Celebrating 20 years: 1996-2016

Petroleum news

page 3 Q&A: Micciche has more questions than answers; needs details soon

Vol. 21, No. 37 • www.PetroleumNews.com | A weekly oil & gas newspaper based in Anchorage, Alaska | Week of September 11, 2016 • $2.50

This week's Mining News

NORTH OF 60 MINING news

page 11 ICMM urges nations to enshrine World Heritages sites with laws

www.MiningNewsNorth.com | The weekly mining newspaper for Alaska and Canada's North | Week of September 11, 2016

NORTHERN NEIGHBORS

Compiled by Shane Lasley

ABEN RESOURCES LTD.

Aben begins recon exploration of Golden Triangle's Forrest Kerr

Aben Resources Ltd. Sept. 7 reported the start of exploration at its 23,000-hectare (53,830 acres) Forrest Kerr property located in British Columbia's Golden Triangle. The 2016 fieldwork is intended to provide reconnaissance-scale geological exploration across the project, which spans roughly 40 kilometers (25 miles). The newly-constructed access road to Galore Creek, a large copper-gold project being advanced by Novagold Resources and Teck Resources, cuts through the north end of the property. This area will be a particular focus of Aben's reconnaissance program. The objective of the current program is to provide confirmation of existing high-grade mineral occurrences, soil and geophysical anomalies, geological and structural relationships. In addition, prospecting and geological mapping will be completed to further identify and confirm target areas for follow-up drilling campaigns. Permitting for future drilling is currently underway.

Silver Range to sell namesake

Silver Range Resources Ltd. Sept. 1 reported the signing of an optional sale agreement with an un-named private British Columbia company, related to the Silver Range zinc-silver-lead project in Yukon Territory. Under the terms of a letter of intent, the purchaser may acquire full ownership of the Silver Range project by making a series of timed share issuances to Silver Range as specific milestone events are achieved before the end of 2020. Silver Range will retain smelter return royalty interests of 2 percent on all future precious metals production and 1 percent on all future non-precious metals production from the Silver Range project. In March, Silver Range elected to change its business model from the advanced exploration of zinc-silver-lead prospects in Yukon to a project generator with a focus on high-grade gold targets in Nunavut, the Northwest Territories and Nevada. Over the past four months, Silver Range has assembled a portfolio of about 16 gold projects and has started to market these properties to interested third parties. The proposed sale of the Silver Range project is consistent with the change of business model.

see NORTHERN NEIGHBORS page 12

NOVAGOLD RESOURCES INC.

With 34 million ounces of gold in reserves, the Donlin Gold project is a prime example of yet-to-developed world-class deposits in Alaska. Donlin Gold LLC – equally owned by subsidiaries of Novagold Resources Inc. and Barrick Gold Corp. – initiated permitting for Donlin Gold in 2012, a process that is expected to be completed late in 2017.

PUBLIC POLICY

Floating Alaska's boat

Mining executive stresses importance of attracting capital during rising tide

By SHANE LASLEY

Mining News

After a particularly long and painful bear market for the mining sector, the more than 25 percent surge in gold prices since the beginning of the year is lifting the share price of mining and mineral exploration companies in Alaska.

"It has been five very long years and hopefully this a start to what is going to be a good run," Greg Beischer, president and CEO of Millrock Resources Inc., told an audience at a recent Alaska Miners Association meeting in Anchorage.

While gold prices topping US$1,350 per ounce is obviously good for miners and explorers of the precious metal, the rise has loosened venture capital for companies across the sector.

GREG BEISCHER

"The tide is rising, and it is floating all boats," Beischer added.

The message left many people in the room wondering if Alaska's ship, which is anchored by sub-US$50-per-barrel oil prices, could also catch this rising tide.

"The geology of Alaska is compelling," the Millrock CEO answered. "Geologists want to come here – they know there are more Pebble deposits, they know there are more Donlin Creek deposits – but the perception is that it is a really tough place to permit a mine."

While Beischer does not personally believe that it is tough to permit a mine in Alaska, the perception persists. And, when mining and mineral exploration companies must make a decision where they can get the best return on their investment, the line between perception and reality blurs.

Mixed view

The Fraser Institute Survey of Mining Companies, which asks the world's mining executives to rank the world's mining jurisdictions on a wide range of issues, is one of the best measures of Alaska's allure to the global mining community.

Reflecting Beischer's message, mining executives participating in the survey feel that Alaska is one of the best places to find world-class mining deposits but are not quite as enthused about the prospects of permitting a mine after such a discovery is made.

When it comes to pure mineral potential, mining executives have ranked Alaska among the top five jurisdictions on the planet for seven years running, including a second place showing among 109 jurisdictions considered in the most recent survey.

While the survey is subjective, this consistent strong endorsement by the global mining community speaks volumes about the mineral potential of The Last Frontier.

However, the same mining executives that collectively consider Alaska the second-richest mineral jurisdiction ranked the state 59th, right below Zimbabwe, when it comes to uncertainty concerning environmental regulations.

The U.S. Environmental Protection Agency's attempt to utilize its presumed authority under the federal Clean Water Act to proactively veto or place restrictions on permits needed to develop the world-class Pebble copper-gold-molybdenum project has become a classic example of this mixed view.

"The Pebble deposit is one of the largest porphyry copper deposits in the world and has good grade," observed a geologist responding to the Fraser survey. "The EPA has declared a pre-emptive veto for permit applications that have not yet been submitted."

"The EPA's effort to circumvent the law and stop Pebble at all costs has had significant negative ramifications on mining development in Alaska," a manager of a large producing company added.

Despite complaints about federal agencies,

see RISING TIDE page 11

Mining executive stresses importance of attracting capital during a rising tide of metals prices. Read more in Mining News, page 9.

State extends Placer unit term

The state is extending the term of the Placer unit by two years.

In a Sept. 7 ruling, Department of Natural Resources Commission Andrew T. Mack gave operator ASRC Exploration LLC until Sept. 7, 2018, to continue work at the unit.

Without an extension, the North Slope unit would have expired in September 2016.

see **PLACER UNIT** *page 18*

Furie about to start KLU A-2 well

During the week of Sept. 11 Furie Operating Alaska expects to start the drilling of the KLU A-1 development well in its Kitchen Lights gas field, Bruce Webb, Furie senior vice president, told Petroleum News in a Sept. 6 email. Currently the company is hooking up the wellhead of the KLU A-2 well that it drilled and completed this summer. The company must complete flow testing of the A-2 well before starting the drilling of the A-1 well, Webb explained. Furie is using the

see **FURIE WELL** *page 14*

DOE reviews future SPR options

The U.S. Department of Energy has released a new review of the U.S. Strategic Petroleum Reserve. The strategic review, mandated by Congress, examines the operation of the SPR, current operational issues and potential routes for addressing those issues. The reserve, by storing large volumes of crude oil, provides the United States with an oil supply buffer capable of mitigating oil supply disruptions. The reserve also enables the country to meet its commitment to maintain emergency oil reserves

see **SPR OPTIONS** *page 15*

EXPLORATION & PRODUCTION

Thomson future?

Deadlines are already passing for 2012 settlement agreement with state

By ALAN BAILEY

Petroleum News

As debate continues over Gov. Bill Walker's plan to continue to move towards the construction of a major gas line from the North Slope for the export of liquefied natural gas, with the AKLNG project involving both the state and the North Slope oil producers coming to an end, interesting questions arise over the future of the Point Thomson gas condensate field on the Beaufort Sea coast, to the east of Prudhoe Bay.

Field development

As currently configured, the Point Thomson field is in a development stage referred to as the initial production system, or IPS, in which natural gas is being continuously cycled through the field reservoir to enable the extraction of up to 10,000 barrels per day of condensate for export along with

But if major gas sales have not been sanctioned by June 2016, engineering for expansion of condensate production must begin, with the possibility of exporting gas from Point Thomson for enhanced oil recovery at Prudhoe Bay being an alternative option, the settlement agreement says.

see **THOMSON FUTURE** *page 20*

EXPLORATION & PRODUCTION

No marketing info

BP won't comply with governor's request for Prudhoe unit gas sales information

By TIM BRADNER

For Petroleum News

BP is giving short shrift to Gov. Bill Walker's demand for confidential information about marketing of natural gas from the Prudhoe Bay field, where BP is operator.

In a refiling of the Plan of Development for Prudhoe's Initial Producing Area filed Sept. 1 with the state Division of Oil and Gas, BP said confidentiality agreements it has signed with the state and other companies for the Alaska LNG Project, as well as the Prudhoe Bay Unit Agreement, prohibit the company from sharing marketing information with other parties, including state officials who have not signed confidentiality agreements.

Having a "duty to produce and market" legal action on the table, and arguing that third party buyers are making reasonable purchase offers, would give Walker leverage in case commercial terms cannot be agreed.

Anti-trust laws also prohibit BP from discussing marketing activities with other Prudhoe Bay owners, BP said in its Sept. 1 letter.

Although the document was filed Sept. 1 the letters were not made available to the public until Sept. 6.

see **MARKETING INFO** *page 18*

PIPELINES & DOWNSTREAM

BC tanker ban looms

Canada gives no indication whether Lower-48 bound Alaska vessels will be affected

By GARY PARK

For Petroleum News

The Canadian government is putting the final touches on its promise to remove crude oil tankers from the northern British Columbia coast.

MARC GARNEAU

JUSTIN TRUDEAU

It is expected to release the details within three months of a strategy Prime Minister Justin Trudeau will hold up as proof that Canada is a serious player in tackling climate change.

Transport Minister Marc Garneau said Canada "wants the world to see we are putting together an approach" to protect ecosystems by protecting the environment and improving marine safety.

But there has been no indication whether the moratorium will affect the movement of about 300 tankers a year from Alaska to Puget Sound and California, which currently operate under a voluntary exclusion zone that requires loaded oil vessels to sail more than 50 nautical miles beyond the British Columbia coast.

Tankers from Alaska are rated as too dangerous to travel through Dixon Entrance, Hecate Strait and Queen Charlotte Sound, the areas that will be embraced by the ban.

Since the Trudeau government was elected 10

see **TANKER BAN** *page 20*

contents

Petroleum News *North America's source for oil and gas news*

● GOVERNMENT

Micciche: More questions than answers

Soldotna Republican says he's willing to listen and keep an open mind about Walker's AKLNG plan, but needs details — and soon

By STEVE QUINN
For Petroleum News

Sen. Peter Micciche says he's tired of rhetoric carrying the day and would like to see resource development decisions "made with a calculator and sound policy." The Soldotna Republican, a member of the Senate Resources and Finance committees, recently listened to the joint Resources committee hearings discussing the prospects of an AKLNG project. He shared his thoughts with Petroleum news via email and several phone conversations.

Petroleum News: After back-to-back hearings with the two Resources committees, what questions do you still have about how the project advances?

Micciche: Respectfully speaking, at this time I have more questions for the administration and AGDC than I have answers. Now that the administration has clearly stated that their desire is to move toward a state-controlled project, I want to know their vision for where their parameters and boundaries of operation, ownership and control structure are drawn.

Since 2014, my impression of the changes to the AGDC board and staff have been that we have evolved from a measured and legislatively supported structure under SB 138 to a "learn as you go" team that has been less organized and far less responsive to the Legislature's questions and concerns. The path has taken us off of the interstate so to speak and onto what seems to be a less-travelled route that is strewn with unconventional and significantly less-proven "back roads" that this pipeline/liquefaction project could take.

I have a responsibility to my district and the people of Alaska that we do not put the state on the hook for a disproportionate level of financial risk. Some seem to have the "build it at all costs" philosophy … one I do not share. Although, this project is extremely important to my district (the terminus of the pipeline and the liquefaction facility) for obvious reasons associated with energy, jobs and investment, as well as to the people of Alaska due to revenue to the GF and wide-spread natural gas distribution for in-state use, incentive for exploration and stable North Slope oil production volumes, etc. one must constantly weigh the benefits against the risk and exposure.

Therefore, my most significant question … if I were only permitted one, would be: "At what level of risk under the current price environment, future dismal projected market conditions and the looming challenge for this project to remain globally competitive would the administration and AGDC believe that the risk is too great to proceed at this time"?

I also agree with (the Legislature's consultants) enalytica from their presentation to joint Resources on the mechanical critical questions that must be answered prior to gaining my support for a state-led or owned project: Why state ownership? What's the organizational plan? What's the project structure? What's the plan for securing/confirming tax-exemption? What's the financing plan? Who are the target investors? What's the risk-sharing strategy?

Ultimately, I will remain courteous, listen carefully and fairly evaluate the options and project potential presented by AGDC and the administration. All of us would like to see this project move forward, I believe the execution and governance structure of a deal and the relative speed of the project's FEED progress is what's in question at this time. The devil, in this case, is truly in the $45-60 billion details.

SEN. PETER MICCICHE

Petroleum News: Do you see this as the state taking over an uneconomic project?

Micciche: I've stated in the past that an Alaska gas pipeline and export project has been actively discussed since I had acne and my voice cracked with puberty. I will be 55 this year and we remain without a clear path forward. The difficulty has always been about the challenging economics of an Alaska project. Of course, due to the time/value of money any Alaska gas pipeline project built 25 years ago would likely seem like a brilliant move today.

However, looking at the global market, as well as our Asia-Pacific market-of-interest for LNG where we sit today, I have become uncomfortable in this project's ability to compete at this time. According to the International Gas Union 2016 World Gas LNG Report: "The decline in oil prices and growing weakness in Pacific demand led all global LNG price markers to fall in 2015, from an average $15.60/MMBtu in 2014 to $9.77/MMBtu in 2015. Japanese import prices, which are primarily linked to oil, fell most dramatically, dropping 78% between January and December 2015." The fall has continued and today the Japanese import price hovers near the $6 mark.

Global commodity markets are dynamic and complicated. Many experts, or at least half of them, fear that this low price environment may remain for quite some time; perhaps becoming the new norm.

You have to ask, how could anyone expect us to compete in a $6-7 per million Btu market from what we know about today's AKLNG cost of supply? Issues become more complicated from there on the demand side. As of January of 2016, there is 301.5 metric tons per annum of viable existing liquefaction capacity with another 142 metric tons under construction globally for an eventual total of 434 metric tons liquefaction capacity.

If proposed liquefaction capacity comes to fruition, the eventual total could reach a whopping 890 metric tons (although it is unlikely many to most of the proposed projects will become or remain economic)

Q AND A

As liquefaction capacity has increased dramatically, demand has remained relatively stagnant. Although the highest year ever for LNG trading at 244.8 metric tons occurred in 2015, it will likely take several to many years for a balance to occur in the market. As the IGU Report also states: "New LNG supplies combined with weaker economic growth, increased competition from competing fuels, and drastically lower oil prices will place downward pressure on LNG prices."

Another significant factor that challenges the ability to finance the AKLNG project and one brought about largely by the availability of uncontracted supply, is the evolution of the longevity of long term contracts. Since the days of the late '60s, the market has become organized, sophisticated and has evolved from nearly exclusively long-term LNG contracts that would negotiate generously to purchase nearly all available cargos in the past, to a significantly greater and growing proportion of spot, short-term and medium term contracts.

Now that we've kind of framed some of the challenges, let's get back to your question. Is the state taking over an uneconomic project? The question is difficult to answer directly. I can say flatly, no, I will not support the state taking over an uneconomic project. Yet, there are far more factors to consider and questions that must be answered prior to such a determination. Can Alaska out-perform the cost of supply of our competitors? Do viable funding options and federal tax advantages exist in a structure that will provide Alaska with a solid economic edge in the market place? Will conditions change dramatically in the 20-30 year horizon of the project to help push the risk profile into the acceptable "green light" range? These are the questions I will be asking before I can support a state-lead project.

Today, honestly, our ability to compete in this current and projected LNG trade environment seems unlikely, but a project as important as AKLNG is to the people of this state is worthy of adequate and focused additional due diligence.

Petroleum News: Wood Mackenzie's presentation, though critical of the state's chances, seemed to provide some hope that the state can move forward with a project. What is your takeaway from its

see **MICCICHE Q&A** page 17

● EXPLORATION & PRODUCTION

ANS production up 4.3% from July

Big jump at Alpine following end of scheduled summer maintenance; Lisburne production drops as maintenance begins at that field

By KRISTEN NELSON
Petroleum News

Production from Southcentral's Cook Inlet averaged 15,729 bpd in July, up 5.6 percent from a June average of 14,900.

Alaska North Slope crude oil production averaged 478,842 barrels per day in August, up 4.25 percent from a July average of 459,327 bpd.

The largest month-over-month increase was at the ConocoPhillips Alaska-operated Alpine field. Alpine was down for scheduled maintenance beginning July 22, so there was no production from that field for the last 10 days of July, resulting in average production of just 36,748 bpd. In August Alpine was down for the first four days of the month, and the field's production averaged 56,864 bpd, up 54.7 percent from July. Alpine production includes satellite production from Fiord, Nanuq and Qannik, with the majority of the field's production from the main Alpine field.

The most recent North Slope information — daily volumes and monthly averages consolidated by major production centers — comes from the Alaska Department of Revenue's Tax Division. More 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 BP Exploration (Alaska)-operated Prudhoe Bay field, the Slope's largest, and the ConocoPhillips-operated Kuparuk River field also saw month-over-month production increases.

The BP Exploration (Alaska)-operated Prudhoe Bay field, the Slope's largest, and the ConocoPhillips-operated Kuparuk River field also saw month-over-month production increases.

Prudhoe includes satellite production from Aurora, Borealis, Midnight Sun, Orion, Polaris, Sag River, Schrader Bluff and Ugnu, as well as production from the Hilcorp Alaska-operated Milne Point and Northstar fields.

Total production shown under Prudhoe averaged 264,549 bpd in August, up 1.6 percent, 4,102 bpd, from a July average of 260,447.

AOGCC data for July show an average of 19,413 bpd for Milne Point, up 2.9 percent from a June average of 18,861 bpd. Northstar averaged 4,521 bpd in July, down 12.9 percent from a June average of 5,193 bpd.

Kuparuk averaged 134,904 bpd in August, up 3.2 percent, 4,159 bpd, from a July average of 130,745 bpd.

Kuparuk includes satellite production from Meltwater, Tabasco, Tarn and West Sak, as well as from the Eni-operated Nikaitchuq field and the Caelus Alaska-operated Oooguruk field.

AOGCC data show Nikaitchuq averaged 24,392 bpd in July, down 0.8 percent from a June average of 24,586, while Oooguruk averaged 15,356 bpd in July, down 6.4 percent from a June average of 16,403 bpd.

At the BP-operated Lisburne field, which includes production from Niakuk, Point McIntyre and Raven, production averaged 18,495 bpd in August, down 18.9 percent from a July average of 22,801. The field went offline Aug. 27 as scheduled maintenance began, and was still down Sept. 6.

Production from Hilcorp-operated Endicott averaged 4,030 bpd in August, down 53 percent from a July average of 8,586. Endicott production includes volumes from satellites Eider, Minke and Sag Delta, as well as from the Savant Alaska-operated Badami field and the ExxonMobil Production-operated Point Thomson field on the eastern side of the Slope.

AOGCC data show Badami averaged 980 bpd in July, up 0.4 percent from a June average of 976 bpd, while Point Thomson, where facilities are still being commissioned, averaged 1,061 bpd, up 50 percent from a June average of 709 bpd.

Cook Inlet up 5.6 percent

Production from Southcentral's Cook Inlet averaged 15,729 bpd in July, up 5.6 percent from a June average of 14,900. AOGCC figures show the largest month-over-month percentage increase, 89 percent, at the Cook Inlet Energy-operated Redoubt Shoal field, which averaged 937 bpd in July, up from 496 bpd in June, an increase of 442 bpd.

The largest per-barrel month-over-month increase was at the Hilcorp Alaska-operated McArthur River field, Cook Inlet's largest, which averaged 5,217 bpd in July, up 20 percent, 869 bpd, from a June average of 4,348 bpd.

Other fields with month-over-month increases include Hilcorp's Granite Point, which averaged 2,559 bpd in July, up 3.4 percent, 85 bpd, from a June average of 2,474 bpd, and Hilcorp's Trading Bay field, which averaged 2,328 bpd in July, up 3 percent, 68 bpd, from a June average of 2,260 bpd.

Cook Inlet fields with month-over-month declines in production include Hilcorp's Beaver Creek, which averaged 101 bpd in July, down 15.3 percent from a June average of 120 bpd; BlueCrest's Hansen field, which averaged 143 bpd in July, down 2 percent from a June average of 145 bpd; Hilcorp's Middle Ground Shoal, which averaged 1,735 bpd in July, down 8.8 percent from a June average of 1,902 bpd; Hilcorp's Swanson River, which averaged 1,899 bpd in July, down 6 percent from a June average of 2,021 bpd; and Cook Inlet Energy's West McArthur River field, which averaged 810 bpd in July, down 28.6 percent from a June average of 1,134 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

Petroleum news
www.PetroleumNews.com

Kay Cashman	PUBLISHER & EXECUTIVE EDITOR
Mary Mack	CEO & GENERAL MANAGER
Kristen Nelson	EDITOR-IN-CHIEF
Susan Crane	ADVERTISING DIRECTOR
Heather Yates	BOOKKEEPER
Shane Lasley	NORTH OF 60 MINING PUBLISHER
Marti Reeve	SPECIAL PUBLICATIONS DIRECTOR
Steven Merritt	PRODUCTION DIRECTOR
Alan Bailey	SENIOR STAFF WRITER
Tim Bradner	CONTRIBUTING WRITER
Eric Lidji	CONTRIBUTING WRITER
Wesley Loy	CONTRIBUTING WRITER
Gary Park	CONTRIBUTING WRITER (CANADA)
Steve Quinn	CONTRIBUTING WRITER
Judy Patrick Photography	CONTRACT PHOTOGRAPHER
Mapmakers Alaska	CARTOGRAPHY
Forrest Crane	CONTRACT PHOTOGRAPHER
Tom Kearney	ADVERTISING DESIGN MANAGER
Renee Garbutt	CIRCULATION MANAGER
Ashley Lindly	RESEARCH ASSOCIATE

ADDRESS
P.O. Box 231647
Anchorage, AK 99523-1647

NEWS
907.522.9469
publisher@petroleumnews.com

CIRCULATION
907.522.9469
circulation@petroleumnews.com

ADVERTISING
Susan Crane • 907.770.5592
scrane@petroleumnews.com

Bonnie Yonker • 425.483.9705
byonker@petroleumnews.com

FAX FOR ALL DEPARTMENTS
907.522.9583

Petroleum News and its supplement, Petroleum Directory, are owned by Petroleum Newspapers of Alaska LLC. The newspaper is published weekly. Several of the individuals listed above work for independent companies that contract services to Petroleum Newspapers of Alaska LLC or are freelance writers.

OWNER: Petroleum Newspapers of Alaska LLC (PNA)
Petroleum News (ISSN 1544-3612) • Vol. 21, No. 37 • Week of September 11, 2016
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. — $118.00 1 year, $216.00 2 years
Canada — $206.00 1 year, $375.00 2 years
Overseas (sent air mail) — $240.00 1 year, $436.00 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.

● FINANCE & ECONOMY

Global energy giant surfaces in $28B deal

Enbridge to buy Spectra, create North America-wide diversified infrastructure company, reduce high-carbon dependence

By GARY PARK
For Petroleum News

Calgary-based Enbridge has struck a friendly deal to acquire Houston-based Spectra Energy to create North America's largest energy infrastructure company, quickly relegating what would otherwise have been a setback for the Canadian firm.

The US$28 billion all-stock transaction, expected to close in the first quarter of 2017, will immediately bring under the same umbrella secured projects valued at $20 billion and another $37 billion of projects under development.

Based on the 12 months ended June 30, the new entity would have generated combined revenues in excess of $31 billion and combined earnings of $4.4 billion.

Enbridge President and Chief Executive Officer Al Monaco, designated to retain those roles, said that combining Enbridge's position as North America's largest carrier of crude oil with the continent's "premier natural gas infrastructure company" will create a "true North American and global" energy leader.

Greg Ebel, Spectra's president and CEO who will become chairman of Enbridge, said the merged company could be the most diversified energy infrastructure company in the world by establishing the "finest platform for serving customers in every region of North America."

Sandpiper shelved

The deal came only four days after Enbridge shelved what was seen as a key link in its grand plan to increase shipments out of North Dakota's Bakken to PADD II, Eastern Canada and the Gulf Coast which had already been postponed from a 2017 startup date to 2019.

The $2.6 billion Sandpiper line covering about 600 miles to Superior, Wisconsin, was designed to carry 225,000-325,000 barrels per day.

In early August, the project had already been thrown into doubt when Enbridge Energy Partners — the partnership that operates the U.S. portion of Enbridge's oil pipeline network — and Marathon Petroleum said they planned to terminate their transportation and joint-venture agreements for Sandpiper.

Enbridge said an EEP review had concluded that Sandpiper should be shelved "until such time as crude oil production in North Dakota recovers sufficiently to support the development of new pipeline capacity."

Based on those projections, Enbridge said Sandpiper no longer fits into its "five-year planning horizon."

Enbridge and Marathon have invested $800 million in the project, including money for pipeline and regulatory efforts and were facing intensified opposition from American Indian tribes and environmental groups.

The Enbridge-Spectra entity would currently have an enterprise value of $127

see **SPECTRA DEAL** page 6

LAND & LEASING

BOEM closes sale comment period

The Bureau of Ocean Energy Management has closed the public comment period for a draft environmental impact statement for a Cook Inlet oil and gas lease sale, proposed to be held in June 2017 as part of the federal government's current five-year outer continental shelf lease sale program. The lease sale applies to federal waters of the lower Cook Inlet, rather than state waters of the upper Cook Inlet where operating oil and gas fields are located.

The Cook Inlet Regional Citizens Advisory Council has expressed its disappointment that BOEM has turned down a request to extend the comment period beyond 45 days.

The Cook Inlet Regional Citizens Advisory Council has expressed its disappointment that BOEM has turned down a request to extend the comment period beyond 45 days. In a Sept. 6 release CIRCAC said that there had been multiple requests for a comment period extension, especially given the fact that the comment period encompassed a time of year during which fishermen with concerns about the proposed sale are busy fishing.

"We are disappointed that BOEM is not ensuring that they hear from those Alaskans with the most knowledge of Cook Inlet resources and who have the most at stake," said CIRCAC Executive Director Michael Munger. "By turning down rational requests for a reasonable extension, BOEM either does not care to receive that input or is under pressure to rush this forward on their timeline; neither of which is acceptable."

Previous federal Cook Inlet lease sales in 1982 and 2004 drew no bidders, while two proposed sales were cancelled in 2009 and 2011 due to lack of industry interest. The lower Cook Inlet region has promising petroleum geology, including known oil source rocks. But the region has seen little exploratory drilling, probably because of high drilling costs and uncertainties over the quality of potential oil and gas reservoir rock units.

—ALAN BAILEY

UTILITIES

RCA sets HEA deregulation election rules

The Regulatory Commission of Alaska has issued an order acknowledging a plan by Homer Electric Association to ballot its members on whether to become exempt from regulation by the commission. The Sept. 1 order sets the rules under which the ballot must be conducted.

Although as a public utility HEA requires a certificate of public necessity and convenience from the commission, under state statutes the utility can opt out of commission regulation provided that a majority of the utility's members vote for deregulation. The idea is that regulation of the utility's operations passes from the commission to the utility's board, which is in turn elected by the utility's membership.

In compliance with state law, HEA plans to mail ballots to its members along with electricity bills sent out during October.

In compliance with state law, HEA plans to mail ballots to its members along with electricity bills sent out during October. Utility members will have to return the ballots within 30 days of receipt. Approval of the deregulation move requires a simple majority but at least 15 percent of the membership must vote.

The commission requires samples of the ballot mailing prior to the election, and, to ensure that all returned ballots meet the timing deadlines, requires the use of distinctive envelopes for different groups of members who will receive ballots at different times. The commission says that it will hire an accounting firm to process and count the ballots and will certify the election within 60 days after all of the ballots have been received, or by Dec. 27. HEA hopes that deregulation, if approved by its membership, will go into effect on Jan. 1.

In its order the commission has also agreed to maintain the confidentiality of information obtained during the election process about HEA's members.

HEA sees deregulation as a move to local control, eliminating the cost and time involved in going through commission rate cases, thus enabling the utility's board to make immediate decisions over issues such as implementing new electricity sources and making changes to electricity rates. Having already notified its members about the election, the utility is holding public meetings about the deregulation initiative in Homer on Sept. 28 and in Kenai on Sept. 29.

During a commission public meeting on Aug. 24 some commissioners asked Homer Electric to make sure that it presents complete and accurate information to its members about the background to the deregulation proposal.

—ALAN BAILEY

● GOVERNMENT

BOEM spells out its Arctic mission

Sees itself as a valued partner in managing federal offshore resources, and in scientific expertise and sustainable development

By ALAN BAILEY
Petroleum News

The Bureau of Ocean Energy Management has published a document summarizing what the agency sees as its mission in the Arctic. The agency is responsible for managing offshore energy and mineral resources in federal lands of the outer continental shelf. In Arctic Alaska those lands primarily consist of the outer continental shelf of the Beaufort and Chukchi seas. The agency says that it has a vision of being a valued partner in domestic and international Arctic matters relating to Arctic marine resource stewardship, scientific expertise and sustainable development.

The outer continental shelf of Alaska potentially holds more than 23 billion barrels of undiscovered oil and more that 108 trillion cubic feet of undiscovered natural gas, BOEM says. But the region also holds offshore renewable resources such as wind, wave and tidal energy, as well as significant resources in terms of gold; rare earth minerals; and sand and gravel. The agency says that since 1973 it has invested about $450 million in environmental and socioeconomic research in Alaska, and has completed more than 500 scientific reports. With traditional knowledge as part of the agency's social science portfolio, BOEM actively consults with local and tribal governments, the agency says.

Agency goals

BOEM has set itself several goals in support of its Arctic vision. It says that it promotes energy independence, environmental protection and economic development through responsible, science-based management of Arctic energy and mineral resources. It engages with the state of Alaska and interagency partners on Arctic domestic affairs and in support of the U.S. National Strategy for the Arctic Region. It also engages with indigenous peoples and organizations for the use of traditional knowledge in the stewardship of natural resources. The agency says that it establishes its Arctic expertise and experience for the furtherance of national and international Arctic science, policies and stewardship. And the agency supports the Department of State and other agencies in engaging in international work in the Arctic, including activities carried out in conjunction with the Arctic Council, BOEM says.

Other BOEM interactions in carrying out the agency's mission include those with industry, academia, non-governmental organizations, local governments and international Arctic endeavors.

And as examples of BOEM-led projects, the agency cites the development in 2014 of guidelines for oil and gas safety systems management and safety management; the completion in 2013 of an Arctic marine shipping assessment; the completion in 2010 of an assessment of the effects and potential effects of oil and gas activities in the Arctic; and the preparation in 2009 of Arctic offshore oil and gas guidelines. ●

Contact Alan Bailey at abailey@petroleumnews.com

continued from page 5

SPECTRA DEAL

billion and is strongly positioned to participate in the movement of natural gas to support LNG export ventures.

Monaco said Enbridge has been exploring opportunities over the past two years to invest in natural gas and renewable energy projects to rebalance its earnings away from oil over the long-term and join the global shift to a lower-carbon economy.

The deal is valued at $40.33 per Spectra share, an 11.5 percent premium over the company's closing price on Sept. 2. Enbridge shareholders will own 57 percent of the new company. ●

Contact Gary Park through publisher@petroleumnews.com

● NATURAL GAS

Partners: Work needed before FEED decision

Producers said in February AKLNG could stay in pre-FEED pending better economics, or state could take over, push on to FEED decision

By KRISTEN NELSON

Petroleum News

How we got to a state-led Alaska liquefied natural gas project and whether the North Slope producers support that plan were topics of interest to the joint House and Senate Resources committees Aug. 25, the second day of a two-day AKLNG hearing (see earlier stories on the hearings in the Aug. 28 and Sept. 4 issues of Petroleum News).

The state's producer partners in AKLNG — BP, ConocoPhillips, ExxonMobil — discussed work needed to progress the project, but said they did not oppose the state taking over work on the project.

Bill McMahon, senior commercial advisor with ExxonMobil, led off the company presentations, reminding legislators that the misalignment between the state and AGDC and BP, ConocoPhillips and ExxonMobil had been discussed at a June 29 AKLNG update.

He noted that the administration had been pressing to have certain agreements in place by the end of the 2016 legislative session. But the agreements the administration wanted, McMahon said, did not include a fiscal agreement, which, he said, is necessary for the project to move from pre-FEED, preliminary-front end engineering and design, into the FEED stage.

> *"At no time has ExxonMobil said that the Alaska LNG project should stop or that it should be put on the shelf."*
> **—Bill McMahon, ExxonMobil**

FEED will be a vastly more expensive step in the stage-gated project process.

The state and its North Slope producer parties have been working toward a project to take North Slope natural gas to market as LNG, based on ownership of the resource, with the state planning to take its production tax as gas, as well as royalties, bringing its equity share in the project to 25 percent.

The pre-FEED stage is scheduled to be complete this year and the goal was to go to a FEED decision in 2017.

The choices

McMahon said that when it became clear that the agreements the governor wanted would not be in place by the end of the 2016 regular legislative session, two concepts were presented for advancing the project.

The project could transition to a state-led project so that the Alaska Gasline Development Corp., the state's gas project company, could continue with the goal of entering FEED in 2017.

The alternative, McMahon said, was to change the pace of the project to match current market conditions, continue to advance regulatory approvals, reduce project costs and work on fiscal and commercial agreements — all of which would provide the information necessary for a FEED decision.

"Now at this point I want to set the record straight on some things that have been said," McMahon told legislators. "At no time has ExxonMobil said that the Alaska LNG project should stop or that it should be put on the shelf."

He said that "despite these repeated mischaracterizations, and now that the Walker administration has decided to pursue a state LNG project," ExxonMobil is actively engaged in developing a plan to bridge from the four-party pre-FEED joint venture agreement to a state-led LNG project.

McMahon said key components of a bridging plan include completion of pre-FEED deliverables and filing remaining draft resource reports with the Federal Energy Regulatory Commission; selecting a target date to turn

see **AKLNG HEARING** *page 14*

● PIPELINES & DOWNSTREAM

Petro Star royalty oil contracts approved

DNR approval only needed for 1-year contract starting Jan. 1; legislative approval required for 4-year contract starting in 2018

By TIM BRADNER

For Petroleum News

The state has approved a sale of state royalty oil to in-state refiner Petro Star Inc. that will supply up to 23,500 barrels per day beginning Jan. 1 for the company's two Alaska refineries.

Over five years the royalty oil sales to Petro Star will decline to an estimated 10,500 bpd, however, because they are linked to a percentage of declining Slope production.

The state gives priority to in-state refiners for royalty oil to help ensure capacity is available to meet regional needs. As North Slope production declines independent refiners like Petro Star face difficulties in purchasing crude because major Slope producers prefer to supply crude to their own downstream refineries. State royalty oil can provides an additional supply of crude oil.

Diane Hunt, spokeswoman for the state Department of Natural Resources' Division of Oil and Gas, said the state will net additional revenues of between $29 million to $37 million under the Petro Star royalty sales compared with what it would have been received had the royalties been paid under "royalty in-value" paid by North Slope producers.

In kind or in value

Under its oil and gas leases Alaska has the option to take its royalty in kind, in the form of crude oil, or "in value," with the royalty paid by producers based on the value of crude oil at the field.

Alaska's royalty varies between 12.5 percent and 16.75 percent on its oil and gas leases but the state does not sell more than 95 percent of its royalty barrels in kind.

Alex Nouvakhov, chief commercial officer in the DNR, said Petro Star will pay the state a price based on the sales price of Alaska North Slope crude on the U.S. West Coast minus a negotiated $1.95 "differential" which accounts for the oil being delivered within Alaska rather than on the West Coast.

The differential is the same that is paid under another state royalty oil contract agreed to last year with Tesoro Corp. for that company's refinery at Nikiski, near Kenai, he said.

"The net benefit to the state is the difference between the proceeds that would have been obtained if the volume had been taken in-kind," Nouvakhov said.

Two contracts

The sale to Petro Star is in the form of two contracts, one for one year that is to begin Jan. 1, 2017, and a second contract for four years beginning Jan. 1, 2018.

The one-year royalty oil contract can be done without legislative approval but the longer four-year contract will require an okay by lawmakers in the Legislature's 2017 regular session, DNR said in its statement. Legislative approval for royalty contracts made to in-state refiners is typically routine.

The contracts will supply two Petro Star refineries, one with a processing capacity of 22,500 bpd at North Pole, near Fairbanks in Interior Alaska, and a second at Valdez, in south Alaska at the southern terminus of the trans-Alaska oil pipeline, with a processing capacity of 60,000 bpd.

In a typical year Petro Star produces 56 percent of its products in the form of jet fuel, 33 percent in the form of ultra low-sulfur diesel and 11 percent as home heating oil. The company supplies 50 percent to 60 percent of the home heating oil sold in Interior Alaska as well as naphtha sold to Golden Valley Electric Association of

see **ROYALTY OIL** *page 15*

● FINANCE & ECONOMY

US crude production for ’17 up 200,000 bpd

North Sea Brent averaged $46 per barrel in August, up $1 from July; 4th consecutive month with average price between $44 and $49

By KRISTEN NELSON

Petroleum News

The U.S. Energy Information Administration is projecting U.S. crude oil production in 2017 to average 8.5 million barrels per day, up 200,000 bpd from the agency’s estimate in its August Short-Term Energy Outlook.

EIA Administrator Adam Sieminski said the decline was “not expected to be as steep as in previous forecasts, because of improved drilling rig efficiencies and more rigs drilling.”

ADAM SIEMINSKI

The new outlook, released Sept. 7, says U.S. crude averaged 9.4 million bpd last year and is forecast to average 8.8 million bpd this year.

EIA said it estimates that U.S. crude production has fallen by 1.2 million bpd since April 2015, with almost all the decline in the Lower 48 onshore, a decline partly offset by growing production in the federal Gulf of Mexico.

The agency expects production to decline in most Lower 48 onshore areas through 2017, but expects the rate of decline to slow from 100,000 bpd in the second and third quarters of 2016 to only some 20,000 bpd in 2017.

EIA said the current price outlook is expected to limit onshore drilling and completions, but “that is expected to be partially offset by continued increases in rig and well productivity and falling drilling and completion costs.”

Lower 48 production is projected to average 6.2 million bpd in 2017, down from 6.5 million in the third quarter of 2016 and from an annual 6.7 million bpd average for all of 2016.

Production from the Gulf of Mexico is projected to average 1.9 million bpd by the fourth quarter of 2017, up from a 2015 average of 1.5 million bpd.

Overall, U.S. crude oil production is projected to be relatively stable between 8.5 million and 8.6 million bpd for most of 2017 except during the third quarter when EIA expects some production declines due to hurricane-related outages. U.S. production is expected to stabilize in 2017 because of productivity improvements, lower breakeven costs and forecast oil price increases, the agency said.

Crude prices

EIA said the increase in the average spot price for North Sea Brent crude by $1 to $46 per barrel in August came in spite of global increases in oil inventories and the increase in U.S. oil rig counts, and said market reaction to a potential Organization of the Petroleum Exporting Countries deal to freeze production at current levels put upward pressure on August prices.

The agency said it expects global oil inventory builds to continue in the near future, averaging 600,000 bpd in the second half of this year, but remaining below levels seen last year and early this year. But even with the slowing pace of inventory builds, inventories are continuing to grow and high levels are expected to contribute to Brent prices staying in the $40 to $50 per barrel trading range for the next two quarters.

EIA said it forecasts Brent to average $45 per barrel in the fourth quarter of this year and the first quarter of 2017, but said global economic developments and geopolitical events could push prices near the top or bottom of the $40 to $50 per barrel range.

Global inventory draws are expected to begin in mid-2017, the agency said, and that expectation would contribute to rising prices in the second quarter of 2017, with Brent forecast to average $52 per barrel in 2017, and $58 per barrel in the fourth quarter of 2017, reflecting the potential for more significant inventory draws.

Average West Texas Intermediate is projected to be $1 per barrel lower than Brent this year and next, “based on the assumption of competition between the two crudes in the U.S. Gulf Coast refinery market,” EIA said.

Natural gas

U.S. natural gas consumption is forecast to average 76.4 billion cubic feet per day this year and 77.1 bcf per day in 2017, compared to 75.2 bcf per day in 2015, EIA said.

2016 increases are primarily due to use of natural gas in the electric power sector, which is expected to increase 5.4 percent, before declining 2.3 percent in 2017, as rising natural gas prices contribute to increased use of coal.

Marketed natural gas production in June averaged 77.5 bcf per day, down 2.7 bcf from a record high daily average in February, the agency said.

EIA said it is forecasting production increases in the second half of 2016 through 2017 in response to forecast increases in price and in liquefied natural gas exports.

Natural gas pipeline exports to Mexico have risen this year, the agency said, with gross pipeline exports projected to increase in 2016 to an average of 5.6 bcf per day before declining slightly in 2017.

LNG gross exports are projected to rise this year to an average of 0.5 bcf per day and to 1.5 bcf per day in 2017.

Net imports of natural gas averaged 2.6 bcf per day in 2015 and are expected to decline to 0.2 bcf per day in 2017, with the U.S. becoming a net exporter of natural gas beginning in the second quarter of 2017.

The Henry Hub natural gas spot price averaged $2.82 per million British thermal units in August, unchanged from July, and EIA said it expects natural gas prices to gradually rise, averaging $2.42 per million Btu this year and $2.87 per million Btu in 2017. ●

Contact Kristen Nelson at knelson@petroleumnews.com

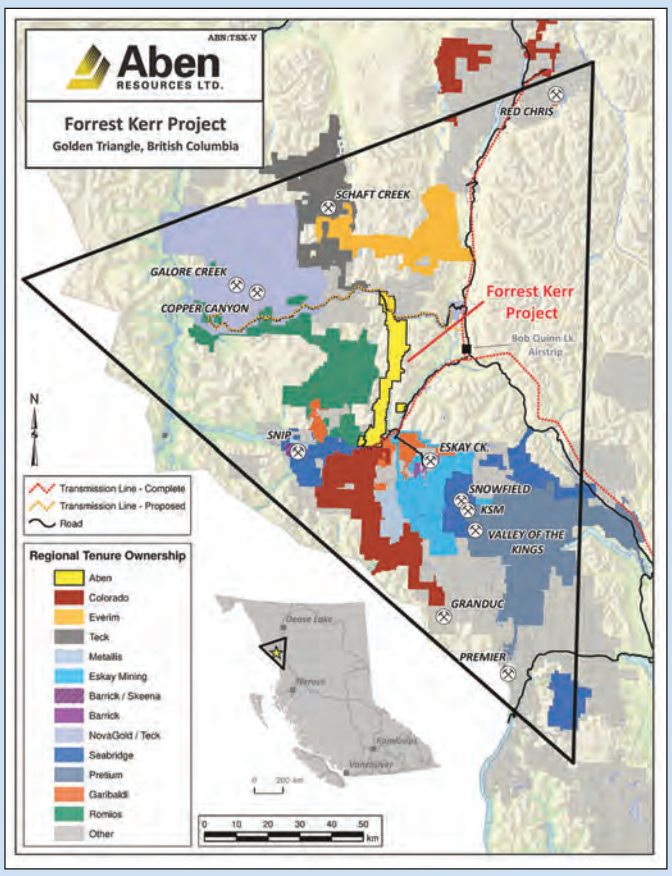
NORTH OF 60 MINING news

page 11 ICMM urges nations to enshrine World Heritages sites with laws

www.MiningNewsNorth.com The weekly mining newspaper for Alaska and Canada's North Week of September 11, 2016

NORTHERN NEIGHBORS

Compiled by Shane Lasley



ABEN RESOURCES LTD.

Aben begins recon exploration of Golden Triangle's Forrest Kerr

Aben Resources Ltd. Sept. 7 reported the start of exploration at its 23,000-hectare (53,830 acres) Forrest Kerr property located in British Columbia's Golden Triangle. The 2016 fieldwork is intended to provide reconnaissance-scale geological exploration across the project, which spans roughly 40 kilometers (25 miles). The newly-constructed access road to Galore Creek, a large copper-gold project being advanced by Novagold Resources and Teck Resources, cuts through the north end of the property. This area will be a particular focus of Aben's reconnaissance program. The objective of the current program is to provide confirmation of existing high-grade mineral occurrences, soil and geophysical anomalies, geological and structural relationships. In addition, prospecting and geological mapping will be completed to further identify and confirm target areas for follow-up drilling campaigns. Permitting for future drilling is currently underway.

Silver Range to sell namesake

Silver Range Resources Ltd. Sept. 1 reported the signing of an optional sale agreement with an un-named private British Columbia company, related to the Silver Range zinc-silver-lead project in Yukon Territory. Under the terms of a letter of intent, the purchaser may acquire full ownership of the Silver Range project by making a series of timed share issuances to Silver Range as specific milestone events are achieved before the end of 2020. Silver Range will retain smelter return royalty interests of 2 percent on all future precious metals production and 1 percent on all future non-precious metals production from the Silver Range project. In March, Silver Range elected to change its business model from the advanced exploration of zinc-silver-lead prospects in Yukon to a project generator with a focus on high-grade gold targets in Nunavut, the Northwest Territories and Nevada. Over the past four months, Silver Range has assembled a portfolio of about 16 gold projects and has started to market these properties to interested third parties. The proposed sale of the Silver Range project is consistent with the change of business model.

see **NORTHERN NEIGHBORS** *page 12*

NOVAGOLD RESOURCES INC.

With 34 million ounces of gold in reserves, the Donlin Gold project is a prime example of yet-to-developed world-class deposits in Alaska. Donlin Gold LLC – equally owned by subsidiaries of Novagold Resources Inc. and Barrick Gold Corp. – initiated permitting for Donlin Gold in 2012, a process that is expected to be completed late in 2017.

PUBLIC POLICY

Floating Alaska's boat

Mining executive stresses importance of attracting capital during rising tide

By SHANE LASLEY

Mining News

After a particularly long and painful bear market for the mining sector, the more than 25 percent surge in gold prices since the beginning of the year is lifting the share price of mining and mineral exploration companies in Alaska.

"It has been five very long years and hopefully this a start to what is going to be a good run," Greg Beischer, president and CEO of Millrock Resources Inc., told an audience at a recent Alaska Miners Association meeting in Anchorage.

GREG BEISCHER

While gold prices topping US$1,350 per ounce is obviously good for miners and explorers of the precious metal, the rise has loosened venture capital for companies across the sector.

"The tide is rising, and it is floating all boats," Beischer added.

The message left many people in the room wondering if Alaska's ship, which is anchored by sub-US$50-per-barrel oil prices, could also catch this rising tide.

"The geology of Alaska is compelling," the Millrock CEO answered. "Geologists want to come here – they know there are more Pebble deposits, they know there are more Donlin Creek deposits – but the perception is that it is a really tough place to permit a mine."

While Beischer does not personally believe that it is tough to permit a mine in Alaska, the perception persists. And, when mining and mineral exploration companies must make a decision where they can get the best return on their investment, the line between perception and reality blurs.

Mixed view

The Fraser Institute Survey of Mining Companies, which asks the world's mining executives to rank the world's mining jurisdictions on a wide range of issues, is one of the best measures of Alaska's allure to the global mining community.

Reflecting Beischer's message, mining executives participating in the survey feel that Alaska is one of the best places to find world-class mining deposits but are not quite as enthused about the prospects of permitting a mine after such a discovery is made.

When it comes to pure mineral potential, mining executives have ranked Alaska among the top five jurisdictions on the planet for seven years running, including a second place showing among 109 jurisdictions considered in the most recent survey.

While the survey is subjective, this consistent strong endorsement by the global mining community speaks volumes about the mineral potential of The Last Frontier.

However, the same mining executives that collectively consider Alaska the second-richest mineral jurisdiction ranked the state 59th, right below Zimbabwe, when it comes to uncertainty concerning environmental regulations.

The U.S. Environmental Protection Agency's attempt to utilize its presumed authority under the federal Clean Water Act to proactively veto or place restrictions on permits needed to develop the world-class Pebble copper-gold-molybdenum project has become a classic example of this mixed view.

"The Pebble deposit is one of the largest porphyry copper deposits in the world and has good grade," observed a geologist responding to the Fraser survey. "The EPA has declared a pre-emptive veto for permit applications that have not yet been submitted."

"The EPA's effort to circumvent the law and stop Pebble at all costs has had significant negative ramifications on mining development in Alaska," a manager of a large producing company added.

Despite complaints about federal agencies,

see **RISING TIDE** *page 11*

● CONSERVATION

Mining group calls on nations to protect World Heritage sites

By SHANE LASLEY

Mining News

A group of the world's largest mining companies have taken the lead in protecting World Heritage sites and are pushing for global governments to follow suit.

"The conservation of World Heritage sites is a collective responsibility we all share, and ICMM wants to see more movement from governments to protect them," said Tom Butler, CEO, International Council on Mining and Metals.

ICMM is a coalition of 23 global mining companies that include names familiar to Alaska's mining sector – Anglo American, Antofagasta Minerals; Barrick Gold; Sumitomo Metal Mining; and Teck Resources.

There are a total of 1,052 World Heritage sites globally, including 48 in the United States and Canada.

One such site – Kluane/Wrangell–St. Elias/Glacier Bay/Tatshenshini-Alsek – covers 24.2 million acres of lands that blanket the mountainous area were Alaska, British Columbia and Yukon Territory meet.

Spectacular glacier and icefield landscapes as well grizzly bear, caribou and Dall sheep habitat are what prompted the four park systems to be declared a World Heritage site in 1994.

Situated between the rich "Golden Triangle" region of northwestern British Columbia and the copper and gold deposits that extend westward into Alaska, this area has been lamented by some geologists as the richest mineral region on earth that will never be explored.

ICCM said that while its members, along with JP Morgan and Shell Oil Co., have made a stand against exploration and mining in areas such as this metals-rich but protected region, only a handful of other companies have made similar commitments.

"Our members voluntarily decided in 2003, not to mine or explore in World Heritage sites. Yet 13 years later, other companies and industries are still operating in these precious sites," said Butler.

The coalition of miners said this is compounded by the fact that only two of the 192 countries that ratified the World Heritage convention have enshrined this protection in domestic legislation – South Africa and Australia.

"While 23 leading mining companies have voluntarily made a commitment not to mine or explore in World Heritage sites, their voluntary action alone is not enough to safeguard these sites," ICMM penned in a Sept. 5 statement. "It recommended that countries incorporate their commitments under the World Heritage Convention in their national legislation." ●

SHANE LASLEY

A glacier flows away from Mount Logan, Canada's highest peak, in Kluane National Park and Reserve in southwestern Yukon Territory. Kluane is part of a larger World Heritage site that blankets 24.2 million acres of lands where the borders of Alaska, British Columbia and Yukon Territory meet.

continued from page 9

RISING TIDE

many feel that regulators at the state level somewhat offset their more antagonistic federal counterparts.

"Alaska's Large Mine Permitting Team within the Office of Project Management and Permitting has the unique ability to bring federal and local permitting agencies to the table in order to avoid duplicative efforts in the permit process. Without this group in place, developers and operators would face an uphill battle in attempting to open and operate mining projects," a mining manager commented.

Attracting investment

With Alaska's budget deficit north of US$3 billion on persistent low oil prices, lawmakers are looking for new flows of cash to Alaska's coffers.

For perspective, Alaska's budget shortfall is larger than the worth of all the zinc, gold, silver, lead and coal mined in Alaska during 2015.

Despite the daunting task of balancing the state's budget in the short term, a number of economists believe mining has a role to play in the state's long-term prosperity.

"We have trillions of dollars of natural resources left to be developed in this state. I think that we are still a very young state, and in the long run, this is going to be the beginning of Alaska's resource development curve," according to Mark Edwards, economist, Northrim Bank.

Donlin Gold, with roughly US$45.8 billion of gold reserves at the current price, and Pebble, with a roughly US$356 billion copper-gold-molybdenum deposit on state lands, are prime examples of the untapped world-class mining potential in Alaska.

For this potential to be realized, Beischer contends that Alaska needs to let global miners and mineral exploration companies know that the state is open for business.

"The main thing is to tell the mining world that we want mining here. That has to come right from the top – the governor has to say, 'we want you to invest in our state'," the Millrock CEO informed convention participants.

Alaska's rich mineral endowment gives the state an advantage on this front.

While concerns over environmental regulations weigh on the minds of global mining executives, Alaska still ranked sixth on the Fraser Institute survey's investment attractiveness index, which weighs both the perception of mining policies and the pure mineral potential.

Maintaining and building on this favorable reputation during the incoming tide could help draw the capital needed to explore and develop the state's world-class mineral potential, and possibly make Alaska more buoyant in the process.

"It is our job to attract as much of that venture capital available worldwide to our state; so that means, we have to do our best to make Alaska an attractive place for mining exploration and development," Beischer added. ●

NEWS NUGGETS

Compiled by Shane Lasley

Endurance prepares to drill Elephant Mountain

Endurance Gold Corp. Sept. 6 said a drill has been mobilized to begin a five-hole drill program at its optioned Elephant Mountain gold property in the Rampart-Manley Hot Springs area of Interior Alaska. In keeping with exploration plans announced in June, three targets within a 1,800- by 600-meters intrusive-hosted gold target have been prioritized for drilling. South Zone, the highest priority drill target, has very few outcrop exposures but has yielded the highest gold values in rock samples from the property. Surface grab rock samples from South Zone include: 12.98 grams per metric ton, 5.21 g/t, 4.44 g/t, 3.02 g/t, and 2.59 g/t gold associated with iron oxide stained and altered granitic rocks. In 1991, Placer Dome collected a grab sample from the South Zone target that assayed 12 ounces per ton gold (411.4 g/t gold). Sampling by Endurance in 2015 confirmed a continuous 1,000-meter-long soil anomaly exceeding 100 parts per billion gold with peak values up to 320 ppb gold. The interpreted source area of the anomaly remains untested by drilling. North Zone target is a 1,200- by 500-meter gold-arsenic soil anomaly with peak values of up to 1,540 ppb gold. Central Zone, an area with no outcrop, is interpreted to be an area of altered intrusive. Located 76 miles northwest of Fairbanks, Elephant Mountain can be accessed by highway, road and all-terrane vehicle trails from Eureka, an historic and active placer gold mining camp.

Contact North of 60 Mining News:

Publisher: Shane Lasley • e-mail: publisher@MiningNewsNorth.com

Phone: 907.229.6289 • Fax: 907.522.9583

Petroleum news

North of 60 Mining News is a weekly supplement of the weekly newspaper, Petroleum News.

Shane Lasley	PUBLISHER & NEWS EDITOR
Rose Ragsdale	CONTRIBUTING EDITOR
Mary Mack	CEO & GENERAL MANAGER
Susan Crane	ADVERTISING DIRECTOR
Heather Yates	BOOKKEEPER
Marti Reeve	SPECIAL PUBLICATIONS DIRECTOR
Steven Merritt	PRODUCTION DIRECTOR
Curt Freeman	COLUMNIST
J.P. Tangen	COLUMNIST
Judy Patrick Photography	CONTRACT PHOTOGRAPHER
Forrest Crane	CONTRACT PHOTOGRAPHER
Tom Kearney	ADVERTISING DESIGN MANAGER
Renee Garbutt	CIRCULATION MANAGER
Mapmakers Alaska	CARTOGRAPHY

ADDRESS • P.O. Box 231647
Anchorage, AK 99523-1647

NEWS • 907.229.6289
publisher@miningnewsnorth.com

CIRCULATION • 907.522.9469
circulation@petroleumnews.com

ADVERTISING
Susan Crane • 907.770.5592
scrane@petroleumnews.com

FAX FOR ALL DEPARTMENTS
907.522.9583

Several of the individuals listed above are independent contractors

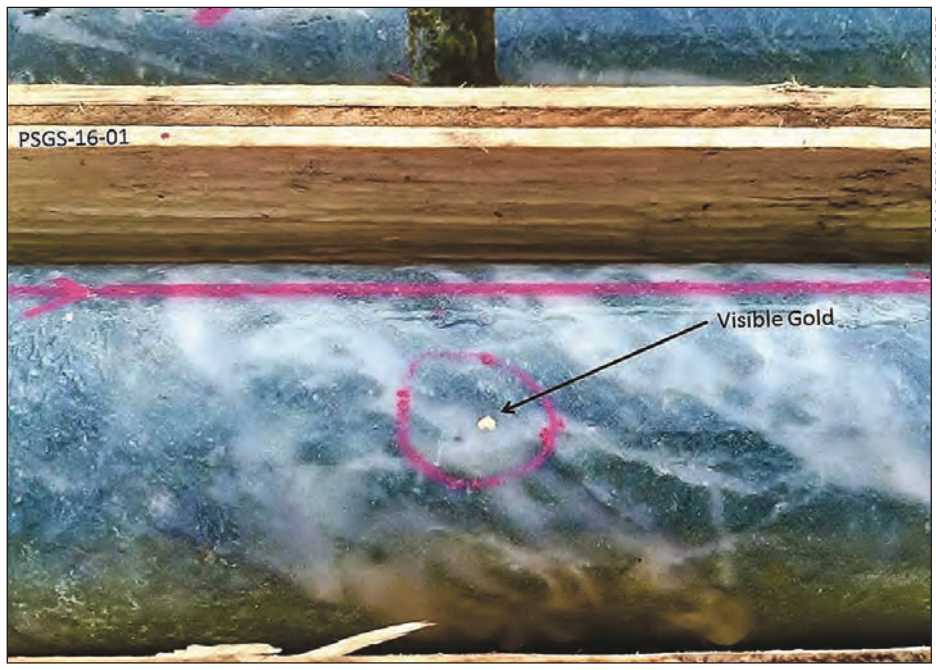
NORTH OF 60 MINING NEWS is a weekly supplement of Petroleum News, a weekly newspaper.
To subscribe to North of 60 Mining News,
call (907) 522-9469 or sign-up online at www.miningnewsnorth.com.

continued from page 9

NORTHERN NEIGHBORS

Silver Range expands Nunavut gold portfolio

Silver Range Resources Ltd. Sept. 7 said it has staked and conducted preliminary exploration at the Quartzite gold property in Nunavut's Kivalliq region. Located near Kaminak Lake, 130 kilometers (80 miles) southwest of Rankin Inlet, the Quartzite property covers 10 documented gold occurrences along a nine-kilometer (5.6 miles) area. At the West End zone, quartz carbonate veins carry gold with galena and pyrite. Historical sampling of this material returned assay values of up to 17.3 grams per metric ton gold. Confirmatory sampling during 2016 returned grab samples results of up to 27.3 g/t gold. The central Eva Lake zone covers an extensive train of meta-volcanic-hosted quartz-galena-chalcopyrite-pyrite float. The best historical sampling from this area returned results of 132 g/t gold. Confirmatory sampling during 2016 returned results of up to 26.2 g/t gold. At the eastern Joan Lake zone, pyrite-bearing quartz veins in carbonate-altered mafic meta-volcanic rocks returned historical assays up to 17.8 g/t gold. Confirmatory sampling during 2016 returned results of up to 9.53 g/t gold. Historical work in the area by Noble Peak Resources included an electromagnetic and magnetic field survey covering a portion of the claims. No drilling has been conducted on the property. Silver Range is building and exploring a portfolio of high-grade gold targets in Nunavut, the Northwest Territories and Nevada to meet an increasing demand for gold projects in politically stable jurisdictions.



GOLDSTRIKE RESOURCES LTD.

Goldstrike Resources' Plateau property in the Yukon Territory has become known for an abundance of visible gold. The company said the first hole of its 2016 program contains the most plentiful VG seen on the property so far.

Visible gold cut in first 2016 hole at Plateau

Goldstrike Resources Ltd. Sept. 6 said the first hole drilled at the Goldstack zone at its Plateau property, PSGS-16-01, cut 45.5 meters averaging 6.05 grams per metric ton gold. The company said this hole contains the most abundant visible gold seen in drill core to date at Plateau, a Yukon Territory property known for the presence of VG. So far this year, the company has completed 11 holes at Goldstack. All holes have intersected mineralized stockwork and breccia, and the zone remains open, confirming the robust nature of the mineralized body. The company said the results show that within the mineralized zone, the gold is hosted in parallel vertical fractures similar to the orientation of high-grade veins identified at Bonanza, a recently recognized zone that is located 4,000 meters along strike to the northwest. It is also on trend with the new Goldback zone, where bedrock grab samples returned up to 7.0 g/t gold. Follow-up prospecting and mapping have now extended Goldback from 480 to 580 meters on-trend and uphill from the Goldstack. Six new bedrock grab samples from this zone returned values from below detection level to exceeding the fire assay limit of 10 g/t gold.

IDM discovers new zone at Red Mountain

IDM Mining Ltd. Sept. 6 published results from 13 underground holes drilled at it Red Mountain gold project, located 15 kilometers (nine miles) east of Stewart, B. C. Highlights from the recent underground drill results include: 13.77 averaging 5.72 grams per metric ton gold and 34.89 g/t silver in hole U16-1181, a step-out south of the Marc zone; 14.19 meters averaging 5.78 g/t gold and 24.15 g/t silver in hole U16-1185, drilled up-dip of Marc; U16-1187: six meters averaging 7.43 g/t gold and 12.51 g/t silver in hole U16-1187, which discovered the NK zone; and 15 meters averaging 15.52 g/t gold (capped) and 44.82 g/t silver in hole U16-1193, a Marc zone infill and metallurgical hole. U16-1187, the NK zone discovery hole, was drilled vertically to test a projected step-out of isolated, historic intercepts below the Marc zone. IDM said mineralization at NK occurs at a sediment-porphyry contact, about 100 meters below the underground workings. The NK zone, named after assistant project manager Natalie King, is 70 meters outside of the current resource estimate at Red Mountain. "In addition to the successful step-out holes to the south of the Marc Zone, the discovery of the NK Zone has significant potential for resource growth and highlights the many exploration opportunities at Red Mountain," said IDM Mining President and CEO Robert McLeod. "Future drilling will target potential resource expansion from these wide and high-grade intercepts at the Marc and NK Zones as well as several other untested targets."

Darnley Bay cuts deal for BC copper project

Darnley Bay Resources Ltd. Sept. 1 said it has entered into an agreement to acquire full ownership, subject to a royalty, in the Nak copper-gold project, located 80 kilometers (50 miles) northeast of Smithers, B. C. Located in the Babine Lake area of central British Columbia, the road-accessible Nak project occurs in a copper-gold porphyry belt that includes the former Bell and Granisle mines, the Morrison deposit and numerous other advanced prospects. Together Bell and Granisle produced 130 million metric tons of ore grading 0.4 percent copper and 0.15 grams per metric ton gold. The Nak property was originally explored by Noranda in the 1960s and 1970s and more recently by a number of junior exploration companies through the mid-1990s. Highlights from historical drilling at Nak include 70.7 meters grading 0.25 percent copper and 1.17 g/t gold; 12.5 meters grading 2.61 percent copper and 0.14 g/t gold; and 18 meters grading 1.32 percent copper and 0.2 g/t gold. A geophysical survey completed by Copper Ridge Exploration Inc. in 2008 identified a low chargeability and high magnetic susceptibility zone interpreted to be associated with the gold-rich mineralization at Nak's Southern zone. A single hole drilled in the Southern zone during 2008 returned 0.115 percent copper and 0.257 g/t gold across the entire 316.5 meters from the surface to the bottom of the hole. To acquire Nak, Darnley Bay has agreed to pay prospector Bernie Kreft C$150,000 in cash over five years. The company has also agreed to pay bonus payments of C$25,000 on 1,500 meters of drilling; another C$25,000 upon 3,000 meters of drilling; and an additional C$125,000 and 250,000 common shares will be payable upon a total of 10,000 meters of drilling. Darnley Bay may elect to pay C$250,000 in cash, or pay a combination of shares and cash equivalent of C$250,000, in lieu of the obligation to issue the 250,000 shares. Darnley Bay has a work commitment of C$25,000 to be completed by the end of May 26, 2017, and a total of C$500,000 by the third anniversary of the agreement. Kreft will retain a 2 percent net smelter royalty, 62.5 percent of which can be purchased for C$1.5 million. Darnley Bay said this transaction is consistent with its strategy to acquire interests in several base metal deposits at or near the feasibility stage. In March, the company announced an option to acquire the Davidson molybdenum deposit near Smithers, and in May, the explorer entered an option to acquire the Clear Lake zinc project in Yukon Territory.●

● GOVERNMENT

Feds release new high-res Alaska maps

Elevation maps based on 2-meter resolution commercial satellite imagery depict the surface of the state in astounding detail

By ALAN BAILEY
Petroleum News

The White House has announced the publication by the National Geospatial-Intelligence Agency and the National Science Foundation of the first release of new high-resolution topographic maps of Alaska. The maps were generated from two-meter resolution images captured from commercial satellites.

The resolution of the maps is astounding. For example, a topographic image of Anchorage shows the pattern of buildings in the city and even depicts aircraft parked on the apron at Anchorage Ted Stevens International Airport.

President Obama triggered the mapping project, called Arctic Digital Elevation Models, or ArcticDEMs, through an executive order in January 2015. The president's visit to Alaska in the summer of 2015 reinforced the president's determination to see first release of the new maps of Alaska in 2016, with the entire Arctic to be mapped by 2017, the White House says. The mapping initiative also comes in conjunction with U.S. chairmanship of the Arctic Council.

The maps are available to the public through a web portal at nga.maps.arcgis.com

High-speed imagery

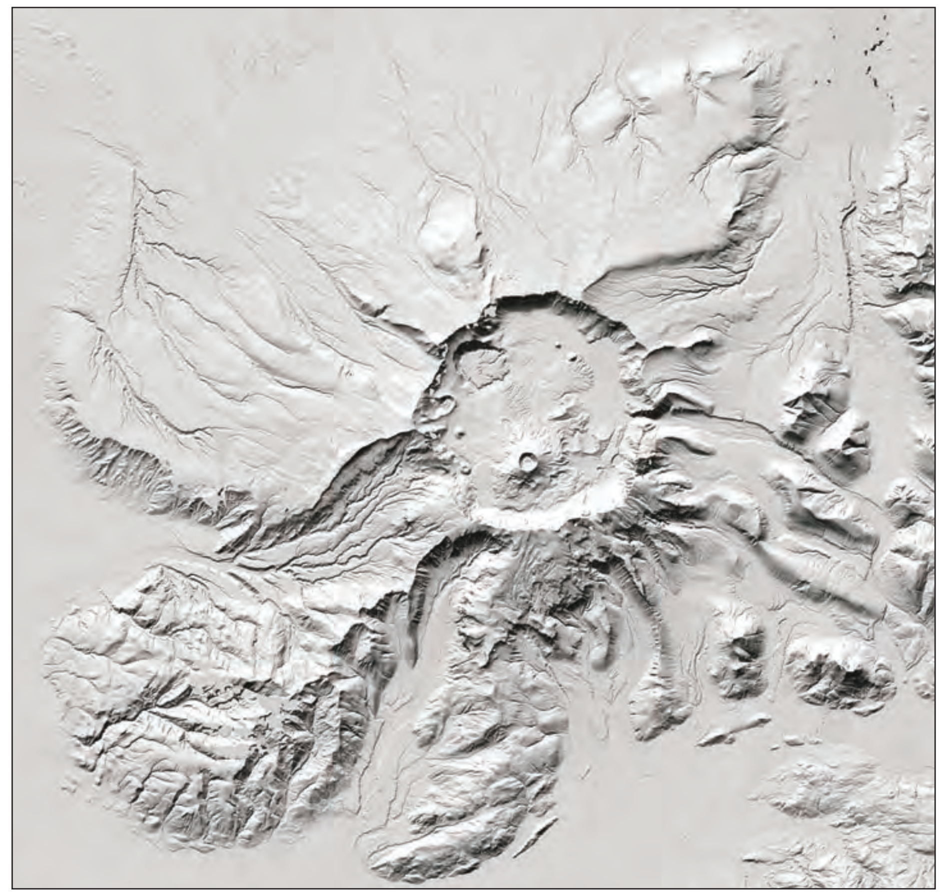
The use of satellite imagery and computer processing enables the detailed mapping of vast areas of territory at speeds previously unimaginable. And, using the imagery as a basis, the map producers have been able to generate various forms of shaded relief images, as well as traditional contour maps.

However, capturing of the imagery does require clear skies, a factor that can make the mapping of cloud-prone regions such as southeast Alaska challenging. Areas where there have been gaps in the coverage have been excluded from the initial release of the maps but should be filled in a subsequent release, based on imagery collected in June 2016, according to a statement published by the map producers.

Monitoring change

The ability to rapidly obtain the data for the maps opens up the possibility of generating regular map updates, to monitor the changes over time of landforms including the monitoring of coastal erosion. Accurate mapping and monitoring can help identify buildings and infrastructure at risk from storm surges and identify places to safely shelter from storms. Satellite imagery can be collected and digital elevation models produced at regular intervals — weekly, monthly or annually — to observe and document changes as they occur, the White House says.

Under the leadership of the NGA and the NSF, a number of organizations have been participating in the map production. These organizations include the Environmental Systems Research Institute Inc., the U.S. Geological Survey, the state of Alaska, the Polar Geospatial Center at the University of Minnesota, Ohio State University, Cornell University and Blue Waters at the University of Illinois at Urbana-Champaign. ●



THE WHITE HOUSE

This sample of a digital map with relief shading from the new Arctic Digital Elevation Models mapping of Alaska depicts Mount Aniakchak, a volcanic caldera in the Aleutian Range.

Contact Alan Bailey at abailey@petroleumnews.com

● PIPELINES & DOWNSTREAM

North Dakota oil pipeline protest turns violent

By JAMES MACPHERSON
Associated Press

A protest of a four-state, $3.8 billion oil pipeline turned violent after tribal officials say construction crews destroyed American Indian burial and cultural sites on private land in southern North Dakota.

Morton County Sheriff's Office spokeswoman Donnell Preskey said four private security guards and two guard dogs were injured after several hundred protesters confronted construction crews the afternoon of Sept. 3 at the Dakota Access pipeline construction site just outside the Standing Rock Sioux reservation. One of the security officers was taken to a Bismarck hospital for undisclosed injuries. The two guard dogs were taken to a Bismarck veterinary clinic, Preskey said.

Tribe spokesman Steve Sitting Bear said protesters reported that six people had been bitten by security dogs, including a young child. At least 30 people were pepper-sprayed, he said. Preskey said law enforcement authorities had no reports of protesters being injured.

There were no law enforcement personnel at the site when the incident occurred, Preskey said. The crowd dispersed when officers arrived and no one was arrested, she said.

Vicki Granado, a spokeswoman for Dallas-based Energy Transfer Partners, which is developing the pipeline, said the protesters broke through a fence and "attacked" the workers.

The incident occurred within half a mile of an encampment where hundreds of people have gathered to join the tribe's protest of the oil pipeline, which is slated to cross the Dakotas and Iowa to Illinois.

The Standing Rock Sioux have gone to court to challenge the Army Corps of Engineers' decision to grant permits for the project, and a federal judge will rule before Sept. 9 on whether construction can be halted.

The tribe fears the pipeline will disturb sacred sites and impact drinking water for thousands of tribal members on the reservation and millions farther downstream.

The protest Sept. 3 came one day after the tribe filed court papers saying it found several sites of "significant cultural and historic value" along the pipeline's path.

Tribal preservation officer Tim Mentz said in court documents that the tribe was only recently allowed to survey private land, where researchers found burials, rock piles called cairns and other sites of historic significance to Native Americans.

Standing Rock Sioux Chairman David Archambault II said in a statement that construction crews removed topsoil

see PROTEST page 14

continued from page 1

FURIE WELL

Randolf Yost jack-up rig, stationed at the Julius R gas production platform, to conduct the drilling.

Producing from KLU No. 3

Gas production from the field comes from the KLU No. 3 well, originally drilled as an exploration well but later converted for production. Furie is supplying gas to Homer Electric Association, for power generation, and to Aurora Gas, for supply to the Tesoro oil refinery at Nikiski on the Kenai Peninsula.

An additional contract to supply gas to Enstar Natural Gas Co., the main Southcentral Alaska gas utility, comes into effect in 2018 but is contingent on Furie drilling two Kitchen Lights development wells this year.

Webb said that, with the KLU No. 3 well having more than enough capacity by itself to support Furie's currently operating gas supply contracts, the company cannot justify the cost of fully completing the A-1 well this year — presumably it will drill the well to target depth and then suspend the well for future completion. However, the company has fully completed the A-2 well.

"Having the A-2 well on line is a good insurance policy for production/deliverability," Webb said.

He said that in preparation for the Enstar contract Furie anticipates drilling another development well, the KLU A-3, and completing both the A-1 and the A-3 wells, in 2017.

Under capacity

Although information about the size of the Kitchen Lights field has not been made public, it is clear that the field is operating well under capacity.

Currently Furie's contract with Homer Electric allows for the supply of 12 million to 18 million cubic feet of gas per day, depending on the time of year. The Enstar contract anticipates gas delivery rates in the range of 10 million cubic feet to 22 million cubic feet per day. With the single subsea pipeline that delivers gas from the Julius B platform to Furie's gas processing facility in the Kenai Peninsula having a capacity of 100 million cubic feet per day, Furie has in the past said that it hoped for initial production of 85 million cubic feet per day from the Kitchen Lights field. And Furie's development plan for the field envisages the eventual construction of two 100 million-cubic-feet-per-day subsea pipelines from the offshore platform.

Although there is a predictable market for the supply of local utility gas from the Cook Inlet basin, that market is small and it tends to be captured by relatively long-term gas supply contracts. Another potential market for Cook Inlet gas is a liquefied natural gas export facility operated by ConocoPhillips on the Kenai Peninsula. But, because of difficult market conditions, with low LNG prices, ConocoPhillips is not currently exporting LNG from the plant. Agrium Inc. has been considering re-opening its fertilizer plant on the Kenai Peninsula — that plant uses natural gas as feedstock. And two companies have been considering building additional LNG plants on the shores of the Cook Inlet — one primarily for the supply of gas to Japan and the other for LNG supplies for the Alaska Interior in conjunction with the Alaska Industrial Development and Export Authority's Interior Energy Project.

—ALAN BAILEY

Contact Alan Bailey
at abailey@petroleumnews.com

continued from page 7

AKLNG HEARING

the project over to AGDC; effectively handling progression of FERC NEPA (National Environmental Policy Act) process to AGDC; supporting access to pre-FEED data and information for a state LNG project; and selling the Alaska LNG Project LLC to AGDC so it will have access to LNG plant land, the Department of Energy LNG export authorization and the AKLNG website and logo.

McMahon said that once a state LNG project is up and running ExxonMobil will still have a major role in the development of North Slope natural gas. He said ExxonMobil has always been will be make its gas available to a project under "mutually agreed and commercially reasonable terms."

ConocoPhillips, BP

ConocoPhillips has been saying for some time that it was unlikely to participate in FEED in 2017. Darren Meznarich, project integration manager for ConocoPhillips for Alaska North Slope gas, said his company remains in support of completing pre-FEED work, but is unlikely at this point to agree to participate in FEED in 2017 due to economic headwinds. ConocoPhillips is, he said, willing to participate in a transition to a state-led project, but said the company still has many questions on the concepts proposed by the state and the Alaska Gasline Development Corp., the state's entity for ANS gas development. Meznarich also said ConocoPhillips continues to be willing to make its gas available on mutually agreeable and commercially reasonable terms.

Dave Van Tuyl, resource manager for BP in Alaska, said BP continues to believe that Alaska North Slope gas presents a tremendous opportunity — something the company has believed since the 1970s, he said. (See details of BP's comments in Sept. 4 Petroleum News story on the Aug. 25 hearing.)

Walker said there is a "critical misconception" that the project will move ahead under any circumstances "financed by the permanent fund."

Van Tuyl said BP supports the state-led project structure and is discussing with AGDC and internally what form BP's support might take.

The governor's take

In an Aug. 25 press release Gov. Bill Walker noted the findings of a Wood Mackenzie report that "the traditional model of a producer owned and financed gasline is not likely appropriate given today's market environment," but said he was pleased to note there is a strong potential for an economically viable project "by exploring some of the alternate project structures currently being investigated by AGDC," such as third party investors and project financing.

"Now is not the time to shelve that excellent work and start over at a future date," he said, citing the more than $500 million and several years the project team has spent on engineering, permitting and other work necessary to complete pre-FEED, and calling for "a collaborative cooperative spirit by all decision-makers and stakeholders to adapt to changing conditions and work together to determine if there is a viable path forward."

Walker said there is a "critical misconception" that the project will move ahead under any circumstances "financed by the permanent fund."

He said that will not happen. Financing, if the project is economically viable, will be "by long term purchase contracts secured before the first piece of pipe is laid, not by the permanent fund. This is how projects around the world are financed and Alaska's will be no exception," Walker said.

Walker told the Alaska Dispatch News in an interview published in early September that the state will know within a year whether potential buyers and investors will support the project, and if the interest is not there, the state will back off. ●

Contact Kristen Nelson
at knelson@petroleumnews.com

continued from page 13

PROTEST

across an area about 150 feet wide stretching for 2 miles.

"This demolition is devastating," Archambault said. "These grounds are the resting places of our ancestors. The ancient cairns and stone prayer rings there cannot be replaced. In one day, our sacred land has been turned into hollow ground."

Preskey said the company filmed the confrontation by helicopter and turned the video over to authorities. Protesters also have posted some of the confrontation on social media.

Morton County Sheriff Kyle Kirchmeier said in a statement that "individuals crossed onto private property and accosted private security officers with wooden posts and flag poles."

"Any suggestion that today's event was a peaceful protest, is false," his statement said. ●

continued from page 1

SPR OPTIONS

under the terms of the International Energy Program.

The bulk of the reserve, currently amounting to about 695 million barrels, is stored in underground salt caverns at four major sites on the Gulf Coast. In addition, as part of the SPR, the Northeast Gasoline Supply Reserve holds 1 million barrels of crude oil, while the Northeast Home Heating Oil Reserve holds 1 million barrels of ultra-low sulfur distillate.

The Bipartisan Budget Act of 2015, passed by Congress as a consequence of federal budget negotiations, involves the sale of some SPR oil to close a budget gap. The act requires a drawdown of the reserve by 58 million barrels between fiscal years 2018 and 2015. The act also authorizes the sale of up to $2 billion worth of worth of crude oil between fiscal years 2017 and 2020 to fund an SPR modernization program.

The FAST Act, also passed by Congress in 2015, to fund improvements to the U.S. surface transportation infrastructure, requires a further SPR drawdown and oil sale of 66 million barrels between fiscal years 2023 and 2025.

Against this background, the new DOE strategic review has come to a number of conclusions, with associated recommendations.

Old infrastructure and connections

The review says that the critical infrastructure used for moving oil in the SPR has exceeded its serviceable life, resulting in an increasing frequency and severity of equipment failures. This issue justifies the planned sale of oil for the funding of a modernization program, the review says.

The review also comments that dramatic

> *The president's drawdown authority under the act could usefully be expanded to allow a full drawdown of the reserve in the event of a severe energy supply interruption.*

changes in the pattern of U.S. oil supplies, as a consequence, in particular of shale oil development, have triggered corresponding changes in the flows of oil supplies around the nation. For example, the oil flows through some pipelines have been reversed, causing some midstream flow congestion. As a consequence, with the connections between the SPR and the U.S. oil supply infrastructure being designed for an outdated oil supply pattern, the forcing of SPR oil into the distribution system would require the curtailment of some crude oil supplies from domestic sources, thus undermining the purpose of using the reserve.

As a result, in certain situations the effective oil distribution capacity of the SPR could be at least 2 million barrels per day less that the design drawdown capacity of 4.4 million barrels per day, the review says.

One option for addressing this problem would be to use modernization funds from oil sales for a project to enable the marine distribution of reserve oil. An assessment of risks to the world oil market, and the need for effective U.S. intervention in that market in response to a global oil supply crisis, coupled with a need to deal with the current constraints on the distribution of oil from the SPR in the United States, all indicated that this marine distribution funding would be justified, the assessment says.

Managing drawdowns

However, while the planned drawdown of some of the SPR stocks is projected to bring significant economic benefits to the nation, any further drawdown in stocks would require a fuller analysis of costs and benefits. Moreover, in terms of the modernization program funded by some of the drawdowns, the modernization of the SPR's distribution infrastructure must take precedence over adding dedicated marine terminals. And, while drawing the reserve down below 530 million barrels would significantly reduce the SPR's effectiveness, the benefits gained from the SPR level off at volumes above 600 million barrels, the review says.

The storage capacity at the existing storage sites is gradually falling, as geological forces cause the storage caverns to shrink during periods of maintenance-related reduced cavern pressures. Projected cavern volumes are sufficient to handle anticipated SPR inventories, given the planned inventory drawdowns. But any strategy to rebuild the inventory back to levels above 598 million barrels in the future would require investment in cavern development. Moreover, decisions over which caverns to drawdown in the upcoming drawdown cycle will impact any future ability to rebuild the inventory, the review says.

However, in the interests of avoiding a permanent reduction in the SPR capacity and to maintain the SPR's operational flexibility, all four existing SPR sites should remain in operation, the review says.

The review also recommends some changes to the Energy Policy and Conservation Act, the original 1975 act authorizing the SPR. The president's drawdown authority under the act could usefully be expanded to allow a full drawdown of the reserve in the event of a severe energy supply interruption. And the oil release authorities of the Northeast Gasoline Supply Reserve and the Northeast Home Heating Oil Reserve need to be aligned, the review says.

—ALAN BAILEY

Contact Alan Bailey at abailey@petroleumnews.com

continued from page 7

ROYALTY OIL

Fairbanks, an electric cooperative serving Interior Alaska.

Petro Star also purchases other crude oil from North Slope producing companies, typically from independent producers like Anadarko Petroleum and Caelus Energy that do not own downstream refineries.

The company has an advantage is that it can take crude oil from the trans-Alaska oil pipeline, which is near both the North Pole and Valdez plants, and return all of the residual oil, the unused portions of the crude, to the line.

In contrast, another Alaska refiner, Tesoro, must ship its North Slope crude by tanker from Valdez to its Cook Inlet refinery, and sell or dispose of its residual oil, sometimes at a loss, Tesoro has said.

Petro Star does pay a fee, however, to other trans-Alaska oil pipeline shippers for the effect of a slight degradation of the crude oil downstream from where residual oil is injected under a "quality bank" formula agreed to by pipeline shippers and the Federal Energy Regulatory Commission. ●

Contact Tim Bradner at timbradner@gmail.com

Petroleum news

Oil Patch Bits

Doyon Foundation receives language revitalization grant

As reported on newsminer.com Sept. 5, the Doyon Foundation received a $900,000 grant to revitalize five Athabascan languages through online education, according to a Doyon Foundation news release.

The Native American language preservation and maintenance grant was awarded by the Administration for Native Americans, which is a nonprofit group with a mission to promote self-sufficiency in cultural preservation.

"We are humbled and grateful to have been awarded in a highly competitive selection process. This news is very exciting, and this project will be a huge assist to those wanting to teach and learn their ancestral language," said Allan Hayton, director of the foundation's language revitalization program, in the news release.

The Native American language preservation and maintenance grant was awarded by the Administration for Native Americans, which is a nonprofit group with a mission to promote self-sufficiency in cultural preservation.

The Doyon Foundation will use the grant money to create 280 online lessons in the next three years. The courses will be to readily available to educators and students throughout Alaska.

The online courses will be created through a partnership with the nonprofit group 7,000 Languages, which has a mission of preserving languages throughout the world.

The Athabascan languages Holikachuk, Denaakk'e, Benhti Kenaga', Hän and Dinjii Zhuh K'yaa will be the focus of these online courses. The foundation's end goal is to create online lessons for all languages used in the Doyon region of Alaska and Canada.

"As Native people, our languages are part of our identity and are very precious to us. Our children, grandchildren and great-grandchildren deserve to have the opportunity to learn their language," the foundation's executive director, Doris Miller, said in the release.

Established in 1989, the Doyon Foundation is a nonprofit arm of Doyon Ltd.

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

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

continued from page 3

MICCICHE Q&A

brief presentation?

Micciche: The Wood Mackenzie report largely reiterates the answers I discussed when you asked if the state is taking control of an uneconomic project. They clarified that the AKLNG project is one of the least competitive projects on a cost of supply basis compared with likely competitors. As far as cost of supply reduction levers discussed in the report, a debt financed, tolling project owned by the state of Alaska has piqued my interest. I have more to learn about such an option prior to commenting further.

There are other levers that could potentially assist in a successful project, yet many of those "levers" come in the form of credits and other subsidies currently less-than-popular with a large proportion of the administration's base. Tax incentives, accelerated depreciation, royalty relief and similar incentives are unlikely to be offered. The few areas where the state could assist in a meaningful way with the potential to reduce the cost of supply, such as the tax exempt status of the state's interest seem cloudy at this point as to whether or not the IRS would rule in favor.

The report also explains that time must be invested to understand and account for the more peripheral benefits to Alaska and for Alaskans. Those benefits have been discussed by the Legislature for years, such as jobs, an in-state gas supply, monetizing the state's share of gas that today remains stranded and potential increases in oil production once finding gas is no longer a liability when reserves one day have an avenue to the marketplace.

Petroleum News: What are your thoughts on the tax exempt status pursuits?

Micciche: I am clearly not an expert in federal tax issues and certainly encourage AGDC to eventually request a formal ruling from the IRS. I reviewed the Manley and Brautigam Aug. 22 letter to the Legislative Budget and Audit Committee, Jermain Dunnagan & Owens letter, and the Alaska Gasline Port Authority letters from 1999 and 2000.

The letter seems to sum it up effectively: "(T)he IRS is historically dedicated to limiting tax exempt financing. According to the US Congress Joint Committee on Taxation, the tax exempt bond subsidy is generally considered to be inefficient because, in most cases, the cost in terms of forgone tax revenues exceeds the value of the subsidy to state and local governmental issuers."

Throughout my prior life, work and public service experience, I've been more accustomed to similar suggestions as the tax exempt status being more thoroughly vetted prior to being ready for prime time release. I encourage AGDC and the administration to further develop ideas prior to introduction in order to improve the credibility of both organizations.

I would categorize my faith in any substantive federal tax relief that could significantly benefit the economics of the project as being doubtful at best, unless the state is willing to take on the lion's share of the financial liability of the project. From where I sit today after reviewing the letters, there seems to be a risk/benefit exchange largely weighted to the negative on liability for the state in order for an exemption to be realized. I have much more to learn on the subject, however dueling opinions need further clarification.

Petroleum News: Is it still prudent to move forward, even at a slower pace? The other alternative seems to be to mothball the project entirely, which could make things too expensive to dust off and try again when investment dollars are available.

Micciche: I believe that although the economics of the project have clearly become rather challenging, the potential benefits have never diminished. Therefore, I strongly believe that there is a need to evaluate significantly slowing the spend by revising the FEED schedule, while keeping the project alive. I could spend several minutes reiterating the benefits of an AKLNG project.

In my district, the community has supported and participated in the project since its inception. Field work, land acquisition, community engagement and other related processes have resulted in increased employment and investment. The community remains prepared to support and engage whenever the opportunity arises.

The benefits to Alaskans along the route likely to enjoy in-state natural gas are also undeniable. From air quality issues in Fairbanks to the cost of energy throughout the spine of Alaska, this project will create economic opportunities unparalleled since the construction of TAPS.

Alaska cannot afford to retract from forward progress and energy relief for everyone from seniors and families in Fairbanks to potential industrial anchors located throughout the state. As most know, I have been involved in the LNG industry most of my life. In addition to the people benefitting from significant revenue for generations from the sale of currently stranded gas reserves to support quality state services, I envision an eventual Alaska that enjoys coastal distribution of LNG in ice-free areas, supplemented by traditional hydrocarbon sources and economic renewables.

Alaskans must not lose hope in the future viability of any project. Market conditions are dynamic by nature. What none of us have before us is a commodity price crystal ball. The crude market, which often dictates LNG prices in the few remaining traditional oil-linked regions, has and can change dramatically in a period of time that sometimes seems like overnight.

I sincerely hope that producers will remain involved at some significant level and that the administration will nourish stronger relationships that encourage their participation. I believe that the AKLNG project or a similar concept will eventually occur or the state will continue down a road of limited economic diversification and an overexposure to the effects of a single commodity. However, it must be built only after adequate due diligence proves an acceptable level of risk exposure measured against adequate benefits to the people of our great state. Although most are supportive of a successful, responsible project, building at all costs is not an option and I hope a message that rings clear in the halls of the Legislature, the administration and AGDC.

Petroleum News: We know that the AKLNG project terminus happens to be in your district. What is the mood on the Kenai Peninsula right now considering it seems like the project may be stalled at this point?

Micciche: It's interesting. You know I sit down with many people and groups in my district to discuss the project. It comes up often. This project would be a major positive economic driver on the Kenai for many years to come when and if it comes to fruition. Whether they are project sup-

see **MICCICHE Q&A** *page 19*

continued from page 1

MARKETING INFO

In a statement BP spokeswoman Dawn Patience said, "BP and the other PBU working interest owners believe the POD submittal is complete and the POD should be approved. The level of information provided is consistent with the previous PODs that DNR has approved each year since 2000. This POD satisfies all of the Prudhoe Bay Unit Agreement's and POD regulations' requirements."

Beyond unit operator role

BP said in its response that the state's requests for marketing information go beyond BP's role as the unit operator.

"BP Exploration (Alaska) Inc., as Prudhoe Bay operator, is not involved in marketing of hydrocarbons produced from the unit. Such action is outside the scope of operations conducted by the PBU operator and is prohibited by the Prudhoe Bay Unit Agreements executed by the state of Alaska and the PBU working interest owners," which include ConocoPhillips and ExxonMobil.

The Sept. 1 responses are consistent with BP's responses in earlier letters written this year in response to the requests for marketing information.

The request for confidential marketing information has been puzzling to Alaska industry officials, as well as state legislators. It is known that the marketing information request was initiated by the state Department of Law when Craig Richards was state Attorney General.

Requests from division

The requests were made by the Division of Oil and Gas in response to BP's filing earlier this year of its proposed development plan, a document filed annually for all state oil and gas units. The plans describe the unit operator's plans for the year, describing well activity and major maintenance, for example.

Information on marketing of oil and gas resources in the units was not previously requested until this year, and there have been no changes in state regulations to require additional marketing information.

Other unit operators have complied with the requests by including a paragraph or a few sentences saying that marketing activities are ongoing or, in some cases, that no information is available, and the division has approved those plans.

Prudhoe treated differently

Prudhoe is being treated differently, however. BP's proposed plan was rejected and the information on marketing was asked for again, with a deadline of Sept. 1 for the submission of the information. Meanwhile, Prudhoe's current plan, from 2015, was extended until Nov. 1, which is the final deadline for resolving the issue.

In a separate letter filed Sept. 1, ExxonMobil, a major Prudhoe lease owner, said it agrees with BP that the 2016 plan of development filed by BP on March 31, "satisfies the requirements of the Prudhoe Bay Unit Agreements and applicable Department of Natural Resources regulations."

"The Prudhoe Bay initial participating area is fully developed to efficiently and economically maximize hydrocarbon recovery. As the (submitted) Plan of Development indicates, the current focus is to use Prudhoe Bay natural gas to increase oil recovery through reservoir pressure maintenance or to use as fuel, NGL (natural gas liquid) extraction, and miscible injection," in enhanced oil recovery, ExxonMobil said in its letter.

Initiated by Law

The request for confidential marketing information has been puzzling to Alaska industry officials, as well as state legislators. It is known that the marketing information request was initiated by the state Department of Law when Craig Richards was state Attorney General.

Many in industry see it as a preliminary step in a possible "duty to produce and market" action against the Prudhoe leaseholders.

Richards as well as Gov. Bill Walker have long argued that litigation and other procedures under the "duty to produce and market" language in state oil and gas leases could force producers to develop and sell undeveloped gas, or oil.

With Prudhoe Bay, the argument would be that by failing to adequately undertake marketing for Prudhoe's undeveloped gas, the leaseholders are reneging on their obligations under the lease. If that could be established the state could issue a default notice and move to reclaim the leases and the oil and gas resources.

Default action downplayed

In statements to the press both the governor and new Natural Resources Commissioner Andy Mack have downplayed this, saying they have no intention of pursuing a default action on the leases.

Mack said separately that he believes a compromise will be reached.

Still, the Division of Oil and Gas has not dropped the request.

BP and the other lease owners say they cannot legally comply with the request, so the companies feel the governor is putting them in a "Catch 22" and creating the legal basis for a default action.

While default seems far-fetched, particularly since Prudhoe is a producing oil field with the gas now used to produce more oil, some in industry see Walker's action as an attempt to gain leverage on the producers to make Prudhoe gas available to a state-led gas pipeline project.

The governor has said he hopes to entice Asian LNG buyers to invest in the project, which is to be led by the Alaska Gasline Development Corp., the state's gas corporation.

BP and other Prudhoe producers have agreed to sell gas to third-party buyers on mutually agreed and commercially reasonable terms, but the governor has always been suspicious that the producers will really agree to sell their gas, and those sales will be the underpinning for the governor's pipeline plan.

Having a "duty to produce and market" legal action on the table, and arguing that third party buyers are making reasonable purchase offers, would give Walker leverage in case commercial terms cannot be agreed.

The belief is that the producers might not want to risk having this complex, controversial issue go into the state courts, and would agree to a more favorable settlement on gas sales terms. ●

Contact Tim Bradner at timbradner@gmail.com

continued from page 1

PLACER UNIT

Earlier this summer, after completing its first exploration well as the unit, ASRC Exploration asked the state for a five-year extension to the unit terms and proposed a two-year plan to conduct preliminary work toward potentially developing the area.

The state felt that a five-year extension "would be contrary to the public's interest in maximizing competition among parties and offering acreage for lease if resources are not diligently developed" and a shorter extension balanced the needs of the company and the public. Without an extension, the leases would become available to other operators.

A unit automatically expires five years after it become effective without an extension from the state. An exploration program is a common reason for providing an extension.

Earlier this year, ASRC Exploration completed the Placer No. 3 exploration well. The company has yet to release well results but suggested that the well expanded the known size of the Placer reservoir and appears to be capable of producing commercial volumes.

ASRC Exploration would spend the first year "determining reservoir extent and characteristics and defining infrastructure needs" and the second year "reservoir mapping and development well planning, performing engineering and cost studies for infrastructure locations, and proposing a participating area," according to the ruling.

—ERIC LIDJI

Contact Eric Lidji at ericlidji@mac.com

continued from page 17

MICCICHE Q&A

porters or not folks are keenly interested. In fact, I stopped by Kaladi Brothers in Soldotna this morning on the way to the landfill (there is no municipal trash service on the Kenai) and was stopped at a table full of gentlemen wanting to know about the status of the project.

To explain the risk to Alaskans of the "built it at all costs" philosophy this morning I talked about what happened during the Gulf of Mexico regasification folly which began in the early to mid-2000s. Sabine Pass LNG in Cameron Parish, Louisiana, is a prime example of why persistent risk reduction and diligence is so incredibly important prior to the state becoming involved in owning or controlling a larger proportion of an AKLNG project.

Sabine Pass is one of several LNG regasification facilities that were built in the Gulf region that represented billions invested between the various facilities. The Sabine Pass facility is the largest receiving and re-gas terminal in the world. The facility was ready for service in 2008, yet it was prepared for a market that no longer existed. Timing was everything in this case. By the time the LNG import terminals were ready for service, the natural gas shale boom resulted in an oversupply in the market and few cargos were ever received by the terminals.

Why is this discussion relevant in a coffee shop? Several reasons. First, I am not poking at most of the great energy industry minds that made the final investment decisions to construct Gulf LNG import terminals. No one could have foreseen the success and effects on supply of shale gas in the U.S. The point is, while corporations may be capable of absorbing such market reversals through the proportional impacts on millions of shareholders, our 740,000 Alaskan shareholders and potential taxpayers simply cannot absorb a similar mistake in the tens of billions of dollars.

Petroleum News: Let's take a look ahead to next session. Another bill looking to change our state's tax credit and tax structure is expected. What are your thoughts on that?

Micciche: Look at how that entire conversation was framed last year. It seemed like the administration was focused on SB 128 (Permanent Fund bill) only the votes for 128 seemed to target were on those from the left who were more focused on tax credits, tax credits largely created by the left. On the harder right you had the discussion until you cut enough we are not going to support SB 128. What the public has to understand is we had to drag people across the finish line to support the changes that did occur in HB 247. It gets into how far are people willing to go into SB 21. I think we pushed folks on the right to the limit of what they think we should be doing right now. They believe just as the industry does in stable tax policy. Although tax policy should be somewhat flexible as time and conditions change, any wide scale change to our tax policy is going to be difficult next year.

Petroleum News: Do you believe the state has a stable tax regime across all price points?

Micciche: Well with a net tax system the state is always going to be exposed at the lower end, but with SB 21 and as supplemented by HB 247 is certainly better than ACES for the state. When I think about what's best for Alaska and what keeps companies investing in Alaska, I do. I think we've got the right balance under these current conditions while keeping projects we expect to see coming on line moving forward. If you think about it, the reduction in decline and the first production increase occurring last year in this price environment. It's really something that didn't seem to get a lot of attention.

So ultimately my job as a legislator is to find a balance that is in the best interest to the people of the state of Alaska. Remaining rigid on either side has simply not been effective. The changes the far left wanted to make on tax policy would have been equally ineffective as no changes whatsoever. I think where we are is a balance. That balance can change as conditions change. I hope the others won't have a no changes at any costs philosophy or on the other side what seems to be a continued disdain for a stable tax environment. Rigidity has been counter-productive and legislators need to operate with open minds and take the time to understand tax policy. ●

Contact Steve Quinn at squinnwrite@gmail.com

EXPLORATION & PRODUCTION

US drilling rig count up 8 to 497

The number of rigs drilling for oil and natural gas in the U.S. increased by eight to 497 the week ending Sept. 2.

A year ago, 864 rigs were active. Depressed energy prices have sharply curtailed oil and gas exploration. Houston oilfield services company Baker Hughes Inc. said 407 rigs targeted oil, up one from the previous week; 88 targeted natural gas, up seven. Two were listed as miscellaneous.

Among major oil- and gas-producing states, Oklahoma, Wyoming and Texas gained four rigs each, Pennsylvania was up two, while North Dakota and West Virginia increased by one apiece.

Louisiana declined by seven and Colorado was down one.

Alaska, Arkansas, California, Kansas, New Mexico, Ohio and Utah were unchanged.

The U.S. rig count peaked at 4,530 in 1981. It bottomed out in May at 404.

—ASSOCIATED PRESS

GOVERNMENT

LIOs to close on Friday afternoons

The state's 22 Legislative Information Offices will now be closed on Friday afternoons as a cost-cutting measure when the Legislature is not in session.

Juneau radio station KTOO reports (http://bit.ly/2cbES6v) the closing of the offices will save nearly $300,000. The closures began Sept. 2 after the Legislature's in-house administrative council voted 9-1 on Sept. 1.

Staff members in the remote offices facilitate teleconferencing so residents can participate in legislative meetings. They also serve as a contact for state government and sometimes even process applications for the state's oil wealth fund checks. The cuts come as the state looks for ways to close a multibillion-dollar budget deficit.

—ASSOCIATED PRESS

continued from page 1

TANKER BAN

months ago Garneau has been working with the ministers of Fisheries and Oceans, Natural Resources and Environment, along with First Nations, the British Columbia government and other stakeholders to ensure "we get this right," he said.

Garneau's latest consultations have involved the Haida First Nation on Haida Gwaii (previously known as the Queen Charlotte Islands), followed by discussions with participants in the third annual meeting of British Columbia cabinet ministers and the province's Native leaders.

To also demonstrate its continued efforts to "develop our economy," the government has pledged to take measures to expand the role of Canada's busiest and third-busiest ports at Metro Vancouver and Prince Rupert, which account for about 55 percent and 9 percent of all containerized traffic entering and leaving Canada.

But Trudeau has left little question about his overall objective, declaring again in June that "crude oil supertankers just have no place on the British Columbia north coast," although he said his government is determined to get "the balance right between building a strong economy and protecting the environment."

Tankers from Alaska are rated as too dangerous to travel through Dixon Entrance, Hecate Strait and Queen Charlotte Sound, the areas that will be embraced by the ban.

The strategy will include measures to improve marine safety and protect the environment, consistent with British Columbia Premier Christy Clark's demand for a "world-leading" spill response system.

Garneau told the Vancouver Sun that the north coast ban will have no connection with the government's anticipated decision later this year on Kinder Morgan's controversial application to triple capacity on its Trans Mountain pipeline from Alberta to the Port of Vancouver and Puget Sound to 890,000 barrels per day.

"I'm not linking this to anything," he said. ●

Contact Gary Park through publisher@petroleumnews.com

continued from page 1

THOMSON FUTURE

crude oil from the North Slope. No gas is exported from the field: Gas is either recycled for condensate production or burned as fuel gas for the field facilities.

But ExxonMobil did not embark on the massive Point Thomson development just to produce 10,000 barrels per day of condensate. In fact, the condensate export pipeline from the field has a maximum capacity of 70,000 bpd. The plan has been to continue the development of the field along one of two routes: Expand the gas cycling system to produce condensate at a higher rate, or convert the field primarily to a gas field, albeit with some continuing condensate production along with the gas.

The eventual export of natural gas from Point Thomson forms a resource cornerstone of a North Slope gas line project.

A challenging field

The Point Thomson field is particularly difficult to develop, in part because of the exceptionally high reservoir pressure, and in part because it is a retrograde field in which condensate in the reservoir will tend to liquefy as the pressure is drawn down. The need for directional drilling to reach the offshore reservoir sands from onshore drilling pads compounds the difficulties.

And, although the field contains a massive hydrocarbon resource, much of this resource consists of gas, which, in the absence of a North Slope gas line, is stranded from world gas markets.

Following decades of delay in developing the field and efforts by the state to terminate the Point Thomson unit because of the lack of field development, in 2012 the state and the field's working interest owners signed a settlement agreement, specifying terms under which the unit could be retained. That settlement agreement spelled out a commitment by ExxonMobil and the other working interest owners to move forward with the IPS development, and then to proceed with one of the two full development routes.

Terms of the settlement

The settlement agreement says that if major gas sales are sanctioned by the end of 2016, the Point Thomson working interest owners must conduct a Point Thomson development project in support of those sales. But if major gas sales have not been sanctioned by June 2016, engineering for expansion of condensate production must begin, with the possibility of exporting gas from Point Thomson for enhanced oil recovery at Prudhoe Bay being an alternative option, the settlement agreement says.

So, with June 2016 having passed, with the end of 2016 approaching, and with no decision on major North Slope gas sales in sight, what will happen to the Point Thomson field? The state has indicated that after its takeover of leadership of the AKLNG project, a decision on whether to proceed to the front-end engineering design phase of the project is unlikely before late 2018.

The state presumably still sees gas production from Point Thomson as a vital component of a major gas line project. But will the project hiatus, while the state conducts the work needed to make a FEED decision, trigger a corresponding delay in Point Thomson development?

Ultimate hydrocarbon recovery

In an application in 2015 to the Alaska Oil and Gas Conservation Commission for approval to export gas from the Point Thomson field in conjunction with the AKLNG project, ExxonMobil said that ultimate hydrocarbon recovery from the field would be approximately the same, regardless of which of the two field development routes was taken. Gas exporting would result in lower ultimate condensate production than ramped up gas recycling, but the gas production would compensate for the reduced condensate output. However, the company also indicated that intensive studies conducted in the 2000s had indicated that a major expansion of gas cycling at the field, to maximize condensate recovery, would not be economically viable.

The state presumably still sees gas production from Point Thomson as a vital component of a major gas line project. But will the project hiatus, while the state conducts the work needed to make a FEED decision, trigger a corresponding delay in Point Thomson development?

That leaves the possibility of gas production for enhanced oil recovery on the North Slope as the alternative possibility for Point Thomson, if the North Slope gas line project does not come to fruition. For many years gas produced along with oil and re-injected into field reservoirs has underpinned continuing oil production as oil fields have aged.

The viability of using gas for ramped up enhanced oil recovery in the Prudhoe Bay field will presumably depend on some combination of future oil prices and the cost of recovering increasingly elusive pockets of oil remaining in the field.

There are other opportunities on the North Slope for the use of gas for enhanced oil recovery, including the development of major viscous and heavy oil resources in the region, and the support of oil recovery in various oil fields. However, the viability of these applications for natural gas will obviously depend on factors such as the development and production costs involved, as well as on oil prices.

Still focused on gas

Statements made by ExxonMobil indicate that the company remains intent on expanding gas production from Point Thomson.

"The Point Thomson field will provide a foundation for future gas development on the North Slope," Hans Neidig, ExxonMobil public and government affairs manager for Alaska, told Petroleum News in a Sept. 6 email. "We are working to progress planning for a potential gas expansion concept that would be a supply source for the proposed Alaska LNG project, which is now transitioning to a state project."

In testimony to a joint meeting of the Alaska Senate and House Resource Committees on Aug. 25, ExxonMobil Senior Commercial Advisor Bill McMahon commented that his company is committed to providing gas from Point Thomson for a state LNG project. However, before committing to new investments at Point Thomson and Prudhoe Bay in preparation for major gas sales, ExxonMobil would need robust gas sales and purchase agreements, with assurances that the purchaser would be able to receive and pay for ExxonMobil's gas, McMahon said.

As this issue went to press, the state administration had not responded to a request for a comment on the Point Thomson settlement agreement status. ●

Contact Alan Bailey at abailey@petroleumnews.com