Petroleum news

page Feige holds HOA, MOU reviews in advance of enabling legislation

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February Mining News inside

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

ConocoPhillips files applications for new viscous oil development

ConocoPhillips Alaska has added another project to those it has announced since passage of oil tax reform by the Alaska Legislature last spring.

The company said Feb. 18 that it has submitted permit applications for a viscous oil development targeting the West Sak reservoir at Kuparuk River.

The development, 1H NEWS, Northeast West Sak, includes a nine-acre extension to existing drill site 1H, which would support new wells and associated facilities.

The company said project approval is anticipated in late 2014 with construction beginning in 2015 and continuing through 2016.

see **NEW PROJECT** *page 20*

No quit in BC premier; shrugs off idea LNG chance going away

In the three years since she was elected leader of British Columbia's governing Liberal Party, Christy Clark has delivered a robust message on LNG's potential for riches — notably her claim of 100,000 jobs and a C$100 billion fund to wipe out the provincial debt.

SHANE LASLEY

CHRISTY CLARK

She started out in 2011 telling British Columbians they had no time to waste if they hoped to beat out rival countries seeking Asian markets. "If we don't fight for this, we could lose it."

Then two years ago, she had upped the stakes, declaring that LNG was on a fast track. "Three lines up and running by

see **NO QUIT** *page 19*

PIPELINES & DOWNSTREAM

TAPS worth upheld

Owners suffer defeat as Alaska Supreme Court confirms $9.98 billion valuation

By WESLEY LOY
For Petroleum News

The Alaska Supreme Court has handed the owners of the trans-Alaska pipeline system, or TAPS, a defeat in a case concerning the taxable value of state's most vital physical asset.

In a 38-page opinion issued Feb. 19 and written by Chief Justice Dana Fabe, the high court upheld former Superior Court Judge Sharon Gleason's landmark ruling that put the value of TAPS for property tax purposes at $9.98 billion.

The pipeline owners including BP, ConocoPhillips and ExxonMobil had argued TAPS was worth less than $1 billion.

"We find no error in the superior court's standard or method of valuation of the Trans-Alaska Pipeline System, nor in the specific deductions it made to account for depreciation," the Supreme Court concluded.

But her valuation still wasn't as high as municipal governments wanted. The pipeline passes through these municipalities, which share in the property tax collections.

The opinion pertains only to the 2006 tax year. The ruling, however, likely will have importance for subsequent tax years that remain in dispute.

see **TAPS VALUATION** *page 18*

EXPLORATION & PRODUCTION

West Eagle a dry hole

Buccaneer finds no hydrocarbons in primary target, plans to plug, abandon well

By ERIC LIDJI
For Petroleum News

The West Eagle No. 1 well is a dry hole, according to operator Buccaneer Energy Ltd.

On Feb. 17, the Australian company said it plans to plug and abandon the onshore exploration well in the southern Kenai Peninsula at its current depth of 3,700 feet.

The well reached its primary target and provided enough information for preliminary analysis, according to the company, but "while the analysis confirmed that the sands encountered exhibited excellent reservoir qualities, there were no indications of the presence of hydrocarbons in the target zones," Buccaneer said in a recent statement.

In addition to seeking standard tax credits for the $9.44 million well, Buccaneer said it would ask the state to return two bonds the company paid to backstop its commitments.

While Buccaneer said that it permitted the well to much greater depths and was interested in testing deeper formations, the lack of oil or gas in the targeted sands "has significantly increased the risks associated with the deeper objectives," according to the company.

Buccaneer said its board is in "discussions with

see **DRY HOLE** *page 19*

LAND & LEASING

Healy exploration okay

Alaska Supreme Court rejects appeal against Usibelli coalbed methane license

By ALAN BAILEY
Petroleum News

The Alaska Supreme Court has rejected an appeal against a decision by the Alaska Department of Natural Resources, or DNR, to issue a license to Usibelli Coal Mine to explore for coalbed methane in the Healy area of the Alaska Interior. In a Feb. 14 decision the court said that DNR acted properly in its environmental assessment of the proposed exploration activities and, hence, that the decision to issue the license was lawful.

The exploration license encompasses about 200,000 acres of state land between Healy and Nenana, immediately east of Denali National Park. A state exploration license gives a company exclusive rights to explore for oil or gas in state lands for a specified number of years, with a commitment to some level of exploration expenditure during that time.

Coalbed methane production involves drilling wells into coal seams and then pumping water out of the coal, thus reducing the pressure in the coal and releasing natural gas into the well.

Denali Citizens Council, a public-interest group in the Denali Borough, had raised the appeal against the Healy license. According to the council's website, the council opposes coalbed methane exploration in settled areas and in areas viewed as important to tourism in the Healy area.

see **HEALY EXPLORATION** *page 18*

contents

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

● GOVERNMENT

House Resources works state's LNG deals

Co-chair Feige wants committee prepared when it gets enabling legislation; Legislature could sideboard administration authority

By STEVE QUINN
For Petroleum News Bakken

House Resources Committee co-chair Eric Feige doesn't have Gov. Sean Parnell's bill (House Bill 277 and companion Senate Bill 138) in front of his group just yet. He'll await the Senate's version. But he's keeping his team plenty busy reviewing two agreements between the state and prospective industry partners: ExxonMobil, ConocoPhillips, BP and TransCanada. The committee is also reviewing what really happens to the current law, the Alaska Gasline Inducement Act.

Feige, a Republican from Chickaloon, sat down with Petroleum News to discuss his views on advancing a gas line project.

Petroleum News: You're a little more than one-third through the session. What's your game plan as the Senate hears SB 138?

Feige: The main objective at this point is to make sure the committee members understand the basic foundational documents — that is, the heads of agreement and the memorandum of understanding with TransCanada. If they understand the actual commercial deal that has been negotiated at this point, if they understand the mechanics of that, they will be a lot better equipped to deal with the enabling legislation when it comes around from the Senate.

They will be able to put the changes in law in context with the actual commercial deal. Keep in mind that part of the agreements — HOA and MOU — is that if the enabling legislation is not satisfactory to one or more of those parties, those deals blow up. To some degree we are in a box in certain areas, but there are certainly opportunities for us as the Legislature to put additional restrictions, sideboards, whatever you want to call it.

We can add our own requirements to that legislation. Exactly what form that will take, I don't know yet. We've still got a lot of pondering to do. In this first round of briefings, we've heard certainly from the administration; we've heard from the project team; we've heard from our own consultants; we've heard from our own lawyer, Don Bullock, who has been involved in all of this oil and gas legislation over the last 10 years. He's very well schooled and understands a lot of the possibilities we have front of us.

Petroleum News: What about AGDC (the Alaska Gasline Development Corp.)?

Feige: I've talked to individual board members with AGDC, phone conversations with AGDC management. All of the different players in this, we are talking to them, so we make sure we understand what they believe it's all doing.

The companies — that is the producers — they have certainly their part of the overall heads of agreement commercial structure of this thing. They saw the MOU with us and TransCanada at the same time as I did. We had private conversations with each of those companies to basically hear what they have to say about the TransCanada arrangement.

Right now we haven't come up with any showstoppers that are really going to muck with this deal in any significant way. For us, at this point, we have basically two options before us.

One is to terminate AGIA, go through what I refer to as the AGIA divorce. That would cost about $130 million for us to buy all of the accumulated studies and science that has been done in preparation for this project under the AGIA process. That would entail bringing somebody on to the project team to help manage construction on the pipeline and provide technical expertise on the pipeline.


REP. ERIC FEIGE

The big worry for us is that it could cause a significant delay on the project. It appears the producers are certainly reasonably comfortable with TransCanada. They recognize that they know their business. They have been involved in this project for roughly five years in a fairly detailed level. There are some certain benefits in that regard to keeping them around.

The other option we have is the MOU. To go forward with that arrangement, it would involve a conveyance of equity of the midstream portion of the project. That equity has a value and a significant value. The terms of the MOU also provide some significant financial benefits to the state in just how we finance our portion and how we manage our risk in the project.

Petroleum News: So do you see this as an option between losing AGIA or going with the MOU?

Feige: No. I think the question is do you want to continue with the momentum that has started. I think TransCanada certainly brings advantages to the table based on their familiarity with the project, their company expertise in building and operating pipelines. The question is do we really want to change horses in midstream?

Petroleum News: With the MOU and the enabling legislation, you are setting aside AGIA, even if it isn't a formal repeal, correct?

Feige: Essentially the licensee under AGIA has agreed to walk away from AGIA in return for this MOU.

Petroleum News: So what would be the benefit of formally getting rid of or terminating AGIA?

Feige: The only benefit for actually repealing AGIA — or terminating it — is essentially not have that law kind of obfuscating the political situation as things go forward. By eliminating it, you eliminate all questions that somehow we could end up going back to that. That is something we will have to consider, whether or not we want to do that as part of this enabling legislation or not. If you do, you might as well make it all contingent upon approval of the enabling legislation. If they agree that the enabling legislation is satisfactory, then that's an opportunity to take AGIA and get it off the table.

Q AND A

Petroleum News: You weren't in office when AGIA was passed. The Legislature was in a 120-day session back then. Though the bill wasn't introduced right away, details of the bill were slowly being released. You have 90. Is that enough time?

Feige: I believe we will be able to get through it in 90 days. We had a sense of what was coming, too. We have the benefit of all the previous go arounds in the law. I think there has been a pretty good effort on the part of the project team to get information out about the project. Steve Butt from Exxon does a pretty good job of explaining things in easily understood terms of how all this works together. It's pretty important for not only legislators, but people of the state to understand exactly what it is we are getting into. This whole gas line deal is somewhat unconventional because involving the state as an owner in a project is not something we typical do in the United States. There is precedent in other parts of the world, but for the state to act as a business partner, especially a project of this size, it's certainly unprecedented in the United States.

Petroleum News: You talked about Don Bullock having tremendous experience in these issues. Do you feel the Legislature is equipped with enough institutional knowledge or do you see it as a balance of fresh ideas and institutional knowledge?

Feige: There is certainly plenty of institutional knowledge. I know my committee is comprised of very senior members of the Legislature. Most of my guys have been around the block when it comes to all of these pieces of legislation the last eight years or so. They are pretty well versed. The key to this is getting a variety of information from a variety of sources. I certainly don't want to depend on any one individual whether it's the lawyer or the consultant or a member of the committee. We are going to try to get as much diversification in our information. Ideally in a perfect world it all lines up and meshes together and everybody agrees with everybody. Where there are disagreements, we'll try to suss out why there are disagreements and try to ascertain what the truth is.

Petroleum News: Speaking of prior knowledge and time served with the state. You are on your fourth year here both as a member of the House and as co-chair of House Resources. What have you learned in that time?

Feige: Oh my God. The education on this job has been pretty good. We went through two rounds of oil tax legislation. Both of which were big fights. The next thing about this gas line deal is it's not a big fight. We are not arguing over whether or not the state government should be spending the money into the economy or whether the private sector should be spending the money into the economy. Hopefully we've settled that. There is general consensus that the state of Alaska needs and would certainly benefit greatly from a gas line project, whether it's the AKLNG project or a bullet line down to Southcentral. Either one of those projects

see **FEIGE Q&A** page 15

● PIPELINES & DOWNSTREAM

Kinder Morgan gets no breaks

Tripling Trans Mountain capacity faces same First Nations, enviros, local government resistance as Keystone XL, Northern Gateway

By GARY PARK
For Petroleum News

Trans Mountain has discovered that 61 years of careful stewardship and building bridges to First Nations will carry little weight as it enters the regulatory review process for its planned C$5.4 billion Trans Mountain expansion from the Alberta oil sands to the British Columbia and Washington state coasts.

With Canada's National Energy Board on the verge of setting a 15-month schedule for public hearings on the project it is being swamped with applications for intervener status, including an unprecedented request from the Coast Salish which crosses the Canada-U.S. border.

The proposal involves raising capacity on Trans Mountain to 890,000 barrels per day from 300,000 bpd, with 540,000 bpd tagged for the Westridge Dock in Port Metro Vancouver to be exported to the Asia-Pacific basin.

A large portion of the balance would be destined for refineries in Washington's Puget Sound.

The project largely involves twinning the Trans Mountain system, with 600 miles of new 36-inch diameter pipe, a section entering the fast-growing and heavily populated Greater Vancouver region.

An expanded Westridge Dock would transfer up to 630,000 bpd of crude a month to 34 Aframax class tankers, each with capacity of about 650,000 barrels.

The First Nations say their bid for participation reflects how dramatically the public view of pipelines and oil sands development has changed since Trans Mountain was brought into service.

If the National Energy Board and Canadian government approve the plan, construction could start in 2015, with first deliveries of oil sands bitumen to the Pacific Coast set for 2017.

Municipalities apply to participate

Five municipalities, including the City of Vancouver, have submitted their applications to participate in public hearings, while more than 40 First Nations, including four from Washington state, have joined the line-up.

The concerns are primarily concentrated on the danger of accidents and spills from the pipelines or tankers moving through the Port Metro Vancouver area and crossing the U.S.-Canada border in the gulf west of British Columbia and Washington state.

Kinder Morgan has suggested all along that it has an edge over Enbridge's Northern Gateway project because of its record of involving communities and residents along the existing Trans Mountain right of way since 1953 that it hoped would tip the balance of public opinion in its favor.

But First Nations counter that until recently they have not even been entitled to hire lawyers to challenge resource projects.

The City of Vancouver has mounted increasing opposition to the expansion and said its application for intervener status is based on "substantial increases in tanker traffic, land-based storage and transport of dilbit (diluted bitumen), all of which directly impacts and increases risks to Vancouver's economy, public health and safety and the environment."

It estimated an oil spill would cost the Canadian economy C$20 million per day in lost shipping and cleanup work, endangering the city's C$3.6 billion a year tourism industry and its C$250 billion of commercial and residential waterfront property.

Mayor Gregor Robertson said Kinder Morgan's proposal "represents all risk and no benefit for Vancouver."

First Nations say view has changed

The First Nations say their bid for participation reflects how dramatically the public view of pipelines and oil sands development has changed since Trans Mountain was brought into service.

"The wishes and wants and participation of (aboriginal communities) weren't even considered then," said Ernie Crey, a spokesman for the Sto:lo Tribal Council. "If a pipeline passed over or near a reserve, that was a matter between the company and government."

A joint application by the four U.S. First Nations in the Coastal Salish community voices concerns about the impact of any spills on either side of the U.S.-Canada border.

"The tribes are part of the Coast Salish people, whose political, social and economic linkages spanned the international border long before that border existed," said the U.S. tribes, who underscored their reliance on salmon and shellfish for traditional and economic purposes.

Kinder Morgan did not immediately react to the petitions, although its Canadian President Ian Anderson said two months ago that the company "will fully address the needs and interests of British Columbia and the residents."

They said the Salish Sea has already been "deeply impacted by a pollution-based economy."

Swinomish Chairman Brian Cladoosby said in a statement that "we have decided no more and we are stepping forward."

Company has said it will address concerns

Kinder Morgan did not immediately react to the petitions, although its Canadian President Ian Anderson said two months ago that the company "will fully address the needs and interests of British Columbia and the residents."

He said the regulatory filing includes the "views, concerns and observations" Kinder Morgan gathered during meetings with First Nations, affected citizens, the public and other stakeholders including the government of British Columbia.

Anderson said Kinder Morgan has developed a close relationship with First Nations during the operating life of Trans Mountain and is now seeking "explicit letters of support for the project."

British Columbia Environment Minister Mary Polak said Feb. 14 her government will not prejudge the process, but insists on Kinder Morgan meeting five conditions, including a plan to handle spills on water or land, full consultation with First Nations and direct economic benefits for the province. ●

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CORRECTION

CD-5, not Mooses Tooth

In a Q&A with Sen. Hollis French in the Feb. 16 issue there is a reference to ConocoPhillips Alaska's plans to go ahead with Mooses Tooth.

The project that ConocoPhillips had decided to go ahead with prior to the passage of Senate Bill 21 was CD-5. Mooses Tooth is still in the permitting stage.

—PETROLEUM NEWS

● FINANCE & ECONOMY

EIA projects Brent to weaken in '14, '15

Expects strong domestic crude oil production growth continuing through 2015, to 7.4 million bpd in 2014, 8.4 million bpd in 2015

By KRISTEN NELSON
Petroleum News

The U.S. Energy Information Administration is projecting the Brent crude oil price to weaken as supply growth exceeds growth in demand.

In its February Short-Term Energy Outlook the agency said the Brent crude oil spot price, which averaged between $108 and $112 a barrel for the fourth consecutive month in January, is expected to average $105 a barrel this year and $101 a barrel in 2015.

Growth in crude oil supply is from non-Organization of the Petroleum Exporting Countries sources, EIA said.

The West Texas Intermediate spot oil price, which averaged $94 per barrel in November and $98 per barrel in December "because of strong U.S. refinery oil runs," averaged $95 per barrel in January. WTI is projected to average $93 this year and $90 per barrel in 2015.

The discount of WTI to Brent averaged $18 in 2012, fell below $4 per barrel in July 2013 and averaged $14 per barrel in January. EIA said it expects the discount to average $11 over 2014-15, "reflecting the economics of transporting and processing the growing production of light sweet crude oil in U.S. and Canadian refineries."

Strong domestic crude growth

EIA said it expects strong growth in domestic crude oil production, primarily in the Bakken, Eagle Ford, and Permian regions, continuing through 2015.

Estimated U.S. crude oil production was 7.4 million barrels per day in 2013 and is projected to grow to 8.4 million bpd this year and to 9.2 million bpd in 2015. Both 2014 and 2015 production was revised downward from the agency's January forecast "because of indications that severe weather this winter has caused temporary slowdowns in completing new wells."

The U.S. high for production was 9.6 million bpd in 1970.

Bakken production averaged 880,000 bpd in 2013 and surpassed 1 million bpd in December. Eagle Ford production in South Texas exceeded 1 million bpd in May and reached an estimated 1.22 million bpd in December, the agency said.

Production in the U.S. federal Gulf of Mexico averaged 1.25 million bpd in 2013, down slightly from 2012, and EIA said it is forecasting 1.38 million bpd from the Gulf of Mexico in 2014 and 1.59 million bpd in 2015.

2005 was the peak for share of U.S. liquid fuels consumption met by net imports, reaching 60 percent, falling to 35 percent last year.

EIA is projecting a net import share of 25 percent in 2015, the lowest level since 1971.

Natural gas

Domestic natural gas consumption is expected to average 70.2 billion cubic feet per day this year, EIA said, an upward revision of 0.8 bcf per day from January, largely attributable to an increase in January consumption.

The agency expects natural gas marketed production to grow 2.2 percent in 2014 and 1.2 percent in 2015.

Liquefied natural gas imports have been declining for several years because higher prices in Europe and Asia are attracting sellers. Growing domestic production has replaced pipeline imports from Canada, EIA said, although exports to Mexico have increased, trends expected to continue through 2015.

Natural gas spot prices averaged $4.71 per million British thermal units at Henry Hub in January, up 47 cents per million Btu from December, due to "bitterly cold weather" in January. The agency said it expects price increases seen in the past few months to reverse with the end of winter.

Henry Hub prices are expected to average $4.17 per million Btu this year and $4.11 per million Btu in 2015.

Natural gas working inventories fell by 262 bcf to 1.923 trillion cubic feet at the end of January as colder-than-normal temperatures resulted in greater heating demand and larger-than-normal withdrawals. A new record high monthly withdrawal in January surpassed the previous high set in December. ●

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● ENVIRONMENT & SAFETY

New Alaska oil spill regs go into effect

Challenges of conducting a marine emergency response offshore Alaska require special rules; response network monitors traffic

By ALAN BAILEY
Petroleum News

Vessels operating in the seas offshore Alaska need to comply with new U.S. Coast Guard oil pollution regulations going into effect on Jan. 30, Ed Page, president of the Alaska Maritime Prevention and Response Network, told a meeting of the Alaska Regional Response Team, or ARRT, on Jan. 29. The ARRT coordinates federal oil spill response planning in Alaska.

Because of the impracticality and prohibitive cost of meeting all of the terms of the regulations in most areas around Alaska, the Alaska Maritime Prevention and Response Network has obtained Coast Guard approval of what are called Alternative Planning Criteria, or APC, a set of procedures that meet the objectives of oil spill prevention laws and the associated Coast Guard regulations. A vessel operator can comply with the law by registering with the Alaska Maritime Prevention and Response Network and following the procedures prescribed in the APC, Page said.

Non-tank vessels

The new regulations and associated APC apply to non-tank vessels. A similar APC has been in operation for more than 20 years for barges carrying fuel oil around the Alaska coast, Page said. And an APC for oil tankers operating in Alaska waters went into effect in May 2012.

Although much attention has been paid to the potential for an oil spill associated with offshore oil drilling or from an accident involving an oil tanker, the U.S. Coast Guard and others, including Alaska coastal communities, are also concerned about the possibility of environmental damage resulting from a fuel oil leak from any wrecked ship. Vessel traffic in northern waters has been increasing in recent years, as the extent of summer Arctic sea ice has receded.

The new APC applies to a wide variety of vessels, including tugs, ferries, drill ships, bulk cargo vessels, fishing vessels and passenger vessels, according to the APC documentation.

Response requirements

Coast Guard oil spill response regulations require the availability of staged inventories of spill response equipment, and the availability of vessels and crews to deploy and operate that equipment. Other than in the Cook Inlet and Prince William Sound regions, where there are stockpiles of spill response equipment in support of the oil industry, the huge distances, lack of support infrastructure and winter darkness around the Alaska coast make spill response contingency arrangements very challenging. The APC documentation says that, without the approved APC, full compliance with regulations in Alaska would be "largely ineffective" and could cost the shipping industry somewhere in excess of $100 million per year, a figure that translates to a cost of $100,000 per vessel.

This level of expense is impractical and, if imposed, would have the undesirable, unintended consequence of driving shipping to foreign ports — vessels operating out of foreign ports and transiting international shipping routes are not subject to U.S. oil spill prevention and response laws, Page said. For example, a ship that might otherwise depart from

see **OIL SPILL REGS** *page 6*

● NATURAL GAS

Municipalities worry about property tax

Senate Resources told communities want seat at the table in discussions on PILT, payment in lieu of taxes, not just consultation

By KRISTEN NELSON

Petroleum News

Municipalities are expressing dissatisfaction with the property tax consultation role assigned to them under the heads of agreement which the state has negotiated for equity participation in an Alaska LNG project.

And they are unwilling to wait until later to see that their concerns are met.

The HOA that the state signed with the North Slope producers and TransCanada, which requires legislative approval, specifies that once enabling legislation is passed and work moves to pre-FEED, pre-front end engineering and design, the administration will consult with local governments on PILT, payment in lieu of property tax for the Alaska LNG project.

But the Fairbanks North Slope Borough, the Kenai Peninsula Borough, the North Slope Borough and the City of Valdez, wrote the governor Feb. 11 to express concerns with the potential impacts of the project on local governments.

The mayors said they "have become concerned about the lack of information provided to municipalities regarding the impacts of the ongoing negotiations, particularly local government concessions that may be considered during pending gas pipeline negotiations with the North Slope producers."

Three of the four also testified on their concerns to Senate Resources Feb. 19. The committee is hearing the enabling legislation, Senate Bill 138.

The mayors told the governor they want "to participate in the discussions and to negotiate and agree to terms that directly impact municipal tax structure and revenues."

Municipalities have disagreed with the state over property tax valuation of the trans-Alaska oil pipeline, most recently winning in the Alaska Supreme Court (see story page 1 of this issue).

The HOA provides: "Subject to consultation by the Administration with local governments," PILT — payment in lieu of property tax — would be paid by project participants on each component of the project. "For the Alaska LNG Project, the PILTs would be on a unit rate per throughput basis (e.g. cents per thousand cubic feet, etc.) and could be level or escalating dollar payments for the Alaska LNG Project components."

The HOA also provides for impact payments "to help offset increased service and other costs borne by the State and local governments during construction of the Alaska LNG Project."

The HOA also provides for impact payments "to help offset increased service and other costs borne by the State and local governments during construction of the Alaska LNG Project."

It's the next step

Deputy Revenue Commissioner Mike Pawlowski told Petroleum News in a Feb. 20 email that the administration has consistently testified that the HOA "is the beginning of the process of developing a large-scale LNG project in Alaska and that passage of SB 138 and the momentum for the project it would create (Pre-FEED) is necessary to begin conversations with local governments about the property tax issue."

In a Feb. 17 letter to Kathie Wasserman, executive director of the Alaska Municipal League, Pawlowski said: "The base for any PILT or impact payment system is undefined and the Administration has always viewed the development of such a concept as only working if it is a consensus approach developed with local governments." He also told Wasserman that any revisions to property tax for the Alaska LNG project "would need to be returned to the legislature for consideration in a future legislative session."

Pawlowski told Petroleum News that the administration recognized during development of the HOA that "certain fiscal terms needed to be clarified to enable the project to advance" including establishment of the state's gas share, royalty plus production tax, and commensurate investment.

"We recognized that property tax is an outstanding issue that could only be resolved through an active consultation with local governments. The HOA contemplated this process as part of the next steps for the project," he said.

Not just the gas pipeline

The municipalities appeared to be concerned about property taxes on both the LNG project and the existing oil pipeline infrastructure.

John Hozey, Valdez city manager, told Senate Resources that Valdez was encouraged by the momentum for the project, but concerned that momentum undermines the ability of local government to provide services. The life blood of communities is property tax, he said. Oil and gas taxation has been offered as an incentive to producers in the past, he said, and said Valdez implores legislators to resist any change of property taxes without the input of the communities it will affect.

Mike Navarre, mayor of the Kenai Peninsula Borough, told the committee that consulting with municipalities is not adequate. The municipalities will be living with the impacts long after the project is finished and while the Kenai Peninsula Borough is in favor the Alaska LNG project, it wants to negotiate on its own.

Navarre said he has talked to the governor about the issue and been told it's too early for that discussion. Navarre told the committee it's "never too early" for the property tax discussion.

Sen. Peter Micciche, R-Kenai, a former mayor of Soldotna, said he'd met with Navarre and didn't believe the municipalities were "lurking like wolves," but said it was important to have an eye out for their concerns.

Mayor Luke Hopkins of the Fairbanks North Star Borough told the committee Fairbanks supports a large gas line to an LNG plant for export. He said mayors were concerned that the terms for a PILT have already been negotiated and said amending language has been submitted to Sen. Bishop, a Republican committee member from Fairbanks. Hopkins said the mayors are asking to be at the table and in negotiations.

Sen. Anna Fairclough, R-Eagle River, asked Navarre if the Alaska Municipal League could come up with language. Fairclough told Hopkins the state was looking for certainty in gas line costs and said a way was needed to determine value in a way that is durable so costs can be incorporated into the structure of an agreement. ●

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continued from page 5

OIL SPILL REGS

Seattle might instead depart from Prince Rupert in Canada, he said.

Managing risks

The APC manages oil spill risk by setting rules for vessel routings that minimize accident risk. These rules ensure that safe distances are maintained from land and that transits through the Aleutian Islands use the larger, and hence safer, inter-island passages. A vessel tracking system monitors the movements of vessels registered with the APC, enabling an around-the-clock lookout for unusual vessel movements, with network staff notifying the vessel operator and the Coast Guard of any activity that suggests an elevated risk or that involves infraction of the APC rules. The Coast Guard is responsible for rule enforcement.

The vessel tracking system can also help locate any vessels that might be able to assist in the event of a marine emergency, the APC documentation says.

Alaska Chadux Corp., an oil spill response organization that supports the APC, is maintaining an inventory of spill response equipment that it and other organizations around western Alaska have staged and that could be deployed for a response. The Alaska Maritime Prevention and Response Network has also announced a strategic partnership with the Marine Spill Response Corp. for the cascading of out-of-state spill response resources into Alaska, should need arise. The Marine Spill Response Corp. is a major oil spill response organization, with stockpiles of spill response equipment staged at several locations in the Lower 48.

APC rules

Under the terms of the APC, the master of any vessel registered with the APC must ensure the operation of the on-board equipment needed for the vessel tracking system and must notify the Coast Guard if the vessel encounters any hazardous condition, such as a deficiency in the vessel's propulsion system, when operating within 200 miles of the Alaska coastline. The master must also notify in advance both the Coast Guard and the Alaska Maritime Prevention and Response Network if, for some reason, the vessel is unable to comply with the APC vessel routing rules.

There are also rules specific to vessel operations in sea-ice conditions.

Had the new APC been in operation in the past, major marine accidents such as the grounding of the Selendang Ayu could have been prevented, Page said. The Selendang Ayu, a bulk cargo ship, ran aground and broke up off Unalaska Island in the Aleutians in 2004, resulting in six deaths and a significant oil spill. ●

Contact Alan Bailey at abailey@petroleumnews.com

EXPLORATION & PRODUCTION

TGS applies for Chukchi seismic permit

Geophysical company TGS has applied to the Bureau of Ocean Energy Management for a permit to conduct survey operations in the Chukchi Sea during this year's Arctic open water season. The application says that the company plans to conduct 2-D seismic and gravity surveying operations between Aug. 1 and Oct. 31 using a survey vessel towing an air-gun sound-source array and a single streamer of seismic hydrophones. A scout vessel will monitor for marine mammals in the area of the survey operations.

A map of the survey area indicates that the surveying is planned over much of the northern U.S. Chukchi Sea, and extending north and west in what appear to be international waters.

TGS conducted survey operations in a similar region during the 2013 open water season but has not commented on the outcome of those operations. The company has said that it wants to acquire high-quality modern 2-D seismic data that companies can license as an information source for exploration decisions.

—ALAN BAILEY

● EXPLORATION & PRODUCTION

Shell shelves oil sands plan

By GARY PARK

For Petroleum News

Royal Dutch Shell has issued a barely disguised hint that LNG is overhauling its oil sands developments in Canada by placing an indefinite hold on a planned 200,000 barrels per day bitumen mine in Alberta.

It advised the federal government's Canadian Environmental Assessment Agency that it is pushing back its plans for a two-phase mine at Pierre River in northern Alberta, while it reevaluates "the timing of various asset developments with a focus on maintaining a competitive business and successful delivery of near-term growth projects."

It is not clear whether the strategy shift will affect Shell's other oil sands ventures, including its 80,000 bpd, two-stage Carmon Creek project in the Peace River region of northwestern Alberta, plans for expansions in its core northern Alberta leases by adding 200,000 bpd to its Jackpine mine and a proposed expansion and debottlenecking of 115,000 bpd at its Muskeg River mine in partnership with Marathon Oil.

In halting work on the Pierre River project — with includes Chevron and Marathon as minority partners — Shell has suspended on-going reviews after obtaining regulatory approval for two phases of 40,000 bpd each, coming on stream in 2017.

"Until the implications of these changes are understood and Shell's evidence has been updated, Shell is not prepared to proceed to a hearing on the project," Andrew Rosser, vice president of heavy oil sustainable development and regulatory, said in a letter to the environment agency.

Winning back investors

Under new Chief Executive Officer Ben Van Beurden, Shell has committed itself to careful investment as it seeks to win back investors who are disenchanted with rising costs and spending plans by the world's No. 3 oil company.

That new mood of caution has seen Shell announce delay of its 2014 plans for drilling in Alaska and postponing development of an LNG venture in offshore Australia, while issuing a rare profit warning in January before disclosing a 49 percent plunge in fourth-quarter earnings.

Shell's Canadian unit said its focus is now on "more imminent" growth opportunities in Canada, with Pierre River always viewed as a "long-term" prospect.

But everything points to a continued drive towards a final investment decision on its massive LNG Canada project in British Columbia, which has regulatory approval to export up to 24 million metric tons a year over 25 years, half of that assigned to a first phase which could cost an estimated C$15 billion.

With Korea Gas (which is looking to sell part of its share), Mitsubishi and PetroChina each holding 20 percent stakes, the project took another step forward Feb. 12 when the partners entered an agreement to acquire or lease a wharf and associated land from mining giant Rio Tinto, which operates an aluminum smelter at the deepwater port of Kitimat on the northern British Columbia coast.

The terms of that arrangement were not disclosed, but Shell said the deal gives LNG Canada an opportunity for future expansions.

Shell bought a former methanol terminal in Kitimat from Cenovus Energy for an undisclosed amount in 2011. ●

Contact Gary Park through publisher@petroleumnews.com

LAND & LEASING

Pioneer asks for Oooguruk expansion

Pioneer Natural Resources Alaska Inc. is asking the state to expand the Oooguruk unit to include three small and irregular leases in the center of the near-shore North Slope unit.

The Texas-based independent, which is in the process of selling its Alaska holdings, wants the state to add ADL 392113, ADL 392157 and ADL 392158 into the unit.

The expansion would add some 156 acres to the roughly 53,187-acre unit. The small acreage position represents all the un-unitized acreage Pioneer still holds in Alaska.

The three leases are surrounded by the unit, but not included in its boundaries. The company acquired the three leases in the lease sales of December 2011, several months after the state last expanded the boundaries of the Oooguruk unit, in August 2011.

The most recent expansion of Oooguruk added the Nuna prospect onto the southern end of the unit. Pioneer must decide by this summer whether to sanction a Nuna development.

Toward the end of last year, Pioneer announced plans to sell its stake in the Oooguruk unit to the privately held independent Caelus Energy Alaska LLC. The small Texas-based company has previous said it intends to start work on Nuna "pretty much immediately."

The deal was announced in late October, but Pioneer filed the application and remains the operator and leaseholder listed in Alaska Department of Natural Resources filings.

The state is taking comments through March 17.

—ERIC LIDJI

ENVIRONMENT & SAFETY

More dialogue over CINGSA pressure

When Cook Inlet Natural Gas Storage Alaska, or CINGSA, finished topping up its Kenai Peninsula storage reservoir in November, ready to support high utility gas demand in the coming winter, the company discovered that the reservoir pressure exceeded the permitted maximum for the facility. The company notified state authorities of the discrepancy and subsequently received a notice of violation from the Alaska Oil and Gas Conservation Commission. There is still a continuing dialogue over exactly how the pressure ended up being too high.

CINGSA has been conducting some reservoir modeling to try to nail down the precise cause of the pressure anomalies, the company said.

On Dec. 26 the commission sent a letter to CINGSA requesting further clarification of how the company had failed to spot the approaching excess pressure, even although CINGSA said that it had been using one of the facility's wells to monitor the reservoir pressure as the reservoir filled.

In a Jan. 30 response CINGSA confirmed that it had been monitoring the pressure using one of the wells. But as the company watched the transient pressure, as gas was injected underground, the company believed that once the pressure stabilized across the reservoir, it was unlikely that the pressure would exceed the permitted maximum.

CINGSA had previously experienced unexpectedly high pressures during some earlier shut-in tests and had attributed these pressures to some technical issues associated with re-pressurizing the reservoir, a depleted gas reservoir in an old gas field. And, given the lack of a sufficient operational track record for the relatively new CINGSA facility, it was impossible to tell whether the high pressures represented transient pressures resulting from that reservoir refilling, or whether the well had encountered a pocket of high-pressure gas from the original gas field.

CINGSA has been conducting some reservoir modeling to try to nail down the precise cause of the pressure anomalies, the company said.

The company has undertaken to adopt a more conservative approach to its pressure management in the future.

—ALAN BAILEY

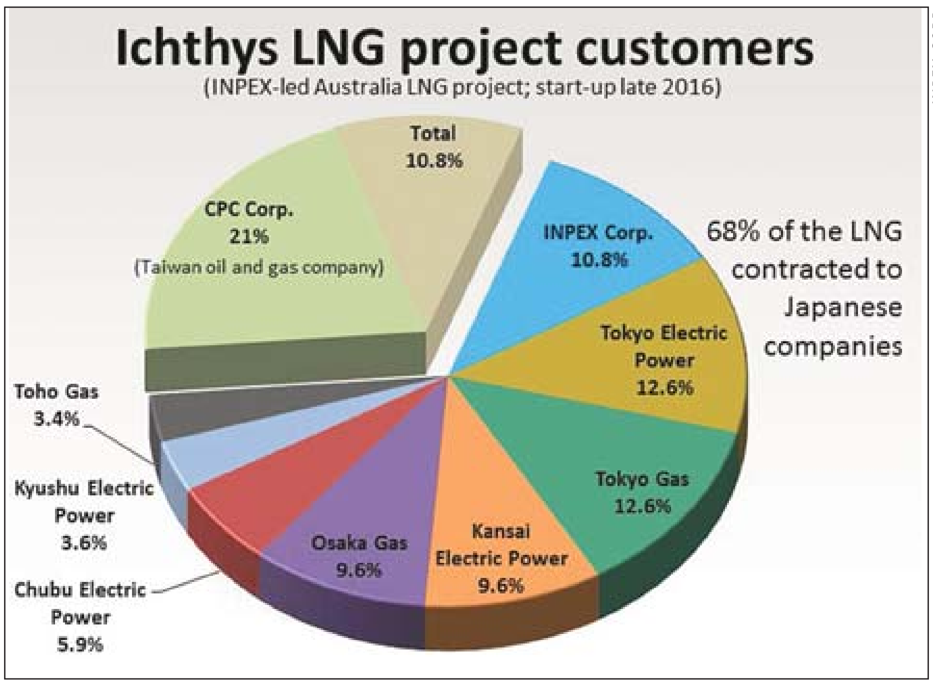
● NATURAL GAS

Utilities increasingly invest in LNG

Tokyo Gas, Chubu Electric, other Japanese utilities aren't waiting for gas to arrive, but are signing up to develop LNG projects

By JEANNETTE LEE

Researcher/writer for the Office of the Federal Coordinator



The Ichthys LNG project under construction in Australia has 68 percent of its output under contract to Japanese buyers, most of that to seven utilities. INPEX Corp. is an oil and gas producer and the project operator.

Overseas investment to grow

Unlike the United States, energy security for Japan doesn't start at home. With meager fossil fuel reserves of its own and no gas pipeline connections to other countries, Japan meets more than 95 percent of its gas demand with LNG imports.

The archipelagic nation was the world's largest LNG consumer even before an earthquake and ensuing tsunami in March 2011 caused a meltdown of the Fukushima Daiichi nuclear plant and prompted Tokyo to shut down the country's nuclear power plants. Since the accident, Japan has ramped up its imports of oil, coal and LNG to fill in the gaps left by shuttered nuclear facilities. As of 2012 about half of the country's electric power came from LNG, according to the U.S. Energy Information Administration.

Natural gas consumption in 2012 was about 4.4 trillion cubic feet, up 24 percent from 2010 mostly as a result of the nuclear disaster.

But as Darwin demonstrated, Fukushima wasn't the catalyst for Japanese utilities acquiring equity stakes in foreign LNG projects.

The push for ownership is one of several strategies designed to avoid gas shortages and high prices following the expiration of long-term LNG contracts inked in the 1970s and 1980s with exporters based primarily in Southeast Asia, according to the U.S. Energy Information Administration.

With Japan's Prime Minister Shinzo Abe pushing for greater competition and lower electricity prices, the utilities are under pressure to keep costs down and push hard for better deals before passing higher fuel costs on to consumers. Given the high level and expense of Japan's energy needs now and into the future, some of largest electric and gas utilities appear poised to expand their presence at the owners' tables of LNG projects.

Australia, with its proximity to Japan and promise as a dependable, long-term source of LNG, has been a magnet for investment by utilities, but it's by no means the only country the utilities are targeting.

Tokyo Gas seeks to take majority stakes in medium-sized LNG projects in Southeast Asia or Africa, according to an article by Bloomberg News in October 2013. This would be a major new strategic move for one of Japan's top importers.

Shigeru Muraki, an executive vice president at the utility, told Bloomberg that Tokyo Gas is interested in plants that can produce as much as 3 million metric tons per annum of LNG — about the same size as Darwin LNG. The utility can have more operational control through ownership in mid-sized projects, rather than large ones, he said. Tokyo Gas already holds small shares in big Australia projects with LNG capacity ranging from about 4 mtpa to 16 mtpa.

Osaka Gas likewise has plans to "aggressively enter this upstream stage of the natural gas value chain," the company said in its 2009 report on corporate social responsibility.

With Japan's Prime Minister Shinzo Abe pushing for greater competition and lower electricity prices, the utilities are under pressure to keep costs down and push hard for better deals before passing higher fuel costs on to consumers.

In 2008, the company bought into its first overseas LNG plant with a 10 percent share of the $10 billion Freeport LNG import terminal on Quintana Island, Texas. Like many underutilized U.S. import terminals, Freeport LNG now wants to get into the export business, moving some of the nation's shale gas riches to overseas markets. The U.S. Department of Energy has signed off on Freeport's export application, but the project sponsor is still waiting for approval from the Federal Energy Regulatory Commission for its construction and operation plans.

Utilities not the only players

LNG project ownership can help not only the utilities' bottom lines, but puts them in a position to potentially generate business for Japan's other industries. Muraki of Tokyo Gas has mentioned the possibility of teaming up with other Japanese companies such as engineering contractors JGC Corp. or Chiyoda Corp., and plans to expand its LNG shipping fleet.

Japan's financial institutions are also involved. The Japan Bank for International Cooperation states that one of its top priorities is "obtaining natural gas by supporting the acquisition of interests and development of LNG-related projects as well as imports."

JBIC's assistance includes hundreds of millions of dollars in loans to Osaka Gas to buy equity in Gorgon LNG and Ichthys LNG, both under construction in Australia. The Japan Oil, Gas and Metals National Corp., tasked under Japanese law with securing a stable supply of oil and natural gas, is another financing source for the utilities, as are private banks.

Japan's oil and gas companies and commodity traders have a longer history

see UTILITIES & LNG page 9

continued from page 8

UTILITIES & LNG

than the utilities of backing overseas LNG projects and tend to take larger stakes.

The Japanese energy company INPEX is operator and majority owner of the Ichthys LNG project under construction in Australia. Mitsubishi, a conglomerate known globally for its autos and electronics, is also a major import agent for Japan's utilities and is backing LNG projects in Russia, Malaysia, Brunei, Oman, Indonesia and Western Australia, according to its 2013 annual report.

Mitsubishi and fellow conglomerate Mitsui last year each took an ownership stake in the Cameron LNG export plant in Lake Charles, La., proposed by a Sempra Energy subsidiary. That project is waiting on U.S. government approval and a final investment decision.

Korea, China stalking projects, too

Korea Gas Corp., the world's largest single LNG importer, is also using project ownership to seek more control and oversight of its gas supply and to buy it at better prices. Like neighboring Japan, South Korea has little in the way of domestic fossil fuel resources and has had to reduce its nuclear capacity in recent years.

With its core business on the distribution side, South Korea's sole LNG importer brings in 35 mtpa of LNG annually. The government-owned company has an effective monopoly over the purchasing, import and wholesale distribution of natural gas, according to the U.S. Energy Information Administration.

In addition to holding minority equity stakes in about half a dozen LNG projects under construction and proposed in Africa, the Middle East, Australia and North America, KOGAS has pounced on new fields in East Africa and the Mediterranean Sea, buying up blocks alongside more established producers like Italy's Eni.

In December 2013, a KOGAS executive told the Alaska Journal of Commerce that investing in a gas project in Alaska as well as buying the fuel is a possibility someday. "At this moment, actually, the timing is a little bit far away," said Kwon Young, executive vice president and resources business division chief operating officer.

China's big national oil and gas companies, rather than its utilities, are investing in LNG projects and purchasing the gas. They tend to hold larger — albeit still minority — shares in LNG projects than either the Korean or Japanese buyers.

In June 2013, China National Petroleum Corp. agreed to purchase a 20 percent stake in the $27 billion Yamal LNG project in the Russian Arctic. Yamal, which reached a final investment decision in December 2013 with production startup targeted for 2017, is just one of several projects drawing China's interest.

Europe's utilities are not following their Asian counterparts into LNG project investments, in part because they depend less on LNG as a percentage of the overall fuel mix.

The nation's largest refiner, Sinopec, is the foundational buyer and owns a 25 percent stake in Australia Pacific LNG, which is under construction and scheduled to start exporting gas in 2015. (ConocoPhillips holds a 37.5 interest in Australia Pacific LNG.)

Sinopec is also scoping out the investment potential of projects in British Columbia.

"The Chinese companies are new to this game and want to learn the biz," Herberg said. "CNPC and Sinopec want to gradually be able to lead these projects on their own."

Europe's utilities are not following their Asian counterparts into LNG project investments, in part because they depend less on LNG as a percentage of the overall fuel mix. FACTS Global Energy consultant Nelly Mikhaiel noted that Japan's extreme dependence on LNG makes anything that enhances security of supply an attractive prospect.

Profit and success not guaranteed

Profitability is another attraction of investment in LNG projects. Project sponsor agreements often include ownership rights for a share of the gas, giving the utilities protection against upswings in price, which hurt them as buyers.

"If the markets soar, as they are now soaring, they will earn some of the high cost back in the way of profits," Zach Allen, an analyst at energy advisory firm PanEurAsian Enterprises, told The Wall Street Journal in April 2012.

Tokyo Gas, for one, forecasts a $25.7 million increase in its operating income from investments abroad for the fiscal year ending March 2014. The projected earnings will come from the Pluto LNG project and a Barnett basin shale gas project in Texas.

"The best part of the value chain is having a stake in the upstream production and liquefaction," Herberg said. "That's where a big chunk of the money is to be made."

But as with any investment, nothing is guaranteed. Following the 2011 earthquake, Tokyo Electric, which owns and operates the Fukushima Daiichi nuclear plant, lacked the finances to maintain its 15 percent equity share in the licenses for the Wheatstone gas field and 11.25 percent interest in the proposed Wheatstone liquefaction terminal in Australia. (Wheatstone is under construction and scheduled to go online in 2016.)

In June 2012, Mitsubishi along with one of the world's largest shipping companies, Nippon Yusen Kabushiki Kaisha, came to TEPCO's rescue by joining the project, effectively knocking Tokyo Electric's share down to less than 1 percent of both the gas reserves and LNG plant.

Under pressure from the South Korean government, KOGAS is trying to scale back its ownership stakes in Australian and Canadian projects. A Wall Street Journal article in 2013 reported that Seoul wants its national energy companies to improve their financial standing by selling unprofitable, non-core overseas assets. The country's energy giants have amassed large debt loads in the past five years in acquiring energy resources abroad.

Aside from adverse events at home, there is risk that the projects themselves won't go well for any number of reasons: The cost of materials might skyrocket, labor costs might increase, poor weather could put construction on hold, demand might fizzle, fellow suppliers might push down prices by flooding the market, or there might not be as much gas as originally expected.

"The risk is that you get into a poor project in terms of profitability and you don't make money after investing a lot of capital," Herberg said.

Relationships build projects

The international oil and gas companies heading LNG projects are willing to welcome their customers as fellow project sponsors for good reason: Without buyers, there is no project.

"Rarely can the projects get under way without long-lasting commitments from these customers to buy cargoes annually for 15-25 years," Herberg said. "For majority owners, when they bring in a really small partner who's also a buyer, what that generally does is make the investor a reliable buyer."

The upstream partnership "in a sense cements a partnership for the supply contract," Herberg said, "and it all fits together better."

Mikhaiel thinks the increasing involvement of LNG customers as project sponsors ultimately makes overcoming the differences between buyers and sellers "quicker and more trouble-free."

Asian LNG buyers, in particular, have been pushing hard for changes in the traditional formula that yokes the cost of natural gas in their region to the global price of oil. Producers, however, are resisting the change, arguing they need the high, oil-linked prices to finance the mega-billions of upfront capital costs and provide their desired rate of return.

"The LNG industry is built on cooperation," Mikhaiel said. "If you have got the buyer with a seat at the table of a sellers consortium, and all parties are cognizant of what's driving each other, this can only facilitate understanding since the views of the other party will always be expressed in a timely fashion." ●

Part 1 of this story appeared in the Feb. 16 issue of Petroleum News.

Editor's note: This is a reprint from the Office of the Federal Coordinator, Alaska Natural Gas Transportation Projects, online at www.arcticgas.gov/japan-utilities-increasingly-invest-lng-projects.

● ENVIRONMENT & SAFETY

The burning question in ice conditions

Arctic oil spill JIP publishes report on the effectiveness of in-situ burning in a response to an oil spill in ice-laden water

By ALAN BAILEY
Petroleum News

As companies such as Shell turn their eyes to the Arctic seas as a new frontier for the discovery and development of oil resources, some people are skeptical about the possibility of cleaning up an oil spill, should some accident occur in the ice-laden waters of the far north. Can oil realistically be removed from between ice floes? And what if oil becomes trapped under a continuous ice sheet?

1 2 SERIES

One technique that the oil industry has proposed for responding to an Arctic offshore spill is the in-situ burning of oil, a technique that the industry says has the potential to remove large volumes of oil from the sea, depending on sea and ice conditions.

An Arctic oil spill technology joint industry program, or JIP, has published a new report overviewing current knowledge of in-situ oil burning in ice-affected waters and providing insights into the feasibility of the technique and into some of the issues involved in the technique's application.

According to the JIP website the JIP, with a membership composed of nine major oil companies including Shell, BP, ExxonMobil, Statoil and ConocoPhillips, was formed in 2012 as a collaborative venture under the International Association of Oil and Gas Producers, to expand industry knowledge of Arctic oil spill response. The JIP is conducting laboratory research projects into the use of oil dispersants, environmental effects, oil slick trajectory modeling, remote sensing of oil and in-situ burning. The program may also at some time involve Arctic field testing of response techniques, the website says.

Current knowledge

The JIP's new in-situ burning report presents a synthesis of current knowledge about this technique, rather than the results of some new laboratory or field research done by the JIP. The objective is to encourage the consideration and acceptance by industry, regulators and other stakeholders of in-situ burning as a viable technique in ice-affected waters, the report says.

"In general, in-situ burning has proved effective for oil spills in ice conditions and has been used successfully to remove oil spills in ice-covered waters resulting from storage tank and ship accidents in Alaska, Canada and Scandinavia since the 1970s," the report says.

The report says that, while in-situ burning has rarely been used in dealing with marine oil spills, success with the technique in eliminating 220,000 to 310,000 barrels of spilled oil from the Gulf of Mexico following the Deepwater Horizon disaster has increased interest in the technique's use.

Depends on ice conditions

But the feasibility of burning oil in a situation involving sea ice would depend on the precise ice conditions, the report says. In the presence of floating pack ice or drift ice, the concentration of ice on the sea surface would determine whether spilled oil could be burned. In the case of consolidated land-fast ice, the process of encapsulation and migration of the oil would be a determining factor.

"Mid-winter, although associated with long periods of darkness and cold temperatures, provides a stable ice cover that not only naturally contains oil within a relatively small area but also provides a safer working platform for surface oil removal," the report says.

see **ICE CONDITIONS** *page 11*

Testing the dynamics of burning oil in ice

In a research study funded by the Bureau of Safety and Environmental Enforcement a team of scientists in the Worcester Polytechnic Institute has conducted laboratory experiments, putting some factual science around the practicalities of burning oil trapped in cavities in the surface of sea ice. In-situ oil burning has been promoted as an effective technique for responding to an offshore oil spill in sea-ice conditions but apparently no one has previously carried out a scientific study of the dynamics of how oil burns in ice.

According to a report on the results of the new study, the research team placed samples of North Slope crude oil in circular ice cavities of various sizes and carefully measured the results of igniting the oil. For comparison, the team also measured the results of burning oil in a rigid container. The tests showed that, because ice around a cavity melts during a burn, with the diameter of the cavity increasing while melt water raises the level of the oil, oil burns at a faster rate in an ice cavity than in a container of similar size. However, as the ice-walls of the cavity melt, a lip tends to form at the top of the cavity, causing some oil to become trapped in the cavity's sides, the study report says.

Burn efficiency increases with cavity diameter and ranges from 32 percent for a small cavity to around 85 percent for a larger cavity, 128 centimeters across, the report says.

The team developed a mathematical model for predicting the results of a burn, using parameters such as the ice cavity dimensions and the temperature of the ice. Predictions from this model corresponded reasonably well with the observed burn results in the experiments, the study report said.

—ALAN BAILEY

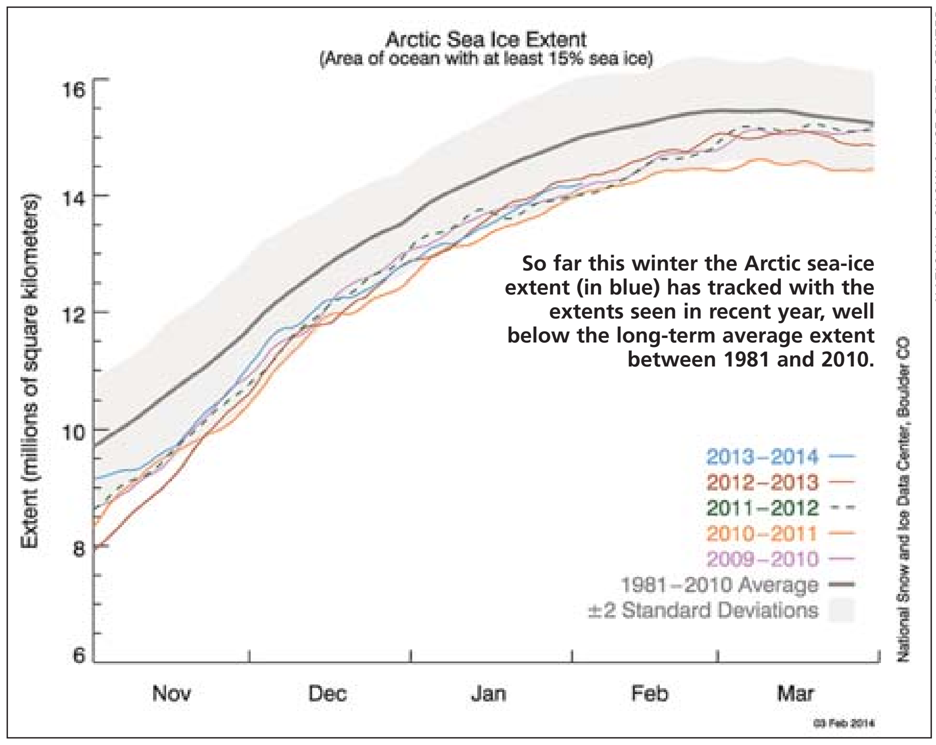
● ENVIRONMENT & SAFETY

Arctic sea ice still below average

Winter temperatures in the Arctic have been relatively warm as the sea-ice extent continues to be relatively low for the time of year

By ALAN BAILEY

Petroleum News



NATIONAL SNOW & ICE DATA CENTER

To someone facing the icy winds and heavy snow of the severe winter that has struck large areas of North America, the concept of the Arctic being warmer than usual may seem less than credible. But in January, Arctic temperatures were above average, according to data presented by the National Snow and Ice Data Center, or NSIDC. And, with those higher than normal temperatures, the extent of the Arctic sea-ice cover has tracked well below its long-term average, as the ice extent continues to grow towards its winter maximum.

The average ice extent in January was 5.3 million square miles, an extent 309,000 square miles below the January average between 1981 and 2010, and 61,800 square miles above the record low January extent set in 2011, NSIDC says.

Regional variation

The ice extent is below average in the Barents Sea, the Sea of Okhotsk and the Bering Sea, while being close to average in Baffin Bay, the Labrador Sea and the Gulf of St. Lawrence. The below average ice conditions in the Bering Sea marks a change from recent winters, in which Bering Sea ice has been relatively extensive. The last time that below average conditions were observed in the Bering in January was in 2005, NSIDC says.

In the past three years a new satellite system has enabled measurements of estimated Arctic sea ice thicknesses, thus enabling estimates of the total ice volume, a parameter that more meaningfully represents the total amount of ice on Arctic seas than does the areal extent of the ice. These volume estimates indicate that the ice volume in the fall of 2013 was about 50 percent higher than in the fall of 2012, thanks mainly to the retention of thick, multi-year ice around northern Greenland and the Canadian Archipelago, NSIDC says. However, this apparent recovery in ice volume must be viewed in the context of long-term trends, with the October 2013 volume thought to be among the lowest volumes of the last 30 years, NSIDC says.

Arctic oscillation

January air temperatures were 4 to 7 F above average over the central Arctic Ocean and 13 to 14 F above average over the North Atlantic region, NSIDC says. NSIDC attributes these temperature anomalies to a negative "Arctic oscillation" pattern, a situation in which air pressure over the Arctic is higher than normal. By contrast, December saw a positive Arctic oscillation, with lower than normal Arctic air pressures, warm conditions over Siberia and Eurasia, and cold weather in Greenland, Alaska and Canada.

According to information on the National Oceanic and Atmospheric Administration website the Arctic oscillation is linked to the polar vortex, the atmospheric feature much in the news of late as the prime culprit behind the North American freeze up. When there is a strong negative Arctic oscillation, as of late, the polar vortex, the high-altitude jet stream wind system that circles the pole, tends to weaken and meander around, allowing cold polar air to flow south.

Curiously, the polar vortex does not appear to have weakened around the entire northern hemisphere — as a consequence Alaska, Scandinavia, Europe and western Russia have seen warmer than average weather, NOAA says. ●

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continued from page 10

ICE CONDITIONS

There is a range of effective burning options that could enable high oil removal rates from spills under or on fast ice, the report says.

But burn options in moving pack ice are more limited, with a likelihood of highly variable removal rates, depending on the ice conditions.

"In these conditions it is often only possible to track the oil until it is released from the ice the following spring and ignite and burn it then," the report says.

The report reviews the history and the results of research and development for a number of technologies that could be used for oil burning in ice-infested water, including oil igniters, fire-resistant boom, floating burners and additives for assisting the burn procedure. The report says that the following technologies are currently commercially available: two types of igniter for use with oil pools contained by fire booms; two aerial ignition systems; four types of fire boom for us in open water and in light drift ice; and two chemical agents that can herd uncontained oil in pack ice conditions.

Environmental tradeoff

In-situ burning has the effect of removing oil from the sea and ice by converting the oil into a plume of soot and combustion gases, while leaving a residue in the sea. And so the merits or otherwise of using burn techniques revolve around the tradeoff between the environmental harm caused by leaving the oil spill untreated and the environmental impact of the burn's airborne plume and remaining residue.

The report says that, while a number of studies have pointed to burn emissions such as particulate carbon and sulfur dioxide having the potential to pose a threat to wildlife or human health downwind of an oil burn, exposure to these materials would fall below thresholds for health impacts within a few kilometers of the burn site. The use of prescribed separation distances between burn sites and sensitive downwind areas can mitigate any smoke hazards, the report says.

In addition, burn residues remaining at a site after a burn appear to pose little threat to either aquatic resources or people, with the residues representing a small proportion of the original oil slick and consisting of material equivalent to highly weathered oil.

"Case studies of burns in major spills have revealed no significant impacts to human or ecological resources," the report says.

And hypothetical risk evaluations support the view that in almost all circumstances burning crude oil on water poses a lower risk to humans and the environment than does leaving the oil in place, unburned, the report says.

Issues to consider

But planning and implementing a safe and effective controlled burn of spilled oil in ice-laden water requires the consideration of several issues involving the feasibility of the burn, the resources needed to carry out the burn and the procedures to avoid or minimize health risks and environmental impacts. The report comments that operational experience of in-situ burning in open water conditions is somewhat limited and that experience in ice-affected water mainly stems from field experiments of limited size. However, in-situ burning has a potential role in a number of Arctic offshore scenarios, including in open water; in various conditions of drift and pack ice; and in a near-solid ice cover, the report says. ●

Editor's note: Part 2 of this story will appear in the March 2 issue.

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● FACILITIES

Arctic port would be protracted project

US Coast Guard feasibility report to Congress highlights the enormous challenges involved in developing a deep-draft harbor

By WESLEY LOY
For Petroleum News

A deep-draft seaport to support rising Arctic Ocean activity would reasonably take 10 to 20 years to build, says a feasibility report from the U.S. Coast Guard.

The report doesn't flatly state whether such a seaport would, in fact, be feasible.

It does underscore, however, the enormous planning, financing and logistical challenges of building a port to support industrial and government operations in the remote polar sea.

As it stands now, no seaport capable of accommodating deep-draft vessels exists along Alaska's northern coastline.

In recent years, interest has grown in establishing a port, with Arctic ice receding and more waters opening up for navigation. Further, oil and gas exploration is expected to increase in the Beaufort and Chukchi seas.

Lack of deep-draft ports

The Coast Guard wrote the eight-page feasibility report at the direction of Congress.

"The U.S. marine presence in the Arctic is still in its infancy," the report says. "Only a small percentage of navigationally significant U.S. Arctic waters have been surveyed with modern technology to determine and chart precise depths and accurately depict all hazards to navigation. Currently, a majority of coastal communities in this area have small, shallow-draft ports, which can only be serviced by barges and small boats. There are no deep-draft seaports in western or northern Alaska and few places of refuge. The nearest facilities and vessels supporting the U.S. Arctic for emergency response are located in Kodiak, Dutch Harbor and Adak, which are 800-1,000 nautical miles from the Arctic Circle."

The Coast Guard report focuses on the same two sites the U.S. Army Corps of Engineers recently cited as most promising for a deep-draft port: Nome and nearby Port Clarence Bay.

Both are near the shipping lanes passing through the Bering Strait, gateway to the Arctic Ocean. That's where a deep-draft seaport should be, the Coast Guard report says.

Daunting construction environment

The Coast Guard says an Arctic deep-draft seaport could help promote U.S. security interests, energy security and independence, the safety of mariners and the environment, and economic development.

"The U.S. Arctic region contains significant quantities of natural resources available for extractive activities. These include oil and gas, a wealth of minerals, timber and fish," the report says. "If harvested sustainably, these valuable resources could provide long-term economic opportunities for Alaska Native corporations, tribal communities, regional commercial enterprises, entrepreneurs and investors. A deep-draft seaport could become a logistics and support link for these activities."

The report doesn't give an estimated cost for the port. It says construction could be done in stages, and could involve both private and government funding.

"Developing and maintaining a deep-draft seaport and its accompanying infrastructure anywhere requires resources. This is especially true in the Arctic region, where construction costs can run several times as much as a similar project in the lower 48 states or even elsewhere in Alaska," the report says.

Development will be difficult, as the potential sites are iced over for several months of the year. Most of the essential building materials would have to be imported, along with dredging and construction equipment, the Coast Guard says.

Project cost would depend on the scope of the project, including construction of such features as breakwaters, piers, cargo handling and ship repair facilities.

The report emphasizes sensitivity to Arctic indigenous people, who have adapted to life in one of the world's harshest climates and "now must prepare to deal with increases in commercial shipping, oil and gas development, mining and other economic activities"

The Coast Guard also stresses care in siting the seaport, saying: "Alignment of federal, state, local and tribal support to authorize and approve such a deep-draft seaport project would prove to be of immeasurable value in making it a success." ●

Contact Wesley Loy at wloy@petroleumnews.com

● FINANCE & ECONOMY

9th Circuit revives BP shareholder suit

Case stems from pipeline leaks in 2006 at Prudhoe Bay; investors allege misleading company statements, seek to recover losses

By WESLEY LOY
For Petroleum News

A federal appeals court has revived a BP shareholder lawsuit stemming from high-profile pipeline leaks in 2006 in the Prudhoe Bay oil field.

In a 42-page opinion issued Feb. 13, the 9th U.S. Circuit Court of Appeals in San Francisco reversed a lower court's dismissal of the case.

The case began in 2008, when BP shareholders filed a class action alleging the company made false and misleading statements about the condition of its pipelines and BP's maintenance and leak detection practices.

The plaintiffs want relief for investment losses incurred after the second of two leaks forced a partial shutdown of Prudhoe Bay and allegedly caused a 4 percent drop in BP's share price, the 9th Circuit opinion says.

Two spills, big trouble

The Prudhoe Bay pipeline leaks caused a world of trouble for field operator BP Exploration (Alaska) Inc.

The first spill was discovered in March 2006 in the field's western operating area. At 212,252 gallons, it was the largest oil spill ever on the North Slope.

A second, much smaller spill occurred later in 2006 on Prudhoe's eastern side. This second spill forced a partial field shutdown, briefly rattling world oil markets and unleashing intense regulatory and congressional scrutiny for BP.

The cause of the spills was corrosion in oil transit lines, major pipes that carry sales-grade crude oil to the trans-Alaska pipeline.

BP Alaska's maintenance and corrosion monitoring practices on these pipelines were shown to be seriously lacking, and the company ultimately pled guilty to a federal pollution misdemeanor.

The federal and state governments each brought civil suits against BP. The company agreed to pay a $25 million to settle the federal suit. The state, in its case, won more than $255 million.

'Simply not plausible'

The 9th Circuit opinion recounts BP's troubles stemming from the spills, and focuses in particular on certain statements from former Prudhoe Bay field manager Maureen Johnson.

The court considered not only whether these statements were misleading, but rose to the level of scienter, defined as "a mental state embracing intent to deceive, manipulate or defraud."

As an example, the court examines a statement attributed to Johnson in an Associated Press article on March 15, 2006, about two weeks after the first spill. Johnson was quoted as saying corrosion seen in the oil transit line in a 2005 inspection appeared to be occurring at a "low

see SHAREHOLDER SUIT page 13

● FINANCE & ECONOMY

ISER sees spike in industry spending

The UAA group expects a 33% increase in oil and gas sector spending over 2013, if companies complete planned programs

By ERIC LIDJI
For Petroleum News

If the real world abides by industry plans, the oil and gas sector could see a 33 percent increase in spending this year, according to an annual University of Alaska forecast.

The Institute of Social and Economic Research at the University of Alaska Anchorage expects oil and gas companies to spend some $4.255 billion this year in the state, almost half of the $9.1 billion in total construction spending the researchers expect this year.

Last year, ISER estimated the oil and gas sector would spend $3.2 billion in Alaska, according to the report by Scott Goldsmith, Mary Killorin, and Linda Leask.

"The growth is being driven by the continuing high price of oil, the increase in the cost of inputs to all phases of oil and gas operations, the growing need to maintain the aging infrastructure and facilities on the North Slope and in Cook Inlet, and perhaps most importantly, by the climate of optimism created by passage of the new production tax on oil and gas that went into effect at the start of 2014," the researchers wrote in the forecast.

The forecast presents a snapshot of industry intentions, but intentions can go unrealized if commodity prices change, if weather proves too treacherous for development work or if companies discover they have been too ambitious in their planning. ConocoPhillips and BP have both recently said they plan to increase their budgets this year, and smaller players on the North Slope and in Cook Inlet have also laid out big programs. But Shell recently cancelled its Chukchi Sea plans for 2014 because of legal delays and both Linc and Repsol have reduced activities in recent years due to unforeseen events.

ISER produces the report annually for the Construction Industry Progress Fund and the Associated General Contractors of Alaska. Northrim Bank underwrote the forecast.

Majors spending

The large increase in oil and gas industry spending that ISER expects this year comes largely from work planned by BP and ConocoPhillips. Those two companies each announced large budget increases after the passage of the More Alaska Production Act.

The industry-supported law eased taxes for oil production starting this year. During the primary election this coming August, voters will be asked to uphold or repeal the law.

After several years of limited exploration, ConocoPhillips plans to drill two wells in the National Petroleum Reserve-Alaska this winter. The company also plans to continue work on its CD-5 pad and conduct preliminary engineering at its GMT-1 pad, as well as additional fieldwork at the Kuparuk River unit. BP recently announced a 25 percent increase in Alaska spending this year, including a seismic program at Prudhoe Bay.

The three other North Slope producers have also suggested increased workloads for the year ahead. Eni Petroleum recently announced plans to expand development at its Nikaitchuq unit to test the shallower N sands. Savant Alaska is completing a slate of projects at the Badami unit left unfinished during 2012 or 2013. Pioneer Natural Resources is expanding the physical presence of its Oooguruk unit. The large independent recently announced plans to sell the field to the small privately held Caelus Energy, which said it is eager to sanction a proposed Nuna development at the unit.

Repsol, Linc and Great Bear Petroleum have all announced exploration campaigns for 2014 that are similar to their workloads from last year, and North Slope newcomers such as NordAq Energy and Royale Energy have preliminary exploration work for this winter.

ExxonMobil is continuing its work to bring the Point Thomson unit online by the deadlines in its settlement agreement

see **ISER FORECAST** *page 14*

continued from page 12

SHAREHOLDER SUIT

manageable corrosion rate."

The appeals court said it agreed with the lower court that this statement was misleading, based on inspection data that showed high corrosion rates.

The "key question" was whether the plaintiffs had adequately pled the element of scienter, the appeals court said. The lower court doubted it; the appellate judges disagreed.

The appeals court added it was "simply not plausible" to think Johnson either misunderstood the data or did not have access to it. The court noted her doctorate degree in chemical engineering, and her key position as Prudhoe Bay unit leader and "gatekeeper of information on the Prudhoe Bay pipelines."

The opinion examines other statements from BP and company executives, and ultimately reverses the lower court dismissal of the shareholder lawsuit.

"In the end, we conclude that after six years of preliminary litigation, the allegations should now be tested on the merits," the appeals court concluded. "We return the matter to the district court for that purpose."

Dawn Patience, the Anchorage spokeswoman for BP Alaska, provided a statement to Petroleum News that said in part:

"Since 2006, BP has made measurable improvements to safety and reliability on the North Slope. We have significantly increased spending on corrosion monitoring and prevention, such as in-line smart pig inspections. Annually, BP does more than 100,000 pipeline inspections for corrosion under insulation on the North Slope."

A smart pig is a tool that runs through a pipeline, looking for problems such as corrosion. ●

Contact Wesley Loy at wloy@petroleumnews.com

● EXPLORATION & PRODUCTION

Canada opens door to India

Husky Energy sells million barrels of Atlantic crude to India, paving way for possible new market, dangling alternative to US, Asia

By GARY PARK
For Petroleum News

Husky Energy has demonstrated the potential benefits of TransCanada's proposed Energy East pipeline project by establishing that a route to the booming Indian market for Canadian crude is possible.

Although only one small step for Western Canada's landlocked producers, it does convey a low-key message that Canada is not limited to finding buyers for its crude in the United States.

The recently invigorated Husky under the leadership of Asim Ghosh and the ownership control of Hong Kong billionaire Li Ka-shing has announced that one million barrels of crude from offshore Newfoundland's White Rose field was sold to state-owned Indian Oil Corp. in November for export to the subcontinent's refineries.

That trail-blazing deal was made possible by the Indian's government's decision to approve the use of crude from Atlantic Canada in its refineries.

It gives even greater impetus to the Energy East plan to deliver 1.1 million barrels per day from the Alberta oil sands and Saskatchewan Bakken to refineries in Ontario, Quebec and New Brunswick and possibly establish tanker terminals in Quebec and New Brunswick to export crude to Europe and India.

Until now, India has barely registered a blip on Canada's export radar, with shipments beyond the United States accounting for only 3.9 percent in 2011 and 2.9 percent in 2012. Because those volumes represent commercially sensitive transactions, the National Energy Board does not disclose the destinations.

Peter Sutherland, president of the Canada-India Business Council, described the shipment as a far-sighted move and said he hopes the Husky shipment is a "forerunner of things to come."

Issue landlocked crudes

Phil Skolnick, an analyst with Canaccord Genuity, rated the test sale as a positive development for landlocked Western Canadian crudes, whose producers have been stalled in their attempts to open new routes to the United States and Asia.

He suggested that if Canadian producers — who face no legal impediments to exporting beyond North America — can establish new markets, the door might even be opened for U.S. crude in Canada.

Ghosh, Husky's chief executive officer, said the Indian sale could "open up a potentially very large market."

The future of sales to India hinges on a bidding process that currently sees West African crude "undercutting the market by just a few cents," Ghosh told a webcast conference call with analysts.

He said it would not require a very large price difference "to open up a huge market for us in India and we're taking the appropriate steps to make ourselves accessible to that market."

India could be 'cost competitive'

Ghosh said that if Energy East goes ahead, India could become a "cost competitive destination for Canadian crude."

Chief Operating Officer Rob Peabody said the crude Husky is producing in Western Canada and Atlantic Canada is a "very robust" 34-degree API crude "that can be used to make a large suite of products."

"The surge in ultra-light crude (in North America) is good to make gasoline and chemical products, but not a lot else," he said.

Ghosh said the glut of North American light crude is "substantially" benefitting Husky at its Lima, Ohio, refinery, which is being repositioned at a cost of C$300 million to handle up to 40,000 barrels per day of heavy crude from Western Canada and enable the company to "move between heavy and light as the markets move."

Husky reported it is making "good progress" in developing its three satellite extensions at White Rose and is averaging 14,000 bpd from a fifth well at North Amethyst that was brought online in the fourth quarter, while production from a deeper Hibernia formation is expected to start later this year.

The company said gas injection is planned for the current quarter at the South White Rose field and first oil is expected later this year.

Peabody confirmed that Husky and operator Statoil are committed to moving ahead "fairly quickly" with the three discoveries they have made in Newfoundland's deepwater Flemish Pass and have contracted a rig for 18 months to drill five wells, four of them classified as delineation.

He said the initial focus will be on the Bay du Nord discovery, which the partners view as a standalone project, followed by another eight to 10 high-potential prospects.

Peabody said it is likely that decisions will be announced in 2015 on a development program. ●

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PIPELINES & DOWNSTREAM

BP's Badami field transfer now complete

BP has wrapped up the sale of the Badami pipeline system to Nutaaq Pipeline LLC.

Nutaaq is a partnership of Savant and Arctic Slope Regional Corp.

Badami is the easternmost producing oil field on Alaska's North Slope.

Two pipelines crossing state land support Badami. One is a sales oil line that ties into the Endicott pipeline to the west. The other is a multipurpose utility line that parallels the oil line.

Savant and ASRC in early 2012 acquired the Badami field from BP, and the pipeline transfer is a follow-up to that deal.

BP's Anchorage spokeswoman, Dawn Patience, provided this statement to Petroleum News:

"On Thursday, Feb. 6, BP Transportation (Alaska) Inc. completed the final transfer of the Badami oil and products pipelines to Nutaaq Pipeline LLC. This completes the handover of the Badami field/assets to a new operator that we hope will continue to develop the Badami resources for the benefit of Alaska."

The Badami oil pipeline will be of increased importance in coming years, as it will carry production from ExxonMobil's Point Thomson field now under construction farther east on the Slope.

—WESLEY LOY

EXPLORATION & PRODUCTION

Linc spuds second Umiat well

Linc Energy has spud the Umiat No. 23H well.

The Australian independent spud the horizontal well at the onshore oil field in the foothills of the Brooks Range Mountains on Feb. 15, the company said Feb. 18.

Having drilled the Umiat No. 18 vertical well last winter, Linc is drilling a horizontal well into the same interval to provide "comparative flow testing" of the two approaches.

The notoriously shallow reservoir for the Umiat oil field is partially located in permafrost, which has created technical problems for exploration outfits since the 1940s.

As it did last year, Linc built a 102-mile snow road from the Dalton highway to the Umiat field to support drilling operations, but the road was unnecessary for the early stages of drilling activities. The company cold-stacked the Kuukpik No. 5 drilling rig onsite over the summer, which allowed it to get a head start on exploration activities this winter.

"Our intention is that this season's drilling results will move some of the reserves to the proven category whilst also firming up our plans to use horizontal drilling techniques to commercially develop this world class billion barrel asset," Linc CEO Peter Bond said in a statement, adding that the company expect to release results in the first half of the year.

—ERIC LIDJI

continued from page 13

ISER FORECAST

and Brooks Range Petroleum Corp. is continuing work on its Mustang development while it ponders exploration activities this year.

The ISER forecast also includes stakeholder spending from non-operating leaseholders such as Chevron and Anadarko, and ongoing activities on the trans-Alaska oil pipeline.

In the Cook Inlet, the ISER forecast sees continued spending from Hilcorp, which is the dominant player in the region after acquiring the assets of Chevron and Marathon.

The forecast also includes activities from Apache, Armstrong, Aurora, Buccaneer, Cook Inlet Energy and Furie. Recent transactions have changed the composition of the basin. Armstrong recently sold its North Fork unit to Cook Inlet Energy and Buccaneer recently sold its stake in the Cosmopolitan prospect to its partner BlueCrest Energy. Those transactions do not appear to have impacted immediate work plans.

The forecast also considered potential work in the Nenana and Copper River basins. ●

EDITOR'S NOTE: ISER used reporting from Petroleum News, among other sources of information, in compiling its forecast of oil and gas industry spending.

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continued from page 3

FEIGE Q&A

are going to bring a cheaper form of energy and in plentiful quantities to last for the foreseeable future. That will have a great benefit to the people of the state and the economy of the state, and offer a chance to get out from under the quite frankly very costly energy situation that we are in now. That is the ultimate benefit, and probably the greatest benefit to the state. If we get a project that exports 2 bcf or 3 bcf a day of liquefied natural gas overseas, great. There is certainly a benefit to the state. But if that doesn't pencil out for whatever reason, the opportunity to have a smaller diameter line in place and ready to go if that larger line failed, puts us in a pretty good position.

Petroleum News: If this enabling legislation passes, can the state move forward on an in-state line bigger than 500 mcf?

Feige: If the enabling legislation goes through, part of that, is the terms of TransCanada basically withdraws and we agree to withdraw from AGIA. I'm not sure what we will do with the laws themselves, but certainly that would also remove the restrictions on the line. At this time, I don't believe that's the intent of that Legislature to increase the size of that line to anything bigger. That line is primarily for in-state use of the gas, whether it's to heat homes in Fairbanks, to provide security of supply in Anchorage, to supply large mining projects that would now be economical because they have a cheaper supply of energy, or to make LNG out of the gas and ship it around the state to places like Bethel and help them heat their homes. It would obviously require some build out of infrastructure. There has been some talk that somehow AGDC is angling to build a bigger project and compete more directly with AKLNG. I talked to the managers and I talked to the board. I don't believe that's the case. We can certainly put intent language in the enabling legislation to reinforce that. I think the Legislature would much rather go with the larger AKLNG project with — as the governor calls it, the ace in the hole — of the smaller line that for a time is going to more or less move in parallel, but at some point get parked on the shelf as a ready-to-go-project, in case the big line does fail.

Petroleum News: What are your greatest concerns about what's in front of you?

Feige: One of my major concerns in this whole thing is the possibility of the cost overruns in this project. I think our biggest risks for cost overruns are in the pipeline portion of the project and the (gas treatment plant), the GTP because it's a very complicated piece of machinery and it's being built 70 degrees north latitude. The logistics and the opportunities for things to go awry are much better there and the remote logistics of the pipeline than in the building of a liquefaction plant in Nikiski. So being able to manage our risks appropriately and having TransCanada assist us in that brings great benefit to the state. We still have yet to hear from Commissioner (Angie) Rodell with the Department of Revenue. She has had a major influence, especially on the financing arrangements of the MOU. We'll probably hear from her (the week of Feb. 24) but we have to work out the exact time regarding that aspect of the project, the various places that we can option into the line. We can go back and take 40 percent of our share back from TransCanada at FEED. Depending on how this thing goes forward, we can option in — or not. This whole deal depends on finding customers willing to buy the gas and pay a price that is high enough to justify doing the project. If the Japanese, the best they can offer up is $12 an mcf delivered to Japan, that's probably not going to float the boat on this deal. But if they come in at a rate that guarantees all of the investments throughout the whole supply chain, as long as those investments are going to get paid back and paid back in a way that is satisfactory to all the parties involved, then the project is going to go forward. But we are not going to know that for another couple of years anyway, at least not until late fall or early winter of 2015.

Petroleum News: You had at one time favored Valdez as the terminus for the pipeline, but Nikiski has emerged as the leading candidate. What are your thoughts on that?

Feige: You know obviously I'm disappointed that it did not go to Valdez. Based on my conversation with the project manager, there were some fundamental engineering problems with setting up a liquefaction facility in Valdez. The footprint of that facility, the requirement that it be above a certain height above sea level for Tsunami risks, a requirement that it be on tectonically stable ground really limited it to just a couple of potential sites within Valdez arm and one of those sites was actually the town site. I don't expect everybody to move — again. The other option was to have to blast away a good portion of the mountain to get enough level ground. That put the cost significant higher. It was mostly an engineering decision. Frankly, it wasn't my decision to make. One of the amendments we put in HB 4 was a requirement for AGDC to, as soon as a construction decision has been made on a line, they are statutorily mandated to start looking at all of the potential distribution lines coming off the main line. It's my hope the Fairbanks/Richardson Highway corridor is going to see a benefit from that because that's an area of the state that is certainly reachable to a pipeline.

Petroleum News: So what's the bottom line on this?

Feige: The biggest question we have is how much of our state treasury do we put at risk. We can take a larger share of this pie in terms of the overall project, but the greater share we take, the greater our risks are in the investment. Another question is at what point do you get the greatest reward for the investment? Obviously we are going to have to come up with some kind of equity investment to make this project go. Just by making it go, we receive tremendous benefits as a state: a boost to the economy by the reduction of energy costs, not just in Fairbanks but throughout the Bush if you can move LNG cheaper than you can provide diesel that's a significant savings.

Just by having the project go, the state derives a huge benefit. The more you invest above that, certainly the return would be greater to the treasury. You still have that basic benefit as a whole to the state's economy. The more you invest, the more return you have to the treasury.

What we want to avoid is the situation where we take a little bit too big of a bite on the project, there's an overrun and all of the sudden now instead of being able to pay for it out of savings, we have to go and borrow above and beyond what we had originally planned. We don't want to get into a position where all of the sudden we can't make the cash calls and that starts to diminish our ownership in the project. We have to be very prudent in that regard. ●

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Petroleum news

Oil Patch Bits

Tara Ballard named Five Star employee for January

COURTESY FIVE STAR

Five Star Oilfield Services announced that Tara Ballard has received Five Star recognition as the employee of the month for January. Ballard has worked as a bull cook for Five Star Oilfield since May of 2013. She always maintains a fun work environment with her positive attitude. Ballard's supervisor nominated her and said that she keeps them going strong week after week and is an asset to Five Star. As a bull cook she is responsible for a variety of duties, it is hard work and she stays busy and gets it all done with a smile on her face. She is always willing to take on anything that is asked of her. We appreciate her dedication to her job, her supervisor said.

Propeck joins Global Diving in Gulf of Mexico

Global Diving & Salvage Inc. announces the hiring of John Propeck as general manager for its Gulf Coast regional office in Houston, Texas. In this position, Propeck will be responsible for the day-to-day undertakings of this region both administratively and operationally. He will lead the development of new and ongoing business opportunities within Global's core service lines: offshore operations, marine construction, and casualty response.

JOHN PROPECK

"John brings with him a wealth of history, experience, and knowledge that is hard to find," said Devon Grennan, Global CEO/president. "His management and leadership will be a great asset as we expand our client base and service offerings in the Gulf Coast region."

Propeck brings with him more than 45 years of multi-faceted experience in the commercial diving and maritime industry. He began his career as a commercial diver, logging more than 1,000 days in saturation. He has more than 20 years of program and project management experience, including business development, marketing, sales, purchasing and procurement management.

CGG enhances portfolio with TerraSpark's software

CGG has enhanced its software portfolio with the addition of TerraSpark's Insight Earth, advanced 3D visualization and interpretation software. Insight Earth greatly enhances seis-

see **OIL PATCH BITS** *page 20*

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ExxonMobil
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Fairweather
Five Star Oilfield Services
Flowline Alaska
Fluor
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Golder Associates
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Pebble Partnership
Petroleum Equipment & Services
PND Engineers Inc.
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PRA (Petrotechnical Resources of Alaska) 2
Price Gregory International
Remote Access Technology (RAT)
Resource Development Council
Ravn Alaska (formerly Era Alaska) 9

Q-Z

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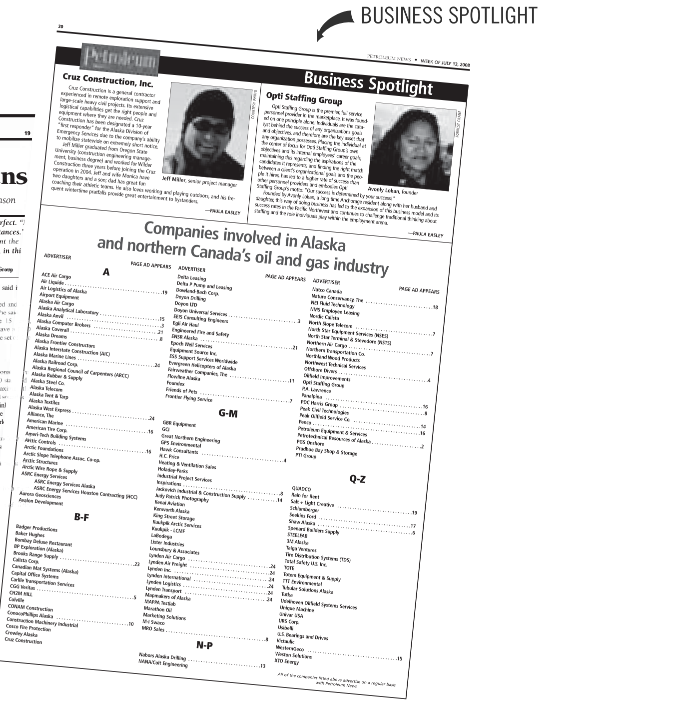

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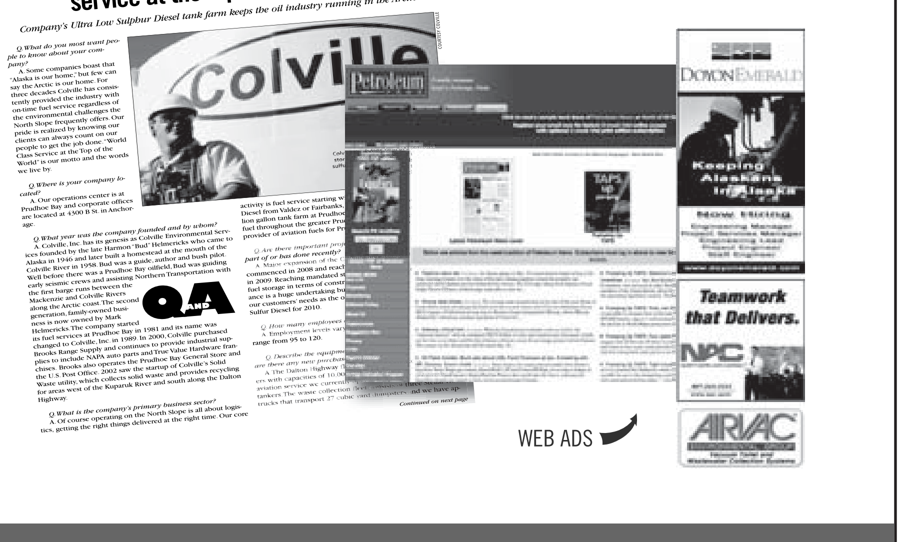

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continued from page 1

HEALY EXPLORATION

Gas from coal

Coalbed methane production involves drilling wells into coal seams and then pumping water out of the coal, thus reducing the pressure in the coal and releasing natural gas into the well. The Healy area has abundant coal seams, with possible coalbed methane potential. And, hurting from the high cost of fuel oil, people in the Interior are looking for new energy sources that might lower their energy bills.

But coalbed methane exploration in Alaska has proved controversial — in 2005 a coalbed methane exploration project in the Matanuska-Susitna Borough came to naught following vigorous complaints from local residents, who were concerned about surface land access rights and issues such as disturbance from industrial activities.

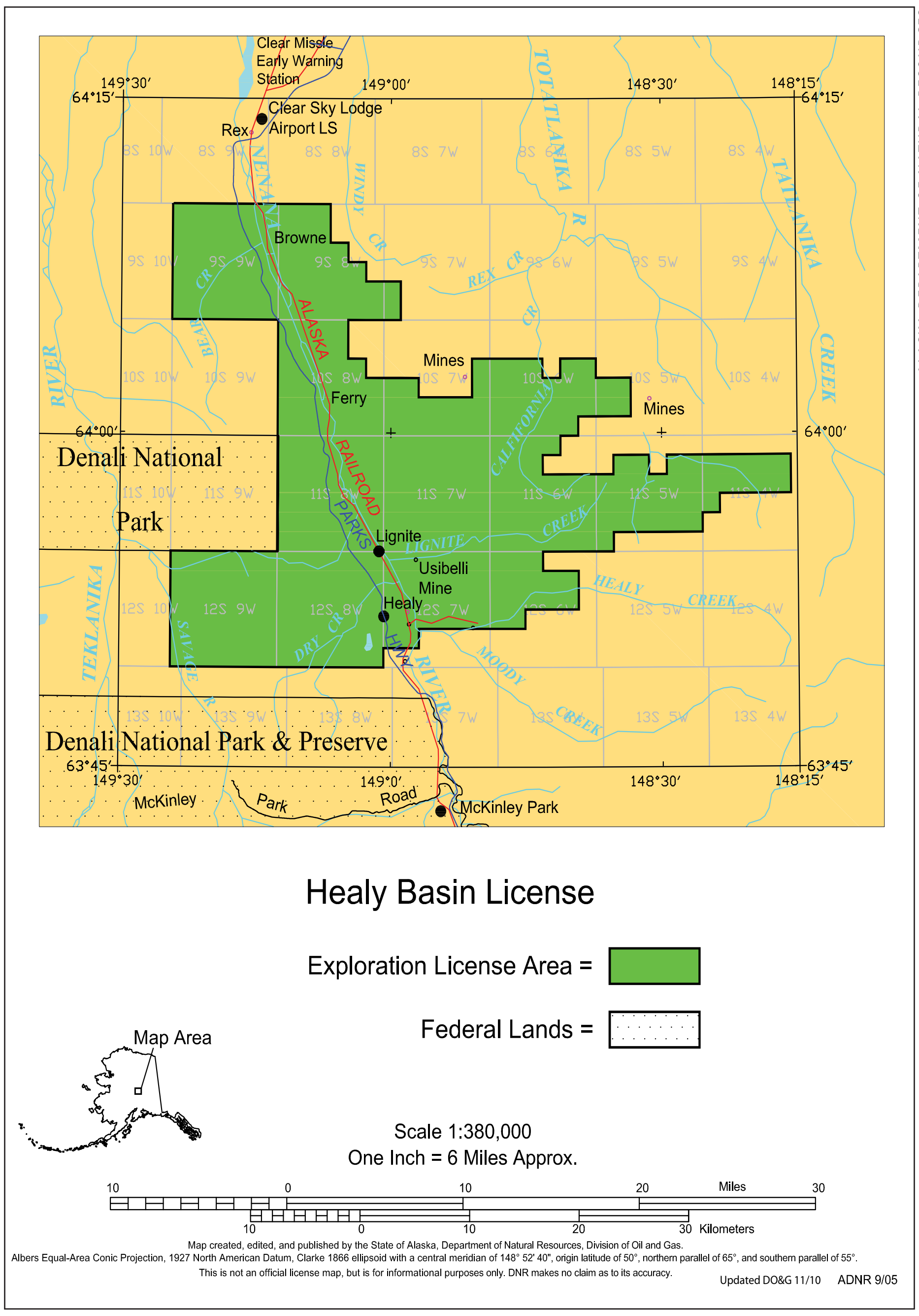
Applied in 2004

Usibelli originally filed its exploration license application in April 2004. In August 2005 DNR issued a preliminary best interest finding, the document that includes an environmental evaluation of the proposed exploration activities and which is an essential precursor to a license decision. That best interest finding determined that the potential benefits of exploration outweighed the possible adverse impacts.

But in the wake of the debacle over coalbed methane development in the Matanuska Valley, the question of exploration in the Healy area lay dormant for several years. In 2006 the Denali Borough Assembly passed an ordinance banning gas exploration or development in about 40 percent of the exploration license area. The state, however, with subsurface rights in its lands, said that the assembly's action was illegal.

Final finding

In June 2010 DNR issued a final best interest finding, upholding the issue of the exploration license while also retaining the original boundaries of the license area. The state denied a request by Denali Citizens Council that the area west of the Nenana River should be excluded from the license — DNR said that environmental mitigation measures associated with the license would minimize environmental impacts and that eliminating such a large area from the license would make exploration uneconomic. In its final finding DNR also modified some of the mitigation measures in the preliminary finding, eliminating some general measures relating to noise levels, eliminating a requirement that Usibelli obtain consent from all property owners in a residential subdivision before constructing drilling pads or compressor stations but committing to requiring the mitigation of noise impacts on a site-by-site basis.



The Healy exploration license encompasses about 200,000 acres of state land north from Healy, to the east of the Denali National Park.

Appealed

After failing to persuade DNR to change its final finding, Denali Citizens Council appealed the DNR decision to Alaska Superior Court. And when that court upheld the DNR decision, the appeal was elevated to the Alaska Supreme Court.

In its appeal, the Denali Citizens Council claimed that the state had not presented an adequate argument in support of its statement that reducing the size of the license area would render exploration uneconomic. The council also argued that DNR's decisions over mitigation measures in the final finding had been "arbitrary and capricious." And the council said that the best interest finding is inconsistent with the state's land use plan for the Tanana basin area.

But the Supreme Court judges, in their decision over the appeal, have now said that, since there is no legal requirement for DNR to consider the economic impacts of alternatives to the proposed license, questions over the economic impacts of reducing the license area are irrelevant to the license decision.

Not arbitrary

And DNR's treatment of mitigation measures was not arbitrary, the judges said. For example, DNR had explained that changes to noise mitigation requirements were intended to ensure flexibility, especially when some land lots in the exploration area remain unoccupied and undeveloped for long periods of time. Moreover, although in its final finding the state had changed its criteria for granting exceptions to mitigation measures, that change had not been substantive, the judges said.

Finally, the judges found that the best interest finding is consistent with the Tanana Basin Area Plan —the plan explicitly accommodates the possibility of oil and gas development, besides which there is no precedent for viewing a plan of this type as legally binding, the judges said. ●

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continued from page 1

TAPS VALUATION

BP 'disappointed'

Petroleum property taxes are an important government revenue source in Alaska, though not as big as other streams of oil dollars including production taxes and royalties.

BP holds the largest share of TAPS, and a company spokesperson provided Petroleum News this statement on the ruling:

"BP Pipelines (Alaska) Inc. is disappointed with the court's decision and will evaluate its legal options. Higher taxes like the excessive property taxes upheld by the court harm the long-term economic sustainability of the oil and gas industry in Alaska."

The Alaska Department of Revenue annually assesses the value of TAPS for property tax purposes. The State Assessment Review Board can adjust those assessments.

In recent years, the assessments have fluctuated considerably, and have led inevitably to court battles.

Dueling valuation methods

The value of the 800-mile pipeline is undeniable. It carries close to 600,000 barrels of North Slope crude oil per day to the tanker port at Valdez, and revenue from this oil funds much of the costs of state government.

No other means exists to carry this oil.

The dispute between the owners and the state essentially boils down to how TAPS should be valued.

The owners have argued the pipeline value should be based on its stream of tariff income for moving oil. And oil throughput on the pipeline has been gradually declining.

The Department of Revenue takes a different approach, preferring to value the pipeline based on its replacement value.

In her ruling on the 2006 tax year, Judge Gleason put the TAPS value at level much higher than even state officials did.

But her valuation still wasn't as high as municipal governments wanted. The pipeline passes through these municipalities, which share in the property tax collections. A higher TAPS valuation is better from their perspective.

The municipalities, like the TAPS owners, appealed the Gleason decision to the Alaska Supreme Court.

The high court's opinion upholds Gleason's view on how best to value TAPS.

"The superior court found that the Trans-Alaska Pipeline System's primary value is its utility in transporting North Slope oil reserves," the opinion says.

A tax on oil?

The opinion says the owners implied that Gleason, in effect, had improperly imposed a tax on the value of North Slope oil reserves.

"But the owners have not shown that the superior court considered the value of Alaska North Slope oil reserves for any other reason than to support the conclusion that the Trans-Alaska Pipeline System has a unique use value distinct from its tariff income," the opinion says.

Gleason found that the owners would rebuild TAPS "not for its tariff income but in order to monetize the Alaska North Slope's $350 billion worth of oil reserves," the opinion says. "But the superior court did not include the $350 billion figure as part of its replacement cost calculation. Instead, the superior court used the presence of those reserves to explain its determination that tariff income could not adequately capture the pipeline's value as a special-purpose property."

Justice Daniel Winfree, joined by Justice Craig Stowers, dissented in part to the majority opinion. ●

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continued from page 19

NO QUIT

2020, the first by 2015. They are clearing the land for the first one already. This is on its way to becoming a reality."

A year ago her government opened a pre-election session of the provincial legislature with a renewed warning. "Fellow British Columbians, this is the opportunity before us, but only if we seize it. It is not years away; it is now. Our province faces fierce competition from Australia and other natural gas producers. If we do not win this opportunity now, there may be no opportunity to win tomorrow."

Earlier in February, after launching a new legislative session, she was emphatic that the window of opportunity remains open. "No, we are not getting ourselves behind. Every day I get more confident that the likelihood that an LNG industry will be created in British Columbia is stronger."

There is little doubt that Clark's resolute pitch in last year's provincial election, when she wiped out a 20 point deficit in the polls to post a landslide victory, reflects her relentlessly upbeat style.

Province's moon shot

Lieutenant-Governor Judith Guichon, in delivering the Clark government's agenda for the new session, compared the administration's pursuit of LNG to President John Kennedy's challenge to put an American on the moon before the 1960s ended.

"We choose to do this not because it will be easy, but because it is hard," Guichon said. "Because it will serve to organize and measure the best of our energies and skills, because that challenge is one we are willing to accept, one we are unwilling to postpone, and one which we intend to win."

Clark agreed the LNG challenge may fall short of Kennedy's moon challenge for drama, but said the hard path ahead needs a government that is ambitious and unafraid.

She insisted, despite two delays, that an LNG framework will be unveiled this year and will include tax policies, benefits for First Nations and environmental measures to make the industry the cleanest in the world.

Adrian Dix, leader of the opposition New Democratic Party, scoffed at the parallel with Kennedy.

"To quote someone who had a broader vision of the future only serves to emphasize the lack of it on the part of the premier," he said.

A spokesman for Finance Minister Mike deJong said the fiscal framework, which has been delayed twice and is now promised for this year, includes an exhaustive review of tax regimes in other jurisdictions — not least the United States — and leaves the British Columbia government certain that it "will be highly competitive."

Lack of accord

But industry observers hint that the delay in reaching an accord with LNG proponents may reflect the province's high construction costs and the prospect of taxes tied to the government's environmental goal of producing the world's "cleanest" LNG.

Geoff Morrison, British Columbia manager for the Canadian Association of Petroleum Producers, said the fiscal regime, including royalties on gas produced in British Columbia and corporate taxes, and the construction costs will be

see **NO QUIT** *page 20*

continued from page 1

DRY HOLE

major shareholders and third parties regarding financing" to determine how the dry hole will impact its ongoing efforts to get enough money to undertaken its ambitious workload in Alaska, but the company said it might have to sell assets or raise additional funds to pay down a private equity loan due at the end of June. For now, Buccaneer is taking some comfort in its other Alaska projects.

"After having enjoyed discoveries at the Kenai Loop and Cosmopolitan fields, the results of the West Eagle well are disappointing. The company will now focus its efforts toward Tyonek Deep and Kenai Loop," Buccaneer CEO Curtis Burton said in a statement.

In addition to seeking standard tax credits for the $9.44 million well, Buccaneer said it would ask the state to return two bonds the company paid to backstop its commitments.

The original West Eagle unit agreement required Buccaneer to post two $600,000 bonds to guarantee drilling commitments. The state would return the first if Buccaneer spud a well by Sept. 1, 2013, and the second if Buccaneer completed the well by the same date.

The Alaska Department of Natural Resources placed the West Eagle unit in default last year when Buccaneer missed those deadlines. The cure required Buccaneer to spud a well by Dec. 1, 2013, to get the first bond and complete the well by Jan. 31, 2014, to get the second bond. Buccaneer spud West Eagle No. 1 on Jan. 22 and stopped drilling Feb. 11.

If the state refunds both bonds and issues the entire tax credit rebates Buccaneer plans to request, the company believes the state will pay $5.09 million of the cost of the well.

Another setback

The West Eagle dry hole is the latest in a recent string of setbacks for Buccaneer.

Buccaneer recently sold its stake in the Cosmopolitan prospect and its interest in the Endeavour jack-up rig to raise money for other projects. The largest of those were the offshore Southern Cross and Northwest Cook Inlet units, which Buccaneer recently relinquished after missing numerous state-mandated drilling deadlines at both fields.

The onshore Kenai Loop field continues to produce gas — some 8.7 million cubic feet per day from two wells, according to Buccaneer — but Buccaneer is embroiled in a legal battle with neighboring Cook Inlet Region Inc. over drainage issues. The dispute has kept a third well from coming online and could jeopardize Buccaneer's small revenue stream.

The remaining project in the Buccaneer portfolio is Tyonek Deep, a deep oil prospect that Buccaneer farmed-in last year at the ConocoPhillips-operated North Cook Inlet unit.

Buccaneer had previously announced a joint venture to pay for two exploration wells at Tyonek Deep, and at several other Alaska prospects, but the deal fell apart late last year.

Buccaneer had $28.9 million available at the end of January, but after paying $11.1 million in expenses related to Kenai Loop, West Eagle and Southern Cross, $8.3 million in payments required under its contract with the Alaska Industrial Development and Export Authority on the Endeavour rig and $3.7 million in other working costs, Buccaneer had only $5.8 million in the bank as of Feb. 7, according to the company. ●

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continued from page 1

NEW PROJECT

First oil would be in 2017 for the $450 million project, with production expected to peak at 9,000 barrels of oil per day. There would be some 150 jobs during construction.

Third new project

The company said this is the third new project it has initiated since the Alaska Legislature passed oil reform legislation, Senate Bill 21, in the spring of 2013.

After passage of SB 21 ConocoPhillips announced plans to pursue development of Greater Mooses Tooth No. 1 in the National Petroleum Reserve-Alaska and drill site 2S in the Kuparuk River unit.

"Combined with 1H NEWS, these three new projects would represent an investment of about $2 billion, significant new production, and jobs for hundreds of workers during construction," Trond-Erik Johansen, president of ConocoPhillips Alaska, said in a statement.

"In addition to our plans for these new projects, we have also added two rigs to the Kuparuk fleet," Johansen said. "These rigs are already adding production and providing several hundred new jobs for Alaskans."

The company said it "believes the improved business climate created by tax reform will continue to create jobs for Alaskans and Alaska businesses, add new revenue for the state and add tens of thousands of barrels of new production from the North Slope," and also said that it expects to have more "North Slope production-adding investments to announce in the near future."

Kuparuk satellite

West Sak is a Kuparuk River satellite, a shallow viscous oil accumulation. Drilling began in 2000 and 2001 from the core West Sak area in the south and Alaska Oil and Gas Conservation Commission records show 509,662 barrels of West Sak production at Kuparuk through the end of 2013.

Appraisal drilling was done in the NEWS area, north and northwest of the core area, in 2005-06 at drill sites 1Q and 3J and from an ice pad north of drill site 1H.

A NEWS participation area was approved by the Alaska Division of Oil and Gas in 2009.

West Sak satellite development was identified by former ConocoPhillips CEO Jim Mulva in April 2011 as a project the company would pursue if the production tax, then ACES, Alaska's Clear and Equitable Share, was changed. Mulva spoke in Anchorage as Gov. Sean Parnell's first attempt at oil tax reform was going down in defeat.

—KRISTEN NELSON

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continued from page 16

OIL PATCH BITS

mic interpretation systems and provides the interpreter with guided tools that can automate the fault extraction process, precisely define salt bodies, deliver fast depictions of paleo-depositional environments and enable the visualization of discrete fracture networks in unconventional plays. Insight Earth brings the most complicated structures into clear definition and delivers superior results.

With Insight Earth joining its Hampson-Russell and Jason software, CGG offers a full and complementary suite of tools to provide its worldwide clients with best-in-class reservoir characterization technology. These include advanced seismic interpretation, petrophysical analysis, well-to-seismic ties, inversion, reservoir property determination and geomodeling.

"Insight Earth and its industry-renowned visualization and interpretation capabilities strongly complements our reservoir characterization software to address the most difficult subsurface challenges, enabling our clients to reduce the risks and costs associated with the discovery and production of hydrocarbons," said Sophie Zurquiyah, senior executive vice president of CGG's geology, geophysics & reservoir division.

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

continued from page 19

NO QUIT

weighed together before final investment decisions are made.

"Clarity and certainty and transparency are good, but getting it right is also important," he said.

Natural Gas Development Minister Rich Coleman has suggested the tax will likely cover a percentage of revenue or profits, while sheltering the LNG owners from commodity price fluctuations and ensuring the province benefits from the sale of its gas resources.

Acknowledging these concerns, Clark has said she will freeze British Columbia's current carbon tax until other North American jurisdictions get in line with the province.

Currently, British Columbia charges C$30 per metric ton of carbon emitted from all combustion engines — while Alberta collected C$15 per metric ton from companies that emit more than 100,000 metric tons of greenhouse gases a year.

Additional costs are likely to be associated with obtaining a "social license" in British Columbia, including benefits to First Nations in particular and other affected communities.

But the Clark government bases its confidence on the fact that a dozen sizeable LNG projects are on the drawing boards and, for many, have involved hefty investments in drilling for feedstock gas, acquisition and preparation of sites and planning for pipelines from northeastern British Columbia's shale gas deposits to LNG terminals on the coast.

Pending US projects

However, if British Columbia wants to check on what Clark has been implying about competition, it doesn't have to check any closer than the United States, where the American Petroleum Institute estimates there are 22 pending applications to process LNG for export beyond North America.

Where British Columbia and Canada hold an edge is in their greater latitude in issuing export permits.

When the Department of Energy, on Feb. 13, approved an application for Sempra Energy to export 1.7 billion cubic feet per day from its Louisiana it raised to six the prospective shipments to non-FTA countries and lift the level of authorized exports to 8.7 bcf per day.

Among economists there is a broad consensus that once those volumes reach 12 bcf per day they will be at a tipping point that could see domestic U.S. gas prices start to rise.

Analysts with Clearview Energy Partners said that approvals above 12 bcf per day would exceed the "upper bound of the range of economic outcomes" studied by the U.S. Energy Information Administration and NERA Economic Associates.

Paula Gant, the Department of Energy's deputy assistant secretary of energy for oil and natural gas, said the agency had not yet changed its approval process and expected to continue issuing non-FTA permits about every six to eight weeks.

In comparison, Canada's National Energy Board has approved seven export permits that probably surpass the 100 million metric tons per year, with two applications filed for another 44 million metric tons per year, with the federal regulator giving no hint of unease over whether Canada has the gas resources to meet these levels and cover its own domestic needs for well into the future.

—GARY PARK

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