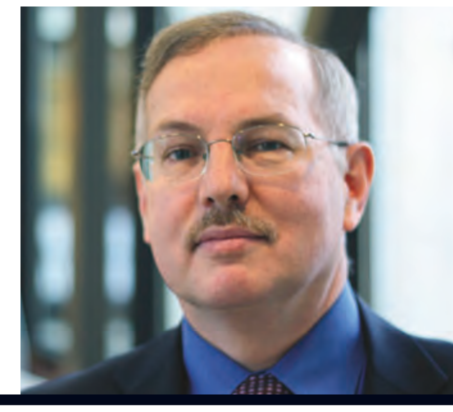
Petroleum news



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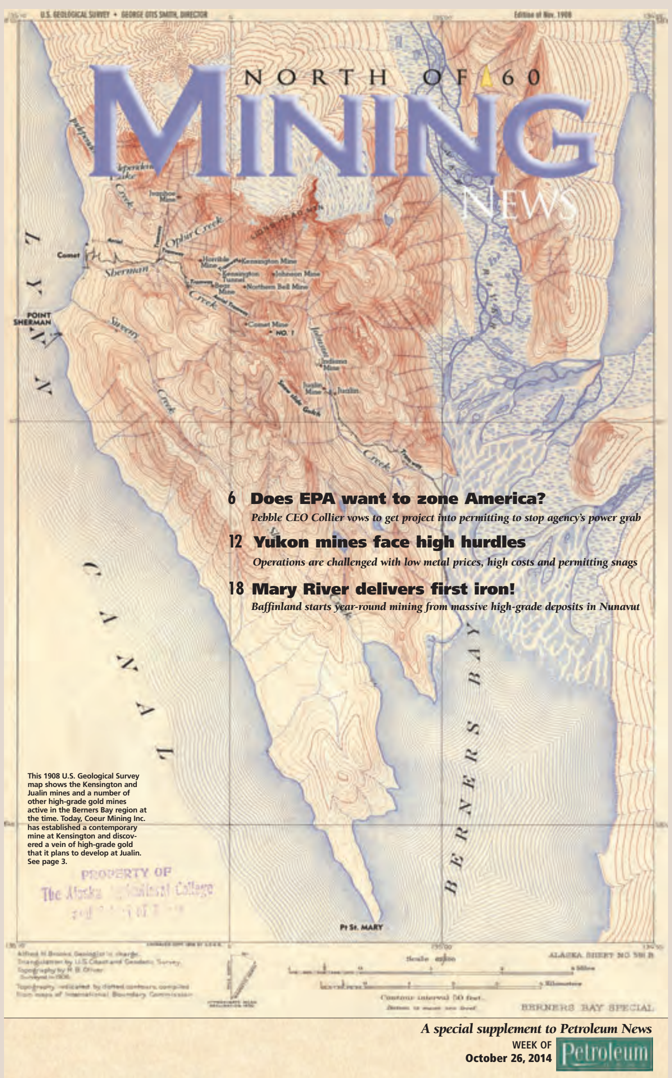

The October issue of North of 60 Mining News is enclosed.

Furie moving Kitchen Lights platform to Seattle for winter

Furie Operating Alaska is relocating its Kitchen Lights gas production platform south to Seattle for the winter, rather than trying to overwinter the platform in the Cook Inlet region, Bruce Webb, company vice president, told Petroleum News Oct. 22.

"It turned out that was the least expensive option and the option with the least risk," Webb said.

Furie had planned to install the platform in its Cook Inlet Kitchen Lights unit during the summer of 2014, in hopes of bringing an offshore gas field that the company has discovered on line by the end of the year. But, following a delay during the shipment of the platform to Alaska from Texas, where it was manufactured, the platform did not arrive in the inlet until September. By that time it was too late to begin platform installation before

see PLATFORM MOVE page 14

Buccaneer sale set for October

The Alaska assets of Buccaneer Energy Ltd. will go on the auction block by the end of October, according to a recent ruling from a federal bankruptcy judge in Texas.

If Buccaneer gets more than one qualified bid, the bankrupt Australian independent will hold an auction starting the morning of Oct. 27, according to the terms of an Oct. 17 ruling from Judge David R. Jones of the U.S. Bankruptcy Court for the Southern District of Texas. If the solicitation fails to yield any qualified bids, Buccaneer would instead ask the court for permission to sell its assets directly to AIX Energy LLC, its largest creditor.

A proposed sale agreement has been drafted but needs court approval to be finalized. The draft agreement currently omits the name of the buyer and the amount of the purchase.

The court intends to hold a hearing on Oct. 31 to finalize

see BUCCANEER SALE page 8

LAND & LEASING

Kachemach unit saga

Termination follows yearlong efforts to unify efforts west of Kuparuk

By ERIC LIDJI
For Petroleum News

The area between the Kuparuk River unit and the Colville River unit has been called "the billion-dollar fairway" because of its prospective geology and proximity to infrastructure.

And yet, the region hosts no production.

The recent termination of the Kachemach unit highlights the challenges in the crowded region, where numerous companies are simultaneously pursuing exploration projects.

Procedurally speaking, the Alaska Department of Natural Resources terminated the unit because operator Brooks Range Petroleum Corp. failed to propose an adequate remedy for curing a default.

The proposed remedies show Brooks Range Petroleum trying to unify the Kachemach unit and the Placer unit, which are adjacent in the area west of the Kuparuk River unit.

The North Slope unit went into default on July 25, 2013, after the company failed to drill either of two wells by May 31, 2013, as required by the unit agreement.

But the story behind the decision to terminate the Kachemach unit includes the work of two other lessees in the region: ASRC Exploration LLC and

see UNIT SAGA page 14

NATURAL GAS

BC gives way to industry

Outline of final LNG tax regime slashes proposed rate in half, introduces credit

By GARY PARK
For Petroleum News

The British Columbia government ended two years of high stakes poker by playing its final hand Oct. 21 that will either sway the LNG industry to sanction a handful of projects or head for other gambling tables.

The province's often-postponed fiscal regime, which has evolved from quiet backroom negotiations into public bluff and bluster in recent weeks, was unveiled by Finance Minister Mike de Jong to strong indications of support from leading proponents.

The overriding conclusion is that the government has paid heed to industry warnings and scaled back its hopes for turning LNG into a multi-billion-dollar revenue trough.

De Jong said the opportunity for British Columbia to develop a thriving industry remains.

"But the design and tax structure needs to take into account changing circumstances in the market and potential for return," he said, conceding "it's not quite as lucrative as it once was."

Expected to be approved this fall

Under the planned legislation, that is expected to be approved this fall by the provincial legislature and take effect on Jan. 1, 2017, the initial income tax on operating revenues will stay at 1.5 percent as targeted last February, but a planned second tier to be imposed once the LNG terminals

see TAX REGIME page 12

EXPLORATION & PRODUCTION

A hive of activity

Drilling rig returning to Point Thomson as field development continues

By ALAN BAILEY
Petroleum News

ExxonMobil is activating the powerful Nabors 27E drilling rig, for transportation by ice road in the coming winter to the company's huge Point Thomson gas condensate field on the North Slope, company executives told Petroleum News Oct. 16. The rig will continue drilling operations that were started at the field several years ago.

With up to 1,200 people and 70 Alaska companies involved in activities ranging from gravel laying to pipeline installation, field development has been moving steadily ahead, said Nathan Sanborn, project manager for the Point Thomson Initial Production System. The company has spent the last couple of years developing infrastructure, including the gravel pads, gravel roads and the airstrip. And the pipeline that will deliver condensate from the field to the North Slope pipeline system has been completed, as has the permanent operations camp for the field, Sanborn said.

In 2009 and 2010 ExxonMobil used the Nabors 27E rig to drill two wells in the field from an existing exploration gravel pad, a pad that is now called "central pad."

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● GOVERNMENT

Edgmon talks Arctic policy, rural issues

Dillingham Democrat says local, indigenous voices important for work of Alaska Arctic Policy Commission multination Arctic Council

By STEVE QUINN
For Petroleum News

House Rep. Bryce Edgmon has spent a warm summer studying the world's coldest regions, in part preparing for the next legislative session. The Dillingham Democrat is seeking a fifth term unopposed, so he's looking forward to discussions and hearings that follow interim work with the state's Arctic Policy Commission.

Edgmon, a member of the House Finance Committee, spoke to Petroleum News about his views on Arctic policy, and the pending two-year term the United States will have as chair for the worldwide Arctic Council.

Petroleum News: For starters, what's a lawmaker for Dillingham doing investing time into Arctic policy?

Edgmon: Well, my interest originally came from the fact that I represented the city of Unalaska and its direct ties to shipping and to the Arctic. Basically a lot of what happens in the maritime industry, including the Coast Guard controls the Bering Sea. With the Northern Waters Taskforce we held a hearing in Unalaska and with the Arctic Policy Commission, we held hearing in Unalaska. Both were very important hearings with a lot of participation from a lot of the local communities and entities involved with shipping, fuel and repair work and salvage operations. It's centered around the fact that Unalaska is the hub for a billion dollar a year ground fishing industry but it's also the nexus point for a lot of ships involved in the great circle trade routes and with its year round deepwater ports, Unalaska is able to provide a lot of services. I'll be back to representing them come next January officially when my district and Bob Herron's district goes back to their original configurations. These last two years were a bit of a hiatus under redistricting.

Petroleum News: So as Arctic exploration resumes in the next few years do you see Unalaska's role as a hub getting stronger?

Edgmon: Absolutely. In fact with Shell's earlier attempts into the Arctic, Alaskans played a very important role in their staging efforts. From what I understand Shell will be trying again and if they can get their regulator clearance, Shell will be using Unalaska as a place to stage a lot of their operations.

REP. BRYCE EDGMON

Petroleum News: So what are you hearing from the folks in Unalaska? Are the happy about this? Do they have any concerns?

Edgmon: The community of Unalaska is very forward-looking. They are always looking out into the future. They are looking strategically in terms of what lies in the best interests of their community. They fully understand they will be a regional center for a very valuable Bering Sea fishing industry, but they also realize with the services and natural access to various points, they can play a big role in Shell's efforts as well as anyone else's efforts to drill in the Arctic. So I think Unalaskans are prepared and ready to seize any opportunities that might come their way and are expecting they will play a big role in the opening of the Arctic.

Petroleum News: So what concerns are you hearing from the Aleutian communities like Unalaska?

Edgmon: their concerns parallel the concerns we've heard elsewhere along the coast with a lot of big ships suddenly coming through the Bering Strait choke points. Admiral (Thomas) Ostebo termed it big ships going through the Bering Sea garden, so the concerns I'm hearing parallel what you're hearing further north along the coast — a lack of response capabilities, a lack of ability to respond to a big ship if it goes adrift in a certain place at a certain time. I think the people of Unalaska have been proactive in terms of addressing a big issue in terms of big ships going aground. They have pioneered an emergency towing system effort they have been able to utilize once or twice already. As someone who has represented Unalaska in the past, I see a very progressive community in terms of looking at their own interests in the future.

Petroleum News: You attended some hearings recently in Nome and Kotzebue that were specific to the Arctic Policy Commission, but certainly of interest. What are you hearing from people like Admiral (Robert) Papp and Fran Ulmer?

Edgmon: Well we heard a strong commitment to their personal involvement in terms of making opening of the Arctic a national imperative and I think they fully grasp the importance of their advisory role to Secretary Kerry who will be the U.S. Chairman of the Arctic Council when that takes place next spring. We all know Fran Ulmer's public service to Alaska and Admiral Papp is interested in learning more about Alaska, learning more about the intricacies of the Arctic. I was very impressed with both of their devotion to sitting

see **EDGMON Q&A** page 11

ENVIRONMENT & SAFETY

Trouble on the high seas

Russian cargo ship laden with bunker oil loses power off Haida Gwaii, towed to shore by US tugboat but leaves ammunition in wake

By GARY PARK

For Petroleum News

Evidence of the risks associated with moving crude oil tankers in the notoriously stormy waters off British Columbia's northern coast is rapidly piling up, culminating in the enlistment of a large U.S. tugboat to aid a stricken Russian cargo ship off the west coast of Haida Gwaii.

When the container ship Simushir lost power Oct. 16 in stormy seas it was feared the vessel, carrying a cargo of mining materials and 450 metric tons of bunker oil and diesel, could run aground on Haida Gwaii (formerly the Queen Charlotte Islands).

A Canadian Coast Guard boat Gordon Reid tried three times to attach lines to the Simushir, but all three snapped, prompting a call for aid from the U.S. boat Barbara Foss which secured the cargo ship and delivered it to Prince Rupert for repairs.

Two other vessels, the Canadian Coast Guard's Sir Wilfrid Laurier and the U.S. Coast Guard cutter Spar, were also on standby to provide assistance, but neither was properly equipped to secure and tow a large ship.

The incident occurred on the last day of a four-day meeting of Haida leaders when one of the leading agenda items had been a resolution to ban tankers off Haida territory.

"It's kind of ironic that just before we have this conversation this real-life situation (comes) upon us," said Haida Nation President Peter Lantin, although he did concede that the Coast Guard intervention had likely "averted a catastrophe."

Although the vessel is not an oil tanker, its difficulties highlighted the relentless argument about the risks posed by Enbridge's C$7.9 billion Northern Gateway pipeline and the expansion of Trans Mountain's pipeline.

The two, representing a combined 1.4 million barrels per day of crude bitumen shipments from the British Columbia coast to Asia, would add more than 500 tanker sailings to the area.

British Columbia Environment Minister Mary Pollack said quickly that her province under Premier Christy Clark has been making its case that the Canadian government is not equipped to handle a crude-related marine disaster.

Clark's government has set five conditions that must be met before it will endorse Northern Gateway, including a "world-leading marine oil spill response, prevention and recovery systems."

Pollack said the incident involving the Simushir, which was built in the Netherlands in 1998, underlines the need for the federal government to act on British Columbia's demand.

Roger Girouard, an assistant commissioner with the Canadian Coast Guard, said his main concern was the fuel and diesel oil onboard and the danger of the ship running aground, although he suggested that if the Russian vessel had broken up there would have been an ally in the rough seas and the absence of migratory birds.

Girouard said environmental response assets from government agencies and private industry had been deployed to the area as a precautionary measure.

Lantin, whose community has resolutely opposed Northern Gateway, said the Simushir incident had been a "good training exercise and an eye opener. It really shows us how little we're prepared," noting it took 20 hours for the Canadian Coast Guard to reach the scene.

An Enbridge spokesman reiterated the company's Northern Gateway promises to provide two pilot boats for every tanker leaving the terminal at Kitimat, noting that crude tankers would not be allowed to operate in stormy conditions.

The company is committed to install land-based radar along British Columbia's north coast as well as new lights and buoys in the Douglas Channel out of Kitimat to help guide tankers.

It also said all tankers will be double-hulled, less than 20 years old and certified by the International Maritime Association.

But the concerns among First Nations, environmentalists and coastal communities have been accumulating in recent weeks based on reports by government agencies and universities.

Documents released by Canada's Transportation Safety Board show cargo vessels and cruise ships with British Columbia pilots on board were involved in 20 collisions or "risks of collisions" in waters off the province last year.

The information highlighted the fact that although the presence of pilots contributes to the safety of shipping traffic it cannot eliminate the risk of an accident, including those potentially caused by other vessels.

Ben West, a campaigner with Forest Ethics Advocacy and a leading opponent of crude exports from the British Columbia coast, told the Vancouver Sun that "increased oil tanker traffic means drastically increased risk. It's not a matter of if a spill will happen. It's a matter of when. So why would we want to bet on even worse odds."

A separate research report issued in September found that leaking recreational boats and other small craft are more likely to foul British Columbia waters than major spills from tankers.

Two Canadian universities and several federal departments discovered during three years of gathering data from 100 defined "pockets" on the British Columbia coast that vessels other than big tankers — recreational boats, marinas, cruise ships and fishing boats — cause the most spills.

Stefania Bertazzon, a University of Calgary scientist who led the study, speculated that large tankers and cargo ships are not the major contributors to spills because "they are more heavily regulated. They need to undergo port-side inspection and we also believe they are aware of (aircraft) surveillance."

She said the long-term continual spills from smaller vessels have a "greater impact on the environment than the big catastrophic spills that catch everyone's attention."

In mid-July the bulk carrier ship Amakusa Island — with a licensed British Columbia pilot on board — ran aground near Prince Rupert while moving to an assigned anchorage at a coal terminal, ripping a gash in the ship's hull, without causing any environmental damage.

However, Coastal First Nations executive director Art Sterritt, describing the weather conditions at the time as "very, very good," said the incident showed human error is unavoidable.

"Mistakes happen and no matter what kind of technology you have or how good your pilots area — all that stuff that Northern Gateway has been throwing at us — people are fallible and accidents happen," he said. ●

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● PIPELINES & DOWNSTREAM

A simplification for Cook Inlet gas

RCA is reviewing the agreement for consolidating four Hilcorp gas transportation pipelines into a single gas pipeline entity

By ALAN BAILEY
Petroleum News

In what is presumably the closing chapter in the lengthy and complex process of amalgamating four Cook Inlet gas pipelines into a single pipeline system, a Regulatory Commission of Alaska hearing on Oct. 15 formally gathered information that the commissioners need to adjudicate over the proposed pipeline consolidation.

Hilcorp Alaska had acquired the four lines — the Kenai Nikiski Pipeline, the Kenai Kachemak Pipeline, Cook Inlet Gas Gathering System and Beluga Pipeline — when the company took over Chevron's and Marathon's Cook Inlet assets a few years ago. Hilcorp wants to manage the four pipelines as a single pipeline entity, the Kenai Beluga Pipeline, or KBPL. Following protracted negotiations between the gas producers, utilities, pipeline companies and other parties with interests in the pipeline system, at the end of August Hilcorp published a settlement agreement, laying out the terms and conditions under which the new pipeline entity would work.

The implementation of KBPL requires Regulatory Commission of Alaska approval — Hilcorp wants the new system to go into operation on Nov. 1, with temporary operating authority from the commission if necessary.

Postage stamp rate

KBPL will have what is called a "postage stamp" transportation rate, meaning that shippers of gas through the system will pay the same dollar fee per volume of gas shipped, regardless of where the gas enters and leaves the system. This arrangement will presumably eliminate the transportation costs from the complex equation of figuring out the optimum pipeline route through which to ship gas. Under the existing four-pipeline configuration, each line has its own tariff and shipping rate, an arrangement that can lead to considerable inefficiency in pipeline use and needless bottlenecks in gas delivery. And high transportation costs at some points on the pipeline system can put some gas fields at an economic disadvantage.

Ed Jaroch, pipeline manager for Hilcorp Alaska, told the commission that, in addition to forming Kenai Beluga Pipeline LLC to manage the company's Cook Inlet gas pipeline assets, Hilcorp has formed a company called Harvest Alaska LLC that will hold all of the company's regulated pipelines in Alaska. In addition to the gas pipelines, those pipelines include the Swanson River oil pipeline on the Kenai Peninsula, the Cook Inlet oil pipeline on the west side of the inlet, and five North Slope pipelines that Hilcorp is acquiring from BP, assuming that the North Slope acquisition closes later this year.

Became integrated system

Jaroch reviewed the history of his company's Cook Inlet gas lines, saying that the pipelines had been built independently for various purposes, with two of the lines starting out as oil and gas field gas-gathering lines. For various reasons, over the years the pipelines had transitioned into a more integrated, public-service gas transmission system, with some of the lines also being converted for bi-directional gas flow, Jaroch said. And, following the start-up of the Cook Inlet Natural Gas Storage Alaska facility, or CINGSA, on the Kenai Peninsula, the pipeline system became fully bidirectional, Jaroch explained. The unbundling or dispersion of gas-fired power generation capacity around the Southcentral Alaska electric utilities has also increased the number of gas shippers using the pipelines, he commented.

And given the amount of pipeline integration, the separate management of four independent pipelines had become unwieldy, increasing regulatory costs by a factor of four and stacking the costs of long-haul gas shipments, as the gas molecules traverse from one pipeline to the next, Jaroch explained.

The KBPL consolidation provides a solution to all of these problems, Jaroch said.

"I'm here to support this settlement agreement. It is a tremendous thing," he said.

Working gas

A key additional benefit that the settlement agreement will bring is the ability for Hilcorp to hold what is referred to as "working gas," extra gas that the company can keep in hand to smooth out mismatches between shipment requests by shippers and pipeline gas throughputs. The company is already in the process of moving 50 million cubic feet of working gas into the CINGSA storage facility, he said. The working gas will enable a reduction in the frequency with which gas shippers have to nominate how much gas they want to ship.

"That working gas is a tremendous benefit to the system," Jaroch said. "It allows us to go from as many as 24 nominations per day across four pipeline systems to six cycles per day on one pipeline."

Hilcorp is introducing an Internet-based system for shippers to enter nominations and manage their own gas shipments.

The settlement agreement also accommodates the possibility of adding extra gas compression to the pipeline system, to improve the east to west transportation capacity of the system and to provide additional system reliability.

Gas imbalance handling

The agreement also includes the possi-

see **RCA REVIEW** *page 6*

● FINANCE & ECONOMY

Falling prices shake up global economies

Weaker global economy causes oil price drop after 4 years of relative stability; producing countries suffer, consumers benefit

By JONATHAN FAHEY
Associated Press Energy Writer

A sudden plunge in the price of oil is sending economic and political shockwaves around the world. Oil exporting countries are bracing for potentially crippling budget shortfalls and importing nations are benefiting from the lowest prices in four years.

The global price of oil is $84 per barrel, down $31, or 27 percent, from its high point for the year. Oil consumption globally is 91 million barrels per day. That means the world's oil producing countries and companies are bringing in as much as $2.8 billion less in revenue every day — and consumers, shippers and airlines are saving a comparable amount on gasoline, diesel and jet fuel.

"The problem is that countries get accustomed to a certain level of income, and then spend," says Edward Chow, a senior fellow at the Center for Strategic and International Studies. "It seems like a windfall at first but when it lasts long enough you get used to it."

The global price of oil was relatively stable for nearly four years, averaging $110 per barrel. Increased production in the U.S., Canada, Iraq and elsewhere made up for declining supplies in nations such as Iran and Libya and helped meet rising global demand.

That delicate balance has been upended by a weaker global economy. Demand is slowing while production, particularly in the U.S., continues to surge.

Consumer-driven economies benefit. For example, drivers in the U.S. are paying the lowest gasoline prices since 2011, giving them more money to spend.

In general the plunge in prices is good for those who have to buy fuel, and bad for those who sell it. But it has far wider and more complex effects on economies around the globe that are only starting to be felt.

Major exporters

OPEC countries and other major exporters will feel the biggest impact. The cash-strapped governments of Russia, Venezuela and Iraq are among the most vulnerable.

Oil is cheap to produce in these countries, so they still make money at lower prices. But their government budgets are based on expectations of oil prices of $100 or more.

On Oct. 14, Russian President Vladimir Putin expressed concern that lower oil prices could force the government to cut spending. Researchers at the state-owned Sberbank, Russia's largest bank, estimate that the country needs an oil price of more than $104 per barrel to balance its budget next year.

In Venezuela, the government leans heavily on oil revenue to fund spending on housing projects, community organizing and other social programs. Now, oil production is falling at a time when the country desperately needs cash. Earlier in October, the analysis firm Stratfor Global estimated that Venezuela needs oil at $110 to continue meeting its obligations.

Venezuelan Foreign Minister Rafael Ramirez called for an emergency OPEC meeting to allow member countries cut production to keep prices above $100.

Saudi Arabia, the world's largest exporter and OPEC's most influential member, might not rush to cut production, however, even though it would start running a deficit with oil at $85 per barrel, according to Merrill Lynch. With a large reserve fund — estimated to be $700 billion — it could withstand a longer period of lower prices.

Saudi Arabia may be interested in using lower prices to force Western oil companies to cut back on some less profitable production in an effort to secure market share.

Iraq is counting on rising revenue both from high oil prices and increasing production to help it fight the insurgency gripping the country and recover from war. Revenue may now fall instead.

Asia

The picture is reversed in Asia, where most countries are major importers and some subsidize the price of fuels.

China is the second-largest oil consumer and on track to become the largest net importer of oil. Falling prices will provide China's economy some relief, according to Huang Bingjie, professor from the School of Economics and Management at China University of Petroleum. But lower oil prices won't fully offset the far wider effects of a slowing economy.

India imports three-quarters of its oil and analysts say falling oil prices will ease the country's chronic current account deficit. Samiran Chakraborty, head of research in India for Standard Chartered Bank, also says the cost of India's fuel subsidies would fall by $2.5 billion during its current fiscal year if oil prices stay low.

Japan imports nearly all of the oil it uses. Following the accident at the Fukushima Dai-Ichi nuclear power plant in 2011, Japan has turned more to oil and natural gas, which is priced based on oil, to generate electric power. But the lower prices are a mixed blessing. Rising energy prices have helped to push inflation higher — a key aim of Prime Minister Shinzo Abe's deflation-fighting "Abenomics" growth strategy.

North America, South America and Europe

Low prices could eventually threaten the boom in oil production in such countries as the U.S., Canada, and Brazil because that oil is expensive to produce. Investors have dumped shares of energy companies in recent weeks, helping to drag global stock markets lower.

For now, lower crude oil and fuel prices are a boon for consumers. In the U.S., still the world's biggest oil user, consumer spending accounts for two-thirds of the U.S. economy, and lower energy prices give consumers more money to spend on things other than fuel.

The same is true in Europe. Christian Schulz, senior economist at Berenberg Bank, says that a 10 percent fall in oil prices would lead to a 0.1 percent increase in economic output. That's meaningful because the 18-country currency union didn't grow at all in the second quarter. ●

—AP Writers Hanna Dreier in Caracas, Youkyung Lee in Seoul, Christopher Bodeen in Beijing, Muneeza Naqvi in Mumbai, Aya Batrawy in Dubai, Elaine Kurtenbach in Tokyo, David McHugh in Frankfurt and Nataliya Vasilyeva in Moscow contributed to this story.

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RCA REVIEW

bility of using operational balancing agreements, or OBAs, between KBPL and parties connecting to the pipeline system, Jaroch said. OBAs deal with gas imbalances, the inevitable discrepancies between the shipment volumes that shippers have requested and the volumes that are actually shipped. Currently imbalances are distributed between shippers, pro-rata the volumes of gas that the shippers are transporting. Under an OBA, KBPL and a connecting party, another pipeline for example, would agree on how to deal with any gas imbalances at the pipeline interface, thus guaranteeing shipper deliveries and taking the shippers out of the imbalance adjustments. ●

Contact Alan Bailey at abailey@petroleumnews.com

● GOVERNMENT

Alberta on slippery slope

Crude markets turmoil raises concern about sands, tight oil capital investments; analyst thinks worst-case scenario will need US$60 prices

By GARY PARK
For Petroleum News

The latest round of stomach-churning lurches in stock and crude markets have sent economic and political shockwaves around the globe, forcing the petroleum industry's big players to ponder heading for high ground by either shelving or scrapping projects.

Assuming oil prices continue to get a severe workout some of the answers will start emerging over the next few months as capital spending plans for 2015 and beyond are unveiled.

In Alberta, which depends for economic activity and growth on one of the largest piles of multibillion-dollar projects in the world, the finger pointing, as it often does in times of a pricing crisis, is being directed at OPEC leader Saudi Arabia which market experts believe would be happy to see prices remain around US$80 a barrel or lower for an extended period.

The Saudis reportedly want to apply the brakes to the production of more costly crudes, notably the Alberta oil sands and U.S. oil from shale.

After the International Energy Agency, IEA, slashed its forecast earlier in October for demand growth and benchmark crude prices slumped to their lowest level in four years, Canada's Finance Minister Joe Oliver exposed the nervousness within government circles by refusing to forecast where commodity prices were heading.

"They tend to be somewhat volatile and we're monitoring the situation," he said of a deteriorating supply-demand picture.

Canada could take big hit

That bland assessment was in contrast with a research report by BMO Capital Markets that noted a drop of 22 percent in the price of oil over four months could deliver a C$3 billion hit to the federal government's bottom line, wiping out a cushion built into the budget forecast to cover unforeseen events, while cooling the Alberta economy which is Canada's growth engine.

Gene McGillian, an analyst with Tradition Energy, told Bloomberg that the "dual combination of economic fear and ample supplies continues to pressure oil. The market just cannot find bottom."

As it has done for more than 40 years, OPEC is wielding the biggest stick by allowing prices to tumble to the point where companies blink, with the Saudis ignoring a plea from Venezuela to call an emergency meeting to discuss production cuts by the cartel to raise prices back above US$100.

Saudi Arabia may be interested in using lower prices to force Western oil companies to cut back on some less profitable production in an effort to secure market share.

Development pinned to prices

Amid the upheaval, RBC Capital Markets issued a report that pinned concerns over the development of oil sands and shale formations on an "uncertain commodity price landscape."

However, it suggested the impact on the industry of sub-US$80 oil could take "months" to realize.

"The market is posing the question, at what price do the oil sands and tight oil plays decelerate from a growth perspective?" RBC asked.

The RBC report said US$80 oil would serve as a drag on drilling in shale formations such as the Bakken, Permian and Eagle Ford as producers high-graded their portfolios, but suggested an extended slump from premium prices would take longer to show up in the oil sands.

It said the long lead times for oil sands projects, along with improving heavy oil pricing dynamics, would be unlikely to bring about a rapid change in developments that are under construction.

"Oil sands producers, mindful of their financial positions and large capital outlays associated with developments, would likely adopt a more measured approach when it comes to embarking on new projects," RBC said.

The report forecast oil sands production will grow by 250,000-275,000 barrels per day in the 2010-20 period, which is more upbeat that the 175,000 bpd forecast by the Canadian Association of Petroleum Producers.

US$100 WTI estimate

RBC and the IEA, based on data from the Canadian Energy Research Institute, estimate new oil sands mining projects need West Texas Intermediate prices of US$100 to break even.

Economists with BMO Capital Markets said it would probably take a sustained period of sub-US$80 oil to trigger a widespread dial back or delay in project planning, but noted that even the price slump has prompted Statoil to stall its Corner oil sands project and Total/Suncor Energy to shelve their Joslyn mine.

The IEA has calculated that thermal recovery projects that use pad drilling need an economic threshold of US$85, but RBC, CAPP and some producers have put that breakeven price at US$75.

FirstEnergy Capital analyst Martin King suggested the mid-US$60s is a worst-case scenario, but emphasized that his firm is forecasting WTI prices in the mid-US$90s.

FirstEnergy is not alone. Scotiabank commodities expert Patricia Mohr predicts WTI will average US$99 this year and US$98 in 2015, while Brent will be about US$107 in both years. CIBC expects US$97.50 for WTI this year and US$90 in 2015.

Short-term vs. long-term

Newly elected Alberta Premier Jim Prentice, previously one of Canada's leading bankers, said he will not confuse "short-term market cycles with the long-term economics" of his province's petroleum industry.

He said that although global oil prices have dropped 25 percent since June, Alberta's bitumen prices have not fallen nearly as sharply.

"There's been a softening of the blow, first because of a lower Canadian dollar and secondly because of lower condensate prices," he said. "Alberta has actually, on a relative basis, held its position much better."

But Prentice said the current crude price levels have "significant implications" for his province.

He said this is "a time for prudence and caution" for Alberta to ensure its finances "remain in order."

"Everyone is trying to determine how long this low-price environment will last," Prentice told the Globe and Mail. "Clearly it will have implications in terms of capital investment decisions in the energy sector."

One of the best hopes for Alberta is achieving access to tidewater and open tanker routes to new markets, allowing producers to benefit from global prices, he said.

"Once we're able to secure pipeline access into the Asia-Pacific basin, Canadian crude will essentially become the benchmark standard for the entirety of the basin," Prentice said.

However, he conceded that the chances of building the Keystone XL, Energy East, Northern Gateway and Trans Mountain expansion pipelines "will take time."

"They hinge very substantially on our ability to strike partnerships" among provincial governments and with First Nations, he said. ●

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GOVERNMENT

SHANE LASLEY

New GMC to be open for business in spring

Progress is being made on the state's new Geological Materials Center in Anchorage, a significant expansion over the existing Eagle River facility.

The Department of Natural Resources said in an Oct. 20 release that relocation to the new facility at 3651 Penland Parkway will begin at the end of October, with the new facility to be fully functional and open for business in the spring of 2015.

Among the geologic materials to be housed in the new 100,000-square-foot heated building are thin sections, core and cuttings representing more than 13 million feet of oil and gas drilling, 300,000 feet of core drilling from mineral projects, 115,000 surface rock samples and 96,000 pulps.

DNR said the new GMC will be an improvement over the Eagle River facility, with many features enhancing access to the facility's library of geologic materials, including significantly expanded and improved core viewing facilities, large private viewing rooms, conference rooms, new microscopes, new sampling equipment and wireless Internet access.

Ahead of schedule

DNR said that the state's ability to convert the old Sam's Club on Penland Parkway in Anchorage into the new GMC was a significant time and money savings, allowing the new facility to be completed several years ahead of the draft plan. The original budget — for construction of a completely new facility — was $45 million, but DNR said purchase of an existing building which required only slight modification dropped the cost of the project to some $24.5 million.

The relocation also puts the geologic samples and science at the fingertips of more students from K-12 to the university, and DNR said Walmart made a "significant contribution" toward purchase of the building, allowing "the new GMC to offer enhanced educational opportunities at the new facility."

—PETROLEUM NEWS

continued from page 1

BUCCANEER SALE

the sale.

The court is accepting objections to the proposed sale through Oct. 29. The sale has been complicated by an ongoing correlative right dispute at the onshore Kenai Loop gas field.

Cook Inlet Region Inc. previously challenged one aspect of the sale in particular: selling all the assets in bulk rather than allowing potential buyers to bid on specific assets.

—ERIC LIDJI

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● UTILITIES

Enstar files gas delivery rate increase

Request to RCA to approve new fees for shipping gas through utility's pipelines raises concerns by power companies, others

By ALAN BAILEY
Petroleum News

Enstar Natural Gas Co., the main Southcentral Alaska gas utility, has filed a tariff advice with the Regulatory Commission of Alaska, asking the commission to approve increases in the rates that Enstar charges its customers for delivering gas through its pipeline network. The utility says that this will be the first increase in its rates since 2010 and that the rate increase is needed to restore the company's return on its equity to the level approved in its last rate increase.

Power companies that use copious quantities of gas for power generation, along with a number of other gas users, have filed comments with the commission, expressing concern about the proposed increases.

The utility says that this will be the first increase in its rates since 2010 and that the rate increase is needed to restore the company's return on its equity to the level approved in its last rate increase.

Reasonable return

As a regulated utility, Enstar is allowed to make what is referred to as "a reasonable return" on its cost of doing business: The utility has to submit an analysis of its costs to the commission, to allow the commission to assess whether a requested rate charged to customers fits that reasonable return criterion.

The two major components in the fees that Enstar charges its customers for their gas consist of the cost of the gas that the utility buys from gas producers and the price that Enstar charges for shipping that gas through its pipeline network to the customers' gas meters. This new tariff filing applies to the second of those charges.

Enstar, in its filing with the commission, says that there have been a number of additions to its "rate base," the costs used to justify rate levels.

Two-stage increase

Enstar proposes increasing the fees in two stages: an initial increase amounting to 1 percent of the utility's revenues, starting on Nov. 1, and an additional increase, bringing the revenue increase to 5.06 percent, after commission approval. For general gas consumers the initial rate rise would bring rates from a current range of 10.87 to 11.26 cents per 100 cubic feet of gas, to a range of 11.28 to 11.42 cents. The final rise would bring the rates to a range of 11.45 to 13.37 cents for users of modest amounts of gas, and to 88.55 cents for general consumers with meters rated for consumption of more than 3,000 cubic feet per hour.

Enstar says that a typical residential monthly bill will increase by $5.64 as a result of the rate increases.

Power station impacts

Apparently the operators of gas-fired power stations would see sharp increases in the rates for the delivery of gas through Enstar's pipeline system. In a filing with the commission, Bradley Evans, CEO of Chugach Electric Association, said that the Southcentral Power Project, the new power plant operated in south Anchorage by Chugach Electric and Municipal Light & Power, would see a gas delivery price increase of 101.7 percent as a result of the proposed rate changes. While accepting that much has changed since Enstar's last rate increase, Evans requested the commission to conduct a formal hearing, to ensure that the rates are just, reasonable and in the public interest. Joe Griffith, general manager of Matanuska Electric Association, has told the commission that his utility strongly opposes the proposed rate increases. The rates for gas that his utility will need next year for its Eklutna power station will increase by 100 percent, Griffith said.

The Anchorage Home Builders Association has questioned the validity of some of Enstar's cost parameters. And the United Association of Plumbers and Steamfitters has filed a formal complaint, citing a list of what it claims are deficiencies in Enstar's rationale behind its rate-increase proposal.

Cost additions

Enstar, in its filing with the commission, says that there have been a number of additions to its "rate base," the costs used to justify rate levels. These additions include improvements to the utility's pipeline infrastructure; some upcoming upgrade projects; the cost of gas stored in the Cook Inlet Natural Gas Storage Alaska facility on the Kenai Peninsula; and the required replacement of a portion of a pipeline between Kenai and Anchorage. ●

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LAND & LEASING

BOEM to do EIS for Cook Inlet sale

The federal Bureau of Ocean Energy Management said Oct. 21 that it will prepare an environmental impact statement for a potential Cook Inlet lease sale

Scoping meetings are scheduled for Nov. 12 in Seldovia, Nov. 13 in Nanwalek, Nov. 13 in Homer, Nov. 14 in Soldotna and Nov. 24 in Anchorage. The Nanwalek meeting will begin at noon; all other meetings will begin at 7 p.m. The purpose of the meetings is to solicit comments on the scope of the EIS for the Cook Inlet sale.

BOEM said the EIS will focus on the potential effects of leasing, exploration, development and production of oil and natural gas in the proposed lease sale area.

"We look forward to receiving thoughtful, substantial input on this EIS," Acting BOEM Director Walter Cruickshank said in a statement. "In particular, we need to hear from residents of the communities along Cook Inlet on how the proposed leasing area is currently being used and what specific areas need extra attention. To address these issues, we will use rigorous science together with traditional knowledge and input we receive from The Notice of Intent to Prepare an EIS," he said.

The sale is part of the 2012-17 five-year proposed outer continental shelf oil and gas leasing program, approved by the secretary of the Department of the Interior in August 2012.

The Cook Inlet lease sale area identified in November 2013 includes "most of the areas identified by industry in their responses to the March 27, 2012, Request for Interest," BOEM said, but excludes the majority of areas designated as critical habitat for beluga whales and northern sea otters, and the critical habitat areas for Steller sea lions and the North Pacific right whale. In addition, there is a buffer between the area considered for leasing and the Katmai National Park and Preserve, the Kodiak National Wildlife Refuge and the Alaska Maritime National Refuge. The proposed sale area also excludes subsistence use areas for the Native villages of Nanwalek and Port Graham identified during the Cook Inlet lease sale 191 process, BOEM said.

There will be a 45-day public comment period from the Oct. 23 publication in the Federal Register. If held, the sale is tentatively scheduled for November 2016.

—PETROLEUM NEWS

FINANCE & ECONOMY

Miller Energy gives Alaska CEO new deal

Miller Energy Resources Inc. has worked out a handsome new employment agreement with the company's point man in Alaska.

Under the agreement, David Hall will receive an annual salary of $475,000, the company said in an Oct. 9 filing with the U.S. Securities and Exchange Commission.

The company also agreed to issue Hall an option to purchase 200,000 shares of Miller's common stock at a strike price of $4.05 per share, which was the closing price of the stock on Oct. 7.


DAVID HALL

"Given the importance of our Alaskan operations and assets to our company and Mr. Hall's history with and understanding of those assets, the board deemed it critical to secure Mr. Hall's services in a written agreement," Miller said.

Hall, 45, is the chief executive officer of Cook Inlet Energy LLC, the Anchorage-based subsidiary of Tennessee-based Miller. Hall also holds the title of chief operating officer of the parent company.

Nearly all of Miller's oil and gas production comes from Alaska's Cook Inlet basin.

Hall has a deep familiarity with the company's main assets, having worked as a manager for prior operators Pacific Energy Resources Ltd. and Forest Oil Corp.

It was Hall who formed Cook Inlet Energy and teamed with the Miller folks in late 2009 to grab a collection of oil and gas properties out of Pacific Energy's bankruptcy. The properties included Osprey, the southernmost offshore platform in Cook Inlet, and the West McArthur River oil field.

Since then, Hall has led efforts to rehabilitate and grow these assets. Miller also has been active in acquiring other assets such as the North Fork natural gas field on the Kenai Peninsula.

The new employment agreement appears to represent a big raise for Hall. At last report, he had a base salary of $375,000.

—WESLEY LOY

● PIPELINES & DOWNSTREAM

State approves North Pole cleanup plan

Departments of Environmental Conservation, Law, OK contaminated soil, groundwater plan proposed by Flint Hills Resources

By KRISTEN NELSON
Petroleum News

The Alaska departments of Environmental Conservation and Law said Oct. 20 that the state has approved a cleanup plan proposed by Flint Hills Resources for contaminated soil and groundwater at its North Pole refinery property.

Flint Hills acquired the refinery in 2004 from Williams Alaska Petroleum Inc. Sulfolane, an industrial solvent, was found in wells near the refinery in the fall of 2009.

"The discovery and investigation of sulfolane contamination has been unprecedented in Alaska due to the distance that sulfolane has traveled in groundwater and the number of private drinking water wells affected," the departments said.

On a website for the North Pole refinery project, DEC said the groundwater plume is some 2.5 miles wide, 3 miles long and nearly 300 feet deep, "making it one of the largest in the state, with many private properties impacted."

The department said Flint Hills responded quickly after discovery of the sulfolane contamination and provided affected residents with alternative water supplies, with nearly 300 alternate drinking water supplies installed.

Future use limited

The departments said cleanup actions in the plan "are designed to protect onsite workers and eliminate migration of contaminants off the North Pole refinery property." Groundwater treatment, recovery of fuel and other contaminants from groundwater and excavation of contaminated soil from certain areas are included in the plan.

Flint Hills has shut down operations at the North Pole facility and has the facility up for sale. The departments said the cleanup plan also includes "management practices for a future owner of the property and limits future use to industrial operations in order to prevent contact with the remaining contamination."

"We will continue to work with Flint

see CLEANUP PLAN page 10

LAND & LEASING

State adds 8 tracts to North Slope sale

Eight previously deferred tracts have been added to the 2014 North Slope areawide oil and gas lease sale.

The Alaska Department of Natural Resources Division of Oil and Gas also said in an Oct. 15 statement that terms and conditions for 34 lease tracts have also been changed, from north sub-region to Arctic Slope Regional Corp./state tracts. The division had announced the fall lease sales Oct. 1.

The eight previously deferred North Slope tracts are between the Colville River unit and the Kuparuk River unit east and northeast of Nuiqsut and appear to be tracts formerly included in the Kachemach unit.

The eight previously deferred North Slope tracts are between the Colville River unit and the Kuparuk River unit east and northeast of Nuiqsut and appear to be tracts formerly included in the Kachemach unit (see story on page 1).

Bids will be opened for the North Slope areawide oil and gas lease sale, along with the Beaufort Sea areawide and North Slope Foothills areawide sales, Nov. 19 at the Dena'ina Civic and Convention Center in Anchorage beginning at 9 a.m.

Details on the sales, including tract maps, are available on the division's website at http://dog.dnr.alaska.gov/Leasing/LeaseSales.htm.

—PETROLEUM NEWS

● LAND & LEASING

State claims acreage at ANWR boundary

2011 Beaufort Sea sale sets off review of ownership; Alaska now seeking conveyance of nearly 20,000 upland acres at refuge border

By KRISTEN NELSON
Petroleum News

The state of Alaska has been working on boundary issues at the Arctic National Wildlife Refuge on the eastern side of the North Slope and is now seeking conveyance of nearly 20,000 acres of uplands at the state's boundary with ANWR. The state will also begin asserting ownership of roughly 3,000 acres of disputed tidal and submerged lands along the Beaufort Sea coastline.

The state said it previously requested the uplands acreage, which is between the Staines and Canning rivers, under the Alaska Statehood Act and Alaska National Interest Lands Conservation Act.

While lands within ANWR are not available for state ownership, the state said the western boundary of ANWR "has been improperly mapped" for many years by the U.S. Fish and Wildlife Service, which manages the refuge. The state said the federal agency's map includes land that is not within ANWR.

"My administration began a thorough review of the boundary dispute after the Department of Natural Resources received bids in 2011 for oil and gas tracts on tidal and submerged lands at the state-federal boundary," Gov. Sean Parnell said in an Oct. 17 statement.

The Department of Natural Resources said in the Oct. 17 statement that the Parnell administration's work built on earlier work on the boundary dispute by state and federal agencies. The renewed effort began in 2012 and included historical and legal research as well as a field inspection by DNR and the Department of Law in 2014.

Parnell said he was pleased that the state has "developed a solid case for priority conveyance of lands" which the state originally selected in 1964.

State ownership of these lands has implications for future oil and gas activity on the eastern North Slope. "Just a few miles away, we are seeing billions of dollars of investment at the Point Thomson field," Parnell said.

"Alaskans have suffered from many roadblocks to resource development on federal lands," DNR Commissioner Joe Balash said in the Oct. 17 statement. "Our hope is that the BLM will move quickly to convey lands that we can offer for oil and gas leasing and development."

The state's request for priority conveyance of the uplands was filed by DNR with the U.S. Bureau of Land Management, which is charged with conveying lands to the state to fulfill its land entitlement.

Beaufort Sea leases awarded

When DNR's Division of Oil and Gas began working with the Division of Mining, Land and Water to determine available acreage that could be awarded in two tracts receiving bids at the 2011 Beaufort Sea areawide oil and gas sale, they determined further research was needed to clarify the boundary, DNR said in an Oct. 21 statement.

"As a result of that initial work, in 2013, DNR began preparing to assert ownership of the disputed tidal and submerged lands."

During the research, Mining, Land and Water "determined that uplands between the Canning and Staines rivers also were improperly mapped as part of ANWR."

DNR said that after a thorough review of the western boundary of ANWR, "the Division of Oil and Gas today awarded two Beaufort Sea leases pending since 2011 and published tract maps for the Nov. 19 North Slope and Beaufort Sea oil and gas lease sales that accurately reflect the boundary." The leases, ADL 392120 and ADL 392122, were among five on which a bidding partnership of J. Andrew Bachner (90 percent) and C. Keith Forsgren (10 percent), were high bidders.

DNR said the division's actions were based on the state's "assertion that it owns roughly 3,000 acres of tidal and submerged lands along the Beaufort Sea coastline that were improperly mapped as part of ANWR."

"I'm pleased that we are now able to award these leases to the 2011 bidders and clarify the acreage that is available for oil and gas exploration in this highly prospective region," Balash said. "Our next step is to determine how the State's assertion will affect existing leases on tidal and submerged lands along the ANWR boundary."

DNR said that for many years the U.S. Fish and Wildlife Service has depicted ANWR's western boundary as the Staines River, "despite legal descriptions that identify the Canning River as the boundary." This uncertainty over the western boundary "has created roadblocks for state land managers seeking to administer oil and gas lease tracts at the boundary, particularly on tidal and submerged lands along the Beaufort Sea coast," DNR said. ●

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CLEANUP PLAN

Hills and any prospective purchaser to resolve any remaining questions about future responsibilities related to the contamination and facilitate a purchase," Alaska Attorney General Mike Geraghty said in the departments' statement. "Finalizing how the contamination at the property will be addressed and what management practices and use restrictions apply is an important step."

The state sued Williams Alaska Petroleum and Flint Hills Resources earlier in the year, claiming that sulfolane contamination continued and spread after Flint Hills acquired the refinery, and that a long history of spills and leaks of petroleum products from the refinery also continued through 2012 (see story in March 23, 2014, issue).

Flint Hills announced its decision to close the refinery in February, citing a dispute over ground contamination liability as compounding difficult market conditions for the plant. ●

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EDGMON Q&A

through long meetings, being very attentive and personable while listening to everyone in Nome and Kotzebue. We definitely have two very committed individuals in the right positions.

Petroleum News: Do you gain a sense that Admiral Papp is interested in the economic development prospects the Arctic presents or is it more on the conservation climate change side of things?

Edgmon: I think that's an excellent question because the members of the Arctic Policy Commission, we've all been concerned about the lack of emphasis on the economic development portion on the Arctic and how it relates to Alaska. Admiral Papp in Nome talked about his definition of national security and how it's not a one-dimensional term. It's important to look at it more though a lens of it being a multidimensional term incorporating economic, environmental, shipping and other factors. He told me he's going to go forward with that viewpoint of the Arctic and its importance to national security to Alaska but the nation as a whole.

Petroleum News: What is your view on the economic development potential?

Edgmon: It's a critical component that comes out of the Alaska Arctic Policy Commission. Based on the work that we've done thus far and in terms of the recommendations we will submit to the Legislature, I think it will be the cornerstone of any work product in terms of what comes out of the policy statement. In terms of our ability as a commission or as a state to affect what happens at the federal level in the Arctic, that is another question. I think it's a question that makes many of us on the commission somewhat uneasy. We started our process as a commission with underlying goals to affect what's happening back east in terms of having Alaska involvement. We've spent a lot of time on Arctic issues. A lot of our northern communities, places like Nome, Kotzebue and Barrow have a lot of personal knowledge and history, as well as being a place for high-level meetings and forums of Alaska. So my personal vision is that has to be a very important part of whatever the Legislature puts on the desk of the governor. I don't detect any dissention on that point. Economic development needs to be up there with a lot of other points.

Petroleum News: So what do you believe are the priorities for the Arctic? Infrastructure gets talked about a lot?

Edgmon: Things are happening so fast in the Arctic. I think back to our first meeting with the Northern Waters Taskforce — the Arctic Policy Commission's predecessor — on Oct. 1, 2010, when we held an all day listening session. We heard from 20 some entities. It was a true drinking from the fire hose experience. All of this stuff was going on and there was no central repository.

One of my priorities, and I make no bones about it, I represent rural Alaska. I represent the Alaska Native communities. Part of my heritage is that of being an Alaska Native. One of my priorities is to make sure that the Arctic policy statements and any recommendations that go forth to the Legislature, properly address the role of the indigenous people of the Arctic.

I had the opportunity to attend last year's Arctic Circle conference in Reykjavik, Iceland, and heard from members of the Inuit Circumpolar Conference, members in Greenland, Norway, Russians and so forth. The bigger picture, of course, is the Arctic is a frontier in so many ways when you look at the lack of international agreements on shipping, fishing, transboundary oil and gas issues, just a whole range of subject matter. You also get the sense that Arctic nations — all eight of them involved in the Arctic Council — are also viewing it as an opportunity to recognize that the role of indigenous people is important to their individual strategies. They are a big part of what's happening in the Arctic today.

Petroleum News: Canada is said to be an example of integrating the indigenous people for their Arctic policies. As Canada gets ready to pass the gavel as Arctic Council chair, do you get a sense of that?

Edgmon: Absolutely. We heard that a lot in Nome and Kotzebue recently. Local involvement and decision making — having a seat at the table as it was termed — was incredibly important to the people of the area, all up and down the coast, for that matter, have been consulted by federal entities, but not directly involved with decisions that affect their communities. My sense is these communities want to change the paradigm to be more included in the big decisions and the small decisions that affect their communities.

Petroleum News: You mentioned having seat at the table. Is that becoming meaningful? Is Washington taking it seriously?

Edgmon: I think to some degree sure. We are having some meaningful meetings with Ambassador Bolton and Admiral Papp, and with others who have been involved in the Arctic decision making at this point. Have we seen the full alignment that we would like to see, I would say, no. But in fairness, I'm not as directly involved in the state-federal relationships as co-chairs (Bob) Herron and (Lesil) McGuire. I think it's going to be an uphill battle to assert Alaska's will to what happens back east in that age-old frustration of decisions being made for Alaska thousands of miles away is going to continue to be a problem for us as the Arctic opens up. That said, I think we are very fortunate to have someone like Fran Ulmer being in a key advisory position. I heard Admiral Papp in Nome and Kotzebue commit to naming one or more indigenous persons to assist him and Ms. Ulmer with the work that they are doing before and during the U.S. period of chairing the Arctic Council.

Petroleum News: So do you get a sense the United States is behind on drafting Arctic policy that guides the country?

Edgmon: I think we are definitely behind. We are in catch-up mode. I had an opportunity to travel to Scandinavian counties these last few years. It's not like they have Arctic strategies or policy statements that are fully refined. What I'm seeing are a lot of other countries, Iceland for example, are sort of in the same catch-up mode as the United States. Finland revised their Arctic policy statement. I believe the Russians have as well. So has Sweden. It all depends on how fast the ice is melting and the northern sea route becoming more open. Just the fact that a lot of countries are viewing the Arctic as being a big part of their national interest happening a lot sooner than they would have earlier

see **EDGMON Q&A** *page 13*

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TAX REGIME

pay off their capital costs has been cut in half to 3.5 percent — but rising to 5 percent by 2037 — from 7 percent, lessening what many in the industry had said could be the undoing of British Columbia's dream of a revenue windfall.

As a result, the government estimates it would capture C$800 million in a 10-year period from one medium-sized LNG plant like those being proposed by Petronas (Pacific NorthWest, designed to start at 12 million metric tons a year and possibly grow to 18 million metric tons), a Shell-led consortium (LNG Canada, coming on stream at 12 million metric tons a year, with an option to double) and Chevron (Kitimat LNG, targeting 11 million metric tons a year). The 7 percent tax was forecast to yield C$1.5 billion per plant over 10 years.

Natural gas tax credit

As an added incentive to advance LNG ventures, the government has introduced a new provincial natural gas tax credit that would shrink corporate income tax rates to as low as 8 percent from 11 percent.

That translates into an estimated C$150 million a year for each plant, although the full amount would not be collected until 7 years after a plant comes onstream, meaning the largest returns would not begin flowing until the late 2020s.

De Jong would not say whether the tax revenues would still flow into a Prosperity Fund, which Premier Christy Clark had once touted as a C$100 billion nest egg to pay for provincial services.

Although no LNG projects have been completed in British Columbia, there are 18 proposals, but Clark — endorsed by analysts — said Oct. 21 it is likely that only five will proceed.

De Jong rejected suggestions that the province has been pressured into lowering its tax rate, saying that while companies have "aggressively" made their case that they would like no tax, the government has been determined to see it extracts a fair return for British Columbians, who own the gas resource.

He conceded that since British Columbia first tested its tax structure there have been "significant changes" in the global LNG market, as selling prices have declined because of growing supplies, an easing of China's economic growth, Japan's possible return to nuclear power, a drop in oil prices that has shrunk oil-indexed LNG contracts and pressure from potential buyers to negotiate Henry Hub-based contracts.

In addition, de Jong said rising construction costs in Australia have raised expectations in British Columbia, while competition for resources is likely to trigger cost inflation.

"We need to be competitive ... we do need to strike a balance and ensure that our overall cost structure compares favorably because the (LNG proponents) poised to make decisions will be looking at this aspect of our regulation and taxation and they will be adding it to an overall analysis of costs," he said.

Balance cited by industry

Backers of the Shell-operated LNG Canada said the final tax framework "provides balance and consideration of the challenges faced by the LNG sector in B.C. We are pleased to have certainty ... and consider it an important input to our decision-making process," the partnership said.

It said work will now turn to areas such as "skills training and labor availability, protecting the environment, community needs and overall fiscal competitiveness and certainty."

Pacific NorthWest, which has been the most outspoken critic of the February tax proposal, said it now needed time to more closely assess the new regime.

Spencer Sproule, a senior adviser for the project, said the consortium continues to believe that British Columbians are entitled to benefit from natural resource extraction.

"At the same time, it is imperative that all levels of government recognize the need to remain competitive with other jurisdictions around the world" that are working on LNG export plans, he said.

Geoff Morrison, the British Columbia manager for the Canadian Association of Petroleum Producers, said companies involved in the upstream end of LNG are pleased the government has delivered on its promise to clarify the tax position, allowing proponents to move ahead with final investment decisions. ●

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EXXONMOBIL ALASKA

The export pipeline from the Point Thomson field has capacity to handle up to 70,000 barrels per day of condensate, a light form of oil. Initial field production is estimated to be 10,000 barrels per day.

High-tech systems can ensure safety

ExxonMobil is using some hi-tech methods to ensure safety at its Point Thomson field on Alaska's North Slope.

One of these techniques involves the use of ground surveillance radar to detect polar bears as they wander onto the field's development pad, Christina Nordstrom, Point Thomson project technical manager, told Petroleum News. The idea behind this novel system is to detect bears as they approach the site in inclement weather or darkness, so that it is possible to move everyone out of the way before a bear becomes a threat, she said.

ExxonMobil's wildlife supervisor worked with the Alaska Zoo to calibrate the radar system, to ensure that the system can detect bears at various angles of approach, she said.

"So far we've been pretty successful in detecting bears on stormy nights. … It's been pretty neat," Nordstrom said.

No disturbance to bears

Operations essentially shut down, with everybody going inside, when bears come across the Point Thomson pad, said Nathan Sanborn, project manager for the Point Thomson Initial Production System.

"We take it pretty seriously, both not to disturb the bears and to keep our people safe," Sanborn said.

Each year ExxonMobil conducts a helicopter based infrared survey along the company's planned ice-road route, to detect polar bear dens, if necessary re-routing the road to avoid bear interactions, Nordstrom said.

Personnel detectors

Sanborn also described a safety system being piloted at Point Thomson in which people wear vests fitted with detector chips. Sensors built into vehicles operating at the field can detect the vests, alerting the vehicle operator to the proximity of a person, say walking behind the vehicle. This system is proving particularly valuable in dark or foggy conditions, Sanborn commented.

ExxonMobil is also working with Honeywell on the development of a specialized Arctic hard hat, with a wrap-around back that provides extra protection if someone slips on the ice and falls backwards. Some people wearing conventional hard hats have been injured as a result of this type of fall in Arctic situations, Sanborn said.

—ALAN BAILEY

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POINT THOMSON

Pad and road construction at the field's surface site has involved moving more than 2 million cubic yards of gravel over the past two winter construction seasons, said Christina Nordstrom, Point Thomson technical manager. And the construction of roads between the pads, and to the airstrip and the project's water source, has involved building four bridges, she said.

Fuel tanks have been installed, capable of holding up to 2.1 million barrels of diesel fuel, both for power generation prior to field startup, and for use as an alternative to gas-fired generation once the field is in operation.

A challenging field

The Point Thomson field is particularly challenging to develop. The field reservoir contains a mixture of natural gas and condensate, a very light form of oil, at a very high pressure. And, with the reservoir extending offshore, offset from the onshore surface well pads, field development involves drilling deviated wells into those high pressures, a technically difficult operation. 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 an injection well.

In the absence of a means of marketing gas from the field, initial field production will consist of just condensate, with the gas being continuously recycled. A small amount of gas will be used as fuel for the production facilities.

Initial drilling

In 2009 and 2010 ExxonMobil used the Nabors 27E rig to drill two wells in the field from an existing exploration gravel pad, a pad that is now called "central pad." The company has since expanded the pad, so that it can accommodate the field's production facilities and support infrastructure.

Nordstrom said that tests using those initial wells indicated good pressure communication between the wells through the reservoir, an important factor in achieving success with the gas recycling production technique.

"All of the indications that we have from the two wells that were drilled in 2009 and 2010, and the subsequent reservoir modeling, support good communication," Nordstrom said. ExxonMobil has a pretty good handle on how the production will work out, she said.

And Sanborn commented that, with ExxonMobil having had experience of drilling more challenging deviated wells elsewhere, the company is confident in its ability to successfully carry out the necessary drilling at Point Thomson.

Initial development plan

In 2012, following a protracted legal dispute, ExxonMobil and the state of Alaska agreed on an initial development plan for Point Thomson. That plan envisages an initial production rate of 10,000 barrels of condensate per day from the field, with production starting at the end of the winter of 2015-16. Sanborn confirmed that the Point Thomson project is on target for achieving the plan objectives, with field startup anticipated prior to May 2016 and involving the cycling of 200 million cubic feet of gas per day for condensate production.

The pipeline that ExxonMobil has constructed for exporting condensate from the field has a maximum capacity of 70,000 barrels per day, presumably to accommodate potential future field expansion. As it stands, the pipeline could handle production above 10,000 barrels per day, should the hydrocarbons produced from the field contain more condensate than anticipated, Sanborn said. But initial gas compression facilities being installed in the field limit the gas recycling to a maximum of that 200 million cubic feet per day figure, he said.

However, the scale of the $4 billion development at Point Thomson, including an airstrip that can accommodate a DC-6 aircraft and a 200-person operations camp, would appear to signal expectations of further development to come. With natural gas

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EDGMON Q&A

anticipated.

Petroleum News: It's common to hear criticisms of groups formed to study as yet another group studying the issue. Do you believe the Arctic Policy Commission has fulfilled its mission as outlined and as a follow-up to the Northern Waters Taskforce?

Edgmon: I really do. To dig into the opening the Arctic subject is to learn that it is multifaceted, that it's fast moving and to learn that any conclusions we draw today will change tomorrow. All 26 of us on the commissions have realized that the work product we hand over to the Legislature is a work in progress if you fast forward five, 10 or 20 years from now. We have traveled to a number of communities, seen firsthand and talked to local leaders. I'm comfortable that what we do bring to the Legislature for the 2015 session will be reflective out there of what needs to be done by way of Alaska being more involved.

One thing for sure is we need a full-time legislative committee to work on the many issues associated with this new frontier. I fully support that. In terms of the policy commission continuing, I think there is merit in it. But with larger budget deficits in the future, we have to be mindful that commissions cost money and be careful to where we can allocate those dollars in the future.

Petroleum News: Let's talk a little bit about the future. The oil tax debate has ceased, at least for now, with voters approving the upholding of SB 21. Do you think this can make it easier for the Legislature to move forward?

Edgmon: As we talk about SB 21, the elections haven't taken place, and I'm not saying A or B is going to happen, but it will be interesting to see if there are any residual effects. That said, SB 21 is firmly in place. We do go forward. I don't expect the elections to have a groundswell of change in the Legislature, but we don't know what's going to happen with the governor's race at this point. In terms of other resource development discussion, the back and forth will be with the fiscal climate. That's the bigger driver than anything else.

Petroleum News: Still looking ahead, and with that in mind, do you have any concerns that the state can't afford to be a partner in this project?

Edgmon: I think we would all have concerns with a project that has been touted somewhere between $45 billion and $65 billion with the caveat that these bigger projects could be cost overruns of up to 30 percent or even more. When you look at the state's share of the equity financing, we have to factor in the costs and our longer-term outlook relative to spending and our savings and to our financial wherewithal like our ratings. So there is definitely a concern about it. When we passed SB 138 last session, with overwhelming support I might add from both the House and the Senate, it wasn't lost on anybody the hurdles that lie ahead between the stage we are at today and getting Alaska's gas finally to market. Those hurdles are breathtaking when you look at the scope of the project itself.

Petroleum News: Do you feel the steps taken thus far demonstrate that things are working or could things be better?

Edgmon: I think it demonstrates to me that things are happening, that there is momentum. The project offices are being set up in Houston, Calgary and Anchorage. The staffing arrangements are coming together. All the money spent on regulatory data, and preliminary design work, all of that indicates there is alignment on the industry side and the state. We are going forward taking the steps necessary toward the fall or winter of 2015, when the Legislature can have the special session to make more commitments and have this thing going forward.

Petroleum News: Now you and co-chair Alan Austerman worked pretty hard to make sure the rural areas get consideration. Do you feel this came together well?

Edgmon: As with any oil and gas bill that comes to the House Finance Committee, we have worked hard to make sure that there be a meaningful addressing of rural Alaska's failure to get affordable energy down the road. SB 138 has certain provisions in there tied to Alaska's energy policy and the Alaska Affordable Energy Act. The fact that rural energy is also going to be the focus of the Alaska Gasline Development Corp. is key. We worked hard with our Senate counterparts to make sure rural Alaska didn't get overlooked. I would also say on that subject that I was impressed with a lot of the provisions on SB 138 that draw upon all the experiences collectively we as legislators have had.

Petroleum News: There's only so much the Legislature can do next session but what would you like to see accomplished between now and next year's special session?

I would like to hear more progress being made like we have been. When you look at a project of this scope, you're looking at the interlocking of a lot of things at one time: financing, engineering, the overall economics. All of this is kind of moving in tandem going forward. It's a lot of moving parts, meanwhile you've got a global market moving, changing and shifting. Hopefully this is setting the stage for us moving to the next phase for us getting the largest private sector project in North America. ●

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GOVERNMENT

EPA extends public comment to Nov. 14

The U.S. Environmental Protection Agency and the U.S. Army Corps of Engineers have extended the public comment period on the proposed definition of "Waters of the United States" under the Clean Water Act to Nov. 14.

The proposed rule was published in the spring with comments closing July 21, a date which was later extended to Oct. 20 and has now been extended for a third time (see story on proposed rule in March 30, 2014, edition).

The agencies said the extension to Nov. 14 is at the request of stakeholders and to allow comments on new supporting materials which were to be available from the Science Advisory Board by Oct. 20.

Under the proposed rule, all territorial seas, navigable waters, interstate water and tributaries of these waters would be considered U.S. waters, as would navigable water impounded behind a structure such as a dam. The rule also defines tributaries. All waters, including wetlands, adjacent to these water categories would also be waters of the U.S.

U.S. Sen. Lisa Murkowski, R-Alaska, slammed the proposed rule when it came out, saying it would place most rain-dependent and seasonal pools, as well as wetlands near rivers and streams, under federal permitting jurisdiction.

Peter Lehner, executive director of the Natural Resources Defense Council, called it good news and said EPA was applying commonsense protections.

—PETROLEUM NEWS

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PLATFORM MOVE

the winter sea-ice season, so Furie decided to defer the installation until after the spring sea-ice breakup in 2015.

Several options

The company considered various options for what to do with the platform during the winter, including the possibility of stashing the massive equipment at Port Mackenzie, across the Knik Arm from the city of Anchorage.

But Furie wants to start platform installation in May, at a time when the platform, if staged at Port Mackenzie, might still be hemmed in by sea ice, Webb said. And, with no docks large enough for mooring the barge, keeping the equipment in Alaska would require the constant use of a tug boat, in somewhere like Kachemak Bay or Resurrection Bay, or perhaps in Prince William Sound, he said.

Moreover, with the equipment configured for installation and hook up prior to the winter, everything would have had to be weatherized prior to staging the equipment in southern Alaska, Webb said. Taking into account all of these various factors, moving the barge with the equipment back to Seattle proved the best solution, he said.

Continued drilling

Meantime, Furie's Spartan 151 jack-up drilling rig has competed the drilling of the Kitchen Lights unit No. 5 well and the rig is now stacked in Port Graham for the winter, Webb said. The rig will return to upper Cook Inlet in the spring to drill the Kitchen Lights No. 6 well.

Furie and its predecessor company, Escopeta Oil Co., have been engaged in a program of drilling in the offshore Kitchen Lights unit since the fall of 2011. The Kitchen Lights unit No. 1 well was located in the Corsair block, one of the four exploration blocks that constitute the unit. The company subsequently drilled the Kitchen Lights No. 2 well, also in the Corsair block, and the Kitchen Lights No. 3 in the central block, to the south of the Corsair block.

Furie announced the discovery of a significant gas field, although the size of that field remains unclear, based on publicly available information. The company has proceeded with field development, centered on the No. 3 well, the planned location of the platform that the company is now having to stage in Seattle for the winter. The company has stashed piping at Port MacKenzie, for the subsea gas pipeline that will deliver gas from the platform to surface facilities, already under construction near East Foreland on the Kenai Peninsula.

Furie has also continued its exploration program, drilling the Kitchen Lights unit No. 4 well in the northern block of the unit in 2013 and 2014, and now completing the Kitchen Lights No. 5 well in the central block. Webb said that the Kitchen Lights unit No. 6 well, planned for next spring, will be located in the southwest block of the unit.

—ALAN BAILEY

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UNIT SAGA

Repsol E&P USA Inc.

Four remedies

Exploration activities in the region date to the 1960s.

But current activities began within the past decade. In December 2010, Brooks Range Petroleum asked the state to form the Southern Miluveach unit over 40 leases covering some 60,864 acres. The state approved two smaller units: the Southern Miluveach unit with five state leases covering some 8,960 acres and the Kachemach unit with 11 joint state of Alaska and Arctic Slope Regional Corp. leases covering some 16,487 acres.

The unit agreement split Kachemach into two exploration blocks — A and B — and required Brooks Range Petroleum to complete a well in Block A targeting the Caribou trend and another well in Block A targeting the Moonlight trend by May 31, 2013.

The unit went into default when Brooks Range Petroleum missed the deadline.

As is common in state land management, the Division of Oil and Gas gave the company a chance to cure the default. The cure involved drilling the two wells by May 31, 2014, with a year extension for the second well if the first one ended up being a dry hole.

Brooks Range Petroleum did not drill any wells at the unit by the new deadline.

On June 18, 2014, the Division of Oil and Gas gave the company a chance to propose a "remedy" for its failure to cure the default, which is also a standard part of the regulatory process. In such cases, one of the potential remedies is the termination of the unit.

In a July 17, 2014, response, Brooks Range Petroleum proposed four remedies.

Of those, two concerned properties outside the Kachemach unit. The first was for the state to approve an expansion of the nearby Placer unit. The second was for the state to extend the terms of nearby Brooks Range Petroleum leases located outside the unit.

The other two remedies involved shrinking the Kachemach unit.

In the first, Brooks Range Petroleum would have voluntarily relinquished the leases in Block B, which would have contracted the unit to Block A. In the second, Brooks Range Petroleum also would have contracted the unit down to Block A. But then it would have considered asking the state to expand Kachemach to include the nearby Placer unit or the proposed Tapqaq unit. If the state agreed to the expansion, the company would either have committed to specific exploration work for Block A or have relinquished the unit.

Brooks Range Petroleum asked the state to keep its July 17 response confidential because the document contained "the proprietary commercial strategy of our company."

While state statute offers confidentiality for certain types of information, "commercial strategies" is not among them, according to the state. Petroleum News requested the document, but the Department of Law had yet to process the request by press time.

Information in this article about the contents of the July 17 response came from a paraphrased reference to the four remedies in Sept. 5 ruling from the state.

The ruling rejected all four proposed remedies.

While recognizing why Brooks Range Petroleum would want to "consider the status of other projects when making decisions about (the Kachemach unit)," Natural Resources Commissioner Joe Balash wrote that the state "considers whether to terminate a unit based on issues related to that unit." That negated the first two proposed remedies.

Balash rejected the other two remedies "because they do not sufficiently protect the public interest." Specifically, he wrote, the proposals would have allowed the company to hold leases without making specific work commitments for exploration activities.

The Placer saga

The proposed remedies show Brooks Range Petroleum trying to unify the Kachemach unit and the Placer unit, which are adjacent in the area west of the Kuparuk River unit.

The Placer leases were originally a prospect within Kuparuk. Operator ConocoPhillips Alaska Inc. drilled Placer No. 1 and Placer No. 2 in February and March 2004, respectively, and later farmed out the prospect to ASRC Exploration LLC, an exploration arm of Arctic Slope Regional Corp., an Alaska regional Native corporation based in Barrow.

The leases contracted out of the unit in June 2005 and later expired. ASRC reacquired the prospect in a 2006 lease sale and became operator of Placer No. 1 in June 2010.

In January 2011, ASRC applied to form the Placer unit over four leases covering some 8,769 acres. In September 2011, the state approved a four-lease unit

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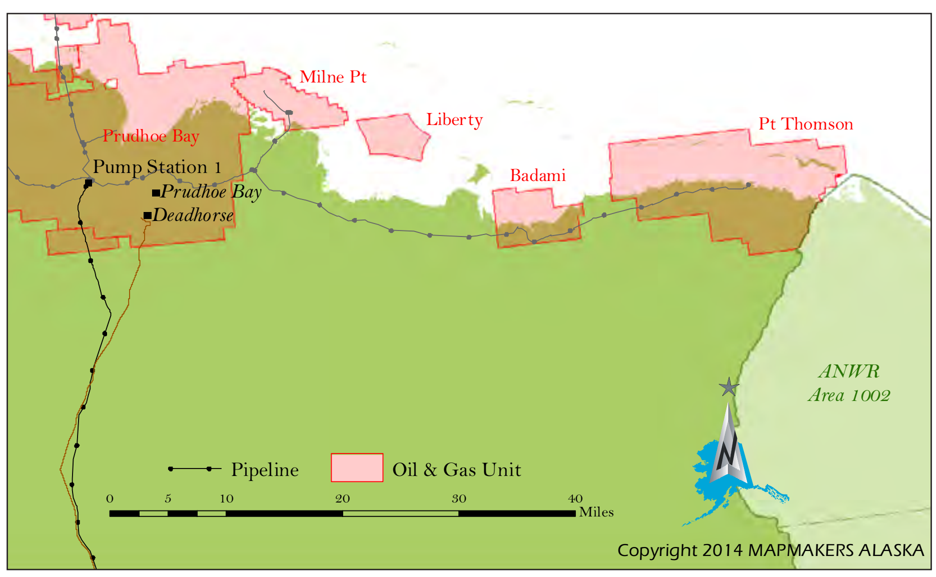
POINT THOMSON

The Point Thomson central pad in August 2014. The permanent operations camp on the pad has been completed, as has the installation of diesel fuel tanks. The major facility modules are scheduled to arrive by barge in the summer of 2015, with smaller modules to be transported by truck from Anchorage in the winter of 2014-15, using a winter ice road to reach the field site.



Situated at a remote location a long distance east of the central North Slope oil infrastructure, access to ExxonMobil's Point Thomson field is by barge in the summer, ice road in the winter and by air to the field's airstrip. The company has built a pipeline to deliver condensate from the field to the North Slope pipeline system at Badami.

reserves of 8 trillion cubic feet, a quarter of the total Prudhoe Bay gas reserves, there are definite future opportunities, Sanborn said.

"We're laying the foundation for whatever comes in the future," he said.

Pad configuration

Although eventual Point Thomson development may involve the use of three surface gravel pads, the existing central pad plus a west pad and an east pad, the initial development will only require the central and west pads. The necessary extensions to the central pad and the construction of the west pad have both been completed, Nordstrom said. The central pad currently houses the field's permanent operations camp and several temporary construction camps, Sanborn said. The well cellars for wells on both pads have also been completed, he said.

At field startup, one of the two previously drilled wells on central pad will act as a gas injector well, with production coming from the other central-pad well, Sanborn explained. Then, upon completion of facilities at west pad and completion of the pipeline tie-in between that pad and central pad in the first quarter of 2016, a well to be drilled from west pad will become the field's production well, with both wells on the central pad then becoming gas injectors.

With a larger internal diameter than the central pad wells, the west pad well will have a higher production capacity than either of the other wells, Nordstrom said. In addition to being designed with smaller diameters, the two central pad wells will require corrosion resistant liners, following the discovery of hydrogen sulfide in the gas coming from the Point Thomson reservoir, she said.

Drilling activities

This winter the Nabors 27E rig will drill a disposal well, complete the two central pad wells and install the liners in those wells, Sanborn said. The rig will then move to the west pad to drill the single well there. Drilling on west pad will start in the fourth quarter of 2015, in anticipation of field startup in 2016, Nordstrom said.

The Nabors rig was upgraded several years ago to enable it to handle the challenging drilling of the two initial Point Thomson wells. ExxonMobil has commissioned further rig upgrades, including the installation of a more powerful top drive, prior to mobilizing the rig for the coming phase of drilling, Sanborn said.

Module construction

Meantime, fabrication of the major production modules for the Point Thomson field has been progressing in South Korea. Weighing a total of about 10,000 tons, the modules consist of a utilities module, a process separation module, a power generation module and a control building. Completion of the modules is anticipated in the next nine months or so, in preparation for shipment in June 2015, for barging to the Point Thomson site that summer, Sanborn said.

On-site work during the coming winter will include the building of the foundations for the processing facilities, Nordstrom said.

Meantime engineering company CH2M Hill is installing underground features such as some of the cabling in central pad, in preparation for the arrival of the modules. The company is also installing some of the on-pad flowlines that will connect wells to surface facilities, Sanborn said.

CH2M Hill has fabricated a large switchgear module, one of several modules being manufactured in Anchorage for transportation by truck to the North Slope. ASRC Energy Services is also involved in the fabrication of some of these modules, which include a methanol injection module, a grey-water module and a metering skid, Sanborn said. The various truckable modules will be completed by the end of this year, for shipment by winter ice road to the Point Thomson site, Sanborn said.

Focus on safety

With programs like "drips and drops," the inspection for oil leaks of any vehicles using the field's ice road during the winter, and the immediate cleanup of any oil spilled on pads or roads, safety performance and environmental protection form significant components of the Point Thomson project, Sanborn said. ExxonMobil has established a "Point Thomson Academy," a training school that operates two-day safety and environmental courses for all on-site supervisors, he said.

So far the Point Thomson project has only seen a few minor injuries, with no lost-time incidents, Sanborn said.

And given the need to inject gas at 10,000 pounds per square inch into the field reservoir, the Point Thomson project team is ensuring that all equipment has appropriate pressure ratings and can operate at those high pressures in the Arctic cold, Sanborn said.

"We fully test everything, 100 percent," he said.

Moreover, field operators hired for Point Thomson are undergoing a two-year, on-the job training program, gaining experience in the operation of similar high-pressure fields elsewhere in the world, Nordstrom commented. ●

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UNIT SAGA

covering just 1,480 acres, which included a 3,500-foot drainage radius around the bottom hole location of Placer No. 1. The unit agreement gave ASRC Exploration until the end of 2011 to re-process seismic data and until June 30, 2013, to drill a well or re-enter Placer No. 1.

In mid-2012, after reprocessing the seismic data, ASRC Exploration asked the state to expand the unit to include all of the acreage it had originally requested — 8,769 acres.

According to the company, the seismic data "indicates that the Kuparuk sand at Placer extends well beyond the current unit boundaries." Specifically, the Placer sand appeared to merge with Brooks Range Petroleum's Appaloosa prospect, located to the south.

The state denied the expansion request in January 2013, saying the company needed to meet its original work commitments before it should be granted a six-fold expansion.

ASRC Exploration appealed the ruling. Without an expansion, the company claimed, any drilling at Placer would essentially create a "twin" of the existing Placer No. 1 well.

Uniting the units

The two companies came together later in the year.

Officials from ASRC Exploration and Brooks Range Petroleum met with the state on Sept. 12, 2013, to present "a unified position" for exploration in the greater Placer area.

Working together, the companies proposed drilling an exploration well in 2014.

The meeting convinced the state to approve the expansion. The decision gave ASRC Exploration until June 30, 2014, to test Placer No. 1 and drill a second well. The decision also required ASRC Exploration to post $5.4 million in performance bonds and gave the company until Dec. 15, 2013, to finalize the farm-out with Brooks Range Petroleum.

Soon after the ruling, Brooks Range Petroleum filed an exploration plan to drill the Placer No. 3 and Placer No. 4 wells. But the company told Petroleum News that the filing was merely a contingency and that the companies still needed to finalize an agreement.

The agreement never materialized, at least not to the satisfaction of the state.

"Unfortunately, and not due to a lack of effort on (ASRC Exploration's) part, successful implementation of those terms was not achieved despite several extensions," Balash wrote in a March 7, 2014 letter to ASRC Exploration President Teresa Imm.

By that time, the billion-dollar fairway had become even more complicated.

In addition to the pending drilling commitments at Placer and Kachemach, Repsol E&P USA Inc. had recently spud the Qugruk No. 5 exploration well in the region and appears to have applied to form the Tapqaq unit. (The March 7 letter made passing reference to the proposed Tapqaq unit, noting only that it would contain the Qugruk No. 5 well.)

With the Placer unit, the nearby Kachemach unit and the proposed Tapqaq unit, "three lessees intend to drill multiple wells in adjacent leases which are already unitized, or proposed to be unitized, and those wells may be targeting the same potential reservoir or reservoirs," Balash wrote. Given the potential for inefficient development, "I have decided to defer unit decisions in this area until the end of the drilling season," he added.

That deferral may have mistakenly led Brooks Range Petroleum to conclude that it had some breathing room at Kachemach. According to the Sept. 5, 2014, termination notice from Balash, Brooks Range Petroleum "referenced" the March 7 deferral letter in its July 17 response proposing the remedies for its failure to cure the default at Kachemach.

"This letter does not state, nor should it in any way be interpreted to imply, that my decision on any given matter is dependent on whether I affirm or deny another matter," Balash wrote. "Facts pertaining to surrounding land or to the parties can be pertinent to a decision. But DNR considers each application and decision on its own merits. I will not affirm one appeal in exchange for denying another, nor will I affirm an appeal in exchange for a party agreeing to consider performing work in another area."

Stepping stones

If all goes well, Brooks Range Petroleum will become the first company to develop the billion-dollar fairway next year, when it brings the Mustang field into production.

The Mustang field is part of the Southern Miluveach unit, which the state split from Kachemach. The current Southern Miluveach unit is south of the Placer unit and southeast of the Kachemach unit. The area between is a swath of un-unitized leases.

Brooks Range Petroleum is developing the field through a public-private partnership with the Alaska Industrial Development and Export Authority. The public corporation invested $20 million in a $24 million infrastructure program including a road and drilling pad at the field and is investing up to $50 million in a $225 million processing facility.

When AIDEA was considering its initial investment in the Mustang project, no later than 2012, officials saw the potential to use the field as a "stepping stone" to improve the economics of other fields in the region. Toward that end, AIDEA required the processing facility to be established in an "open use" arrangement and has encouraged Brooks Range Petroleum to expand the facility in the future to accommodate regional production.

How those aspirations will play out remains to be seen. ●

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