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page 3 Q&A: Kawasaki: SB 21 went too far; Fairbanks needs energy relief

BUCCANEER ENERGY

The Endeavour jack-up drilling rig

Buccaneer delays Southern Cross; Endeavour to drill at Cosmo next

Looking to avoid getting caught in the fast approaching icy season, Buccaneer Energy Ltd. is postponing plans to drill a well at its offshore Southern Cross unit this year.

The Australian independent said that it recently moved its Endeavour jack-up drilling rig to Port Graham three weeks earlier than planned for "minor winterization work and annual hull inspections." From Port Graham, the rig is scheduled to head back across Cook Inlet to drill the Cosmopolitan No. 2 well at the prospect off the coast of Anchor Point.

Buccaneer plans to return to Southern Cross when the next summer drilling season begins in mid-April 2014, but before the company can drill it must first negotiate extensions to the drilling commitments it will be missing by cancelling the program this year.

Those include a private farm-in agreement with Hilcorp Alaska LLC on two of the four leases at the unit. Buccaneer farmed-in the two leases in 2010 from Chevron Corp., which subsequently sold its Cook Inlet assets to Hilcorp. Among other commitments, the arrangement requires Buccaneer to drill a well on the leases to a depth of at least 8,500 feet. Buccaneer said it is currently in negotiations with Hilcorp to extend the agreement.

see **DRILLING DELAY** *page 20*

Nikiski chosen as lead site for ANS gas LNG plant, terminal

The Nikiski area on Southcentral Alaska's Kenai Peninsula has taken the lead as a site for the liquefaction facility and terminal for the proposed Alaska LNG project.

The project proponents — ExxonMobil, BP, ConocoPhillips and TransCanada — said Oct. 7 that more than 20 locations were evaluated based on conditions related to the environment, socioeconomics, cost and other project and technical issues.

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Commenting on that decision, Alaska Gov. Sean Parnell said the companies have agreed "to pursue the acquisition of property in the Nikiski area to site the liquefaction facilities associated with the Alaska LNG project," and called the decision "real progress" toward his administration's goal of a natural gas pipeline.

Parnell also said in a statement that the "project is taking

see **TERMINAL CHOICE** *page 20*

PIPELINES & DOWNSTREAM

New crude crossing

Report says construction could begin within months on inlet subsea pipeline

By WESLEY LOY
For Petroleum News

Construction of a new subsea crude oil pipeline across Cook Inlet could begin as soon as 2014.

That's the word from the Cook Inlet Regional Citizens Advisory Council, a congressionally sanctioned organization that monitors oil industry activity in the inlet.

"Cook Inlet RCAC has been informed that Tesoro is considering the installation and operation of a trans-Foreland subsea pipeline to transport crude oil from the west side of Cook Inlet to Tesoro's refining facilities in Nikiski," the council reported in its October newsletter. "Although still in the planning stages, all indications are that this pipeline is going to be built and construction could begin as early as spring 2014."

In January, Miller said Tesoro had agreed to fund up to $1.4 million in design costs for the proposed pipeline.

Cook Inlet Energy's idea

This news seems to build on a proposal that first emerged more than a year ago from Cook Inlet Energy LLC, a west side oil and gas producer.

The company had said it was pursuing a 29-mile, $50 million subsea pipeline from its Kustatan production facility near West Foreland point to the

see **SUBSEA PIPELINE** *page 19*

NATURAL GAS

Higher but not highest

The cost of Cook Inlet gas to consumers still compares favorably with elsewhere

By ALAN BAILEY
Petroleum News

Sticker shock over gas prices for Southcentral Alaska gas consumers in recent years, as prices have risen in response to tightening gas supplies from the Cook Inlet basin, have led to comments about Alaska gas transitioning from being the cheapest in North America to the most expensive. But while this perspective on the price of gas at Cook Inlet wellheads may be true, the situation for the prices that consumers experience is more nuanced.

Take for example the rates that Enstar Natural Gas Co., Southcentral's main gas utility, charges its residential customers.

Apparently this disparity in prices between Alaska and elsewhere in the United States arises from the high transmission and distribution costs for gas delivered to many Lower 48 residents.

According to data presented on Enstar's website the average cost of gas to residential customers in 2013 has been $8.47 per thousand cubic feet for gas, with that figure dropping a bit in the third quarter. Between April and the end of June Enstar

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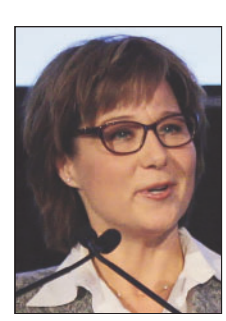
NATURAL GAS

Clark dances to LNG beat

BC premier wants common ground with project proponents, maximum tax revenues

By GARY PARK
For Petroleum News



SHANE LASLEY

CHRISTY CLARK

British Columbia Premier Christy Clark is on the run these days in her efforts to find common ground with LNG proponents while staying ahead of a growing clamor over the potential environmental impact of an LNG export industry.

She spent a week in Toronto and Washington, D.C., selling the virtues of British Columbia as a launching pad for shipments to Asia, while fending off critics who are challenging her "commitment to have the cleanest LNG facilities in the world."

Clark told reporters in Washington — prior to an upcoming trip to Asia — that a tax regime for LNG exports should be unveiled within two months, based on a "positive initial response" to a draft proposal from the industry.

"We're still working through the details" of a plan to be turned into legislation in the spring, she said, but was guarded on the likely contents.

Clark said only that the formula would allow the British Columbia government to "take some of the upside, but also live with some of the downside, as prices rise and fall."

The end result is crucial to her hopes of developing a C$100 billion "prosperity fund" from

see **BC'S LNG DEBATE** *page 18*

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● GOVERNMENT

Kawasaki: SB 21 tax change went too far

Lack of definition of 'new oil' also problem; on gas line, Fairbanks Democrat says state's second-largest city in tough position

By STEVE QUINN
For Petroleum News

House Rep. Scott Kawasaki has been on the front lines of oil and gas issues since he first took office in 2007. The Fairbanks Democrat first cut his teeth on resource development by serving on the Special Committee on Oil & Gas and the House Resources Committee.

This legislative session, Kawasaki held a seat on the House Finance Committee, which reviewed major oil and gas legislation, starting with Senate Bill 21, Gov. Sean Parnell's oil tax reform and House Bill 4, which provides the Alaska Gasline Development Corp. the authority to advance in-state gas line.

Kawasaki sat down with Petroleum News to discuss recent developments with the large-diameter line, the fierce debate on bringing natural gas to Fairbanks and the referendum seeking to overturn SB 21.

Petroleum News: Let's start with SB 21. You've got a two-pronged issue with the bill: getting a clear definition of new oil and the pending referendum set for next year's ballot in August.

Kawasaki: I supported the referendum. I feel this Senate bill was rushed through the process this year. We still don't have an audit of the original numbers. We still are lacking a lot of the data to prove up the concept will work: if we lower taxes we'll increase production. That's what's been sold to us all along. Just the justification to move so quickly on an issue so large wasn't there four years ago when we first started, and it wasn't there this year again. So I definitely support having the public engaged and involved in this process.

Petroleum News: You talk about this process being pushed through so quickly, but ACES (Alaska's Clear and Equitable Share, the production tax bill passed under former-Gov. Sarah Palin in 2007) was pushed through six committees, three each in the Senate and House, and those favoring it didn't subscribe to the premise of 30 days being too short. How do you reconcile that?

Kawasaki: ACES was only a 30-day session, too. But the Legislature heard from the governor even before that in 2007 saying she would like to introduce a bill dealing with having the state earn some sort of equity in our oil and gas resources. I think it was the right thing at the time with the numbers that were given. I wasn't 100 percent sold on ACES. I talked about a gross-based floor at the time or a gross-based tax component to it. Ultimately the Legislature said we don't want that. We want an up or down net-based profits tax. Whereas maybe we went too far on one side with ACES, I think we've gone extremely too far on this governor's bill. We certainly are incentivizing fields like Kuparuk, Alpine and Prudhoe Bay that we know are exceptionally profitable fields to develop. Rather than staying mid course where we should we've gone now too far to the other side. In addition to that, I don't think we've done enough to incentivize middle players and small players in oil and gas development. That is going to be a real big issue coming up as we try to find more young entrepreneurial businesses in the North Slope and the rest of Alaska.


REP. SCOTT KAWASAKI

Petroleum News: Still on SB 21, there is still the issue of drafting regulations that clearly define what new oil is.

Kawasaki: We asked the question several times during hearings in the Finance Committee and they never came up with a real answer about what new oil is going to be. Now we're in a predicament where the state has to come up with regulations based on what the Legislature discussed at those times. The amount of testimony is pretty slim. Is a new barrel of oil from a new field? That's kind of what I had hoped it would be. I think that's what most legislators hoped it would be. Or is new oil just a barrel of oil more than oil that was produced in the previous year? I don't have a way to reconcile that question right now. I can certainly tell you that what we want to see is new oil in the existing TAPS pipeline — new oil from new fields from more exploration and more development. I don't think we get there with SB 21.

Petroleum News: So do you see that provision coming back to the Legislature for rework in the form of a new bill?

Kawasaki: I think ultimately new legislation and tweaked legislation might be in order. The problem is opening this up again leaves it up to the same politics as usual we've seen the past couple of years. It can be a really divisive issue.

Petroleum News: Then how do you propose to reconcile that or is that for the referendum to do as a mandate to rework SB 21?

Kawasaki: if the Legislature actually sat down as a group and said we want to see new oil and this is what new oil should be, and let the committee process take care of that, then that would be the most perfect course of action. I think people, whether they were experts on the issue, or whether they were involved in the Resources and Finance committees in the House and Senate or whether they were new members, even these new members thought that new oil meant new oil and new oil was going to be oil from new fields not oil from existing fields from Alpine and Kuparuk which are wildly profitable.

Petroleum News: On to natural gas, you attended the LNG symposium that Legislative Budget and Audit put together a few months ago, what was our take on it?

Q AND A

Kawasaki: I think the takeaway was there is a willing buyer, which is Asia, now more than ever because of Fukushima, and there are willing buyers we are close to in proximity. And as a state, I think, rightly so the folks there are urging that we become a willing seller. Again, there are all sorts of issues that come into play about the costs of monetizing the gas and how much it's going to cost the state and the fiscal impacts. We have willing buyers who want our gas; we should get something to get that moving. I guess two years ago when we were talking about LNG and LNG exports, we were hearing that Russia could move us out of the market. It doesn't look like they are moving with any kind of speed, either, but it doesn't mean we can let up. We need to push harder.

Petroleum News: What would you like to see done to advance a project, whether it's a large-scale line or a smaller line driven by HB 4?

Kawasaki: I've always been a fan of ANGDA (the former Alaska Natural Gas Development Authority), which is a large-scale line from the North Slope to tidewater, through the spine of the state to Valdez. It makes more sense from an economic standpoint being a larger line. The economics of a small line don't seem to play out. I've been a supporter of having a big line and it makes sense that it goes along the existing pipeline route. I think it makes sense that there be some alignment necessary between what AGDC wants, which is purely an in-state pipeline and what AGIA wants. When we tailored AGIA, we said we wanted to have in-state use of gas. We created a Y-line, one that could be used for LNG export and the rest of it going through to the Midwest in the United States.

That's what I supported at the time. That would have made the economics of the project and it would have helped Alaskans the most. Hearing that poten-

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● GOVERNMENT

Judge rebukes Alberta for 'bias'

Issue exclusion of Oil Sands Environmental Coalition from Southern Pacific Resource project hearing based on views of Pembina

By GARY PARK

For Petroleum News

The Alberta government sent two top-level cabinet ministers on a swing through 10 European countries earlier in October, at a cost of C$87,500 to taxpayers, in another attempt to head off a European Union vote later this year that would single out the oil sands as more environmentally harmful than conventional oil.

What was once viewed as an obscure issue has taken on a new life form as TransCanada advances its plans to build a pipeline to Saint John, New Brunswick, where the Irving Oil refinery could eventually produce fuels for export to Europe.

International Relations Minister Cal Dallas and Environment Minister Diana McQueen were also left to ponder the timing of their lobbying mission, designed to trumpet government initiatives on environmental monitoring and greenhouse gas reductions.

Damning court ruling

Instead they clashed with one of the most damning court rulings ever issued against the provincial government and the oil sands.

Court of Queen's Bench Justice Richard Marceau said government actions to exclude the Oil Sands Environmental Coalition from a 2012 hearing on a project by Southern Pacific Resource were "tainted" and "biased."

Looking for a legal precedent in Canada, he went back to a 1959 ruling by a Quebec premier to deny a liquor license to a restaurant owner to "envision a more direct apprehension of bias."

"This is a black mark for the government of Alberta," said Simon Dyer, policy director of the Alberta-based Pembina Institute, a research and advocacy organization at the heart of the coalition's court action.

Marceau said that "pivotal" to his decision was an August 2009 "briefing note" for Alberta Environment to exclude Pembina because it had published negative reports about the oil sands, indicating it was "less inclined to work cooperatively" with the government on industry issues.

He said the bias against Pembina "breached the rules of fundamental justice."

Dyer said Albertans "have a right to a fair oil sands regulatory process, including the right to be heard and raise concerns.

"At a time when evidence is mounting that cumulative impacts from oil sands are exceeding regional thresholds, it is essential that directly affected stakeholders with credible information get a fair hearing."

No appeal decision

A spokeswoman for McQueen said the government, which has yet to decide whether it will appeal, would reassess who should speak when the second phase Southern Pacific proposal comes before regulators.

But Alberta Premier Alison Redford offered a much blunter view of the ruling, arguing it was her government's right to make sure the review process for oil sands projects did not get bogged down by interveners who were not directly affected by proposals.

However, Energy Minister Ken Hughes said new legislation provides a "clear opportunity for people ... to make (their) case at the front end of the hearing process."

Junior producer

A junior producer, Southern Pacific produced 4,254 barrels per day in the second quarter from a project designed to reach 12,000 bpd, but it is waiting until volumes and revenues reached a certain level before giving a commercial designation to the operation. Its second phase is being planned to deliver 24,000 bpd.

Joe Anglish, environmental spokesman for the Wildrose Party — the major opposition party in the Alberta legislature — said the government "briefing note" is further proof of government zeal to clamp down on dissent, making it even harder to convince the world that Alberta is serious about reducing pollution in the oil sands.

"The worst thing we have ever done to our oil sands is to go out and create a story about how wonderful we are, but then we don't practice it."

That argument didn't dissuade the Alberta cabinet ministers from attacking the European Union for assigned a greenhouse gas emission value to oil sands-derived bitumen that is different from other fuel sources.

"Even by the EU's own documentation, 60 percent of all the EU crude oil sources don't have any lifecycle emissions reporting at all," Dallas told the Financial Post. "The level of transparency in terms of some of the practices in the originating countries that are producing oil for the European Union is of significant concern to us."

He estimated that 80 percent of oil exported to the EU comes from countries that use high flaring of natural gas and high venting of gas into the atmosphere, but claimed they do not declare emissions that are likely above the oil sands. ●

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● NATURAL GAS

A continuing Cook Inlet gas-price saga

There's no competitive spot market but with pressure on supplies, prices are likely to continue rising for utility customers

By **ALAN BAILEY**
Petroleum News

Decades ago, encouraged by exceptionally low prices for natural gas from the Cook Inlet basin, gas became the fuel of choice for heating buildings in much of Southcentral Alaska, while gas-fired generation became the favored source of electrical power. But the last 10 years have seen major increases in Cook Inlet gas prices. And, as prices have risen, so have people's monthly utility bills.

Peaked in 2009

During the Anchorage Mayor's Energy Task Force meeting on Oct. 2 Moira Smith, vice president and general counsel of Enstar Natural Gas Co., Southcentral's main gas utility, commented that the price that Enstar pays for gas climbed steadily during the 2000s and peaked at $8.76 per thousand cubic feet in 2009, subsequently falling back to $6.32 in the fourth quarter of 2013.

And the price of gas to consumers has followed a parallel trend: A chart of historical gas prices on Enstar's website shows prices, including the fees that Enstar charges for distributing gas to customers, rising from $4.41 per thousand cubic feet in 2003 to $10.46 in 2009 and dropping to $7.39 currently.

The historic substantial rise in gas prices is a reflection of tightening gas supplies from the Cook Inlet basin, Smith said, adding that, because of the terms of a consent decree agreed between Hilcorp Alaska and the State of Alaska, it is safe to assume that gas prices will rise in the future. Hilcorp is the dominant Cook Inlet gas producer.

But what exactly determines the pricing of gas from the Cook Inlet basin, and how has the current pricing situation arisen?

Glut of gas

Most of the gas produced in the basin comes from large gas fields discovered in the 1960s during a search for oil at that time. In the early days of the Cook Inlet gas industry, with the oil companies happy to sell a huge excess of stranded Cook Inlet gas to local power and gas utilities at bargain-basement prices, the utilities established long-term contracts with gas producers. And, as was the habit at the time, the price of the gas was indexed to the price of crude oil.

Fertilizer and liquefied natural gas plants were also constructed on the Kenai Peninsula, to provide industrial outlets for some of that excess gas.

The Cook Inlet gas industry motored along happily until the 2000s, at which time declining rates of production from the by-then aging gas fields put strains on the supply side of the gas market. In 2007 the Kenai Peninsula fertilizer plant closed because of a shortage of adequate gas supplies. The liquefied natural gas plant cut back on its production, eventually becoming mothballed in early 2013.

The gas war

Meantime, with their old gas supply contracts starting to come to the ends of their terms, Southcentral utilities started to seek new contracts to ensure continuity of energy supplies to their customers. And that led to an acrimonious battle over setting acceptable prices for the gas, in what one commissioner in the Regulatory Commission of Alaska characterized as the "the Cook Inlet gas war." The Regulatory Commission of Alaska, or RCA, is the state agency responsible for regulation of the utilities.

The RCA, although it has no authority to regulate gas producers, does have to review and approve utility gas supply contracts, including the gas prices set in those contracts. But, all Cook Inlet gas having been sold through long-term contracts, there was no open or "spot market" in which equable price levels could be set using the traditional levers of supply and demand. And the sale price of exported Cook Inlet liquefied natural gas, a possible price indicator for Cook Inlet gas, was commercially confidential and driven by the economy of Japan, the destination of the product.

The need for new, and expensive, development and exploration drilling to bring online additional Cook Inlet gas resources required new contract gas prices sufficient to make a financial return on those drilling costs. At the same time, tightening gas supplies elsewhere in North America were driving up gas prices across the continent — Cook Inlet gas producers such as Unocal and Marathon Oil found themselves competing for drilling capital with regions where drilling for gas could be more lucrative than in Southcentral Alaska.

Henry Hub pricing

In 2001 RCA approved a landmark gas supply contract between Unocal and Enstar, indexing gas prices to three-year trailing average prices in the Henry Hub gas market in the Lower 48. The concept was to link gas prices in Alaska to those in the Lower 48, so that Cook Inlet gas exploration and development could compete for capital with gas projects elsewhere.

But as gas prices in the Lower 48 climbed, prices in the new Alaska contract also increased, becoming a major factor in that peak Enstar gas price of $8.76 in 2009.

Impacted by rising prices, people in Alaska questioned the indexing to Henry Hub, a market that has no obvious commercial connection with the Cook Inlet. In 2005, for example, a spike in Lower 48 gas prices following hurricane Katrina caused a knock-on price hike in the Unocal-Enstar contract, despite the hurricane sweeping through territory thousands of miles from Alaska.

Pricing impasse

In 2006, amid the gas-price controversy, RCA rejected a Henry Hub-indexed gas supply contract negotiated between Enstar and Marathon. In 2008 Enstar went back to RCA with two new contracts it had negotiated with ConocoPhillips and Marathon, this time with prices indexed to baskets of North American gas price points. The commission responded to the 2008 contracts by requiring a commission-mandated price cap, based on a 12-month trailing average of prices in five North American basins. But the two Cook Inlet gas producers rejected this proposal, forcing the commission to allow the contracts to go into effect temporarily, to avoid a shortfall in Cook Inlet utility gas supplies.

In 2009 RCA convened a technical workshop to try to hammer out some kind of acceptable formula for setting Cook Inlet utility gas prices. But the major gas producers, citing concerns about anti-trust liability, declined to participate.

New precedent

However, in September 2009 the commission set a new gas-price precedent by approving a gas supply contract between Enstar and Anchor Point Energy LLC, the operator of the North Fork gas field in the southern Kenai Peninsula. That contract included gas prices indexed to a three-month average of gas futures on the New York Mercantile Exchange, but with specified price floors and ceilings. And, starting in 2010, other new contracts with Southcentral utilities using a similar pricing formula were approved, thus demonstrating that the logjam in regulatory approvals had been finally been cleared.

Shale gas revolution

Meantime, elsewhere in North America, in an entirely unanticipated turn of events, the advent of shale gas development involving the drilling of horizontal

see **GAS-PRICE SAGA** *page 7*

● FINANCE & ECONOMY

Encana's new boss clears decks

Suttles delivers on pledge for 'bold' action, removing old executive guard to 'get back to winning,' regaining investor confidence

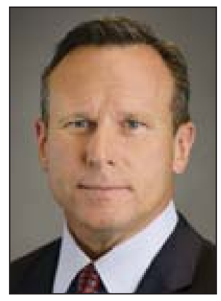
By GARY PARK
For Petroleum News

Doug Suttles needed only three months to let the 4,000 employees of Encana know that they are entering a new era, far removed from the once-cozy existence that elevated them to the No. 1 spot among North American natural gas producers and the largest market-cap on the Toronto Stock Exchange. Half of that value has been lost since 2010.

When Suttles was named chief executive officer on June 11, it was obvious the Encana board of directors was responding to a growing clamor from investors who had seen their stock values dragged down by the shale gas revolution.

The unspoken demand was for Encana to make a radical departure from its tradition of succession planning from within.

The third generation in his family to make a career in the petroleum industry, Suttles graduated in mechanical engineering from the University of Texas 30 years ago, spent eight years in Alaska in various engineering and leadership roles and moved to places such as Russia, Trinidad and the North Sea before getting saddled with his highest profile as BP chief operating officer, leading the company's response to and resolution of its 2010 Macondo blowout in the Gulf of Mexico.


DOUG SUTTLES

Gentle massaging not expected

Nobody was lulled into thinking that Encana was in for gentle massaging when Suttles arrived in Calgary and said he was not planning any immediate management shakeup.

"We need to get a strategy in place first and then we'll see what it means to other elements," he said.

Two months later, employees were put on notice, when Suttles announced that "the things we need to change we need to change in a big way — a bold way — and we need also to make sure we are leveraging our strengths."

One of his overriding priorities, he declared, was to maintain a strong balance sheet which "gives us confidence to act, it gives our investors confidence and it actually allows us to capture opportunities in a world which is likely to continue to be volatile."

"We believe that by implementing our new strategy we will get back to winning; we will get back the Encana many people have known for many, many years," he said.

Building blocks revealed

The building blocks for that new strategy were revealed Oct. 2, after Suttles made a whirlwind tour of the vast majority of Encana's operations, when he removed much of the old guard from the executive team and established a much tighter group.

Gone are: Jeff Wojahn, president of the USA Division (after 23 years with the company); Eric Marsh, senior vice president with the USA Division (13 years); Bill Stevenson, executive vice president (21 years); Bob Grant, executive vice president (28 years); and Bill Oliver (31 years).

Top appointments in the new organizational structure include Mike McAllister, new executive vice president and chief operating officer, and David Hill, executive vice president, exploration and business development, who will concentrate on identifying and securing top-tier resources for Encana.

Suttles said the overhauled structure "aligns with the core competencies needed to get Encana back to winning."

It has "clear accountabilities across the company that are directly tied to the areas we need to focus on to be successful," he said.

Analyst: Performance will be key

RBC Dominion Securities analyst Greg Pardy, while acknowledging that establishing senior leadership is important to Encana's game plan, said "demonstrated operating performance will be the key in the months ahead."

Mike Tims, chairman of energy investment dealer Peters & Co., said the market is still looking for more details on the "overall strategy" for Encana, especially information on "future capital allocation plans" which is where the "real future of Encana will be written."

In a New York investor presentation in September, Suttles provided the broad-brush strokes of what might be contained in the company's 2014 capital budget when he said the company has far too many plays, many of them in dry gas, and hinted at confirmation of a major new North American shale basin in west-central Alberta's liquids-rich Duvernay formation. ●

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● NATURAL GAS

Malaysia's Petronas outlines LNG jackpot

By GARY PARK

For Petroleum News

Malaysia's state-owned Petronas expects to invest C$36 billion over 30 years on all aspects of British Columbia's Pacific NorthWest LNG project being developed by its Canadian unit, Progress Energy Resources, said Malaysian Prime Minister Najib Razak.

At a joint news conference with his Canadian counterpart Stephen Harper, ahead of the annual Asia-Pacific Economic Cooperation summit in Bali, Razak said the spending estimate represents the "largest foreign direct investment in Canada" by any country.

"We believe this project will be mutually beneficial because it will open up Canadian energy to new markets, principally East Asia," he said.

Harper delivered a more muted response, saying his government views the Petronas investment "very positively" and is "very excited" about the possibility of further investment by the giant Malaysian company.

Many obstacles

That response likely reflected Harper's awareness of how many obstacles have to be overcome before the planned Pacific NorthWest LNG project can come onstream in 2019.

He also offered a cautionary note, saying government foreign investment policy "involves the use of discretion when it comes to state-owned enterprises."

Razak said he is confident that not only the Harper government, but future Canadian administrations, will support Petronas' Canadian investments.

The venture, which includes Japan Petroleum Exploration as a 10 percent partner in the integrated shale gas development and LNG liquefaction terminal, has yet to receive an export permit from Canada's National Energy Board and environmental reviews by the Canadian and British Columbia governments, all pointing to a final investment decision by late 2014.

In addition, it is not yet clear whether off-take customers have been lined up by Petronas for the anticipated 12 million metric tons per year of LNG.

The total investment package includes the almost C$6 billion already spent by Petronas to acquire Progress Energy Canada and its gas holdings in the North Montney shale field of British Columbia; C$5 billion for a pipeline to be built by TransCanada; C$11 billion for the LNG terminal near Prince Rupert; and the balance on gas development and processing facilities in British Columbia. ●

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NATURAL GAS

AIDEA commissioning GTL/CTL study

The Alaska Industrial Development and Export Authority wants to make a plan for converting local natural gas and coal resources into liquids to sell worldwide.

The public corporation plans to spend between $250,000 and $400,000 commissioning the study to consider the business case for an Alaska gas-to-liquids or coal-to-liquids facility. The funding comes from a legislative appropriation made earlier this year.

The contractor will develop a plan for an operation capable of making jet fuel or diesel from the considerable gas and coal resources in Alaska. The plan will consider the entire supply chain for such a facility, looking at everything from the raw materials, to the operating cost of existing technologies, to potential locations for a facility, to synergies with other industries, to the potential markets for Alaska liquids. If the plan finds such an operation to be feasible, the contractor would also lay out next steps for the proposal.

ExxonMobil studied a North Slope GTL plant in the 1980s and 1990s, and BP operated a pilot project in Nikiski from 2003 to 2009. Many independent entities have also promoted the technology for Alaska.

Goal markets for gas

A big hope for the facility is to create additional markets for Alaska natural gas, not only the stranded supplies on the North Slope but also the constrained supplies in Cook Inlet, where the desire to encourage exploration is hampered by the limited local market.

Those dreams have fueled similar projects in Alaska in the past. ExxonMobil studied a North Slope GTL plant in the 1980s and 1990s, and BP operated a pilot project in Nikiski from 2003 to 2009. Many independent entities have also promoted the technology for Alaska.

While the technology for turning gas or coal to liquid is somewhat established, the cost of the process has generally been prohibitive, especially with oil prices at historical highs.

AIDEA is taking proposals through Oct. 17 and plans to award the contract sometime around Oct. 30. The contract runs for 151 days, or until approximately March 31, 2014.

—ERIC LIDJI

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GAS-PRICE SAGA

wells and hydraulic fracturing of gas source rocks upended the gas industry, ultimately creating a glut of gas and causing gas prices to plummet. In the aftermath of this upheaval gas prices in Canada and the Lower 48 remain below levels that are economically viable for gas producers.

The indexing of Cook Inlet utility gas prices to North American gas markets subsequently caused Southcentral gas prices to fall below their 2009 peak — the price in that Unocal contract with Enstar has dropped to just $4.06 per thousand cubic feet. And, with no new gas supply contracts on the horizon, Southcentral utilities started formulating emergency plans for dealing with pending gas supply shortfalls, including the possibility of importing liquefied natural gas into the region.

Hilcorp arrives

In early 2012 Hilcorp, a newcomer to the Cook Inlet oil and gas industry, completed its takeover of the Unocal Cook Inlet assets, which had previously been purchased by Chevron. And in April 2012 Hilcorp announced that it was also buying Marathon's Cook Inlet properties. But Hilcorp's pending dominance of the Cook Inlet gas industry triggered an anti-trust investigation by the Federal Trade Commission and the State of Alaska, leading to the consent decree with the state as a condition for Hilcorp completing its Marathon Cook Inlet takeover.

Price ceilings set in the consent decree are higher than current spot prices for gas in Lower 48 markets and increase in annual steps from $6.60 in 2013 to $7.72 in 2017. The price ceilings, which now appear to be forming the basis of prices in new utility gas supply contracts that RCA is willing to approve, presumably represent a compromise between price levels that Hilcorp views as viable and that the state can accept as reasonable.

And a recent flurry of new utility gas supply contracts with Hilcorp, ensuring gas supplies through to end-March 2018, indicates that sufficient gas can be developed from the Cook Inlet fields until then with viable pricing. What will happen to gas supplies and, hence, gas prices after that time remains to be seen. ●

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● FINANCE & ECONOMY

EIA expects Brent to continue to weaken

Spot prices down on restart of some crude production in Libya, moderated concerns over conflict in Syria; WTI also projected down

By KRISTEN NELSON
Petroleum News

Brent crude oil spot prices are down from a recent September peak, the U.S. Energy Information Administration said in its September short-term energy outlook.

Brent crude oil spot prices peaked at $117 per barrel early in September, the EIA said Oct. 8, but were at $108 per barrel at the end of the month "as some crude oil production restarted in Libya and concerns over the conflict in Syria moderated."

The agency said it expects the Brent crude price to continue to weaken, averaging $107 per barrel in the fourth quarter of the year and dropping to $102 per barrel in 2014, a continued weakening based on the growth of non-OPEC supplies.

West Texas Intermediate crude oil prices are projected to average $101 per barrel in the fourth quarter and $96 per barrel next year. The discount of WTI to Brent, which averaged $18 in 2012 and dropped to $3 per barrel this July, averaged $5 in September; EIA said it expects that discount to average $6 per barrel in the fourth quarter and next year.

Non-OPEC supply growth

Liquid fuels production from non-Organization of the Petroleum Exporting Countries is projected to increase by 1.5 million barrels per day in 2013 and 2014, EIA said. That production contributes to a decline in call on OPEC crude oil and global stocks, the agency said, projected to fall from an average of 30.2 million bpd this year to 29.6 million bpd in 2014.

North America is the largest source of non-OPEC supply growth, with production projected to increase by 1.4 million bpd this year and by 1.1 million bpd in 2014, "resulting from continued production growth in U.S. onshore tight oil formations and from Canadian oil sands."

With U.S. crude oil production expected to rise from an average of 6.5 million bpd in 2012 to 7.5 million bpd this year and 8.5 million bpd in 2014, U.S. liquid fuel net imports are expected to continue to decline to an average of 5.3 million bpd in 2014. The net import share of U.S. consumption — which peaked at more than 60 percent in 2005 — is projected to fall to 28 percent next year, the lowest level since 1985, the agency said.

EIA said it is looking for smaller rates of production growth from Central and South America, Asia and Oceania and Africa.

Kazakhstan's Kashagan oil field, the largest to be discovered in the past 35 years, is expected to begin commercial production in October. EIA said "significant potential, technical challenges and high development costs may limit its expansion," and the agency expects output to reach only 25,000 bpd by the end of the year.

OPEC production to decline

EIA said it projects OPEC liquid fuels production to decline by 800,000 bpd this year and by an additional 300,000 bpd in 2014.

"The declines in 2013 mostly reflect supply outages among some OPEC producers, along with an overall decrease in Saudi Arabia's production in response to the increase in non-OPEC supply," the agency said.

In the first quarter of 2013 Saudi Arabia's crude oil production averaged 830,000 bpd lower than in the same period of 2012, but rose from 9.1 million bpd in March to 10.2 million bpd in August, "in part to offset recent global supply disruptions," EIA said. The agency said it expects Saudi Arabia and other OPEC members to cut back production as disrupted production comes back online and non-OPEC supply continues to grow.

Unplanned disruptions included widespread protests at key oil installations in Libya. Planned maintenance at Iraq's southern oil terminals resulted in an export decrease of some 450,000 bpd.

Total OPEC surplus crude oil production capacity averaged 1.7 million bpd in the third quarter, 300,000 bpd below the year-ago average and 1.4 million bpd below the historical 2010-12 average.

EIA expects surplus OPEC capacity to increase to an average of 2.4 million in the fourth quarter.

Natural gas

EIA said Henry Hub natural gas spot prices averaged $3.61 per million British thermal units in September, up 19 cents from August. The agency said prices declined from April through August, but began increasing in September in anticipation of the winter heating demand.

The Henry Hub price averaged $2.75 per million Btu in 2012 and the EIA is forecasting a $3.71 per million Btu average this year, rising to $4 per million Btu next year.

The agency said it expects that domestic natural gas consumption, which averaged 69.7 billion cubic feet per day last year, will average 70 bcf per day this year and 69.4 bcf per day in 2014.

EIA said colder winter temperatures are expected in 2013 and 2014, compared to record warm temperatures in 2012, and those colder temperatures are expected to increase the amount of natural gas used for residential and commercial heating.

But the year-over-year price increase is expected to contribute to declines in natural gas used for electric power generation, from 25 bcf per day last year to 22.1 bcf this year and 21.6 bcf in 2014. ●

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● NATURAL GAS

NordAq backing LNG export plan

The independent believes eligible suppliers should band together to reopen mothballed facility; sees demand and price incentives

By ERIC LIDJI
For Petroleum News

Another small Cook Inlet independent is throwing its weight behind a proposal to resume liquefied natural gas exports from the mothballed ConocoPhillips facility in Nikiski.

"NordAq is engaged in active exploration for additional gas reserves in Cook Inlet and is committed to finding new reserves of natural gas to both sustain the local utility market and provide an additional surplus that could be directed for LNG as an export or for in-state use," NordAq Energy Inc. President Robert Warthen wrote to the Regulatory Commission of Alaska. "In the absence of an LNG option natural gas prices will continue to remain artificially low and create a disincentive for exploration and development."

The RCA is not responsible for approving exports, but because the state regulatory body approves local gas supply contracts it is seen as the de facto price-setter for the region.

Just last year, ConocoPhillips announced plans to mothball the 45-year-old export terminal because shrinking local gas supplies made it difficult to secure contracts with its traditional Asian buyers. Unexpected demand from Asia ultimately kept the facility open through March 2013, when the most recent federal export license expired.

> *"In the absence of an LNG option natural gas prices will continue to remain artificially low and create a disincentive for exploration and development."* —**NordAq Energy Inc. President Robert Warthen**

The market completely changed, though, when Hilcorp Alaska LLC signed short-term supply contracts with the major buyers in the region, including Enstar Natural Gas Co.

With local demand met through early 2018, many producers worry about being shut out of the market, should they discover new supplies. To guarantee companies have an incentive to explore, the State of Alaska recently asked ConocoPhillips to apply for a three-year export license for the facility. ConocoPhillips said it is evaluating the proposal.

NordAq is currently considering two natural gas developments: the Shadura project in the Kenai National Wildlife Refuge and the Tiger Eye unit on the west side of Cook Inlet.

Market and pricing

The current conversation about the facility has been about finding a way to expand the market for Cook Inlet gas. By focusing on the "artificially low" prices fostered by the absence of the facility, NordAq is raising an issue previously absent in the discussion.

It is inconclusive whether exports would drive up local prices, or whether local demand would drive up export prices, especially because local prices and export prices are both determined by multiyear contracts, and also because, in the past, ConocoPhillips and its former partner Marathon have typically supplied the plant, in addition to operating it.

The proposed arrangement would turn the facility into a market for numerous third parties, which could create relatively more liquidity in a notoriously illiquid market.

Sensing this, Warthen wrote that NordAq "believes that an export renewal should not be the singular burden of one operator to support. All companies with surplus gas reserves should be considered as candidates for providing gas to manufacture and export LNG." ●

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FINANCE & ECONOMY

US workers plug Alberta gap

Alberta is developing a growing two-way bond with the United States, shipping oil and natural gas south of the border and bringing American workers into the province to keep the resource sector operating.

A four-year pilot project started in 2012 by the Alberta government has already seen almost 900 highly skilled Americans help plug some of Alberta's 50,000 unfilled jobs that are expected to reach 120,000 within a decade.

"The Alberta government has been really farsighted in implementing accelerated programs to recognize skills," said Laura Dawson, author of Conference Board of Canada report.

She also credited labor unions "which have been instrumental in helping get foreign skills from the United States recognized," even though the North American Free Trade Agreement does not allow mutual recognition between Canada and the U.S. for regulated trades and professions.

Temporary certification

But, on a temporary basis, Canadian unions can certify the skills of an American worker, who have comparable training and experience, while unions that co-exist across the border can help facilitate the entry of Americans into Canada, the study said.

However, Dawson said a permanent solution to Canada's looming labor crunch requires building a domestic workforce.

Alberta Deputy Premier Thomas Lukaszuk said that although hiring Canadian workers is cheaper and more practical, the province currently has 70,000 temporary foreign workers, which points to the severe labor shortage.

The Alberta government said work permits issued under the pilot program from July 2012 to August 2013 were: Steamfitter-pipefitters 721 (320 from the U.S.), welders 967 (U.S. 177), ironworkers 453 (U.S. 355), carpenters 154 (U.S. 12), estimators 81 (U.S. 22) and heavy-duty equipment mechanics 92 (U.S. eight).

—GARY PARK

● UTILITIES

Who will foot the transmission bill?

Should the State of Alaska fund major upgrades to the Railbelt power transmission grid as part of the state's infrastructure?

By ALAN BAILEY
Petroleum News

The vexed question of what to do about the Alaska Railbelt's aging power transmission network emerged again during a discussion at the Anchorage Mayor's Energy Task Force on Oct. 2.

The network suffers from risks associated with single points of failure were an avalanche, for example, to damage some remote stretch of transmission line. And, with recent and continuing changes in power generation capacity around the grid, the grid configuration is no longer fully capable of flexibly delivering power from some generation plants to electricity demand centers. In particular, the Alaska Energy Authority has recently concluded that the grid layout artificially constrains the use of power from the Bradley Lake hydropower facility in the southern Kenai Peninsula — the authority has recommended nearly $1 billion in grid upgrades, including a new subsea high-voltage direct current transmission line from the northern Kenai Peninsula to the west side of Cook Inlet, to de-bottleneck power transmission and reduce the risk of a major transmission outage.

But who is to pay for upgrades to the grid?

A state role?

Officials from Railbelt electric utilities told the task force that the utilities do not have the financial resources to foot the transmission upgrade bill. And there seemed some level of agreement between the officials and the members of the task force that the state should play a role in the funding, with the transmission network being a key component of the state infrastructure, somewhat analogous to the highway system and the ports.

Joe Griffith, general manager of Matanuska Electric Association and president of the Alaska Railbelt Cooperative Transmission and Electric Co., told the task force that he had met with Gov. Sean Parnell to discuss the problem.

"Frankly the utilities are out of slack," Griffith said. "We've spent all our money on gas contracts and new (generation) plants and we don't have any more latitude to take on additional debt."

Griffith said that inefficiencies in the transmission network cost the utilities about $150 million per year and that the current network is inadequate to support a new major hydropower facility being planned for construction at Watana on the Susitna River.

"You know you're not going to get a Watana if you don't fix the transmission because no one will ever sign a sales agreement if you can't deliver the energy and the capacity," Griffith said.

Jim Posey, general manager of Anchorage utility Municipal Light & Power, said that the transmission problems could be resolved with adequate state funding.

"The transmission piece will probably come together if the state puts enough money on the table to make sure that we're doing the robust $100 million to $120 million per year of connectivity improvements," Posey said. ●

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● LAND & LEASING

State conditionally approves Otter unit

Cook Inlet Energy is pleased, aims to 'prove up' gas prospect; DNR decision on appeal clarifies Alaska policy on oil and gas units

By WESLEY LOY

For Petroleum News

Cook Inlet Energy LLC has won conditional approval to form a new oil and gas unit at the company's Otter prospect on the inlet's west side.

Alaska's oil and gas director, Bill Barron, in May denied the unit application. But the Anchorage-based company appealed to the commissioner of the Department of Natural Resources.

Joe Balash, the acting commissioner, affirmed Barron's denial. But Balash exercised his discretion under law to propose a modified Otter unit agreement.

Cook Inlet Energy could accept or reject the proposal, and on Oct. 8 the company announced its acceptance.

"We are very pleased to get this unit approved," said David Hall, the company's chief executive. "We will now focus our attention back to proving up the Otter prospect. During the appeal period we received a pipeline right of way approval from the DNR which will enable us to develop the field immediately upon encountering commercial quantities of gas."

Cook Inlet Energy is a subsidiary of Tennessee-based, publicly traded Miller Energy Resources Inc.

State's unit policy clarified

The commissioner's decision on appeal not only allows Cook Inlet Energy to consolidate and extend its Otter leases, it clarifies state policy on unit formation.

Specifically, the decision makes clear that an "exploration unit" is acceptable to the state. That is, unit status isn't just for acreage ready for actual production.

Further, the decision shows the state is willing to approve a unit even if only one company holds the leases, as is the case with Otter.

Otter is a natural gas prospect about nine miles north of the ConocoPhillips-operated Beluga River gas field.

Cook Inlet Energy in January applied to form a 5,855-acre unit out of portions of four state leases.

The company previously had drilled an exploratory well, the Otter No. 1, on lease ADL 390579.

Technical problems plagued the project, however, and the company was unable to reach full depth. Cook Inlet Energy plugged the well in January, the commissioner's decision said.

The company, in filing the unit application, was looking to avoid the loss of some of its Otter acreage. It faced an Oct. 1 deadline to restart operations on the Otter No. 1 well or lose the lease, and an adjacent lease was due to expire on Sept. 30.

The Otter unit approval has the effect of extending the leases. The unit will have a five-year term, the commissioner's decision said.

Drilling obligations

The commissioner essentially accepted the drilling commitments Cook Inlet Energy originally offered for the unit. Balash did, however, require the company to provide a few more specifics, such as estimated drilling start dates, well depths and bottom-hole locations.

Balash also imposed another condition: Cook Inlet Energy must post a $1.2 million performance bond, payable to DNR in the event of default on the unit agreement, including the associated plan of exploration.

The bond protects the state's interest, the commissioner's decision said, as the state could otherwise offer expired acreage in a future lease sale.

The hope is that Cook Inlet Energy eventually will produce at Otter, yielding royalty revenue for the state, the decision said.

Under the plan of exploration, the company must complete one of two options: re-enter and deepen the Otter No. 1 well, or drill a new exploratory well by March 31, 2015.

Further, Cook Inlet Energy will drill a delineation well by March 31, 2016.

The commissioner's decision noted that Cook Inlet Energy could have utilized a new state law to secure a one-time extension of the expiring leases, rather than form a unit.

But Balash determined unitization offered at least some benefit over proceeding at Otter lease by lease.

No reservoir seen

Balash found that Barron denied the Otter unit application primarily because Cook Inlet Energy had proposed a development plan that lacked "firm development commitments."

Barron concluded, based on confidential geologic, geophysical and engineering data submitted by Cook Inlet Energy, that the company had shown a potential hydrocarbon accumulation but not evidence of a reservoir.

Cook Inlet Energy used a law firm, Crowell & Moring, to appeal Barron's unit denial. The appeal noted the company already had spent more than $10 million on exploration activity at Otter. Further, the appeal argued state officials appeared to have unlawfully adopted a new policy against "exploration units."

Balash, however, wrote that Cook Inlet Energy's appeal repeatedly mischaracterized and misrepresented the Barron's findings.

"In particular, CIE argues the Director found 'that exploration units are not permissible,' that 'unitization is incompatible with exploration,' and that 'a unit can only contain a reservoir or be formed solely for production activities.' The Commissioner has carefully reviewed the Director's Decision and these alleged findings are nowhere stated or implied in that decision," the commissioner's decision said. ●

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EXPLORATION & PRODUCTION

Exxon seeks Pt. Thomson spill plan renewal

ExxonMobil is applying for renewal of an oil spill cleanup plan for the Point Thomson oil field now under construction on Alaska's North Slope.

The plan formally is known as an Oil Discharge Prevention and Contingency Plan, or C-plan for short.

The plan formally is known as an Oil Discharge Prevention and Contingency Plan, or C-plan for short.

An Oct. 3 public notice from the Alaska Department of Environmental Conservation said the proposed C-plan concerns ExxonMobil's ability to "contain, control and clean up an oil discharge" from oil storage tanks and a well blowout from the Brookian formation during winter drilling.

The "response planning standard" for oil storage tanks is 4,302 barrels, and 5,700 barrels of oil per day for a blowout, the notice said.

It added that ExxonMobil's strategy for addressing a condensate blowout is "voluntary ignition."

The C-plan renewal application is evidence of continued progress toward production from Point Thomson, located on coastal state acreage some 60 miles east of Prudhoe Bay. State officials have waited decades for ExxonMobil and its partners to develop the field, which was discovered in the 1970s.

ExxonMobil plans to begin production in early 2016 of 10,000 barrels per day of natural gas condensate, a form of light oil.

Partners in Point Thomson include BP and ConocoPhillips.

The DEC is taking public comment until Nov. 4 on ExxonMobil's C-plan application.

—WESLEY LOY

● GOVERNMENT

$45K fine stands against ConocoPhillips

Alaska Oil and Gas Conservation Commission reaffirms earlier finding that company committed violations at Kuparuk injection well

By WESLEY LOY

For Petroleum News

State drilling regulators have reaffirmed a $45,000 fine against ConocoPhillips Alaska Inc. for alleged violations at a well in the Kuparuk River unit on the North Slope.

In a final decision and order dated Oct. 3, the Alaska Oil and Gas Conservation Commission gave the company 30 days to pay the civil penalty.

The case began in December 2012, when the commission issued an enforcement notice to ConocoPhillips regarding an injection well known as KRU 3Q-16.

ConocoPhillips internally determined the pressure anomalies did not constitute communication, but this effectively prevented the commission's review of the issue, the order said.

The notice said the company failed to complete a mechanical integrity test on 3Q-16, and failed to promptly report to the commission a "pressure communication" in the well.

ConocoPhillips asked the commission to reconsider the matter, and a hearing was held during the summer.

see CONOCO FINE page 15

GOVERNMENT

Alaska royalty board to meet

The state's proposed contract to supply crude oil to Tesoro for its Kenai Peninsula refinery will be among the topics on the agenda for an upcoming meeting of the Alaska Royalty Oil and Gas Development Advisory Board.

The board's job is to "facilitate wise development" of Alaska's oil and gas royalty interests. The board has eight members: five public members appointed by the governor plus the state commissioners of commerce, natural resources and revenue.

Bob Roses, a former state legislator, is currently board chairman.

The state's share of oil and natural gas produced from leased, state-owned land is referred to as royalty oil and gas. Sales of royalty oil and gas generate major revenue for the state.

The Department of Natural Resources is proposing a one-year contract to sell 5,000 to 15,000 barrels per day of North Slope royalty crude oil to Tesoro, which operates a refinery at Nikiski.

DNR projects the sale will provide $189 million to $568 million in revenue to the state over the course of the contract.

Kevin Banks, a DNR petroleum market analyst, told Petroleum News he plans to provide a briefing to the royalty board on the Tesoro contract.

In part because of the contract's short term, legislative approval and a board recommendation to the lawmakers isn't needed, Banks said.

"If Tesoro wants to extend this contract or have a new multiyear contract that starts after this one, the royalty board has to weigh in," he said.

Banks said the board also has requested that he "tell them a bit about how the state sets its lease and lease sale terms and conditions."

The royalty board is scheduled to hold its public meeting at 1 p.m. Oct. 30 in room 1270 in the Atwood state office building at 550 W. 7th Ave. in downtown Anchorage.

—WESLEY LOY

FINANCE & ECONOMY

Oil above $101 on hopes for US budget deal

By PABLO GORONDI

Associated Press

Oil prices edged above $101 a barrel Oct. 10 on hopes that U.S. political leaders will find a deal to raise the debt ceiling and after the temporary abduction of the Libyan prime minister reminded investors of threats to crude supplies.

By early afternoon in Europe, benchmark oil for November delivery was up 42 cents to $102.03 a barrel in electronic trading on the New York Mercantile Exchange. The contract for the benchmark grade fell $1.88 to close at $101.61 Oct. 9.

President Barack Obama will meet with top House Republicans at the White House to seek a deal to raise the government's debt limit in the short term to prevent the first default on U.S. debt the week of Oct. 14. Such a default could have a devastating effect on the global economy — and therefore for energy demand — so hopes of a deal underpinned crude prices.

Meanwhile, investors were monitoring developments in Libya, where Prime Minister Ali Zidan was abducted by gunmen from the hotel where he resides. He was freed hours later, but the event reminded markets of the risk to supplies from key crude producers in the region.

In the U.S., however, supplies remain high. The Energy Department said crude stocks rose by 6.8 million barrels the week ending Oct. 4, more than three times over analysts' expectations, at a time of year when consumption is seasonally weak.

Demand is not expected to grow, either. In its latest monthly report, the Organization of the Petroleum Exporting Countries kept its main forecasts for oil consumption unchanged since September. It estimates global crude demand at 89.7 million barrels a day in 2013.

Demand for OPEC's own crude is seen at 29.9 million barrels a day this year — that is 500,000 barrels a day less than in 2012 and is estimated to fall further to 29.6 million barrels a day in 2014.

Brent, the benchmark for international crudes, rose 45 cents to $109.51 a barrel on the ICE Futures exchange in London.

In other energy futures trading on Nymex:

• Wholesale gasoline rose 2.93 cents to $2.6523 per gallon.

• Natural gas surged 8.7 cents to $3.766 per 1,000 cubic feet.

• Heating oil added 1.71 cents to $3.0345 per gallon.

FINANCE & ECONOMY

RCA extending quality bank timeline

State regulators are taking a little more time to decide whether they should re-examine the system used to value the various crude stocks moved on the trans-Alaska oil pipeline.

The Regulatory Commission of Alaska now plans to make a decision by Nov. 11.

Flint Hills Resources Alaska LLC filed a complaint in August against BP, ConocoPhillips and ExxonMobil — the owners of the pipeline — saying the system for determining crude values needed to be revamped to account for market changes.

The complaint concerns the methodology for determining the "quality bank," which is a fund used to compensate shippers when the value of crude oil that a company removes from the end of the pipeline differs from the value of crude the company put into the pipeline. This phenomenon arises because numerous companies are shipping varying qualities of crude oil through the 800-mile pipeline at the same time.

The pipeline owners refrained from commenting on the complaint other than to campaign for the status quo — a relatively simple formula used both for intrastate and interstate shipments — but third parties Anadarko Petroleum Corp. and Tesoro Petroleum asked the RCA to throw out the complaint. They said the market changes Flint Hills identified had failed to meet the standard required for changing the quality bank methodology.

While the RCA is required to decide within 30 days of receiving a complaint whether to launch an investigation, the commission can extend the timeline to accommodate additional filings. The new Nov. 11 timeline will give the RCA time to consider the request to dismiss the case before deciding whether or not to launch an investigation.

—ERIC LIDJI

EXPLORATION & PRODUCTION

Shell CEO confirms commitment to Alaska

During an interview with the Financial Times Shell CEO Peter Voser said that his company remains committed to its Alaska outer continental shelf oil exploration program, the London based newspaper reported on Oct. 6.

"The Arctic theme is one we're looking at from a strategic point of view at Shell," Voser said.

Voser said that Shell had "gone the extra mile" in its approach to oil spill prevention in its Arctic exploration and that in 2012 the company had run into problems with "the fourth barrier" of its spill prevention measures, a reference presumably to difficulties with the company's Arctic oil containment system.

"That was a big disappointment to me personally as well, because we didn't deliver on that," Voser said, according to the Financial Times report.

Voser also expressed his concern about the accident in which Shell's floating drilling platform, the Kulluk, ran aground in the Gulf of Alaska. However, he characterized this incident as a maritime accident, rather than an accident directly involving oil drilling.

Voser said that Shell does not yet know if it will return to the Alaska Arctic outer continental shelf in 2014 or 2015 to seek oil in its leases.

"But over the months to come we will get more clarity on how we are prepared and how we can drive this forward," he said. "I still see this as a great long-term prospect but we need to prove it's there, and that's why we're spending the money."

Voser said that he thinks that Arctic offshore oil will be developed but that the possibility that development may ultimately prove uneconomic is a normal form of exploration risk. Development will require companies with the appropriate technology and financial means, working collaboratively with governments and regulators, he said.

—ALAN BAILEY

● GOVERNMENT

Judge hears conflicting oil spill estimates

Multibillion-dollar question: Government experts estimate 4.2 million barrels; BP 2.45 million; agree 810,000 barrels captured

By MICHAEL KUNZELMAN
Associated Press

For weeks after BP's massive 2010 oil spill in the Gulf of Mexico, people across the globe were captivated by a live video feed from underwater cameras that showed the company's blown-out well belching plumes of black crude into the water.

On Oct. 7, more than three years later, clips from the spill cam were projected on a screen in a New Orleans courtroom while lawyers for BP and the federal government quarreled over how much oil gushed out of BP's Macondo well during the 87-day crisis. The images helped some of the scientists calculate how much oil polluted the Gulf.

Determining how much oil spilled is a multibillion-dollar question for U.S. District Judge Carl Barbier, who is presiding over the trial involving the deadly Deepwater Horizon rig explosion and the nation's worst offshore oil spill. The judge ultimately could decide how much more money BP owes for its role in the disaster.

Government experts estimate 4.2 million barrels, or 176 million gallons (666 million liters), spilled into the Gulf. BP has urged Barbier to use an estimate of 2.45 million barrels, or nearly 103 million gallons (389 million liters), in calculating any Clean Water Act penalties. Both sides agree that 810,000 barrels, or 34 million gallons (128 million liters), escaped the well but were captured before the crude could pollute the Gulf.

Under the Clean Water Act, a polluter can be forced to pay a maximum of either $1,100 or $4,300 per barrel of spilled oil. The higher maximum applies if the company is found grossly negligent, as the government argues BP should be. But penalties can be assessed at amounts lower than those caps.

Using the government's figures, a maximum penalty if the company is found grossly negligent could total $18 billion. Using the company's figures, that maximum penalty would be around $10.5 billion.

During opening statements Oct. 7 for the latest phase of the trial, lawyers for BP and the government outlined conflicting scientific theories to explain their different estimates.

Justice Department attorney Steven O'Rourke accused BP experts of "cherry-picking" data and disregarding information collected during its spill response efforts.

"The evidence will show that those theories are not valid," said O'Rourke, who noted that the government's estimate would make BP's oil spill roughly 16 times larger than the 1989 Exxon Valdez spill in Alaska, which dumped 11 million gallons of oil into the Prince William Sound.

BP lawyer Mike Brock said the government's estimates don't account for the uncertainty of flow conditions between the April 20 blowout and the July 15 capping of the well.

"BP will present information and opinions based on known data — known data before the spill and known data after the spill," he said. "It's an industry standard approach to resolving or solving a problem like this."

Government experts estimate that oil started flowing out of the Macondo well at a rate of roughly 62,000 barrels per day but dropped to a rate of 53,000 barrels per day when BP used a capping stack equipped with a pressure gauge to seal the well. O'Rourke said four government experts employed four different methods and reached strikingly similar estimates.

Conversely, BP's experts concluded that flow rates increased over time, due in part to the erosion of steel rams on the rig's blowout preventer. Brock said the government based its estimate on the flawed theory that erosion of cement, drill pipe and other obstructions in the well ended within hours of the blowout.

"The government has not accounted for events within the well on a day-by-day basis," Brock said.

Brock showed Barbier excerpts of email exchanges between government officials in an effort to show that they were under pressure from President Barack Obama's administration early in the spill to quickly estimate its size. One of the officials suggested they could determine the flow rate over time by "backtracking" from a current estimate.

O'Rourke urged the judge to disregard BP's efforts to portray government scientists as "political hacks."

"There was no conspiracy. There was no government agenda," he said. "They were there to get the right answers and to help." ●

EXPLORATION & PRODUCTION

Great Bear to gather more seismic data

In an Oct. 7 interview with the Alaska Public Radio Network Ed Duncan, president of Great Bear Petroleum, said that his company plans to gather more seismic data this winter. The company, which is hoping to develop shale oil resources on Alaska's North Slope, has already conducted two 3-D seismic surveys in its leases, one of them during the winter of 2012-13.

The company operates a broad swath of oil and gas leases over territory thought to be prospective for shale oil, south of the conventional oil fields in the central North Slope.

The company has drilled two shale oil test wells in its leases and has been testing rock samples obtained from those wells. Duncan has previously said that Great Bear will use its seismic data, well data and rock sample analyses to determine what drilling to do next, to determine the feasibility of North Slope shale oil production.

Duncan also told the radio station that Great Bear will unveil its development plan at the end of 2014. A decision on a development plan will presumably depend on further drilling and testing.

At the time of going to press Great Bear had not responded to a request from Petroleum News for confirmation of Duncan's statements to the radio station.

—ALAN BAILEY

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CONOCO FINE

The company "presented nothing during the hearing" to warrant a change in the enforcement action, the commission's final order said.

'Out of compliance'

ConocoPhillips operates Kuparuk, the state's second most productive oil field after Prudhoe Bay.

The company was supposed to conduct a mechanical integrity test on well 3Q-16 on or before Sept. 25, 2012, but this wasn't done, the commission said.

"The well was out of compliance, but continued injection for 37 days," the final order said.

Further, a review of pressure data indicated "significant pressure anomalies," which were not reported to the commission, the order said.

Regulations specify that if signs are seen of pressure communication or leakage in any casing, tubing or packer, the operator "shall notify the commission by the next working day."

The failure to notify spanned 33 days, the order said.

ConocoPhillips internally determined the pressure anomalies did not constitute communication, but this effectively prevented the commission's review of the issue, the order said.

Mitigating factors

The commission said it reduced the civil penalty from the statutory maximum after considering a number of mitigating circumstances, including the company's "general history of satisfactory compliance and practices," its eventual notification to the commission, the lack of an actual threat to public health or the environment, and the company's shut-in of the well after determining it was out of compliance.

However, the commission noted two past cases involving ConocoPhillips and "missed" mechanical integrity tests on wells.

In addition to paying the $45,000 fine, the commission ordered the company to "provide a detailed description of its Underground Injection Control regulatory compliance program."

Also, the company must provide details of its tracking system for determining when mechanical integrity tests are required.

Lastly, ConocoPhillips must provide a "root cause analysis" addressing the violations. ●

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ALTERNATIVE ENERGY

NIF makes breakthrough in nuclear fusion

According to reports by the BBC and other news outlets the National Ignition Facility, or NIF, has succeeded in generating a nuclear fusion reaction that generated more energy than was required to cause the reaction to take place. This net gain in energy is thought to be a critical step towards what scientists refer to as "ignition," the point at which a nuclear fusion process generates more energy than it consumes, a milestone in paving the way to the use of the technology for power generation.

Nuclear fusion, as distinct from nuclear fission, the conventional form of nuclear energy in which heavy atoms are split, involves the fusion of hydrogen nuclei to form helium atoms, a process which generates energy in the sun but which requires extremely high pressures and temperatures. With readily available raw materials as feedstock and no radioactive waste products, nuclear fusion is a potential future power generation technology.

NIF, a facility based in the Lawrence Livermore National Laboratory, has been experimenting with a nuclear fusion technique involving the bombardment by laser beams of a fuel pellet containing hydrogen atoms that are targeted for fusion. The technique entails the use of 192 laser beams from the world's most powerful laser to compress and heat the pellet, the BBC report says.

Earlier this year a white paper published by the American Security Project said that the Lawrence Livermore National Laboratory would progress plans for a demonstration power plant if the laboratory could succeed in obtaining a net gain of energy from a fusion reaction.

In the south of France an internationally funded research organization called ITER is building a multibillion dollar nuclear fusion facility to test an alternative fusion technique involving the heating of plasma to 150 million degrees centigrade.

—ALAN BAILEY

EXPLORATION & PRODUCTION

Kenai Loop well tests at 5.9 mmcf

A Buccaneer Energy Ltd. well at the Kenai Loop field flowed at a rate of 5.9 million cubic feet per day in an initial four-point test, the company announced Oct. 8.

A local subsidiary of the Australian independent tested an interval at 9,700 feet at the onshore Kenai Loop No. 1-4 well, drilled to test a fault between two prior wells.

A four-point test measures flow rates at different choke sizes for short periods of time.

Buccaneer had previously said it was aiming to bring Kenai Loop No. 1-4 online at 3 million to 5 million cubic feet per day by the end of the year. The gas field just north and northeast of the city of Kenai currently produces some 10 million cubic feet per day.

The testing had been delayed by a debate over correlative rights. Now, Buccaneer is "assessing if additional prospective zones intersected while drilling will also be tested."

Buccaneer drilled the well using the Glacier No. 1 rig, which is now scheduled to begin work at the West Eagle unit in the southern Kenai Peninsula northeast of Homer. The unit is currently in default because Buccaneer failed to drill by a September deadline, in part because of delays related to its oil spill contingency plan, according to the company.

Now, Buccaneer must spud the West Eagle No. 1 well by Dec. 1

—ERIC LIDJI

Petroleum News

Oil Patch Bits

Mulcahy awarded Anchorage Chamber Gold Pan Award

COURTESY URS

Pete Mulcahy of URS Corp. was awarded the Anchorage Chamber of Commerce's 2013 Gold Pan Award in the Distinguished Community Service category at the annual event held on Sept. 13 at the Dena'ina Center.

The Anchorage Chamber of Commerce describes nominees for the award as active participants in the community who demonstrate outstanding community service, creativity, and excellence and have significantly improved the city of Anchorage by achieving success in business through growth and quality performance.

Mulcahy has been active in the community since moving to Alaska in 2000. He is involved as a volunteer in many community organizations such as Rotary, Chamber of Commerce and the Chugiak Volunteer Fire Department. In his role as business development manager, he brings his business knowledge to URS by establishing strategies to develop new business and by serving as a key client contact. In his free time, Mulcahy enjoys hiking, biking, kayaking, and snow machining.

ASRC once again tops list of Anchorage businesses

Arctic Slope Regional Corp. said it is pleased to be recognized by the Alaska State Chamber of Commerce, Alaska Business Monthly magazine and local business leaders as the top Alaska-owned and operated corporation. This is the 19th consecutive year that ASRC has ranked No. 1 on the "Top 49ers List," based the prior year's gross revenues.

"To top this distinguished list for nearly two decades is truly an honor," said Rex A. Rock Sr., ASRC president and CEO. "We set aggressive goals at the beginning of 2012 that helped us clear some challenging hurdles as they relate to the national economy, and I believe this plan will help ASRC to see continued growth in the future. I certainly would also like to congratulate the other prominent companies on this list as well."

In 2012 ASRC's revenues topped $2.6 billion, the most ever in the company's 40 year history. ASRC has five major business segments, including petroleum refining and marketing, energy support services, construction, government services and resource development.

Jensen Maritime awarded contract for Jones Act tankers

Jensen Maritime Consultants, Crowley Maritime Corp.'s Seattle-based naval architecture and marine engineering company, said the company has been awarded a new construction

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

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KAWASAKI Q&A

tially Nikiski is being looked at as the number one option for an off-take point for LNG, I share everybody else's excitement. We've been talking about a big natural gas line and it looks like it's one step closer.

For Fairbanks, this means we can have an off-take near Fairbanks. With such a large volume, we'll be able to take off as much as we need for local use. I know they said they are looking at other potential places, but it looks like that one is the top of the list now. I'm excited about having a large-scale gas line and I think Fairbanks will be part of the mix.

So there is momentum going on that gas line.

Petroleum News: You supported HB 4 this year when you didn't support it when it was HB 9 the previous legislative session. How come?

Kawasaki: I did support HB 4 this year. I was also very critical of it missing Fairbanks. One of my big issues was that it's a line that won't help Fairbanks directly. If we really wanted to have an in-state line, shouldn't we have an in-state line that serves the state's second largest city that's currently starved for gas? We were able to add some amendments that gave us a straddle plant to provide gas here. I still think that a small-diameter gas line to Anchorage makes less sense than a large gas line to Valdez for major export makes more sense. It does in an economic fashion and it provides gas for the entire in-state market.

Petroleum News: So what made you support it?

Kawasaki: That one provision made it more sweet for me to able to support it. Even though I didn't support other iterations before, Fairbanks is in a real tough position. As desperation sets in, we are willing to try more and more things. The small pipeline might be helpful. Even a small help makes a difference here in Fairbanks.

Petroleum News: What would you like to see next then?

Kawasaki: From the standpoint of Fairbanks, everybody has been talking about in-state gas and local use, but a lot of the debate and a lot of the forward movement has been about export. I don't want to get so wrapped around export without also considering in-state use and figuring out how we as Alaskans take advantage of our own resources. Export is going to be the anchor, but we sometimes get too wrapped around that. I would like to see us talk a little bit more about in-state use. In addition, I think the next step is a real timeline. I think that will show us light at the end of the tunnel and I think that's what the state needs.

Petroleum News: So if you get that timeline, is that enough for the executive branch to begin negotiating a long-term fiscal policy?

Kawasaki: I think that gets us to the table. Neither side wants to share their cards. We don't want to give out too much concession on our natural gas. On their side, they don't want to say, we'll do it, until they know what concessions they are going to get. A show of faith from the Big Three and TransCanada would be, give us a reasonable timeline and reasonable expectations. That gets us to the table.

Petroleum News: OK, so still in the Fairbanks area, getting LNG to that market has been pretty heated. What's your take?

Kawasaki: Well, they anticipated the hearings being done in four to five days. I'm concerned with the testimony I've heard from Fairbanks Natural Gas and IGU and especially the comments from the RCA (Regulatory Commission of Alaska) themselves. I was critical of the governor's original plan on trucking LNG bill. I didn't think it was enough cash to get this job done. He ended up adding a significantly larger amount. Ultimately, a project like this and the build-out necessary to get gas into a person's home is going to cost much, much more. Even though the bill passed unanimously, I'm still critical that we didn't put enough cash in there to get the job done.

Petroleum News: So then what's your view on the bickering between the two groups?

Kawasaki: I don't know if any legislator has picked a side. I don't know that's what we want to do. There is room for both of them working together. I don't know what RCA wants. That could potentially be a big problem. Either RCA grants a certificate or doesn't grant it, or puts conditions on it to one or the other. They are autonomous of the Legislature and autonomous of the governor. They are looking at the economics of the area and they could come up with a different decision from what we as legislators want to see: getting natural gas to Fairbanks as fast as possible and a build-out as fast as possible.

Petroleum News: Let's go to the Arctic. Where do you think the state's future lies with Arctic policy?

Kawasaki: So much of our Arctic policy is driven either by U.S. trading or International trading and Alaska has, unfortunately, been playing second fiddle for the situations that are happening in our own backyard. This state needs to spend a lot more time, a lot more energy, a lot more resources to make sure Alaska's stakes have a seat at the table rather than get run over by China and Russia — all the other traders who want to come through the Bering Sea. As a state we need to have a hand in this and

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OIL PATCH BITS

JENSEN MARITIME CONSULTANTS

management contract for four new 330,000-barrel, Jones Act product tankers, being built by Aker Philadelphia Shipyard Inc., for Crowley. With construction scheduled to begin in January, Jensen is already establishing on-site offices and personnel at the Philadelphia shipyard to ensure strong working relationships with Aker staff and a seamless construction and delivery program. Delivery of the new veteran class tankers is expected in 2015 and 2016.

The project is the second major construction management project that Jensen has signed since it officially announced the launch of its new, in-house construction management program. The team first managed the construction of two new fireboats for the Port of Long Beach. But long before the program was formally established, Jensen construction management professionals were already at work managing multiple high-profile projects, including the construction and deliveries of all four Crowley high-bollard-pull ocean class tugboats and 17 articulated tug-barges.

Given the growth in Jensen's construction management business, the company has promoted Ray Martus to vice president of construction management reporting to Jensen Vice President Johan Sperling. Most recently Martus was director, new construction, for Jensen. In his new role, Martus will oversee Jensen's construction management division, which brings together the unique skills of both Crowley and Jensen throughout the entire lifecycle of design and construction.

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.

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BC'S LNG DEBATE

LNG tax revenues to eliminate provincial debt, which is currently about C$50 billion, and pay for education, health care and other programs.

Clark said she is well aware that overtaxing the LNG sector and driving away investment would undo those objectives.

"I have a job to do to make sure we extract every penny we can" from LNG, but "at the same time I don't want to imperil the business case for them. We don't want to chase the business away," she said.

Complex tax legislation

Clark has conceded the new tax regime is "some of the most complex tax legislation that our drafters have ever done."

Hanging over the government's head is the industry's warning that levying a special export tax could render British Columbia uncompetitive with other LNG jurisdictions.

By embracing LNG as the new underpinning of her province's economy, Clark granted an exemption to LNG projects by ruling that the natural gas consumed at liquefaction plants would be "clean energy."

Environment Minister Mary Polak said earlier in October that her major challenge in developing a clean environmental policy is ensuring that it doesn't hurt the bottom line of LNG companies, but she wouldn't say whether that would completely exempt greenhouse gas emissions from gas-powered LNG plants.

Merran Smith, director of Clean Energy Canada at Tides Canada, said Clark's commitment to have the world's cleanest LNG facilities does not have much credibility if it ignores emissions from the production and transportation of natural gas, even though the premier said she never intended to capture emissions produced at the upstream end of the LNG chain.

To deflect criticism on another issue, the Clark government has launched a C$650,000 study, to be completed by spring, into the impact on air quality from LNG operations at the deepwater port of Kitimat, the epicenter of the LNG sector.

"You can't cut virgin old-growth trees out of a forest, run them through a green sawmill and call it eco-lumber," Smith said.

A Tides Canada report concludes that British Columbia's proposed LNG plants will produce three times more carbon dioxide per metric ton of LNG that other leading facilities in Australia and Norway.

Study launched

To deflect criticism on another issue, the Clark government has launched a C$650,000 study, to be completed by spring, into the impact on air quality from LNG operations at the deepwater port of Kitimat, the epicenter of the LNG sector.

The town already has an aluminum smelter and is targeted for three LNG plants, marine terminals for two or more pipelines (including Enbridge's Northern Gateway connection from the oil sands) and an oil refinery, all of which could generate about 220 tankers per year.

The government said the study would "inform regulatory and policy development for future industrial activity in the Kitimat area ... prior to new projects being approved and in operation."

Smith said "we know there are going to be air pollution issues related to burning gas to power the compression for LNG ... pollution that causes acid rain, smog and health problems."

"We shouldn't be burning gas in (the Kitimat) air shed when we could be using clean renewable electricity," she said. ●

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LAND & LEASING

Potential Alaska state and federal oil and gas lease sales

Agency	Sale and Area	Proposed Date
DNR	Beaufort Sea Areawide	Nov. 6, 2013
DNR	North Slope Areawide	Nov. 6, 2013
DNR	North Slope Foothills Areawide	Nov. 6, 2013
BLM	NPR-A	November 2013
BOEM	Chukchi Sea	May 2016
BOEM	Cook Inlet (special interest)	November 2016
BOEM	Beaufort Sea	May 2017

Agency key: BLM, U.S. Department of the Interior's Bureau of Land Management, manages leasing in the National Petroleum Reserve-Alaska; BOEM, U.S. Department of the Interior's Bureau of Ocean Energy Management (formerly Minerals Management Service), Alaska region outer continental shelf office, manages sales in federal waters offshore Alaska; DNR, Alaska Department of Natural Resources, Division of Oil and Gas, manages state oil and gas lease sales onshore and in state waters; MHT, Alaska Mental Health Trust Land Office, manages sales on trust lands.

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KAWASAKI Q&A

be at the table when negotiations are happening. It's unfortunate we are not as involved and this administration is not as involved as we should be. Even though we are outside the three-mile limit of federal waters, it's basically the backyard of our backyard and we need to be more concerned about what's happening there.

Petroleum News: Do you have any closing thoughts?

Kawasaki: As Fairbanks residents, we are trying to really find solutions to get the second largest city in the state some energy relief. My goals are sooner rather than later, but doing it right whether it's natural gas through trucking or through a pipeline, or whether it's coal.

Even with our challenges, sometimes we overlook good news like Nikiski and Great Bear Petroleum with the shale play across the North Slope. That's great news that someone is looking to monetizing it. It's all part of the mix that's going to be part of TAPS, so it's good news because we haven't really taken advantage of our shale play like the folks in North Dakota with the Bakken. ●

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SUBSEA PIPELINE

Tesoro refinery near East Foreland point. That explains its name — the Trans-Foreland Pipeline.

Cook Inlet Energy is a subsidiary of Tennessee-based Miller Energy Resources Inc.

In January, Miller said Tesoro had agreed to fund up to $1.4 million in design costs for the proposed pipeline.

Petroleum News was unable to reach representatives of Tesoro and Cook Inlet Energy for comment.

Advantages of subsea line

As it stands, crude oil produced on Cook Inlet's west side is shipped out via tankers. The inlet's enormous tides and dangerous drifting ice add extra risk to the inlet crossings.

"Cook Inlet RCAC is very supportive of Tesoro's proposed project," the council said in its newsletter. "With the installation of the crude oil pipeline, there will be an alternative means of transporting crude oil from Cook Inlet's west side facilities. We will continue to advocate for the installation of the pipeline and Tesoro has been invited to present their plans and status of the project at the Council's Board of Directors December meeting in Anchorage."

Cook Inlet Energy has said a subsea pipeline could offer other advantages, such as reduced oil transportation costs.

Another concern is the threat that nearby Redoubt volcano poses to the Drift River oil terminal, where tankers load. Eruptions in 2009 knocked the terminal out of service and idled oil production on the inlet's west side for months.

The Cook Inlet RCAC said it had been in contact with Cook Inlet Energy and also Hilcorp Alaska, a major inlet oil producer. Hilcorp "has indicated that they are awaiting additional information before committing to utilizing the pipeline," the council newsletter said.

The newsletter further said that two consultants, Glosten and Northern Economics, have been engaged to do a cost-benefit analysis of the cross-inlet pipeline. ●

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GAS PRICES

paid an average price of $6.33 for the gas that it purchased from gas producers to deliver to its customers, with the remainder of the residential gas price consisting of Enstar's fees for managing and operating its system for transporting and distributing gas to consumers.

These figures make an interesting comparison with data for the Lower 48 states.

Average U.S. prices

According to information presented on the Energy Information Administration's website, the average price of natural gas for residential consumers in the United States varied between a minimum of $9.19 per thousand cubic feet in January 2013 to $16.15 in July. An EIA official explained to Petroleum News that the disparity in prices between winter and summer is an artifact of the way in which the prices are calculated. Essentially, the agency divides the total cost of the gas to consumers by the volume of gas used. And, since a significant component of that cost consists of fixed utility service fees, low gas usage in the summer compared with the winter results in the same service fees being spread over fewer cubic feet of gas in the summer, resulting in a higher per-thousand-cubic-foot cost.

However, assuming that the utilities plan to remain solvent, the average price that they charge their customers must be somewhere in the $9.19 to $16.15 range. By comparison, EIA quotes the average cost of residential gas in Alaska as ranging from $9.18 in February to $9.84 per thousand cubic feet in July, numbers that are a bit higher than those of Enstar but lower than those for the U.S. as a whole.

Distribution costs

Apparently this disparity in prices between Alaska and elsewhere in the United States arises from the high transmission and distribution costs for gas delivered to many Lower 48 residents. Unlike in Southcentral Alaska, where residents live a relatively few miles from Cook Inlet gas wells, Lower 48 consumers may in some cases live hundreds of miles from where gas is produced, with gas having to be transported through a network of gas transmission lines. EIA says that factors such as regional competition in the gas market, regional gas consumption levels and state regulations also impact gas prices.

And unpacking that U.S. average price data into price data for individual states shows a wide variety of price levels. Alabama, for example, saw prices ranging from $14.44 in January to $22.06 in July, while gas-endowed Texas saw prices ranging from $7.75 to $12.16 between January and May.

EIA data also shows wholesale gas prices at the Lower 48 Henry Hub market varying between $3.33 and $4.16 per thousand cubic feet, prices below Enstar's average cost of gas during the summer and prices that analysts view as too low for profitable natural gas development.

Power generation

The price situation for gas sold to power stations for electricity generation is also interesting. According to a tariff advice filed in May by Chugach Electric Association, a major Southcentral Alaska power utility, Chugach Electric's contracted gas supplies at that time for its gas-fired power stations ranged in price from $3.44 to $7.75 per thousand cubic feet, with the higher pricing within that range relating to more recently initiated contracts.

According to EIA the average price of gas delivered to power stations in the United States this year has ranged from $4.34 to $4.85 per thousand cubic feet. The agency says that the average price for gas used for power generation in Alaska ranged from $4.43 to $4.82 in that same period. ●

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DRILLING DELAY

DNR must extend unit terms

Buccaneer must also get the Alaska Department of Natural Resources to extend the terms of the Southern Cross unit agreement. The state placed the unit in default last year after Buccaneer failed to meet a prior work commitment. Buccaneer needed to drill by Oct. 31, 2013, to cure the default, but in his default notice Division of Oil and Gas Director Bill Barron said failure to meet the new deadline would not result in the termination of the unit, which was the penalty Buccaneer had initially proposed in its plan of exploration.

The reason, Barron wrote, was because the division had approved the unit based in large measure "on the exploration and development benefits of Buccaneer bringing a jack-up rig to Cook Inlet that would not only serve Buccaneer in drilling its prospects, but could also create a unique circumstance where the rig could be shared with other operators, thereby promoting exploration and development of other offshore Cook Inlet fields and providing increased potential for economic growth and employment opportunities."

Buccaneer said negotiations with the state are under way.

Changed location

After drilling at Cosmopolitan earlier this year, Buccaneer moved its Endeavour rig to Southern Cross and had already installed the 30-inch diverter and well control equipment on the conductor pipe when it noticed "some settling of the rig's legs into the seabed."

Subsequent tests found "scouring," or evidence of sand movement around the legs of the rig. The company attributed this movement to strong currents, and chose an alternate drilling location some 450 feet southeast of the original location. While state regulators approved the change, Buccaneer subsequently decided it could not complete the well by the end of October, which is when the state typically ends the summer drilling season.

With work under way at Port Graham, Buccaneer said it expects to move the Endeavor rig to Cosmopolitan by late November. The company still needs final permits for that well.

—ERIC LIDJI

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TERMINAL CHOICE

shape" and "presents a new opportunity for synergy and alignment among the producers and the project being pursued by the Alaska Gasline Development Corporation."

AGDC was established by the Alaska Legislature to pursue an in-state gas pipeline, which could also become a spur line for in-state deliveries off of a major line from the North Slope.

Pipeline routing work continues

Steve Butt of ExxonMobil, senior project manager, said in the statement from the companies that this is a step forward for the Alaska LNG project.

He said that in addition to site selection factors, Nikiski "also results in a pipeline route that provides an access opportunity to North Slope natural gas by the major population centers in Fairbanks, Mat-Su Valley, Anchorage and the Kenai Peninsula."

While Nikiski is the lead site, secondary locations continue to be considered, the companies said. And work continues on a number of engineering, technical, regulatory, fiscal, commercial and permitting issues.

The project concept includes a gas treatment plant on the North Slope, an 800-mile pipeline with up to eight compressor stations and at least five off-take points for in-state gas delivery, and a liquefaction plant and terminal.

"The teams are currently preparing for more detailed engineering and design work, consistent with previously released plan phases," the companies said.

Cost of the project has been put in the $45 billion to $65 billion range, and the companies noted that "competitive, predictable and durable oil and gas fiscal" terms are required for the project.

The project concept includes a gas treatment plant on the North Slope, an 800-mile pipeline with up to eight compressor stations and at least five off-take points for in-state gas delivery, and a liquefaction plant and terminal.

Site competition

Valdez City Manager John Hozey said in a statement that Valdez, which has been promoting that city as the site for the liquefaction plant and terminal, would continue to "make the case for its port."

He said it was a step closer to having ANS gas for export, but also said, "Valdez has been working with industry for decades to successfully deliver North Slope crude to market." Valdez has "many unique attributes ... as a terminal location," he said. "The city will therefore continue working with the project managers to insure they have all the best information when finalizing this decision."

The Richardson corridor

Most legislative response to the announcement was positive, although Rep. Eric Feige, R-Chickaloon, said he was disappointed and continues to support a Richardson Highway route.

Feige said that in conversations he has had with project managers, "Valdez was a lead contender but in the end was not the optimal spot because of civil engineering challenges, site preparation and excessive snow load."

Six Valdez sites were evaluated but represented the same "engineering hurdles and permitting concerns," he said, adding that he hoped solutions to the concerns could be created and that the location will be reevaluated before a final decision.

Feige said this decision increases the likelihood of a merger between the mainline project and AGDC and with that in mind, he said he urges AGDC "to look at the Richardson Highway corridor as the number one priority for constructing a smaller pipeline off the big line and supplying lower-cost energy to the corridor."

Mainline, AGDC proponents pleased

Rep. Mike Hawker, R-Anchorage, and House Speaker Mike Chenault, R-Nikiski, sponsors of HB 4, said in a statement that they were pleased by the Nikiski selection.

Hawker praised the selection as "the route with the potential to serve the majority of Alaskans," and Chenault said the route makes sense because of the long history of Nikiski and the western Kenai Peninsula in supporting LNG exports. (The state's original LNG export facility, not currently active, is at Nikiski.)

HB 4 created AGDC as a standalone state corporation charged with developing an in-state gas pipeline and also charged AGDC with evaluating a merger with the larger project.

In a statement Democratic House legislators also praised the announcement.

House Democratic Whip Chris Tuck of Anchorage said Nikiski is "a location that allows room to build a value-added industrial base."

Rep. Scott Kawasaki, D-Fairbanks, said the big line "allows ample gas for Alaskans to meet local heating and energy needs by tapping into the resources going south."

"The key now is to find a way forward that pencils out for both Alaskans and the industry," said Anchorage Democratic Rep. Andy Josephson.

"A large-diameter line gets the lowest cost gas to Alaskans and the most revenue to the state," said Rep. Les Gara, D-Anchorage.

—KRISTEN NELSON

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