 or Canadian markets.

Begich said he was responding to skyrocketing energy prices in Interior and rural Alaska.

The bill adds an in-state natural gas transportation system and an in-state gas line and associated liquefied natural gas project to the purview of the Office of the Federal Coordinator of Alaska Natural Gas Transportation Projects.

"Alaskans are crying out for some kind of solution to the rising cost of energy — particularly in rural Alaska and communities like Fairbanks," Begich said in a statement. "High energy prices and potential energy shortages threaten our state's economic stability. We have to start proposing solutions in an effort to bring costs down."

The legislation provides the same regulatory deadlines, expedited judicial review and tax advantages currently applicable to a natural-gas pipeline traveling the Dalton Highway to Canada to any natural gas project bringing North Slope gas to a market in Alaska or elsewhere.

"I have always said the market will determine if we can build a project and where," Begich said. "It's government's role to provide a swift and certain regulatory environment and then get out of the way. This bill does just that. Federal permitting and tax benefits for an instate natural gas project will make any option more financially feasible for private-sector developers and hopefully bring relief to Alaskans facing high energy prices."

Begich said he would seek further comment from stakeholders before formally introducing the bill.

—PETROLEUM NEWS

Valdez lives up to its snowy reputation

As a few roofs in Anchorage collapsed under the weight of record snowfalls in the 2011-12 winter, Valdez, the location of the marine terminal where oil from the trans-Alaska pipeline is loaded into tankers for shipment south, lived up to its reputation as the snow capital of Alaska.

"More than 450 inches of snow fell in Valdez between October and April, with the majority falling during the month of December 2011," Alaska's State Pipeline Coordinator's Office wrote in its annual report, published in October.

With the rate of snow accumulation quickly outpacing normal snow removal capabilities, the large volumes of snow on infrastructure such as oil storage tanks at the marine terminal became a prime concern for pipeline and terminal operator Alyeska Pipeline Service Co. and for state agencies, the report says.

Alyeska had to prioritize the snow removal needs and mobilize extra snow removal crews to ensure the safety of personnel and to minimize any oil discharge risk at the terminal, the report says. Staff from the Alaska Department of Environmental Conservation and environmental program specialists in the State Pipeline Coordinator's Office monitored snow accumulation and removal daily, consulting with each other and Alyeska to make certain of the safe, continued operation of the terminal, the report says.

—ALAN BAILEY

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PIPELINE UPGRADES

oil temperatures in the pipeline south of North Pole. Since February 2012 an energy savings initiative at the refinery has reduced the temperature of the residues by 20 to 25 F, while a cut back in refinery production has resulted in a corresponding drop in the volumes of refinery residue, the report says.

Pipeline vibrations

Alyeska has also been addressing issues associated with pipeline vibrations at the three mountain passes that the line crosses: Atigun Pass in the Brooks Range, Isabel Pass in the Alaska Range and Thompson Pass, north of Valdez. The vibrations first appeared in the 1990s at Thompson Pass, where Alyeska has mitigated the problem by increasing the downstream backpressure in the line, the report says. The company is trying a similar approach at Atigun Pass.

"Preliminary indications are that vibrations have been reduced and APSC (Alyeska) is evaluating the data to see if TAPS can operate continuously with this backpressure," the report says.

With metal fatigue damage being predictable by a mathematical analysis, an engineering study of the vibrations concluded that vibration induced stresses at Atigun Pass will not result in any risk of a pipeline rupture "in the intermediate or near future," the report says. However, the vibrations have caused cracks to appear in some of the "shoes" that cradle the pipeline on the above-ground pipeline support structures in the Chandlar Shelf area on the south side of the pass. Alyeska now regularly monitors and, as necessary, replaces the shoes in the affected area, the report says. The company is also taking steps to improve the shoe design and is installing accelerometers for better vibration data logging and analysis.

Alyeska has also been addressing issues associated with pipeline vibrations at the three mountain passes that the line crosses: Atigun Pass in the Brooks Range, Isabel Pass in the Alaska Range and Thompson Pass, north of Valdez.

Vibration levels in Isabel Pass, although increasing, are much lower than in the other two passes, the report says.

"The original TAPS design has built-in redundancies. Such safety factors include the allowance for limited (pipeline) support failure," the report says. "For these reasons, and others, the vibrations in these areas do not appear to constitute an integrity threat." ●

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NATURAL GAS

Small-scale LNG a niche which can grow

By BILL WHITE

Researcher/writer for the Office of the Federal Coordinator

The famous face of LNG involves multibillion-dollar developments rescuing stranded treasures of natural gas, shipping it across oceans aboard tremendous tankers to distant cities where customers crave a less polluting alternative to oil or coal to make electricity and heat homes.

BILL WHITE

But running in the background is a more mundane facet of liquefied natural gas.

This facet, unlike its globe-trotting brother, doesn't involve multinational lending consortia, trade-balance considerations and national-interest debates. It involves consuming LNG in sips not gulps, deliveries by trucks not tankers.

This part of the industry might be considered niche LNG.

The cast of characters includes local gas utilities that want a small cache of gas compactly warehoused for quenching demand spikes during cold snaps.

And pipeline companies that need a spurt of extra gas to maintain pressure and reliability at times of high consumption.

And off-the-pipeline-grid industrial sites — a mine, perhaps, or a small community — that need a fuel that can be trucked in affordably.

This small side of LNG mainly encompasses the original commercial use of liquefied natural gas — as a so-called peak-shaving fuel for utilities — a use of natural gas that started 70 years ago, well before the launch of international trade in LNG.

But money also is getting invested and plans are being drawn to find other niche markets for LNG.

Small-scale LNG champions dream of small power plants on isolated islands burning LNG not oil-based fuels.

They want to extend the reach of natural gas into transportation fuels — a domain oil dominates — with heavy-duty trucks powered by LNG not diesel, and ships burning natural gas not oily bunker fuel.

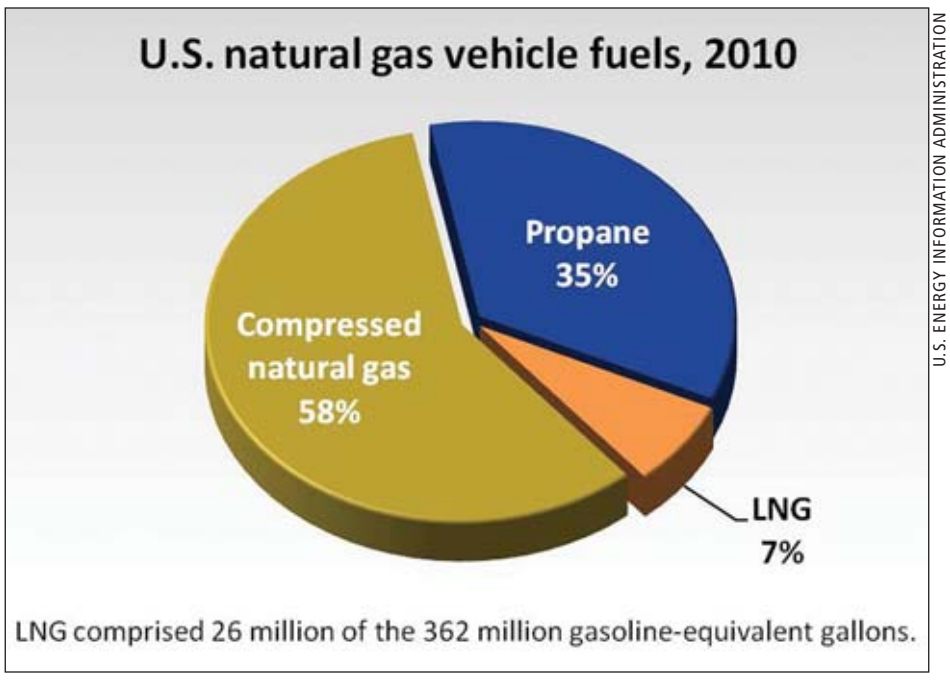
They want oil fields powered by LNG not diesel. And remote oil fields liquefying associated gas production rather than burning or venting it.

"Small-scale LNG is ... increasingly being used as a means of monetizing early gas from fields distant from infrastructure, reducing the need to flare," a Shell executive wrote in "LNG 2012," a Petroleum Economist publication.

Much R&D effort is getting channeled to niche LNG, trying to minimize the disadvantages of small economies of scale in an industry defined by megaprojects.

If costs can be wrung from the machinery of small-scale liquefaction, transportation, storage, regasification or how engines consume LNG, the resulting efficiencies can make niche LNG an important growth sector for the industry.

"On the back of innovations in small-scale liquefaction and engine technology, the spread of gas to transport may yet have the potential to become a second wave of the LNG business," as Ajay Shah, head of strategy and portfolio in Shell's Global LNG business, put it in "LNG 2012."



U.S. ENERGY INFORMATION ADMINISTRATION

Two forces — economic, environmental

It's almost impossible to draw a sharp line separating natural gas liquefied for export from LNG made for niche uses.

Some LNG stored to slake utility demand spikes — called peak-shaving gas — is homemade and some is imported. Some homemade LNG is trucked across the border as exports.

Still, certain information is available that sketches an outline of the industry:

In the United States, one plant made LNG for export — in Nikiski, Alaska — and 59 made LNG for peak shaving, according to Energy Information Administration 2008 figures. In addition, the United States had 41 other sites where LNG was trucked in and stored for peak shaving, but where no LNG making occurred.

Worldwide, about 260 peak-shaving and storage sites exist, according to the University of Texas Center for Energy Economics. That compares with 26 plants in 19 countries that make LNG for export and about 90 plants worldwide that receive, store and regasify large volumes of imported LNG.

But equating number of plants with LNG production would be misleading, like assuming convenience stores outsell supermarkets because there are more of them. A typical U.S. LNG-for-peak-shaving plant can process 5 million to 20 million cubic feet of gas per day, according to Black & Veatch, a global engineering and construction firm involved in developing LNG projects. (That's not much; a typical house might consume 50,000 cubic feet of gas per year for heat; much more in Alaska, less in Alabama.) But the world's LNG-for-export plants range in size up to 5.4 billion cubic feet a day; the average processing capacity is about 1.5 bcf, roughly 100 times larger than the typical peak-shaving LNG plant.

In other niche markets, LNG has barely a toenail hold. In the United States natural gas provides just 0.2 percent of vehicle fuel, and almost all of that gas is compressed methane or propane, not LNG.

As of last year, only 29 of the tens of thousands of ocean-going vessels used LNG as their main fuel. Most were ferries serving the seas around Norway. However, many of the world's 370 LNG tankers use boil-off, or vaporized, gas from their cargo for some of their energy needs.

The drive to grow small-scale demand for LNG stems from two potent forces.

One is economic. A gap has opened between oil and natural gas prices in parts of the world. In an era when oil prices have averaged a lofty $90 a barrel for the past five years, pained consumers of oil are hunting for less-expensive fuels.

In North America the price gap is acutely wide, making fuel switching more alluring. Oil is sold in increments of 42-gallon barrels and natural gas in incre-

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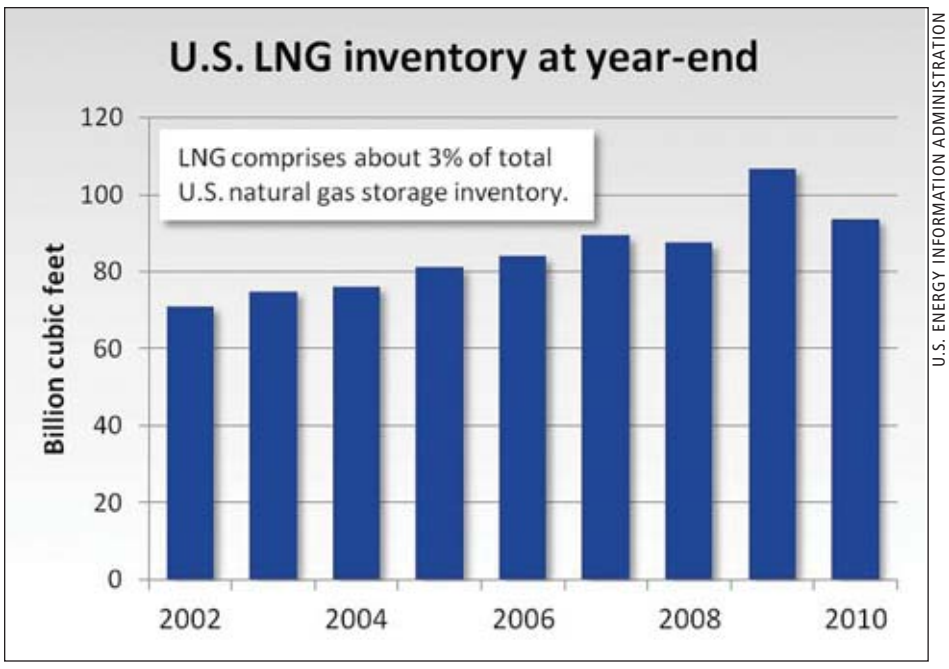

U.S. ENERGY INFORMATION ADMINISTRATION

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SMALL-SCALE LNG

ments of 1,000 cubic feet. Because a barrel of oil packs about six times more energy than 1,000 cubic feet of gas, on a pure energy basis oil should be priced about six times higher than gas. But in North America today, amid a shale-gas supply glut, oil is priced 25 times higher than gas. That kind of gap shortens the break-even moment of switching fuels.

The other force at play is environmental. Natural gas burns more cleanly than other fossil fuels, and governments are demanding fewer toxic and greenhouse-gas emissions from power plants, ships, trucks and other fuel users.

The most beaming optimists see a glorious future for LNG, one in which LNG-powered engines guzzle 31 bcf a day of the fuel in North America alone, as one consultant predicted at a Canadian energy conference this fall. Or the ocean's ships burning 4 bcf a day worth of LNG in their boilers, as executives with GDF Suez, a major European energy company, predicted in "LNG 2012."

Others think that's crazy talk.

Below we look briefly at some niche uses of LNG.

Peak shaving by utilities

In the chain of events that routes methane from deep underground in some faraway place to the pilot light on your furnace, storage is a key link.

Storage balances the wild swings in natural gas consumption during the year — high demand for heat during winter, high demand for air conditioning during summer — with the steady flow of gas production year-round. Excess production gets stored during slack demand so utilities can use the gas later, sort of like canning the fall harvest to eat during winter and spring.

The U.S. Energy Information Administration calls gas storage and peak shaving "a risk-management calculation" by the utility or pipeline company. It's costly to install storage and peak-shaving plants. "However, the cost of a service interruption, as well as the cost to an industrial customer in lost production, may be much higher" if they don't have gas when they need it.

In addition, storing gas means a local utility avoids reserving tremendous — and expensive — space on supply pipelines, space the utility would use only rarely during demand spikes. "The objective is to maintain sufficient local underground natural gas storage capacity and have in place additional supply sources such as LNG and propane air to meet large shifts in daily demand, thereby minimizing capacity reservation costs on the supplying pipeline," the EIA says.

In the gas-storage game, LNG plays a bit part.

Most gas storage occurs in large volumes, with gas as a vapor piped underground into depleted gas fields, salt caverns or aquifers. Heading into this winter, U.S. utilities, producers, traders and pipeline companies has almost 4 trillion cubic feet of gas packed into underground storage — a record amount. With gas production of about 67 billion cubic feet a day in the dead of winter and gas consumption of perhaps 90 bcf a day, this stockpile, plus imported Canadian gas, will help keep the lights on and furnaces warm.

By contrast, LNG stored in above-ground tanks totals a mere 90 bcf or so, not all of it for peak shaving. The big disadvantage of LNG storage for peak shaving is that it's expensive relative to underground storage. The big advantage is the

see **SMALL-SCALE LNG** *page 15*

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SMALL-SCALE LNG

LNG is close by and can be put to use quickly.

New England is a hotbed of gas liquefaction for peak shaving because the area hosts no underground storage sites and pipeline capacity into the region is either limited or non-existent in rural areas. At year-end 2010, 17 of the nation's 67 sites where LNG was stored largely for peak shaving were in New England, according to EIA data.

Trucking, not piping, LNG

LNG is either made at peak-shaving sites or trucked there in special insulated tanks — commonly 40-foot-long Thermos bottles on wheels. LNG is too cold — minus 260 — to be piped anywhere; steel pipe exposed to the frigid LNG would shatter.

The United States doesn't import much LNG, but the lion's share of it arrives at a receiving terminal in Boston harbor. That terminal can warm the gas back into a vapor and inject it into two interstate natural gas pipelines and the local gas utility's pipes. The terminal also features four truck-loading bays that can send out 100 million cubic feet a day. The terminal operator, GDF Suez, boasts its customers include local gas distribution companies throughout New England, power plants, gas marketers and industrial users.

China is another cradle of trucked LNG.

Black & Veatch and its Chinese partner Chemtex International have built or are building 16 LNG distribution plants across China, according to "LNG 2012." A 4-year-old plant called Erdos in remote Inner Mongolia has four loading stations that fill 33 trucks a day on average.

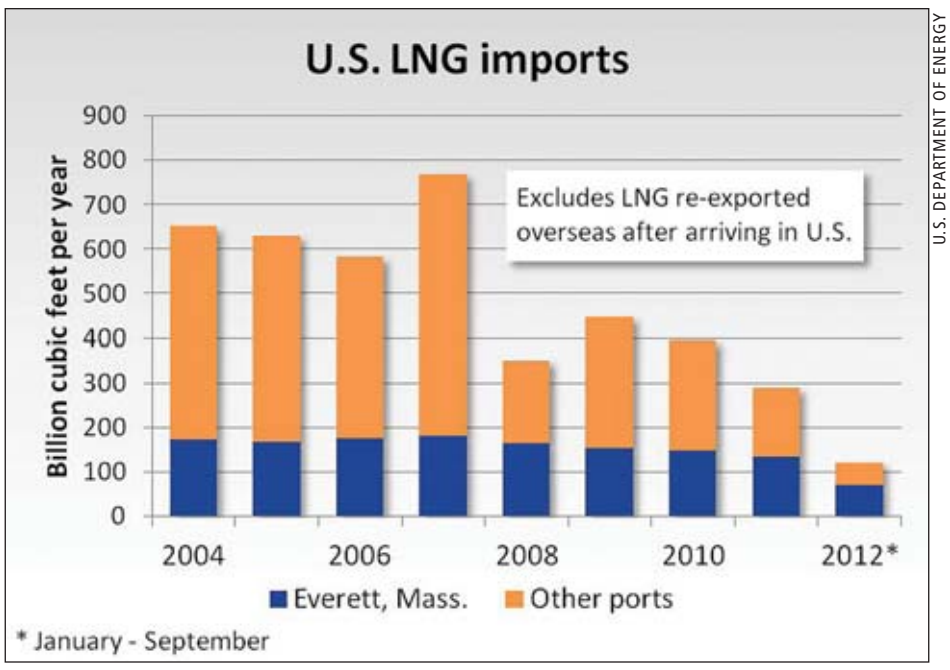
"The model for Chinese developments is a central LNG plant which distributes LNG to multiple gas users in industrial and residential markets," Black & Veatch executives wrote in the article.

One of the executives, Shawn Hoffart, presented this fall at a London conference about the latest innovation: a new northern China plant that uses coal from a nearby mine as the feedstock to make LNG and methanol. He estimated the plant will make 78 truckloads a day of LNG.

On a very small scale, some U.S. LNG gets trucked to remote users in Mexico.

A U.S. company called Applied LNG Technologies has been trucking LNG to Mexico since at least 1998 from a liquefaction plant in Topock, Ariz.

Last year the company trucked 1.6 bcf across the border, according to the Energy Department. It's a niche business, to say the least. Last year the U.S. piped 500 bcf of gas to Mexico.



U.S. DEPARTMENT OF ENERGY

Applied LNG plans to double the capacity of its Arizona liquefaction plant so it can sell more LNG as vehicle fuel in California, another market it serves.

LNG gets trucked in small quantities elsewhere around North America to users off the gas pipeline grid. For example, since 1998, Fairbanks Natural Gas LLC has trucked LNG from its small liquefaction plant served by Alaska's Cook Inlet gas fields to customers 300 miles north in Fairbanks. Last year it delivered about 900 million cubic feet to 1,100 customers, mostly commercial accounts eager to avoid high-cost fuel oil. Fairbanks Natural Gas, and separately the Fairbanks-area electric utility and a nearby oil refinery, are considering trucking larger volumes of LNG about 350 miles south from Alaska's North Slope fields.

Hawaiian utilities also are moving to import LNG instead of burning more costly and dirtier oil-derived fuels. Because Hawaii's demand would be so small, the gas utility looks to start with a pilot project of LNG delivered in insulated containers loaded aboard cargo ships that call on the state. In time, the gas and electrical utilities might work together to expand the imported volume enough to justify tanker deliveries rather than truckloads.

Among pending applications at the U.S. Department of Energy for permission to export LNG is one from a business eying the market of Caribbean utilities that burn oil. Florida-based Carib Energy wants permission to export 3.44 bcf a year "to any country located within Central America, South America or the Caribbean which has or in the future develops the capacity to import LNG" stored in containers that cargo ships would carry.

"Carib ... will transport the LNG within the United States over highways, using approved 40-foot ... LNG containers," its application says. The project anticipates loading no more than 11 trucks a day. The exports could occur from any of a variety of southern U.S. ports.

The buyers would include power plants, industrial and commercial customers that need small amounts of LNG "and would not otherwise be served by very large suppliers of LNG," Carib's application says.

LNG for heavy-duty trucks

LNG is a niche fuel for vehicles, too.

Only 3,354 vehicles in the U.S. use LNG as a fuel, according to the EIA.

Many of them are trucks that move cargo around the huge neighboring ports of Los Angeles and Long Beach, California. To cut air pollution, those ports prohibit drayage trucks from burning dirty fuels.

Most of the trucks now burn clean diesel, but some — 8 percent of the Los Angeles port fleet — use LNG. The ports have LNG fueling stations to make sure the gas is available to truckers.

Some city and regional buses, garbage trucks, heavy-duty tractors also use LNG.

Putting more LNG-fueled vehicles on North American roads might be confined to heavy-duty vehicles, even though natural gas is priced so much lower than oil-based fuels. Big fuel-guzzling trucks that are on the road all day can recoup faster the higher up-front cost of LNG vehicles.

Still, LNG vehicles will remain a rare sight until the industry surmounts some formidable barriers:

LNG vehicles are much more expensive. "While emission reductions are comparable ... there is a much greater cost associated with the purchase of LNG trucks versus new clean diesel trucks," says a white paper from the Port of Long Beach. The report pegged the cost of an LNG truck at $100,000 above the cost of a diesel truck.

LNG vehicles need refueling sooner. A gallon of LNG packs less energy than a gallon of diesel. An Energy Information Administration report said a 150-gallon diesel tank will take a heavy-duty truck about 1,000 miles compared to about 300 to 400 miles for a similar size tank of LNG.

Few places exist to refuel. It's the classic chicken-and-egg riddle. "Unless more natural gas vehicles enter the market, there will be little incentive to build more natural gas fueling infrastructure nationally or in local or regional corridors," the EIA said in 2010.

Of the nation's 3,820 natural gas fueling

see **SMALL-SCALE LNG** *page 17*

Petroleum news

Oil Patch Bits

Crowley's tugboat, Guard, performs heroic rescue

Crowley Maritime Corp. said Nov. 12 that the crew aboard its tugboat the Guard recently performed a heroic rescue of a man who was struggling to stay afloat in the waters outside of San Francisco Bay.

COURTESY CROWLEY

The rescue took place during the early morning hours of Oct. 31, while the tugboat was standing by outside the Golden Gate Bridge, waiting to escort a tanker into San Francisco Bay's anchorage. Crowley's Perry Overton, captain of the Guard, noticed the man treading water a little more than a mile and a half from the bridge. Working quickly, the crew tossed the man a life ring and Crowley's Chief Engineer Keith Madding donned a survival suit and entered the frigid 55 degree waters to help the fatigued man climb the Guard's emergency ladder. Once aboard, the crew removed the hypothermic man's wet clothing and wrapped him in warm blankets until the Coast Guard arrived and could perform other life-saving treatments.

Following the rescue, the Guard resumed escort duties on the tanker, bringing it to its destination as scheduled.

The Guard's crew has been nominated by the National Park Service for a Citizen's Award for Bravery, which is an honor awarded by the secretary of the Interior in Washington, D.C.

Jacksonville-based Crowley Holdings Inc., a holding company of the 120-year-old Crowley Maritime Corp., is a privately held family and employee-owned company. The company provides project solutions, transportation and logistics services in domestic and international markets by means of six operating lines of business: Puerto Rico/Caribbean Liner Services, Latin America Liner Services, Logistics Services, Petroleum Services, Marine Services and Technical Services. Offered within these operating lines of business are: liner container shipping, logistics, contract towing and transportation; ship assist and escort; energy support; salvage and emergency response through its TITAN Salvage subsidiary; vessel management; vessel construction and naval architecture through its Jensen Maritime subsidiary; government services, and petroleum and chemical transportation, distribution and sales. Additional information about Crowley, its subsidiaries and business units may be found on the Internet at www.crowley.com.

Calista Corp. board of directors reinstates Guy

Calista Corp. said Nov. 7 that days after its annual meeting of shareholders, the board of directors voted to reinstate Andrew Guy as president and CEO. The decision was made at a special board meeting.

Earlier in the year, the board placed Guy on administrative leave pending an investigation.

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

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

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

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SMALL-SCALE LNG

stations, only 59 serve up LNG; the rest provide compressed natural gas or propane, according to the Department of Energy. However, that was 21 more stations than three years earlier. Two-thirds of the stations are in California, providing little geographic range for a long-distance trucker.

Some efforts are afoot to make LNG fuel more available. A database kept by Zeus Intelligence lists 27 stations planned or under construction in the U.S. and Canada. Only some will be open to the public; the rest will fuel private fleets.

An organization called Clean Energy Fuels hopes to develop a chain of LNG fueling stations across the country. For now, the focus is on a couple of high-traffic corridors in California and Texas.

Natural Gas Vehicles for America, another advocacy group, has laid out its own roadmap for wider use of LNG-powered trucks.

A similar effort is under way in Canada, called the Canadian Blue Corridor, which would space LNG fueling stations every few hundred miles along major trucking corridors.

The fine print of such ambitions typically seeks government assistance to help the LNG-fuel industry refine its technology and build itself to a point where economies of scale lower costs and let it stand on its own.

In China, a nation plagued by air pollution, the government has rolled out a policy designed to boost use of natural gas as a vehicle fuel, especially LNG.

Buses, taxis, trucks and ships should be preferred users of natural gas as China moves to increase gas use while keeping supply and demand under control. "The policy push would lead to the world's biggest fleet of LNG-fuelled vehicles," according to a news account.

Fuel for ships

The chicken-and-egg riddle restrains widespread use of LNG fuel for ships as well. The world has only a few places where ships can top off their tanks.

A new Lloyd's Register report on LNG's prospects as a marine fuel foresees widespread use by shipping fleets only far into the future, especially if LNG can be priced much lower than competing oil-based fuels.

Lloyd's is one of the big international organizations that establish technical standards for ship construction and operations. In its report, Lloyd's predicted just 4 percent of new ships delivered by 2025 — 653 ships total — would use LNG fuel. These ships most likely will be container ships, cruise ships or oil tankers, Lloyd's says.

Driving the ship industry's embrace of LNG are new International Maritime Organization rules on pollution emissions. Most deep-sea vessels are powered by oil-based bunker fuel steeped in sulfur — with high emissions of harmful sulfur dioxide.

The IMO is a United Nations' arm set up to bring consistency to worldwide shipping oversight. The new rules impose tight limits on sulfur content of shipping fuels, especially along busy shipping corridors, including the U.S. coast. Those limits get tighter over time. (International ships likely will continue burning heavy fuels in open waters then switch to cleaner fuels near coasts.)

LNG has virtually no sulfur. It can meet the new pollution standards. But that also is a feature of low-sulfur diesel — though distilling 'clean' diesel from crude oil is costly.

Another advantage: Diesel refueling is widely available around the globe. Not so for LNG refueling. A couple of European ports and Singapore do hope to establish themselves as LNG refueling stations.

Lloyd's predicts LNG fuel will start picking up market share around 2019, before even-stricter IMO standards kick in. But by 2025 LNG will fill just a small fraction of global bunker-fuel demand and comprise a likewise small portion of LNG production, Lloyd's says. Constraints on LNG as a fuel include the high cost of outfitting ports and ships, and the lack of investors willing to pay these costs.

A small U.S. cargo line announced in August that it will convert to LNG its two 9-year-old ships that haul cargo from Washington state to Alaska. Totem Ocean Trailer Express got a waiver from meeting the IMO standards while it converts its ships.

"The comprehensive project will also lead to the establishment of long-term supplies of LNG for use by other sectors of the transportation industry" in the Seattle-Tacoma region, a Totem executive noted.

A group called American Clean Skies Foundation hopes other U.S. boat owners follow Totem's lead. Clean Seas envisions a way for LNG fuel use to rise among some ships in U.S. waters, but the price gap between gas and oil must remain wide.

In a new report, Clean Skies says new liquefaction plants and storage would be needed to supply ports where no LNG exists today. Further, the cost of converting a ship from oil fuels to LNG ranges from $7 million for a medium-sized tug to $24 million for a Great Lakes bulk carrier.

Even if the gas remains much cheaper than oil, a vessel that's running almost nonstop — thus burning a lot of fuel — would need 10 years or more to recoup its upfront investment in LNG, Clean Skies concluded.

"Despite low natural gas prices, some vessels will not generate high enough annual fuel cost savings to provide a reasonable payback period for the high vessel conversion costs," Clean Skies said.

"Successful projects will require both a motivated vessel owner and a motivated LNG supplier." ●

Editor's note: This is a reprint from the Office of the Federal Coordinator, Alaska Natural Gas Transportation Projects, online at www.arcticgas.gov/small-scale-lng-niche-business-room-grow

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OIL PATCH BITS

COURTESY CALISTA CORP.

The reasons for the investigation are confidential. However, the newly formed board reviewed the investigative report and found no merit to any allegations or complaints. As a result the board immediately called Guy back to his former position with full authorities and prerogatives.

"As a result of the work of our dedicated and focused employees, Calista Corp. continues on a successful business path, matching or exceeding revenues and operating income compared to the same period last year," Guy said. "We need to focus on continuing to fulfill our ANCSA-directed obligations to both our Shareholders and our region."

Global Diving & Salvage welcomes Lawrence to team

ANDREW LAWRENCE

Global Diving & Salvage Inc. said Nov. 7 that it has hired Andrew Lawrence as salvage engineer, based out of corporate headquarters in Seattle, Wash. As part of the Marine Casualty Response Service Line, Lawrence will develop salvage plans, provide detailed engineering support, and assist with project management during emergency and routine operations.

Lawrence served as a Coast Guard officer for eight years, including 5 years at the Coast Guard's premiere engineering office, the Marine Safety Center. At the Marine Safety Center, he served on the Salvage Engineering Response Team, providing rapid engineering support to Coast Guard field units in response to vessel casualties throughout the United States. Lawrence has a broad range of ship construction knowledge gained by reviewing hundreds of ship designs for stability and structural safety.

"Global Diving and Salvage is pleased to have Andy as a part of the team and provide in-house salvage engineering expertise to the Marine Casualty Division," said David DeVilbiss, vice president, Marine Casualty Response Service Line. "Global is now able to extend the level of service we can offer our customers, further providing custom solutions to the most difficult of situations."

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SANDS OUTPUT

delivering oil to the British Columbia coast for export to Asia.

Without new export capacity, the IEA said Western Canadian oil production will exceed regional consumption and current export capacity before 2016, largely because the rise in light/tight oil volumes in the U.S. has "been nothing short of spectacular," with the Bakken at 600,000 bpd by mid-2012 and the Eagle Ford achieving 300,000 bpd at the same time.

The report noted that Canada has joined that race, reaching 190,000 bpd in 2011 from the Canadian sector of the Bakken and from other emerging plays and is projected to reach more than 500,000 bpd by 2035, with natural gas liquids from shale plays increasing significantly, offsetting falling production from conventional gas plays.

Water needed

The IEA estimates that oil sands mining and upgrading requires 0.9 cubic meters of water per barrel of synthetic crude produced, while in-situ recovery need 0.2 cubic meters per barrel produced.

The bulk of that water for oil sands mining operations is drawn from the Athabasca River, the major waterway in northeastern Alberta, which contributed 85 percent in 2010, up from about 66 percent in 2009.

However, in-situ operations sources just over 80 percent of their water needs from groundwater (such as deep saline aquifers) in 2010, making no withdrawals from the Athabasca River.

Currently about half the water withdrawn by in-situ operations is fresh water, although projects are increasingly turning to water from saline aquifers.

Based on anticipated production trends, the IEA estimates total water withdrawals in the oil sands will grow to 520 million cubic meters in 2035 from 220 million cubic meters in 2010.

The IEA said that given increasing reliance on saline aquifers or waste water, water availability does not pose an immediate risk to operations.

The report projected that North American exports of LNG (including projects in Western Canada) would reach 35 billion cubic meters by 2020 and top 40 billion cubic meters in 2035, with two-thirds destined for Asia.

It forecast that Canadian gas production will climb rapidly through the outlook period, reaching about 190 billion cubic meters in 2035, with higher shale gas and coalbed methane output offsetting a decline in conventional supply. ●

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US seen overtaking Saudis as biggest oil producer

The United States will become the world's largest oil producer by around 2020, temporarily overtaking Saudi Arabia, as new exploration technologies help find more resources, the International Energy Agency forecast Nov. 12.

In its World Energy Outlook, the energy watchdog also predicted that greater oil and natural gas production — thanks partly to a boom in shale gas output — as well as more efficient use of energy will allow the U.S., which now imports some 20 percent of its energy needs, to become nearly self-sufficient around 2035.

That is "a dramatic reversal of the trend seen in most other energy-importing countries," the Paris-based IEA said in its report. "Energy developments in the United States are profound and their effect will be felt well beyond North America — and the energy sector."

Rebounding U.S. oil and gas production is "steadily changing the role of North America in global energy trade," the IEA said.

Mideast oil to Asia

For example, oil exports out of the Mideast will increasingly go to Asia as the U.S. becomes more self-sufficient. That will increase the global focus on the security of strategic routes that bring Middle East oil to Asian markets. Tensions between Iran and Western powers have raised concerns that oil exports from the Persian Gulf could be blocked in a potential conflict over Tehran's alleged plan to develop nuclear weapons.

The IEA added that global trends in the energy markets will be influenced by some countries' retreat from nuclear power, the fast spread of wind and solar technologies and a rise in unconventional gas production.

The agency concluded that despite the rising use of low carbon energy sources, huge subsidies will keep fossil fuels "dominant in the global energy mix."

"Taking all new developments and policies into account, the world is still failing to put the global energy system onto a more sustainable path," the IEA said.

Global energy needs are forecast to increase by a third by 2035, with 60 percent of the additional demand coming from China, India and the Middle East.

—PABLO GORONDI, Associated Press

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LINC ACTIVITY

northwest, to drill Umiat No. 16, a vertical well into the Lower Grandstand. The program calls for collecting four 60-foot core samples from the formation and flow testing the well after completion.

From there, Linc plans to skid the rig approximately 10 feet to drill Umiat No. 16H, a horizontal well into the same interval. The side-by-side test is "important for assessing the performance of the horizontal production well in contrast to the vertical producer."

While government expeditions drilled 12 wells at Umiat between 1946 and 1979, the current program would be the first to test horizontal drilling techniques at the field.

After drilling the side-by-side wells, Linc plans to move the rig to the east to drill Umiat No. 23, targeting natural gas in the deeper horizons below the Lower Grandstand.

The natural gas would be used for reservoir maintenance, according to Linc. Specifically, the company plans to inject cold gas into the Upper and Lower Grandstand to maintain reservoir pressure for production, a solution also proposed by previous lessees at Umiat.

Because at least part of its oil horizons are embedded in shallow permafrost, the Umiat field creates challenges for secondary recovery and pressure maintenance operations, Renaissance Umiat LLC explained in a January 2010 article in Oil & Gas Journal.

Aiming to figure out why early Umiat wells failed to produce as expected, a 1960 U.S. Bureau of Mines study found that warm drilling mud might have thawed the permafrost, allowing water into the reservoir sands. When this water inevitably froze, it plugged the formation. To combat this problem, Renaissance and others had proposed cold gas injections as a way to maintain reservoir temperature and therefore improve permeability.

After targeting and potentially producing natural gas from the well Linc plans to plug Umiat No. 23 back to the oil sands in the Lower Grandstand for an additional flow test.

In addition to those four wells, Linc is permitting two alternate locations — Umiat No. 18 and Umiat No. 19 — and said "one or both" could be drilled this winter, "if time allows."

Previously, Linc outlined a five-well program for Umiat this winter, including a disposal well, two shallow vertical wells, one deep vertical well and one deep horizontal well.

Earlier this fall, Linc staked seven potential well locations with the U.S. Bureau of Land Management, the six previously mentioned wells and an Umiat No. 23H horizontal well.

This summer, Linc outlined an "aggressive timeline" to bring Umiat online within five to seven years. The company estimates peak production could be 50,000 barrels per day.

—ERIC LIDJI

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BP PAYOUT

than $255 million.

$8.09 per barrel

Most of the state's winnings are the result of a recent binding arbitration proceeding.

A three-member panel of arbitrators on Oct. 31 awarded the state $245,410,959 for the loss or deferral of oil and natural gas liquids, or NGLs, from the Prudhoe Bay unit and the related Greater Point McIntyre area.

BPXA also will pay the state $10 million to settle civil assessments for the spills, the Alaska attorney general's office said.

The two sides agreed to submit the sole issue of the state's royalty claims to arbitration. Previously, lawyers for BPXA had made substantial headway in reducing the company's liability in the case, winning dismissal of the state's claim for back taxes.

The arbitrators were Mark Kantor, of Washington, D.C.; Thomas W. Reavley, of Austin, Texas; and tribunal chair Thomas J. Brewer, of Seattle.

In their ruling, the arbitrators found that the state did indeed sustain royalty damages. And they rejected BPXA's argument that the state hadn't suffered any harm because the lost or deferred production was quickly made up.

The arbitrators put the state's royalty loss at 30,344,971 barrels of oil and NGLs, and said the production won't be recovered until the end of field life.

The panel then calculated the state's damages award, including interest, at $245,410,959.

That translates to about $8.09 per barrel.

BPXA has partners in Prudhoe Bay and Point McIntyre, the main ones being ConocoPhillips and ExxonMobil.

Company spokeswoman Dawn Patience on Nov. 8 issued this statement on the arbitration outcome:

"We are pleased to finally resolve the last remaining claim from the 2006 Prudhoe Bay spill. Our share of the judgment is approximately $66 million. With this behind us we can now move forward, operating North America's largest oil field in a safe, reliable and compliant manner to the benefit of Alaska and the rest of the United States."

'Rebound' argument rejected

The arbitrators held a hearing between May 22 and June 26 in Anchorage on the royalty dispute. The hearing was closed to the public.

Their 35-page ruling is fascinating and very clearly written, but quite technical in places, particularly in the discussion of how the state's damages were calculated with respect to oil and NGLs that might not be produced for decades.

Fundamentally, as owner of the land on which the Prudhoe Bay field is located, the state is entitled to receive 12.5 percent of the volume, or value, of the oil and gas produced. That's the state's royalty.

A major point of contention for the numerous lawyers and experts participating in the arbitration was whether the production shortfalls experienced after the pipeline leaks were later made up.

BPXA argued "there was a relatively quick rebound in production, in a higher price environment," with the net result being that the state wasn't injured, the arbitration ruling says.

"BPXA coined the term rebound in this case as a shorthand way of referring to various well and reservoir phenomena that can cause a well or wells to produce at a higher rate after a period of being rested or 'shut in,'" the arbitrators wrote.

But the tribunal ultimately found BPXA's rebound argument "unpersuasive."

Field performance did improve in the years following the pipeline spills, with a "noticeable lessening" of the decline rate in oil production, but it wasn't due to rebound, the arbitrators wrote. Rather, most of the production enhancements in the 2006-2010 timeframe stemmed from "a substantial increase in capital expenditures" for work such as drilling and well workovers.

Such activities to promote field production and arrest natural decline are the normal duty of a prudent field operator, the arbitrators said.

The arbitrators also determined on the evidence that Prudhoe Bay oil production was, and is, constrained by the field's gas-handling facilities. A great deal of gas emerges from wells mixed with the crude.

Because of the gas-handling limitations, the production deferrals experienced in the wake of the 2006 leaks "could not be, and were not, recovered simply by running the field at a greater capacity later," the arbitrators said.

Although the state raised the possibility that "some or all of the oil in question will never be recovered," the arbitrators found a lack of evidence to support that. ●

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SHELL DRILLING

vessels, and hence their departure from the Sivulliq site, because of rough seas, but the refueling was completed during the week ending Nov. 10, Smith explained, adding that at no time did sea ice threaten any harm to the Beaufort Sea fleet. Shell also conducted a required crew rotation prior to the fleet's departure for the south.

The Kulluk is designed to withstand sea ice and had been moored in the Canadian Arctic for an extended period of time before Shell acquired it several years ago.

There have been media reports that Shell plans to replace the cranes on the Kulluk before next year's drilling season, but Smith said that Shell has not yet decided on that possibility.

"We essentially de-rated the capability of our cranes in colder temperatures so that no one attempted lifting operations that could have proven unsafe," Smith said. "It's common for equipment to operate less efficiently in cold temperatures and that's something we will consider as we ready the rigs for 2013."

Shell ended up drilling the top hole sections — the top 1,400 to 1,500 feet — of one well in the Burger prospect and one well in the Sivulliq prospect during this year's open water season. The company anticipates returning to the Arctic in the summer of 2013 to continue its drilling program, presumably drilling to potential hydrocarbon bearing zones in those two wells that have already been started.

—ALAN BAILEY

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RDC CONFERENCE

CD-5 going ahead

Olds said ConocoPhillips will be going ahead with CD-5, and will start construction in 2013.

CD-5 will be the first development in the National Petroleum Reserve-Alaska, and crude oil from that drill site will tie back into the Alpine production facilities on state lands. Development was held up for years in disputes over how oil, and personnel, would cross the Nigliq Channel of the Colville River, which lies between Alpine and CD-5. The Corps of Engineers approved a bridge proposal earlier this year.

Olds cautioned that ConocoPhillips moved CD-5 forward "before the current tax regime," spending a lot of time and money to advance technology for the project, but before ACES was put in place.

Olds didn't provide details on CD-5 development plans, but ConocoPhillips Alaska spokeswoman Natalie Lowman told Petroleum News in an email that plans remain as the company described them a year ago, starting with completion of engineering design work, ordering of materials and equipment and beginning of fabrication next year and construction "over two years to coincide with the ice road access to Alpine." Lowman said first production is expected in late 2015.

Olds said the company sees other opportunities in NPR-A, but they are farther from infrastructure, with smaller accumulations and higher risk.

ConocoPhillips has two federal units — Greater Moose's Tooth and Bear Tooth — farther west in NPR-A.

Focus on light oil

Minge said that in adjusting its plans to fit with the state's policies, BP is going to stop, within the next few months, its heavy oil pilot investments and stop further investments in viscous oil.

He said the company's plans "have really been mismatched against the state policy" and "probably a little too focused on some of the more challenged resources and we've got to take some steps to invest into the easier light oil."

He also said BP will focus on making dollars go further.

Efficiency and technology will be a focus, and Minge said the company will "take some significant steps to make our business more efficient."

> ***"We've got opportunities, but it needs the right business climate to continue to advance these."***
> **—Nick Olds, ConocoPhillips Alaska vice president, North Slope operations and development**

That includes increasing investment "into the easiest oil, the light oil" in order to "put off the decline as much as we possibly can to grow the cash flow."

He said that includes de-bottlenecking facilities and "looking at taking infrastructure out of service so that we don't have to pay to maintain that."

Money will be moved, Minge said: "Our capital's about the same — but we're going to move it into short-term, easier oil."

It's short-term

What the new plan does, Minge said, is takes "more oil out of the tank faster and you're not actually progressing resources for the very long term."

If the State of Alaska has a short-term, 10-to-15-year mindset, "ACES is perfect." In the short term, it's the right approach, he said.

"But if you want to take a long-term view and have a sustainable oil business and have a real shot at gas, change is needed."

Minge said he finds real disagreement among Alaskans he talks to on whether oil taxes should be changed, but no disagreement on the goals: "Everyone wants a sustainable oil business; everyone wants a major gas project to go forward in the state; everyone wants affordable energy for in-state needs — and it couldn't be any more dire than it is in the Interior of Alaska; and everyone wants jobs."

Minge called ACES a "short-term going-out-of-business policy" and said it has delivered predictable short-term results: "The State of Alaska is doing extremely well, taking vast amounts of the upside in oil prices."

"It's also clear that the long-term investment is down, especially capital going into production enhancement activities," Minge said, with production decline continuing at 6 to 8 percent a year.

"And ACES is a major impediment to a major gas project," Minge said.

He said a change in tax policy would make Alaska more competitive and draw more investment, slowing production decline and creating "a healthy long-term oil business with a long-term future to generate revenue" to the state and the producers, while creating jobs and allowing "for legacy infrastructure to be maintained for the very long term," increasing odds of a major gas project going forward.

"So what do Alaskans get for the X-billion-dollars-a-year giveaway? They get a future," Minge said.

One big argument against changes in taxes has been the lack of guarantees, he said.

The state's tax and royalty system is similar to those in many places BP works, and "I'm not aware of any tax and royalty regime in the world where there is this debate: What will you promise me to get a reduction?"

Elsewhere, he said, economic theory is used.

"The sovereign government determines the policy; investors respond to this policy."

If taxes are changed in Alaska and there is no investment increase, "the taxes can always be changed back," he said.

> ***Minge said that in adjusting its plans to fit with the state's policies, BP is going to stop, within the next few months, its heavy oil pilot investments and stop further investments in viscous oil.***

ACES and the gas line

Minge argued that a tax change is needed to move the gas project forward.

Physically, the oil and gas are in the same reservoir, come out of the same wells, go into the same flowlines and pipelines and are processed in the same infrastructure, he said.

Then there is the length of a gas project, Minge said, with the timeline submitted to the governor showing a final investment decision by 2016, five or six years of construction and a project life of about 40 years.

Combined, that's out to 2062-63, he said.

"That means at that time Prudhoe Bay infrastructure is 90 years old and it needs to look a whole lot better than most people do at 90 years old if it's going to enable this gas project to go forward."

Then there is the huge investment, $45-$65 billion, "slightly less than the total capital budgets of ExxonMobil, BP and ConocoPhillips combined in 2012," he said.

As the companies look at cash flows from the project they ask if they could write off the capital investment against oil taxes.

"And the fact of the matter is we know there's no way — the State of Alaska can't afford it; the State of Alaska would go broke," Minge said.

Which means the producers would have to invest the money upfront, "10 years of investment before we get one dime of revenue."

And there's something else about that $45-$65 billion, Minge said.

"We assume that the project economics start at the fence line of Prudhoe Bay and Point Thomson," so no gas project investment is required at Prudhoe Bay.

"But we also say the operating cost on the slope is essentially zero — we look at the operating cost of the project from the fence line down," he said.

Prudhoe Bay facilities were designed for 30 to 35 years, and if "it needs to be 90 years old, we need to be investing today into that infrastructure so that it will last out to 2065," Minge said. "The tax policy of ACES does not support that."

Opportunities for Conoco

ConocoPhillips' Olds discussed some of the opportunities that the company sees in Alaska.

At Kuparuk, he said, the company is looking at designed wells.

Over the last few months the company has implemented "what we call an octa-lateral, four laterals going out one way, four going out the other way." That's complex, he said, and requires a technology investment.

And at Kuparuk "the targets are smaller, they're higher risk and so we need to continue to use innovation and technology to go after them," which also requires a good business climate, Olds said.

There are also opportunities south of Kuparuk, he said.

"They are some small satellite developments that are years in front of us," but require the company to ask if the size is there, if the risk is acceptable and if the business climate is there to support the work.

Viscous oil, being produced at West Sak, needs technology for more development.

And heavy oil, with a billion barrels at Kuparuk, will require "significant technology to advance it. Currently there's not a commercial application to unlock that potential," he said.

"We've got opportunities, but it needs the right business climate to continue to advance these," Olds said.

While there may be big Chukchi discoveries in the future, they would be at least a decade from production, he said, and legacy fields are the immediate source of production, with 4 billion barrels of potential recoverable over that decade.

But that production will require "substantial investment" in new wells and infrastructure tie-ins, "and that's on top of the renewed infrastructure investment that we're doing."

It requires investment, he said, and while ConocoPhillips increased its investments in the Lower 48 from $1.6 billion in 2010 to $4.8 billion in 2012, "in Alaska, we've remained flat at $900 million."

There is opportunity to invest in Alaska, he said, "we just need the business climate to do so." ●

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