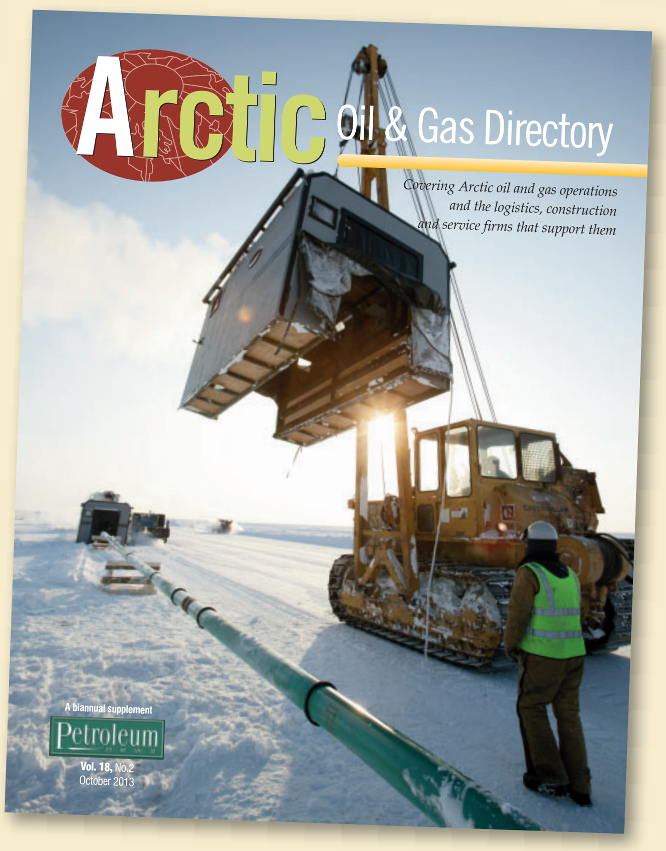
Petroleum news

page 4 Q&A: Herron, Bethel Democrat says Arctic policy voice important

Vol. 18, No. 40 • www.PetroleumNews.com — *A weekly oil & gas newspaper based in Anchorage, Alaska* — Week of October 6, 2013 • $2.50

Latest Arctic Directory released



Hilcorp: 2nd oil exploration well, Frances 1, planned for Ninilchik

Hilcorp is about to drill a second exploration well, the Frances 1, in the Ninilchik unit on the west coast of Alaska's Kenai Peninsula, Hilcorp spokeswoman Lori Nelson told Petroleum News in a Sept. 30 email.

Earlier this year the company applied to change its plan of operations for the Susan Dionne pad in the unit to allow the drilling of a 12,000-foot-deep oil exploration well from the pad. The application said that the company might drill a second well if that first well proved successful.

see **FRANCES WELL** *page 21*

BP seeks in-state TAPS hike; would close gap with other line owners

Every year, for six years, the owners of the trans-Alaska oil pipeline have separately sought increases to rates they charge to ship North Slope crude to markets in Alaska.

All the owners except BP, that is.

While the other owners have been incrementally bumping up their rates year after year since 2008, the operator of Prudhoe Bay and three other producing North Slope units has maintained the in-state shipping rate established after a major regulatory ruling in 2002.

see **TAPS HIKE** *page 21*

Canadian Beaufort plans; JV in regulatory phase for 2020 drilling

An Imperial Oil partnership with ExxonMobil and BP Canada has entered the formal regulatory phase that could see an initial exploration well start drilling in the Canadian sector of the Beaufort Sea in summer 2020.

But even if a commercial-size strike was made the joint venture has no thoughts on how development would proceed.

Imperial spokesman Pius Rolheiser told Petroleum News the companies view the area as "potentially prospective for exploration, but it has a high degree of exploration uncertainty and has

see **BEAUFORT JV** *page 19*

EXPLORATION & PRODUCTION

BP's Liberty island

Regulators reveal company's thinking on how to proceed with stalled Alaska project

By WESLEY LOY
For Petroleum News

In June 2012, BP Exploration (Alaska) Inc. made the startling announcement that it was dropping its ambitious plan to develop the offshore Liberty field using ultra extended-reach drilling from shore.

In the 15 months since, it has been less than clear what alternate approach, if any, BP might take on Liberty.

But now, the company's direction is becoming evident.

On the U.S. Bureau of Ocean Energy Management website devoted to Liberty, this statement has appeared:

"BP Exploration (Alaska) is now proposing a stand-alone drilling and production processing island as the safest and most environmentally responsible course of development for the Liberty Prospect."

In a Nov. 20, 2012, letter to the BSEE, the company said recovery from the Liberty leases could be as much as 15 percent higher using "development concepts" other than ultra extended-reach drilling.

Suspension of production granted

Dawn Patience, spokeswoman for BP Alaska, told Petroleum News on Oct. 2 she had no reason

see **LIBERTY'S FATE** *page 24*

EXPLORATION & PRODUCTION

A license for Ahtna

Native corporation wants to explore for gas in state land near Glennallen

By ALAN BAILEY
Petroleum News

The director of Alaska's Division of Oil and Gas has published a finding, saying that it is issuing an oil and gas exploration license to Ahtna Inc., the Native regional corporation for the Copper River region. The license, called the Tolsona Exploration License, encompasses about 72 square miles of state land west of Glennallen in the Copper River basin. The finding, published on Sept. 30, says that, in evaluating the license application, the state studied environmental and other factors in a 950-square-mile area straddling the eastern end of the Glenn Highway.

State exploration licenses provide a means of access to state lands for oil and gas exploration in regions outside the state's major oil and gas provinces. Any requests for reconsideration of Ahtna's license must be submitted to the division within 20 days of the issuance notice.

"Exploration activities will begin late 2013 with a minimum investment of $415,000 (US) over the next 1 to 2 years." **—Michelle Anderson, president of Ahtna**

Address energy costs

Michelle Anderson, president of Ahtna, told Petroleum News in an Oct. 1 email that the Native

see **AHTNA LICENSE** *page 19*

EXPLORATION & PRODUCTION

Umiat horizontal planned

Linc's 1-to-2 well program smaller, but can start more quickly than deferred plan

By ERIC LIDJI
For Petroleum News

Linc Energy Ltd. could drill as many as two wells at the Umiat prospect this winter to test horizontal drilling techniques at the oil field in the foothills of the Brooks Range.

The Australian independent plans to drill and flow test the Umiat No. 23H this coming winter. Time permitting, Linc might also drill an Umiat No. 24H well this winter.

The program picks up where Linc left off earlier this year at Umiat, but not entirely.

Linc had originally planned to drill between four and six wells at Umiat this past winter, but weather-related delays forced the company to defer all but one — the Umiat No. 18 vertical well. By cold-stacking the Kuukpik No. 5 rig at the permanent Seabee drilling pad, Linc had intended to get a head start on completing the program this coming winter.

According to Ryder Scott, the 154.5 million barrels of oil equivalent of P2 reserves at Umiat now has a net present value (at 10 percent return) of $2.465 billion, up 65 percent from a net present value of $1.496 billion estimated before the changes to the tax code.

The work Linc deferred this past winter includ-

see **UMIAT DRILLING** *page 22*

contents

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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 L3-31, workover	BP
Dreco 1000 UE	16 (SCR/TD)	Prudhoe Bay DS 04-03, workover	BP
Dreco D2000 Uebd	19 (SCR/TD)	Alpine CD4-291	ConocoPhillips
AC Mobile	25	Prudhoe Bay Y-13A	BP
OIME 2000	141 (SCR/TD)	Kuparuk 1C-150	ConocoPhillips
Kuukpik	5	Rigged up on Umiat Disp#1	Linc Energy Operations Inc.
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Prudhoe Bay	Stacked
AC Coil Hybrid	CDR-2	Kuparuk 2F-18	ConocoPhillips
Dreco 1000 UE	2-ES (SCR-TD)	Prudhoe Bay	Available
Mid-Continental U36A	3-S	Prudhoe Bay	Available
Oilwell 700 E	4-ES (SCR)	Prudhoe Bay	Available
Dreco 1000 UE	7-ES (SCR/TD)	Kuparuk	ConocoPhillips
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 Canrig 1050E	27-E (SCR-TD)	Prudhoe Bay	Available
Emsco Electro-hoist	28-E (SCR)	Prudhoe Bay	Stacked
Oilwell 2000	33-E	Prudhoe Bay	Available
Academy AC Electric CANRIG	99AC (AC-TD)	Prudhoe Bay	Available
OIME 2000	245-E (SCR-ACTD)	Oliktok Point	ENI
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Prudhoe Bay Drill Site Z-08B	BP
Superior 700 UE	2 (SCR/CTD)	Prudhoe Bay Well Drill Site F-09C	BP
Ideco 900	3 (SCR/TD)	Kuparuk Well 3K-23	ConocoPhillips
Parker Drilling Arctic Operating Inc.			
NOV ADS-10SD	272	Prudhoe Bay DS 18	BP
NOV ADS-10SD	273	Prudhoe Bay DS W-59	BP

North Slope - Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
BP			
Top Drive, supersized	Liberty rig	Inactive	BP
Doyon Drilling			
Sky top Brewster NE-12	15 (SCR/TD)	Spy Island SP08-N7	ENI
Nabors Alaska Drilling			
OIME 1000	19AC (AC-TD)	Oooguruk ODSN-02	Pioneer Natural Resources

Interior Alaska

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Nabors Alaska Drilling			
Academy AC electric CANRIG	105AC (AC-TD)	Nenana Basin	Doyon Ltd.

Cook Inlet Basin – Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Kenai Land Ventures LLC (All American Oilfield Associates, labor Contract)			
Taylor	Glacier 1	Kenai Loop Drilling Pad #1	Buccaneer Energy Ltd.
All American Oilfield Associates			
IDECO H-37	AAO 111	On the West side for NordAq Energy's Tiger Eye Central Well	NordAq Energy
Aurora Well Services			
Franks 300 Srs. Explorer III	AWS 1	NCU 2, workover	Aurora Gas
Doyon Drilling			
TSM 7000	Arctic Fox #1	North Kenai, stacked	Contracted to ConocoPhillips Winter of 2013/2014
Nabors Alaska Drilling			
Continental Emsco E3000	273E	Kenai	Available
Franks	26	Kenai	Stacked
IDECO 2100 E	429E (SCR)	Kenai	Available
Rigmaster 850	129	Kenai	Available
Academy AC electric Heli-Rig	106-E (AC-TD)	Kenai	Available

Cook Inlet Basin – Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
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 Drilling, management contract)			
		Monopod A-32, workover	Hilcorp Alaska LLC

Mackenzie Rig Status

Canadian Beaufort Sea

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
SDC Drilling Inc.			
SSDC CANMAR Island Rig #2	SDC	Set down at Roland Bay	Available

Central Mackenzie Valley

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Akita			
TSM-7000	37	Racked in Norman Well, NT	Available

The Alaska - Mackenzie Rig Report as of October 3, 2013.
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*

	Sept. 27	Sept. 20	Year Ago
US	1,744	1,761	1,848
Canada	390	388	359
Gulf	62	63	48

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

● GOVERNMENT

Herron: Alaska needs Arctic policy voice

Bethel Democrat has key seat on Arctic Policy Commission while advocating for state to have crucial role in advancing its interests

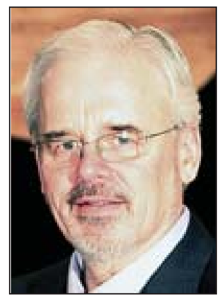
By STEVE QUINN
For Petroleum News

Rep. Bob Herron hasn't sat in his office for too long during the Legislature's interim. He's been to Barrow and Unalaska for work as co-chair with the Arctic Policy Commission. He shares these duties with Sen. Lesil McGuire, both of whom are also Arctic policy co-chairs representing the Pacific Northwest Economic Region group.

Herron steadfastly believes Arctic policy and Alaska having a voice at an international level should be a statewide priority.

Herron is a Bethel Democrat who aligns himself with the State House's Republican caucus, but that doesn't mean he completely agrees with some of the heavier hitting legislation. Herron supported a change to the state's oil tax system, but not the new law ushered in called Senate Bill 21.

Herron discussed both issues plus a few others with Petroleum News.


REP. BOB HERRON

Petroleum News: What do you see as the value of the commission to the state?

Herron: Arctic policy, Arctic issues — pardon the pun — is hot right now. I'm not trying to make light of it. We live in the Arctic. We live in Alaska. Under the definition of the Arctic by U.S. law, almost half of Alaska is within those boundaries, including the Bering Sea, which is very important to many people not only around the world, but specifically Alaskans, especially along the Yukon River and the Kuskokwim because both of those major tributaries flow into the Bering Sea and the Bering Sea — quote-unquote — feeds Alaska in so many different ways.

So should we be involved in Arctic policy? You bet we should be. Should we be defending and protecting our own interests? Should we be making sure that Arctic policies at the international level, national level and sub-national level are in our best interests? You bet. The only reason the U.S. is an Arctic nation is because of Alaska. So Alaskans should be, must be and will be a part of that debate.

Petroleum News: What have you learned so far since the commission has been formed?

Herron: A lot of people are looking at Alaska and doing their studies and we don't even know what they are doing. We need to be out there telling people that we are not just a bunch of frontiersmen or indigenous people who have been here a long time. We're not just here because it's fun and cool; it's our lives. The executive branch — the Parnell administration — has got to do its job. The Alaska Legislature, when it comes to Arctic policy, has to have an important role in that — maybe in a parallel track with the administration.

We are going to make policy decisions that affect Alaskans. We are going to make budget decisions that affect Alaskans, yet should we be sensitive to international and national Arctic policy decisions? I believe we should. One of the things the commission is learning is that it's a very large project; it's a very large issue; it's dynamic; it's ever changing. There is a very large interest by the public sector, the private sector and by the people who live here.

There are a lot of studies going on and there are a lot of studies under way that people don't know are taking place. There are hundreds of silos of research projects that don't know about one another. We are learning that a lot of those projects are proprietary or the people doing the research think they are proprietary. Alaskans should be concerned about what is being studied and how can Alaskans benefit from it.

Petroleum News: OK, let's go with that. How can Alaska benefit from an Arctic policy?

Heron: There are two kinds of people I like to characterize and they are not bad people. The first is you're in some large city in the Lower 48 who will never, ever get to Alaska. They want this place that's pristine and untouched. They don't recognize there are people who live up here and have families with a whole infrastructure that's been going on for a long time. So somehow these people want to take a snapshot and that's the way they want Alaska to be forever.

Then there is the other side, people who have been to Alaska but would never live here. They want to make rules about how we should live up here. They want to put us in a snow globe. They want us to be in this perfect zoo, this little ecosystem that's perfect. They want us to be this nice little people who live in nice little igloos with subsistence lifestyle and pat us on the head and say everything is perfect. They want to make decisions for us.

So the commission has decided that we are not going to be part of those two scenarios in a negative way. We are going to be proactive. We are going to be partners with our federal counterparts. We want to be part of a decision process where we are not merely stakeholders. We are sovereign citizens of this land. When you are a sovereign citizen, you don't come begging to your partners with whom you are going to set national and state policy. We are going to be equal partners. That's what Alaska needs to demand of this Arctic policy debate.

Petroleum News: You folks had a meeting in Unalaska recently. Do you see that as a particular hub for Arctic oil production and exploration?

Herron: I didn't realize this until we saw a presentation and that's during Captain Cook's voyages around the north Pacific, he limped into Unalaska with a broken rudder. The history in Unalaska for the last couple hundred years is remarkable. The most recent history comes during World War II and now the fishing industry.

Just the strategic location of Unalaska and Dutch Harbor is tremendous. Unalaska is considered part of the Arctic. It has a deepwater port that is strategically located. It's year-round. It will play an important role as will other ports like Nome, which is not as large as far as capacity or Port Clarence below the Bering Straits. Future infrastructure we build on north of the

see HERRON Q&A page 18

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OWNER: Petroleum Newspapers of Alaska LLC (PNA)
Petroleum News (ISSN 1544-3612) • Vol. 18, No. 40 • Week of October 6, 2013
Published weekly. Address: 5441 Old Seward, #3, Anchorage, AK 99518
(Please mail ALL correspondence to:
P.O. Box 231647 Anchorage, AK 99523-1647)
Subscription prices in U.S. — $98.00 1 year, $176.00 2 years
Canada — $185.95 1 year, $334.95 2 years
Overseas (sent air mail) — $220.00 1 year, $396.00 2 years
"Periodicals postage paid at Anchorage, AK 99502-9986."
POSTMASTER: Send address changes to Petroleum News, P.O. Box 231647 Anchorage, AK 99523-1647.

● NATURAL GAS

LNG dangles as big gas prize

Producers in US, Canada, count heavily on LNG exports to support operations; little hope for Alberta, where gas in downward spiral

By GARY PARK
For Petroleum News

While gas producers in the United States and Canada battle for a diminishing share of the "home" pie, hopes for a resurgent market increasingly focus on LNG exports.

For now, though, it's a much grimmer mood in Canada, which has seen the share of its production destined for the U.S. shrink from two-thirds to one-half of output in the last five years.

Consider Alberta, still the mainstay gas region, where royalties have plunged to an estimated C$965 million this fiscal year from C$6 billion in 2006-07, with field activity falling to about 1,000 wells this year from 16,000 during the bonanza years.

Production in the province has declined to about 10 billion cubic feet a day this year from 14 bcf a day in 2006, while the industry has seen one of its previously key markets in the U.S. Northeast evaporate as the Marcellus shale has raced to almost 8 bcf a day from 2 bcf a day in 2005 and, according to Peter Howard, president of the Canadian Energy Research Institute, could be destined for 23 bcf a day.

B.C. immediate beneficiary

Even if LNG export projects do get off the ground, the immediate beneficiary will be British Columbia, which holds the largest untapped resources in its northeastern corner and the best access to liquefaction and tanker terminals on the Pacific Coast.

Howard doubts LNG exporters from Canada will include Alberta production in their mix any time soon because of their focus on the more cost-effective Montney formation in British Columbia.

Those looking for a shred of hope were offered a morsel by Mike Ekelund, assistant deputy minister at Alberta Energy, when he spoke to a LNG conference in Calgary.

He said that based on years of cooperation between Alberta and British Columbia to promote the natural gas industry there should be opportunities for both provinces to supply international markets through LNG terminals.

Ekelund said the two provinces have for decades shared gas pipeline networks and he is counting on working with British Columbia "to expand the network to provide buyers with access to world class resources."

But the chances of British Columbia giving up much, or any, of its dream to cash in on LNG is remote.

Howard acknowledged the reality. "There are no easy answers for Alberta producers," he told the Financial Post. "The next several years are going to be challenging."

Ziff sees B.C. in lead

The importance to North American producers of seizing a role in the LNG industry is reflected in a new forecast by Calgary-based Ziff Energy, now a division of Solomon Associates, which predicts British Columbia has the best chance of leading a production recovery in Canada.

If export projects from the Pacific Coast are up and running by 2018 they will set the stage for British Columbia gas

Consider Alberta, still the mainstay gas region, where royalties have plunged to an estimated C$965 million this fiscal year from C$6 billion in 2006-07, with field activity falling to about 1,000 wells this year from 16,000 during the bonanza years.

production of more than 4 bcf per day by 2020, more than a four-fold increase from current output, the study said.

Otherwise Alberta will be left to rely on its oil sands operations and a shift to gas-fired power plants which the study predicted should see demand rise to between 5 bcf and 6 bcf a day in 2020, compared with present levels of 3.4 bcf per day.

Bill Gwozd, senior vice president of gas services, forecasts 90 percent of Alberta's growth will come from the oil sands.

Ontario, by far Canada's most populous province at 13 million people, is forecast to top 3 bcf a day, an increase of 500 million cubic feet per day as power generation shifts to gas from coal.

Collective revenues tumble

But Peter Tertzakian, chief energy economist at ARC Financial Corp., also puts the numbers into a more rigorous perspective, noting that Alberta producers collective revenues have tumbled C$30 billion from their 2005 peak and production has nosedived 30 percent as U.S. shale plays have claimed market share from Western Canada, led by the Marcellus which now accounts for 13 percent of U.S. output.

Tertzakian said Marcellus expansion is "unlikely to slow, with high quality rocks making the cost of the gas relatively low" and the play's close access to major consuming regions.

He said the best chance of recovery for Western Canadian producers is accessing Asian markets with LNG, noting that British Columbia gas operations are "ramping up output in anticipation."

Gwozd conceded that cheaper types of coal are also causing a shift away from gas by power producers and said that could be a short-term issue until governments start tackling climate-change concerns.

He suggested there could also be good news on the horizon, with the Ziff report predicting "very strong" gas demand in Canada and the Southwest region of the U.S., "moderate" gains in the interior West and "minor" gains in the Midwest and Northeast, while the Southeast and Pacific Coast remain flat.

Backing off predictions

For now, many forecasters are having to back off recent predictions that North American demand would rise to 30 trillion cubic feet a year, or about 82 bcf a day. Current consumption is in the range of 72 bcf-80 bcf a day, but Solomon Associates is counting on 95 bcf a day by 2020, with the 30 tcf-a-year mark being reached in 2016 or 2017.

Gwozd said world LNG demand for gas should double to 60 bcf a day by 2020.

Calgary-based Peters & Co. said that although 20 percent fewer rigs are drilling for gas than last year, average U.S. production for 2013 is likely to remain unchanged at 66 bcf a day, edging up to 67.4 bcf a day in 2014.

"Production from shale gas drilling continues to drive supply growth in the U.S. with the Marcellus and associated gas from oil/liquids plays — including the Bakken, Eagle Ford, Utica and parts of the Permian — offsetting declines that have occurred in all other areas over the past year," the investment dealer said.

Peters said U.S. shale plays accounted for about 19 bcf a day, or 32 percent of U.S. production, in 2010 and, by the end of 2014, should be at 50 percent or 34 bcf a day, further stiffening competition for Western Canadian gas.

Bentek is counting on U.S. production rising by about 23 percent over the next five years to 80 bcf a day, driven by more efficient shale gas drilling, projecting year-end 2013 production of 65 bcf a day.

see THE LNG PRIZE page 6

● EXPLORATION & PRODUCTION

ANS crude production up 19% from August

North Slope production up on completion of summer maintenance; August Cook Inlet production, led by Trading Bay, up 8% over July

By KRISTEN NELSON

Petroleum News

Alaska North Slope crude oil production was up in September following the August completion of scheduled summer maintenance on the trans-Alaska oil pipeline, averaging 523,554 barrels per day, a 19.2 increase over the August average of 439,152 bpd.

August figures for Cook Inlet, the latest available, show the Southcentral basin averaged 16,247 bpd, up 7.6 percent from July, with the largest increase, 61.9 percent, at Trading Bay.

On the North Slope, all fields except Endicott showed month-over-month production increases in September.

The largest per-barrel increase was at the BP Exploration (Alaska)-operated Prudhoe Bay field, which averaged 291,150 bpd in September, up 52,653 bpd, 22.1 percent, from an August average of 238,507 bpd.

Prudhoe Bay production includes volumes from western Prudhoe satellites (Aurora, Borealis, Midnight Sun, Orion and Polaris) as well as from the BP-operated Northstar and Milne Point fields.

Production figures for September are from the Alaska Department of Revenue's Tax Division which reports ANS crude oil production consolidated by major production centers and provides daily production and monthly averages. Detailed data, including Cook Inlet and individual North Slope fields and pools, is reported by the Alaska Oil and Gas Conservation Commission on a month-delay basis.

> *The ConocoPhillips Alaska-operated Kuparuk River field had the largest month-over-month percentage increase, averaging 134,525 bpd in September, up 22.5 percent, 24,741 bpd, from an August average of 109,784 bpd.*

Kuparuk biggest percent increase

The ConocoPhillips Alaska-operated Kuparuk River field had the largest month-over-month percentage increase, averaging 134,525 bpd in September, up 22.5 percent, 24,741 bpd, from an August average of 109,784 bpd. Kuparuk volumes include satellite production from Meltwater, Tabasco, Tarn and West Sak, as well as production from the Eni-operated Nikaitchuq field and the Pioneer Natural Resources Alaska-operated Oooguruk field.

August AOGCC figures for Nikaitchuq show an average of 14,074 bpd, up 2,012 bpd, 16.7 percent, from a July average of 12,062 bpd. Oooguruk averaged 8,266 bpd in August, commission figures show, up 790 bpd, 10.6 percent, from a July average of 7,476 bpd. Oooguruk produces from three formations — Kuparuk, Nuiqsut and Torok — with Kuparuk and Torok production roughly flat, month-over-month, and Nuiqsut production, which accounts for the bulk of Oooguruk volume, up 13.7 percent, to 7,030 bpd in August from 6,202 bpd in July.

BP-operated Lisburne, which includes Point McIntyre and Niakuk production, averaged 29,984 bpd in September, up 20.3 percent, 5,049 bpd, from an August average of 24,935 bpd.

The ConocoPhillips-operated Alpine field averaged 61,188 bpd in September, up 8.5 percent, 4,800 bpd, from an August average of 56,388 bpd. Alpine production includes volumes from three satellites: Fiord, Nanuq and Qannik. AOGCC data for August shows 64 percent of Alpine production coming from the main field in that month, with Fiord making up 31 percent, followed by Qannik at 3 percent and Nanuq at roughly 2 percent.

The BP-operated Endicott field was the only one on the North Slope to show a decline in production from August to September. The field averaged 6,707 bpd in September, down 29.7 percent, 2,831 bpd, from an August average of 9,538 bpd. Endicott production includes the Savant-operated Badami field, which AOGCC data shows averaged 1,243 bpd in August, down 7 percent, 97 bpd, from an August average of 1,340 bpd.

Climbing well above 15,000 bpd

In July, Cook Inlet oil production broke through the 15,000 bpd barrier; in August it broke through 16,000, averaging 16,247 bpd, up 7.6 percent from a July average of 15,099 bpd.

The Hilcorp-operated Trading Bay field had the largest month-over-month increase, averaging 2,208 bpd in August, up 61.9 percent from a July average of 1,364 bpd. Hilcorp has been reworking wells it acquired in January 2012 when it took over Chevron's Cook Inlet assets, increasing production in the basin.

The Hilcorp-operated Swanson River field averaged 2,450 bpd in August, up 13.2 percent from a July average of 2,165 bpd.

Cook Inlet Energy, which has also been reworking existing fields it took over after Pacific Energy went into bankruptcy in 2009, produced 1,690 bpd from Redoubt Shoal in August, up 12.3 percent from a July average of 1,505 bpd.

Hilcorp averaged 4,471 bpd in August at McArthur River, up 3.7 percent from a July average of 4,311 bpd.

Other Cook Inlet fields had month-over-month declines.

Cook Inlet Energy's West McArthur River field averaged 588 bpd in August, down 16 percent from a July volume of 700 bpd.

Middle Ground Shoal, operated by ExxonMobil subsidiary XTO, averaged 2,467 bpd in August, down 5.5 percent from a July average of 2,610 bpd.

Hilcorp's Granite Point averaged 2,221 bpd in August, down 3 percent from a July average of 2,290 bpd, and Hilcorp's Beaver Creek averaged 152 bpd in August, down 1.3 percent from a July average of 154 bpd.

ANS crude oil production peaked in 1988 at 2.1 million bpd; Cook Inlet crude oil production peaked in 1970 at more than 227,000 bpd. ●

Contact Kristen Nelson at knelson@petroleumnews.com

continued from page 5

THE LNG PRIZE

US LNG exports

Jack Weixel, director of energy analysis at Bentek, told a Pittsburgh conference the forecast is based on a steady rise in gas use for manufacturing and power generation, while counting on LNG exports starting in 2015 or 2016.

Based on those assumptions, he forecast gas prices will reach a 2018 average of $4.09 per million British thermal units compared with the current $3.40, with most U.S. producing basins seen as profitable at about $2 because of associated hydrocarbons, such as crude oil and gas liquids.

At $4, Weixel said all U.S. producing basins would be profitable.

He said U.S. LNG exports should consume 8.8 bcf a day by 2023 based on signed memoranda of understanding between shippers and customers covering 11.6 bcf a day.

Weixel doubted that LNG will have much impact on U.S. domestic gas prices, meaning the U.S. will "be the next great natural gas exporter by the time we get to 2018 because we can afford to."

Of the challenges facing gas, he said the chief threat could be posed by legislation banning hydraulic fracturing. ●

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GOVERNMENT

Sullivan confirms unitization policy

Says DNR will only approve an exploration unit if applicant has demonstrated the existence of a potential hydrocarbon accumulation

By ALAN BAILEY
Petroleum News

Rumblings of discontent over the Alaska Division of Oil and Gas' apparent reluctance to approve exploration units surfaced in June, when executives from several companies engaged in Alaska oil exploration sent a letter to Dan Sullivan, commissioner of the Alaska Department of Natural Resources, complaining about what the companies claimed to be the division's infringement of state laws relating to oil and gas unitization. The Division of Oil and Gas is a division within the Department of Natural Resources.

The companies involved consist of ASRC Exploration, Brooks Range Petroleum Corp., Buccaneer Alaska, Great Bear Petroleum Operating LLC, Linc Energy, Royale Energy, Savant Alaska and UltraStar Exploration.

But in a letter dated Sept. 24 Sullivan responded by affirming his department's unitization policies and saying that the Division of Oil and Gas approves exploration units in situations where the unit applicant has sufficiently established the presence of a "potential hydrocarbon accumulation" in the proposed unit.

Purpose of a unit

A unit, a lease-management tool normally applied during the development of a proven oil or gas field, is a vehicle whereby several oil and gas leases with disparate leaseholders can be tied together as a single entity with a single ownership structure, to avoid ownership complications and conflicts when developing the field. However, Alaska laws also allow the formation of a unit over an exploration prospect, in a situation where the prospect spans multiple leases — the idea is to encourage an efficient exploration and delineation drilling program in a situation where different leases are owned by different people.

But the formation of a unit also has the effect of extending the terms of leases beyond their original expiry dates. So questions can arise over whether an application to form a unit is intended to aggregate lease ownership or whether it is a tactic to defer lease termination.

And the state regulations for unit formation give the commissioner of the Department of Natural Resources, or DNR, wiggle room to use discretion over unitization decisions: The commissioner must evaluate whether unitization will "promote conservation of all natural resources" and "promote the prevention of economic and physical waste," while considering factors such as the geologic characteristics of a potential hydrocarbon accumulation and the unit applicant's exploration and development plans, the regulations say.

In conflict with law?

The companies objecting to current exploration unit policies said that DNR has been in conflict with state laws by only allowing unitization in situations where there is a proven hydrocarbon reservoir, rather than an unproven potential hydrocarbon accumulation.

"Companies are not going to invest in acquiring and exploring state acreage if DNR refuses to unitize leases where geologic data demonstrates resource potential," the companies wrote in their letter to Sullivan. "Further, the division's new policy has prevented multiple companies from conducting exploration activity, including drilling wells."

Current policies, only allowing unitization of acreage where development is imminent, result in development delays, wastage and unnecessary environmental impacts, the companies wrote. Furthermore, the Division of Oil and Gas has changed its unitization policies without consulting with industry, the companies argued.

10 units approved

In his response Sullivan said that every unitization application is unique and that the Division of Oil and Gas continues to approve applications "on the basis of a sufficient showing of a potential hydrocarbon accumulation." Since January 2011 the division has received 15 applications of which 10 were approved, with five of those approvals being based on the existence of potential hydrocarbon accumulations, Sullivan wrote. The other five approved applications demonstrated both potential accumulations and the existence of hydrocarbon reservoirs, he wrote.

"DNR will continue to ensure that unitization promotes conservation, prevents waste and maximizes the ultimate recovery of oil and gas resources," Sullivan wrote. "DNR will also continue to comply with its unitization regulations and state law and follow the established practice of forming units over a reservoir or potential hydrocarbon accumulation to develop the unitized area." ●

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FINANCE & ECONOMY

Bristol Bay Native Corp. buying Peak

Bristol Bay Native Corp. has signed an agreement to acquire Peak Oilfield Services Company LLC from Nabors Alaska Services Corp. The companies said Sept. 30 that the acquisition is subject to customary closing conditions, with closing expected in the fourth quarter.

Peak provides support for the oil and gas industry companies in four primary areas: the Alaska North Slope, Cook Inlet, Valdez and North Dakota.

Peak provides support for the oil and gas industry companies in four primary areas: the Alaska North Slope, Cook Inlet, Valdez and North Dakota.

BBNC is a diversified Alaska Native corporation, with subsidiaries operating in oilfield and industrial services, construction, government services, petroleum distribution and tourism.

Nabors Alaska Services Corp. is a subsidiary of Nabors Industries Ltd., which owns and operates the world's largest land-based drilling rig fleets and has one of the largest completion services and workover and well services fleets in North America.

"This divestiture is consistent with our objectives to streamline our businesses and extract value from core operations while enhancing our financial flexibility," Tony Petrello, Nabors Industries chairman, president and CEO, said in a statement. "Proceeds from this transaction and other third quarter asset sales will more than cover the approximate $207 million premium paid to refinance $785 million of higher-cost debt through our recent tender offer which reduced annual interest expense by over $40 million," he said.

"Peak's commitment to providing the highest quality professional services fits well with BBNC's long-term strategic objectives," Jason Metrokin, president and CEO of BBNC, said in a statement. "Peak's business model enhances BBNC's ability to accomplish our core mission of enriching our shareholders' Native way of life," he said.

BBNC already has two companies providing services to the oil and gas industry: CCI Industrial Services and Kakivik Asset Management.

—PETROLEUM NEWS

● LAND & LEASING

BLM sets NPR-A bid opening for Nov. 6

Agency offers 408 tracts covering 4.5 million acres for lease in a broad area east to west through the central part of the reserve

By ALAN BAILEY
Petroleum News

The federal Bureau of Land Management has set bid opening for its 2013 National Petroleum Reserve-Alaska oil and gas lease sale for 1 p.m. on the afternoon of Nov. 6. The State of Alaska previously announced bid opening for its fall North Slope, Beaufort Sea and Foothills oil and gas lease sales for the morning of that same day.

The same-day sales are aimed at allowing bidders to acquire acreage on both state and federal lands simultaneously.

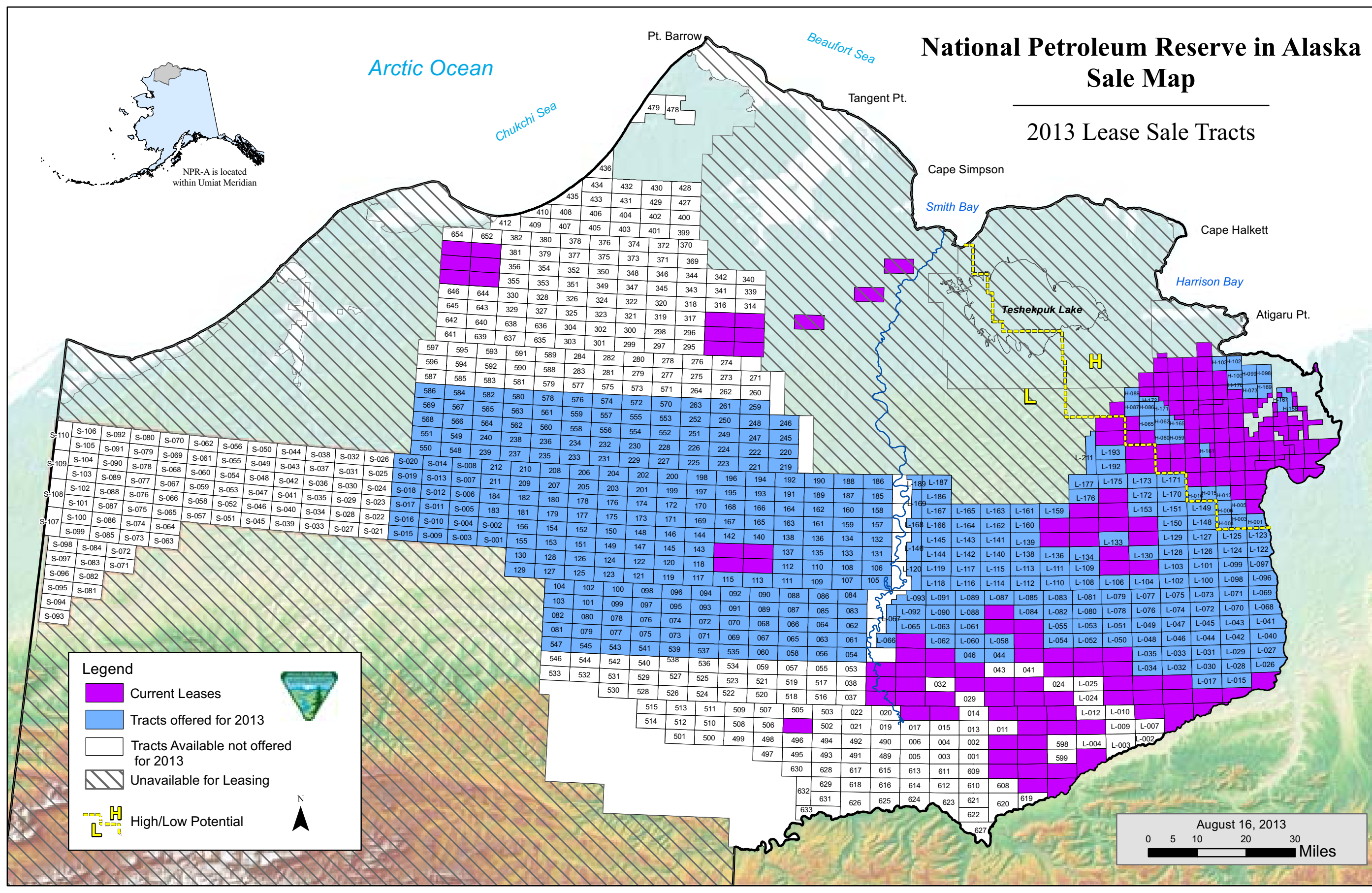
BLM said in a Sept. 30 Federal Register notice that sealed bids are due Nov. 4, with the Nov. 6 opening of the bids taking place at the BLM offices in Anchorage.

President Obama has directed BLM to hold annual lease sales in NPR-A as part of his strategy for the development of U.S. energy resources, the agency said.

"The energy resources of the National Petroleum Reserve in Alaska are essential to meeting our nation's energy demands and will enhance domestic energy production and decrease dependency on foreign oil sources," said Bud Cribley, BLM-Alaska state director. "The November sale is in line with the president's direction to continue to expand domestic energy production, safely and responsibly."

408 tracts

The agency is offering for lease 408 tracts covering a total area of about 4.5 million acres in a broad swath of land running west to east across the central and eastern parts of the reserve. This represents a bit less than half the total acreage that might have been offered from land earmarked for potential oil and gas exploration in BLM's NPR-A activity plan.



U.S. DEPARTMENT OF THE INTERIOR, BUREAU OF LAND MANAGEMENT

During the summer BLM invited nominations and comments on tracts that might be made available in the sale, to gauge industry interest and give conservation groups and other stakeholders an opportunity to provide input to the scope of the sale — the selection of tracts for inclusion in the sale was "based on evaluation of comments received, natural resource information, resource potential, industry interest and subsistence values," BLM said.

When recent NPR-A lease sales began in 1999, BLM included in sales all land tracts available for lease within what were then the Northwest and Northeast planning areas of the reserve. However, in 2011 the agency began asking for nominations for tracts prior to sales, to limit the sales to those tracts that industry might want to bid on.

On the web

See previous Petroleum News coverage:

"Nominations sought for NPR-A sale," in June 9, 2013, issue at www.petroleumnews.com/pnads/350375313.shtml

"Interior issues NPR-A plan decision," in March 3, 2013, issue at www.petroleumnews.com/pnads/577223115.shtml

Activity plan

And following the issuance in February of BLM's new integrated activity plan for the entire NPR-A, this year's lease sale encompasses the whole of the reserve, albeit with large chunks of the reserve deemed by that plan to be out of bounds for oil and gas leasing. BLM said that the land on which oil exploration could take place likely holds about 72 percent of the undiscovered oil in NPR-A. But some people have expressed vehement concern that BLM's plan excludes from leasing much of the northern part of the reserve, a region that may be highly prospective for oil and gas.

The lease sale does include the handful of remaining unleased tracts in the extreme northeast of NPR-A, an area that BLM categorizes as "high potential" and where ConocoPhillips has been conducting an active exploration program. ConocoPhillips is in the process of developing what will be the first operational oil field in NPR-A in what the company refers to as its CD-5 project, in the northeastern part of the high-potential area.

Land tracts in the high-potential area are half the size of tracts on offer elsewhere in the reserve and require relatively high bids of at least $25 per acre. The rental rate on high potential tracts is $5 per acre. Elsewhere in the reserve the minimum bid per tract is $5 per acre, with a rental rate of $3 per acres. And should oil be successfully developed in any of the tracts, the royalties from oil production would be 16 2/3 percent in high-potential tracts and 16 1/2 percent elsewhere.

Detailed information on the sale is available on the BLM Alaska website at www.blm.gov/ak. ●

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● ENVIRONMENT & SAFETY

10,000 walrus come ashore in NW Alaska

By DAN JOLING
Associated Press

An estimated 10,000 walrus unable to find sea ice over shallow Arctic Ocean water have come ashore on Alaska's northwest coast.

Scientists with the National Oceanic and Atmospheric Administration on Sept. 27 photographed walrus packed onto a beach on a barrier island near Point Lay, an Inupiat Eskimo village 300 miles southwest of Barrow and 700 miles northwest of Anchorage.

The walrus have been coming to shore since mid-September. The large herd was spotted during NOAA's annual arctic marine mammal aerial survey, an effort conducted with the Bureau of Ocean Energy Management, the agency that conducts offshore lease sales.

An estimated 2,000 to 4,000 walrus were photographed at the site Sept. 12. The U.S. Fish and Wildlife Service, the agency that manages walrus, immediately took steps to prevent a stampede among the animals packed shoulder to shoulder on the rocky coastline. The agency works with villages to keep people and airplanes a safe distance from herds.

COURTESY NOAA

Young animals are especially vulnerable to stampedes triggered by a polar bear, a human hunter or a low-flying airplane. The carcasses of more than 130 mostly young walruses were counted after a stampede in September 2009 at Alaska's Icy Cape.

The gathering of walrus on shore is a phenomenon that has accompanied the loss of summer sea ice as the climate has warmed.

Winter in Bering Sea

Pacific walrus spend winters in the Bering Sea. Females give birth on sea ice and use ice as a diving platform to reach snails, clams and worms on the shallow continental shelf.

As temperatures warm in summer, the edge of the sea ice recedes north. Females and their young ride the edge of the sea ice into the Chukchi Sea. However, in recent years, sea ice has receded north beyond continental shelf waters and into Arctic Ocean water 10,000 feet deep or more where walrus cannot dive to the bottom.

Walrus in large numbers were first spotted on the U.S. side of the Chukchi Sea in 2007. They returned in 2009, and in 2011, scientists estimated 30,000 walruses along one kilometer of beach near Point Lay.

Remnant ice kept walrus offshore in 2008 and again last year.

The goal of the marine mammals survey is to record the abundance of bowhead, gray, minke, fin and beluga whales plus other marine mammals in areas of potential oil and natural gas development, said NOAA Fisheries marine mammal scientist Megan Ferguson in an announcement.

"In addition to photographing the walrus haulout area, NOAA scientists documented more bowhead whales, including calves and feeding adults in the Beaufort Sea this summer compared to 2012," said Ferguson. "We are also seeing more gray whale calves in the Chukchi Sea than we have in recent years."

Environmental groups say the loss of sea ice due to climate warming is harming marine mammals and oil and gas development would add to their stress. ●

● NATURAL GAS

Canada, Japan seek LNG fit

By GARY PARK

For Petroleum News

Canada and Japan need each other so badly in the liquefied natural gas sector that they have started bilateral efforts to speed development of projects by ramping up Japanese investment in natural gas production and attempting to find common ground on LNG prices.

The two prime ministers — Canada's Stephen Harper and Japan's Shinzo Abe — agreed to an early start to talks at the level of cabinet ministers, pointing to the growing pressures on Japan to find energy sources to replace the shutdown of its nuclear industry after the Fukushima disaster in 2011.

Japan has already established a foothold in British Columbia gas fields and as a minority partner in LNG projects, with an array of companies such as Mitsubishi, Idemitsu Kosan, Japan Petroleum Exploration, Sumitomo Hitachi, Toyota and Inpex acquiring stakes, and Japanese financial institutions expected to join the list.

At his Ottawa meeting with Harper in late September, Abe praised Canada as a stable source of natural gas that could provide the commodity at competitive prices.

Kyodo News, the Japanese news agency, said Abe's government was ready to help finance pipelines and infrastructure to accelerate Canadian LNG shipments to Japan, possibly as early as late 2018.

Japan wants diversification

Susumu Fukuda, Japan's consul general in Calgary, said that with more than 90 percent of Japans oil imported from the Middle East Canada is a "very important possibility to promote diversification" of Japan's natural resource supplies.

He said that next to Australia, Japan prefers to do business with Canada rather than the United States, where energy exports pose greater complications.

Japan also takes an edge by preferring "more friendly" partnerships and joint ventures over China's push for corporate control, which collides with Canada's foreign investment barriers.

The test of the new alliance will come when they try to attach a value to LNG.

As the world's largest LNG consumer, Japan pays the highest prices anywhere — sometimes up to US$16 per million British thermal units, while the rest of Asia is driving bargains that are tied to world oil prices.

Kyodo News, the Japanese news agency, said Abe's government was ready to help finance pipelines and infrastructure to accelerate Canadian LNG shipments to Japan, possibly as early as late 2018.

Keisuke Tsujimoto, general manager in Canada for the Japan Oil, Gas and Metals National Corp., said the Japanese government is eager to build a relationship with the British Columbia government to achieve a memorandum of understanding for natural gas.

He said that such a deal, along with working out an acceptable LNG pricing mechanism, would encourage Japanese investment in midstream and upstream sectors.

Tsujimoto said such a deal could be finalized in December when British Columbia Premier Christy Clark visits Asia.

Tokyo Gas has suggested a more realistic price for LNG could be about US$11 per million British thermal units, based on a Henry Hub gas price of US$4 per million Btu. ●

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INTERNATIONAL

Norway methane hydrate research center starts up

A new center for research into Arctic methane hydrate deposits has opened in the Arctic University of Norway in Tromso. Called the Center for Arctic Gas Hydrate, Environment and Climate, or CAGE, the center will bring together a variety of geologists, geophysicists, oceanographers and other scientists to carry out research into the properties of the hydrates and the ways in which hydrate deposits interact with the Earth's atmosphere, oceans and climate system, according to a report by science news service phys.org.

Methane hydrate is an ice-like material consisting of molecules of methane, the main component of natural gas, trapped in a lattice of water molecules.

Methane hydrate is an ice-like material consisting of molecules of methane, the main component of natural gas, trapped in a lattice of water molecules. The material, only stable within a certain range of relatively high pressures and relatively low temperatures, occurs commonly below the seafloor in coastal shelf areas and, onshore, under Arctic permafrost.

Although some of the hydrates are viewed as a potential future source of natural gas as a fuel, there are also major concerns about the potential dissociation of the material as a consequence of global warming. Such dissociation could release huge quantities of methane, a potent greenhouse gas, into the atmosphere, thus accelerating the warming of the climate and ultimately generating carbon dioxide that will add to ocean acidification.

CAGE will carry out basic research into both the energy resource and environmental aspects of methane hydrate, phys.org says.

—ALAN BAILEY

NATURAL GAS

Utilities review gas supply situation

New Cook Inlet supplies have brought welcome relief but future remains uncertain until sufficient new reserves established

RCA OKs Hilcorp gas contract with CEA

The Regulatory Commission of Alaska has approved a gas supply contract between Hilcorp Alaska and Chugach Electric Association that will ensure that Chugach Electric can obtain all of the gas that it needs to operate its gas-fired power plants until the end of the first quarter of 2018. The commission has already approved a similar contract between Hilcorp and Enstar Natural Gas Co.

In a letter order issued on Sept. 10 the commission said that it approves Chugach Electric's ability to recover the cost of the gas through the rates that it charges its customers.

The contract, which goes into operation in 2015, specifies prices ranging from $7.13 to $8.03 for regular "base load" gas supplies, with price markups of 25 and 50 percent for gas needed to meet peak demand and to meet emergency needs.

Commissioner Norman Rokeberg, while concurring with the commission's decision, has raised concerns about the potential difficulty for Cook Inlet gas explorers in finding markets for newly discovered gas, given the manner in which Hilcorp's contracts have tied up the utility gas market until 2018.

Chugach Electric, saying that it is concerned about providing a gas market for independent producers, has now submitted a gas supply contract with Cook Inlet Energy Inc. to the commission for approval. Cook Inlet Energy is an oil produc-

see **CEA CONTRACT** page 15

By ALAN BAILEY
Petroleum News

A relative boom in exploration activity in the Cook Inlet basin coupled with several new utility gas supply contracts coming in quick succession from gas producer Hilcorp Alaska has produced a sense of euphoria over what had until recently been viewed as an emergency over pending shortages in Southcentral utility gas supplies. And, with both the Alaska Department of Natural Resources and the U.S. Geological Survey having published reports indicating the likelihood that substantial volumes of as yet undiscovered and undeveloped gas remain in the basin, some people view the gas supply situation as having been resolved.

But the utilities, with a duty to ensure supplies of gas and electricity to their customers for years into the future, require certainty in the form of adequate proven, commercially viable gas reserves, behind pipe and linked to firm gas supply contracts with producers, if their officials are to sleep soundly at night, assured that lights will stay on and that buildings will remain heated.

The utilities are discussing with ConocoPhillips the potential to import liquefied natural gas at Nikiski, the port where ConocoPhillips' mothballed LNG export facility is located.

And, on that basis, the Southcentral utilities still see significant future uncertainty, despite emerging news about gas discoveries and gas field developments in the Cook Inlet basin.

During a meeting of the Anchorage Mayor's Energy Task Force on Oct. 2 the utilities overviewed their current gas supply situations.

Gas to 2018

Moira Smith, Enstar Natural Gas Co. vice president and general counsel, explained that a new contract between Enstar and Hilcorp, coupled with several other existing contracts, provide Enstar sufficient gas under contract to meet its anticipated annual gas demand through to the first quarter of 2018. However, Enstar does not have sufficient contracted gas to meet all of its 2018 needs and has no gas under contract beyond the end of 2018, Smith said.

A new gas storage facility, the Cook Inlet Natural Gas Storage Alaska, or CINGSA, facility on the Kenai Peninsula, now provides a key service for all of the utilities by storing excess summer-produced gas to support high levels of gas demand during the winter. However, the withdrawal of gas from CINGSA during the winter requires careful management, Smith explained, because gas withdrawals reduce the reservoir pressure in the facility, thus reducing the maximum rate at which gas will flow from the facility to support gas deliverability needs.

And meeting those deliverability needs remains tight.

Deliverability gaps?

Currently, with the ConocoPhillips liquefied natural gas export facility on the Kenai Peninsula having closed its doors, there is an excess gas supply from the Cook Inlet basin. But, based on its existing firm gas supply and gas storage contracts, Enstar does see theoretical gaps in its ability to deliver gas sufficiently rapidly to meet possible peak winter demand in future winters, Smith said. However, the utility anticipates being able, in practice, to meet that demand by obtaining additional gas through a gas bidding system that it has established, potentially supplemented by some contractual arrangements for the supply of gas that is not guaranteed. It is also typically possible to add gas into CINGSA during some of the warmer winter weather, she said.

CINGSA is likely to hold an open season next year, to explore the possible need to expand its storage capacity, Smith said.

Insurance options

With annual gas supply volumes pro-

see **GAS SUPPLIES** page 15

PIPELINES & DOWNSTREAM

Arrest made on pipeline graffiti threats

The 800-mile trans-Alaska pipeline, much of which courses above ground through lonely countryside, occasionally has been the target of vandals.

Most infamous, perhaps, was the 2001 incident in which a man shot the pipeline with a high-powered rifle near Livengood, causing a hole that spewed a large volume of oil.

Now we have more mischief to report, this time near the village of Tazlina.

The Alaska State Troopers said pipeline security on Sept. 25 reported graffiti on the line, including "Car Bomb" and death and sexual threats toward a trooper and his family in the Glennallen area.

Troopers responded to the scene and saw graffiti on six sections of the pipeline, an agency press release said. The graffiti included multiple statements regarding death to law enforcement, and a death list with the names of Glennallen troopers.

A black spray paint lid was found at the scene, the press release said.

Further investigation revealed Ryan Vukson, 29, of Glennallen, had purchased the paint the day prior and was seen the night of the crime with the same color paint on his hands, troopers said.

Vukson was arrested without incident on charges of terroristic threatening, criminal mischief and criminal trespass. He was jailed in Palmer on $30,000 bail.

—WESLEY LOY

GOVERNMENT

AOGCC sets 2014 CO 360 hearing date

The Alaska Oil and Gas Conservation Commission has set a Jan. 7 public hearing date to gather information on disposition of gas liquids at the Prudhoe Bay oil pool.

The commission said field operator BP Exploration (Alaska) is disposing of natural gas liquids under Conservation Order 360 which the commission issued in the mid-1990s, and is transporting the maximum amount of NGL that can be handled by the trans-Alaska oil pipeline, with the remaining NGL used to create miscible injectant for enhanced oil recovery.

The commission noted that at a June 2012 hearing BP offered evidence that Prudhoe Bay oil production would increase if additional miscible injectant were available, testifying that for every barrel of propane used for MI, 0.6 barrels of oil was recovered and 0.7 barrels of propane recovered for re-use as MI.

The commission said that after the 2012 hearing BP advised the commission that the commission had misinterpreted BP's evidence on the quantity of MI per injected barrel which is recoverable.

The commission said the purpose of the January hearing is to gather evidence on two issues: whether the commission should alter CO 360 to require that additional MI be used to extract oil; and whether the commission has misinterpreted BP's 2012 testimony.

The commission said the outcome of the inquiry may lead it to reopen CO 360 and/or Other Order 75 (issued following the 2012 hearing) for amendment.

The hearing will take place at 9 a.m., Jan. 7, at the commission's Anchorage office, with any pre-filed testimony to be offered due Dec. 6.

—PETROLEUM NEWS

EXPLORATION & PRODUCTION

Forget XL — oil sands will grow

By GARY PARK

For Petroleum News

Whether or not Keystone XL is stalled or scrapped, capital spending in the Alberta oil sands will continue unabated, peaking in 2016 at C$29.7 billion if the TransCanada project goes ahead, said a report by RBC Dominion Securities analyst Mark Friesen.

Even if XL faces delays and removes C$8.1 billion from investment in the 2014-17 period, C$7.8 billion of that deferral will be transferred into the 2018-20 period, he said.

The analysis estimates that if XL remains on hold, 300,000 barrels per day of an expected 1.6 million bpd of increased output will be affected in the 2015-17 timeframe, but expects crude-by-rail could largely offset that setback and might have the positive result of easing short-term inflationary pressures in the oil sands region of northern Alberta.

In fact, investment bank Canaccord Genuity said in a September study that other pipeline and new rail terminal proposals mean XL is "no longer a necessity."

Investment bank Peters & Co. expects Canadian companies to spend US$1 billion on rail terminals in Western Canada over the next two years and up to C$5 billion on new rail tanker cars.

Capital biggest issue

The RBC report said the biggest issue facing oil sands growth — even greater than the risks posed by pipeline capacity and technology development — is the availability of capital for projects, especially for smaller operators.

It said about C$26 billion has been earmarked by oil sands producers, more than half of it budgeted for thermal recovery projects, noting that the 10 largest spenders will account for 84 percent of the capital outlay and control more than 90 percent of the approved capacity additions.

RBC forecasts that cost inflation in the thermal sector will average 3 to 4 percent a year over the next seven years, a change from the runaway inflation in recent years that resulted in budget overruns of up to 40 percent.

Pressures on skilled labor will come from two current megaprojects — the North West Redwater Partnership's 150,000 bpd refinery near Edmonton (which is expected to need a peak workforce of 8,000) and a 109,000 bpd expansion of ConocoPhillips' Surmont operation (peaking at 3,000 workers).

The report pegs the long-term supply costs of greenfield in-situ projects at US$76.38 per barrel of West Texas Intermediate, assuming a heavy oil price differential of 18 percent and 12 percent after-tax return.

However, RBC said higher quality bitumen resources and existing investments in infrastructure could help industry leaders such as Cenovus Energy, MEG Energy and Suncor Energy build thermal recovery projects at lower oil prices. ●

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● EXPLORATION & PRODUCTION

Potential 'game changer' for Canada

By GARY PARK

For Petroleum News

Statoil, drawing on its experience in Norway's offshore, and its minority partner Husky Energy have added a large building block to what shapes up as a new production basin in Atlantic Canada.

Statoil as operator, with Husky holding a 35 percent stake, have reported their third oil discovery in the past three years and are estimating they have up to 800 million barrels of recoverable crude from just two of those finds.

The Norwegian company said that after more exploration Flemish Pass could become a core producing area post-2020 and be a "game changer for Canada."

'New petroleum system'

Statoil spokesman Ola Moreten Aanestad said the partnership's latest discovery is "the largest pure oil discovery made by Statoil outside Norway. We are opening up a new petroleum system."

The find, about 310 miles northeast of St. John's, Newfoundland, resulted from a sidetrack well of the original discovery announced in August.

The Mizzen discovery in Flemish Pass in 2010 is believed to have up to 200 million barrels of recoverable reserves, while volumes will not be confirmed for the Harpoon discovery made during the summer until evaluation work has been completed.

All three finds are in about 3,600 feet of water and have yielded light oil of 34 API from Jurassic reservoirs with high porosity and high permeability.

Seismic, additional drilling

Statoil Executive Vice President Tim Dodson said an "optimal development solution" depends on more work, including seismic and additional exploration and drilling, given that only a few wells have been drilled in the large license area.

Aanestad was reluctant to compare Flemish Pass with other mega-finds, including Statoil's Sverdrup discovery offshore Norway, which holds about 3.3 billion barrels.

"I can't speculate on that ... but this is an area we have great faith in," he said.

Lars-Henrik Roren, a Norwegian analyst with Enskilda, doubted the Flemish Pass will match the Sverdrup play, but suggested there could be a "few more" finds in the range of 100 million barrels. He said more complete details will probably not be known for 12 to 15 months.

Roren said Statoil does not have any more rig slots available until 2016, although the company could be "more flexible with its rig capacity."

Offshore Newfoundland has been producing since 1997 and expects to average 230,000 barrels per day this year from the shallow-water Hibernia, Terra Nova and White Rose fields, with Herbon due to join the trio in 2018 with another 150,000 bpd. ●

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● ALTERNATIVE ENERGY

Alaska searches for energy alternatives

Yakutat community aims to generate electric power from waves; AEA awarded federal grant to develop rural wood energy projects

By WESLEY LOY

For Petroleum News

Both urban and rural Alaska are heavily dependent on expensive fossil fuels for electricity and heat.

As a result, innovators, communities and government agencies continually pursue alternative sources of energy.

Two projects generating attention recently include an effort to harness the power of ocean waves at Yakutat, northwest of Juneau.

Another effort will focus on further developing wood as an energy resource in rural Alaska.

Yakutat wave project

Yakutat is located on the Gulf of Alaska, and is known for large waves that attract adventurous surfers. About 700 people live at Yakutat.

"Like many rural Alaskan communities, Yakutat faces an energy crisis driven by high costs of electrical power and heating fuel and by complete dependence on outside sources of petroleum products," the City and Borough of Yakutat website says. "The municipal power company operates diesel generators for 100 percent of the electricity used locally."

To face what it calls an energy crisis, Yakutat has embarked on a "renewable energy self-sufficiency program."

"Yakutat aims to be the first municipality in North America to generate electrical grid power from wave energy," the website says. "Our community offers close proximity to a tremendous source of power, the Gulf of Alaska!"

On Jan. 30, the Federal Energy Regulatory Commission issued a preliminary permit to Resolute Marine Energy Inc. for a Yakutat wave energy project.

The Boston-based company is focusing on development of patented nearshore wave energy technology, and a prototype device could be deployed in Yakutat by fall of 2014, the Yakutat website says.

On Sept. 23, the Alaska Department of Natural Resources said it would issue a one-year land use permit to Yakutat to place scientific instruments on submerged state acreage. Data will be collected about two miles seaward, a DNR public notice said.

Wood to energy

Alaska Sen. Lisa Murkowski and Congressman Don Young recently announced the Alaska Energy Authority had been awarded federal funding to promote the development of rural wood energy projects.

"Alaska has always relied on wood-based resources for heat and power, and recent technological advancements have dramatically increased their efficiency while decreasing their impact and cost," Young said in a joint press release with Murkowski.

Agriculture Secretary Tom Vilsack on Sept. 11 announced $1.1 million in grants to organizations in Alaska, California, Idaho, Minnesota and New Hampshire to form statewide teams to stimulate development of wood energy projects.

Vilsack called it part of the Obama administration's "all of the above" energy strategy.

Under terms of the grants, private, state and federal organizations will work together on wood energy projects.

"Collectively, $2.9 million will be spent on this effort — $1.1 million in federal funds and $1.8 million in non-federal funds," a U.S. Department of Agriculture press release said. ●

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GAS SUPPLIES

jected to fall short of demand less than five years into the future, the utilities are still looking at "insurance" options for guaranteeing continuing energy supplies beyond early 2018. And, with continuing uncertainty about the future construction of a pipeline system that might deliver North Slope gas into Southcentral Alaska, the import of gas, probably from Canada or the Pacific Northwest, remains a possibility. Although the utilities had considered the import of gas in compressed form they now view the import of liquefied natural gas as a more practical option, Smith said.

The utilities are discussing with ConocoPhillips the potential to import liquefied natural gas at Nikiski, the port where ConocoPhillips' mothballed LNG export facility is located. And, with the likely need for an environmental assessment or an environmental impact statement for the import arrangements, establishing these arrangements would likely be a multiyear project, Smith said.

Lee Thibert, senior vice president of Chugach Electric Association, said that the ability to bring in or store extra gas at Nikiski would be an excellent backstop for winter gas supplies. An import facility might cost somewhere in the range of $50 million to $135 million, he said.

Chugach Electric

The gas supply situation for Chugach Electric, a major Southcentral electric utility, appears somewhat similar to that of Enstar, with existing gas supply contracts and a new contract with Hilcorp carrying the utility through to the first quarter of 2018, but with no gas currently under contract beyond the end of that year.

Chugach Electric wants to offset its gas consumption by diversifying further into renewable energy resources, including increased hydropower capacity from the Kenai Peninsula and, eventually, power from a planned major hydropower facility at Watana on the Susitna River, Thibert said. However, the Watana-Susitna system, potentially a supplier of a significant portion of Chugach Electric's needs, is not expected to come on line until 2024-25, he said.

Matanuska Electric Association

Joe Griffith, general manager of Matanuska Electric Association, said that his utility also now has secured gas supplies through to 2018 for the new gas-fired power plant that the utility is building at Eklutna, north of Anchorage. The engines being installed in the new plant are dual-fuel reciprocating engines, rather than turbines, with the capability of switching instantly from gas to diesel fuel, should need arise, Griffith said.

A key issue that now needs to be addressed is ensuring a healthy gas market for the several companies that are currently engaged in Cook Inlet exploration, given the small size of the local utility gas market in relation to the investment required to find and develop Cook Inlet gas, Griffith commented. He said that the ability to export LNG from the basin seems the only obvious way to resolve this conundrum.

Municipal Light & Power

Jim Posey, general manager of Anchorage electric utility Municipal Light & Power, commented on the importance of finding new gas supplies from Cook Inlet and having a means of ensuring gas supplies beyond 2018. ML&P obtains most of its gas through its partial ownership of the aging Beluga gas field on the west side of Cook Inlet. The utility also has a small gas supply contract with Hilcorp through to the first quarter of 2014 and has requested RCA approval of a new contract with ConocoPhillips that would run from April 2014 to December 2019, Posey said. ●

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CEA CONTRACT

er and active oil and gas explorer in the Cook Inlet basin.

The prices in the contract, ranging from $6.12 to $7.31 per thousand cubic feet, are 10 percent lower than those in Chugach Electric's approved contract with Hilcorp. But the Cook Inlet Energy contract makes no firm commitment, either for Cook Inlet Energy to supply gas or for Chugach Electric to purchase any gas that Cook Inlet energy may offer for sale.

—ALAN BAILEY

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GOVERNMENT

BSEE extends comment period for safety rule

The Bureau of Safety and Environmental Enforcement, or BSEE, said Sept. 26 that it is extending by an additional 45 days the public comment period for a proposed offshore safety systems rule. Comments must now be filed by Dec. 5, BSEE said.

The proposed rule relates to safety regulations for systems such as subsea pumping, foam firefighting equipment, emergency shutdown systems and gas lift used in oil production facilities on the U.S. outer continental shelf.

The proposed rule relates to safety regulations for systems such as subsea pumping, foam firefighting equipment, emergency shutdown systems and gas lift used in oil production facilities on the U.S. outer continental shelf.

The rule was originally published on Aug. 22 with a closing date of Oct. 21 for public comments. But BSEE has received "multiple requests from various industry representatives to extend the comment period" and the agency determined that an additional 45-day comment period was warranted, BSEE said. With no major revision having been made to the relevant regulations since they were published in 1988, it is now necessary to update the regulations to take account of new technologies such as the use of subsea well trees, BSEE said.

"These new technologies are more complex than those that were traditionally used for shallow water drilling on shelf areas, where equipment was traditionally placed on the rig itself, rather than on the seafloor," BSEE said. "With the shift to deeper water in the past decade, more specialized requirements and regulations are required for these newer and emerging safety technologies."

—ALAN BAILEY

● EXPLORATION & PRODUCTION

Update from Conoco on Alaska investments

Trond-Erik Johansen, president of ConocoPhillips Alaska, reviews work under way since passage of bill reducing state taxes on oil

By KRISTEN NELSON
Petroleum News

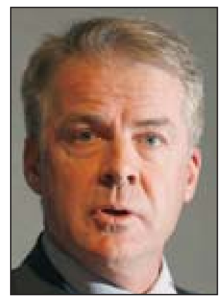
In April ConocoPhillips Alaska laid out work it planned in response to passage of Senate Bill 21, Gov. Sean Parnell's oil tax revision.

In late September Trond-Erik Johansen, president of ConocoPhillips Alaska, gave the Alaska World Affairs Council an update on that work.

The addition of a rig at the ConocoPhillips Alaska-operated Kuparuk River field has resulted in 1,300 barrels of oil per day of new production online since May, Johansen said Sept. 27, and also supports 95 direct new jobs as well as some 700 indirect jobs.

In April the company also said it was working with Kuparuk co-owners to fund a new drill site on the southwest flank of the unit. Johansen said gravel will be laid this winter in preparation for construction of that new drill site, Kuparuk drill site 25.

The drill site will develop a discovery ARCO Alaska made with the KRU 21-10-08 well in the late 1980s. ConocoPhillips appraised the discovery with the Shark Tooth No. 1 well in the winter of 2012. The company began permitting work for the drill site and an access road in early 2013, with 300,000 cubic yards of gravel to be placed this winter and pipelines and power lines installed the following winter.


JUDY PATRICK
TROND-ERIK JOHANSEN

Johansen said first oil is expected from drill site 25 in 2015 with estimated peak production of 8,000 bpd; he pegged the development cost at $595 million.

NPR-A

Johansen said the Greater Moose's Tooth-1 development in the National Petroleum Reserve-Alaska, a major new development, would cost an estimated $890 million, with first oil in 2017 and estimated peak production of 30,000 bpd. He characterized the development as similar to CD-5 and said ConocoPhillips Alaska would seek approval for Greater Moose's Tooth-1 in late 2014.

CD-5, sanctioned in late 2012, is a single-pad development, with a road and a bridge and pipelines over a channel of the Colville River, with crude oil sent to the Alpine facilities for processing. Construction on that project, also called Alpine West, is projected to begin in 2014 with partner approval. While first oil is estimated for late 2015 or 2016, the development is facing court challenges from environmental groups.

ConocoPhillips also plans two winter exploration wells in NPR-A, wells that Johansen said were questionable last year.

There are also projects at Prudhoe Bay, operated by BP Exploration (Alaska), and Johansen said BP has discussed those projects.

In late June Janet Weiss, president of BP Alaska, told the Resource Development Council that in addition to a $1 billion increase in Prudhoe Bay investment for the next five years, previously announced, and $3 billion in western region Prudhoe projects under evaluation, the Prudhoe owners are moving forward on development of the Sag River formation. BP is also reworking economics for Northwest Schrader at its wholly owned Milne Point field, she said.

The repeal issue

Answering audience questions after his presentation, Johansen said that even though there is a referendum scheduled on Senate Bill 21, engineering for Kuparuk drill site 25 and for NPR-A is going ahead.

If the August 2014 vote turns the tax change upside down, some things may be stopped, he said.

But he noted that ConocoPhillips has hired 50 people since May and expects to have hired 120 by the end of the year. And, he said, they wouldn't have done all these projects without SB 21.

Some would have been done, he said, but at a much slower pace. ●

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● GOVERNMENT

Obama signs bill with legacy well money

Funds from closure of Federal Helium Reserve to be used to remediate old federal wells sites in National Petroleum Reserve-Alaska

By WESLEY LOY
For Petroleum News

President Obama on Oct. 2 signed legislation that could steer millions of dollars toward cleanup of derelict federal wells, known as legacy wells, in the National Petroleum Reserve-Alaska.

The new law, titled the Helium Stewardship Act of 2013, is designed to eventually close the Federal Helium Reserve in Texas.

What to do with the reserve had for many years been the subject of controversy and debate in Washington.

Alaska Sen. Lisa Murkowski helped author the helium act. Murkowski is the top-ranking Republican on the Democrat-controlled Senate Energy and Natural Resources Committee.

Closure of the helium reserve is expected to generate about $500 million in revenue over the next decade, Murkowski said in a press release.

The new law dedicates some of the money to reduction of the federal debt.

It provides $50 million to remediate and close abandoned oil and gas wells on current or former national petroleum reserve land. Wells in Alaska and in other states are eligible for the funding.

But the vast majority of the $50 million is expected to come to Alaska, a Murkowski aide told Petroleum News.

'An environmental crime'

The NPR-A is a vast tract on Alaska's North Slope.

Murkowski and other Alaska elected officials and regulators have been pounding the Interior Department for months to do something about the reserve's legacy wells.

Federal departments drilled 136 test wells between 1943 and 1982.

Today, the wells are the responsibility of the Interior Department's Bureau of Land Management, which manages the petroleum reserve and also operates the Federal Helium Reserve.

Murkowski and the other critics say the BLM has neglected the legacy sites, some of which are junk-strewn and have wells that were never properly plugged and abandoned.

They have complained the BLM is moving far too slowly to clean up the legacy wells. BLM officials have countered that cleanup is extremely costly, and that many of the wells don't really need any attention.

After the helium act cleared Congress, Murkowski said the funding should help spur action.

"For years, we fought just to get a couple of million dollars dedicated to the cleanup of the legacy wells, so I'm pleased we were able to obtain $50 million to begin seriously addressing what is nothing short of an environmental crime against Alaska," Murkowski said. "Securing the funding during these days of tight budgets and competing federal priorities was challenging, but the legacy wells are a federal responsibility that has been ignored for far too long."

BLM's cleanup plan

North Slope Borough Mayor Charlotte Brower welcomed the helium bill's passage.

"For many years, BLM has lacked the resources necessary to clean up and remediate high-priority wells in a timely manner," she said.

She noted how the Obama administration proposed a fiscal year 2014 Interior Department budget that would pay for legacy well cleanup by diverting Alaska's share of revenue generated from oil and gas activity in the NPR-A.

Brower called that proposal "unacceptable," and Murkowski said it would be "dead on arrival."

Murkowski is the ranking Republican not only on the Senate Energy Committee, but also the Senate Interior Appropriations Subcommittee. Both have jurisdiction over the BLM.

The helium law allocates the well cleanup money across three fiscal years, a North Slope Borough press release said.

On Sept. 23, the BLM released a final "strategic plan" to plug and clean up NPR-A legacy wells.

The BLM said half, or 68, of the legacy wells require no action "because they have been remediated or pose no threat to the public or the environment."

The U.S. Geological Survey continues to use another 18 wells as part of climate change studies.

The plan identifies 50 wells as requiring attention, including 16 priority wells.

The first wells slated for cleanup work are at Barrow and on the Simpson Peninsula southeast of the village.

The BLM didn't specify a total cost to carry out the cleanup plan. But the money available from the helium bill is likely insufficient.

"BLM's plan is a good start," Murkowski said. "It doesn't cover all of the sites, but it takes care of the most serious environmental threats first." ●

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HERRON Q&A

Bering Straits is going to play a key part. Yes, Unalaska has been for centuries and will continue into the future to play a huge role for Arctic exploration.

Petroleum News: Still on the Arctic, Shell got off to a slow start last summer and had to postpone operations until next year. Do you have any concerns about further delays?

Herron: Sure we've got to be prudent and do things correctly, and I think that's the intent of everyone involved. You've got to look at it from a half full glass rather than a half empty glass. I tend to use this philosophy in everyday life: things I attempt are not failures; they are successful attempts. I'll give them the benefit of the doubt. It didn't work out the way they wanted. They took those steps. Those are lessons that are hard learned. Sometimes you have to take those steps that don't succeed. I hope they and other members of the industry keep at it.

Petroleum News: Shifting to oil already under production, SB 21 continues to be a hot-button topic long after it's passed and now we have an effort to overturn it before the voters next year. What are your thoughts on this as it unfolds. You've got two issues on the table: the referendum and the concerns over drafting regulations defining new oil?

Herron: I voted no on SB 21. I signed the referendum because I believe SB 21 went too far. Did there need to be changes to ACES? Absolutely. I said that all along. It went too far, too fast. So should SB 21 be overturned and then rethought? That's why I signed the petition and that's why I'm going to support the ballot initiative.

On the House floor, I advocated for changes. I debated and talked with my colleagues. I told them it went too far. The question I asked was, is this being fiscally conservative? Is this fiscally responsible?

What I mean by that is, if it were my household, and of the two wage earners, one of them lost their job for whatever reason. So you cut back on the extras and you pay your mortgage and you feed your kids. You spend on what's necessary. But your savings account you protect it at all costs. You save it for real emergencies, catastrophic events.

So where I disagreed on SB 21, the tax is immediate (Jan. 1, 2014), so we'll just take from the savings account to sort of back feed it. I disagree with it. I asked literally every oil company who came to my office to confirm that I was voting no and I asked them this. I don't care what the formula is, but let's call the "n" number "x," so the way SB 21 is we come to a certain date and revenue drops to that "x" factor in the formula. What if it was played out three or four years? In the first year there would be 25 percent reduction in taxes, then the next year there would be 50 percent until the fourth year we would have 100 percent of that "x" factor. I asked all of the oil companies if they would accept that. They all said yes because they were getting that number that advocated for.

That's why I believe SB 21 was too much, too fast. That's why I voted no. I don't think it's fiscally conservative or fiscally responsible.

Petroleum News: OK, on to the second issue of drafting a regulation that clearly and concisely defines new oil.

Herron: Whoever writes that regulation is going to be the wordsmith of 2013. There will be so many 'ifs,' "ands" and "ors." I just don't think they are going to come up with regulatory language that makes sense. I don't think I'll understand it. I just don't know if I'll know what new oil is. Maybe my glass has changed from half full to half empty. I'm just not confident that the regulation will make any sense to me.

Petroleum News: On to the gas line issue, what would you like to see happen to advance a gas line project, be it the larger line or the smaller line?

Herron: I was on an ExxonMobil-sponsored trip to Coldfoot to see what their crews are doing on the ground. I asked them that specific question. When is the line going to go? They said we are not going to come up with an answer until we have gas tax certainty. I think we have a ways to go yet. Whether it's a small line or a big line, the producers are going to need gas tax certainty. So is that going to be a debate in 2014 or a debate in a special session? Probably (a special session). I don't know when that special session is going to be. I'm just a believer the producers are not convinced they have gas tax certainty.

Petroleum News: What else did you learn on that trip?

Herron: That the producers are serious about spending billions on a facility on the North Slope. But what I took away still is they are not prepared to make the decision until they get the gas tax certainty.

Petroleum News: There are two schools of thought: You don't provide gas tax certainty until you have a firm project on the table; you won't get a firm project without the gas tax certainty. The negotiations rest with the executive branch. What would you like to see happen?

Herron: I think for some, let's give them the certainty. For a lot of legislators, it's show me first, then if it's going to work then you will get the certainty. We want to push the envelope. We want the project that makes the most sense. I agree with critics and pundits who have commented on this since I've lived in Alaska. We are going to move forward. It's going to take the producers as well to push gas through any vessel, any gas line. At the moment for me, it's show me what you got. Show me what makes sense. This is why you need gas tax certainty — then we'll talk about it.

Petroleum News: Do you have any closing thoughts to what we discussed?

Herron: There's a lot going on in our state. For Alaska and the United States, plus the Yukon and Northwest Territories, and their national government, we have much more in common than we do differences. The things that Alaska, Yukon and the Northwest and how much these jurisdictions have in common and can benefit from the Beaufort Sea, I believe we have tremendous opportunities in the next three to four years with Canada being the chair of the Arctic Council and the United States coming up after that.

That's why I think the Alaska Arctic Policy Commission in its preliminary report to the Legislature in 2014 and its final report in 2015 right before the U.S. takes over as chair of the Arctic Council is important.

The Legislature in working with the Parnell administration or any future administration — it doesn't matter if you are a legislator from Ketchikan, Barrow, Bethel, Anchorage or Fairbanks — these issues of the Arctic are going to play a huge role in our daily lives. Whatever the Arctic policy is, it all has to be about what benefits Alaska, because we know many of these policies are going to impact us and not in a policy way. The Legislature and the Parnell administration, we have so many things to deal with, so many constituencies that are asking for help. By the constitution we are required to assist them. Because of the opening of the Arctic and the potential of oil and gas — and many other minerals — these policies affect us.

What our Canadian partners do in relation to Prince Rupert is going to have a tremendous effect to Alaskans. One of them is the great circle route. Right now we've got 3,000 quote-unquote innocent passage ships going through our waters because it's the shortest route. If Prince Rupert opens up for all the resources Canada wants to export, that number of ships could go up to 6,000 annually. It doesn't take but a few close calls and one disaster and Alaska could be impacted in a negative way, tremendously for a long, long time.

What Arctic policy means to any Alaskan — it doesn't matter where he or she lives — is if we are not on top of it, if we are not talking about Arctic policy, all the way from oil and gas to ships coming through our waters, we have to be aware of it and protecting ourselves. At the same time, those policies have to benefit you and me, not benefit just someone else. If it doesn't benefit Alaska, we should work to minimize those potential impacts to us. ●

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BEAUFORT JV

significant challenges."

In filing a project description with the Inuvialuit Environmental Impact Screening Committee, which acts as advisor to Canada's National Energy Board, and the Northwest Territories government, the partnership has indicated growing confidence following the collection of seismic data in 2008 and 2009 and three years of gathering field data in 2009-11.

Rolheiser said the submission "in effect initiates the formal regulatory review," which operator Imperial hopes will be completed by 2016.

Sanctioning after approval

Assuming regulatory approval, the joint venture would then make a sanctioning decision, allowing it to secure a floating drilling system which it believes is best suited to the area.

A well would be expected to take two years to complete based on an annual drilling season of 120 days from May to November.

The two exploration licenses — 476 (Ajurak) and 477 (Pokak) — carry combined work commitments of C$1.76 billion.

The water depths are estimated at about 5,000 feet and target subsea vertical depths of 12,500 feet to 22,300 feet.

Rolheiser said the licenses, which are about 110 miles northwest of Tuktoyaktuk on the shores of the Beaufort, would be the farthest offshore and deepest that Imperial has ever drilled in the area.

The venture is at the leading edge of possible revival of Beaufort exploration which has included 92 wells that have so far yielded two major discoveries.

The venture is at the leading edge of possible revival of Beaufort exploration which has included 92 wells that have so far yielded two major discoveries — the 1984 Amauligak strike by Gulf Canada Resources, since taken over by ConocoPhillips, estimated at 235 million barrels of oil and 1.36 trillion cubic feet of natural gas and a 2005 find by Devon Energy, reported to hold 240 million barrels of oil. Neither has advanced to commercial development plans.

Chevron Canada is evaluating results from its 2012 seismic program covering 1,412 square miles, 145 miles northwest of Tuktoyaktuk, while Norway's Statoil has farmed in on a 508,000-acre parcel in the Beaufort, which is west of the joint-venture licenses.

NWT wants venture to proceed

Northwest Territories Industry Minister David Ramsay said his government is now "anxious" to see how far the Imperial venture can proceed given its importance to the regional economy since the sidelining of the Imperial operated Mackenzie Gas Project, which had been designed to ship up to 1.8 billion cubic feet per day natural gas from the Mackenzie Delta to southern Canadian and U.S. markets.

The next three years, building up to a final investment decision in 2016, could include a public environmental hearing, authorizations for drilling operations, agreement on a plan to employ and train Canadians and northerners and a program to dredge and install facilities at Tuktoyaktuk Harbor.

Still to be resolved is how the partnership would comply with a National Energy Board regulation, which followed the BP Macondo well rig explosion and oil spill in 2010, that operators must be prepared to drill a same-season relief well if there is a blowout.

Imperial said its primary well control approach, which will be outlined in future applications for specific wells, would be prevention, including wells designed for the range of expected risk.

Industry interest in Canada's Arctic region, despite a flurry of drilling in the Central Mackenzie Valley, is otherwise lukewarm.

Aboriginal Affairs and Northern Development Canada reported the annual call for bids in the Central Mackenzie Valley that closed Sept. 19 yielded only two successful bids, with four other parcels bypassed.

High Level Energy bid C$18 million for 100 percent of a parcel covering 200,000 acres, while International Frontier Resources landed rights to a lease covering 163,000 acres for C$1.2 million. The leases require qualifying exploration work within five years to gain an extension to a nine-year permit.

—GARY PARK

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AHTNA LICENSE

corporation considers obtaining the license to be a first step towards addressing energy costs in the Glennallen area while also providing employment opportunities for the corporation's shareholders.

"Ahtna Inc., an Alaska Native corporation headquartered in Glennallen, fully supports the Alaska DNR commissioner's finding in issuing an oil and gas exploration license to Ahtna in the Tolsona Lake area west of Glennallen," Anderson said. "The Ahtna Inc. board will be assessing their financial investment scenarios to develop natural gas in the Copper River area. Exploration activities will begin late 2013 with a minimum investment of $415,000 (US) over the next 1 to 2 years."

Huge basin

The Copper River basin, occupying a huge lowland area between the Alaska Range, the Chugach Mountains, the Talkeetna Mountains and the Wrangell Mountains, has petroleum geology quite similar to that of the prolific Cook Inlet basin to the west. However, although the Mesozoic rock unit that sources oil in the Cook Inlet region is known to exist in the Copper River area, differences in the precise nature of the rocks are thought to make the Copper River basin more prospective for natural gas than for oil.

Any commercial gas resource discovered in the Copper River area, especially if close to the road system, could presumably be used for local power generation.

The new exploration license area lies immediately west of Ahtna land where Texas-based independent Rutter and Wilbanks drilled a gas exploration well and a series of sidetrack wells between 2005 and 2009. Rutter and Wilbanks reported a possible gas find in its Glennallen well. However, the company eventually abandoned the drilling project, having been stymied by severe technical problems associated with water production and abnormally high subsurface pressures.

Sparse exploration

And, in general, exploration of the Copper River basin has been very sparse.

According to information provided in the state's finding for Ahtna's exploration

see **AHTNA LICENSE** *page 23*

Petroleum news

Oil Patch Bits

Crowley presents scholarships to maritime cadets

Crowley Maritime Corp. awarded three Thomas B. Crowley Sr. Memorial scholarships to California Maritime Academy students Andrew Leonard, Jeff Harcq and James McSweeney during the 2013 Containerization and Intermodal Institute's Connie Awards dinner in Long Beach, Calif.

COURTESY CROWLEY

Leonard has had a long-time passion of the water and boating, and began researching maritime academies while still in high school. He now serves as the residential assistant for his freshman class, is a member of the Associated Students of the California Maritime Academy and is an active supporter of the greater City of Vallejo, Calif.

When Harcq applied to Cal Maritime, he had already obtained his 50-ton master's license and had more than 10 years experience as a mechanic for the Correct Craft boat dealer in San Diego. As a student, he has fully embraced his role as a valuable mentor for his younger classmates by sharing his real-world experiences in the classroom.

During one of the fishing seasons, McSweeney was approached by a Cal Maritime alumnus who encouraged McSweeney to return to school. After being accepted to the school, he began pursuing his U.S. Coast Guard 3rd Mate Unlimited license and a Bachelor of Science degree in marine transportation.

Crowley Chairman, President and CEO Tom Crowley Jr., established the Thomas B. Crowley Sr. Memorial Scholarship Program in honor of his father, who guided the company to extraordinary heights before passing away in 1994.

Fairweather's Tulugaq launch bolsters data collection

COURTESY TULUGAQ LLC

Following the recent acquisition of VDOS, a worldwide leader in airborne remote sensing operations, Fairweather LLC has announced the formation of subsidiary Tulugaq LLC, a partnership between Fairweather, Olgoonik Corp. and Kaktovik Iñupiat Corp. Tulugaq (pronounced "too-lu-gak") is the Native Alaskan word for "raven." The company was formed to

see **OIL PATCH BITS** *page 22*

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

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TAPS HIKE

Even though the prior increases remain temporary until regulators officially approve or reject them, the changes have created a disparity between the BP and the other owners.

Now, BP is catching up.

Under a proposed increase, BP would charge $3.97 per barrel to ship oil from the North Slope to North Pole, up from a current rate of $1.25 per barrel. And the current rate of $1.96 per barrel to ship to off-take points in Valdez would increase to $6.31 per barrel to the PetroStar Valdez Refinery and $6.34 per barrel to the Valdez Marine Terminal.

BP wants the higher rates to go into effect on Oct. 23.

While the increase would more than triple the rate BP charges to ship North Slope oil to local markets, the higher rates would still leave BP as the cheapest local shipping option on the pipeline. ConocoPhillips currently charges $4.32 per barrel to ship to North Pole and as much as $6.87 per barrel to ship to Valdez, while ExxonMobil currently charges $4.09 per barrel to ship to North Pole and as much as $6.47 per barrel to ship to Valdez.

Historically, Koch and Union Oil Company of California have owned small stakes in the pipeline system, but Koch recently transferred its 3.0845 percent interest to the three largest owners and Unocal is in the process of transferring its 1.3561 percent interest.

For ratemaking purposes, each company owns an "undivided" stake in the pipeline, meaning each can set its rates individually, so long as the combined rates stay below a certain cap. A company looking to ship oil then "rents" space from one of the owners.

In filings, BP said it needs the increase to offset declining throughput and rising ad valorem taxes — the same reasons the other owners have given for their rate increases.

Between 2000 and 2013, throughput went from 1 million barrels per day to some 550,000 barrels per day while ad valorem taxes went from $57 million to $237 million annually.

Those trends have been consistent year after year, though. As for why BP is looking to increase its rates now, after six years of holding firm, the company declined to elaborate.

BP estimates it would earn nearly $53 million per year under the higher rates, up from some $16.4 million per year under the current rates. The majority of the earnings — some $48.8 million — would come from shipments to the Valdez Marine Terminal with the rest coming from shipments to the Golden Valley Electric Association off take in North Pole. BP does not expect to make local shipments to the PetroStar Refinery in Valdez.

A complex case

The request adds yet another layer to a complex regulatory matter.

The State of Alaska and the owners of the pipeline have long debated the appropriate method for determining the shipping rates. The two sides reached a settlement in 1985, but a 1997 court case challenged the system. In 2002, the RCA decided the previous rates were too high, and forced the pipeline owners to refund nearly $10 billion to shippers.

For years after the ruling, the pipeline owners continued to propose rate changes calculated using the older methodology and the RCA in turn rejected every request.

Starting in 2008, though, ConocoPhillips sought a rate increase calculated under the newer methodology. ExxonMobil, Unocal and Koch quickly followed suit.

As is typical, the RCA approved those increases on a "temporary and refundable basis," meaning the companies could charge the higher rate while regulators investigated the matter, but ran the risk of having to issue refunds if regulators rejected the increases.

Those four companies continued to seek rate increases year after year, creating an overlapping series of temporary and refundable rates, and high exposure for refunds.

The RCA eventually consolidated 12 cases — three each from the four companies — to consider a range of issues, particularly around whether and how to incorporate the costs of the over-budget Strategic Reconfiguration project into shipping rates. Because many of those same issues are also before the Federal Energy Regulatory Commission, which handles shipping rates for out-of-state-markets, the two bodies held numerous concurrent hearings on the consolidated cases over a period of months last year and this year.

While those cases progressed, though, the pipeline owners continued to file annual rate increases, which the RCA also accepted on a temporary and refundable basis. The fate of those requests will largely depend on what the RCA decides in the consolidated case.

BP, though, considers its request to be "significantly different" than the others, and said the RCA should consider it separately, rather than consolidating it into the larger case.

And BP is also asking the RCA to adopt a "simplified tariff procedure," a common regulatory practice allowing companies to adjust rates quickly within certain parameters.

The stakes for an increase

Even when appropriate, higher tariffs are a burden to third parties.

The State of Alaska calculates its royalties after deducting tariffs, which means higher shipping rates decrease the amount of revenue the state earns from oil production.

Higher shipping rates also make it more expensive for independent companies on the North Slope. While Anadarko Petroleum Corp. has been fighting increases for years, the North Slope is now home to more independent producers than at any point in its history.

Finally, higher shipping rates increase the cost of running the refineries that buy oil from the pipeline, which is why Tesoro and PetroStar often push back against increases.

—ERIC LIDJI

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FRANCES WELL

Nelson said that Hilcorp had recently completed the drilling of the first exploration well, the Ninilchik Unit Susan Dionne No. 8, using the Saxon 147 drilling rig.

"We will be using the same rig, the Saxon 147 rig, to drill Frances 1," Nelson said. "We should begin rigging up next week."

No results are publicly available from drilling of the first well.

The Ninilchik field, which was discovered in 1961 and went into production in 2003, is a natural gas field. There have been six oil exploration wells previously drilled in the Ninilchik unit, with one of these, a well drilled in 1978 at Clam Gulch, having minimal oil shows, Nelson has previously said.

—ALAN BAILEY

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UMIAT DRILLING

ed the Umiat No. 23H well, but it also included four proposed wells that are not on the agenda for this coming winter. Those four wells are the Umiat DSP No. 1 Class II disposal well, the side-by-side Umiat No. 16 vertical and Umiat No. 16H horizontal wells, and the Umiat No. 19 vertical well.

Linc now plans to defer the disposal well until the development phase of the program.

Earlier this year, Linc described Umiat No. 18 and Umiat No. 23H as a vertical and a horizontal well into the same interval of the Lower Grandstand formation. The idea was to conduct "comparative flow testing" for economic purposes, but Linc ultimately delayed the flow test at Umiat No. 18 because of an apparent blockage in the well.

Linc said it "employed multiple techniques to clean the perforations such as methanol, solvents, and surfactants to remove any ice or other debris in an attempt to re-establish flow," but was unsuccessful and has since been reviewing the mechanical issue.

With Linc now eying a horizontal development program at Umiat, the company no longer plans to flow test Umiat No. 18, saying it is more important to learn how horizontal wells flow at the field.

While drilling Umiat No. 18, Linc collected some 300 feet of core samples, which the company described as "dripping oil." Having completed an analysis in Houston, the company now says the sample indicated "outstanding rock properties" for a lighter oil reservoir, including 16-18 percent porosity, air permeability of 70-270 millidarcies and "friable" (or soft) sandstones that Linc believes is "preferred for optimal oil flow."

More valuable?

The results of this initial analysis have also convinced Linc that the Lower Grandstand reservoir is "completely saturated with hydrocarbons," the company said in a statement.

The U.S. Navy discovered and delineated Umiat with 12 wells drilled between 1946 and 1979.

"We have captured many learnings from last year and confidently approach this winter's drilling program with the knowledge and expertise to successfully achieve our current goals," Linc Energy CEO and Managing Director Peter Bond said in a statement. Among the goals for this year, he added, is to flow oil from horizontal wells, which he said could potentially move some of the "probable" reserves at the field into the "proved" category.

Considered among the largest undeveloped oil fields in Alaska, Umiat is believed to hold more than 1 billion barrels of oil in place. In September 2012, the consulting firm Ryder Scott Co. LP estimated the field contains reserves of 154.5 million barrels of proved and probable (P2) oil equivalent and 194 million barrels of proved, probable and possible (P3) oil equivalent, with "probable" meaning at least a 50 percent chance of actual recovered volumes meeting or exceeding the P2 estimate, and "possible" meaning at least a 10 percent chance of actual recovered volumes meeting or exceeding the P3 estimate.

Those reserves are more valuable since Alaska revised its oil production tax earlier this year, according to a recent third party valuation Linc included with its drilling plans.

According to Ryder Scott, the 154.5 million barrels of oil equivalent of P2 reserves at Umiat now has a net present value (at 10 percent return) of $2.465 billion, up 65 percent from a net present value of $1.496 billion estimated before the changes to the tax code.

"We see this legislation as a win-win for the citizens of Alaska and for Linc Energy," Bond said in a statement. "The ultimate addition of 50,000 barrels per day to the (trans-Alaska oil) pipeline as well as the utilization of multiple Alaskan contractors employing hundreds of Alaskan citizens presents a significant positive economic impact."

In August 2013, Linc sold "rights to certain oil and gas tax credits" from the State of Alaska to the investment firm Apollo Investment Corp. for some $24.7 million.

Another snow road

As it did this past winter, Linc plans to construct a 102-mile snow road this coming winter to connect the remote Umiat drilling operation to the Dalton Highway.

With the rig and associated equipment already stacked near the drilling location, though, Linc will be able to begin drilling as soon as it can build shorter in-field ice roads.

The company described the drilling and testing of Umiat No. 23H as its "proposed minimum program," and described the Umiat No. 24H well as "a good second option."

Umiat No. 24H was not among the well locations Linc previously permitted at the field.

The U.S. Navy discovered and delineated Umiat with 12 wells drilled between 1946 and 1979. Umiat No. 18 was the first well drilled since modern technology and higher prices led explorers to investigate whether the complex Umiat reservoir — which is shallow, low pressure and partially buried in permafrost — could now be developed economically.

Linc had previously said it intended to bring Umiat online by late 2017, but recently told Petroleum News it "plans to aggressively develop this field once commerciality is determined." ●

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OIL PATCH BITS

provide specialized airborne support to further Fairweather's remote sensing and real-time scientific data collection capabilities, and offer greater efficiency to oil and gas exploration and production efforts through the ability to share assets and programming costs between projects.

Tulugaq's operations are bolstered by the purchase of a new Diamond DA42 optionally manned aircraft outfitted with live streaming high-definition video, infrared and ultra-high resolution digital cameras. Future integration will include the addition of multispectral sensors. Tulugaq is one of the few operators of the DA42 in the U.S. and the only operator in Alaska. Originally designed for government work, the DA42 is designed to collect data in harsh weather and no-light conditions. The aircraft's low profile and quiet operation allows Tulugaq to conduct complex missions without disturbing the Arctic's many species of protected wildlife.

Tulugaq flight operations will be performed by an Alaska team with more than 40,000 hours of flight experience in Alaska and more than 2,000 hours of manned and unmanned flight experience worldwide. For more information visit www.fairweather.com.

Trimble receives UAA 2013 Alumni of Distinction Award

Stephen Trimble of URS Corp. was recently honored with the UAA Alumni of Distinction Emerging Leader Award.

UAA describes the nominees as alumni who have made a significant impact on their industry or profession or contributed to the community, and have strived to make a difference in the lives of others.

Trimble has built a career on connecting the dots and bringing people together. He serves as a political appointee on three commissions for the State of Alaska: the Alaska Arctic Policy Commission, Alaska Minerals Commission and the Alaska Emerging Energy Technology Fund Advisory Committee. He also serves as a trustee for the Nature Conservancy, as chair of the UAA Geological Sciences Advisory Board, co-chair of the UAA College of Arts & Sciences Advisory Board and president of the Gold Cord Development Corp. Trimble is also currently involved in the development of the state's first Arctic policy, advising the governor and the Legislature on ways to mitigate constraints on the development of minerals in the state, advising the state in funding emerging energy technology projects, ensuring the natural wealth and vast landscapes of Alaska remain healthy for future generations and advising the university on strategic matters in the college and department of which he is an alum.

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

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AHTNA LICENSE

license, a total of 14 exploration wells have been drilled in the basin, starting in 1953. One well, the Moose Creek Unit No. 1, drilled in 1963 near the future site of the Rutter and Wilbanks well, encountered gas and water at a depth of 5,430 feet, but production testing was not conducted. And, like the Rutter and Wilbanks well, this well encountered subsurface overpressure at a depth of 6,075 feet.

The Salmonberry Lake Unit No. 1 well drilled in 1963 to the north of the new exploration license area encountered multiple zones with high contents of organic carbon and with associated methane gas at depths ranging from 2,600 feet to 3,900 feet.

The Ahtna Inc. No 1 well drilled in 1979 near the village of Gulkana, to the northeast of the exploration license area, encountered a trace of gas in one subsurface zone.

Earlier license

The Rutter and Wilbanks Glennallen well was an offshoot of an exploration program initiated in 2000 when Anschutz Exploration Corp. obtained a state exploration license in the Copper River basin. That license included the area of the new Ahtna license but covered a much larger acreage of state land. In addition to the territory included within the state exploration license, Anschutz's area of exploration interest included some Ahtna land.

Forest Oil became a 50-50 partner with Anschutz in the Copper Valley exploration venture; Rutter and Wilbanks, together with its partner Delphi, also bought into the project. Some 2-D seismic was shot within the exploration area.

In 2005, with the exploration license due to expire, Forest Oil and Anschutz successfully converted a part of the license area relatively close to Glennallen to state leases. And, at about the same time, Rutter and Wilbanks started its ill-fated drilling project on Ahtna land.

Pacific Energy subsequently bought out all of Forest Oil's Alaska properties, including the Copper River basin leases. However, Pacific Energy later became bankrupt. The Division of Oil and Gas has told Petroleum News that the leases subsequently terminated because of the non-payment of lease rents. ●

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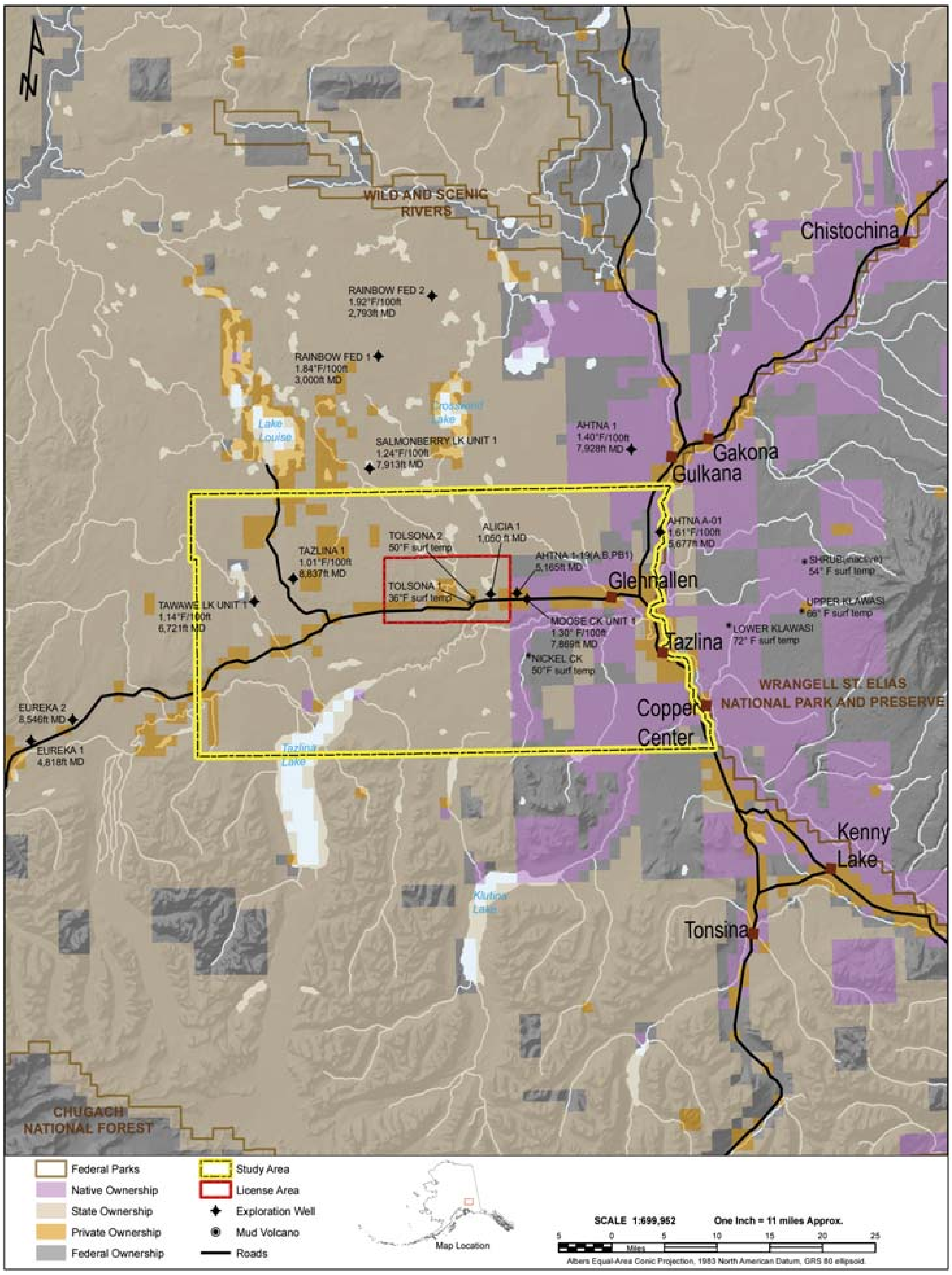
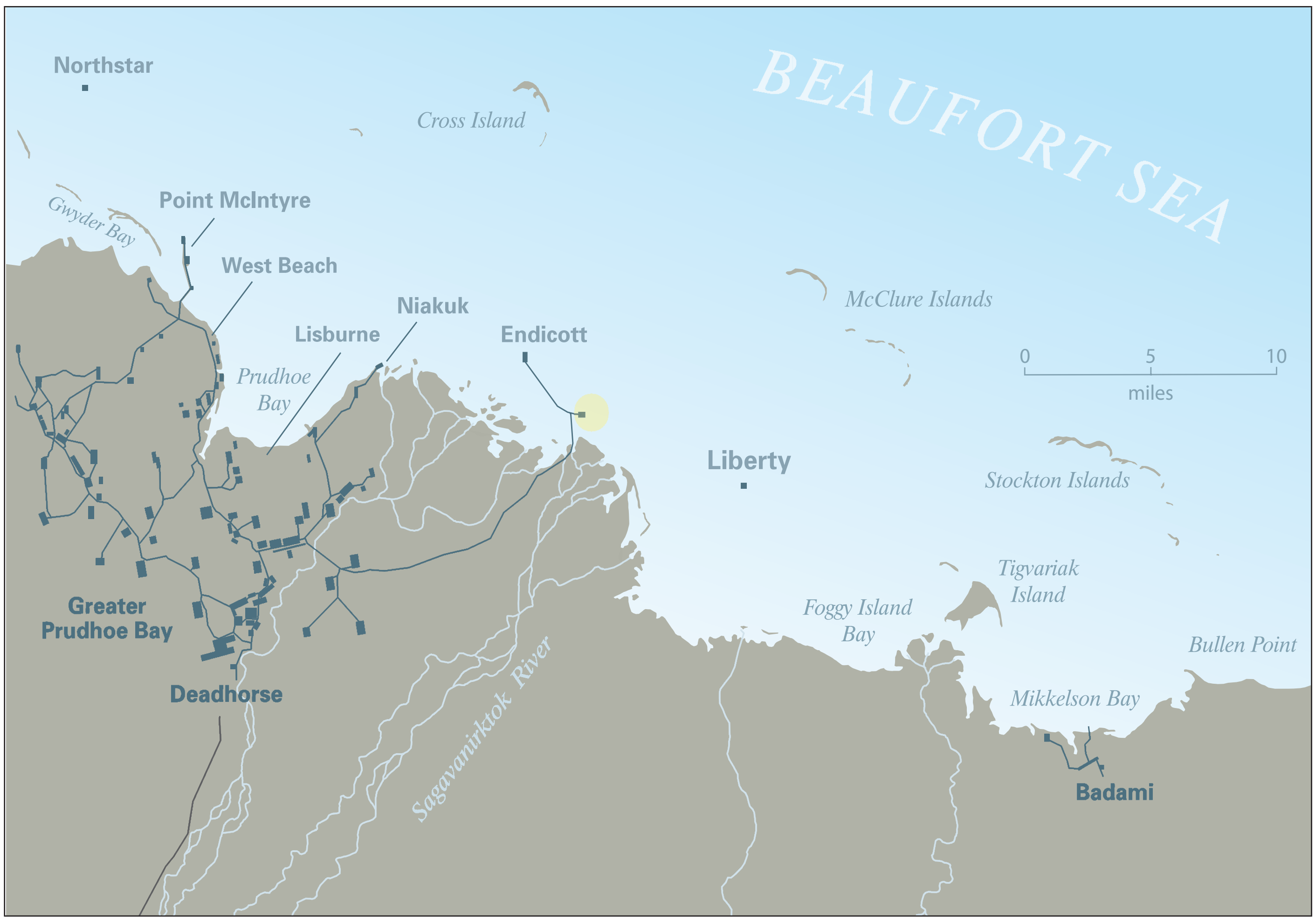


Ahtna's Tolsona exploration license encompasses state land just west of where Rutter and Wilbanks drilled its Ahtna 19-1 gas exploration well between 2005 and 2009.



COURTESY BP

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LIBERTY'S FATE

to doubt the accuracy of the statement on the BOEM website.

BP has been working with government officials on how to proceed with Liberty, located on federal leases in shallow water, about 20 feet deep, in the Beaufort Sea about six miles offshore and 15 miles east of Prudhoe Bay.

In December 2012, the BOEM's sister agency, the Bureau of Safety and Environmental Enforcement, granted BP a two-year "suspension of production" for Liberty unit leases OCS Y-1585 and Y-1650.

The agency gave the company until Dec. 31, 2014, to submit a new development and production plan for the unit, and cited the end of 2020 as the goal for first oil.

Back to initial idea

BP originally had hoped to put Liberty into production in 2011.

Those plans, however, crumbled amid technical problems with the custom rig Parker Drilling Co. built for the project, as well as federal regulatory complications apparently stemming from the Deepwater Horizon disaster in the Gulf of Mexico in April 2010.

Today, the gigantic rig remains idle on a pad at BP's Endicott field. The pad was where BP had planned to drill what it said would be the longest extended-reach holes ever attempted to tap the offshore Liberty reservoir.

BP had said drilling these superwells from land was the best approach.

But now, the company has returned to its initial idea of constructing a gravel island at Liberty with production facilities and a buried subsea pipeline to carry oil to shore.

That's what BP did for its Northstar field, which sits in federal and state waters northwest of Prudhoe Bay.

150 million barrels

BP drilled and tested Liberty No. 1, the discovery well, in early 1997.

The company's most recent publicly stated resource estimate for the Liberty field is "approximately 150 million barrels of recoverable, high-quality light oil."

Proceeding with an artificial production island offers some difficult challenges. Questions will be raised about the potential impact to bowhead whales, which Native hunters pursue for food. Also, a unique kelp bed known as the Boulder Patch is in the vicinity of Liberty.

The fate of the Liberty drilling rig remains undecided, Patience said.

In its June 2012 announcement, BP said it decided against extended-reach drilling after doing "a detailed 18-month review of the rig systems, an analysis of the project's risk and economics, and an assessment of the evolving regulatory framework."

The rig needed substantial modifications to its mud, hydraulics, pipe handling, heating and other systems, BP said.

Retrofitting the rig is now seen as too costly, Patience said.

In a Nov. 20, 2012, letter to the BSEE, the company said recovery from the Liberty leases could be as much as 15 percent higher using "development concepts" other than ultra extended-reach drilling.

That letter said BP already had spent in excess of $1 billion toward development of the Liberty unit. ●

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