Petroleum news

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NEWS NUGGETS

Compiled by Shane Lasley

Ucore orders pilot REE separation plant

Ucore Rare Metals Inc. July 8 reported that it has commissioned the construction of a pilot plant that will test the use of molecular recognition technology for the separation of rare earth elements at bulk scale. Ucore has contracted with IBC Advanced Technologies Inc. for the design and construction of the plant, targeting completion before the end of 2015. The test plant, "SuperLig-One," will be constructed at IBC facilities in American Fork, Utah. Once complete, the unit will then be relocated to a third party facility for an independent review of pilot scale test procedures. "We anticipate that the SuperLig-One unit will be a high-value asset for Ucore," said Ucore President and CEO Jim McKenzie. "The intention is for the unit to be a test mule, capable of accepting pregnant leach solution and bulk concentrates from multiple prospective REE feedstock locations around the world. Ucore confirms that it has entered into agreements with various REE feedstock providers, and will be securing test material from a variety of locations over the next six months as construction is under way. One high-priority source of pilot scale test material will be the Bokan-Dotson Ridge project in Southeast Alaska." Ucore said the SuperLig-One unit, currently being designed at IBC, will be modular and portable. This will make the plant capable of transport to remote testing sites as required. Columnar units within the plant will contain customized proprietary SuperLig® products that are designed to selectively separate the metal being targeted. To optimize utility, the unit will be customizable over time, with capacity for treating varying ratios of metals in different feed solutions. At a bench scale, the SuperLig platform successfully separated the entire suite of rare earths. Ucore said the SuperLig-One unit is being designed to deploy this achievement at pilot scale, refining each of the lanthanides with the exception of promethium, plus yttrium and scandium to uniformly high purity. In addition to REE separation, IBC has an extensive inventory of pre-existing SuperLig products capable of selectively targeting a range of valuable metals, such as platinum group metals, gold, silver, uranium, bismuth, copper, cobalt, nickel, indium, and rhenium, as well as a host of nuisance materials. Ucore has an exclusive agreement with IBC for the use this technology for all metals in the tailings processing sector, as well as all processing applications related to rare

see **NEWS NUGGETS** page 14

TECHNOLOGY METALS

China rules REE prices

Molycorp bankruptcy raises questions on future of U.S. rare earths sector

By SHANE LASLEY

Mining News

What does Molycorp Inc.'s bankruptcy have to do with the price of rare earths in China? Some analysts say everything, while other experts in the field point to other weaknesses as the root cause of the American REE Goliath's undoing.

When China put a chokehold on its exports of rare earth elements in 2010, Molycorp was already well on its way to seizing the opportunity to reopen the Mountain Pass Mine in California, an operation hailed for its ability to re-establish an American supply of these coveted high-technology minerals. As a result of this move to be a major non-Chinese source of rare earths, Molycorp stock rocketed from around US$10 per share in April 2009 to US$74 a share one year later. Five years hence, stock in the American rare earth miner has plummeted to less than US10 cents per share and in a bid to keep Mountain Pass in operation the company has filed for protection from its creditors under Chapter 11 reorganization.

While rare earth prices are only a fraction of what they were when Mountain Pass went into production, at least one rare earths expert contends that Molycorp's troubles are largely a product of dumping too much money into restarting the California rare earth mine and not enough into the needed supply chain infrastructure.

"The fundamental reason for the failure of Molycorp has been its business model's lack of recognition of the fact that China's success in monopolizing the rare earth space is due entirely to its constructing a total domestic rare earth supply chain feeding into the huge Chinese domestic end user manufacturing industry," Jack Lifton, a technologies metals consultant, wrote in a June 1 column for InvestorIntel.

Despite the plight of Molycorp, Lifton believes there is hope for other companies that are looking at building smaller rare earth mines on American soil and have invested the resources into developing the

*"The fundamental reason for the failure of Molycorp has been its business model's lack of recognition of the fact that China's success in monopolizing the rare earth space is due entirely to its constructing a total domestic rare earth supply chain feeding into the huge Chinese domestic end user manufacturing industry," —**Jack Lifton, technologies metals consultant***

requisite downstream technologies.

"There is some light at the end of this tunnel. A very few juniors are attempting to build in-house capacity to separate the rare earths from clean concentrates, and as Chinese costs move sharply upward along with Chinese demand for consumer goods, there is an opportunity for a domestic North American total rare earth supply chain of the right size," Lipton wrote.

Ucore Rare Metals Inc., which is advancing the Bokan Mountain project in Southeast Alaska, Rare Element Resources Ltd., which has applied for permits to develop its Bear Lodge project in Wyoming, are two companies that fit Lifton's description.

Bokan Mountain and Bear Lodge both have healthy percentages of the more highly sought heavy rare earth elements, and both companies have developed innovated technologies to separate the tightly interlocked rare earths.

Rollercoaster rare earth prices

While business strategy played a role, Molycorp's sharp rise to notoriety and precipitous fall to bankruptcy tracks a similar rollercoaster-like curve of REE prices.

For example, europium oxide rose from US$475 per kilogram in 2008 to a peak of US$3,800/kg in 2011. Today, this mineral used as a red phosphor in televisions has fallen to about US$225/kg. Most of

see **REE PRICES** page 13

Molycorp Inc. bankruptcy raises questions on the future of the U.S. rare earths sector. Read more in Mining News, page 11.

Shell fleet continues to mobilize; impact of vessel damage unclear

Some of the vessels participating in Shell's Chukchi Sea exploration drilling project have departed Dutch Harbor for the drilling area, Shell spokesman Luke Miller told Petroleum News in a July 6 email. But the semi-submersible drilling rig, the Transocean Polar Pioneer, remains in Dutch Harbor for the time being, and the drilling vessel Noble Discoverer is still in transit from the U.S. West Coast to Dutch Harbor, Miller said.

Shell has said that it hopes to start drilling in the third week of July, but the timing will depend on how quickly the winter sea ice retreats from the drilling locations

The drilling project has encountered a problem in that, on July 3, the crew of the ice management vessel, the MV Fennica, discovered a leak in the vessel's ballast tank after the

see **SHELL FLEET** page 22

2nd round of Cook Inlet producer changes as Hilcorp picks up MGS

Hilcorp Alaska is in the process of acquiring the Middle Ground Shoal field, cycling a Cook Inlet oil field well past its peak through to a third owner.

Platforms and facilities installed by Shell in 1964 and 1967 at the Middle Ground Shoal field in Cook Inlet were sold to Cross Timbers Oil Co. in 1998. It was a transfer from a major which had worked on initial Cook Inlet development to an independent, focused on getting more oil out of an existing field past its peak and too small to be of continuing interest to a major producer.

As Cook Inlet production continues to decline, now averaging fewer than 20,000 barrels per day compared to a peak in 1970 of more than 227,000 bpd, the basin has seen the depar-

see **HILCORP MOVES** page 24

EXPLORATION & PRODUCTION

Taking a next step

ExxonMobil applies for AOGCC gas injection order for Point Thomson field

By ALAN BAILEY

Petroleum News

In another move towards bringing the huge Point Thomson gas condensate field on the North Slope into production, ExxonMobil, the field operator, has applied to the Alaska Oil and Gas Conservation Commission for permission to inject gas into the field reservoir. In a July 7 AOGCC public hearing company officials told the commissioners that the production of condensate from the field will require the recycling of 194 million cubic feet per day of natural gas from the field, with that gas being injected at high pressure into the reservoir through two injection wells.

The Point Thomson field reservoir contains a mixture of natural gas and condensate, a very light form of oil, at a very high pressure. Because reservoir pressure must be maintained, to prevent the condensate dropping out of solution inside the reservoir, gas at high pressure will need to be continuously cycled through the reservoir using an appropriate configuration of wells. Condensate will be extracted from the gas after the gas reaches the surface through a production well, before the gas is sent back underground through injection wells. The condensate will be transported by

But results from the PTU-15 and PTU-16 wells have caused the company to rework the model, with those wells demonstrating that the quality of the reservoir is better than previously thought, Dougherty said.

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EXPLORATION & PRODUCTION

Cosmo partially approved

Second Cosmopolitan unit smaller than first, proposal, covers core development

By ERIC LIDJI

For Petroleum News

The state has partially approved the formation of the Cosmopolitan unit.

Alaska Department of Natural Resources Division of Oil and Gas Director Corri Feige has agreed to let operator BlueCrest Energy Inc. form a unit over portions of five Cook Inlet leases known to include oil reservoirs in the Hemlock and Starichkof reservoirs but declined to let the unit include two other leases and a segment of a third, according to a June 26 decision.

Feige partially denied the request because BlueCrest did not commit to develop or delineate those additional areas of the proposal Cosmopolitan unit area, she wrote.

The approved unit covers 14,423 acres off the coast of Anchor Point. At its maximum extent, the unit boundaries BlueCrest had proposed would have covered 22,535 acres.

The initial plan of development for the unit, which runs through the end of the year, concerned state officials, who are eager to maximize development in the area.

see **COSMO UNIT** page 23

NATURAL GAS

25-year tax shelter

BC-Pacific NorthWest deal promises compensation for tax hikes, regulatory changes

By GARY PARK

For Petroleum News

The British Columbia government of Premier Christy Clark wants to tie the hands of current and future administrations over 25-year periods by shielding projects against any changes to provincial taxes and regulations.

A 37-page project development agreement signed in May with Malaysia's Petronas, operator of the Pacific NorthWest consortium, is designed to establish the "rules of the game" for Pacific NorthWest that will carry over to any other projects, Finance Minister Mike de Jong said.

He said the deal provides a "measure of stability."

The pact locks in the status quo on three taxes that apply to the sector: The LNG income tax enacted by the provincial legislature last year; the natural gas tax credit on corporate income taxes; and the British Columbia carbon tax. A similar lock-in would apply to any greenhouse gas regulations.

The project development agreement also includes a "me too" clause that would allow Pacific NorthWest to take advantage of any more favorable terms negotiated with other projects.

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● GOVERNMENT

Gara: Walker's tax credit vetoes prudent

Anchorage Democrat House Finance Committee veteran anxious to see progress on Alaska LNG project, says current plan needs tweaking

By STEVE QUINN
For Petroleum News

House Rep. Les Gara arrived in the Capitol halls in 2003, and has spent most of his time on the House Finance Committee. He's seen several major tax rewrites and some starkly different plans to advance a natural gas line plan to tap into the North Slope's vast reserves.

The Anchorage Democrat shared his thoughts on where things stand with the state's resource development prospects, including the pipeline that would deliver natural gas to a liquefied natural gas export facility.

Petroleum News: During the budget debates you were pretty steadfast on bringing the oil tax credits into the budget debate. Ultimately, it played a role in the governor's final vetoes. Were you surprised?

Gara: Hopefully industry understands reality. Some of these investors are from outside of Alaska. We'll always pay the tax credits that we owe. With the $4.5 billion deficit, we've got to level out the payments. There is a statute that puts a minimum on what the state us obligated to pay. Gov. Walker is still paying more than $400 million more than we are required to and I'm sure he'll still keep paying at that level. Applications come in — first come first paid.

If we run out of money this fiscal year, the folks at the end of the line will have to wait an extra two or three months. It shouldn't be a big burden. Not when schools are being cut and seniors are facing cuts. It's a pretty minimal burden for an oil company. Hopefully the outside investors will have enough familiarity with the law to understand that.

Petroleum News: Do you want to see whether these credits are working as people hoped when you return next session?

Gara: It's always worth it to know whether the credits are working. You don't want to give a company hundreds of millions of dollars for something that they would have done without the state money. That's when tax credits fail. You want to make sure the tax credits are encouraging new development that wouldn't have happened without the tax credits otherwise you're just giving away money. It's worth it always to take a look at how the tax credit system is working and analyze whether the development would have happened anyway. We probably need to narrow the definition a little bit. We need to take a look at our oil tax system to make sure it's fair to industry and it's fair to the state. Right now I think the state is getting the short end of it.


REP. LES GARA

Petroleum News: If any of these credits come under ACES, you supported those in 2007.

Gara: I voted for ACES and I thought it was a good deal. The state brought in a whole bunch of new players who are still developing in Alaska. They have incentive to say they are here because of the new oil tax law, but they came here under ACES. We are still seeing development from companies who came up here under ACES. That's just the truth about it. As somebody who voted for ACES, you also still have to see if it needs to be tweaked. I would have changed ACES some, but not given away the farm as some did when they passed SB 21 in 2013.

That bill says all fields after 2002 get the state a near zero or a negative net present value in production taxes. We can't live on a negative net present value on a production tax. That was a major giveaway that needs to be looked at.

Petroleum News: The governor says this is a starting point for review. Do you see it that way, too?

Gara: The governor is pro development. I'm pro development. But there is a difference between pro development with the governor and former great governors like Wally Hickel and Jay Hammond. They were all pro development, but they wanted to make sure the state got its fair share. We need to fund schools and roads and energy projects. If we just give away our oil with a production tax that results in near zero or negative net present value, then the state is managing its oil resource way worse than any private company would manage its assets. No company invests in things that don't bring a positive net present value.

Q AND A

Petroleum News: Speaking of taxes and the governors, Gov. Walker sent a letter to the Resources committees that was made public. One of the things he noted is that he believes the state would be willing to take a 25-year term on fiscal stability and believes a state constitutional amendment is necessary. How do you feel about a constitutional amendment for the gas taxes?

Gara: I'm going to have to go into this with my mind open. I don't necessarily like tying the rate down because the rate that Gov. Parnell got passed is among the lowest in the world. If it were a rate that was much more fair, I would consider locking it in. If you've got a flat tax and all of the sudden the price went up to $30 an mcf, I think it would be a loser if you didn't have some sort of clause if you didn't allow the tax to move a little bit. If he was going to promise a locked-in tax rate, I would hope it would be a better tax rate than what Gov. Parnell proposed.

Petroleum News: Gov. Walker also said he would not include oil for the locked-in rate. Do you prefer a separation if there is to be an amendment?

Gara: Yeah. I'm going to have to consider the whole locked-in rate thing on gas. I don't think you ever want to ever lock in your oil taxes. When Gov. Murkowski tried to do that in early 2000s, he would have locked in oil taxes that would have cost us probably over $10 billion in lost revenue. Thank God we didn't go with his locked-in tax rate and we changed the law and built a surplus, which is why the state can survive fiscally right now.

Petroleum News: Do you think the public would have an appetite for this kind of amendment if it were just on natural gas?

Gara: I think the public, if it saw a fair tax rate on natural gas and saw a fair project for the state of Alaska and saw companies willing to engage in Alaska hire, saw gas prices and gas production for in-state use and export, I think their minds would be open. This is a long-term dream for this state so I think everybody wants to move it forward. You just want to make sure it's fair terms.

Petroleum News: Another issue being discussed is a 42-inch line with expansion capabilities versus a 48-inch line. The governor has said he wants a 48-inch line. What are your thoughts?

Gara: I agree with the governor on that. You want the line to be bigger because it produces cheaper natural gas. You want the bigger line because that allows for more room for natural gas for independent producers. The smaller the line the more it gets monopolized by the Big 3 oil companies. The bigger the line, the better chance we have of attracting independent explorers.

Petroleum News: So what would be wrong with a 42-inch line with expansion capabilities?

Gara: The first round of expansions tend to be affordable but the second round of expansion tends to be so expensive that nobody will be able to do it, so

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● FINANCE & ECONOMY

Low oil prices push US production down

EIA forecasts Brent to average $60 per barrel this year, $67 in '16; US production projected to continue falling through early '16

By KRISTEN NELSON
Petroleum News

The U.S. Energy Information Administration is forecasting the North Sea Brent crude oil price to average $60 per barrel this year and $67 per barrel in 2016. EIA said in its Short-Term Energy Outlook, issued July 7, that during June Brent averaged $61 per barrel, down $3 per barrel from May, but noted that prices fell some $4 per barrel July 6 in the aftermath of the no vote on the economic package in Greece, as well as on lingering concerns about lower economic growth in China, higher exports from Iran and continuing growth in global petroleum and other liquids inventories.

While a percent drop of that volume is unusual, EIA said, monthly Brent prices have averaged between $55 and $65 per barrel since falling to $48 per barrel in January.

The agency said oil prices have been relatively stable in recent months despite consistent growth in global petroleum and other liquids inventories, up by an estimated 1.9 million barrels per day in June and an average of almost 3 million bpd in April and May, compared to an average build of 800,000 bpd in the second quarter of 2014. EIA said it projects inventory builds will moderate somewhat in the coming months, but expects inventories to remain high compared with previous years.

EIA cautioned that current values of futures and options contracts "continue to suggest high uncertainty in the price outlook."

WTI up $1 from May

West Texas Intermediate spot prices are projected to average $5 per barrel less than Brent this year and next.

EIA said WTI averaged $60 per barrel in June, up $1 per barrel from May.

Crude oil inventories at Cushing, Oklahoma, which had increased for 20 consecutive weeks to a record 62.2 million barrels April 17, have decreased by 5.8 million barrels as of June 26, EIA said. "Along with falling Cushing inventories, strong U.S. refinery runs and production outages in Canada have put upward pressure on the price of WTI crude oil," the agency said.

EIA cautioned that current values of futures and options contracts "continue to suggest high uncertainty in the price outlook."

US production in decline

"While U.S. crude oil production is expected to decline over the months ahead, total output in 2015 is on track to be the highest in 45 years," EIA Administrator Adam Sieminski said in a statement.

"The forecast decline in U.S. monthly oil production through early 2016 is the result of low oil prices, which pushed oil companies to reduce their investment in drilling that resulted in the lowest number of rigs drilling for oil in nearly five years," he said.

"While U.S. crude oil production is expected to decline over the months ahead, total output in 2015 is on track to be the highest in 45 years." —EIA Administrator Adam Sieminski

The agency said U.S. crude oil production averaged 8.2 million bpd last year and is projected to increase to 9.5 million bpd this year and decline to 9.3 million bpd in 2016, a forecast of some 40,000 bpd higher for 2015 and 2016 than in the June Short-Term Energy Outlook, with the increase reflecting upward revisions of estimated Gulf of Mexico production in the second quarter of 2015.

EIA said it estimates that U.S. crude oil production averaged almost 9.6 million bpd in the first half of the year, 300,000 bpd higher than the average production in the fourth quarter of 2014, despite a 60 percent decline in oil-directed rigs since October.

The agency said the most recent estimates, through April 2015, indicate U.S. output of 9.7 million bpd in April, and said it estimates U.S. production began falling in May, down some 50,000 bpd from April, and while total U.S. production increased in April, "the data indicate that onshore production began declining in April."

First quarter 2016 production is projected to average 9.2 million bpd, with production expected to begin rising in the second quarter, returning to an average of 9.6 million bpd in the fourth quarter.

EIA said 13 Gulf of Mexico projects are scheduled to come online in 2015 and 2016, pushing production in the area from an average of 1.4 million bpd in the fourth quarter to almost 1.7 million bpd in the fourth quarter of 2016, a 17 percent increase.

Unattractive economic returns

EIA said expected U.S. crude oil production declines are due to "unattractive economic returns in some areas of both emerging and mature onshore oil production regions, as well as seasonal factors such as anticipated hurricane-related production declines in the Gulf of Mexico."

Cash flows and capital expenditures are down this year, the agency said, prompting companies "to defer or redirect investment away from marginal exploration and research drilling to focus on core areas of major tight oil plays. Reduced investment has resulted in the lowest count of oil-directed rigs in nearly five years."

But projected oil prices this year do remain high enough to support development drilling in core areas of the Bakken, Eagle Ford, Niobrara and Permian basins, EIA said, with falling drilling rig and completion costs making rig count increases and resumption of onshore production growth possible next year. ●

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● EXPLORATION & PRODUCTION

Canada's shifting sands

Oil sands sector leans toward 'bite-sized' projects, away from mega operations, with some applications pulled, growth scaled back

By GARY PARK

For Petroleum News

Imperial Oil has launched production ahead of schedule from an C$8.9 billion expansion of its largest oil sands operation entering a robustly priced market for heavy oil.

The second phase of the company's Kearl oil sands mine will double capacity to 220,000 barrels per day (with plans in the works to add another 125,000 bpd), making the major contribution to an expected increase this year of 300,000 bpd to Alberta's current oil sands output of 2 million bpd.

Also in the startup stage are ConocoPhillips' 118,000 bpd second phase at its Surmont in-situ facility; Husky Energy's initial 60,000 bpd at its 200,000 bpd Sunrise project; and Imperial's addition of 40,000 bpd to its 140,000 bpd Nabiye Cold Lake in-situ operation.

All of those elements carry a ring of business-as-usual, but that's far from accurate amid the economic, political and environmental turmoil afflicting the sector, as oil prices remain on a wobbly high-wire and companies make desperate efforts to shore up their balance sheets in anticipation of more downside risk around the corner.

Even so, Imperial can draw some comfort from its Kearl experience, with Chief Executive Officer Rich Kruger noting that the project benefited significantly from his company's "design one/build multiple" approach combined with the expertise of its 70 percent parent ExxonMobil in project planning and execution and lessons learned from Kearl's initial phase.

Low discount

CIBC World Markets analyst Arthur Grayfer told clients that after achieving Kearl's 220,000 bpd capacity in the next year the facility is "expected to remain flat for a couple of years as management determines optimal bottlenecking initiatives," which should take place in 2018.

Martin King, a commodities analyst at FirstEnergy Capital, said the new Kearl volumes coincide with a discount of less than 8 percent between Western Canada Select and West Texas Intermediate, compared with the usual spread in the teens.

"We, along with everyone else, really weren't expecting to see these single-digit differentials that you've seen over the past month or so," he said.

But King is forecasting that the differential will return to the low teens later this year if WTI remains around US$60 a barrel.

The mild uptick in prices has helped counter lingering oversupply concerns, regardless of OPEC's continuing effort to use prices as the tool to build its market share.

Some production hikes, some delays

Some of the major oil sands producers have even hiked production in recent months, while lowering expansion plans to conserve cash, although Imperial and sector leader Suncor Energy have opted to finish work that was started before the slide in oil prices last year, while indicating they will shift their focus from mega-mines to drilling programs that deliver quicker returns and require less investment.

Once the Suncor-led Fort Hills mine — in partnership with Teck Resources and France's Total — starts a 50-year, 180,000 bpd production life in 2017, the company will scale back its growth program to one drilling project a year of up to 40,000 bpd, said Chief Executive Officer Steve Williams, adding that there is no sign on the horizon of Suncor's next mine.

Suncor has estimated Fort Hills can generate a 13 percent internal rate of return over its lifetime.

Others joining that school of thought include Royal Dutch Shell, which pulled a regulatory application to build a 200,000 bpd Pierre River mine and stalled by at least two years its 80,000 bpd Carmon Creek project in northwestern Alberta.

For the second time this year, Sunshine Oilsands has delayed the start of steam-injection at its 5,000 bpd West Ells project, which was scaled back two years ago from its targeted two-phase, 40,000 bpd development.

What startled many observers was the shaky explanation from Sunshine, which said it wanted to "assure facilities performance and achieve nameplate capacity."

It said construction is "substantially completed" and various facilities are in the middle of being commissioned, yet the company — 14 percent owned by Chinese entrepreneur Kwok Ping Sun — opted to back away.

If Sunshine was looking for a reason to be edgy one was offered by insolvent Laricina Energy, which has shut down its 100 percent owned Germain commercial demonstration project and is negotiating with 40 percent partner Osum Oil Sands to close its Saleski pilot and shelve plans for a C$520 million, 10,700 bpd commercial project.

For now Laricina is operating under bankruptcy protection from a demand by a subsidiary of the federal government's Canada Pension Plan Investment Board for payment in full of senior secured notes.

Husky: 'bite-sized modules'

Speaking for those who have deeper pockets, Rob Peabody, chief operating officer of Husky, said the in-situ, or thermal-recovery sector of the oil sands, is now giving preference to "more bite-sized modules," which can be constantly replicated, allowing operators to "strip out engineering costs."

Consistent with that line of thinking, Husky has started steaming operations at its 10,000 bpd Rush Lake thermal recovery project in Saskatchewan and has three more in-situ operations due on stream over the next few years — its 10,000 bpd Edam East project, its 10,000 bpd Vawn project and 4,500 bpd at Edam West.

Among the startups, Pengrowth Energy is now ramping up output from its Lindberg project in the Cold Lake area of northeastern Alberta, doubling volumes this year to 10,500 bpd and aiming for 16,000 bpd by the end of 2015.

The contrast in construction and operating costs is obvious at the high end, with Cenovus Energy needing only 430 workers to produce 136,000 bpd from its Foster Creek in-situ project, while Syncrude Canada's 400,000 bpd mine and upgrader has about 8,500 workers on site.

Concern over taxes

But the lingering concern for all oil sands operators is how far the new Alberta government will go in raising corporate taxes and adding to environmental regulations.

Tim McMillan, president of the Canadian Association of Petroleum Producers, said producers are prepared to take a greater leadership role on climate action as part of the growing global drive to reduce greenhouse gas emissions.

He said Alberta "developed the technology to get the oil out of the sand — and we are just as committed to get-

see **SHIFTING SANDS** *page 6*

Making case for Keystone

Grasping at a new opportunity, TransCanada is making a case that Canadian climate change commitments should bolster its case in the Obama administration for Keystone XL.

Development President Alex Pourbaix said announcements by the Canadian and Alberta governments to cut greenhouse gas emissions should be considered by the U.S. State Department as further evidence that the pipeline would not "significantly exacerbate" carbon output — the crunch point established by President Barack Obama to gain his approval through a Presidential Permit.

A letter to the department also noted that chief executive officers of some of the biggest oil sands producers, including Suncor Energy and Cenovus Energy, plus European based operators such as Royal Dutch Shell and Total, have urged tougher carbon pricing measures.

"Clearly recent Canadian, North American and international GHG policy developments are consistent with President Obama's stance on not exacerbating the risk of climate change," Pourbaix wrote.

In any event, he said the United States will need oil to meet its transportation needs for the "foreseeable future" and will remain a net importer of oil "for decades to come," meaning Keystone XL and Canadian heavy crude will play a vital role.

Erin Flanagan, an oil sands analyst with the Calgary-based Pembina Institute, said the Canadian and Alberta policy announcements "have not translated into real change ... so TransCanada's argument that these policy developments should green-light the project don't hold water."

—GARY PARK

GOVERNMENT

Walker vetoes $200 million in tax credits

Calls this first step in discussion; will delay payment to smaller companies; governor also vetoes $175,000 in Arctic Power funding

By STEVE QUINN
For Petroleum News

Gov. Bill Walker's delayed payment of $200 million worth of oil tax credits sent a stark public message about the state's economy: no group or industry gets held harmless.

In what many consider to be the boldest veto in recent memory by an Alaska governor, Walker surprised even those advocating for such a measure when he reduced the amount from $700 million to $500 million.

"We are way beyond low-hanging fruit," Walker said in a July 1 news conference with reporters in Juneau. "We are now into the part where people are going aware of the financial situation we are in."

Walker says this veto begins a renewed look at how the state will stimulate investment into the state's oil patch, be it the North Slope or Cook Inlet.

Walker told reporters that he did meet with various industry leaders, providing them a heads up on his decision before going public.

"What I wanted to emphasize to them this is not a shift in policy; this is not a shift in direction for the state of Alaska," he said. "This is recognizing my fiduciary obligation to the state of Alaska to make sure that everybody is somewhat at the table of this discussion going forward."

GOV. BILL WALKER

Options for tax credits

Those who qualify for tax credits have three options: use it against an obligation should they have one; sell it to a taxpayer with an obligation, likely at a reduced value; or have the state purchase the credit.

Per a formula under Alaska statute, the state needed to have at least $91 million available.

Moving forward Walker says he's concerned that the tax credits could be the state's largest financial obligation, overtaking education and Medicaid, adding that exploration payments could be as high as $1.3 billion next fiscal year.

"We need to be mindful of that, and look to see if there is another way we can provide incentives in such a way that it doesn't drain our resources and we are borrowing money to do that," Walker said.

During the regular legislative session, and special sessions that followed, many leaders in the House and the Senate routinely used the phrase "everything is on the table," when discussing how to address a budget shortfall reaching $3 billion.

That now includes the state's oil tax credit system.

Lawmakers respond

But at what cost, some lawmakers wonder.

"Right now I don't know what message we are sending to some of these independents and the lending institutions that provide financing on these projects," said House Speaker Mike Chenault, a Nikiski Republican.

"So I really don't know what's next," he said, "but it's going to be a discussion we will have to have between now and next session, and then see what transpires out of those."

The veto reflects efforts by Democrats in the respective minorities who sought this delayed payment, but it also caught them by surprise.

House Rep. David Guttenberg, who serves on the House Finance Committee, said no one from his caucus lobbied Walker for the veto.

"I didn't see it coming," said Guttenberg, who did try getting the reduction into the operating budget through amendments in the committee and on the floor.

Guttenberg said he likes the governor's idea of taking a close look at the credits and what value is being brought to the state.

"It's healthy to be looking at what we were doing," said the Fairbanks Democrat. "When we are spending a lot of money, we need to ask ourselves, are we getting the results we wanted? I'm all for the credits. If it produces oil and gas by giving them credits, that's something we should be doing.

"But I still think we need to ask ourselves what we are doing compared to what other jurisdictions are doing. What I'd like to see is a report of what other sovereigns are doing."

Concern for small producers

Senate Resources Chair Cathy Giessel says she's worried that the delayed payment may have undermined the work lawmakers have done the last several years, especially with the tax re-write under Senate Bill 21, but also changes under the Cook Inlet Recovery Act.

"I am concerned that the governor's announcement of postponing $200 million of tax credits has had the unintended consequence of killing financing for these smaller producers," said the Anchorage Republican. "I am hearing from several smaller producers that their financing is now gone, that their projects are now on hold.

"You know the Legislature had worked really hard over the past few years to diversify our oil fields hoping to invite in the smaller producers who would bring in new outlooks, new technology, new funding. All of that has been wildly successful."

Arctic Power funding vetoed

In addition to delaying the credit payments, Walker also vetoed $175,000 for the group that's lobbied with little success to open the Arctic National Wildlife Reserve for oil exploration and production.

This comes six months after Walker spoke out against the Obama administration's intent to designate the coastal area as wilderness.

"You know I have been a long proponent of development of oil and gas in Alaska, and I will continue to work on ways that we can do that. The Arctic Power folks have done a phenomenal job. I remember when Roger Herrera started Arctic Power about 25 years ago, but this year we are not going to fund that effort on Arctic Power.

"I have taken up that challenge a bit, on the opportunity on ANWR. I've had a half a dozen meetings with the secretary of Interior (Sally Jewel) and I've had three meetings with the president. I'll continue to have more. So our not funding Arctic Power should not be interpreted as a lack of interest in ANWR. It's the opposite. It's just an acknowledgement of the fiscal situation we are in right now." ●

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SHIFTING SANDS

ting our carbon out of the air."

The said that since 1990, companies have reduced GHGs per barrel by 30 percent and are investing more than C$1 billion on innovative technologies that will produce oil from bitumen deposits with lower GHGs than other sources of oil.

"Climate change is a global challenge that needs to be tackled with broad-based policies that consider production and consumption by everyone." McMillan said. "We will lead on technology and policy, but climate change is greater than the oil sands, greater than Alberta. Everyone has a role to play." ●

Contact Gary Park through publisher@petroleumnews.com

GOVERNMENT

Not-so-neighborly

Saskatchewan ready to sell its oil and natural gas 'advantages' to industry investors who are having second thoughts about Alberta

By GARY PARK
For Petroleum News

It's not considered fair ball to openly take advantage of your wounded neighbor, but apparently in these tough times for the petroleum industry all is fair.

That seems to be the case between Alberta and Saskatchewan, whose adjoining governments have changed their political colors in the most dramatic fashion.

No Canadian province has experienced longer rule over the past 60 years under the left-wing New Democratic Party than Saskatchewan and no province has been more averse to the NDP than Alberta.

The tide turned in 2007 when Saskatchewan elected Brad Wall as its premier and installed his conservative-minded Saskatchewan Party as its government.

That might have been a mild shock, but it was nothing compared with the May landslide election of the NDP in Alberta, ending 44 years of unbroken Conservative Party rule.

Nervous tremor in Alberta

Under Premier Rachel Notley, the new Alberta government has sent a nervous tremor through its mainstay oil and gas sector by pledging to conduct a review of royalties, possibly starting late this year.

At a time when billions of investment dollars were being pulled off the table, thousands were losing their jobs and corporate taxes were being raised to 12 percent from 10 percent, the prospect of royalty hikes has prompted many companies to warn of pullbacks in their operations.

The new layer of uncertainty has prompted Wall to assure companies that his government won't change its own royalty regime and, in a mildly combative manner, said he will travel to Alberta to promote the "Saskatchewan advantage" which has included a series of incentives and royalty reductions since he came to power.

That message was reinforced by Energy Minister Bill Boyd who told the Global Petroleum Show in Calgary that the shift of capital to Saskatchewan has already happened and more is expected.

"I think companies are looking for jurisdictions where there is stability, certainly regulatory and royalty stability," he said. "A lot of them are saying that they are certainly not looking to make any large investments or new investments (in Alberta) until the atmosphere or the climate is known.

"If royalties are raised too much and it's out of step with the royalty rates in other places than that capital will move to other jurisdictions," Boyd told reporters.

Not that it is in direct competition with Alberta, but Newfoundland, which relies strictly on its offshore oil production as a revenue source, has said it will move back to a generic royalty regime, rather than negotiating separate royalties for separate projects.

Fiscal term review

Graham Kellas, vice president of global research at energy consultancy Wood Mackenzie, said that oil-producing governments around the world that are reviewing their fiscal terms to make up for shortfalls should resist those temptations.

"The oil revenue 'cake' has shrunk and it is hard for governments reliant on oil tax revenue to agree to a smaller slice of what is left," he said. "But, if they don't offer better terms, the industry may simply stop investing."

Alberta Energy Minister Margaret McCuaig-Boyd has continued to reassure the industry that it has little to fear.

"Our approach to strengthening Alberta's energy future will continue to be informed by the expertise of our partners in the industry," she said in an emailed statement. "Our meetings with industry have been productive and collaborative and we are confident they'll continue along that path."

McCuaig-Boyd said the government is asking for the industry's advice, adding that both sides have agreed to "work together as partners for the betterment of a vibrant energy industry."

The Canadian Association of Petroleum Producers said its member companies have met with McCuaig-Boyd several times "to talk about the importance of competitiveness to our industry."

If there is a breakdown in this building relationship, the industry has demonstrated in the past — notably in 1980 after the Canadian government introduced a fixed oil price and in 2007 after Alberta hiked royalties — that it is ready to shut down operations and pull out of Alberta. ●

Contact Gary Park through publisher@petroleumnews.com

ASSOCIATIONS

RDC appoints Hall new executive director

Marleanna Hall has been named the new executive director of the Resource Development Council for Alaska. The appointment was announced at RDC's annual meeting luncheon June 30 in Anchorage, following the announcement that Rick Rogers has retired as executive director and has been named to RDC's board of directors.


MARLEANNA HALL

"Marleanna brings eight years of RDC member issue work and experience to the helm," Ralph Samuels, RDC board president and vice president, government and community relations for Holland America Line, said in a statement.

Hall has been projects coordinator for RDC, and was formerly development director for the Alaska Mineral and Energy Resource Education Fund, now Alaska Resource Education. She previously worked at Tesoro Alaska Co. and the Arc of Anchorage. Hall holds a bachelor's degree in business management-administration from the University of Alaska Anchorage. In 2010 she completed the Leadership Anchorage program through the Alaska Humanities Forum, and in 2012 completed the Anchorage Chamber of Commerce's Leadership and Executive Advancement Program.

Hall, a lifelong Alaskan, lives in Anchorage with her husband Dan.

—PETROLEUM NEWS

EXPLORATION & PRODUCTION

US drilling rig count up 3 prior to 4th

Baker Hughes said the U.S. oil and gas drilling rig count was 862 July 2, up three from the previous week's count of 859. For the same week in 2014 the count stood at 1,874.

Of the 862 active rigs, 640 were drilling for oil and 219 for gas, with three listed as miscellaneous.

In the major oil and gas producing states, North Dakota and Texas were up two rigs. New Mexico and Oklahoma were each up one rig.

Colorado and Kansas were each down one rig. Louisiana was down two rigs.

Alaska, California, Pennsylvania and Wyoming were unchanged.

The U.S. drilling rig count peaked at 4,530 in 1981 and bottomed out at 488 in 1999.

—PETROLEUM NEWS

● ENVIRONMENT & SAFETY

Canada entering a transition

63% of corporate leaders see change in policy direction, away from mining, cars, oil, to info tech, renewable energy, services

By GARY PARK

For Petroleum News

Interviews with 153 Canadian corporate leaders have pinpointed the quandary of the industrial world as it grapples with how far and how fast the economy can act to wean itself off carbon-producing resources.

In its 39th quarterly survey, 63 percent of the Gandalph Group's so-called C-Suite — including a startling 64 percent in Alberta and 91 percent in the industrial heartland of Ontario — agreed that the Canadian economy is too closely tied to Alberta's economy and its natural resources.

They said policy directions must change over the next decade, with the balance tilting to information technology, renewable energy and services and away from mining, automotive and oil.

David Herle and Alex Swann, Gandalph executives, said the C-Suite executives believe that United States-China climate talks will force Canada to do more to reduce its reliance on fossil fuels.

David MacDonald, chief executive officer of Softchoice Corp., a Toronto-based technology services firm, said the need to shift is gaining momentum in corporate and investment circles, reflected by a record spurt in initial share offerings outside the energy sector.

He said there is clear evidence that equity markets are "starting to focus on non-resource-based companies."

MacDonald said that even the Canadian government shares that thinking, reinforced by Prime Minister Stephen Harper's surprising decision recently to join a Group of Seven declaration that the world should abandon fossil fuels by 2100.

But he said that decision is suspect "given the continuous focus by the government on how to export more oil."

Still call for pipelines, refineries

The dilemma among executives who participated in the survey was evident with more than half endorsing government help for energy pipelines, mining and oil refinery construction, which they believe will continue to expand.

However, Chris Dobrzanski, chief economist at the Vancouver City Savings Credit Union, said the executives appear to realize that energy alternatives to the oil sector are becoming more viable, with clean energy projects now reaching a point where they are able to make a dent in traditional power sources.

Willy Kruh, global chair of consumer markets at KPMG, the global professional services company, said the challenges facing Alberta's petroleum industry will also force that province to act on its long commitment to diversification.

He noted that investment in renewable energy projects is expanding beyond venture capitalists to big players such as Suncor Energy, Enbridge and TransAlta, who have steadily expanding clean energy portfolios.

Dobrzanski said the executives are accepting that governments, acknowledging the imperfections of the traditional marketplace, need to play a role in advancing the lower carbon environment through offering incentives to cleaner technology, or by putting a price on carbon.

Role for natural resources

Francis McGuire, chief executive officer of the Major Drilling Group International, a service firm that works closely with the mining industry, was not prepared to accept that the oil and mining sectors will disappear, arguing natural resources will always play a crucial role in the economy.

He had strong support from 57 percent of the C-Suite executives, who said oil will be oil will be a more important factor in 10 years than it is now.

McGuire said Canada's objective should be to apply new technologies to the resource sector, if it hopes to diversify its economic base.

Willy Kruh, global chair of consumer markets at KPMG, the global professional services company, said the challenges facing Alberta's petroleum industry will also force that province to act on its long commitment to diversification.

He said it is "vital" for Alberta to understand the global pressure to change and "truly diversifies."

Has oil peaked?

David Herle and Alex Swann, Gandalph executives, said the C-Suite executives believe that United States-China climate talks will force Canada to do more to reduce its reliance on fossil fuels.

They said most outside the petroleum industry think "oil has peaked in importance to the Canadian economy and will either remain the same or diminish in importance in the next 10 years."

Herle and Swann said the "overwhelming consensus" in the C-Suite is that renewable energy and natural gas will play a growing role over the next 10 years as government policies give priority to a less carbon-intensive economy.

Despite the lack of enthusiasm for government support of industries, they said that almost 80 percent of the C-Suite endorse subsidies to develop clean energy technology.

On the election of the left-wing New Democratic Party government in Alberta, 70 percent of the C-Suite believe the new administration will hurt investment in the province, while 61 percent say the NDP will make it more difficult to gain approval for oil pipelines in Canada and the United States. ●

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ENVIRONMENT & SAFETY

USF&W publishes its polar bear plan

Says main priority for protecting bears is limiting greenhouse gas emissions; management of human interactions also to continue

By ALAN BAILEY
Petroleum News

The U.S. Fish and Wildlife Service has published a draft polar bear conservation management plan, specifying what the agency sees as the threats to the bear population and the steps needed to prevent the future extinction of the species. The development of the plan comes as a legal requirement stemming from the listing in 2008 of the bears as threatened under the terms of the Endangered Species Act. The listing of the polar bear has caused concern among people with economic interests in the Arctic, given potential restriction on economic activity as a consequence of measures taken to protect the bears.

The newly published conservation plan says that, with global warming and the resulting loss of Arctic sea ice being the prime threat to the bear's survival, the focus must be on global action to address the emission of greenhouse gases into the atmosphere. The plan also anticipates the continuation of current programs designed to limit the impacts of human actions on bears.

Comments on the draft plan are required by Aug. 20.

Updated models

Fish and Wildlife says it has updated its climate and bear population models since the bear was listed in 2008. One model now assumes greenhouse gas emissions continuing at current rates, while the other model assumes a leveling out of emissions by around mid-century, with emissions declining thereafter.

"Outcomes for polar bear populations are projected to worsen over time through the end of the century under both scenarios, but the long-term persistence of polar bears may be possible if global greenhouse gas emissions are stabilized at or below the modeled level," Fish and Wildlife said in a July 2 press release announcing the release of the draft conservation plan.

Although the plan acknowledges potential future concerns resulting from oil and gas activities, contamination from oil spills and increased Arctic shipping, the plan says that, with these factors not being identified as threats to the bears, the activities have no associated polar bear recovery criteria. However, the plan outlines actions to minimize the risks of contamination from oil and chemical spills; to protect bear denning habitat from human disturbance and industrial activity; to minimize human-bear conflicts; and to conduct research. The plan also addresses actions to better manage subsistence harvesting of the bears. And the plan will serve as the U.S. contribution to an international action plan being developed by the five polar bear range countries, Canada, Denmark, Norway, the Russian Federation and the United States, Fish and Wildlife says.

"Polar bear conservation requires a global commitment to curb the release of greenhouse gases into the atmosphere," said U.S. Fish and Wildlife Regional Director Geoffrey Haskett. "Until that happens, we're going to do everything within our power to give the polar bear a chance to survive. That's what the plan's about."

Implementation team

Fish and Wildlife proposes transitioning its current polar bear recovery team into a conservation plan implementation team, to facilitate the carrying out of actions under the plan. The agency says that it anticipates the plan being a living document, subject to periodic revisions as new insights arise. The agency has set specific criteria for determining whether the polar bear population is recovering — those criteria include the adult female survival rate; the ratio of yearlings to adult females; the bear population carrying capacity of the bear's habitat; and the rate of human-caused removal of the animals.

In terms of global warming and the global emissions of greenhouse gases, the factors that Fish and Wildlife sees as the bear's primary threats, the agency says that it will engage in a science-based communications effort, highlighting an urgent need for emissions reductions. The objective will be to try to ensure that the appropriate entities in the United States and elsewhere take actions to address human causes of global warming, the conservation plan says.

The plan also says that Fish and Wildlife will support polar bear conservation actions in the other polar bear range countries.

Continuing efforts

Actions to manage human-polar bear conflicts will include a continuation both of partnerships with the North Slope oil and gas industry, and of polar bear patrols

see POLAR BEAR PLAN page 15

USGS says GHG primary polar bear threat

New research has confirmed that global warming and the associated melting of Arctic sea ice form the primary threat to the long-term survival of the polar bear, the U.S. Geological Survey said June 30.

"This conclusion holds true under both a reduced greenhouse gas emission scenario that stabilizes climate warming and another scenario where emissions and warming continue at the current pace," the survey said.

Of particular concern is the possibility of the summer ice-free period lengthening beyond four months, as is forecast for the second half of the current century, according to the scenario in which the current rate of warming continues. Polar bears rely on sea ice as a platform for hunting seals but would have to retreat to land if the ice completely melts, the survey said.

"Other research this year has shown that terrestrial foods available to polar bears during these land-bound months are unlikely to help polar bears to adapt to sea ice loss," the survey said.

Other stressors to the bears, such as trans-Arctic shipping; oil and gas exploration; disease and contaminants; sustainable harvests; and takes in defense of life have negligible impacts on polar bear populations compared with the much larger impacts of sea ice loss, the survey said.

And, while managing threats other than greenhouse gas emissions could slow the decline in polar bear populations, "the most optimistic prognosis for polar bears would require immediate and aggressive reductions to greenhouse gas emissions that would limit global warming to less than 2 C above pre-industrial levels," the survey said.

—ALAN BAILEY

NORTH OF 60 MINING news

page 14 Novagold envisions draft EIS at Donlin Gold by year's end

www.MiningNewsNorth.com *The weekly mining newspaper for Alaska and Canada's North* Week of July 12, 2015

NEWS NUGGETS

Compiled by Shane Lasley

Ucore orders pilot REE separation plant

Ucore Rare Metals Inc. July 8 reported that it has commissioned the construction of a pilot plant that will test the use of molecular recognition technology for the separation of rare earth elements at bulk scale. Ucore has contracted with IBC Advanced Technologies Inc. for the design and construction of the plant, targeting completion before the end of 2015. The test plant, "SuperLig-One," will be constructed at IBC facilities in American Fork, Utah. Once complete, the unit will then be relocated to a third party facility for an independent review of pilot scale test procedures. "We anticipate that the SuperLig-One unit will be a high-value asset for Ucore," said Ucore President and CEO Jim McKenzie. "The intention is for the unit to be a test mule, capable of accepting pregnant leach solution and bulk concentrates from multiple prospective REE feedstock locations around the world. Ucore confirms that it has entered into agreements with various REE feedstock providers, and will be securing test material from a variety of locations over the next six months as construction is under way. One high-priority source of pilot scale test material will be the Bokan-Dotson Ridge project in Southeast Alaska." Ucore said the SuperLig-One unit, currently being designed at IBC, will be modular and portable. This will make the plant capable of transport to remote testing sites as required. Columnar units within the plant will contain customized proprietary SuperLig® products that are designed to selectively separate the metal being targeted. To optimize utility, the unit will be customizable over time, with capacity for treating varying ratios of metals in different feed solutions. At a bench scale, the SuperLig platform successfully separated the entire suite of rare earths. Ucore said the SuperLig-One unit is being designed to deploy this achievement at pilot scale, refining each of the lanthanides with the exception of promethium, plus yttrium and scandium to uniformly high purity. In addition to REE separation, IBC has an extensive inventory of pre-existing SuperLig products capable of selectively targeting a range of valuable metals, such as platinum group metals, gold, silver, uranium, bismuth, copper, cobalt, nickel, indium, and rhenium, as well as a host of nuisance materials. Ucore has an exclusive agreement with IBC for the use this technology for all metals in the tailings processing sector, as well as all processing applications related to rare

see **NEWS NUGGETS** *page 14*

TECHNOLOGY METALS

China rules REE prices

Molycorp bankruptcy raises questions on future of U.S. rare earths sector

By SHANE LASLEY
Mining News

What does Molycorp Inc.'s bankruptcy have to do with the price of rare earths in China? Some analysts say everything, while other experts in the field point to other weaknesses as the root cause of the American REE Goliath's undoing.

When China put a chokehold on its exports of rare earth elements in 2010, Molycorp was already well on its way to seizing the opportunity to reopen the Mountain Pass Mine in California, an operation hailed for its ability to re-establish an American supply of these coveted high-technology minerals. As a result of this move to be a major non-Chinese source of rare earths, Molycorp stock rocketed from around US$10 per share in April 2009 to US$74 a share one year later. Five years hence, stock in the American rare earth miner has plummeted to less than US10 cents per share and in a bid to keep Mountain Pass in operation the company has filed for protection from its creditors under Chapter 11 reorganization.

While rare earth prices are only a fraction of what they were when Mountain Pass went into production, at least one rare earths expert contends that Molycorp's troubles are largely a product of dumping too much money into restarting the California rare earth mine and not enough into the needed supply chain infrastructure.

"The fundamental reason for the failure of Molycorp has been its business model's lack of recognition of the fact that China's success in monopolizing the rare earth space is due entirely to its constructing a total domestic rare earth supply chain feeding into the huge Chinese domestic end user manufacturing industry," Jack Lifton, a technologies metals consultant, wrote in a June 1 column for InvestorIntel.

Despite the plight of Molycorp, Lifton believes there is hope for other companies that are looking at building smaller rare earth mines on American soil and have invested the resources into developing the requisite downstream technologies.

> *"The fundamental reason for the failure of Molycorp has been its business model's lack of recognition of the fact that China's success in monopolizing the rare earth space is due entirely to its constructing a total domestic rare earth supply chain feeding into the huge Chinese domestic end user manufacturing industry,"* **—Jack Lifton, technologies metals consultant**

"There is some light at the end of this tunnel. A very few juniors are attempting to build in-house capacity to separate the rare earths from clean concentrates, and as Chinese costs move sharply upward along with Chinese demand for consumer goods, there is an opportunity for a domestic North American total rare earth supply chain of the right size," Lipton wrote.

Ucore Rare Metals Inc., which is advancing the Bokan Mountain project in Southeast Alaska, Rare Element Resources Ltd., which has applied for permits to develop its Bear Lodge project in Wyoming, are two companies that fit Lifton's description.

Bokan Mountain and Bear Lodge both have healthy percentages of the more highly sought heavy rare earth elements, and both companies have developed innovated technologies to separate the tightly interlocked rare earths.

Rollercoaster rare earth prices

While business strategy played a role, Molycorp's sharp rise to notoriety and precipitous fall to bankruptcy tracks a similar rollercoaster-like curve of REE prices.

For example, europium oxide rose from US$475 per kilogram in 2008 to a peak of US$3,800/kg in 2011. Today, this mineral used as a red phosphor in televisions has fallen to about US$225/kg. Most of

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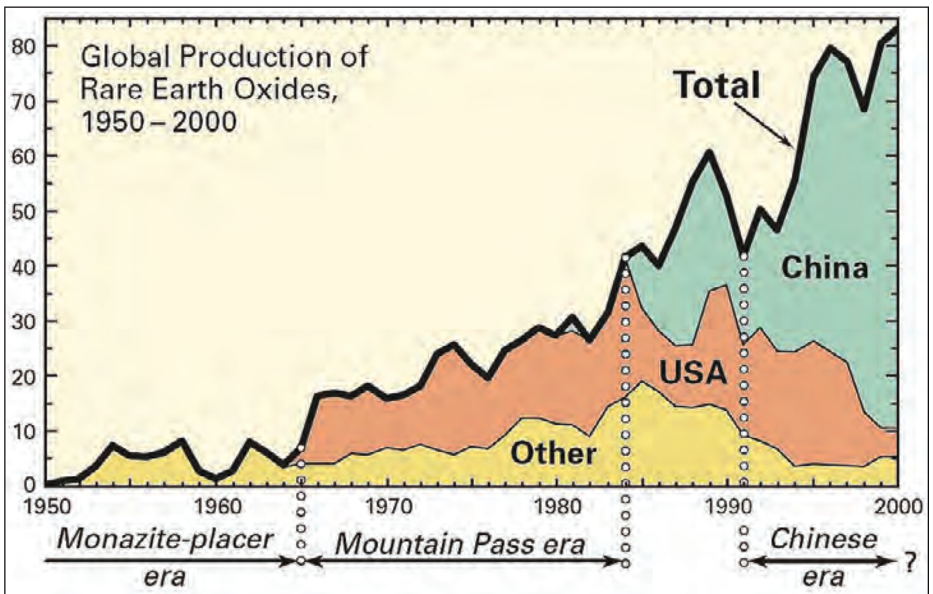
UNITED STATES GEOLOGICAL SURVEY



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REE PRICES

the rare earth oxides – including dysprosium, terbium and neodymium – followed similar tracks.

By the time Ucore completed a preliminary economic assessment for Bokan Mountain, prices for rare earth oxides had settled off their peaks but were still significantly higher than they are today.

At the time, the three-month trailing average for dysprosium oxide was US$948/kg compared with the current selling price of about US$250/kg for the highly magnetic mineral. Likewise, the three-month average price for terbium oxide was US$1,840/kg, this mineral that provides the green in trichromatic lighting is now selling for about US$535/kg; and neodymium, another highly magnetic mineral, averaged US$102/kg in 2013 and is now fetching around US$60/kg.

An August 2014 pre-feasibility study for Rare Element Resources' Bear Lodge project reflects the lower rare earth oxide prices of the time that are still higher than today's prices.

Coming feasibility studies for Bokan Mountain and Bear Lodge will likely take into account lower rare earth prices; many analysts, however, believe these high-tech metals are heading higher.

Middle Kingdom rules rare earths

Whether it is skyrocketing prices in 2010 or lower rates today, the global market price is largely due to how much China sells and the price the country asks for them.

This ability to control the sector results from a monopoly on world supplies of rare earths. Prior to the re-opening of Mountain Pass, China supplied roughly 95 percent of the world's rare earths. Today, even with the California mine in operation, the Middle Kingdom continues to control 86 percent of the market, a share that will return to around 93 percent if the Molycorp restructuring results in the shuttering of Mountain Pass.

The Middle Kingdom gained this dominant position by flooding the market with rare earths in the 1980s. By offering these elements at a fraction of the going rate, mines outside of China, including a previous iteration of Mountain Pass, were uneconomical and forced to close.

Over the ensuing two decades, China has reigned as the global low-cost supplier of rare earths, and these elements have become increasingly important ingredients in a wide range of modern products such as terabyte hard-drives that fit in the palm of your hand, high-efficiency power generation and guided missiles.

China's 2010 announcement that it was cutting its exports of critical rare earths to green energy, high-technology and defense by upwards of 40 percent sparked a price explosion that was fueled further by an over-exuberant market worried about a global shortage.

The Middle Kingdom's chokehold on global supply and excessive export taxes on REEs prompted the United States, European Union and Mexico to file complaints with the World Trade Organization, charges the global commerce group upheld.

Citing environmental concerns, Beijing appealed the ruling. In 2014, WTO rejected the appeal and China lifted its rare earth quotas at the beginning of 2015. The country, however, said exports have not reached the quota cap since 2011, due to weak global demand and rampant smuggling.

The WTO decision prompted China to lift 15-25 percent export tariffs on rare earths, a move that pushed prices lower.

Beijing, however, replaced the export tariffs with a resource tax for rare earths and other metals.

Hangpo Shen, an economist focused on China's rare earth market and editor for InvestorIntel, said the new resource tax will likely push prices higher.

"China's rare earths prices will continue to drive north as the taxes will have to be increased as the environmental costs are factored in," he wrote in a May InvestorIntel column.

Court weighs Molycorp's fate

No matter the price of rare earths in China, Molycorp's fate rests in the hands of a bankruptcy court in the United States.

Ultimately, Molycorp would like to restructure its US$1.7 billion of debt and get US$225 million in additional funds to keep Mountain Pass in operation.

"The actions we have taken today are important steps toward achieving a restructuring of our US$1.7 billion debt with our major creditor constituencies. In doing so, the company expects to exit Chapter 11 with an appropriate financing framework to support our business going forward," explained Molycorp President and CEO Geoff Bedford.

A group of investors that already hold US$650 million in secured Molycorp bonds have agreed to front the additional funds. In return, these investors – led by JHL Capital Group, JMB Capital Partners and QVT Financial LP – would swap their debt for a majority stake of Molycorp when it emerges from Chapter 11.

Oaktree Capital Management, which provided Molycorp with a US$250 million emergency financing in 2014 and has liens on segments of the company's operations, argues that another big financing is unjustified and would only serve to put the rare earth miner further in the hole.

U.S. Bankruptcy Judge Christopher Sontchi agreed with Oaktree's argument and approved a smaller US$22 million interim debtor-in-financing provided by an affiliate of Oaktree. These funds will be used to pay immediate expenses such as payroll and vendor bills. This will provide Molycorp, Oaktree and the other major debtholders time to work out a longer term

see **REE PRICES** *page 14*

NORTHERN NEIGHBORS

Compiled by Shane Lasley

Innovative exploration at Committee Bay

North Country Gold Corp. and Auryn Resources Inc. July 8 reported the start of a C$4 million summer exploration program at the Committee Bay gold project in Nunavut. The exploration program will focus on existing drill-ready targets as well as new areas identified through a recently completed prospectivity analysis on the southwest region of the Committee Bay belt. The companies said the focus of the 2015 program is to bring an innovative exploration approach to the Arctic with the goal of maximizing operational efficiencies to reduce the cost of drilling and regional exploration work. The exploration program will include: 3,000 to 5,000 meters of rotary air blast drilling utilizing a lightweight mobile drill; drone aerial imagery acquisition at 10-centimeter resolution across the entire project area; 60 line-kilometers of induced polarization geophysics; structural mapping; and a till sampling program utilizing bulk cyanide leach methodology. This exploration will focus on known and newly identified targets in the West Plains and Raven areas. Past drilling at West Plains has cut 14.76 grams per metric ton gold over 8.73 meters. At Raven, one hole drilled in 2005 cut 36.22 g/t gold over 2.43 meters. The partners also will continue to advance a deal in which Auryn will buy out the North Country Gold shares it does not already own by issuing 13.8 million Auryn shares valued at approximately US$20.4 million. The merger is expected to close before the end of September. No broker's or success fees are payable in connection with the transaction.

Gahcho Kué Mine on pace for 2016 start

Mountain Province Diamonds Inc. July 7 reported that development of the Gahcho Kué diamond mine is progressing according to plan and budget with the overall project roughly 62 percent complete at the end of May. Key areas of focus are continued dewatering to expose the kimberlites, the placement of concrete foundations and the erection of steel superstructures of the major facilities. A key milestone is to ensure that the process plant building is enclosed by October. Gahcho Kué, located about 300 kilometers (186 miles) northeast of Yellowknife, Northwest Territories, is a joint venture between De Beers Canada (51 percent) and Mountain Province Diamonds (49 percent). Mountain Province President and CEO Patrick Evans said the project is "on track for first production in (second half) 2016." According to a feasibility study completed last year, the Gahcho Kué Mine is anticipated to produce 53.4 million carats of diamonds over a 12-year mine-life. There are currently some 500 employees and contractors on site at Gahcho Kué, and this number is expected to peak at about 650 during the third quarter of 2015. During production, Gahcho Kué will employ about 400 workers.

Copper North improves Carmacks leaching

Copper North Mining Corp. July 2 reported that metallurgical work shows that a finer crush and higher temperatures improve the efficiency for recovering the copper, gold and silver at its Carmacks project in Yukon Territory. A new processing plan consists of crushing to minus-19 millimeters, followed by rod mill grinding to minus-1 then acid leaching copper in an agitated leach tank, fol-

see **NORTHERN NEIGHBORS** *page 14*

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REE PRICES

strategy.

Oaktree wants Molycorp to split the Mountain Pass Mine, which has been a money- losing proposition, from Neo Material Technologies, a company Molycorp bought in 2012.

Neo, which produces and develops iron-boron magnetic powders, rare earths- and zirconium-based materials, and other rare metals, has been the profitable arm of Molycorp.

Oaktree's investments in Molycorp are largely secured by Neo assets.

The debt owed to the investors led by JHL Capital Group, however, is primarily secured by the Mountain Pass Mine.

The Mountain Pass debtors argue that a split would result in mothballing the mine they have a vested interest in, in favor of the profitable downstream metals producing business.

All sides will have an opportunity to make their case during a hearing scheduled for July 20; in the meantime Mountain Pass will continue to churn out rare earths in California's Mojave Desert.

Once the dust settles

Despite Mountain Pass' troubles, there is still hope for the next generation of United States rare earth mines – including Ucore's Bokan Mountain, Rare Elements' Bear Lodge and Texas Rare Earth Resources' Round Top project near El Paso.

Unlike Mountain Pass, all three of these projects are rich in the more valuable heavy rare earths; and smaller mines requiring less capital are planned.

Looking ahead, Lifton believes that once Molycorp's bankruptcy dust settles, Neo Technologies could play a role in the success of three next-generation American rare earth producers.

Through the formation of strategic alliances and off-take agreements with Rare Elements, Ucore and Texas Rare Earth, Neo could emerge as a "savvy rare earth company to supply not only an American domestic market but an Asian market where their particular raw materials are much in demand right now," the consultant said.

"I believe that global capital would support such moves, and it would be difficult for the U.S. federal government to avoid involvement," he penned in a July 2 column for InvestorIntel.

The price of rare earths in China, meanwhile, will continue to factor in the profitability of mining these important materials in the United States. ●

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NORTHERN NEIGHBORS

lowed by gold and silver leaching in similar tanks. The copper leachate is to be processed in a standard solvent extraction electro-winning plant to produce cathode copper sheets, and gold and silver will be recovered using Merrill Crowe to produce doré bars. Test work indicates that raising the temperature of the acid leach for copper improves the overall recovery and significantly shortens the leach time. With a grind size of minus-1mm and a leach temperature of 40 degrees Celsius, recoveries of 88 percent were achieved within four to six hours, less than half the time for a coarser grind at ambient temperature. Copper North said waste heat from the manufacturing of sulfuric acid will be used to heat the leach tanks. Washed slurry is pumped into the gold-silver circuit for cyanidation; also an agitated tank leach. Optimal leach time for a two-stage cyanidation circuit is about 12 hours with recoveries of some 80 percent for gold and 62 percent for silver. With this new information, Copper North said the design work for a process plan as part of a new preliminary economic assessment can resume. The improvements based on the new metallurgical test results should lead to a reduction of equipment size in the leach circuit as compared to the previous studies and are expected to have a significant positive impact on project economics. The company has set a new initial capital cost target of US$150 million for Carmacks, roughly 30 percent lower than costs outlined in a 2014 PEA.

Cooperative foundation laid for Casino

Western Copper and Gold Corp. and the Tr'ondëk Hwëch'in July 6 announced they have entered into an initial cooperation agreement for assessing the Casino copper project, which partially lies in Tr'ondëk Hwëch'in Traditional Territory, Yukon. "The Tr'ondek Hwech'in are pleased to be able to provide effective input into the proposed Casino project," said Chief Roberta Joseph. "We are committed to forging partnerships to support and ensure responsible mining within our Traditional Territory." The agreement, struck between Western subsidiary Casino Mining Corp. and Tr'ondëk Hwëch'in, commits the parties to work cooperatively to review, evaluate and discuss the Casino Project and lays the foundation for establishing future agreements relating to Casino. The components of the agreement aim to assist in maintaining a mutually beneficial and respectful relationship going forward. ●

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NEWS NUGGETS

earths. Ucore's mid-term objective is to have the SuperLig-One unit serve as a prototype for a full sized separation plant to be located in North America.

Redstar extends Shumagin, finds new vein

Redstar Gold Corp. July 2 reported that four step-out holes drilled at the Shumagin prospect of its Unga gold project in Southwest Alaska continues to cut high-grade gold in the Shumagin vein as well as tapping a second older system in the footwall. Highlights from the step-out drilling included 5.0 meters grading 9.35 grams per metric ton gold and 27.6 g/t silver, including 1.0 meters of 41.2 g/t gold and 130.0 g/t silver in hole 15SH018. This high-grade intercept was encountered about 100 meters northeast of 11SH010, a 2011 hole that cut 0.55 meters of 738 g/t gold and 408 g/t silver, and 100 meters above BMS-01, a historical hold that cut 5.49 meters of 24.02 g/t gold and 19.4 g/t silver. While hole 18 was the only step-out hole to cut high-grade gold, all four encountered an older, "Ginguro-style" epithermal breccia vein system in the footwall below younger Shumagin-style quartz veining in every step out drill hole. This new vein system is anomalous in gold and silver where Ginguro-sulfides are encountered and exhibits contrasting epithermal geochemical signatures to Shumagin-style breccia veins with distinctly higher levels of arsenic, antimony and mercury. Redstar says the discovery of this new style of mineralization implies that the Shumagin scarp is a structural corridor that has had a long-lived history of repeated epithermal veining and high-grade mineralization. "The high-grade intercept within Shumagin-style veining in drill hole 15SH018 is important as it proves that the area of historic high-grade gold-silver mineralization could be expanded with systematic drilling. In addition, the discovery of the Ginguro-vein is encouraging, as these textures prevail at high-grade gold deposits worldwide, such as at Gold Corp's Cerro Negro property," said Redstar Executive Chairman Jacques Vaillancourt. The eight holes drill by Redstar this year along with past drilling has outlined an area of high-grade gold mineralization at the Shumagin prospect for roughly 500 meters along strike and about 330 meters of depth. Redstar said trenching has shown the vein system extends for at least 1,200 meters. Redstar said a planned second phase of 2015 drilling will primarily focus on continuing to trace the vein systems at the Shumagin prospect to the northeast. The company also plans to explore some of the other known high-grade targets located within the Unga gold project.

Donlin draft EIS expected at year's end

Novagold Resources Inc. July 8 reported that the permitting process for its 50-percent-owned Donlin Gold project continues to move ahead with the U.S. Army Corps of Engineers planning to issue the draft Environmental Impact Statement for public comment towards the end of 2015. "Reminiscent of 'The Tortoise and the Hare'," Donlin Gold continues to advance at a steady pace, as originally envisioned. In less than two-year's time, subject to market conditions, the co-owners will be in a position to make a go-ahead decision on one of the gold industry's most vital projects," Novagold President and CEO Greg Lang commented on the release of the company's second quarter financial results and projects update. In addition to permitting, Novagold continued to focus on community outreach and work force development in Alaska. Members of Calista Corp., the Alaska Native regional corporation for the Yukon-Kuskokwim region of western Alaska where Donlin is located, visited Barrick Gold Corp.'s Goldstrike Mine in Nevada. Novagold said this tour of an operating mine that is similar to the one being proposed for Donlin and operated by a Donlin co-owner provided a firsthand perspective of what is being proposed for the region. Calista representatives also met with stakeholders, including representatives of the Shoshone Tribe, which furthered the Donlin stakeholders' understanding of the economic benefits, opportunities and challenges that a mining operation offers to local communities and businesses. Novagold said that technical studies at its 50 percent-owned Galore Creek copper-gold project in northwestern British Columbia are being advanced at a measured pace. With about US$135 million in cash and term deposits at May 31, Novagold has sufficient capital to cover its share of the anticipated funding for the Donlin Gold and Galore Creek projects, in addition to general and administrative costs through to the completion of permitting the Donlin Gold project. The company expects to spend roughly US$44.8 million in 2015, which includes the US$15.8 million the company used to repay the principal on the remaining convertibles notes in the second quarter; US$12.6 million for Donlin; US$1.6 million for Galore Creek project; US$1.5 million for joint Donlin Gold studies with Barrick; and $13.3 million for general administrative costs, interest, working capital and other corporate purposes. ●

EXPLORATION & PRODUCTION

June ANS production down 6.9% from May

Major maintenance shutdown in trans-Alaska oil pipeline slows volumes mid-month; May Cook Inlet production down 3% from April

By KRISTEN NELSON
Petroleum News

Alaska North Slope crude oil production averaged 463,289 barrels per day in June, down 6.9 percent from a May average of 497,673 bpd, a drop driven by scheduled summer maintenance at North Slope fields and on the trans-Alaska oil pipeline, which had a 36-hour planned maintenance shutdown June 12-13.

The largest month-over-month decline was at the BP Exploration (Alaska)-operated Prudhoe Bay field, the Slope's largest, where June production averaged 255,399 bpd, down 10.1 percent from a May average of 284,034 bpd.

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

Information for June comes from the Alaska Department of Revenue's Tax Division which reports North Slope oil production consolidated by major production centers and provides daily production and monthly averages. More detailed data, including Cook Inlet and individual North Slope fields and pools, is reported by the Alaska Oil and Gas Conservation Commission on a month-delay basis.

AOGCC data for May show an average of 17,963 bpd at Milne Point, down 8.2 percent from an April average of 19,565 bpd, and 6,186 bpd at Northstar, down 9.9 percent from an April average of 6,866.

The ConocoPhillips Alaska-operated Kuparuk River field, second largest on the Slope, also had a month-over-month decline, averaging 131,812 bpd on June, down 4.5 percent from a May average of 137,959 bpd.

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

AOGCC data for May show Nikaitchuq averaged 22,210 bpd, down 8 percent from an April average of 24,151 bpd, while Oooguruk averaged 14,530 bpd, down 6.7 percent from an April average of 15,566 bpd.

The BP-operated Lisburne field, part of Greater Prudhoe Bay, averaged 19,788 bpd in June, down 9.4 percent from a May average of 21,844 bpd. Lisburne includes production from Niakuk, Point McIntyre and Raven.

Endicott, Alpine up

The Hilcorp-operated Endicott field averaged 8,602 bpd in June, up 18.5 percent from a May average of 7,261 bpd. Endicott includes satellite production from Eider, Minke and Sag Delta, as well as production from the Savant Alaska-operated Badami field, the farthest east production on the North Slope. AOGCC data shows Badami averaged 851 bpd in May, down 9.4 percent from an April average of 939 bpd.

The ConocoPhillips-operated Alpine field averaged 47,688 bpd in June, up 2.4 percent from a May average of 46,575 bpd. Alpine includes satellite production from Fiord, Nanuq and Qannik.

Cook Inlet down 3 percent

AOGCC data show Cook Inlet crude oil production averaged 18,492 bpd in May, down 3.1 percent from an April average of 19,080 bpd.

The largest month-over-month increase was at the Cook Inlet Energy-operated West McArthur River field, which averaged 1,449 bpd in May, up 11.9 percent from an April average of 1,295 bpd.

The only other Cook Inlet field with a month-over-month increase was the Hilcorp Alaska-operated Beaver Creek field, the smallest in Cook Inlet, which averaged 124 bpd in May, up 5.4 percent from an April average of 118 bpd.

The largest percent drop was at the Cook Inlet Energy-operated Redoubt field, which averaged 903 bpd in May, down 17 percent from 1,087 bpd in April.

The largest per-barrel drop was at the Hilcorp Alaska-operated Granite Point field, which averaged 2,346 bpd in May, down 8.8 percent, 227 barrels, from an April average of 2,573 bpd.

The XTO-operated Middle Ground Shoal field, which Hilcorp is in the process of acquiring (see story on page 1), averaged 1,878 bpd in May, down 6.3 percent from an April average of 2,005 bpd.

The Hilcorp-operated McArthur River field, Cook Inlet's largest, averaged 5,875 bpd in May, down 3 percent from an April average of 6,057 bpd.

Hilcorp's Swanson River field averaged 2,533 bpd in May, down 0.8 percent from an April average of 2,554 bpd, and Hilcorp's Trading Bay field averaged 3,385 bpd in May, down 0.2 percent from an April average of 3,392 bpd.

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

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POLAR BEAR PLAN

led by the North Slope Borough, the plan says. And Fish and Wildlife will collaborate with the North Slope Borough, the Alaska Nanuuq Commission and others on robust and sustainable subsistence management strategies for the Chukchi Sea and the southern Beaufort Sea polar bear populations, the plan says. In terms of disturbance to polar bear denning habitat, the plan envisages a continuation of current efforts to detect and map this habitat, coupled with efforts to minimize development and disturbance on the Beaufort Sea barrier islands, where denning habitat is limited.

In the interests of minimizing risks associated with oil spill contamination, the draft plan envisages updating oil spill modeling, and anticipating overlaps between oil spill risks and polar bear activities and important habitats. Fish and Wildlife plans to comment on proposed activities that pose potential oil spill risks in U.S. polar bear habitat. The agency also expects to develop and distribute standard operating procedures for the deterrence of bears and the rescue and handling of oiled bears, the plan says.

The plan also proposes continuing research into factors such as polar bear population dynamics, the ecology of the bears' habitat and bear interactions with humans, to further develop and refine the criteria used to meet the plan's goals.

Fish and Wildlife has pegged the annual cost of implementing the conservation plan at something in excess of $13 million. ●

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● EXPLORATION & PRODUCTION

Greater Point Mac waiting on seismic

BP Exploration (Alaska) has completed North Prudhoe seismic project but said it needs 2 years of processing to understand results

By ERIC LIDJI

For Petroleum News

BP Exploration (Alaska) Inc. appears to be postponing any major development decisions in the Greater Point McIntyre Area until the results of a recent seismic survey can be processed, according to plans of development submitted to the state at the end of June. (See maps)

The Greater Point McIntyre Area incorporates six fields on the east side of Prudhoe Bay — Point McIntyre, Lisburne, Niakuk, North Prudhoe Bay, Raven and West Beach. The region produces little oil compared to the Prudhoe Bay unit as a whole, in part because the region is aging and in part because development drilling has been minimal in recent years. The future of the region depends largely on the results and effectiveness of the large and multi-year North Prudhoe 3-D seismic program, completed earlier this year.

According to BP, it should take one or two years to process the results of the survey, which means that any resulting development drilling will likely be many years away.

Until then, aging fields will continue to decline and suspended fields will remain shut-in.

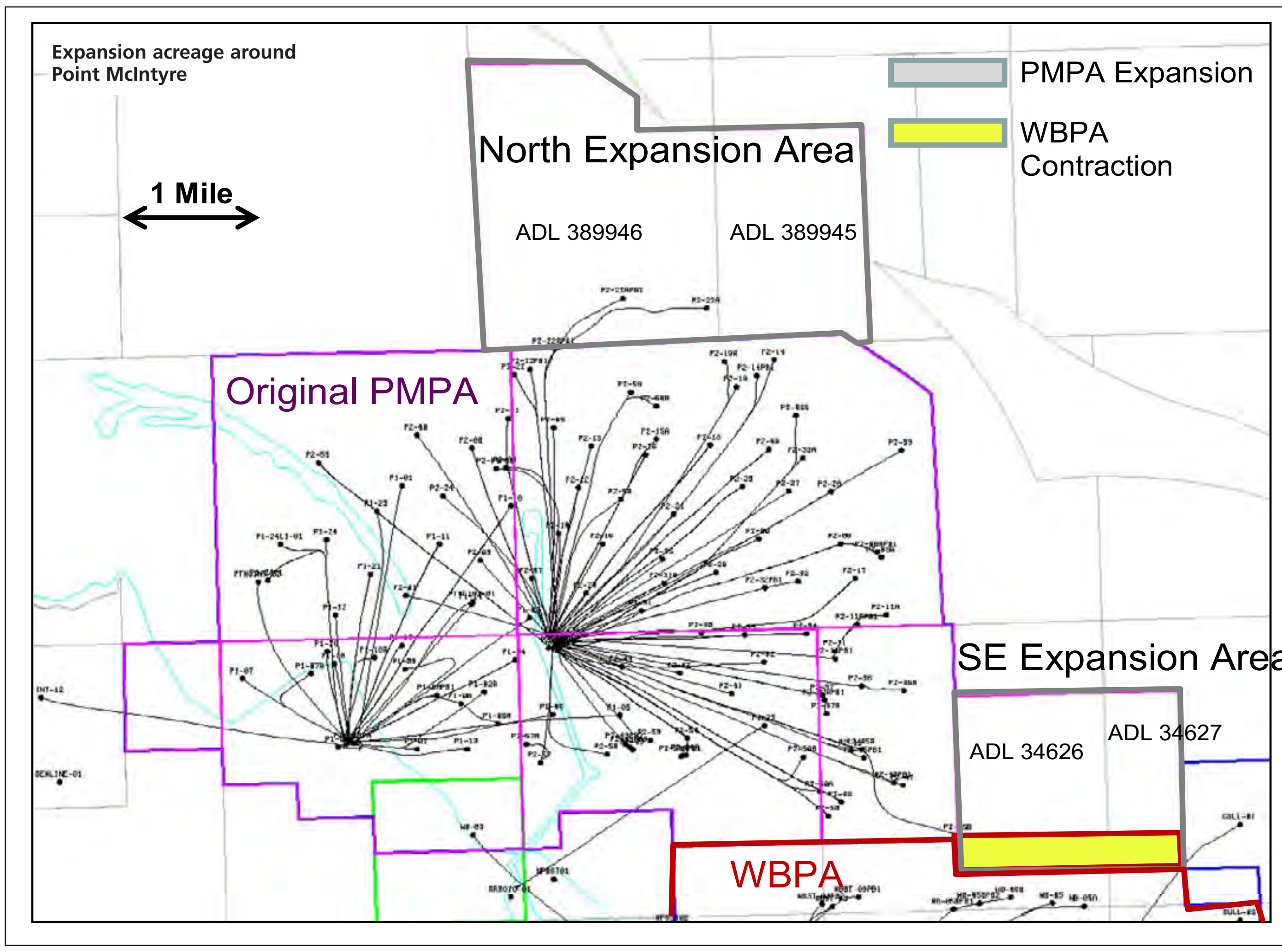
Point McIntyre and Lisburne

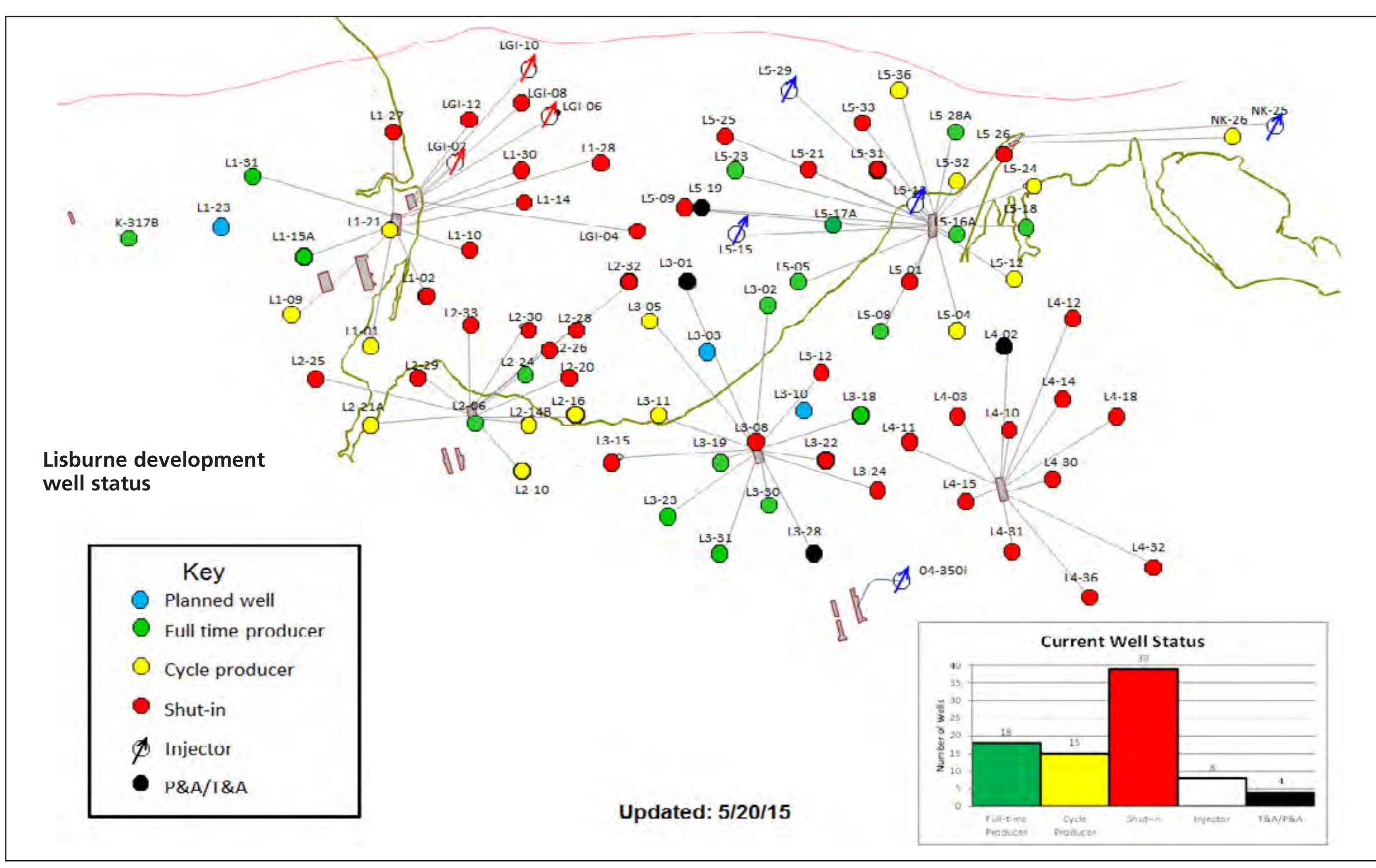
In the year ending March 31, 2015, the Point McIntyre field produced 5.94 million barrels of liquid hydrocarbons at an average rate of 16,370 barrels per day — down from 6.79 million barrels at an average rate of 18,520 barrels per day the previous year. "Long-term oil production is expected to continue to naturally decline from current rates due to increasing water cuts and gas-oil ratios," the company wrote in its plan of development.

In the year ending March 31 Lisburne produced 1.7 million barrels of crude oil, condensate and natural gas liquids at an average rate of 4,800 barrels per day — down from 2.4 million barrels at an average rate of 6,400 barrels per day the previous year.

The main Lisburne Production Center at the aging field is currently gas constrained, which, because of the high gas-to-oil ratio of many wells at the field, impacts oil production. One strategy BP

see SEISMIC SURVEY page 17





● GOVERNMENT

AOGCC fines Linc for lack of data

Says that company should have provided survey data, core analysis reports and log data for three coal gasification appraisal wells

By ALAN BAILEY
Petroleum News

The Alaska Oil and Gas Conservation Commission is fining Linc Energy Operations Inc. $20,000 for the company's failure to provide the commission with some data and reports relating to three wells that the company has drilled onshore on the west side of Cook Inlet.

The wells involved, the Tyex-01, Tyex-01X and Keex-02 wells, form part of a program that Linc is conducting to assess the feasibility of underground coal gasification in the Cook Inlet basin. Underground coal gasification involves igniting underground coal seams and injecting steam and air into the seams. The process results in the conversion of much of the coal into synthetic gas which can be used for power generation or for conversion into conventional natural gas. There are abundant coal seams at a variety of depths in the basin.

Linc drilled the Tyex-01, Tyex-01X and Keex-02 wells in 2012 to depths ranging from 1,450 to 1,700 feet.

AOGCC said in a July 1 order that Linc infringed state regulations by failing to submit inclination surveys, core analysis reports and digital log data for the wells. Linc also failed to respond to commission requests for the information, AOGCC said.

Informal review

Following a notice of proposed enforcement, issued by the commission on April 3, Linc requested and was granted an informal review of the situation. At that conference Linc told the commission that the company had been acting in good faith and that compliance with the commission's requests would not have significantly added to the contents of the commission's database.

The commission subsequently concluded that Linc had failed to collect the required inclination survey information; to understand and implement all of the conditions associated with the company's permits to drill; and to collect required core chips from two of the wells. The company had also failed to provide some other material and laboratory analysis associated with well cores and failed to respond to several requests for information, the commission found.

The commission has, as a consequence, imposed a civil penalty of $20,000 on Linc. The commission also requires Linc to provide all of the required information by Aug. 1, or prove to the satisfaction of the commission that the information does not exist. Linc must also provide a written plan that will ensure that the company's future Alaska operations comply with state regulations. ●

Contact Alan Bailey at abailey@petroleumnews.com

● GOVERNMENT

9th Circuit wants Beaufort permit review

Requires EPA to correct a technical error in Beaufort Sea exploration NPDES permit but otherwise rejects whaling commission appeal

By ALAN BAILEY
Petroleum News

The Court of Appeals for the 9th Circuit has ordered a correction to the Environmental Protection Agency's waste discharge permit for Beaufort Sea exploration but has otherwise rejected an appeal by the Alaska Eskimo Whaling Commission against the validity of the permit. After making the permit correction, the federal agency must reconsider its original decision that discharges within the terms of the permit would not cause unreasonable degradation of the marine environment, a panel of three 9th Circuit judges said in a June 29 opinion.

The Environmental Protection Agency issued its new general permit for wastewater discharges into the Beaufort Sea on Nov. 28, 2012. The permit, which applies to offshore oil and gas exploration but not to oil or gas field development, comes under the National Pollutant Discharge Elimination System. The permit replaced an earlier general permit that had applied to a broad area of the Arctic offshore. The new permit only applies to the Beaufort Sea — EPA has issued a similar NPDES general permit for the Chukchi Sea.

An oil company can conduct exploration activities in the Beaufort Sea without the need for a specific wastewater discharge permit provided it operates within the terms of the general permit and provided it notifies the relevant government agencies of its planned operations.

The Beaufort Sea NPDES general permit authorizes 13 types of discharge from exploration activities, including exploration drilling. Discharges include water-based drilling fluids and drill cuttings; deck drainage; sanitary and domestic waste; and bilge water.

The Alaska Eskimo Whaling Commission appealed the permit, claiming that the EPA had failed to adequately consider the impact of the authorized discharges on subsistence activities, particularly bowhead whale hunting. The whaling commission wanted to see a total prohibition on six of the approved discharge streams, with seasonal restrictions on an additional five streams.

Following normal court practice, the 9th Circuit judges assessed whether the EPA had adequately and rigorously applied the appropriate permitting process when issuing the permit, while the judges deferred to the EPA's technical expertise used in the permitting decision. And the judges subsequently found that the agency had properly

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SEISMIC SURVEY

uses to manage this problem is suspending certain wells for days or even weeks after several days of production, which the company has said will often result in lower gas-to-oil ratios when wells are eventually returned to production.

Earlier this year, BP began drilling the L3-03 well at Lisburne and plans to drill two more development wells — L3-10 and L1-23 — through the remainder of the year. The results of those wells will determine the drilling program for the end of this year and next year.

Smaller fields

Additional drilling opportunities are especially needed at the other satellites.

Niakuk production fell dramatically last year. In the year ending March 31 the field produced 372,000 barrels of liquids at an average rate of 1,020 barrels per day — down from 844,000 barrels at an average rate of 2,300 barrels per day the previous year.

The lone producing well at North Prudhoe was suspended in February 2000 because of safety concerns related to a technical problem. An attempt to return the well to production in 2005 failed. A recently completed evaluation of the well yielded no immediate plans to return it to production, according to BP, but the company believes the results of the seismic campaign could present other development options at the field.

In the year ending March 31 Raven produced 60,000 barrels of crude oil, condensate and natural gas liquids at an average rate of 170 barrels per day — down from 110,000 barrels at an average rate of 3,100 barrels per day during the previous year.

Given that the lone producing well at the Raven field "still produces effectively," according to BP, the company has no plans to sidetrack it during the upcoming year.

West Beach production was suspended in 2001 because declining reservoir pressure and increasing gas-to-oil ratio challenged the economics of the field. Since then, BP has undertaken numerous studies of the field to determine whether it might one day produce again. The future of the field now depends largely on the results of the seismic survey. ●

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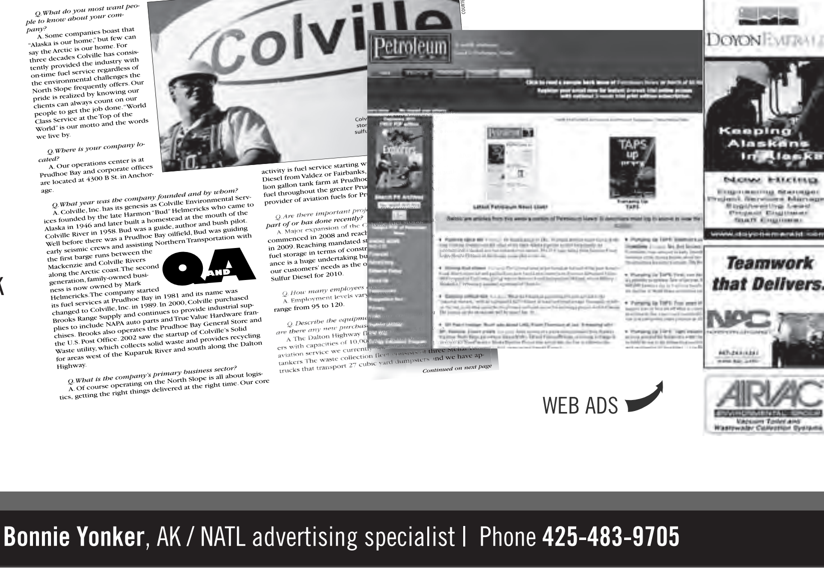

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● EXPLORATION & PRODUCTION

Federal judge tosses incidental take appeal

Says Fish & Wildlife regulations for Chukchi Sea oil exploration are legal under federal statutes for protecting marine mammals

By ALAN BAILEY

Petroleum News

Federal District Court Judge Sharon Gleason has rejected an appeal against U.S. Fish and Wildlife regulations governing the authorization of the unintended minor disturbance of walruses in the Chukchi Sea during offshore oil and gas exploration. A group of six environmental organizations had launched the appeal against the regulations, which Fish and Wildlife introduced in 2013. The Alaska Oil and Gas Association, representing a number of companies in the Alaska oil industry, had intervened in the appeal, in support of Fish and Wildlife.

The regulations at issue are those under which Fish and Wildlife recently issued a letter of authorization to Shell for the minor disturbance of walrus and polar bears during the company's Chukchi Sea drilling program. Essentially, the agency can issue a letter of authorization for an activity, provided that the activity complies with the regulations.

At issue in the appeal is a provision within the regulations that distinguishes the Hanna Shoal region of the Chukchi, a region commonly used by foraging walruses. Under the regulations, Fish and

see INCIDENTAL TAKE *page 23*

● GOVERNMENT

Budget surplus a public relations burden

New Alberta government has C$1.1 billion budget surplus from Conservatives it defeated and accused of financial mismanagement

By GARY PARK

For Petroleum News

It was the best of times and the worst of times for the new Alberta government.

In a startling surprise, it landed a C$1.1 billion windfall — a gift from the Conservative government it turned out of office in May, having built its case for the electoral triumph on claims of financial mismanagement by that administration.

The inheritance represented a budget surplus from the 2014-15 fiscal year that ended March 31, about double the original estimate.

The pain for Premier Rachel Notley and her Finance Minister Joe Ceci was having to grudgingly admit the fact, only because it was required by law to do so by the end of June.

"The surplus is a positive thing, of course," Ceci said after being dragged before news reporters and cameras.

"It's going to help," he said, indirectly referring to predictions by defeated Premier Jim Prentice that Alberta could face an oil and natural gas-driven deficit of C$7 billion in 2015-16, although Notley has indicated that could be closer to C$5.4 billion.

But a more accurate calculation will have to wait until October when the Notley government releases a new budget.

Compounding the awkward state of affairs for the incoming administration was news that Alberta's emergency fund — the so-called "rainy-day" Contingency Account — stands at C$8.2 billion, far exceeding its supposed C$5 billion limit.

In addition, the Alberta Heritage Savings Fund — a close relative of the Alaska Permanent Fund — contains C$18 billion that is available for investment.

Bitumen revenues down, crude, gas up

For the last fiscal year, crude bitumen revenues totaled C$5 billion (down C$530 million from the budget estimate), crude oil revenues were C$2.3 billion (up C$226 million) and natural gas revenues were C$989 million (up C$166 million).

Total revenues were C$45.3 billion, with natural resource revenues accounting for barely 18 percent, well below the recent range of 20 percent to 25 percent.

The outlook is less than cheerful, with West Texas Intermediate, Alberta's crude benchmark, sliding beneath US$60 a barrel fromUS$107 a year ago.

Hikes to taxes

Hikes to corporate and income taxes for those earning more than C$125,000 are expected to generate up to C$800 million in the current fiscal year and C$1.55 billion in 2016-17.

Ceci is not ruling out further tax hikes, noting the government needs C$4 billion a month "to make this place go."

"As a finance minister, I'm always hoping there are additional revenue measures that we can count on," he said, but would not be drawn into speculating on a possible increase in oil and gas royalties.

Todd Hirsch, chief economist at ATB Financial, warned that the wave of layoffs — including 25,100 jobs in the upstream sector — may not yet be over.

"Over the summer months we will see, I think, a few more probably big announcements and some more layoffs in the oil and gas sector," he said.

Hirsch said Alberta's unemployment rate reached 5.8 percent in May and is likely to average 6 percent this year, meaning that over summer and into the fall it will crest to "well above 6 percent." ●

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GOVERNMENT

Agencies test Arctic communications

Federal and state government agencies conducted an exercise on July 2 to test agency communication and coordination procedures for incident response operations in the Arctic, the Bureau of Safety and Environmental Enforcement has announced. Mark Fesmire, BSEE's Alaska region director; Rear Adm. Dan Abel, commander of the U.S. Coast Guard 17th District; and leaders from the Alaska Department of Military and Veterans Affairs, and from the Alaska Department of Environmental Conservation, participated in the exercise. The exercise, the first of several planned to be conducted, simulated an emergency response incident, BSEE said.

A simulated phone call from the Alaska Rescue Coordination Center, notifying the Coast Guard 17th District command center in Juneau of an incident, triggered a chain of actions. The command center briefed Rear Adm. Abel, who then set up a conference call with BSEE, DMVA and DEC. A discussion of agency roles and communications procedures during an Arctic incident concluded the exercise.

The agencies will continue to work together to ensure adequate preparedness and coordination for any potential Arctic events, BSEE said.

—ALAN BAILEY

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PERMIT REVIEW

issued the permit.

However, when submitting evidence to the court the EPA had admitted to a technical error in that it had inadvertently used data for drilling-related effluents rather than cooling water when modeling the impact of the discharge of cooling water into the sea. The court has, therefore, remanded the permit to EPA for rework, requiring the agency to use the correct data to re-evaluate the potential environmental impact of cooling water discharges. However, the judges denied the appeal against the permit in all other respects, saying that EPA had not been "arbitrary or capricious" in its permit decision. ●

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Petroleum news

Oil Patch Bits

AECOM hires Tux Seims as an engineer in training


TUX SEIMS

Tux Seims has joined AECOM's Anchorage office as an engineer in training.

Seims was an intern at URS Corp. in the summer of 2014, shortly before URS combined with AECOM. He returns to AECOM after receiving a bachelor's degree in civil engineering from the University of Alaska Fairbanks.

His experience includes ocean mariculture, assisting with building and designing structures based on coastal needs and water sampling. At the University of Alaska Fairbanks, Seims worked on class projects involving concrete design, water resources experiments and transportation traffic control. His current duties at AECOM include assisting in the development of civil engineering documents and performing construction administration.

Lynden International acquires Haas Industries

Lynden International, a full-service freight forwarding and logistics company, acquired Haas Industries on June 1 to enhance its network and services throughout the Lower 48 and Canada. The acquisition strengthens Lynden's capabilities for home delivery, trade show and specialized delivery services within those markets.

"Lynden and Haas are a great fit and the combination of our two companies will allow us to continue building our domestic service portfolio. Our organizations also share common values and attributes — both believe in building strong partnerships with customers — which will produce a seamless integration of our companies," said John Kaloper, Lynden vice president America division. "We're excited about the possibilities."

Haas Industries began serving customers in 1989 with a vision of offering an unparalleled level of reliability, flexibility and service within the freight forwarding industry. "Over that time, we've forged many long-term partnerships with clients, but ultimately we believe our vision has been achieved. Now is the time to create a new vision; one that produces even greater opportunities for our employees, associates and, most importantly, our customers," said President Keith Haas. Haas Industries is now operating as Lynden International.

Lynden International is one of the Lynden family of companies whose combined capabilities include worldwide air and ocean forwarding, third-party logistics, trade show shipping, shipping to Alaska, truckload and less-than-truckload transportation, scheduled barges to Alaska and Hawaii, charter barges, intermodal bulk chemical hauls, scheduled and chartered Hercules L-382 cargo aircraft and multi-modal logistics.

see **OIL PATCH BITS** page 23

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

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

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GARA Q&A

if you start out with a 48-inch line, you'd have a much greater chance of having competition and vibrant, independent explorers up on the North Slope. If you start out with the smaller line, you have a much greater chance that companies other than the Big 3 won't be able to afford to expand the pipeline.

Petroleum News: The governor also noted possible routes, east versus west Cook Inlet. The tentative preferred route is the western side. The governor would prefer the eastern route. Do you have a preference?

Gara: You know, I think sometimes legislators get parochial on where the line goes. I want the route to be the one that serves the people of Alaska the best and provides the best export business for the state. The route shouldn't be based on where legislators want it for parochial reasons; it should be based on what makes it the cheapest, most effective natural gas project as possible.

Petroleum News: So given all of this, what would you like to see done between now and year's end, particular if there is a special session?

Gara: I hope the governor is able to fix as many of what I consider flaws in Gov. Parnell's gas line plan as possible. I'm hoping by the end of the year there are market players who are wanting to move the gas line forward instead of companies who for many years done some things to get in the way of the project.

Petroleum News: What would some of those flaws be?

Gara: I hope the tax rate gets looked at again. If you're going to consider locking it in, it needs to be fair to the people of the state of Alaska. There is some question about the way the law is presently structured whether independents will be able to get their gas into a gas line. You want independents to be part of the project.

Petroleum News: You mentioned the tax rate, which is really a royalty in kind. If the price goes up, don't we benefit by the price itself with the state's gas in the market?

Gara: It depends on how much TransCanada absorbs if they remain on the project. Royalty in kind can be a good idea or a bad idea. With royalty in kind, you are stuck for paying for that certain amount of gas, even if you don't have that gas. That's a big risk to the state. I hope the governor is looking at the royalty in kind concept. It's something that places a big, big risk on the people of Alaska.

Petroleum News: The governor has also said in an address to AOGA that he would like a larger share of the line, which could mean buying out TransCanada. What are your thoughts on that?

Gara: I would be interested in a larger share of the line if it penciled out. Certainly gas line transportation is a profitable business if it's done right and it might serve the state well to have a larger share of the line but we also need to look at our finances, look at our revenue, look at our budget and look and look to see what the benefits are depending on what the proposal is. I certainly would be open to a larger share of the line.

"The best deal will come together when the governor works things though with interested parties."
—Rep. Les Gara, D-Anchorage

Petroleum News: What about TransCanada? Do you have any preference in their involvement? Building pipelines is its specialty.

Gara: TransCanada has pluses and minuses. They are a very good gas line construction company. They probably have more experience in North America in building a large gas pipeline. On the construction part, they would be one of the good ones. In terms of what share they get under the Parnell proposal for this gas line, I think the governor may have given away too much to TransCanada. Certainly we offered amendments to try and minimize what we thought were some of the giveaways. This in the governor's hands right now and the governor has got to figure out what serves, in his mind, the state the best way and then we get to take a look at it.

Petroleum News: Even with all the gas line talk, there is new exploration about to take place with Shell heading to the Arctic. There was pushback in Seattle not just from environmentalists but those in elected offices at the state and local levels. What are your thoughts on that, politicians weighing in on something happening up here?

Gara: In the end, the project has to be looked at as to whether or not it's safe. Do you have a way to clean up an oil spill on the North Slope? If you do, it makes the project more attractive than if you don't. I don't think politics should get involved. I think science and engineering should get involved.

And I think Congress needs to change the law that essentially says the state gets almost no financial benefit from offshore oil. We should get the same deal that other coast states get for oil beyond the three- and six- mile limit.

Petroleum News: As far as a governor and a mayor and city council getting involved in an agreement that its own entity – the port – had already signed. Is that meddling in another state's affairs or defending their own interests?

Gara: Politicians take positions that sometimes are done for votes rather than for policy. An assembly from another state is going to have no impact on us. They are playing to the voters. Sometimes the Alaska Legislature does stuff like that. I've opposed bills before where clearly they are unconstitutional. We assert we are going to take all federal land for the state of Alaska. Or we assert that federal gun laws have no application in the state of Alaska. Those are false assertions. Those are unconstitutional bills. The state of Alaska does that stuff once in a while. They are playing to voters so I guess politicians aren't above playing to voters sometimes.

Petroleum News: Are you confident Shell is ready to go back up north?

Gara: Shell has a record of subpar performance on its offshore development work in Alaska. They need to show the world they can get their act together. They haven't done the greatest job at it and that doesn't help the project at all. I hope they do safe, responsible development in Alaska. They certainly have gotten off to a rocky start. I'm not a cheerleader. I don't want any company to do something because they are a company. I want a company to do something because they are going to do it responsibly.

Petroleum News: Would this be a make or break year for them?

Gara: I'm not one to draw up lines in the sand. I do hope the work they do this year is done a lot more responsibly than it was in the past.

Petroleum News: Getting back to our conversation on goals for the rest of the year, is there anything particular you would like to see accomplished in a special session or do you not have a hard and fast wish for the special session?

Gara: First and foremost there are some people who are trying to have an early special session on the gas line. The more time pressure you put on the governor, the worst deal the state of Alaska gets. I think the governor needs time to put together the best deal possible and you can't come up with artificial dates to make that happen.

The best deal will come together when the governor works things though with interested parties. In my mind, I don't have a specific date that I think a special session has to happen. The proposal should come to the Legislature once the governor has put it together as strongly as possible and in the best interest to the state of Alaska. That's a policy issue. That's not an issue of picking an arbitrary date on a calendar.

Petroleum News: So if the governor is not able to call a special session this fall, what would your take be on that?

Gara: If the governor weren't able to call a special session this fall, I hope that we are still moving with the gas line project, but he should only call a special session when there is something for the Legislature to do and when he's come up with a proposal that moves the gas line forward with a deal that's in the state's best interest.

That's all I want to hear. It doesn't matter what date that happens on. Whether it's Oct. 1, Nov. 1 or we wait until the regular session because it serves the state's interest the best. That's what's more important to me than picking a date.

Petroleum News: You've noted concerns about the project. Is there anything about the project that gives you optimism that the state is moving forward?

Gara: You know it's hard for a legislator who isn't sitting inside Exxon, BP and Conoco's board rooms to say things definitively. We'd like to pretend that we know exactly what's happening inside those board rooms. The rumor on the street is there is more alignment than in the past. They all have their own interests. I'm not naïve enough to think we can do anything to change the way Exxon, Conoco and BP look at the project. We can set up rules that protect the state. Those are things we can do. We can set up rules to try to move the state forward. But we can't set up rules for what's said inside those board rooms.

Petroleum News: It seems to be more than rumors because we're learning in hearings from the state, TransCanada and the producers more than we did when we heard it during the Murkowski administration.

Gara: I'm encouraged that we are hearing it; of course, you don't know whether it's true until it happens. It's silly for a legislator to pretend they know what's going on inside a board room of a major corporation. ●

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SHELL FLEET

vessel had headed north from Dutch Harbor.

"The vessel returned to Dutch Harbor where, upon inspection, a small breach of her hull was discovered. All appropriate authorities were promptly notified and repair options are being considered," Miller said in a July 7 email.

According to media reports, the Fennica may have struck an uncharted undersea obstacle after leaving Dutch Harbor. Apparently, the vessel had been operating under the guidance of a certified marine pilot.

The Fennica carries Shell's well capping stack, a piece of equipment designed to plug onto the top of a well and seal the wellhead, should a well blowout happen and the well's blowout preventer fail to stop an uncontrolled flow of oil. Shell cannot drill into a potential hydrocarbon bearing zone without having the capping stack staged at an appropriate location.

Shell says it does not know what the impact of the damage to the Fennica will be on the company's drilling plans.

"At this point we do not anticipate any impact on the season but it's too early to know for sure," Miller said. "Any impact to our season will ultimately depend on the extent of the repairs."

Two wells planned

Shell wants to drill two wells this year in the Burger prospect, about 70 miles northwest of the Chukchi coastal village of Wainwright. The prospect is a dome-shaped geologic structure, about 25 miles in diameter and known to contain a major natural gas resource. Shell is betting on finding oil under the gas.

Shell wants to drill two wells this year in the Burger prospect, about 70 miles northwest of the Chukchi coastal village of Wainwright.

Although the company will have two drilling rigs available for the drilling of the two planned wells, the U.S. Fish and Wildlife Service, in the interests of minimizing disturbance to walrus, has prohibited simultaneous exploration activities by drilling rigs within 15 miles of each other. Although Shell has staked out six possible Chukchi well locations, none of these locations appear to lie more than 15 miles apart.

The impact on Shell's plans of this distance limitation has yet to become clear. The Bureau of Safety and Environmental Enforcement requires sufficient time within the summer Arctic open water season to drill a relief well, should a well blowout occur during a planned drilling operation. A relief well plugs an out-of-control well with cement. This relief well requirement significantly limits the time available during the open water season to drill planned wells. According to Shell's exploration plan, an average drilling season length would be sufficient to sequentially complete one well and partially drill a second.

—ALAN BAILEY

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TAX SHELTER

But de Jong emphasized there is nothing to stop the province from raising corporate or sales taxes or "other levies of broad, general application."

As well, the provincial government could raise the carbon tax or tighten GHG regulations, so long as those changes did not specifically target the LNG industry.

Compensation

The key element in the agreement would require the province to compensate LNG operators if tax increases or regulatory changes were to increase costs to the company by C$25 million or more in a calendar year or by a cumulative C$50 million over five years.

At that point, the government would be contractually obliged to offset those costs on a dollar-for-dollar basis, directly or through deductions from other taxes.

The project development agreement also includes a "me too" clause that would allow Pacific NorthWest to take advantage of any more favorable terms negotiated with other projects.

Those conditions along with vague pledges to negotiate terms with First Nations or establish skilled job-training programs will come under scrutiny starting July 13 when a special session of the provincial legislature enacts the legislation and any other LNG agreements.

Jobs, revenues touted

De Jong said the C$36 billion Pacific NorthWest project is expected to employ "upwards of 4,500 individuals" during the construction phase and as many as 1,000 when it embarks on full operation, while the British Columbia treasury is expected to collect C$9 billion in taxes and royalties over the project's operating life.

In answer to those who have asked him how the province can be certain the deal will deliver the projected benefits "when energy prices internationally are in a state of flux," de Jong conceded that "I can't."

He said the estimated investment is the consortium's money — "not mine and not the (taxpayers)" — which the partners are spending based on their analyses and their belief that "there is a fair return to be derived."

The agreement indicates the Clark government hopes to have the legislation enacted by the end of summer, giving the proponent 24 months to meet a number of conditions, including front-end engineering and design, securing federal environmental approval, arranging financial backing and making a final investment decision, setting the stage for commercial operations to start in 2019.

The key element in the agreement would require the province to compensate LNG operators if tax increases or regulatory changes were to increase costs to the company by C$25 million or more in a calendar year or by a cumulative C$50 million over five years.

De Jong said the government would not have devoted so much "intellectual capital" if it thought there was a chance the consortium might balk at going ahead.

Call for firm commitments

Bruce Ralston, the finance spokesman for the opposition New Democratic Party, said the terms are good for the Pacific NorthWest partners, but not good enough for British Columbians because they do not contain firm commitments on jobs and training.

The British Columbia LNG Alliance, which speaks for seven major projects, welcomed the announcement.

"LNG projects are large undertakings that require tens of billions in capital investment and therefore require certainty with respect to the fiscal, legal and regulatory framework," Alliance President David Keane said in a statement.

Among the external hurdles facing Pacific NorthWest is the continuing challenge to gain backing from First Nations — a hurdle that increased in height at the same time de Jong was making his announcement.

The Gitga'at First Nation said it was taking the British Columbia government to court, seeking a judicial review of the project because it had been excluded from "full consultation."

Noting that the Gitga'at community is 60 miles south of Prince Rupert, where Pacific NorthWest plans to locate its liquefaction and tanker terminal, legal experts and observers said challenges are generally based on an aboriginal community's traditional territory.

"Our territory, for example, doesn't go anywhere near Prince Rupert, but that doesn't mean you only use (resources) within your traditional territory," Gitga'at councillor Kyle Clifton told the Financial Post. "We're just looking to have our rights to use the (Prince Rupert harbor and the mouth of the Skeena River) acknowledged."

The British Columbia Environmental Assessment Office listed five First Nations that were entitled to full consultation, but did not include the Gitga'at. ●

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COSMO UNIT

The approved unit includes ADL 384403, ADL 391902, ADL 391903, ADL 391904 and ADL 18790 and excluded ADL 391899, ADL 391900 and a portion of ADL 391903.

What's next?

The initial plan of development for the unit, which runs through the end of the year, concerned state officials, who are eager to maximize development in the area.

The plan calls for offshore and onshore development.

Offshore, BlueCrest plans to drill one vertical well to test both oil and natural gas zones in the southern part of the Cosmopolitan structure at ADL 384403. The well would be plugged at the oil zones and suspended at the gas zones until facilities come online.

Onshore, BlueCrest plans to drill two oil production wells into ADL 18790, each with dual laterals, from the existing Hansen pad, with production expected in the first half of 2016. The company is also planning an onshore disposal well in late 2015 or early 2016.

The current development program called for as many as 38 wells from the Hansen pad.

Given that both ADL 384403 and ADL 18790 already have certified wells, which protect those leases against expiration, even without unitization, the state said it "has concerns about the lack of discussion in the Initial POD regarding delineation of the rest of the reservoir that underlies the other leases." Therefore, the department only approved the initial plan of development through the end of the year and is requiring BlueCrest to submit its second plan of development by Oct. 2. "DNR expects that the second plan of development will provide specific and detailed activities and long-range plans to execute the testing, delineation, and development of the entire reservoir," Feige wrote.

The Cosmopolitan unit is unusual in that it contains a known reservoir, where previous operators have produced oil commercially. After Pioneer Natural Resources Alaska Inc. relinquished the unit, the state sold three leases — ADL 391902, ADL 391903, ADL 391904 — at a special lease sale and imposed special work commitments on the leases.

Apache Alaska Inc. acquired those leases and sold them to BlueCrest and its former partner Buccaneer Energy Ltd. None of those companies met the work commitments.

With BlueCrest already developing the prospect, the state decided to include the three leases in the unit anyway. "If the leases expired, valuable time and loss of revenue could result if the State had to return the leases to a lease sale. To accommodate these leases for the unit, work commitments for the leases will be eliminated, yet the intended activities will be included in a comprehensive unit plan of development," Feige wrote, noting that the leases had increasing rental rates, which should push BlueCrest to act quickly.

Five decades

Pennzoil discovered Cosmopolitan in 1967 but initial drilling results failed to convince the company to develop the field, which was relatively far from existing infrastructure.

A second exploration effort began in the 1990s, starting with ARCO Alaska and, following mergers, continuing with Phillips Inc. and then ConocoPhillips Alaska Inc.

Phillips Inc. formed the first Cosmopolitan unit over seven state leases and two federal leases in 2001 and drilled the Hansen No. 1 well directionally from an onshore pad to an offshore target. In 2003, ConocoPhillips drilled Hansen No. 1A, a sidetrack. A subsequent flow test produced some 1,000 barrels per day and 14,851 cumulative barrels.

In 2005, Pioneer Natural Resources Alaska Inc. joined ConocoPhillips on a 3-D survey covering some 40 square miles of the region. The program "provided a clear view of the perimeter flanks of an anticlinal structure, but the crestal view of the structure was obscured by a gas cloud, rendering a conclusive description of the reservoir structure unobtainable at the time," according to information released recently by BlueCrest.

After the joint seismic program, Pioneer Natural Resources acquired the remaining working interest at Cosmopolitan and became the operator of the unit and the program.

In 2007, Pioneer drilled Hansen No. 1A-L1, another sidetrack off the original Hansen well. The "long-reach undulating lateral well" ran through the upper portion of the Starichkof 8 sub-interval of the sands and tested at 300 barrels per day. In 2010, Pioneer fracture stimulated the Starichkof interval from Hansen No. 1A-L1. An extended flow-test produced 250 barrels per day and more than 33,000 barrels, cumulatively, which the company trucked to the Tesoro refinery under a pilot program for future development.

Although Pioneer went so far as proposing a development program for Cosmopolitan, the company ultimately decided, in early 2011, to sell the field, saying that "subsequent flow test results and engineering studies indicated that the resource potential was not as large as originally estimated." The company terminated the Cosmopolitan unit, relinquished several leases and sold the core leases and wells to Buccaneer Energy Ltd. and BlueCrest.

Even though BlueCrest held a 75 percent working interest in the venture, Buccaneer was the original operator. Together the companies drilled one offshore well using the Endeavor jack-up drilling rig before Buccaneer sold its stake to BlueCrest and filed for bankruptcy protection. BlueCrest quickly began moving toward developing the field. ●

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OIL PATCH BITS

Fugro awarded ExxonMobil Alaska G&G program

Fugro has been awarded a large geotechnical and geophysical program by ExxonMobil Alaska LNG LLC, AKLNG — a consortium of ExxonMobil, ConocoPhillips, BP, TransCanada and the state of Alaska. The 2015 G&G program follows successful completion of a similar but smaller program carried out by Fugro in 2014.

The geotechnical scope of work includes drilling and sampling of borings for the onshore liquefaction facilities, marine terminal and offshore pipelines. It also includes installation of monitoring wells, seismograph and in situ measurement of soil properties. The geological and earthquake engineering scope will include assessment of geohazards, source characterization, probabilistic seismic hazard and site response analyses. Bathymetric, side scan sonar, reflection and refraction surveys and sub-bottom profiling will also be conducted to assist in developing an integrated site model. These studies will assist AKLNG and its contractors to proceed with the FEED level design of the LNG terminal and associated offshore pipelines.

As world leader in geohazards both onshore and nearshore, as well as geotechnical, geophysical, metocean and surveying services for LNG facilities, Fugro also provides worldwide quality assurance and quality control services during project construction phases.

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

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INCIDENTAL TAKE

Wildlife reserves the right to specify some mitigation measures for this region on a case-by-case basis, based on a determination of how a specific activity may impact the walruses.

The environmental organizations claimed that, by not spelling out all mitigation measures up front and by not, therefore, subjecting these measures to public review, Fish and Wildlife was infringing the Marine Mammal Protection Act, the National Environmental Policy Act and the Administrative Procedures Act. Moreover, by leaving uncertainty in what mitigation measures might be applied in any particular instance, Fish and Wildlife could not substantiate its claim that the regulations would ensure a negligible impact of industry activities on walruses during the five-year period that the regulations would be in place, the plaintiffs in the appeal argued.

Arguments rejected

In a July 2 ruling Judge Gleason tossed out all of the plaintiffs arguments, saying that the terms of the Marine Mammal Protection Act can be interpreted as allowing an agency to impose specific mitigation measures additional to those spelled out in advance by regulation. Moreover, under a precedent set in a 9th Circuit Court of Appeals case, the development of incidental take regulations does not require an estimation of the number of animal "takes" that might result from implementation of the regulations, instead requiring a finding that the cumulative impact of the regulations would be negligible, Gleason wrote.

Fish and Wildlife has presented a reasoned analysis for its determination that only a small portion of the walrus population would be impacted by activities conducted under the terms of the incidental take regulations, Gleason wrote.

The court has concluded that Fish and Wildlife's determination of negligible impacts on the walrus population was not "arbitrary and capricious," and that the agency met its obligation to impose mitigation measures to ensure no significant impact on the animals, both through general measures spelled out in the regulations and through a commitment to apply additional measures as necessary in the Hanna Shoal region, Gleason wrote. ●

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GAS INJECTION ORDER

pipeline into the North Slope oil pipeline system, where it will be mixed with crude oil from other fields for delivery into the trans-Alaska pipeline, for shipment to market.

ExxonMobil expects initial production of 10,000 barrels per day of condensate.

Two pads, three wells

At field startup, which ExxonMobil anticipates happening in early 2016, two gravel pads will be in use, a central pad and a west pad. ExxonMobil reservoir engineer George Eleftheriou told the AOGCC commissioners that a single production well will be located on the west pad, while two gas injection wells will be located on the central pad. The central pad will also house field processing facilities and a well for disposing of water produced from the field reservoir along with gas and condensate, Eleftheriou said.

ExxonMobil has previously said that it plans to drill the production well, the PTU-17 well, starting in the fourth quarter of this year. The company drilled the two injection wells, the PTU-15 and PTU-16 wells, in 2009 and 2010, Eleftheriou said. The original development plan envisaged a single injection well and a single production well but, after ExxonMobil discovered that the field holds some corrosive hydrogen sulphide gas, the company had to install protective liners into the two wells that it had already drilled. Those liners reduced the well tubing size, thus requiring the drilling of a separate production well capable of handling the planned 10,000 barrels per day of production, Eleftheriou explained.

ExxonMobil is in the process of completing the PTU-15 and PTU-16 wells so that the wells can operate as injectors. Drilling Engineering Supervisor Alex Podust said that the completions of all of the wells are designed to prevent reservoir sand entering the well bores. Each well completion involves the installation of a perforated casing with mechanical screens, with small-scale, sand filled fractures extending from the wells into the surrounding reservoir rock.

Eleftheriou said that ExxonMobil anticipates initial gas production of about 200 million cubic feet per day. That is a slightly larger rate than the rate of gas injection, given that some of the produced gas will be required to fuel the field's production facilities. However, the gradual loss of gas from the field will not have much impact on condensate production, Eleftheriou said. Gas will be injected into the reservoir at a pressure of about 10,000 pounds per square inch.

Field reservoir

Since the Point Thomson reservoir extends offshore, under the Beaufort Sea, the wells require directional drilling from the onshore pads, with the wells' bottom-hole locations being widely spaced in the reservoir. ExxonMobil Senior Geosciences Advisor Susan Dougherty told the commissioners that the reservoir is in the Thomson Sand, a rock unit that is Lower Cretaceous in age and that lies on top of Pre-Mississippian basement rocks. Shales of what is referred to as the Hue/HRZ and of the Canning formation seal the hydrocarbons into the reservoir sands. The gas layer in the field is about 500 feet thick, Dougherty said.

ExxonMobil had based its reservoir modeling on data from 16 wells that had penetrated the Thomson Sand. But results from the PTU-15 and PTU-16 wells have caused the company to rework the model, with those wells demonstrating that the quality of the reservoir is better than previously thought, Dougherty said. In particular, the PTU-15 well, drilled in 2009, had penetrated 130 feet of what ExxonMobil calls the "open framework conglomerate," a rock with outstanding reservoir quality, given its exceptionally high porosity and permeability. Porosity expresses a rock's capacity to store fluids, while permeability determines the extent to which fluids can flow through the rock.

Dougherty said that the two recently drilled wells had also encountered another type of conglomerate and a clean sand, both of which also exhibited very good reservoir properties.

Reservoir continuity

Moreover, in 2014 ExxonMobil reprocessed the 3-D seismic data for the field and the company has subsequently revised its model for how the reservoir sands were laid down, and how the sand is structured, Dougherty said. The company thinks that the sand was deposited from an ancient river delta in a shallow marine setting. However, while the company previously thought that sediment had been shed in all directions, the revised model involves consistent deposition towards the southwest, leading to broad bands of consistent styles of deposition. That has resulted in increasing confidence that the reservoir is not split into separate compartments, Dougherty said. And, while the seismic data have revealed the presence of faults cutting the reservoir, those faults do not appear to have compartmentalized the reservoir rock, she said.

The continuity of the hydrocarbon reservoir is important for condensate production at Point Thomson, because of the need for pressure communication between the gas injector wells and the production well.

Recycling versus blowdown

Over the years prior to ExxonMobil's development decision, a debate took place over the relative merits of producing condensate from Point Thomson or just producing gas from the field, with the "blowdown" of gas being technically much simpler that the gas recycling production of condensate. The state of Alaska has been anxious to ensure that as much condensate as possible is produced from the field, given that condensate has a higher commercial value than gas. And, in the absence of a North Slope gas export pipeline, there is currently no way of delivering Point Thomson gas to market. The field is thought to hold about 8 trillion cubic feet of gas.

Commission Chair Cathy Foerster asked if ExxonMobil's new three-well production scheme is as good as the original two-well plan in terms of supporting the gas cycling approach to condensate production. Eleftheriou responded that the gas cycling efficiency should be fairly good but is somewhat dependent on the characteristics of the reservoir rocks. The biggest risk to the gas cycling process is an early breakthrough of gas from an injector well to the production well, Eleftheriou said. A breakthrough of gas through the reservoir direct to the production well would presumably undermine the ability of the injected gas to maintain the reservoir pressure.

Eleftheriou, referencing the upcoming drilling of the production well from the west pad, commented that this new well will provide new information about subsurface rocks in the western part of the field.

"We want to make sure that we can maintain deliverability from that well. We hope to see good reservoir quality," Eleftheriou said.

Foerster commented that the performance of initial production at Point Thomson will determine how the field continues to be developed.

"So it's critically important to this agency that you've done your best job of trying to ensure that you've given cycling every chance to succeed," she said.

Foerster also asked about the feasibility of oil production from a thin rim of thick, heavy oil below the gas in the field. Eleftheriou said that, given the high viscosity of the oil and its juxtaposition with oil and water, modeling had indicated that production of the oil would be very challenging, with expensive wells and low oil recovery rates. ●

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HILCORP MOVES

ture not only of Shell, but more recently of Chevron subsidiary Union Oil Company of California and Marathon Oil, which sold their assets in the area to Houston-based independent Hilcorp in 2011 and 2012. ConocoPhillips Alaska, formerly ARCO Alaska, operator of the Beluga River gas field and the North Cook Inlet platform, is the only remaining original Cook Inlet operator.

XTO now exiting

Cross Timbers, since renamed XTO and now an ExxonMobil subsidiary, had a goal similar to Hilcorp's when it acquired Middle Ground Shoal in 1998: To work mature fields, which are no longer significant to major companies, and produce additional oil and gas.

The Cross Timbers' acquisition included 100 percent interest in the two platforms, "A" and "C", and a 50 percent interest in pipelines and onshore processing facilities 50 percent owned by Unocal. Cross Timbers said in 1998 that net production from the field was some 3,600 barrels per day. The company told Petroleum News at the time of the 1998 acquisition that Middle Ground Shoal fit criteria the company looked for, including properties with a long productive history so that production decline is more predictable.

Hilcorp agreement

Hilcorp Alaska said in a July 6 statement that it has executed an agreement to purchase XTO's Middle Ground Shoal assets and that pending state and regulatory approval the transaction was expected to close this fall. The deal includes the "A" and "C" platforms and a tank facility and offices in Nikiski.

Hilcorp said the platforms produce some 1,750 bpd of oil, and said it anticipates making employment offers to all 31 employees who currently operate the Middle Ground Shoal assets.

So what happened to Cross Timbers? When the company acquired Middle Ground Shoal it was growing rapidly. It had formed out of the 1986 acquisition of Southland Royalty Co. in a hostile takeover. Three former Southland employees raised $20 million to purchase production. By 1998 Cross Timbers had grown to market capitalization of close to three-quarters of a billion dollars, the company said.

In 2009 the company, then going by its trading symbol, XTO, was acquired by ExxonMobil for $31 billion based on XTO's Lower 48 natural gas assets.

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