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NEWS NUGGETS

Landslide win for gold

page 15 Experts calling for Trump's win to push gold to nearly US$1,400/oz

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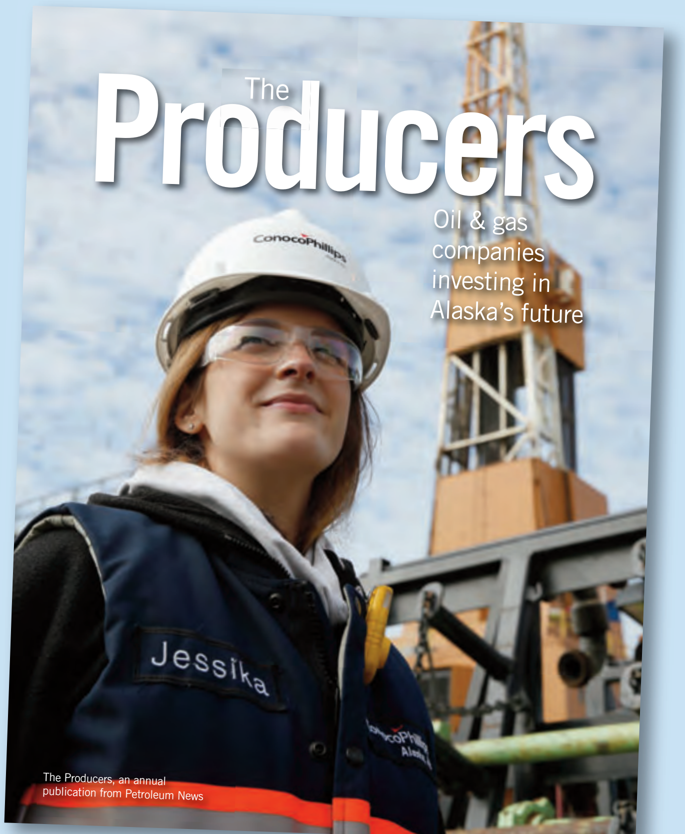
2016 Producers released



Salix no longer engaged in IEP

Salix Inc., the company selected for the construction of a Cook Inlet LNG plant for the Alaska Industrial Development and Export Authority's Interior Energy Project, is no longer involved in the project. Instead, the project team is moving forward on a plan in which a Fairbanks gas utility, formed from the merger of existing utilities Fairbanks Natural Gas and Interior Gas Utility, would expand an existing small LNG plant that FNG owns and operates near Port MacKenzie through a company called Titan.

3-bcf expansion

The idea is to put a 3-billion-cubic-feet-per-year expansion next to the existing LNG plant, a concept that Salix had been working on with the IEP team, Gene Therriault, IEP team

see **IEP CHANGES** page 31

Canada tightens ocean safeguards

Prime Minister Justin Trudeau announced a C$1.5 billion plan to protect Canada's Pacific, Arctic and Atlantic coastlines, which he claims will put Canada in a world-leading position for pollution and protection in its oceans.

He said Nov. 7 that the funding over five years will include a marine safety system, without indicating whether the plan will meet the British Columbia government's demand for three new salvage tugs costing up to C$50 million each and a new Coast Guard station at Prince Rupert.

Nor did Trudeau mention his promise last year to implement a ban on oil tanker traffic off British Columbia's north coast, although Transport Minister Marc Garneau indicated a moratorium could be imposed later this year.

Garneau told reporters the government is close to making an announcement on a ban, indicating the Trudeau administra-

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page 3 Q&A: Kito says AKLNG, state fiscal plan are closely linked

FINANCE & ECONOMY

OPEC deal in question

Trump vows to remove oil sector regulations, open federal land, waters to drilling

By KAY CASHMAN
Petroleum News

With Donald Trump winning the U.S. presidential election, energy expert Daniel Yergin has tempered his belief that OPEC will almost certainly move to freeze or cut oil production at its Nov. 30 summit in Vienna — a move Yergin expected to stabilize oil prices at a $50 floor. A failure to come to an agreement, he said in a Sept. 29 interview, would lead to oil prices in the $40s and a loss of face for the oil cartel.

One reason for pessimism about a Nov. 30 deal:


DONALD TRUMP


DANIEL YERGIN

The 14-member Organization of Petroleum Exporting Countries faces the prospect of increased U.S. oil output under President Trump, who has promised to remove oil industry regulations, open federal land and waters to oil and gas drilling, make the U.S. completely energy independent and double U.S. economic growth.

But how much an OPEC production freeze matters is no longer clear, given Trump's vocal support for the U.S. oil industry and his pledge to revoke

see **OPEC DEAL** page 30

EXPLORATION & PRODUCTION

3Q drilling down

Development drilling on Slope falls from 2015, but stays closer to 2014 levels

By ERIC LIDJI
For Petroleum News

With the exception of the Colville River unit, North Slope development drilling remained down across the board during the third quarter, as it has for much of the year to date.

The operators of the six largest North Slope units — Prudhoe Bay, Kuparuk River, Colville River, Milne Point, Oooguruk and Nikaitchuq — drilled 26 development wells between July and September, down from 35 in 2015 and 33 in 2014, according to completion reports compiled by the Alaska Oil and Gas Conservation Commission.

Although the overall trend points to a large decline in development drilling from 2015, activity

The Prudhoe Bay unit continues to see a strong downward trend.

at the two largest units this year has been similar to 2014 levels. By comparison, Alaska North Slope crude oil traded between $96 and $108 per barrel through the first nine months of 2014, compared to $30 to $44 per barrel during the same period this year.

Well counts represent administrative filings published through October 2016. AOGCC completion reports occasionally lag behind actual drilling and are often revised. With future revisions, these figures could end up being higher but are unlikely

see **DRILLING DOWN** page 29

LAND & LEASING

Tofkat overturned

State allows ConocoPhillips to acquire prospect south of Colville River unit

By ERIC LIDJI
For Petroleum News

The state will allow ConocoPhillips to acquire a package of leases from the former Tofkat unit and possibly add them to the Colville River unit, reversing an earlier decision.

In a pair of decisions, Department of Natural Resources Commissioner Andrew T. Mack allowed a joint venture operated by Brooks Range Petroleum Corp. to transfer 15 leases to ConocoPhillips Alaska Inc. and asked ConocoPhillips to resubmit its previous application to add those 15 leases and seven related leases to the Colville River unit.

In a Nov. 3 ruling, Mack overturned all four reasons that former Division of Oil and Gas Director

In a related Nov. 4 decision, Mack overturned a previous decision from the Division of Oil and Gas to reject a request from ConocoPhillips to expand the Colville River unit to include the former Tofkat unit.

Corri Feige originally gave for rejecting the transfer, back in mid-June 2016.

First, Mack decided that ConocoPhillips' earlier failure to develop the same acreage under different leases could not be the sole factor for preventing the company from leasing the acreage today. "An assignee's previous lack of diligent exploration

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contents

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● GOVERNMENT

Kito: AKLNG, fiscal plan closely linked

Juneau Democrat believes strong fiscal plan gives state better footing for advancing a natural gas pipeline project

By STEVE QUINN
For Petroleum News

House Rep. Sam Kito III may not sit on the Resources Committee or the Finance Committee but he still believes he has an obligation to study as much as he can about resource development. The Juneau Democrat, who just won his second full term in office after being appointed Beth Kerttula's successor, does serve on the Legislative Budget & Audit Committee, which hires resource development consultants. Kito shared his thoughts with Petroleum News on the status of the AKLNG project and the prospects of more debate on oil taxes in the upcoming session.

Petroleum News: You sit on a committee which deals with the costs of consultants, so my first question would be what are your general observations with what's happened over the last year with AKLNG?

Kito: So, from my perspective with prices not coming back up for oil, it means gas prices are low. That means transportation costs are a significant driving factor in marketability for the gas, and Alaska has high transportation costs. The big three oil companies who control a lot of the gas three to five years ago had excess capital that they could put into a project that would allow them to get their gas to market. With continuing low prices and some of the companies looking at losses and profits worldwide, it's becoming more difficult for them.

I can't speak for them but it just appears as though they are looking at the economics and saying it doesn't make a lot of sense for us to spend billions right now because we are losing money. The governor is still interested in getting a gas line, and he has committed to trying to keep the project moving forward regardless of what the supply partners will do.

The supply partners are saying sure we'll provide you with gas. What they are not saying is yes we will provide you with investment capital, which means we have to go find that money someplace else. I'm a little concerned about that because if we leverage ourselves and our financial position too strongly for this one project, we can put our state in a fiscal jeopardy more so than we already are with low oil prices.

So if we are doing the project, certainly we may be able to find investors to advance fund the project but they are also going to want a return on their investment, so we pay them back plus interest, or they are going to want payment in lieu — so gas — out of it. That means in order to get past the point where we've paid off the capital investment, the state of Alaska won't be generating any revenue, so I don't know how long that's going to be. Is it going to be five years before we are paid off? Is it going to be 10 years? What kind of revenue are we doing to get? Those are questions we are going to have before we start going to the front end engineering design phase.

I'm anxiously, like a lot of people, awaiting the announcement in December of what the pre-FEED shows. It may not be as exciting as we think, but I do want to see the information.


SAM KITO

Petroleum News: You mentioned questions for the administration. What other questions might you have about the project?

Kito: It's a question probably more for AGDC than for the governor. That is trying to look forward at the market. I'm hearing more and more that gas is being sold on spot price as opposed to long-term contracts. When we have long-term contracts because of the cost of the infrastructure, it makes sense because then you know your payments.

Long-term contracts lock you in. They lock you in maybe at a lower price, but you get a guarantee of revenue and they get a guarantee of gas. Because there is so much gas coming from other places, I'm hearing gas is being sold on the spot market, which means prices can go up and down a lot more rapidly.

As long as the prices are on an upward trend, that helps us but right now they are flat. The spot market trading does not give us the security that we need to build a big project to get our gas to market. So I worry about that and that's one question I would have for AGDC: How are we poised to interact with the gas market if there is more spot market trading?

Petroleum News: One of the concerns even AGDC's new president (Keith Meyer) brought up was communication between the administration and the Legislature.

Walker: At LB&A, we had a few meetings last year about the project, updates as things came along. This year we haven't. I don't know if it's because we haven't scheduled a meeting or if it's because there isn't as much going on. Last year we had the TransCanada decision so we had to have information to make that decision. We haven't seen anything on pre-FEED but I can imagine if the report is not ready and available until December, the challenge we're going to have is it's going to take a while to start looking at it and at the same time we are starting to deal with our fiscal plan.

One of the things, at least from my perspective that I think we should be carefully considering, is that if we in the state of Alaska actually get to a stable fiscal plan, that puts us on more equal footing with the gas suppliers, and we are not driven as much by the need to have revenue from the gas line coming in by the mid-2020s, then we will be able to be more patient with getting the gas to market when it's available.

I honestly believe the gas suppliers want to move the gas off the North Slope. I don't believe they are going to want to let Prudhoe Bay oil fields decline to the point where people are leaving and they are shutting things down — then have to gear up again. So there is going to be a point where the suppliers are going to want to get their gas out. Right now we want to get the gas out earlier than they need to.

If we have a stable fiscal plan, our timelines could match a lot better so that when the suppliers are ready to ship the gas, and we are ready with a pipeline to produce it and we are not going on a timeline only because the state of Alaska needs revenue.

So solving the fiscal plan actually helps get to a stable fiscal footing and gives us the ability to look at how much money we can afford to put in as an investment to a project on a sustainable basis.

Otherwise we are looking at $2.5 billion FEED investment. Unless we've got some kind of a fiscal plan, we are going to look at taking that out of the earnings reserve of $8 billion, I don't think we can afford to do that right now. I do think we have to take a step back, look at the big picture, and perhaps be a bit patient with when we want to try and have gas flowing through a pipeline.

Petroleum News: Do you think LB&A would need to hire consultants again?

Kito: The Legislature will need consultants. The governor has his consultants. We need to have people who can do some value engineering on the economics. We have had people in the past who have done a fair job. We are going to make sure we have people on tap so when we receive documents that we have the ability to look critically. Very few of us legislators are experts in oil and gas policy or project activities. We are going to need somebody to interpret some of that for us. We've got a slightly different perspective in the Legislature than the governor will so it does make sense to have someone to look at some of those issues.

Petroleum News: Even as very few may be experts, you're not on Finance or Resources, but you still seem to immerse yourself into resource development.

Kito: I would certainly not be somebody I recommend to write a report about the benefits or detriments of any FEED report that comes out. But it's still critical for the state of Alaska as a whole for everyone to be looking at what our resource development strategies are for the future. There are a handful of issues that bubble up as very important for the state and that is one of them. Because it's very important for the state, it's one of those that I need to understand. It takes me a while because I'm not an expert. I like to try an understand things at a level I can communicate to other people.

Petroleum News: You seem to have done that since you took office.

Kito: It's the importance of my job, making sure that I adequately understand the issues that I have to make decisions on.

see **KITO Q&A** page 27

● PIPELINES & DOWNSTREAM

Nutaaq files $1.10 tariff for next year

Badami to Endicott pipeline requested $20.60 rate for November, December, to make up for less Point Thomson volume than expected

By KRISTEN NELSON
Petroleum News

Based on a tariff filing from the Nutaaq Pipeline it appears that ExxonMobil plans to have Point Thomson on full production starting next year. Since startup in April production has been well below the expected 5,000 barrel per day startup rate, and nowhere near the 10,000 bpd expected for full production at the facility.

Nutaaq Pipeline LLC filed a $20.60 per barrel tariff for the Badami Oil Pipeline in October with the Regulatory Commission of Alaska. That tariff revision, up from $2.71 per barrel, was to make up for lower-than-expected volumes on the line coming out of the Point Thomson unit via the PTE Pipeline, which connects with the Badami line at that field (see story in Oct. 30 issue of Petroleum News).

Nutaaq, owned by Glacier Oil and Gas subsidiary Miller Energy, said the $20.60 rate would be only for November and December and would result in a blended average tariff for the line of $5.61 for 2016, lower than blended rates for 2015 and 2014.

The company told RCA when it filed for the increased tariff that the 2017 revised rate would be filed soon and was expected to be about $3 per barrel, which would have been about 30 percent lower than the blended 2016 rate.

The 2017 proposed rate, which Nutaaq filed Nov. 1, is actually considerably lower — $1.10 per barrel.

Nutaaq told the commission the proposed 2017 rate is "based upon updated Point Thomson production estimates for 2017."

Point Thomson volumes

The Point Thomson facility was built to produce 10,000 barrels per day of condensate and reinject natural gas, with initial production rates estimated at 5,000 bpd. Based on data in Alaska Oil and Gas Conservation Commission reports Point Thomson production has varied from a high of 1,591 bpd in April, the month production began, to a low of 31 bpd in September, the latest month for which AOGCC data are available.

From data available from the Alaska Department of Revenue's Tax Division, which wraps Point Thomson production in with that from Endicott and Badami, Point Thomson production appears to have varied considerably from day to day, so the bpd averages calculated from AOGCC monthly volumes are for overall purposes of comparison with the 5,000 bpd expected startup rate and the 10,000 bpd expected full production rate.

Commissioning continues

ExxonMobil told Petroleum News in late October that commissioning of the Point Thomson gas compression system continues.

Production from the April startup through the end of September averaged some 625 bpd.

Nutaaq told RCA that the proposed tariff for 2017 is based on "anticipated materially increased production from Point Thomson, up some 452 percent" from 605,008 barrels this year to 3,341,910 barrels in 2017.

The 2016 estimate for production would be the equivalent of some 2,200 bpd for the nine months. To reach that overall average daily production for the remainder of the year would average some 5,000 bpd.

The 3.34 million barrels estimated for 2017 would be the equivalent of about 9,200 bpd.

Point Thomson is designed to produce up to 10,000 bpd of natural gas condensate and inject up to 200 million cubic feet of recycled gas, ExxonMobil said.

When the field started production in April the initial rate was expected to be some 5,000 bpd of condensate and 100 million cubic feet per day of recycled gas.

ExxonMobil said daily production would fluctuate during commissioning of the gas injection system.

"We will safely ramp up production once these activities are complete," the company said. ●

Contact Kristen Nelson at knelson@petroleumnews.com

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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
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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

FAX FOR ALL DEPARTMENTS
907.522.9583

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OBITUARY

Inupiaq leader Edward Itta passes away

Edward Itta, Inupiaq leader and erstwhile mayor of the North Slope Borough, passed away on Nov. 6 after a long struggle with cancer. Itta, a whaling captain and tireless proponent of the rights of the North Slope Native peoples, became a key figure in negotiations between Shell and the North Slope communities during Shell's recent exploration program in the Beaufort and Chukchi seas.

While upholding community concerns about the potential impact of offshore oil activities on Native subsistence hunting, Itta also took a pragmatic stance, negotiating with the oil industry to find acceptable solutions to difficult issues.


JUDY PATRICK

EDWARD ITTA

While upholding community concerns about the potential impact of offshore oil activities on Native subsistence hunting, Itta also took a pragmatic stance, negotiating with the oil industry to find acceptable solutions to difficult issues.

Some comments that Itta made in a speech to the Resource Development Council's annual conference in 2008 perhaps best express his approach to oil exploration negotiations.

"While we are often on opposite sides of offshore development issues … I sincerely believe that we all have authentic desires to work together in pursuit of the elusive middle ground that benefits everyone who has an interest in the Arctic Ocean," Itta said.

In his speech Itta talked about a resource company wanting to come to Alaska to make a big investment in a big project. The company hired a popular local leader to promote its project. The company spared no expense, explaining its project to the people and clearly wanting to be a good corporate citizen. But the people became increasingly concerned about the speed of the proposed project and the disruption that might ensue, eventually determining that they could not support what was proposed.

No, this comment is not referring to Shell on the North Slope, Itta added. It refers to an abortive attempt to conduct coalbed methane development in the Matanuska-Susitna Borough, he said. Itta had made his point: The protection of community rights and needs is not just a prerogative of North Slope villagers.

"Edward Itta's charismatic and visionary leadership will be sorely missed," wrote Gov. Bill Walker and Lt Gov. Byron Mallott in a Nov. 7 statement. "He was a great leader not only on the North Slope, but also throughout Alaska and the world. He brought recognition and a voice to the Inupiat people on a global level, and helped lead an international discussion on Arctic development."

—ALAN BAILEY

● NATURAL GAS

British Columbia closer to LNG reality

By GARY PARK

For Petroleum News

It's one of the smallest of the 20 LNG projects floated for British Columbia, but it's on the verge of giving Premier Christy Clark some of the ammunition she needs to seek re-election in May 2017 by allowing the province to enter the commercial LNG field.

The government loaded reporters on a chartered boat and a helicopter to deliver them on Nov. 4 to a "special announcement" about the Woodfibre LNG project near Squamish, a short distance north of Vancouver.

Clark and Woodfibre Chief Executive Officer Byng Giraud organized the elaborate event to announce that the privately owned company has the funding in place for a C$1.6 billion natural gas liquefaction plant which they hope will start exporting 2.1 million metric tons a year of LNG to Asia in 2020.

Not all pieces in place

But not all of the pieces are in place and not all of the neighbors or environmentalists are enthusiastic about the plan.

And Clark is far short of her campaign promise in the 2013 election to have an initial LNG plant operating by 2015 and three by 2020, opening the door to 100,000 construction jobs and C$100 billion in revenue for the province.

Woodfibre, owned by Pacific Oil & Gas, which is part of the Singapore-based RGE Group, still needs to secure natural gas feedstock from northeastern British Columbia, obtain a permit from the B.C. Oil and Gas Commission and complete engineering develop cost estimates.

Even so, Giraud said "this project is a go." Clark claimed First Nations leaders support the venture, but one community — the Squamish Nation — did not participate in the event, with Chief Ian Campbell saying "it is too early to celebrate" at a time when 25 conditions set by his community have yet to be resolved.

Two other aboriginal communities remain opposed to British Columbia's environmental approval of a pipeline to deliver gas to the liquefaction plant, expressing disappointment that the province and Woodfibre have announced the project will proceed.

Just a 'sound bite'?

Mario Canseco, vice president of public affairs for polling firm Insights West, said Clark has seized the chance to deliver a "sound bite" by claiming her government "took action and a plant is about to be built. But it's nowhere close to what she promised (for LNG)," he said.

Ed Kallio, an analyst with Calgary-based Eau Claire Energy Advisory, said the announcement was a "pretty big step" toward demonstrating that the Woodfibre board of directors was confident the elements were in place to proceed.

However, he warned that LNG economics are currently upside down, with commodity prices in Asia far below the project costs and unlikely to rise and stabilize before 2020.

Giraud countered that because Woodfibre is a private company it can "take a longer view" of its risks than big public companies which have quarterly obligations to shareholders.

My Sea to Sky, an environmental group, said the facility will damage the ocean environment and will emit about 800,000 metric tons a year of greenhouse gases, while the 60,000 metric tons of LNG aboard each tanker present a significant safety risk to nearby populations. ●

Contact Gary Park through publisher@petroleumnews.com

● ANALYSIS

Time for 'Plan B' for North Slope gas?

Walker's state-led pipeline reasonable effort in circumstances, but time to look at alternatives to LNG, gas pipeline, Heinze says

By TIM BRADNER
For Petroleum News

A former state Natural Resources Commissioner and president of a major Alaska oil and gas operating company has endorsed Gov. Bill Walker's plan for the state to continue pursuit of a large natural gas pipeline and liquefied natural gas, or LNG, project.

However, Harold Heinze, who was the senior executive at ARCO Alaska and ARCO Transportation in the 1980s and was Gov. Walter J. Hickel's DNR commissioner in the early 1990s, also believes it's time to look for a "Plan B" for alternatives for using North Slope gas if Walker's initiative proves unsuccessful.

In an interview, Heinze said that alternatives like gas-to-liquids (where natural gas is chemically converted to liquid form to be shipped through the trans-Alaska oil pipeline), direct loading and shipment by tanker of LNG made on the North Slope and even converting the existing TAPS line to carry natural gas are possibilities that should be seriously examined.

The latter case, shipment of gas through TAPS, would include a new, smaller oil pipeline built to carry crude, but one sized more efficiently for the amounts of oil likely to be produced on the slope.

Completed in 1977, TAPS currently ships about 500,000 barrels per day, a fraction of its original 1.5 to 2 million barrels per day design capacity.

"The Alaska constitution requires that we look at all alternatives for maximizing value in using state resources," Heinze said in an interview.

Walker's state LNG initiative reasonable

"Over the last few years a large-diameter gas pipeline to an LNG export terminal at tidewater in southern Alaska has been the focus of both the North Slope gas producers and the state of Alaska," Heinze said in written comments following the interview.

"After extensive engineering and project management work the producers have concluded they are unable to proceed at this time with further investment because the risks associated with the huge investments overwhelm the potential income and profit streams. No income would be generated until the entirety of the project is completed," Heinze said.


HAROLD HEINZE

Given the situation, Walker's proposal to investigate a state-led effort seems reasonable. "The state of Alaska, under Governor Walker, is proceeding to test the Asian gas market to identify potential customers interested in upstream and in the LNG plant and pipeline, thereby reducing the project risk. This is a worthy effort, to find a way forward," Heinze said.

Taiwan made hard dollar offer

"Past attempts have found potential project partners (in Asia) but failed because the state was unwilling to accept the lowered wellhead values associated with these commercial conditions," Heinze said in his comments.

In this, the former commissioner was referring to an offer made by Taiwan when he was a special advisor to Gov. Hickel and working to find market partners for Alaska gas in Asia.

Heinze developed a firm offer with Taiwan to buy North Slope royalty gas and finance the equivalent of the state's share of an LNG project, although Hickel rejected it, he said.

The offer was to buy state royalty gas for 50 cents per million British thermal units (which roughly relates to the same price per thousand cubic feet) but Hickel rejected it because 50 cents was too low, said Heinze, who presented the offer.

"Governor Hickel strongly supported sales of Alaska gas to Asia but he wasn't willing to give state gas away to get a pipeline," Heinze said in the interview. Hickel's determination to get good value for the state's gas at the wellhead is a consideration often lost in the current discussions over the Alaska LNG Project.

The state's royalty interest is the "Alaska peoples' share" of the gas and the state should make every effort to get top dollar at the wellhead, just as the producers want good value for their gas, Heinze said.

High LNG costs mean low wellhead value?

However, that could now be a challenge, given cost estimates for building the Alaska LNG Project and the outlook for continued low prices for LNG for an extended period.

Studies for the state by consulting firms like Black and Veatch show that even if gas is sold in Asia for $13 per million Btu, a price well above those prevailing, the effective wellhead value could be zero.

Internal studies by industry over several decades reached the same conclusions, Heinze said.

A low or zero wellhead value essentially means no profit in the project, which would be unacceptable to both the state and producers, Heinze said.

The biggest challenge facing Alaska LNG is the complex interaction of the multiple mega-project components and the sheer scale and size of the whole project when compared with many competing projects, which are right at tidewater and don't need an 800-mile new pipeline. The current cost is now estimated at $45 billion.

Gas to liquids an option?

But if Alaska LNG isn't workable anytime soon, what might be? There are possibilities that could see North Slope gas marketed without building a new pipeline. One is gas-to-liquids.

"Given the low flow in TAPS and significant breakthrough technologies (for chemical conversions) it may be attractive to build smaller plants (than the LNG Project) to convert gas molecules into longer hydrocarbons molecules," which would be liquids that could be shipped in TAPS.

"New combinations of catalysts and high-efficiency 'nano' (small scale) reactors could produce synthetic crude oils, diluent for heavy oil and enhanced recovery fluids," the latter two which could aid in production of new conventional oil.

A diluent is a liquid used to thin a thick fluid, like heavy oil, that is too viscous to ship through a pipeline on its own. Having such fluids available is ultimately essential if the huge untapped North Slope heavy oil resources are to be developed.

"A meaningful-sized gas-to-liquids plant could be one-tenth previously envisioned (for gas marketed as LNG) and this would greatly reduce the investment exposure and also provide a decade of follow-on construction using an Alaskan workforce," as the GTL project is incrementally expanded with additional plants on the Slope, Heinze said.

Gas-to-liquids has key advantages over a conventional gas pipeline and LNG project. Two are in using the existing TAPS and eliminating a large LNG plant at the southern end of a new gas pipeline (the LNG plant constitutes about half the cost of the total LNG project).

A third advantage is that a large North Slope plant to remove the 12 percent carbon dioxide in Prudhoe Bay gas is also unneeded, as this function is essentially performed by the gas-to-liquids plant. "Gas-to-liquids processes like carbon dioxide, where an LNG plant cannot tolerate it," which requires its removal, Heinze said.

Direct shipping of LNG from Slope?

There are other ways North Slope gas could be marketed, however. For years people have asked if an LNG project at the North Slope might be feasible. Until recently, the presence of heavy, multi-year ice in the Beaufort Sea made direct shipping of LNG doubtful, but this has changed, Heinze said.

"With the Arctic becoming naturally free of ice over at least the next 20 years, the economics of direct-shipment of LNG should be attractive. Saving the 800-mile pipeline cost is a huge advantage compared with a minimal increase in ice capable tanker costs," Heinze said in his comments.

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ANS GAS

"A plant comparable to the existing Cook Inlet plant would be sufficiently large to achieve the economies of scale at a considerably reduced investment risk," he said. Once in operation, the LNG plant could be incrementally expanded as the volume of shipments grows.

When he was with ARCO and also as a consultant, Heinze was involved in scoping studies of an Arctic LNG transportation system, which envisioned a system of icebreaking LNG tankers, assisted by icebreakers, delivering LNG to storage facilities in the Aleutians where conventional LNG tankers would take delivery.

One conclusion of the study was that the presence of multi-year ice presented operational performance risks, and that icebreaking or ice-strengthened LNG tankers had not yet been demonstrated.

However, that was over 30 years ago. Now the bulk of the ice in the Beaufort Sea is relatively thin one-year ice, a result of climate change, which makes navigation easier and tanker performance predictable.

There is also more experience with Arctic shipping of oil and gas, including LNG, although most of this is on Russia's Northern Sea Route.

One of the problems that confronts Arctic loading of LNG is the shallow depth of the near-shore Beaufort Sea along the northern coast including Prudhoe Bay. If an LNG plant were built onshore a technically challenging cryogenic pipeline several miles out to an offshore loading facility would be needed. In years past there were concerns about how the moving polar icepack would affect an offshore facility and how LNG vessels could be reliably managed in heavy ice.

Climate change again has changed some of that thinking. Even in late winter most of the polar ice is thinner, one-year ice. Also, BP (and now Hilcorp) has safely operated the Northstar production island six miles offshore Prudhoe Bay for 15 years and has demonstrated techniques to manage ice encroachment.

Unlike other offshore artificial gravel production islands like Caelus Energy's Oooguruk and Eni's Nikaitchuq, which are protected from moving pack ice by natural barrier islands, Northstar is in a location fully exposed to the winter icepack.

Northstar is also located in about 40 feet of water, which with some dredging might allow access by medium-sized LNG vessels. A possibility is that if the Northstar field is depleted its gravel island might be incorporated for LNG loading.

A point Heinze made in the interview is that these are engineering problems that could be defined and managed within a changing Arctic environment, and that while LNG ship operations in the Arctic would be costly, those costs pale in comparison with building 800 miles of 42-inch pipe south across Alaska.

Ship gas through TAPS?

The third, which seems most radical at first thought, but commonsense at a more basic level, is converting TAPS to a gas pipeline. There's fundamentally no technical barrier to this, Heinze says, but North Slope oil must still be shipped so this project must be done in connection with building a new, smaller oil pipeline.

"The time has come to address the need for a new oil line that can continue to operate long into the future at rates one fifth of the existing pipeline's capacity," Heinze said in written comments.

At the current rate of oil production decline, TAPS, as it is now configured, may not be economical to operate by the late 2020s.

"A new 20-inch or 24-inch high pressure (pipeline) could use a new universal mono-pipe column support design (in lieu of the current, expensive vertical supports on TAPS) and could use the existing right-of-way, pump stations, terminal and control center," Heinze wrote.

"Once the new line is in service the 48-inch pipe could be converted to low-pressure gas service and with new compression stations it could carry as much as 1 billion cubic feet per day to an LNG plant," which would be built in Valdez.

Heinze has unique perspective

Heinze comes at these questions from a unique perspective, incorporating both creativity and analytics. As a former state DNR commissioner he understands the state's constitutional mandate to maximize the value of state-owned resources and in this case, the royalty share of North Slope oil and gas.

As a former ARCO president, whose Alaska industry career actually started in 1969 when the Slope oil discoveries were confirmed, Heinze has inside knowledge of how industry works and the development challenges of Alaska and the North Slope.

Heinze was also, in recent years, executive director of the Alaska Natural Gas Development Authority, or ANGDA, a kind of predecessor of the state-owned Alaska Gasline Development Corp., or AGDC.-

ANGDA, under Heinze, focused mostly on problems related to getting gas to Alaska communities, such as through lateral lines built off a larger gas pipeline and the use of propane container-sized tanks for waterborne delivery. AGDC, in contrast, is focused on building the entire $45 billion Alaska LNG Project to export North Slope gas. ●

Contact Tim Bradner at timbradner@gmail.com

● FINANCE & ECONOMY

M&As rise due to price, credit upswings

EIA reports 93 E&P mergers and acquisitions in third quarter averaging $179 million each, largest per deal average since 2014

By KAY CASHMAN
Petroleum News

The U.S. Energy Information Administration reported Nov. 2 that exploration and production companies in the United States are increasing merger and acquisition spending as stable crude oil prices and improved credit conditions in recent months allowed companies to purchase assets or entire companies.

The increase in M&A spending "suggests improved investor sentiment in the oil industry," EIA said.

Eye on prices

The deals are concentrated in the Permian region, the area where the most drilling rigs have been deployed recently. The Permian is also the only onshore area where production is expected to increase in October and November, the agency, which supplies independent statistics and analysis, reported.

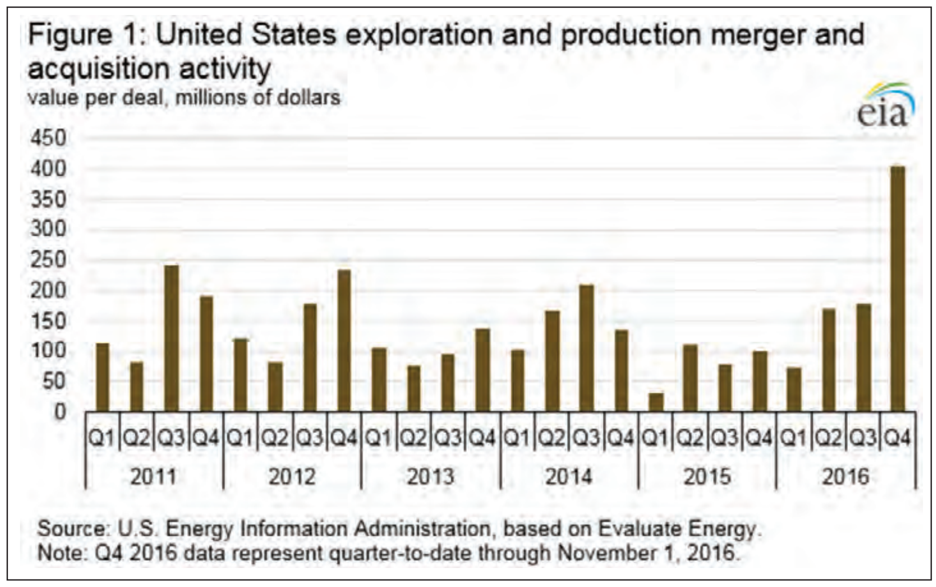
Among others, this sentiment is shared by the chief financial officer of the second largest public oil company in the world. On Nov. 1 in a quarterly earnings conference call, Simon Henry, Royal Dutch Shell's chief financial officer, referred to the Permian as "the hottest properties on earth at the moment … where $50,000 an acre appears to be the going rate."

The increase in M&A spending "suggests improved investor sentiment in the oil industry," EIA said.

The second half of this year through Nov. 1 "already has more M&A spending than the first half of 2016, but on fewer deals," EIA said. "The 93 M&A announcements in the third quarter of 2016 totaled $16.6 billion, for an average of $179 million per deal, the largest per deal average since the third quarter of 2014," the agency said.

Of the 71 deals valued at $1 billion or more since 2011, nine occurred in the third and fourth quarters of this year, as compared with only four in all of 2015.

Six of the larger deals involved assets in the Permian Basin, which accounted for more than half the deal value in the fourth quarter, which saw a total of 28 deals.



EIA listed several recent notable M&A deals:

• SM Energy said Sept. 1 it acquired 24,783 net Permian Basin acres in Howard County, Texas, in its $980 million purchase of Rock Oil Holdings;

• EOG Resources said Sept. 6 it will acquire Yates Petroleum for $2.5 billion, doubling its acreage in the Delaware Basin, part of the Permian Basin area;

• RSP Permian said Oct. 13 it will acquire Silver Hill Energy Partners and Silver Hill E&P for $2.4 billion;

• SM Energy said Oct. 18 it will sell $785 million in Williston Basin assets in the Bakken region and spend $1.6 billion through cash and shares to acquire 35,700 net Permian Basin acres in the Midland Basin from QStar LLC.

More Permian deals have since gone down, including Occidental Petroleum's Oct. 31 acquisition of 35,000 net-acre Permian interests in a $2 billion deal with multiple, undisclosed parties at an average price per acre of $42,000.

Rig count up in Permian

Continued increases in the U.S. rig count "suggest companies are beginning to invest capital in E&P projects. Most increases in rigs over the past six months occurred in the Permian, which now holds nearly as many active rigs as the rest of the United States combined, including both on- and offshore rigs," EIA said.

The agency's Oct. 15 monthly Drilling Productivity Report can be found at www.eia.gov/petroleum/drilling/#tabs-summary-2.

Two related factors likely contributing to an increase in M&As are an increase in crude oil prices and a reduction in credit spreads. On Oct. 19 West Texas Intermediate crude oil prices closed at $51.60 per barrel, the highest level since July 2015 and nearly twice the recent low point of $26.21 per barrel reached in February 2016.

Since Oct. 19 prices have fallen by about $6 a barrel, but remain well above early-year lows.

The "option-adjusted spread of high yield energy bonds to U.S. Treasury bonds, a measure of default risk, declined since oil prices bottomed and is now at the same level it was in November 2014, when oil prices were above $70 a barrel," the agency said.

Credit spreads declined nearly 50 percent compared with October 2015, when prices were in the same $45-$50 range.

On Nov. 1 … Simon Henry, Royal Dutch Shell's chief financial officer, referred to the Permian as "the hottest properties on earth at the moment … where $50,000 an acre appears to be the going rate."

"Improved credit conditions in the energy industry lowers the cost of borrowing and allows many companies to issue equity to increase liquidity in their balance sheets or make opportunistic purchases," EIA said.

Companies that defaulted on a bond or were upgraded to investment grade standing are removed from the Bloomberg High Yield Corporate Bond Index over time.

Continued M&A and investment could lead to an increase in Lower 48 crude oil production, consistent with EIA forecasts that increased production will occur in the second quarter of 2017. However, this production forecast is predicated on the WTI price forecast in the EIA's October Short-Term Energy Outlook, which is highly uncertain. Significant divergence of actual prices from the projected path of $55 per barrel (Brent) in fourth quarter 2017 "could change the pace of new-well drilling, which would in turn affect the production forecast," EIA said. ●

Contact Kay Cashman at publisher@petroleumnews.com

● UTILITIES

What now for Railbelt electricity?

Various initiatives head toward some major decision points over how the transmission grid should be managed, operated and regulated

By ALAN BAILEY
Petroleum News

With Homer Electric Association making moves to cease being regulated by the Regulatory Commission of Alaska while the commission itself continues to monitor efforts by the six Alaska Railbelt power utilities to operate the Railbelt power transmission grid in a more unified manner, it is perhaps time to step back and take a holistic view of the various issues at stake and potential ways forward.

The ultimate objective for the various entities involved in the Railbelt power system is, or should be, to supply power to consumers at the least cost while maintaining an acceptable level of supply reliability. There are also issues relating to the connection of new renewable energy sources to the system, to reduce carbon emissions and diversify the sources of power — proponents of renewable energy argue that these energy sources can provide stable electricity pricing, decoupled from volatile fossil fuel costs.

A single machine

The Railbelt power generation, transmission and distribution system operates as a single, integrated machine, with electrical voltage and frequency having to be carefully synchronized along its entire length, from the southern Kenai Peninsula, north to the Fairbanks area. But, because of the way the system has evolved, different sectors of the system, including the various sectors of the transmission grid, are owned and operated by different utilities. The utilities have worked together successfully over the years to maintain required electrical synchronization and to use their power generation assets to back each other up, supplying each other with power, as necessary.

The interconnected nature and multi-utility use of the transmission grid, a natural monopoly in itself, complicates the regulatory issues.

On the other hand, the aging transmission grid does suffer from flaws. In particular, there are just single transmission lines with relatively modest throughput capacities connecting the highly populated region of Anchorage and the Matanuska-Susitna Borough to Fairbanks in the north, and to the Kenai Peninsula in the south. Utilities at the far ends of these lengthy "extension cords" worry about having sufficient local generation capacity, should one of the lines fail.

The preponderance of power on the grid comes from various natural gas fueled power stations in Southcentral Alaska. The cheapest source of power is the Bradley Lake hydropower facility in the southern Kenai Peninsula. Fairbanks-based utility Golden Valley Electric Association generates power from coal, diesel and naphtha power plants. Three wind farms also supply some power into the grid.

Natural monopolies

As natural monopolies, all of the utilities, at the time of writing, are regulated by the Regulatory Commission of Alaska. A natural monopoly is a company that is a monopoly by nature of its business. It makes little sense, for example, to build multiple power infrastructures in a region, to enable multiple, competing utilities to operate. But, in the absence of competition, there is no means of determining a market price for electricity. Hence the argument for government regulation to ensure fair pricing typically based on the recovery by a utility of its costs plus some reasonable rate of return on its investments. Moreover, in a monopolistic situation, dissatisfied consumers do not have the option of transferring to another service provider — instead, the government regulator provides a vehicle for ensuring quality of service.

A common counterargument to utility regulation is that the regulation stifles innovation by placing the utilities in a straight jacket of "cost plus" pricing, with little incentive to improve profitability through improved efficiency, for example. And the Alaska electricity utilities are cooperatives governed by member-elected boards, with profits going to the membership.

HEA deregulation ballot

Homer Electric Association has been conducting an election of its members to determine whether it will deregulate from the RCA. The deregulation vote only applies to HEA's power distribution system on the Kenai Peninsula. But, if the vote passes, another vote will deregulate the utility's generation and transmission assets.

HEA argues that deregulation will enable heightened flexibility and efficiency in modifying and upgrading its business while also eliminating the cost involved in RCA hearings. The utility says that ratepayers dissatisfied with HEA's services will be able to complain to the HEA board and ultimately to make appeal through Alaska Superior Court. Critics of the deregulation initiative argue that the utility board is too embedded with the utility management to be impartial, and that court appeals would be lengthy and expensive.

An interconnected grid

The interconnected nature and multi-utility use of the transmission grid, a natural monopoly in itself, complicates the regulatory issues. There is continuing debate over the extent to which the transmission grid should be managed and operated as a single entity, rather than by six independent utilities, and what authority, if any, the RCA has over this question. The state Legislature tasked RCA with investigating the grid unification question and in June 2015 the commission issued an opinion that unification should proceed. Since then, RCA has been overseeing voluntary efforts by the utilities to move towards a more unified approach.

Three key issues relating to unification moves are the desire to make maximum use of the cheapest power generation available across the grid, the need for a mechanism for investing in transmission grid upgrades that will benefit multiple utilities and the establishment of a fair mechanism for non-utility power providers to connect to the grid. Another important issue is the establishment of a consistent set of reliability standards for the grid as a whole — at present there are two sets of standards.

If the RCA becomes dissatisfied with progress towards the voluntary unifying efforts, the agency could presumably recommend new legislation clarifying the commission's authority over the various unification issues.

Economic dispatch

In terms of making best use of cheap power, the utilities regularly exchange power under arrangements known as economy sales. However, the holy grail of generation efficiency is a system called economic dispatch, in which the cheapest sources of power are dispatched as much as possible across the grid on a continuous basis. The utilities have been conducting computer modeling, simulating the potential benefits of economic dispatch in the Railbelt, but they have yet to announce any results from this effort.

Meanwhile, two of the utilities, Chugach Electric Association and Municipal Light & Power, are establishing economic dispatch in the Anchorage area, pooling the use of their new high-efficiency gas fired plants in Anchorage. Matanuska Electric Association has said that it is going to join this power pool, thus putting MEA's new power plant at Eklutna, north of Anchorage, into the power generation mix. Questions remain over how, whether or when this Southcentral "tight power pool" might extend to other parts of the Railbelt, especially given the limitations of the single transmission interties to the north and south.

System operator

One key issue relating to a future economic dispatch system is the question of having an operator entity, known as a unified or independent system operator, to oversee the grid, adjudicating grid upgrades, setting rules for grid connection and operating the dispatch of power. The independence or otherwise of this entity from the utilities operating on the grid has become a contentious issue, with the utilities arguing that their expertise is needed on

see RAILBELT ELECTRICITY page 14

● EXPLORATION & PRODUCTION

Hilcorp permitting new Milne Point pad

Company proposing new pad, road and 44-well development program in western end of unit; work to begin this winter

By ERIC LIDJI

For Petroleum News

Hilcorp Alaska LLC is permitting a new drilling pad at the Milne Point unit.

The local subsidiary of the Texas-based independent wants to drill as many as 44 wells at a new Moose Pad at the North Slope unit, according to a recent plan of operations.

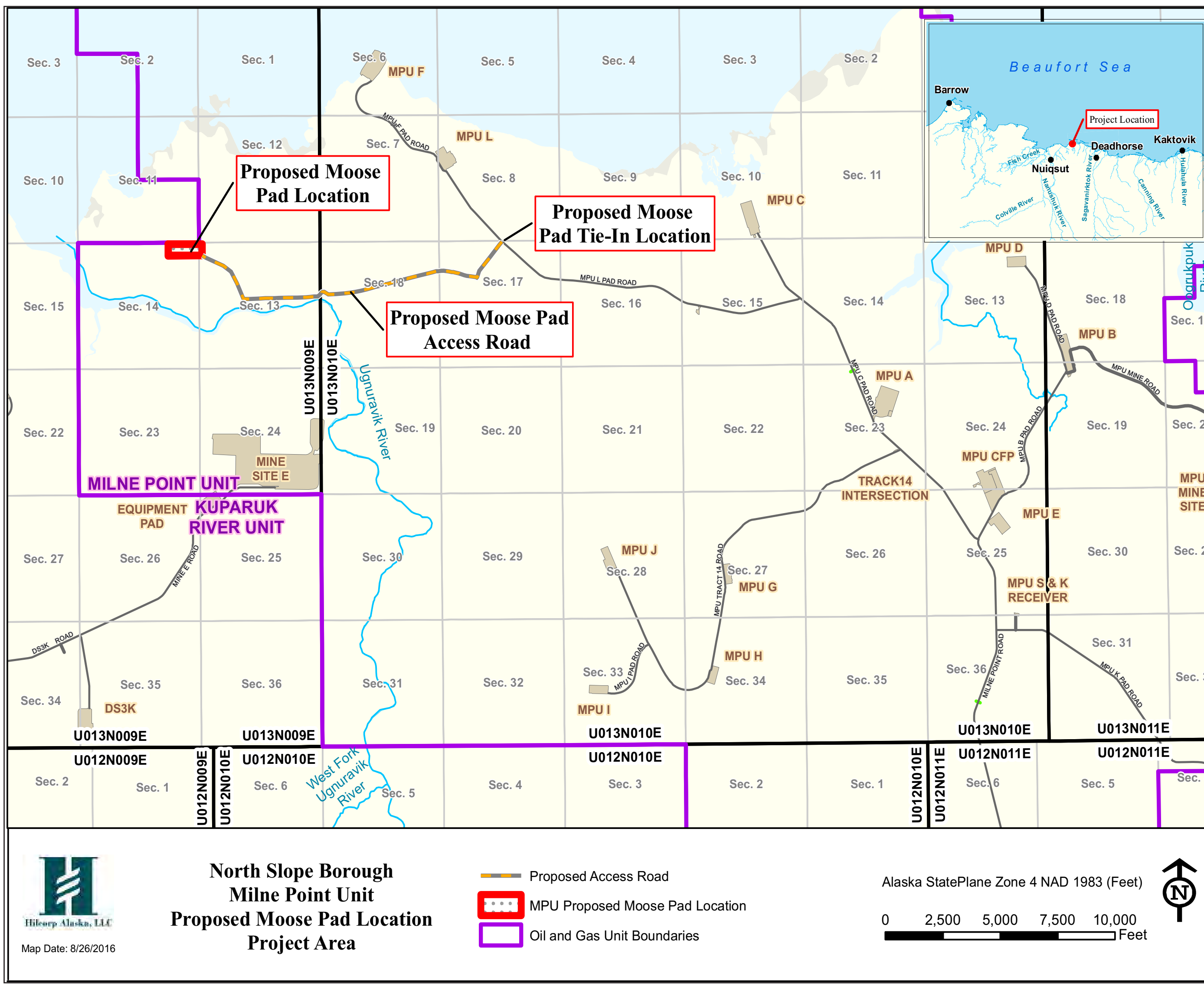
The project would include a 17.22-acre gravel pad, a 2.83-mile gravel road, expanded infrastructure and as many as 44 development wells to access some seven square miles of undeveloped oil reserves in the western half of the unit, according to the company.

Under a timeline included with the permitting application, Hilcorp said it would begin road and pad construction and power installation this winter, install pipelines and facilities the following winter and start a drilling program as early as September 2018.

The proposed Moose pad would initially target oil in the Schrader Bluff formation on leases ADL 25514, ADL 25515 and ADL 25509. From the start, Hilcorp plans to drill production wells for normal recovery and injection wells for enhanced oil recovery.

The Moose Pad project would include a new road branching from the existing

see NEW PAD page 30



continued from page 12

RAILBELT ELECTRICITY

the system operator board while independent power producers want to see an independent board that can ensure a level playing field for all would-be grid users.

In 2011 the Railbelt utilities formed a company called the Alaska Railbelt Cooperative Transmission and Electric Co., or ARCTEC, to try to move forward on the system operator concept, but only four of the six Railbelt utilities are ARCTEC members. However, all of the utilities have been engaged in negotiations aimed at unifying the current transmission grid reliability standards.

Transmission company

One solution that has been proposed for the issues surrounding investment in transmission grid upgrades is the formation of a transmission company, or transco, to own or lease, and operate, the various components of the grid infrastructure. The concept is that, as a private company, the transco could attract private investment in the grid, earning a return on investment through the rates charged for shipping power across the grid. And, by charging a consistent fee for power transmission, rather than having individual utilities pancaking their own individual fees onto the electrons traversing the grid cabling, transmission rates would cease to be an obstacle to the flexible use of the most appropriate power sources, proponents of grid unification say.

But the system operator, not the transco, would adjudicate over how the transmission grid is operated and what upgrades should be made.

The Railbelt utilities have been working with a transmission company from the Lower 48 to develop a plan for transco formation. The results of that endeavor are expected around the end of this year. Some people have expressed concern about the possibility of a single company having a monopoly over transmission grid construction projects.

Investment priorities

And questions remain over how much investment in transmission grid upgrades can actually be afforded or justified. There is also contention over whether an upsurge in construction of new power generation in recent years has resulted in more generation than is actually needed. Although modern new generation plants have reduced power generation fuel consumption, the key parameter in Railbelt electricity costs, some utility electricity rates have increased significantly, to enable the recovery of the cost of generation facility construction.

Utilities have said that they have had to replace inefficient, aging and increasingly unreliable power generation systems, and that some excess capacity is required to ensure power supply reliability. Some people, on the other hand, have argued that some of the money spent on new generation could have better been deployed on upgrades to the transmission network, to enable more efficient use of power generation facilities.

Siting authority

Another tricky issue revolves around the siting of new power generation, and whether the locations where generation facilities pump electrons into the grid best match the overall needs of electricity consumers — if a generation facility at one location swamps the capacity of the local transmission grid, that can impede the flow of power from some other facility. There have been discussions over whether, in fact, RCA should have generation siting authority, to ensure that locations of new generation capacity best meet the needs of Railbelt electricity consumers as a whole. And should the commission also have regulatory authority over transmission grid reliability?

The questions being debated and solutions being put forward for the future of the electrical system in the Railbelt are of great importance to the future economic well being of Railbelt residents and businesses. Changes to the system will impact the economy of the Railbelt for years to come. ●

Contact Alan Bailey at abailey@petroleumnews.com

NORTH OF 60 MINING news

page 17 Coventry begins scoping study for high-grade copper mine in Alaska

www.MiningNewsNorth.com *The weekly mining newspaper for Alaska and Canada's North* Week of November 13, 2016

NEWS NUGGETS

Compiled by Shane Lasley

CONSTANTINE METAL RESOURCES LTD.

Liz Cornejo, exploration manager, Constantine Metal Resources, hikes in to check on drilling at Cap, a prospect located near the main deposit at the Palmer volcanogenic massive sulfide property in Southeast Alaska.

Constantine funds Palmer JV with Ontario gold assets sale

Constantine Metal Resources Ltd. Nov. 7 said it has entered an agreement to sell a portion of its gold properties in Ontario for C$4.5 million, funds that it can apply to furthering exploration at the Palmer project near Haines, Alaska. "Upon closing the transaction Constantine will have more than $5 million in cash to co-fund the exploration development of our advanced flagship Palmer copper-zinc-silver-gold project in Southeast Alaska," said Constantine Chairman Wayne Livingstone. Lake Shore Gold Corp., a division of Tahoe Resources Inc., has agreed to buy Horseshoe, Four Corners and the Meunier, mineral claims adjacent to Lake Shore's Fenn-Gib gold project, from Constantine. In addition to receiving C$4.5 million in cash, Constantine will retain a 1 percent net smelter return royalty on the Horseshoe claims, as well as the right of first refusal on the NSR associated with the underlying property agreement. The agreement does not include Constantine's Munro Croesus, a historical bonanza grade gold property in the area. As part of the agreement, Lake Shore will transfer full ownership of a patented mining claim contiguous to Munro-Croesus to Constantine. Lake Shore will hold a 1.5 percent NSR on this claim. "We continue to control significant landholdings in Timmins, including the past producing Munro Croesus Gold Property, and retain exposure to the Fenn-Gib project through our NSR royalty rights on the properties being sold," Livingstone added. At the onset of 2013, Dowa Metals & Mining Co. Ltd. and Constantine inked a deal that provides the Tokyo-based smelting and mining company with the opportunity to earn a 49 percent stake in the Palmer project by investing US$22 million over a four-year span. Dowa, which has invested roughly US$19.5 million of this earn-in requirement, intends to earn its 49 percent stake in the property by the end of 2016. Any unspent funds at that time will be deposited in an account to cover initial joint venture expenditures. Following formation of the JV and use of the carry-over funds, Constantine and Dowa will fund the project in proportion to their ownership interest.

Redstar completes Unga drilling; readies for bigger 2017 program

Redstar Gold Corp. Nov. 7 reported the completion of a 1,505-meter drill program at its Unga gold project in Southwest Alaska. Spaced over a roughly 750-meter stretch of the 2,000-meter-long Shumagin gold zone, the seven holes drilled during this program targeted the lateral and vertical expansion potential of high-grade gold mineralization at various structural elevations. The first two holes, 16SH019 and 16SH020, tested the

see **NEWS NUGGETS** *page 18*

THE ROYAL MINT

After rocketing nearly US$40 per ounce in overnight trading following Donald Trump's successful bid for the U.S. presidency, gold has settled to pre-election levels.

MARKETS

Landslide win for gold

Experts are calling for Trump's win to push gold to nearly US$1,400/oz

By SHANE LASLEY
Mining News

In the final stretch of the United States presidential election, it became increasingly apparent that the system was rigged in favor of gold. Hillary Clinton, who was the odds-on favorite to win the White House throughout the general election, carries the baggage of perceived criminal misconduct associated with the Clinton Foundation and her tenure as Secretary of State. Donald Trump, on the other hand, is a political outsider running on a platform of shaking up the status quo in Washington D.C.

DONALD TRUMP

Whichever way the election would have gone, a perceived coming instability in the Oval Office was expected by many analysts to favor gold and other safe-haven assets.

"Both major party candidates are likely to hurt confidence in the U.S. economy and solvency; both will be good for gold," Rick Rule, president and CEO, Sprott US Holdings Inc. told Kitco News earlier this year.

"Gold moves on fear, neither candidate inspires confidence," the renowned natural resource investor added.

As it turned out, Trump pulled a stunning upset to become the 45th President of the United States – a win that shook financial markets and pushed gold up sharply in overnight trading.

"Equity markets are down notably in Asian and early European trading. Gold has, by contrast, increased, outperforming other assets, including other safe havens. It is currently trading at over US$1,300 per ounce compared with US$1,275/oz before the vote counting began," Juan Carlos Artigas, director of investment research, World Gold Council, said before markets opened on Nov. 9.

Brexit 2.0

The price of gold has already benefitted from one safe-haven boost this year when the British passed Brexit, a referendum for Britain to exit the European Union.

Gold had been flirting with US$1,300/oz price levels in the two months leading up to the Brexit referendum. It wasn't until mid-June, when it became clear that the referendum for Britain to exit the European Union might actually have the votes to pass, that gold took a one-day peek above the US$1,300 threshold.

As voters went to cast their votes on June 23, markets were unsure which way the Brexit referendum would go and gold had retreated to US$1,262/oz. By late evening in the United States, however, it became clear that a majority of British voters wanted to leave the European Union and the price of an ounce of gold shot up as much as US$100 in overnight trading and opened the next morning at US$1,319/oz.

In the two weeks after Brits cast their votes to leave the European Union, gold prices continued to rise, briefly breaking through US$1,350 on July 5.

Many pundits draw comparisons between the anti-establishment sentiment that led to Brits' desire to break away from the European bloc and the movement in that led to Trump's successful bid for President of the United States.

While experts will continue to discuss whether the Trump presidency is Brexit 2.0, the initial effect on gold was similar.

As it became increasingly apparent that Trump would win his bid for the White House, gold rose sharply in Asian markets, peaking at US$1,338/oz overnight in the U.S.

"It's exactly like Brexit," gold analyst and New York Times bestselling author Jim Rickards said in an

see **WIN FOR GOLD** *page 18*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● EXPLORATION

Coventry scoping Caribou Dome

Australia-based junior takes first look at viability of developing a mine at this high-grade Southcentral Alaska copper deposit

By SHANE LASLEY

Mining News

Considering the success it has had confirming and expanding the zones of high-grade copper at Caribou Dome over the past two years, Coventry Resources Inc. has decided to initiate a scoping-level study to investigate the potential of developing this Southcentral Alaska project.

In a Nov. 8 project update, the Australia-based exploration company said the study, similar to a preliminary economic assessment, will assess the potential of developing a low-cost open-pit mine at this road-accessible project just north of the Denali Highway, about mid-way between Paxson and Cantwell.

A positive result from the scoping study would go a long way to achieving the company's top priority for this sediment-hosted copper deposit.

"Our first objective is to demonstrate that an economically viable mining operation can be developed at the project," Coventry President and CEO Mike Haynes told Mining News earlier this year.

Historical high-grade

The high-grade copper potential of Caribou Dome has been known for some 50 years and been considered a potential high-grade underground copper mine since the late 1960s.

Upon cutting a deal to acquire an 80 percent stake in Caribou Dome early in 2015, Coventry began poring over historical exploration data collected at the project, including results from 95 surface and underground drill holes completed primarily in the 1960s.

Highlights from this historical work include:

•18.1 meters averaging 9.34 percent copper from a depth of 22.7 meters;

•18.4 meters averaging 6.25 percent copper from a depth of 31.4 meters;

•15.4 meters averaging 7.01 percent copper from underground; and

•11 meters averaging 8.2 percent copper from a depth of 29 meters.

Most of the historical drilling focused on three lenses of high-grade copper – four, five and six – with the idea that they would support a small underground mine.

Based on this drilling, historical reserve of 550,000 short tons averaging 5.84 percent copper was calculated for the Caribou Dome deposit in 1970.

Coventry has been confirming and expanding this outcropping copper deposit, with more than 10,500 meters of drilling completed over the past two years.

Highlights from the 22 holes drilled at and around the Caribou Copper deposit in 2015 include:

•14.1 meters averaging 9.9 percent copper from 134.6 meters;

•7 meters averaging 6.8 percent copper from 35.1 meters; and

•3.5 meters averaging 9.3 percent copper from 72.9 meters.

Last year's program also included ground induced polarization geophysical surveys centered on the known mineralization; and extensive soil sampling program that began to unveil the larger potential of the property.

Confirming Caribou Dome

This year, Coventry drilled another 22 holes aimed at increasing the resource base; and improving the understanding of the grade, distribution and thickness of shallow copper mineralization with the idea of developing an open-pit mine at Caribou Dome.

The company recently reported results from five holes targeting shallow mineralization in the heart of the high-grade deposit.

Highlights from this work include:

•11.4 meters of 6.7 percent copper from a depth of 70.2 meters;

•5.7 meters of 7.3 percent copper from 92.4 meters;

•3.5 meters of 1.5 percent copper from 49.2 meters; and

•4 meters of 6.4 percent copper from 156.1 meters.

Coventry says this drilling provides a clearer understanding of the controls on the distribution of mineralization at the heart of the Caribou Dome deposit, which will facilitate more reliable modelling of a potential open-pit starter mine there.

This year's drilling also extended the deposit more than 120 meters to the northeast.

Significant results from recent drilling in this area include:

•4.3 meters of 5.2 percent copper from 220.5 meters;

•1.1 meters of 5.5 percent copper from 532.1 meters; and

•2.9 meters of 2.4 percent copper from 193.4 meters.

The company was unable to ideally position holes in this area due to difficult access and says the mineralization is closer to the surface than indicated by the drill depths due to the angle of the holes relative to the topography.

Confident in the open-pit mining potential at Caribou Dome, Coventry brought a mining engineer on-site to collect the data needed to calculate the capital and operating costs of such a mine. The results of this work will be included in the scoping study, slated for completion early in 2017.

Broader potential

In addition to demonstrating the potential viability of developing a low-cost mine at the known Caribou Dome deposit, Coventry is investigating the broader potential it sees at this easily accessible high-grade property.

"(W)e believe there is potential to discover additional mineralization from one end of the project to the other, over 18 kilometers (11 miles) of strike, as well as at depth," explained Haynes. "We need to, and have commenced, systematically exploring the entire project area. We are undertaking this work in the knowledge that analogous sediment-hosted copper deposits around the world can be both very large (from a tonnage perspective) as well as very-high grade."

A soil sampling program aimed at testing this potential revealed an extensive copper-in-soil anomaly over the entire 7,000 meters

see CARIBOU DOME page 18

NORTHERN NEIGHBORS

Compiled by Shane Lasley

Dominion decides to move HQ to Calgary

Dominion Diamond Corp. Nov. 7 announced plans to relocate its corporate office from Yellowknife, Northwest Territories to Calgary, Alberta. This relocation will impact roughly 100 of the company's Northwest Territories-based employees. The majority of its workforce, however, will continue to be employed in the Northwest Territories. In addition to its workforce at the Ekati mine site, Dominion will maintain an office in Yellowknife for certain key positions. The company's board of directors and senior management decided to make the move to reduce costs and support the long-term viability of the company. "Although this was not an easy decision, it is necessary to support the long-term strength and viability of our operations. The Ekati mine is a pillar of the NWT economy, and this cost reduction effort will allow us to continue to provide northern employment opportunities and benefits well into the future. I can assure our northern partners that we remain committed to the people and communities of the North and will continue to set industry standards for northern and Aboriginal employment and sustainable development," explained Dominion Diamond CEO Brendan Bell. The move, projected to be completed by mid-2017, is expected to save the company approximately C$19 million annually.

Comstock expands VG zone at Yukon project

Comstock Metals Ltd. Nov. 8 reported broad gold intercepts from rotary air blast drilling at its QV property in the White Gold district of the Yukon. The best hole from latest batch of drill results, 16QVRAB017, cut 12.19 meters averaging 5.53 grams per ton gold from a depth of 83.82 meters, within a wider interval of 57.91 meters averaging 1.89 g/t. The broader intercept has slightly higher grades than the inferred resource at the property's VG zone – 4.39 million metric tons averaging 1.65 g/t (230,000 ounces) gold. The company said hole 16QVRAB017 demonstrates that the VG zone is open to the west. Hole 16QVRAB018, drilled to the north from the same location as 16QVRAB017, cut 18.29 meters averaging 1.14 g/t gold.Hole16QVRAB014, drilled to the east of the VG zone, cut 10.67 meters averaging 1.65 g/t gold starting 16.76 meters below surface, within a wider interval of 64.01 meters averaging 0.52 g/t gold. This large intercept is considered important as it correlates with a resistivity low, demonstrating strong potential for extending the VG deposit to the northeast. Comstock said it has completed 2,300 meters of RAB drilling in 32 holes since late August. The company reported results from the first 12 holes earlier this year and assays from the balance of the program, which includes drilling at two other targets on the QV property, are pending.

Hope Bay gold mine on track for early '17 start

TMAC Resources Inc. Nov. 3 said its Hope Bay gold mine in Nunavut remains on schedule to begin production early in 2017. "We remain on track and essentially on budget with our progress to advance the Hope Bay Project towards commercial production in early 2017," TMAC CEO Catharine Farrow said. "As of this week, we are approximately 89 percent complete with construction and assembly and have spent 88 percent of the amount estimated in the 'path to pro-

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Contact North of 60 Mining News:

Publisher: Shane Lasley • e-mail: publisher@MiningNewsNorth.com
Phone: 907.229.6289 • Fax: 907.522.9583

Petroleum news

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Shane Lasley	PUBLISHER & NEWS EDITOR
Rose Ragsdale	CONTRIBUTING EDITOR
Mary Mack	CEO & GENERAL MANAGER
Susan Crane	ADVERTISING DIRECTOR
Heather Yates	BOOKKEEPER
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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

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NEWS NUGGETS

expansion potential of high-grade vein-breccia mineralization below and to the southwest of the main are of the Shumagin zone. Both holes tapped the targeted structure, indicating the expansion potential of the high-grade gold mineralization there. The balance of the holes were drilled along two vertical fans that targeted the down-dip extension of exposed breccia bodies along the Bunker Hill gold zone, where historical drilling has encountered high-grade gold intercepts. Redstar reports that all five holes cut these two breccia veins, indicating the depth expansion potential along Bunker Hill. Assay results from this drilling are expected by December. In the meantime, Redstar is planning for a much bigger drill program at Unga for next spring. This program is expected to continue confirmation and expansion drilling at the Shumagin zone, as well as test other highly prospective exploration targets along the Shumagin trend, a roughly six-mile structural corridor that hosts the Shumagin zone. Apollo-Sitka, a second six-mile structural corridor that is parallel to and about 3,000 meters south of the Shumagin trend, hosts additional targets being considered for drilling next year. Redstar would also like to take a preliminary look at the Centennial gold zone, a prospect on nearby Popof Island, and Zachary Bay, a porphyry copper prospect some 3,500 meters north of the Shumagin trend. After a recent exercise of roughly 35.9 million warrants priced at C10 cents each, Redstar is already well-financed for carrying out its 2017 exploration. Including the C$3.6 million of new cash from this financing Redstar had roughly C$7.5 million in the bank at the end of October. The company is now also focused on ensuring a batch of C12 warrants due to expire on Nov. 27 are fully exercised, which would add another C$3.3 million to the treasury. Other good news for Redstar is its listing on the OTCQB Venture Market in the United States has been upgraded, which should improve the share liquidity and broaden the company's shareholder base and visibility in the U.S.

Northern Empire prioritizes drill targets at Richardson

Northern Empire Resources Corp. Nov. 7 provided results from the summer exploration program at its Richardson gold project in Interior Alaska. This program included 277 line-kilometers of ground magnetic geophysical surveys and the collection of 1,297 geochemical samples. Northern Empire said the geophysical work confirmed the Richardson lineament, a mineralized structural corridor at Richardson, and identified several north-northeast structures that the company has recently identified as possible controls of high-grade mineralization. Chip sampling along one of these structures returned 32 meters averaging 5.73 grams per metric ton gold. "We look forward to our 2017 program where we intend to follow up on the highest priority targets with drilling," said Northern Empire President and CEO Michael Allen. Roughly 25 miles (40 kilometers) northwest of Delta Junction, Richardson hosts multiple gold targets – Democrat Pit, Shamrock and Northwest Camp. Northern Empire said these prospects just north of the Alaska Highway offer the potential for a multi-million-ounce gold discovery within a "drive-to" proven Alaska gold province.

Graphite One raises funds; PEA due out by years-end

Graphite One Resources Inc. Nov. 9 announced the completion of a C$812,000 non-brokered private placement offering that involved the issuance of 10.15 million units at C8 cents per unit. Each unit consists of one common share and one transferable warrant that entitle the holder to purchase one full share for C12 cents. The shares are exercisable for two years but are subject to early expiry if the company's shares trade for C21 cents or more for 10 consecutive days on the TSXV Venture Exchange.

The net proceeds of the offering will be used for exploration and development of the company's Graphite Creek project in Northwest Alaska; finalizing a preliminary economic assessment for the project, slated for completion by years-end; and for general working capital purposes. ●

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WIN FOR GOLD

interview with Bloomberg Surveillance. "I can't believe it's happening twice in six months or less."

Unlike Brexit, however, the morning following the Trump victory gold gave up much of its gains as investors took profits and shifted money to equities on the U.S. stock exchanges that took big hits in overnight trading.

Rickards and many of his fellow analysts expect gold to reach US$1,400/oz in the coming weeks.

In a report published last week, Thomson Reuters GFMS, which specializes in metal markets analytics, predicted that gold push to at least $1,400/oz if the American people voted in Trump.

Others are calling for a more modest gain for gold, leveling at around US$1,350/oz as markets digest the idea of business mogul and reality TV star with no prior political office experience assuming the presidency of the United States.

The World Gold Council sees Brexit and Trump's successful bid for the White House as part of a bigger picture that is supportive for gold in the longer term.

"We are seeing increasingly fractious politics across the advanced economies, and this trend, combined with uncertainty over the aftermath of years of unconventional monetary policies measures, will firmly underpin investment demand for gold in the coming years," said World Gold Council Director Artigas.

Whichever way gold moves in the longer term, on Nov. 8 the safe-haven metal seems to have chalked up another landmark win against the status quo. ●

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NORTHERN NEIGHBORS

duction' plan." By the end of the year, TMAC plans to have 110,700 metric tons of ore containing 52,300 ounces of recoverable gold stockpiled. The company said this stockpile will provide the processing plan with significant feed for start-up and help facilitate a smooth ramp-up to 1,000 metric tons per day of production in 2017. Following the delivery and installation of a second ore grinding circuit to site in 2017, production at Hope Bay is expected to increase to 2,000 metric tons per day in early 2018. As of Sept. 30, TMAC had C$92 million in cash and cash equivalents. This does not included a C$10 million minimum cash balance in a segregated account in accordance with loan requirements and C$19 million invested in guaranteed investment certificates set aside as collateral for environmental rehabilitation bonding and security for compliance under various agreements with Inuit organizations. The existing cash on hand, together with the US$20 million remaining to be drawn on a loan, provide TMAC a roughly C$40 million cushion to achieve commercial production at Hope Bay, slated for the first quarter of 2017.

Additionally, TMAC announced that the Nunavut Water Board has issued an amended water license for an expanded tailings facility for the Doris Mine at Hope Bay to Caroline Bennett, minister for indigenous and northern affairs Canada. The minister has 45 days to review and sign the license but can request a 45-day extension. Upon receipt of the minister's signature, the amended license supports an expanded tailing impoundment area at Doris that will extend the life of the mine from roughly 1.5 years to the current reserve life of six years. ●

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CARIBOU DOME

of strike tested.

One rock chip sample collected at Kopis, about 1,000 meters northeast of the Caribou Dome deposit, returned 9.1 percent copper.

A follow-up IP geophysical survey refined drill targets at Kopis and Trojan, another anomaly further northeast.

Two holes were drilled at Kopis this year. While neither hole hit the sedimentary sequence targeted, one hole cut a narrow interval of chalcopyrite veins that returned 0.9 percent copper over 0.5 meters. While not the grades or widths sought, Coventry is encouraged by the presence of chalcopyrite associated with the IP anomaly at this large and prospective target.

The company also collected about 800 soil samples over a more than 5,000-meter-long prospective area on the far northeastern end of the property. These samples returned assays of up to 0.17 percent copper from a prospect known as Senator, which is about 6.8 miles northeast of the Caribou Dome deposit. Select rock chip samples from outcrops in the area have returned up to 12.1 percent copper. Based on the results of this early work, Coventry has staked 26 claims to extend coverage over the new prospective region. Follow-up work is being planned. ●

● PIPELINES & DOWNSTREAM

Trans Mountain on a knife edge

Canadian government insists it has met obligation to consult with indigenous communities on line; Kinder Morgan braces for protest

By GARY PARK

For Petroleum News

The Canadian government has delivered its boldest hint yet that Kinder Morgan's planned C$6.8 billion expansion of its Trans Mountain crude oil pipeline will receive final approval by a Dec. 19 deadline.

In a surprise stand, Natural Resources Minister Jim Carr said the cabinet of Prime Minister Justin Trudeau will not be bound by its endorsement earlier this year of a United Nations' declaration that "free, prior and informed" consent from First Nations must accompany any government clearance for natural resource projects that affect land claims by indigenous people.

"We believe that to meaningfully consult and accommodate indigenous peoples in the context of energy reviews is the primary responsibility of the government of Canada," he told reporters. "That's what we have done and that is what we will continue to do."

Anderson broadside

Compounding the growing anger among opponents of plans to triple capacity on the Trans Mountain system to deliver 890,000 barrels per day of oil sands bitumen to an export terminal in Vancouver and refineries in Washington state, Kinder Morgan Canada's President Ian Anderson delivered a broadside to those who argue that allowing the expansion to proceed will undermine Canada's plans to lower carbon emissions.

Speaking to the Vancouver Board of Trade, he agreed that a decision on the Trans Mountain proposal "is not unrelated" to carbon policy announcements by government, but voiced his own doubt that humans are contributing to climate change.

"I've read the science on both sides and I don't pretend to be smart enough to know which is right," the plain-spoken Anderson said.

"What I do know is the broad public, political view, societal view, is that over time, we as a race should reduce our reliance on fossil fuels. That's a given," he said.

He later released a statement to clarify his position on climate change, saying "there should be no misunderstanding in what I think or believe. Climate change is real. Fossil fuels lead to higher (carbon dioxide emissions), which in turn contribute to climate change."

"A decision on the pipeline is not unrelated to carbon policy announcements" by government, Anderson said. "We're nowhere near 'yes' yet. We're working hard to get to 'yes'."

But that came after he had twice questioned the source of climate change.

Andrew Weaver, a British Columbia climate scientist and leader of the Green Party in the B.C. Legislature, said the problem with Anderson's remarks is that there isn't science on both sides.

"There is ideology on one side and science on the other," he said, adding "the science is clear. It's been clear for decades."

The Canadian Association of Petroleum Producers refused to go along with Anderson's point of view, insisting that humans are "absolutely" contributing to climate change.

But Alex Ferguson, vice president of policy and performance at CAPP, said the issue of whether climate change is manmade or not is irrelevant to the effort and the billions of dollars being spent by Canada's oil and gas producing companies to reduce carbon emissions.

Simon Donner, a climatology professor at the University of British Columbia, told the Vancouver Sun that it was "embarrassing" for Anderson to display his ignorance on climate change when he was leading a company that was part of "big energy decisions" in Canada.

Regulatory phase

Beyond ongoing public debate, the regulatory phase of the Trans Mountain application is now squarely in the hands of the Canadian government following the release by Carr of the report by an advisory panel that many indigenous communities in British Columbia feel they have not been adequately consulted on the project.

The three-person panel, whose mandate did not include drawing conclusions or making recommendations to the government, heard from thousands of people across B.C. and Alberta, including 35,000 who responded to an on-line questionnaire.

However, it said the government should ask questions about how construction of the pipeline addition could be reconciled with Canada's international climate change commitments.

Carr said the report will be an "important element" in the government's decision.

The panel raised the question of how, in the absence of a national energy strategy, any resource project could be effectively assessed and how the government could meet its commitment to gain consent from First Nations.

It also said the government needed to answer which pipeline route best ensured public safety.

Environment groups — 350.org and Greenpeace Canada — vowed civil disobedience if Trudeau's government gives a green light to the pipeline, with Greenpeace holding training sessions to show protesters "how you can withdraw your consent in ways that the government can't ignore."

Anderson conceded he would be "naive" if he did not expect the hostile protests in North Dakota against the new Dakota Access pipeline to spread into Canada if Trans Mountain gains government approval.

"Hopefully, it's peaceful. People have the right to express their views publicly and in that regard we will accept and acknowledge that," he said.

Anderson said Kinder Morgan has already been in "deep conservation" with the Royal Canadian Mounted Police on "what we can anticipate and what their role needs to be." ●

● ANALYSIS

Gas-to-liquids as an alternative to LNG

Converting natural gas to liquids on Slope would extend life of TAPS, provide more value than LNG; but GTL process more complex

By TIM BRADNER

For Petroleum News

If a conventional gas pipeline from the North Slope is not viable, gas-to-liquids, or GTL, a process that converts natural gas into a liquid, might be a possible alternative. Liquids that are made could be moved through the existing Trans Alaska Pipeline System.

One attraction of this is that a GTL project would boost the volumes shipped through TAPS, extending the pipeline's economic life and lowering the cost of shipping the conventional crude oil produced in North Slope fields.

Another is that the liquids made through gas-to-liquids, whether synthetic crude oil or ultra-clean fuels like diesel or gasoline, can have two to three times the value of North Slope natural gas sold as liquefied natural gas.

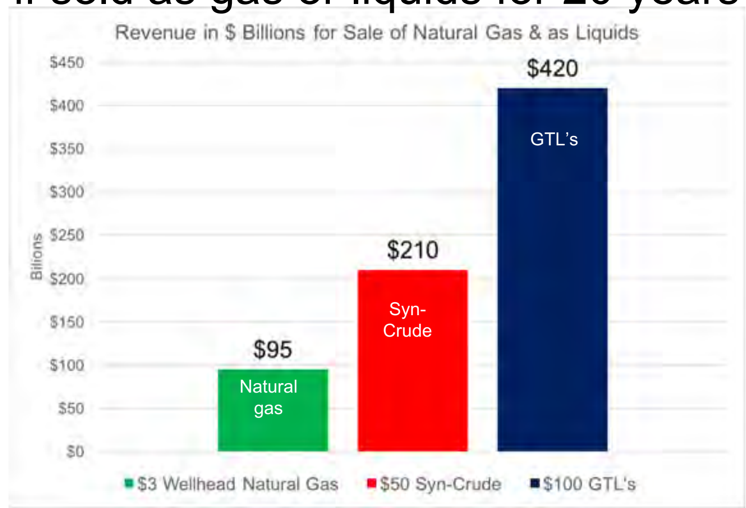
RICHARD PETERSON

That is because the energy in the liquids is sold into higher-value crude oil or fuels markets, and through an existing pipeline, rather than sold into LNG markets, currently oversupplied, through an expensive gas pipeline and gas liquefaction plant that have yet to be built.

As a quick example, if the entire proven 35 trillion cubic feet of natural gas on the North Slope were sold at $3 per million British thermal units, a likely value of the gas on the North Slope, sales could generate $95 billion dollars. If the same amount of gas were converted into GTL liquids, as synthetic crude oil, and sold at $50 per barrel the revenues would be more than $210 billion. If the gas is converted into final products like diesel or gasoline the values would be much higher.

A challenge for GTL, however, is its complexity compared with the relatively simple LNG process of chilling gas into liquid form and shipping and then regasifying it. Also, LNG is done in many places including Alaska, so most major oil and gas companies and gas customers are familiar with it. GTL is done commercially also but in fewer places, so there are fewer companies familiar with it.

Value of North Slope Natural Gas
if sold as gas or liquids for 20 years



$3/mmbtu wellhead natural gas - 35 Tcf of natural gas will make 4.2 billion barrels of liquids sold at a syn-crude oil value of $50/bbl or as GTL's (diesel, gasoline or jet fuel) at $100/bbl

ANGTL, LLC

Shell and Sasol are the most advanced today in their understanding of GTL. Among North Slope producers ExxonMobil is most advanced in GTL, and has previously studied its application to the Slope.

What is it? How does it work?

GTL has its benefits as well as challenges, but fundamentally, what is it? How does gas-to-liquids work?

"GTL plants are giant chemistry sets," which basically rearrange hydrocarbon molecules, says Richard Peterson, an Anchorage-based gas project developer who has worked in the field for years.

"Gas-to-liquids is a generic name for processes that convert a carbon-based gaseous material (the G) into a liquid (the L) at room temperature, through a three-step process," he said.

The most common GTL process is making methanol, a liquid, from natural gas, which is mostly methane.

A second common GTL procedure is the Fischer-Tropsch process, a chemical reaction named the two German scientists who developed it in the 1920s.

While methane-to-methanol makes one product, methanol, Fischer-Tropsch can make several finished products or a synthetic crude oil, which can be sold on its own and blended with conventional crude. Finished products can include products like ultra-clean diesel, gasoline, jet fuel or naphtha made through a conventional refining process.

Some GTL manufacturers, such as Shell, make petrochemicals in addition to fuel products, Peterson said. Shell does a good business with petrochemicals made in its Malaysia GTL plant.

How does it work? A chemistry lesson

Explaining the Fischer-Tropsch process involves a short lesson in chemistry: "The first step, the most expensive in any GTL process, is taking apart the original gas molecule and, in the presence of a catalyst, making a 'synthesis' gas," Peterson explained.

"With methane (the most important component of natural gas) the base molecule is CH_4, there are one carbon atom and four hydrogen atoms. The methane molecule is split with heat, steam (which is water or H_2O) and, using the catalyst, a mixture of carbon monoxide (CO) and hydrogen (H_2) is created," what is known as synthesis gas.

This is sent to a second reactor, where another catalyst is used with an elevated temperature and pressure, and a new, longer-chain, a more complex, carbon molecule is formed, Peterson explained.

This long chain molecule consists of many carbon atoms and twice as many hydrogen atoms. There could be a C_{150} (150 carbon atoms) H_{302} (or 302 hydrogen atoms) in the new molecule.

"The long chain molecule forms a hydrocarbon wax at room temperature, which has the physical appearance of a plain wax candle," Peterson said.

The third, final step of the process is almost identical to a crude oil refinery where in the presence of still another catalyst, and again with elevated temperatures and pressures, the long-chain carbon molecule is split, or "cracked" into many smaller carbon molecules.

"The shorter the molecule chain, the lighter the final material," Peterson said. For example, gasoline is C_5H_{12} whereas diesel is $C_{12}H_{26}$.

Advances in catalysts have resulted in improvements to the GTL process over the years, improving its efficiency. "Iron was replaced by cobalt (in catalysts) to extend the life of the catalysts from months to years, while also improving the conversion efficiency," he said.

An advantage: Fuels are super-clean

One big advantage of the fuel products made though GTL is that they do not contain the harmful compounds, which cause pollution, that are in conventional crude oil and are in the fuels made from conventional crude.

Why are GTLs so clean? "The simple answer," Peterson explains, "is that the liquids made start out as pure methane with the CH_4 molecule. Crude oil also contains carbon and hydrogen but also has contaminates like aromatics, benzenes, sulfur and heavy metals that are difficult if not impossible to economically remove."

"Since it begins as pure carbon and hydrogen the GTL end product ends as pure carbon and hydrogen, without the contaminates," he said.

This is a commercial advantage for GTL, although there is as-yet a limited market for ultra-clean fuels. "GTL plants will make incredibly pure products and can command large premiums over petroleum products based on conventional crude oil," to meet government environmental standards.

"But the market for super-pure products is sometimes limited and will only grow once the supply is shown to be available on a long term basis from several sources," Peterson said.

"Both the Sasol and Shell GTL plants in Qatar are very profitable because there is a very large market in Europe for very pure transport fuels. However, that

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GTL ALTERNATIVE

doesn't mean the next GTL plant will be as profitable, because the market may not be able to absorb more super clean fuels," at least in the near term, Peterson said.

Use of waste heat increases efficiency of process

GTL plants have been criticized as being thermally inefficient compared with LNG, for example converting only 60 percent of the energy content of the natural gas into products as compared with approximately 80 percent through liquefied natural gas.

Peterson said this is so only if the waste heat generated from a GTL plant isn't used. If the waste heat is used, for example to generate power for off-site use, the efficiency can improve to the same level as an LNG project, he said.

"The F-T process produces enormous amounts of heat, thus a GTL plant can produce large amounts of steam to run the plant and even produce waste heat electric power for use outside of the plant," he said. On the North Slope large volumes of natural gas are used to generate power. "A large-scale GTL plant could reduce the need for burning natural gas to generate power."

In other places there are other beneficial products, for example water generated that can be important if the plant is in an arid climate.

"In Qatar, where water is produced from desalination, the water produced through GTL is very valuable. Also, the cost of water for food production and for human needs can be reduced," Peterson said.

How many GTL plant modules needed?

An advantage of GTL over the natural gas pipeline and liquefied natural gas, or LNG, project is that production plants would be built in increments, expanding the project in phases. Revenues from the first phase could help pay for the second phase.

This is an advantage because the capital investment would not come all at once, unlike the pipeline and LNG project where the entire capital investment must be spent before the project can operate and produce revenue. Because of the huge investment needed at the front end a pipeline and LNG project would have to ramp up quickly to full capacity.

A major question confronting the Alaska LNG Project is whether LNG markets can absorb the large volumes needed to make the project viable. In contrast, a GTL project can grow in increments as the market grows for its products.

However, if the GTL plant makes and sells only synthetic crude oil, at least initially, TAPS has sufficient available capacity to accept large volumes of oil, which would allow a large GTL plant to be built initially. This introduces flexibility into a GTL project because the project could initially make synthetic crude oil and then expand gradually into ultra-clean products like diesel as marts develop.

Under any scenario several production plants would be needed, and those could be built in increments. "The size of each plant would depend upon whose technology is used," Peterson said. "Shell's process, for example, would efficiently produce 75,000 barrels per day of product per production module. Sasol's process would most efficiently produce 35,000 barrels of products per day per module."

For the North Slope, "I would assume that a project could be sized to produce somewhere from 100,000 bbl/day to 140,000 bbl/day with an ultimate goal of expanding to 200,000 bbl/day to 240,000 bbl/day," Peterson said, which would require a supply of about 2 billion cubic feet of gas per day.

"At 2 billion cubic feet of gas per day you would run the program for about 45 to 50 years, assuming no new gas is developed," Peterson said. This still leaves an ample supply of gas on the Slope to support a conventional gas pipeline that could be built when LNG markets improve.

This is important because the proven reserves of North Slope gas may not be as extensive as thought if they must support a large gas pipeline and LNG project. Although the companies are confident more gas will be found they have not found it yet.

"If there is only 35 Tcf of proven gas reserves between the Prudhoe Bay Unit and Point Thomson, then at 3.5 billion cubic feet per day the volumes produced and sold to the LNG project would deplete these fields in 27 years," Peterson said.

However, the two fields cannot sustain this level of gas deliverability until the last day, so the available gas volume will drop off with time. "Also, if the PBU needs 600 million cubic feet of gas per day just to operate then really you only have a reserve life of 23 years," Peterson said.

Can GTL products be 'batched' through oil pipeline?

The highest value of a Slope GTL plant would be achieved if the plant could produce products like diesel which would sell at premiums because of the environmental qualities. However, achieving these values depends on the ability to ship these products through TAPS in batches and keeping them separate from the crude oil so as to not contaminate the fuels with pollutants, which would reduce their value.

Shipping synthetic crude oil, of course, requires no batching because it can simply be blended with conventional oil produced on the Slope. This has the added advantage of improving the overall quality of the crude oil moved through TAPS. Peterson thinks this could amount to as much as $1 billion per year.

However, if a North Slope GTL plant were to make final products, like diesel, gasoline or naphtha, the batching could occur in two ways: One is to use "pigs," or mechanical devices that are run through TAPS ahead and behind the liquids to be separated. Pigs are now routinely run through TAPS for maintenance and inspection so this idea is not difficult mechanically.

"Much of the cost to be able to batch in the pipeline, such as the pig 'launchers' and 'receivers' has been spent already, as TAPS has been pigging for years," Peterson said. There would be additional storage tanks needed on the North Slope but probably not at Valdez, since some of the four 500,000-barrel crude oil storage tanks at the Valdez terminal might be converted to store products.

Additional investments will still be needed in TAPS to do mechanical batching — Peterson thinks it might be $750 million to $1 billion — but the higher values for the products shipped compared with that of crude oil would offset this, Peterson said.

There are also ways the GTL products could be separated and shipped without mechanical batching. In the late 1990s ExxonMobil investigated the "phasing" of liquids in a study of a GTL project on the Slope.

In phase, "You mix the two liquids (crude oil and GTL fuel) at the interface," Peterson explained. "How far back the mixing occurs to separate the liquids is hard to say, especially in TAPS where there several locations with steep slope and 'slack flow' from the top of slopes, where there will be tremendous mixing."

"If you can reduce these slack flow areas (shipping higher volumes through TAPS will do this) the mixing will be minimized, but it will still occur," he said.

Why isn't GTL being done now on Slope?

If gas-to-liquids is so attractive, why aren't the North Slope producers pursuing it? At least one producer, ExxonMobil, did a serious study of a GTL plant on the Slope in the late 1990s but in the early 2000s was persuaded by BP and ConocoPhillips, who have less experience with the process, to pursue a conventional gas pipeline to the Lower 48. Lower 48 gas prices were then at record highs.

After shale gas producers sent Lower 48 prices tumbling the producers, at the state of Alaska's encouragement, switched to a gas pipeline and LNG export project in 2012. Subsequently, LNG prices in the Pacific, the intended market, have plummeted as many large LNG projects came on line.

Given this change, the producer companies have now backed away from supporting a pipeline and LNG project but are willing to support, for now, Gov. Bill Walker's continued pursuit of the LNG project.

However, at some point alternatives like GTL and even exotic ideas like a floating LNG ship project pioneered by Shell or ice-class LNG tankers pioneered in Russia, on the North Slope will have to be considered. The major producers, who keep their planning confidential, may be evaluating some of these ideas already. ●

Contact Tim Bradner at timbradner@gmail.com

● FINANCE & ECONOMY

Potential threat looms to investment

World's central banks could pose threat to oil companies should they follow 'carbon bubble' theory put forth by Bank of England

By **KAY CASHMAN**
Petroleum News

According to Daniel Yergin, a potential threat looms for international oil companies from an unexpected source — the world's central banks.

Yergin, vice chairman of IHS Markit and a long-time respected energy industry authority, sees efforts to force publicly listed oil companies to produce information about their exposure to the so-called "carbon bubble" as misguided.

The issue was raised about a year ago by Mark Carney, governor of the Bank of England, and chairman of the Financial Stability Board, at Lloyd's of London, who said in a September 2015 speech that climate change — specifically "transition risk" — could threaten the world's financial stability through a sudden and significant collapse in oil company asset values.

Carney argued that the transition to non-carbon-emitting energy sources could "render the vast majority of (oil gas and coal) reserves stranded," as a result of the world's transition to non-hydrocarbon forms of energy.

Argues oil company investments to become worthless

"The carbon bubble is an argument made to investors in public companies that their investments will be worthless because companies will not be able to produce their reserves at some point in the future. This is a deeply flawed theory," Yergin said in a recent press report in The National, prior to his presentation at the Abu Dhabi International Petroleum Exhibition and Conference.

An energy transition that "unfolds over decades does not constitute abrupt systemic risk to the financial system," Yergin and IHS senior economist Elena Pravettoni said in an October IHS report on the issue, "Do Investments in Oil and Gas Constitute 'Systemic Risk?'"

The calculations of other central banks and fiscal experts have differed from Carney's, including that of his predecessor as governor of the Bank of England in 2012.

Nonetheless, Carney's position has started to gain traction due to his influential position as chairman of the Financial Stability Board, a G-20 group of 20 developing nations that have tasked themselves with improving risk management in the world's richest economies.

A key consideration in this debate is the valuation of oil and gas reserves.

IHS analysis "demonstrates that oil and gas company valuations are primarily based on reserves that will be produced and monetized over a 10–15 year period — a relatively short time frame in which an energy transition is unlikely to unfold," Yergin and Pravettoni reported.

"Furthermore, the recent oil price collapse has proven to be a high-stress 'stress test' for the oil and gas sector. According to IHS Herold, 82 global oil and gas companies lost 42 percent of their market value from June 2014 to December 2015 — equal to $1.4 trillion in market capitalization. Yet, this fall has had minimal systemic impact on the global financial system thus far. Since oil prices fell below $100 per barrel in September 2014, the Dow Jones Index has risen 6 percent," Yergin and Pravettoni reported.

IHS found that about 80 percent of the value of most publicly traded oil and gas companies is based on their proved reserves, which account for roughly 20 percent of the resource base of global international oil companies by volume. Their valuation is based on the present worth of expected cash flow from projects and reserves that will be produced in the short to medium term (typically monetized within 10–15 years) and are consequently at minimal risk of being stranded.

Eye on prices

"Therefore, there is little risk of oil and gas companies being overvalued by potential climate policy restrictions," IHS determined.

Public companies hold 7 percent of world's reserves

Moreover, the alarm over stranded reserves and company valuations fails to take into account the reality that publicly traded international oil companies represent only a small percentage of the world's total reserve base. Only 7 percent of total world oil and gas reserves are fully accessed by these firms — the vast majority are controlled by state-owned national oil companies. Their reserves "are clearly not part of investor portfolios and therefore would not create any direct risk to private financial investors," IHS determined.

Enlarged focus since 2008

The growing focus on climate change by central banks is occurring at a time when independent central banks "are coming under the spotlight for taking on more expansive roles in general. Some critics have argued that this new (G-20) initiative represents an overextended reading of their mandate to protect the financial system from systemic risk," IHS said.

Traditionally, central banks have been concerned with inflation and price stability, economic growth, and employment objectives. The focus on climate change followed the financial crisis of 2008. Since that time, central banks have gained greater responsibilities, expanding their regulatory reach in financial stability and protecting the economy from systemic risk. The term "systemic risk," which also gained wider currency after 2008, denotes, in the words of the International Monetary Fund, a risk that has the potential to lead to a "broad-based breakdown in the functioning of the financial system." It is also defined by the breadth of its reach across institutions, markets, and countries and is intertwined with the notion of an immediate financial collapse," IHS reported.

Carney and former New York mayor Michael Bloomberg, whom Carney asked to oversee a task force to look into the financial risk of climate change, will report in December on whether to recommend the adoption of a code for climate reporting by oil companies. ●

Contact Kay Cashman at publisher@petroleumnews.com

GOVERNMENT

Yukon voters opt for change

Yukon's Liberal Party swept to power in the territorial election Nov. 7, ending 14 years of rule by the Yukon Party, whose leader Darrell Pasloski suffered personal defeat and immediately announced his resignation.

The incoming premier, Sandy Silver, declared he was ready to "hit the ground running" after capturing 11 of the legislative assembly's 19 seats, with six captured by the Yukon Party and two by the New Democratic Party.

A core plank in the Liberal election platform was a promise to improve relations with First Nations, ending a prolonged period of bitterness that often resulted in court action. Silver said self-governing agreements with First Nations are "the pathway to the Yukon's economic future. If we sit down together, we can grow the economy, protect the environment and create good jobs that benefit all Yukoners."

During the campaign he accused Pasloski of ignoring negotiations with First Nations communities in favor of mining interests.

Faced with the temporary closure next year of the Yukon's one operating mine — the Minto copper operation — Pasloski argued that the territorial government needed to support mining if it had any hope of an economic turnaround.

He had also promised to fight the Canadian government's federally mandated carbon tax, while Silver said he would work with the federal administration to ensure the levy did not extract a heavy toll on Yukon residents.

Like the Northwest Territories, the Yukon has also seen its oil and natural gas prospects get sidelined by low commodity prices.

—GARY PARK


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● FINANCE & ECONOMY

Tillerson: $50-60 likely for 3-5 years

Lance, Sheffield agree, but IEA, Saudi minister, OPEC, Pouyanne warn massive investment cuts will result in oil supply shortfall

By **KAY CASHMAN**
Petroleum News

While the International Energy Agency, OPEC, Saudi Arabia's oil minister and Total's chief executive have warned of a looming oil supply crunch due to massive industry spending cuts designed to help producers weather a prolonged price downturn, ExxonMobil, ConocoPhillips and Pioneer's top executives do not think a supply glut with significantly higher prices is in the picture.

In its annual World Energy Investment report in September, IEA said that oil companies have cut investment in new production by 25 percent in 2014 and 24 percent this year. Next year they could cut spending for an unprecedented third year in a row, which the Paris-based agency said could lead to an oil supply shortfall.

Saudi Arabia's Minister of Energy and Industry Khalid Al-Falih and Patrick Pouyanne, the head of French oil giant Total SA, and the Organization of Petroleum Exporting Countries agree with IEA, warning that the market could face an oil shortage if investment continues to decline.


REX TILLERSON


RYAN LANCE

But Rex Tillerson, chief executive of ExxonMobil, told attendees at the mid-October Oil & Money conference in London that production from U.S. tight oil regions will offset a shortfall from other producers and keep prices in the $50-$60 per barrel range for years to come.

Tillerson argued that improving technology and cost cuts will allow companies to produce more oil at prices as low as $40 a barrel, preventing a price "blow out" in the future. He said the United States, the world's third largest oil producer behind Saudi Arabia and Russia, has become a swing producer that will be able to respond quickly to any global supply shortage.


SCOTT SHEFFIELD

Falling costs in the U.S.'s tight oil regions will counteract OPEC's renewed commitment to maintain reasonable output levels, Tillerson said. OPEC members pump approximately 40 percent of the world's oil.

"I don't necessarily have the view that we are setting ourselves up for some big collapse in supply within the next three, four, five years," he was quoted as saying in press coverage of the annual event, noting that large tracts of U.S. oil-producing acreage will become economical at $60 a barrel.

"I don't quite share the same view that others have that we are somehow on the edge of a precipice. I think because we have confirmed viability of the very large resource base in North America ... that serves as enormous spare capacity in the system," he was quoted as saying.

ConocoPhillips's Ryan Lance agrees

Other speakers at the conference echoed Tillerson's views, Bloomberg reported, including ConocoPhillips CEO Ryan Lance, who said new wells were viable at $40-per-barrel-oil in the Permian, Eagle Ford and Bakken basins.

Eye on prices

Per a Bloomberg report, oil production in the Permian basin can grow by 300,000 barrels a day for the next 10 years "easy" by adding just five drilling rigs, said Scott Sheffield, chief executive officer of Pioneer Natural Resources Co.

Tight oil "doesn't take mega-project dollars and it can be brought on line much more quickly than a 3-4 year project," Tillerson said. "Never bet against the creativity and tenacity of our industry."

Saudi Minister Falih argues market is balancing

Their position differed considerably from that of Saudi Arabia's energy minister, who Reuters reported minutes earlier in the conference had warned of impending oil supply challenges due to the continued drop in investment.

"Market forces are clearly working. After testing a period of sub $30 prices the fundamentals are improving and the market is clearly balancing," Falih said.

"On the supply side, non-OPEC supply growth has reversed into declines due to major cuts in upstream investments and the steepening of decline rates," the minister was quoted by Reuters as saying.

"Without investment, that trend is likely to accelerate with the passage of time to the point that many analysts are now (ringing) warning bells over future supply shortfalls and I am in that camp," Falih said.Although OPEC and Russia's plan to freeze or possibly cut production will help reduce a huge overhang of oil supplies and stimulate new investments, the investments will not come soon enough to avoid a shortfall, Reuters reported the minister as saying in his presentation.

Russia is the world's second largest oil producer. ●

Editor's note: Tillerson has worked for Exxon for 40 years and is due to retire before the end of first quarter next year.

LAND & LEASING

BLM announces NPR-A sale for Dec. 14

The federal Bureau of Land Management has published details for its 2016 National Petroleum Reserve-Alaska oil and gas lease sale. Bids will be opened Dec. 14 in Anchorage at 1 p.m. in the Denali Room on the fourth floor of the Anchorage Federal Office Building.

The state's fall oil and gas lease sale opening will occur at 9 a.m. Dec. 14 in the Atwood Building.

BLM said this will be the 13th sale in NPR-A since 1999, will include 145 tracts and offer some 1.4 million acres for lease. There are 134 authorized leases in NPR-A covering more than 895,000 acres, the agency said.

Bid monies received for the 12 previous sales totaled more than $262 million, half of which was paid to the state.

BLM sought public input on tract nominations earlier in the year and then selected tracts based on evaluation of comments received, natural resource information, resource potential, industry interest and subsistence values.

Sealed bids must be received in the BLM Alaska State Office by 4 p.m. Dec. 12. The detailed statement of sale is available on the BLM Alaska website: www.blm.gov/ak.

—PETROLEUM NEWS

● EXPLORATION & PRODUCTION

Furie to complete No. A1 well in 2017

Tells state in current plan it could drill fourth Kitchen Lights development well in 2017 or shift to exploration at offshore unit

By ERIC LIDJI
For Petroleum News

Furie Operating Alaska LLC is mostly sticking to its plans at the Kitchen Lights unit.

In the coming year, the company told the state in a plan of development, it plans to finish the Kitchen Lights Unit No. A1 well and either drill a second development well into the same block or deepen the existing Kitchen Lights Unit No. 4 well to target the Sunfish Channel of the lower Tyonek Formation.

Furie brought the Randolph Yost jack-up rig to the Cook Inlet in May 2016 and completed two wells and started a third before the end of the open water season.

The company drilled the directional KLU No. A2 well to a measured depth of 7,038 feet and a total vertical depth of 5,210 feet before plugging the well back to 2,290 feet to be sidetracked. The KLU No. A2-A sidetrack reached a measured depth of 8,160 feet and a total vertical depth of 7,301 feet and is currently producing, according to the company.

Toward the end of the season, Furie started the KLU No. A1 well. The company intends to complete the well next year, "if advisable based on logs, data and market conditions."

Production from two wells

Kitchen Lights is currently producing from two wells — KLU No. A2-A and the KLU No. 3 discovery well. The wells encountered "numerous layers of pay" in the Sterling and Beluga formations. "The proposed development is designed to efficiently exploit these pools by completing the wells at various intervals. The more prolific Sterling reservoirs may be exploited in the first development wells to increase reserves and deliverability," the company wrote in its plan. The initial well should produce between 15 million and 18 million cubic feet per day of extremely dry gas — approximately 99 percent methane for the time being, although the profile could change over time. "If analyses indicate that the well will support increased flow rates, production may be increased," the company wrote.

The Julius R platform can currently accommodate as many as six wells. The two wells currently online and the two wells proposed for next year would still leave two slots, and while Furie suggested it was eager for the increased deliverability and production, the company told the state that "existing natural gas market constraints through 2019 may have an impact on the necessity of multiple wells." The date refers to the end of several existing Hilcorp Alaska LLC gas supply contracts with large utilities in the region.

2017 plans

The plan proposes two directions for the coming year.

If Furie decides to complete a fourth well into the Corsair block — one of four exploration blocks at the unit — it would be drilled to the stratigraphic equivalent of the Sterling flow-tested zones in KLU No. 3 — approximately 6,964 feet to 6,998 feet measured depth.

The company could also decide to drill the KLU No. 4 well to a depth to target the Sunfish Channel of the lower Tyonek Formation. The company drilled and completed the well in the Northern block of the unit in 2013 and 2014 and said that the well "encountered potential oil and gas reserves." The company proposed deepening the well to target the Sunfish Channel in its previous plan of development in late 2015. ●

Contact Eric Lidji at ericlidji@mac.com

PIPELINES & DOWNSTREAM

Unocal still trying to unload TAPS share

Unocal Pipeline Co. told the Regulatory Commission of Alaska in late October that it is still not in a position to file for transfer of its trans-Alaska oil pipeline operating authority due to unresolved issues with other owners.

The pipeline company has been trying to get out of its 1.35 percent ownership interest in the system since 2012, when it notified other owners it would not continue operation of its share of the line after July 31, 2012.

The original system agreement was for a 30-year term from commissioning, with an option to renew in five-year blocks; a renewal occurred in 2007, expiring July 31, 2012.

The original system agreement was for a 30-year term from commissioning, with an option to renew in five-year blocks; a renewal occurred in 2007, expiring July 31, 2012.

Unocal temporarily suspended its service on the line starting July 31, 2012, pending sale or transfer of its ownership interest and has applied to RCA for numerous extensions since.

In its June 28, 2012, application to RCA for temporary suspension of its service Unocal said it would sell its interest to a third-party or another pipeline owner, subject to right of first refusal by the remaining owners and said it was in active negotiations with the other owners to transfer its ownership interest.

In its latest filing with RCA, Unocal repeated what it has said previously that "Unocal and the other TAPS Carriers have a dispute over several transfer-related matters." Unocal said arbitration continues on a portion of the dispute with litigation on other portions.

—PETROLEUM NEWS

ENVIRONMENT & SAFETY

Polar bear habitat appealed to Supreme Court

On Nov. 4 the state of Alaska and other appellees formally requested the U.S. Supreme Court to review an opinion by the U.S. Court of Appeals for the 9th Circuit upholding the designation of polar bear critical habitat by the U.S. Fish and Wildlife Service.

Fish and Wildlife issued the polar bear critical habitat designation in November 2010, following the 2009 listing of the animals as threatened under terms of the Endangered Species Act. The designation covered 187,157 square miles, including a vast offshore area; barrier islands and spits; and polar bear denning habitat along Alaska's northern coast.

Worried about the possible impact of the habitat designation on economic activity, a number of organizations including the state of Alaska, the Alaska Oil and Gas Association, the American Petroleum Institute, Arctic Slope Regional Corp. and the Inupiat Community of the Arctic Slope appealed the designation in federal court.

The federal District Court in Alaska rejected the critical habitat designation in a 2013 ruling. But in February of this year the 9th Circuit reversed that decision, upholding Fish and Wildlife's broad view that critical habitat should include all territory containing critical habitat features, and not just land that the bears currently use. In June the 9th Circuit declined a request by the appellees to hold an en banc hearing, a procedure that would have involved all of the 9th Circuit judges reconsidering the case, rather than have the case decided by a three-judge panel.

The Supreme Court must now decide whether to conduct a review of the case.

—ALAN BAILEY

Agencies seek dispersant avoidance guidance

The Alaska Department of Environmental Conservation, the U.S. Coast Guard and the U.S. Environmental Protection Agency are seeking public input to identify coastal areas around the Alaska Peninsula and southern Alaska where the use of chemical dispersants in response to oil spills should be avoided. Dispersants that break an oil slick into tiny droplets for distribution through the water column and for rapid breakdown by bacteria can provide a helpful tool as part of an offshore oil spill response but raise concerns about the environmental impacts of their use.

As part of the implementation of the dispersant use plan, agencies want to specify any environmentally sensitive areas where dispersant use should be avoided within the pre-authorization zone.

In January of this year the Alaska Regional Response Team, the advisory board for coordinating the government response to Alaska oil spills, approved a new plan for the use of dispersants around the coast of Alaska. That plan includes a dispersant pre-authorization zone in a region north and south of the Alaska Peninsula and extending around southern Alaska to Prince William Sound. The idea of the pre-authorization zone is to expedite the deployment of dispersants, to minimize the impact of an oil spill on the shoreline.

Of particular concern is the potential for an accident involving an oil tanker operating in the region.

As part of the implementation of the dispersant use plan, agencies want to specify any environmentally sensitive areas where dispersant use should be avoided within the pre-authorization zone. A proposal to use dispersant within any of these avoidance areas would require additional scrutiny before any approval, including consultation with the appropriate government wildlife agencies.

ADEC, the USCG and EPA are inviting public comments on potential avoidance areas and are also holding a series of public informational meetings about dispersants in Kenai, Valdez, Kodiak and Unalaska. Comments are required by Jan. 9. Ultimately, a technical committee will review comments received to recommend avoidance areas for approval as part of the dispersant use plan.

Further information is available at http://nukadraft.wixsite.com/avoidanceareas.

—ALAN BAILEY

Petroleum news

Oil Patch Bits

Fluor completes module fabrication for oil sands project


COURTESY FLUOR

Fluor Corp. said recently that all 358 modules have been fabricated and shipped to the site for its portion of the Fort Hills Energy L.P. oil sands mining project in the Athabasca region of Alberta, Canada. Fluor is performing engineering, procurement, fabrication and construction for the utilities scope of the project.

The project applied Fluor's innovative 3rd Gen Modular ExecutionSM approach, which optimizes process block layouts and provides the capability to fully modularize large-scale industrial facilities. Benefits include improved safety, lower costs, increased productivity and schedule predictability through the transfer of a significant amount of traditional site work to fabrication yards.

Fluor's Supreme Modular Fabrication Inc. joint venture fabrication yard in Canada and three other Canadian yards built the modules. Once at site, the modules are set by Fluor's craft workforce. The site has achieved more than 2.8 million hours without a lost-time incident.

"Achieving this milestone is a testament to the collaboration and commitment of our craft professionals at the SMFI fabrication yard, other module yards and at the project site," said Jim Brittain, president of Fluor's Energy & Chemicals business. "Leveraging our full range of integrated solutions, including our craft workforce, fabrication yards, global sourcing capabilities and 3rd Gen Modular Execution approach, we have reduced the project's capital cost from initial estimates while maintaining schedule."

The Fort Hills Project, an open-pit truck and shovel mine, is owned by Fort Hills Energy LP, a partnership between Suncor Energy, Total E&P Canada Ltd. and Teck Resources Ltd.

Crowley to supply Alaska LNG to power plant in Tok

Crowley Maritime Corp.'s liquefied natural gas services group has recently been awarded a contract to supply Alaska LNG from the Titan Point Mackenzie plant to Alaska Power & Telephone Co.'s Tok power plant.

The contract, executed through subsidiary Crowley LNG Alaska, includes both the product supply and technical services required to successfully leverage the benefits of LNG at the Tok power plant. With Crowley's support, Alaska Power & Telephone will expand environmental sustainability efforts by developing the capability to use LNG to supplement diesel-based power generation. Development of this dual fuel capability is key to providing cleaner, more affordable energy to ratepayers.

Crowley will facilitate the transportation of LNG in a safe and reliable manner from liquefaction facilities in Alaska to the plant in tank trailers authorized by the U.S. Department of Transportation. Once at the plant, the LNG will be re-gasified and piped to a dual fuel kit supplied by ECO/AFS for power consumption.

"Crowley is extremely pleased to be a vital fuel supplier to Alaska Power & Telephone,"

see **OIL PATCH BITS** *page 27*

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

KITO Q&A

Petroleum News: There will be some seats open in Finance and Resources due to retirements. Do you see yourself pursuing one of those seats?

Kito: I actually — from the experience I've had with Leg Council, Legislative Budget & Audit and the Labor & Commerce Committee — I feel there is a lot that can be done either from a majority or minority seat on other one of those.

For me, Budget & Audit, with oversight on a lot of activities on state agencies, is important. With Legislative Council, being in the capital city and making sure we are adequately represented on basically the board of directors of the Legislature is important. The reason I started getting interested in Labor & Commerce is the time the last two years I've been on the committee looking at insurance issues, looking at what the state of Alaska can do to decrease the cost or expenses on the Alaskan public and if we can figure out how to decrease the cost of healthcare, we can save Alaskans a lot of money. One of the ways to do that is to take a closer look at insurance, and that's through Labor & Commerce. Those issues are not as glamorous as the gas line or the budget, but I would certainly want to be on budget subcommittees, but I do think insurance is a huge issue for the state that can help us control healthcare costs.

Petroleum News: Eventually Labor & Commerce could have a role in the gas line when it comes to work force issues.

Kito: AKLNG and other project bills will go through Labor & Commerce, so I'll get a chance to weigh in.

Petroleum News: So as it relates to your seat on Labor & Commerce, what would you like to see done for statewide hire on a project like that?

Kito: Constitutionally, we can't do an Alaska hire preference for anything. What I would like to see, and what I made a comment on when SB 138 passed several years ago, was that I'd like to see something in there that provides training for some of our rural residents. As much as we made the attempt to do that with the Alyeska pipeline during the original oil pipeline project, making sure there are job opportunities for all Alaskans, especially those who are disenfranchised in other ways. That is one thing I would like to see us try and support. It's probably the biggest thing. They did put in a revenue sharing component in SB 138 that allows some of the revenue coming in to actually go to decrease energy costs to rural parts of the state. Making sure that is adequately administered is going to be important in conjunction with the power cost equalization program.

"I think when we start looking at a fiscal plan, we should balance it without natural gas because natural gas revenue will not be coming in for at least 10 years, maybe longer."
—Rep. Sam Kito, D-Juneau

Petroleum News: Would you like to see vocational training should the state get closer to a project sanction?

Kito: We have to manage that carefully and we do need to make sure we are adequately training Alaskans. My thought in adequately training Alaskans is, even though we have a declining budget, make sure we are taking care of the infrastructure that we have, which means keeping Alaskans working on construction projects in Alaska, maybe on a lower level than we've had in the last 10 years but at a level that is stable so that when we do gear up to construct a pipeline we have a good size workforce in the construction trades that have the ability to work on a project and we are not pulling everybody from outside of Alaska.

If we allow our construction industry to collapse because of decreasing budgets and no ability to take care of our existing infrastructure, we will be just like the 1970s when we were bringing up people from Oklahoma, Texas and Louisiana to work on a project in Alaska, then they go back home after that. We need to make sure we are training and providing that workforce during this time before we get to the pipeline.

Petroleum News: You mentioned the provision in SB 138 where a small percentage of revenue goes to rural areas to help with costs. There has been discussion of LNG being important to Southeast, particularly Juneau. What are your thoughts on that and where do things stand?

Kito: I, along with Sen. (Dennis) Egan have received several presentations on the project that Avista has been looking at. One of the things that could happen is infrastructure for natural gas in Juneau but one of the other beneficial components for that is bringing in bulk shipments of LNG, repackaging them into containers and shipping them to smaller communities or canneries or other operations, so we have the ability to have lower-priced, less environmentally damaging fuel for heating Southeast Alaska. There are a lot of people who would like to see more use of electricity. We can but that's also a very large capital expense.

There is quite a bit of natural gas in the state and other places. Once we have the infrastructure in place, we can be a beneficiary of low-cost Alaskan natural gas when that starts producing. In the meantime, there is natural gas available at a pretty reasonable price from the Lower 48 that can be shipped here to Southeast.

It wouldn't be a benefit just to Juneau; it would be a benefit to all of Southeast. There are people who would like to see strictly renewable, but those costs are a fair bit higher for developing and you also have conversion costs for electricity to heat. They are still getting better but are not quite as cost-effective as natural gas.

Petroleum News: Do you see areas like Southeast or others, which are not directly in the path of the pipeline, will have to fend for themselves for energy.

Kito: They should not. I don't know of many places that would really benefit from direct supply of natural gas. There are places that would benefit from excess capital to get off of oil for heat. I do think there are things technology wise that will change over the next 10 years that will make it a lot more affordable to living in some of the smaller communities.

Petroleum News: You had talked about the state having a fiscal plan and how it would help with advancing a gas pipeline project. Part of that is the governor's plan to alter that tax regime. That effort came up short in some people's eyes. What are your thoughts on what happened?

Kito: In the House, we came up with a pretty good compromise to limit the expense of cash credits for gas exploration, which were needed but everybody seemed to agree weren't needed to continue because we found natural gas and weren't receiving any revenue for the natural gas. The other component as the bill went to the Senate and came back was the loss carry forward. That means basically the state of Alaska is helping the Big Three carry their burden. At least two of them have bigger savings accounts than the entire state of Alaska does. So I am a little less concerned about their viability. Prices go up; prices go down. They manage their revenue steam. I do think allowing them to carry forward significant losses is a big burden on the state of Alaska that is not necessary to keep those companies to keep producing oil.

I think when we start looking at a fiscal plan, we should balance it without natural gas because natural gas revenue will not be coming in for at least 10 years, maybe longer. When it does come in and we've got a fiscal plan already in place, any revenue we see from natural gas, we can put right into the Permanent Fund, grow the principal and increase dividends for Alaskans. It's more sustainable that way than it is expecting we will go year-to-year on resource revenue.

Petroleum News: So what would you like to see happen next session?

Kito: I'd like to see us look at the carry forward operating loss for oil and gas. If we have to revisit any credits for oil exploration or gas exploration, in my mind there has to be some reasonable understanding that those credits will result in increased production. We heard the battle about film credits and how they weren't bringing any revenue to the state of Alaska but we completely ignored in that discussion the fact these oil and tax credits were not bringing in what we were expending. I think we need to have that question answered as we offer hundreds of millions of dollars in credits and carry forward losses that we know that they money is going to be coming back to the state of Alaska and it's not just a gift to the industry. ●

Contact Steve Quinn at squinnwrite@gmail.com

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OIL PATCH BITS

said Matthew Sievert, director, Crowley LNG business development. "We have been working side by side with Alaska Power & Telephone for over a year now, assisting with the engineering and design to utilize natural gas and to carry out the logistics necessary to accommodate LNG delivery to the Tok plant. We want to thank Bob Grimm, president of Alaska Power & Telephone, and his staff for having confidence in our services as they develop an innovative fuels portfolio that includes LNG, a cost-effective, safe, reliable and environmentally friendly fuel."

At AP&T's Tok plant, ECO/AFS will install its bi-fuel technology to support LNG usage in the rural Alaska community.

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

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PIPELINES & DOWNSTREAM

Agreement reached on Cook Inlet Pipe Line

Cook Inlet Pipe Line Co., Cook Inlet Energy, the state of Alaska and the Regulatory Affairs and Public Advocacy Section in the Alaska Attorney General's office have reached agreement on a revised tariff for the Cook Inlet Pipe Line.

The Regulatory Commission of Alaska said in a Nov. 3 order that it has accepted a stipulation between the parties, as well as the third amendment to the settlement agreement between CIPL and the state.

CIPL, owned by Hilcorp subsidiary Harvest Alaska, filed an annual rate revision for 2016 in December 2015, increasing the rate for transportation from Granite Point to the Drift River Terminal from $3.76 to $4.47 per barrel based on the 2001 Cook Inlet Settlement Methodology as amended. That methodology was based on an end of life for the pipeline of 2014 and included a 60 cent per barrel surcharge for dismantlement, removal and remediation.

Cook Inlet Energy protested the new rate and RAPA filed to participate in the docket. RAPA told RCA in January that the parties were engaged in discussions which might resolve the issues, and RCA stayed action to allow settlement discussions.

In a Nov. 3 order accepting the settlement reached by the parties in early October, RCA said it was also accepting the third amendment to the settlement agreement between CIPL and the state.

The stipulation from CIPL, CIE, the state and RAPA reduces the tariff from $4.47 per barrel to $3.18 per barrel, effective April 1, 2016. The parties said the amount was calculated using the settlement methodology with an adjusted end of life and termination of the DR&R allowance, changing the end of life for the pipeline for ratemaking purposes from 2014 to 2026 and reducing the DR&R allowance to zero, effective April 1, 2016.

RCA accepted a permanent rate of $4.47 per barrel from Jan. 1 to March 31, 2016. Beginning April 1, 2016, the rate of $3.18 is established as the permanent per barrel tariff rate.

—KRISTEN NELSON

NATURAL GAS

Aurora postpones development plans

Aurora Gas LLC recently withdrew proposed plans of development for its Nicolai Creek unit and Three Mile Creek field as it works through bankruptcy proceedings.

The local independent submitted proposed plans of development for the two Cook Inlet units to the state Division of Oil and Gas in early October but withdrew them less than a week later and asked the state to extend its existing plans through February 2017.

The state approved the extensions. A reorganization plan for the company is due in bankruptcy court by Jan. 6, 2017. The extensions allow the company to wait until it knows the results of those plans, which could change the ownership of the fields.

—ERIC LIDJI

EXPLORATION & PRODUCTION

Armstrong interpreting Pikka seismic

Armstrong Energy LLC is planning another year of seismic work at the Pikka unit.

The company plans to continue interpreting data from recent seismic acquisitions, incorporate the data into its reservoir model and conduct further rock physics studies, according to a plan of exploration recently approved by the state Division of Oil and Gas.

The company also described plans to analyze core samples from the Qugruk No. 5 and Qugruk No. 8 wells drilled in 2015 to help select well locations for future development.

The company also described plans to analyze core samples from the Qugruk No. 5 and Qugruk No. 8 wells drilled in 2015 to help select well locations for future development.

Although not mentioned in the plan, Armstrong is also currently permitting the Pikka No. 1 appraisal well and as many as three sidetracks for the southern tip of the unit, which is located in the central North Slope between the Kuparuk River and Colville River units.

Armstrong recently announced a major discovery at Pikka. The company is waiting for a ruling on a recent request to expand the unit to accommodate development plans.

—ERIC LIDJI

US drilling rig count up 12 to 569

The number of rigs drilling for oil and natural gas in the U.S. increased by 12 the week ending Nov. 4 to 569.

A year ago, 771 rigs were active. Depressed energy prices have sharply curtailed oil and gas exploration.

Houston oilfield services company Baker Hughes Inc. said 450 rigs were targeting oil (up nine from the previous week) and 117 targeted natural gas (up three). Two were listed as miscellaneous.

Among major oil- and gas-producing states, Texas gained six rigs, Oklahoma was up three, Louisiana and North Dakota increased by two each and Colorado added one.

Alaska declined by one.

Arkansas, California, Kansas, New Mexico, Ohio, Pennsylvania, Utah, West Virginia and Wyoming were unchanged.

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

—ASSOCIATED PRESS

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DRILLING DOWN

to be lower.

Except when mentioned, references to "wells" includes laterals and sidetracks but not workover activities to repair aging or damaged wells. The well totals included here count both production wells and injection or "service" wells, but not exploration wells.

Prudhoe, Kuparuk, Colville

The Prudhoe Bay unit continues to see a strong downward trend.

BP Exploration (Alaska) Inc. drilled eight development wells at the unit during the third quarter, compared to 14 wells during the third quarters of both 2015 and 2014. The company drilled 34 wells at the unit through the first nine months of this year, compared to 60 wells during the same period of 2015. The year-to-date totals for this year compare more favorably to the 37 wells that the company drilled in the first nine months of 2014.

Although small, the drilling program during the third quarter was diverse, including one well at the Lisburne field and one well at the Raven field. The company last drilled a Lisburne well in July 2015 and hasn't drilled a Raven well in more than a decade.

The Kuparuk River unit followed a similar trend, with higher totals. ConocoPhillips Alaska Inc. drilled 14 development wells at the unit during the third quarter, compared to 17 wells and 18 wells during the third quarters of 2015 and 2014, respectively. The company drilled 44 wells at the unit in the first nine months of this year, down from 55 wells in the same period of last year and even with 44 wells in the same period of 2014.

The drilling activity at Kuparuk during the third quarter of the year included three wells at the new Drill Site 2S (KRU No. 2S-06, KRU No. 2S-12 and KRU No. 2S-14), three wells with a total of four laterals at Drill Site 1L and a quad-lateral well at Drill Site 3F.

With development of the new CD-5 pad, drilling increased at the Colville River unit.

ConocoPhillips drilled three development wells at the unit in the third quarter, up from two in the third quarter of 2015 and one in the third quarter of 2014. The company drilled 11 wells in the first nine months of the year, up from seven in 2015 and five in 2014.

All the drilling activity in the third quarter of this year was injection wells, which has been a focus for much of the year. The company drilled its first lateral at the CD-5 pad.

Milne, Oooguruk, Nikaitchuq

Activity was negligible at the three smaller units.

Hilcorp Alaska LLC drilled one well at the Milne Point unit during the third quarter of 2016, down from two last year and up from none when BP operated the unit in 2014.

Hilcorp drilled eight development wells at the unit in the first nine months of this year, up from two in 2015 and down from 11 that BP drilled during the first nine months of 2014.

Caelus Natural Resources Alaska LLC and Eni US Operating Co. Inc. both suspended development drilling earlier this year and neither drilled during the third quarter. Caelus operates the offshore Oooguruk unit, and Eni operates the neighboring Nikaitchuq unit. ●

Contact Eric Lidji at ericlidji@mac.com

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OPEC DEAL

the nuclear deal with Iran, an accord that has allowed Tehran to dump upwards of 3.5 million barrels a day on the world market.

Although the Obama administration said it will remain committed to the Iran deal through its final months, Commerzbank, among others, said in a note following the election that if Trump revokes the accord, "oil prices would presumably rise."

Renewed sanctions on oil exports from Iran would most certainly leave room in the market for increased output from the U.S., the world's third largest oil producer behind OPEC leader Saudi Arabia and non-OPEC member Russia.

Eye on prices

"Trump has vowed to lead a fossil-fuel revival to underpin job growth and has also put manmade climate change denial at the forefront of his energy policy," JBC Energy analysts said in a note Reuters reported on Nov. 9 — actions that would likely increase U.S. oil production.

The election results could compound the supply-side headwinds that oil producers face with demand concerns, said Yergin, vice chairman of analysis firm IHS Markit, Reuters reported Nov. 9.

"Buckle up your seatbelts for a more turbulent and uncertain global economy that is ahead," Yergin told the news agency.

"The outcome of the U.S. election adds to the challenges for the oil exporters because it will likely lead to weaker economic growth in an already fragile global economy. And that means additional pressure on oil demand," he said.

BP's Dudley: oil supply, demand balanced

BP Group Chief Executive Bob Dudley discussed the outlook for oil with Bloomberg two days before the U.S. presidential election. Claiming no special information on whether OPEC would or would not cut a deal, Dudley's assessment of the oil market has been voiced by other oil company heads and energy analysts, some of whom are skeptical of an OPEC freeze or cut arising from the Nov. 30 meeting.

Dudley thinks oil supply and demand are already "generally" in balance; "it's just waiting until the stocks drain out."

"I think we could easily see $55 next year," he said.

"I think we're pretty much, on a daily basis, in balance right now within a few hundred thousand barrels a day," Dudley said.

EIA, OPEC forecasts prior to election

In its short-term energy outlook on Nov. 8, the U.S. Energy Information Administration said it expects Brent crude oil prices to average close to $48 a barrel in the fourth quarter and in the first quarter of next year. EIA forecast a Brent price average of $43 a barrel in 2016 and $51 a barrel in 2017.

West Texas Intermediate crude oil prices are forecast to average about $1 a barrel less than Brent prices in 2017.

Prior to the U.S. election, OPEC warned in its recent annual report that oil prices might not rise above $60 per barrel until the end of the decade, in an acknowledgement that an array of bearish forces will combine to keep a lid on a price rally.

OPEC's new World Oil Outlook estimates the price will rise by $5 per barrel each year through the rest of the decade, taking prices up to $60 per barrel in 2020. Last year's OPEC report predicted an $80 per barrel price by 2020.

Trump's impact on OPEC deal uncertain

In an attempt to boost prices, OPEC agreed in late September to cut output, although analyst doubts had increased prior to the election that the cartel would be able to implement the deal at its next meeting on Nov. 30.

Trump's victory "subtly shifts the balance of power in the oil market," analysts at Esai Energy LLC said in a note Nov. 9.

"A Trump presidency that is pro-business will encourage oil development, permit pipelines, reduce corporate profit taxes and generally make U.S. oil more competitive," they said.

Weakening oil prices may appear to "encourage an OPEC deal," but that might not be the case, Market Watch reported Nov. 9.

If OPEC were to cut back on production and raise oil prices, that would "only strengthen the U.S. oil sector, intensifying competition with an industry that now has the full backing of the president and a Republican Congress," said the Esai Energy analysts.

"This means if a good OPEC deal is unreachable, the Saudis are more likely to walk away, under the pretense of taking a 'wait and see' attitude regarding the new president, while continuing to keep the pressure on U.S. shale," they said.

About 52 percent of total U.S. crude oil production, or 4.9 million barrels a day, came from tight oil in 2015, according to EIA.

S&P Global Platts said OPEC's member output hit a record 33.54 million barrels a day in October.

OPEC has kept oil production levels high, which has prevented non-OPEC producers such as the U.S., where oil costs more to produce, from increasing their share of the market. ●

Contact Kay Cashman at publisher@petroleumnews.com

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NEW PAD

Milne Point Unit L Pad Road into an undeveloped area adjacent to the Kuparuk River unit.

The Division of Oil and Gas is accepting comments through Dec. 7.

Expansion underway

Hilcorp acquired a 50 percent working interest in Milne Point from BP Exploration (Alaska) Inc. as part of a larger acquisition in late 2014 and became operator of the unit.

After taking over the unit, Hilcorp spent much of 2015 working on existing wells, performing some 54 workover operations, according to plans of development.

The company began a new development program at the unit toward the end of the year, drilling three wells at L Pad between August and November 2015 and eight wells spread across B Pad, C Pad, J Pad, K Pad and L Pad through the first seven months of this year.

In addition to the drilling program, Hilcorp announced plans to expand the existing B Pad, E Pad and L Pad to accommodate increased drilling and development activities.

Hilcorp first mentioned plans for a Moose Pad in the western half of the unit in its most recent plan of development for Milne Point, submitted to the state in May 2016. The company said, at the time, that the project would be "contingent on market conditions."

The western half of Milne Point is undeveloped, although not unexplored. In early 2007, former operator BP drilled the Pesado No. 1 well and Pesado No. 1A sidetrack on ADL 25515 and the Liviano No. 1 well and Liviano No. 1A sidetrack on ADL 25514. The company plugged and abandoned both wells at the end of the exploration season. ●

Contact Eric Lidji at ericlidji@mac.com

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OCEAN SAFEGUARDS

tion is looking for ways to offset its anticipated green light for Kinder Morgan's expansion of its Trans Mountain pipeline to export 890,000 barrels per day of crude bitumen from the Alberta oil sands.

Garneau told the Canadian Broadcasting Corp. that the ban on tanker traffic is a "mandate item for me and we are going to deliver on it."

How far the moratorium will extend and whether it will affect tanker shipments from Alaska to the U.S. West Coast is not yet clear.

The safety measures will improve tanker safety and spill response regimes which Garneau said are "inadequate" compared with other maritime countries.

"Canada needs a national world-class plan to increase maritime safety and improve emergency response and strengthen partnerships with indigenous peoples and coastal communities," he said.

Scuttling Northern Gateway

It is widely believed that the tanker ban would scuttle the now-slender hopes for Enbridge's Northern Gateway pipeline that would ship bitumen from the deepwater port at Kitimat, but is expected to ease the burden on the government of clearing the final obstacles standing in the path of Trans Mountain.

However, Kitimat Mayor Joanne Monaghan questions why a ban would only apply to the northern coast.

"Is there a difference between crude oil being spilled down south and crude oil being spilled in the north?" she told the CBC.

Garneau carried his pledges to the Heiltsuk First Nation at Bella Bella on the central British Columbia coast where cleanup is still underway following the sinking a month ago of the tug Nathan E. Stewart, when 224,000 liters of diesel fuel were spilled over an area that includes a commercial clam bed.

A British Columbia environment official said about 5,000 vessels a year operate in British Columbia's southern shipping lanes, traffic that is expected to reach 6,200 within two years.

He said the ships carry fuels and products of all varieties, but many are not double-hulled in line with crude tankers.

—GARY PARK

Contact Gary Park through publisher@petroleumnews.com

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IEP CHANGES

lead, told Petroleum News Nov. 9. During the AIDEA board meeting on Oct. 27 the board approved a resolution enabling the purchase of Salix's pre-front end engineering and design documentation, so that the IEP team can continue to pursue the LNG plant expansion project. Apparently, that resolution represented the formal board approval of the takeover of the Salix component of the work program, and the departure of Salix from the project. The resolution does not mention Salix's departure, nor was the departure mentioned during the public section of the board meeting. The resolution did recognize formal acceptance by the board of Salix as the preferred vendor for the LNG plant, an acceptance that Therriault explained was necessary to enable the IEP team to close its procurement process.

AIDEA already owns FNG and the Titan plant. The IEP team has been planning to sell FNG to IGU to form a consolidated utility for Fairbanks, with an agreement on that sale expected by the end of this year. It now appears that the concept for the IEP has evolved into an arrangement whereby the consolidated utility would own and operate the Port MacKenzie LNG plant, the trucking operation for transporting LNG to Fairbanks and the LNG storage and associated gas distribution network in Fairbanks.

Cost reduction

Therriault said that the departure of Salix from the project represents one of a series of moves designed to drive down project costs and hence make natural gas more cost competitive with fuel oil in Fairbanks. This would encourage more people to convert their heating systems to gas, he said. The heating system conversion rate will drive future Fairbanks gas demand and is, therefore, a key parameter in the project economics.

With current low oil prices, IEP's target price for gas in Fairbanks, on an energy equivalent basis, is only slightly less than the price of heating oil in the city, Therriault said. And households and businesses must factor the cost of converting their heating systems to gas into their overall costs of future gas use.

During negotiations involving FNG and IGU in the spring and summer of this year concerns were expressed that what had initially been expected to be a somewhat temporary drop in oil prices appeared instead to be turning into a longer term phenomenon, Therriault explained. Then in August the IEP team approached Salix about the possibility of the company separating from the project, he said. The team was exploring ways of reducing the cost of the gas liquefaction component of the Fairbanks gas supply chain and was trying to see if some of costs associated with the LNG plant could be mitigated, delayed or avoided. But there were certain costs, such as income and property taxes, associated with participation by a for-profit corporation that could not be eliminated. And those fixed costs, spread across a relatively small number of Fairbanks consumers, would significantly push up the unit price of gas in the city, he said.

Utility operation

So, eventually the IEP team asked Salix if the company would sell the products developed so far for the LNG plant to AIDEA, a sale that has now been agreed and approved. The idea now is that the plant would be operated by the Fairbanks utility, under a not-for-profit, cost-of-service utility model, Therriault said.

Therriault also commented that IEP is squeezing other costs out of the gas supply chain through the acquisition of larger LNG trailers for hauling LNG to Fairbanks, and through the planned consolidation of the FNG and IGU LNG storage and gas distribution infrastructure in Fairbanks. The IEP team is also working with the Alaska Railroad to evaluate the rail transportation of LNG. And the IEP team is negotiating a new gas supply from a Cook Inlet gas producer for the Port MacKenzie LNG plant.

—ALAN BAILEY

Contact Alan Bailey
at abailey@petroleumnews.com

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TOKFAT OVERTURNED

and development on lands is an appropriate factor to consider when determining whether an assignment of an interest in those lands would be adverse to the state," Mack wrote. "However, an assignee's earlier failure to explore or develop leased lands is not alone determinative of that assignee's later intent or commitment to develop those lands."

Formerly Titania prospect

ConocoPhillips leased the same acreage during the 1990s, as the Titania prospect, but failed to explore the area and eventually relinquished the acreage back to the state.

Second, Mack decided that a 20 percent royalty interest on the leases, although burdensome, was also not enough of a reason to prevent ConocoPhillips from acquiring the leases. Feige had worried that a 16.66667 percent state royalty interest and a 3.33333 percent overriding royalty interest as part of transfer would overburden the leases, making it difficult for ConocoPhillips to pursue an economic development.

While acknowledging that a "net revenue interest" of 80 percent could "negatively impact development of the leases," and had rejected leases with even lower net revenue interests, Mack noted that the state had previously allowed similar transfers to proceed.

Third, Mack found that the transfer would not harm the public interest by the preventing the state from including the leases in a future sale. The original ruling, he decided, incorrectly assumed that ConocoPhillips would be incorporating the acreage into a producing unit, whereas ConocoPhillips said it intended to explore the acreage.

Putu wells being permitted

ConocoPhillips is currently in the process of permitting the Putu No. 1 well and Putu No. 1A sidetrack on the package of leases and said it could launch an environmental review for a potential development in the areas as early as next year, if drilling results warrant.

Finally, Mack decided it was appropriate for a company to transfer leases during their 90-day "secondary term" to another company. Feige had found that using the 90-day grace period to transfer a lease to another operator went against the spirit of the provision. (A unit protects leases from expiration. If the leases in an expired unit have already passed their expiration date, the secondary term provision creates a 90-day grace period.)

In her original ruling, Feige had allowed ConocoPhillips to acquire seven leases still within their primary term. The reversal allows the company to also acquire the remaining 15 leases from the former Tofkat unit, retroactive to the beginning of June 2016.

In a related Nov. 4 decision, Mack overturned a previous decision from the Division of Oil and Gas to reject a request from ConocoPhillips to expand the Colville River unit to include the former Tofkat unit. Given that the ambiguous leases were the main reason the state had rejected the request, Mack asked ConocoPhillips to resubmit its application fee within 10 days in order to relaunch the review process of the original expansion request. ●

Contact Eric Lidji
at ericlidji@mac.com