Petroleum news

page 7 Conoco's Johansen says industry, government cooperation needed

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Gas pipeline players

JUDY PATRICK

Gas pipeline panel at the Resource Development Council's annual conference, Nov. 18 in Anchorage: Bud Fackrell, president, Denali — The Alaska Pipeline; Tony Palmer (speaking), vice president, TransCanada; and Larry Persily, federal coordinator, Office of the Federal Coordinator for Alaska Natural Gas Transportation Projects. A story on these gas pipeline presentations will be in the Dec. 5 issue.

Obama gets lots of ANWR advice; Alaska's senators urge restraint

Advocates are urging President Obama to use his executive powers to increase protections in the Arctic National Wildlife Refuge.

In recent days the president has received appeals from members of Congress, environmental groups, businesses and religious organizations.

They want to see ANWR declared a national monument, which environmentalists say is a "stepping stone" to new wilderness designations in the refuge.

Proponents of these measures are hanging their exhortations on the upcoming 50th anniversary of the refuge's birth.

On Dec. 6, 1960, Fred Seaton, Interior secretary under President Eisenhower, signed the public land order creating what originally was called the Arctic National Wildlife Range. In 1980, the unit was greatly expanded and renamed Arctic National Wildlife Refuge, which today encompasses 19.3 million acres in Alaska's northeast corner.

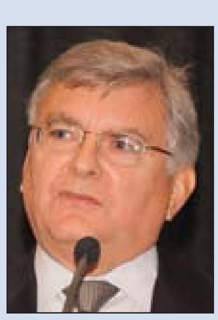
Twenty-five U.S. senators signed a Nov. 19 letter citing the

see **ANWR ADVICE** *page 10*

Nikaitchuq heavy, shallow, cold; multiple challenges at new field

Eni Petroleum plans to bring its Nikaitchuq field on Alaska's North Slope online in December or January. This development includes the first North Slope processing facilities built by a company other than BP or ConocoPhillips.

Eni will send sales-ready crude oil into the Kuparuk Pipeline and from there to the trans-Alaska oil pipeline.



JUDY PATRICK

DAVID MOLES

Eni holds 100 percent of the working interest at Nikaitchuq, the company's Alaska representative and development manager, David Moles, said Nov. 17, which means the company can't share risk with partners.

"But it also offers an opportunity," Moles told the Resource Development Council for Alaska's annual conference, for the company to use "innovative technologies that we're trying to apply in the viscous oil arena … to make Nikaitchuq a success for Eni."

The challenge at Nikaitchuq is that it is a marginally economic field based on viscous oil development, Moles said.

Work at Nikaitchuq was begun by Kerr-McGee. Eni acquired a 30 percent interest from Armstrong in 2005, "and

see **NIKAITCHUQ** *page 13*

EXPLORATION & PRODUCTION

Escopeta succeeds

Has cash, jack-up, heavy lift vessel, state's okay to drill in Cook Inlet

By ERIC LIDJI & KAY CASHMAN
For Petroleum News

After several years of effort, Escopeta Oil says it has the funds and contracts in place to ship a jack-up rig to Southcentral Alaska in February, in preparation for drilling in upper Cook Inlet in April. The Houston independent has also resolved legal issues with the State of Alaska that are crucial to its drilling plans.

Escopeta plans to use the Spartan 151 jack-up rig currently stationed in the Gulf of Mexico, which it will bring to Alaska on a heavy lift vessel owned by Dockwise, an international firm based in The Netherlands.

DANNY DAVIS

"We're doing it. It's going," Escopeta President Danny Davis told Petroleum News on Nov. 23.

"The Spartan rig is currently drilling a well in the Gulf of Mexico. … From there we are moving it to Freeport where Dockwise will load it for Alaska in mid-February. … Our intention is to make the jack-up a Cook Inlet asset, for use by ourselves and others. … We're using almost all Alaska labor. We're using the Arness Dock two miles west of Kenai, and we're opening an office at the dock and possibly in Anchorage," Davis said

If successful, Escopeta would become the first company to bring a jack-up rig to Alaska in nearly

see **ESCOPETA** *page 11*

NATURAL GAS

Still hope for gas pipeline

Study for DNR suggests future L48 gas prices will support gas from North Slope

By ALAN BAILEY
Petroleum News

Amid current speculation about the future of the Alaska oil and gas industry, as oil production from the North Slope slows down and exploration drilling comes to a near standstill, it has become popular to add what some view as fading hopes for a future North Slope gas line to a general list of woes.

For, as the burgeoning development of plentiful supplies of so-called shale gas in the Lower 48 has caused a paradigm shift in the North American gas market, the price of Lower 48 gas has plummeted to levels below the projected transportation rates on a gas line from the Arctic, perhaps rendering the gas line uneconomic.

Objective analysis

In the interests of taking a rational look at the prospects for future Lower 48 gas prices, to replace worry-driven conjecture by objective analysis, the Alaska Department of Natural Resources commissioned consulting firm Black & Veatch to prepare a report on the future of North American gas prices in the context of the new shale gas revolution.

And the Black & Veatch analysts have found that, although there are major uncertainties around future North American gas markets, it is likely that gas

see **HOPE** *page 15*

NATURAL GAS

Gas exports in trouble

Canadian natural gas to US projected to drop 2 bcf per day over next 5 years

By GARY PARK
For Petroleum News

New pipelines in the western United States and a flood of production in the east are expected to take a huge bite out of Canada's natural gas exports, wiping out 2 billion cubic feet per day over the next five years, says a study by research group Bentek Energy.

Canada currently exports about 60 percent of its total gas production of 14.5 bcf per day, although Canada's National Energy Board, in a mid-case forecast, has projected those volumes could fall by 2.2 bcf per day over the next two years.

Colorado-based Bentek warns that the displacement of Canadian gas will outstrip Canadian

The opening next summer of El Paso's Ruby pipeline to Malin, Ore., will see Rockies producers take a slice of the Canadian baseload market in California.

demand growth, acting as a drag on prices and resulting in a drilling downturn pending an increase in consumption by the Alberta oil sands sector, which needs gas to generate steam for thermal recovery projects and electricity for recovery and processing operations.

Bentek also expects the phasing out of coal-fired electricity generation in Ontario will also come to the rescue in the latter part of the forecast

see **GAS EXPORTS** *page 16*

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● EXPLORATION & PRODUCTION

Slaiby says open OCS discussion needed

Warns of possibility of walking OCS development into another ANWR-style standoff if people continue with business as usual

By ALAN BAILEY
Petroleum News

Another potential summer drilling season on the Arctic Alaska outer continental shelf has come and gone without the sight of a drillship on any of Shell's Beaufort and Chukchi sea oil and gas leases. And after about $3.75 billion dollars in expenditure for lease acquisition, seismic surveying, environmental monitoring and the establishment of spill response capabilities, the company has yet to see a drill bit grind its way into any of its offshore prospects.

Time for openness

It's time for everyone — including oil companies and the environmental organizations — to be willing to openly discuss all aspects of offshore development, Pete Slaiby, Shell's Alaska vice president, told the Resource Development Council's annual conference on Nov. 17.

"Unless we're willing to open up and really have these discussions, are we walking the OCS into another ANWR?" Slaiby asked.

Slaiby said that a well known environmentalist had recently told him that environmental organizations see opposition to government regulators as their essential role, even although this particular environmentalist did not especially take issue with Shell's Alaska plans. At the same time the environmentalist bemoaned the lack of progress in developing a national energy policy, dealing with greenhouse gases and addressing the issue of ocean acidification, Slaiby said.

No one can afford to continue with business as usual, Slaiby said.

"If oil companies continue to keep what they're doing behind closed doors, if we're not willing to talk about the longer-term, the real value propositions for the communities we work in, if environmental groups continue as a matter of course to oppose development at every turn, we're surely never going to get anywhere," he said.

Offshore oil and gas development worries people and it is important to take the time to address people's concerns.

"We have to sit down with the stakeholders and look at this in the longer term," Slaiby said.

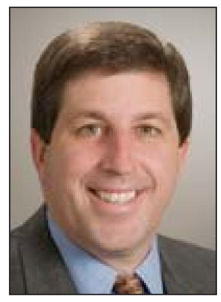
Events of 2010

Slaiby recounted events earlier this year, with the situation appearing promising for Shell's Alaska venture until BP's Macondo well started spewing oil into the Gulf of Mexico, bringing outer continental shelf drilling to a sudden halt.

At the end of March, before the Gulf blowout erupted, President Obama announced that existing leases in the Beaufort and Chukchi seas would remain in place; Interior Secretary Ken Salazar indicated that he was going to submit final documentation to the District of Colombia Court of Appeals, to resolve litigation over the lease sale program that included the 2008 Chukchi Sea lease sale; and Shell prevailed in 9th Circuit Court of Appeals litigation over the company's Chukchi and Beaufort Sea exploration plans, Slaiby said.

"On March 31 … in Shell we were never really closer to what we were trying to do for the last five years," Slaiby said.

Shell started mobilizing its Arctic drilling fleet, an operation that involved moving vessels from places as far away as China, New York and Norway, he said.


PETE SLAIBY

Then, towards the end of May, as oil continued to gush into the Gulf of Mexico, the Department of the Interior notified Shell that the company would not be allowed to drill in the Arctic OCS in 2010, thus nixing the company's drilling plans until the 2011 open water season, at the earliest.

But the U.S. Minerals Management Service, the precursor agency to what is now the Bureau of Ocean Energy Management, Regulation and Enforcement, complied with both the Outer Continental Shelf Lands and the National Environmental Policy Act when permitting Shell's Alaska program, Slaiby said.

"It was a very, very rigorous process that went from top to bottom in looking at these wells," he said.

Simple wells

Shell drills about 100 exploration wells each year and the company's planned Chukchi and Beaufort sea wells are the simplest types of well in the company's portfolio, Slaiby said. Water depths of around 130 feet at the site where Shell had hoped to drill in 2010 compare with the 5,000-foot water depth of the Macondo well. And with lower reservoir pressures than in the deepwater Gulf of Mexico, it would take multiple out-of-control wells in the Alaska OCS to spill oil at the same rate as happened after the Gulf blowout, Slaiby said.

However, with the Department of the Interior not yet having made a decision on whether to re-open Arctic OCS drilling, the status of oil and gas exploration in Alaska remains uncertain — Shell has tried to start breaking the logjam by submitting to BOEMRE an application to drill in 2011 in the company's Beaufort Sea Sivulliq prospect, Slaiby said.

"It's a carbon copy of the plan that we produced last year and the one that passed the test of the 9th Circuit court," he said.

And for its planned 2011 drilling Shell is building a containment dome that could be placed over a leaking well in the unlikely event of a well blowout. In addition, the company has mobilized its Kulluk floating drilling platform to act as a backup relief well rig.

In 2012 the company will put the Kulluk to work as a second drilling rig in the Beaufort Sea, Slaiby said.

Environmental studies

Meantime Shell, in conjunction with ConocoPhillips and Statoil, has been continuing to work on baseline environmental science, using a multidisciplinary approach to take account of every aspect of the Arctic offshore environment, Slaiby said.

"Clearly moving forward (with exploration and development) will mean that there has to be a level of assurance about how the programs will play out from an environmental standpoint," he said.

With around $500,000 spent so far by various organizations on about 5,000 environmental studies, much is already known about the Chukchi and Beaufort seas, Slaiby said. However, more studies will be needed before moving from exploration drilling into a field development scenario, he said.

see SHELL *page 4*

On the Web

See previous Petroleum News coverage:

"NSB and Shell start new science program," in Nov. 7, 2010, issue at www.petroleumnews.com/pnads/75777578.shtml

"Going for the Beaufort; Shell applies for Sivulliq well in '11," in Oct. 10, 2010, issue at www.petroleumnews.com/pnads/630112852.shtml

"Shell adds spill response capabilities," in Sept. 5, 2010, issue at www.petroleumnews.com/pnads/291070081.shtml

GOVERNMENT

Alberta seeks backroom advice

By GARY PARK

For Petroleum News

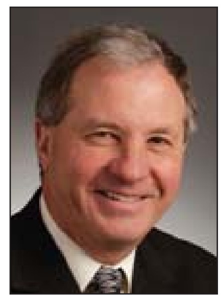
Alberta Energy Minister Ron Liepert has invited many one-time critics of provincial government policy in from the cold.

In his continuing effort to rebuild bridges to the industry he has established a 21-person group, formally known as the Minister's Oil and Gas Economics Advisory Council, whose primary mandate is to offer advice on strategies to improve Alberta's competitiveness in developing its oil and gas resources and continuing to account for 30 percent of the province's Gross Domestic Product.

But any thought that the council's deliberations will be part of the public record have been swiftly dashed.

It needed pressure from two opposition parties in the Alberta legislature to disclose the makeup of the council, even though the members will qualify for C$235 per day for their attendance at meetings and other related work (the chair will get C$325), along with reimbursement for some travel expenses.

The panelists have been appointed for one year, but can qualify for an extension up to three years



RON LIEPERT

Liepert initially refused to say who was on the panel, arguing the group was meant to play an "informal" role and offer advice on what the government "should or should not be doing."

Minutes won't be public

A government spokesman said minutes of the meetings will not be made public, so that the members can engage in "good discussion and debate."

He said Liepert is wants to respect the ideas brought forward and not have them "debated in the public realm."

Liepert told the Calgary Herald he wants to ensure the panel provides a broad perspective of what is happening in the industry and to "keep discussions at a high level, with a long-term focus."

But Paul Hinman, energy spokesman for the Wildrose Alliance party, was not prepared to accept that explanation, demanding to know what was being discussed in privacy that could affect the future of Alberta's lucrative petroleum resources.

As qualified as the council members are, he said "their job is to promote their companies and increase the return on investment for their shareholders. That doesn't always coincide with (the best) interests of Albertans."

A spokesman for Imperial Oil, whose Chief Executive Officer Bruce March is on the panel, said the chance to help formulate government policy was viewed as a "positive thing" by his company.

A spokesman for Imperial Oil, whose Chief Executive Officer Bruce March is on the panel, said the chance to help formulate government policy was viewed as a "positive thing" by his company.

Many groups not represented

Notable by their absence are representatives of environmental organizations, consumer groups, aboriginal communities and industry associations, such as the Canadian Association of Petroleum Producers.

Many on the council were among the most outspoken critics of government policy since Ed Stelmach was elected premier four years ago, especially during the contentious debate over royalty changes.

The panel is chaired by Kathy Sendall, a former Petro-Canada executive. Members include Murray Edwards, vice chair of Canadian Natural Resources; Mike Graham, executive vice president of Encana; Lorraine Mitchelmore, chair of Shell's Canadian operations; Murray Nunns, president of Penn West Energy; Marvin Romanow, chief executive officer of Nexen; Chris Seasons, senior vice president of Devon's Canadian division; Steve Williams, chief operating officer of Suncor Energy; and Susan Riddell Rose, chief executive officer of Perpetual Energy. Others include representatives of the financial services and petroleum services sectors. ●

Contact Gary Park through publisher@petroleumnews.com

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SHELL

And Slaiby said that Shell is particularly proud of its cooperative relationship with the Barrow Arctic Science Consortium. The company has also formed an agreement with the North Slope Borough on a program of science research to address the concerns of users of subsistence resources.

"It's really an opportunity for those stakeholders, those residents, to tell us what's important to study for them," Slaiby said.

North Slope Borough Mayor Edward Itta has lifted the bar when it comes to offshore development, he said.

"He's really asked some tough questions and he's really trying to move these communities to a place where they can be comfortable with it as well," Slaiby said. "We just have to be open for the change."

Publicity in Washington

Back in Washington, D.C., Shell has launched a publicity campaign to inform people there about the company's Alaska program, with an emphasis on the economics of Arctic development and on the company's oil spill response plans. The campaign is also reminding people that Shell has been conducting scientific research into the environment in which the company plans to drill, and that there is some urgency in the need to move forward, Slaiby said.

A decision on the future of offshore exploration and development in the Arctic has yet to be made in Washington, he said.

"Once a decision is made it becomes very, very difficult to walk that decision back," Slaiby said.

With support from the Alaska congressional delegation and the state governor, "we have, I think some real wind in our sails now," he said. But critical decisions lie ahead on Shell's Alaska offshore drilling.

"We need clarity on 2011 because we really can no longer afford to wait for a prolonged decision before we move forward," Slaiby said. "The cost of keeping this opportunity open simply becomes too prohibitive." ●

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● EXPLORATION & PRODUCTION

AIDEA moves on jack-up financing

AIDEA agrees to consider $20M to $30M ownership interest in proposed Buccaneer-purchased rig, conducting feasibility study

By ERIC LIDJI

For Petroleum News

Buccaneer moved two steps closer to bringing a jack-up into Cook Inlet on Nov. 22.

The Alaska Industrial Development and Export Authority agreed to consider owning a piece of the rig and determined that the project was eligible for tax-exempt financing.

Buccaneer Alaska, a local subsidiary of the Australian independent, is looking to buy a jack-up rig by interlocking a series of public funding mechanisms.

To buy the rig, Buccaneer wants to use up to $60 million of Recovery Zone Facility Bonds and wants AIDEA to invest between $20 million and $30 million. Then, to offset those costs, Buccaneer would take advantage of a new tax credit that pays 100 percent of the drilling expenses, up to $25 million, for the first offshore well drilled with a jack-up.

The AIDEA board approved two resolutions that advance that cause on Nov. 22.

The first allows AIDEA to conduct a feasibility study to decide whether owning a portion of the rig is a good business decision. The second allows Buccaneer to get reimbursed for certain expenses if it is ultimately allowed to use the Recovery Zone Facility Bonds.

Exploration companies have been trying to bring a jack-up rig to Alaska in recent years to drill in underexplored corners of the basin, but haven't been able to arrange a program.

Houston independent Escopeta Oil wants to bring a rig to

To buy the rig, Buccaneer wants to use up to $60 million of Recovery Zone Facility Bonds and wants AIDEA to invest between $20 million and $30 million. Then, to offset those costs, Buccaneer would take advantage of a new tax credit that pays 100 percent of the drilling expenses, up to $25 million, for the first offshore well drilled with a jack-up.

Alaska next spring using a traditional approach: accumulating private financing to mobilize, rent and use the rig.

Buccaneer took a different approach in recent weeks. The company believes that a depressed rig market, one-time bond opportunities and the number of underexplored prospects in Cook Inlet making buying a rig a better idea than renting one.

Under an intricate plan, Buccaneer created two new companies to own and operate the rig: a consortium called Kenai Offshore Ventures LLC and a new operating company called Buccaneer Alaska Drilling. Kenai Offshore Ventures would own the rig and generate revenue by leasing it to Buccaneer Alaska Drilling. Buccaneer Alaska Drilling would then charge a day rate to local exploration companies for drilling services.

Buccaneer said that Seahawk Drilling Inc., a Houston-based offshore driller, would physically operate the rig on behalf of the new consortium and operating companies.

Buccaneer said it is in negotiations to buy a cold-water rated jack-up rig. The company said that if the financing goes through, it plans to finalize the contract, winterize the rig at its current location in Malaysia and have it bound for Alaska by next spring. Under that timeline, the jack-up rig would be in Alaska and ready to start drilling by July 2011.

Buccaneer wants AIDEA's help in two ways to finance the acquisition.

The first is by issuing up to $60 million in Recovery Zone Facility Bonds, a tax-exempt bond included in the American Recovery and Reinvestment Act of 2009, also known as the stimulus package. Kenai Offshore Ventures recently announced that it plans to work with Key Banc Capital Markets on the placement of the Recovery Zone Facility Bonds.

Buccaneer's second request is for AIDEA to invest between $20 million and $30 million in the rig. At the meeting, Buccaneer predicted an 8 percent return for AIDEA, as well as a "first out" provision allowing AIDEA to recover its investment before other investors.

One of the recently approved resolutions allows AIDEA to spend up to $150,000 studying whether Buccaneer's proposal is a good business decision. AIDEA expects that evaluation to be completed by its next board meeting, scheduled for Dec. 3. The Recovery Zone Facility Bonds expire if not issued by the end of the year. (See related Escopeta story on page 1.) ●

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● ENVIRONMENT & SAFETY

Standalone regulator urged after crash

Former supreme court justice urges 'separate and independent' agency to control safety in Newfoundland's offshore oil industry

By GARY PARK

For Petroleum News

An inquiry into a helicopter crash last year off Newfoundland-Labrador that killed 17 of 18 people on board has called for an independent regulator to oversee safety in the province's offshore oil industry.

Commissioner Robert Wells, a retired Newfoundland Supreme Court justice, said Newfoundland should follow the lead of Norway, the United Kingdom and Australia and a concept being developed for the U.S. Gulf of Mexico to install a regulator "separate and independent from all other components of offshore regulation … with safety being its only regulatory task."

He also recommended that a rescue helicopter should be ready for deployment within 15 minutes of an accident and that restrictions be placed on the number of night-time flights.

The inquiry followed the March 2009 crash of Cougar Helicopters Flight 491, which was trying to return to its base in St. John's, Newfoundland, after encountering problems while en route to offshore oil platforms.

"I believe the safety regulator should be powerful, independent and equipped with expert advice," wrote Wells in his report to the Canada-Newfoundland and Labrador Offshore Petroleum Board.

His 29 recommendations covered the operation of the offshore industry and changing the responsibilities of the board itself.

Wells had previously asked the board to have a helicopter set aside for emergency response — a proposal that is already being acted upon.

Crash investigated separately

But his mandate did not extent to examining the cause of the crash. That aspect is

see **REGULATOR** *page 6*

● PIPELINES & DOWNSTREAM

KPL rates to stay for another year

RCA gives state, Anadarko and Kuparuk Transportation Co. another year to work out a schedule for hearings to resolve rate case

By ERIC LIDJI
For Petroleum News

The shipping rates on the Kuparuk Pipeline will remain in limbo for at least another year.

The Regulatory Commission of Alaska in early November decided to keep the temporary and refundable rates on the North Slope pipeline in place until Nov. 12, 2011, to give the various parties to the case more time to work out a schedule for hearings and testimony.

At issue is whether the rates charged by Kuparuk Transportation Co., the owner and operator of the pipeline and its nine-mile extension, represent the cost to run the pipeline.

The State of Alaska and Anadarko Petroleum believe so, but the Kuparuk Transportation Co. argues that higher rates are needed to pay for multimillion-dollar upgrade projects on the pipeline at a time when throughput is declining and litigation costs are on the rise.

The RCA gave the three parties until Dec. 6, 2010, to agree on a timetable for hearings.

KTC believes it needs higher rates to help pay for around $75 million in upgrades needed to accommodate smart pigging technology to monitor pipeline integrity.

KTC is a partnership between subsidiaries of ConocoPhillips, BP and Chevron.

The Kuparuk Pipeline moved more than 102 million barrels of oil in 2009.

Rate based on inflation

The Kuparuk Pipeline runs 28 miles across the central North Slope, from a processing center in the Kuparuk River unit to the start of the trans-Alaska oil pipeline. The pipeline also moves oil from Milne Point through a tie-in with the Milne Point Pipeline.

The existing Kuparuk Pipeline went online in 1984. The state quickly challenged the shipping rates KTC set for pipeline. The state and KTC reached a settlement in 1991, setting the rate at 21 cents per barrel, a price adjusted every three years according to the Consumer Price Index. However, they didn't set an underlying formula for future rates.

The RCA most recently approved a change at the end of 2005, setting rates of 19.8 cents per barrel for the entire pipeline, and 14.2 cents per barrel from the Milne Point tie-in.

Following that approval, the state and KTC took another look at the settlement, but couldn't agree to new terms. In 2008, the state took advantage of a provision allowing it to terminate the settlement, and asked the RCA to investigate the rates on the pipeline.

The state claimed that the rates on the Kuparuk Pipeline did not represent the cost to run the pipeline plus a small return, the typical ratemaking metric. Rather than continuing to update the settlement rate, the state wanted to use a traditional ratemaking formula, which it estimated would cut the in-state shipping rates on the pipeline at least in half.

Anadarko Petroleum soon joined the case. The state and Anadarko both have an incentive to keep shipping rates low. The state calculates royalties on the value of oil after transportation. Anadarko doesn't earn a profit until after it pays shipping fees.

Although the projected "windfall" that the state accused KTC of collecting was relatively small, around $6 million a year, the state argued that the increased rates discouraged independent and third-party explorers that would need to rent space on the pipeline.

In March 2009, the three parties reached an agreement for moving forward.

The agreement allowed KTC to keep the 2006 rates in place while the company kicked off a traditional ratemaking process with the RCA, one based on actual operation costs.

KTC filed its new rates in April 2010, asking for a roughly 35 percent increase.

The RCA approved those rates on refundable basis in May, allowing them to remain in effect through November 2010 while the parties organized a hearing schedule. The current rates are now 26.4 cents per barrel to ship through the entire pipeline and 19.3 cents per barrel to ship from the Milne Point tie-in to the terminus at Pump Station 1.

KTC argued that it needed higher rates to help pay for about $75 million in upgrades needed to accommodate smart pigging technology to monitor pipeline integrity. It noted that these costs needed to be spread over fewer barrels because of declining throughput.

The state and Anadarko both challenged the method KTC used to formulate its new rates, but "because the parties have not filed a proposed procedural schedule or requested a prehearing conference, no progress has been made toward determining whether rates are just and reasonable," the RCA noted in a Nov. 4 order. As a result, the RCA agreed to let the temporary and refundable rates remain in effect on the pipeline for another year. ●

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REGULATOR

being investigated by the Transportation Safety Board of Canada, which has already reported that significant mechanical problems occurred when titanium studs broke in flight preventing oil from flowing through the gearbox before the chopper plunged into the Atlantic Ocean.

Once the transportation board has completed its draft report, Wells will have the opportunity to offer more recommendations.

"Offshore oil jurisdictions and regulators differ in the amount of information about safety which they give to the public," Wells said.

"In a free and democratic society such as Canada, as much information as possible on all safety maters should be made public at all times," he wrote.

"After catastrophic disasters over the years — the most recent being the Deepwater Horizon tragedy in the Gulf of Mexico — we are beginning to understand that we are all stakeholders now."

Randell Earle, an attorney for the Communications Energy and Paperworkers Union, said the call for a standalone regulator was an important one for workers in the Newfoundland offshore.

The offshore board said it will take 30 days to review Wells' recommendations.

A C$27 million lawsuit has been filed against Sikorsky Aircraft Corp. and others alleging breach of duty, gross negligence, negligent misrepresentation, reckless and willful misconduct. ●

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● EXPLORATION & PRODUCTION

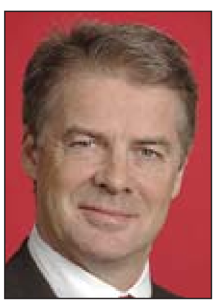
E&P future challenging but not daunting

New head of ConocoPhillips Alaska notes Alaska production down 36% from 2003-10, compared to drop of 1% in Texas; Alaska rigs flat

By KRISTEN NELSON
Petroleum News

Alaska has a world-class resource base, but production is dropping and it will take cooperation between government and industry to put more oil in the trans-Alaska oil pipeline, ConocoPhillips Alaska President Trond-Erik Johansen told the Resource Development Council for Alaska's annual conference Nov. 17 in Anchorage.

Reservoirs now producing on the North Slope are "what I would call the easy oil," Johansen said.



TROND-ERIK JOHANSEN

What the companies want to produce now is "more difficult" and "more expensive to get out of the ground," he said.

West Sak, the viscous oil field overlaying the Kuparuk River field and parts of Milne Point, is "quite challenging" to produce."

"It takes more money; it takes more technology; it takes a lot of effort to get it out of the ground," Johansen said.

Shallower still is Ugnu, a heavy oil accumulation overlaying West Sak.

Heavy oil is produced in Canada and elsewhere, he said.

"But you ought to know it costs a lot of money; it takes a lot of technology; it takes a lot of patience — very, very high breakeven costs to get this oil into the plant and out to the market."

In both cases, however, there is a lot of oil, billions of barrels.

But with declining conventional oil production from the North Slope and the gas pipeline still in the future, "We need to do something in the meantime and it's called filling up the oil pipeline, because the oil is there … you just need to get it to the pipeline."

It will take cooperation between industry and state and federal government, Johansen said, "and it is challenging, but it is not daunting. I think everyone wants to do something about getting some of these resources into the pipeline," he said.

Production decline

The challenges in Alaska have increased, he said, and include Alaska taxes, low-flow issues for the trans-Alaska oil pipeline, NPR-A permitting issues, uncertainty in the outer continental shelf and the North Slope gas market, he said.

Why is production dropping in Alaska and rising in the Lower 48.

"Is it because there is no oil in Alaska? No; lot's of oil in Alaska.

"It is because there was a lot of cheap oil in the Lower 48? No," Johansen said.

In the Lower 48, oil production grew 3 percent from 2003 to 2010; Alaska production declined 36 percent over the same period, he said.

Lower 48 oil production increased when oil prices rose, powered by an increase in oil rigs operating in the Lower 48. In Alaska, however, the rig count dropped from 2003 to 2005 and has been flat ever since.

And for those who say that Alaska is a mature region and that production decline is to be expected, he noted that Alaska has only had serious production for a few decades, compared to Texas which has had commercial production for almost a hundred years.

Yet during 2003-10, Texas production declined only 1 percent compared to the 36 percent decline in Alaska.

Investment issue

Alaska needs the right environment in place for more production, "like you see today happening in the Lower 48," he said.

Johansen said he is "pretty optimistic" that there will be a turnaround in Alaska "because of technology and because of smart decisions between the industry and the state and the federal government to put the framework in place to make sure we can go after it."

But that isn't happening now.

ConocoPhillips drilled at least one exploration well in Alaska every year starting in 1965, Johansen said.

"This year is the first year we didn't drill an exploration well; and we're not going to drill one next year, either," he said.

The company is, however, looking for resources outside of state acreage and is ready to drill in the Chukchi Sea.

A lot of groundbreaking technology work has been done in Alaska, and technology will help with future developments.

But while the company is proud of what it's done in existing state fields, ConocoPhillips — and other companies in Alaska — need "goodwill from the investors that own the company to go after these challenged barrels."

The problem is that today, "all the upside (from new investments) would go to the government and the state and not to the companies that are actually taking the risks."

There are great opportunities, Johansen said, but they require cooperation.

Johansen, previously president of ConocoPhillips' Southeast Asia Exploration and Production organization, was named to head ConocoPhillips' Alaska operations effective April 1, replacing long-time ConocoPhillips Alaska President Jim Bowles, who died while snowmachining on the Kenai Peninsula Feb. 13. ●

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EXPLORATION & PRODUCTION

Armstrong completes North Fork well

Armstrong Cook Inlet completed the North Fork Unit No. 14-25 well in mid-October, according to a recent report from the Alaska Oil and Gas Conservation Commission.

The well is one of two Armstrong permitted with the AOGCC this past summer, the other being the North Fork Unit No. 32-35 well planned to bear south from the well pad.

Armstrong drilled the exploration well from the North Fork pad, where the Denver-based independent also drilled the North Fork Unit No. 34-26 well in the summer of 2008. The results of that well justified the decision to sanction development and delineate the field.

The North Fork unit is about 10 miles north of Homer on the southern Kenai Peninsula.

Armstrong drilled the 11,700-foot directional well bearing east from the pad to a total vertical depth of 10,311, slightly deeper than the 9,000-foot NFU No. 34-26 well.

The well is one of two Armstrong permitted with the AOGCC this past summer, the other being the North Fork Unit No. 32-35 well planned to bear south from the well pad.

With its drilling program this year, Armstrong plans to target both the natural gas potential of the Tyonek formation and the oil potential of the deeper Hemlock formation.

Armstrong is on pace to start natural gas sales from North Fork in 2011.

—ERIC LIDJI

● F I N A N C E & E C O N O M Y

BP looks to kill shareholder lawsuit

Case focuses mainly on Deepwater Horizon disaster; BP lawyers argue English law bars pursuit of 'derivative' claims in Alaska court

By WESLEY LOY
For Petroleum News

Lawyers for BP are seeking dismissal of a "shareholder derivative" lawsuit brought in an Alaska court against the company's board of directors following the Deepwater Horizon disaster.

In a 33-page argument filed Nov. 16 in Superior Court in Anchorage, BP lawyers say the lawsuit rightfully belongs in a court in England, where the company's based.

They also note that the Anchorage case is among more than a dozen shareholder derivative actions that have been filed in state and federal courts in various states, including Louisiana and Texas, since the Deepwater Horizon rig explosion in the Gulf of Mexico. Plaintiffs in these cases are "competing" to assert claims against BP's board for mismanagement, the BP lawyers say.

An English law, the Companies Act 2006, holds that a shareholder seeking to sue derivatively on behalf of a company such as BP must first win permission from the English High Court, BP's lawyers contend in their Nov. 16 argument.

Three cases in one

After the Gulf disaster, plaintiffs identifying themselves as BP shareholders filed a series of lawsuits in Anchorage against BP board members and executives, including the company's former chief executive, Tony Hayward, and John Minge, president of BP Alaska.

Jeffrey Pickett, an Alaska resident, filed the first suit. A couple of city pension funds in Florida brought two more suits. Law firms including Ashburn & Mason of Anchorage and class-action specialist Robbins Geller Rudman & Dowd of San Diego brought all three suits.

In September the suits were consolidated into a single case.

Suing derivatively on behalf of BP, the shareholder plaintiffs seek compensatory and punitive damages, plus improved safety and environmental compliance.

While the case largely focuses on Deepwater Horizon, it also delves into pipeline leaks and other problems in BP's North Slope operations, as well as the deadly Texas City refinery explosion in 2005, as evidence of "gross mismanagement."

Arguments for dismissal

By alleging BP safety violations in Alaska in a suit mostly about the Gulf disaster, the plaintiffs are making "a transparent attempt to manufacture a 'local' element to this action," BP's lawyers argue.

The case should be dismissed, they say, because an Alaska court is not the right forum for a shareholder derivative case involving a company incorporated under the laws of England and Wales.

An English law, the Companies Act 2006, holds that a shareholder seeking to sue derivatively on behalf of a company such as BP must first win permission from the English High Court, BP's lawyers contend in their Nov. 16 argument.

They note that few of the plaintiffs or defendants are residents of Alaska, adding: "The conduct that gives rise to this action — the alleged breach of fiduciary duties and corporate mismanagement — did not occur in Alaska, but rather in London where BP is headquartered."

A BP shareholder derivative lawsuit was brought previously in Anchorage, in 2006, following oil pipeline spills that year in the Prudhoe Bay field. But the case was settled before the state Supreme Court could decide the question of whether it could proceed in Alaska, BP's lawyers say. ●

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● GOVERNMENT

BP Alaska accused of probation violation

Failure to heed warnings on frozen pipe led to rupture, shows negligence, federal official says; extended probation, fine possible

By WESLEY LOY
For Petroleum News

BP Exploration (Alaska) Inc. has a Dec. 20 court date to answer an accusation that it violated its criminal probation imposed after the Prudhoe Bay pipeline spills of 2006.

The company's federal probation officer, Mary Frances Barnes, on Nov. 17 petitioned the U.S. District Court in Anchorage for a summons for BP.

Barnes believes the company committed violations of its three-year term of probation, which was to end on Nov. 28. She's recommending the probation be revoked.

Ruptured pipeline

The violations, Barnes says, center on an incident in November 2009 when a pipeline carrying a warm mixture of crude oil, produced water and natural gas from wells to the Lisburne Production Center ruptured, discharging about 13,000 gallons of oil onto the tundra.

The pipeline, 18 inches in diameter, was looped with a 24-inch pipeline, "meaning that both lines carried the same fluids from a common source to a common endpoint," the court petition says. The 24-inch line did not rupture.

At some point in late May of 2009, flow in the 18-inch line slowed or stopped completely while flow in the larger pipe continued. Later, warning alarms consistently registered low temperatures for the 18-inch line, but BP operators "failed to respond to the alarms and failed to investigate or troubleshoot the cause of the alarms," Barnes wrote. The alarm setting for the pipeline's surface-mounted temperature sensor was set to "informational," a low-priority status indicating to workers that a response was not required.

Around Nov. 14, 2009, after 165 days of low-temperature alarms, BP determined that an ice plug or hydrate blockage had developed in the pipeline. About two weeks later, a BP operator driving along the elevated line discovered a rupture, the petition says.

The formation and expansion of the ice or hydrates overpressured the line. "In effect, the pipeline exploded," Barnes wrote, opening a jagged hole about 2.75 feet long and 1.46 feet wide, the petition says.

BP had experienced a similar rupture in frozen looped pipelines on the North Slope in 2001 and made recommendations to prevent a recurrence. But in its internal investigation into the 2009 rupture, BP "acknowledges that it failed to implement these preventative measures."

BP's failure to follow its own preventative measures, and its lack of response to the low-temperature alarms, constitutes criminal negligence, Barnes wrote.

Fine, more probation possible

In late 2007, BP Alaska was sentenced to three years on probation and ordered to pay millions in fines and restitution after pleading guilty to a misdemeanor pollution violation in connection with a Prudhoe pipeline leak that allowed 212,252 gallons of crude to spill. BP was accused of neglecting the pipeline, allowing corrosion to spread.

Steve Rinehart, BP spokesman in Anchorage, had little to say about the alleged probation violation.

"We will respond in court in due course," he told Petroleum News. He did say the company distributed a "safety bulletin" to workers after the 2009 pipeline rupture explaining what went wrong.

An official in the U.S. attorney's office explained the court could take essentially three actions in response to Barnes' filing. The judge could continue BP's probation, perhaps with new conditions attached. He also could fine the company. Or, it's possible the judge will do nothing if BP can successfully challenge the allegation. ●

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EXPLORATION & PRODUCTION

US rig count decreases by 8 to 1,677

The number of rigs actively exploring for oil and natural gas in the U.S. decreased by eight the week ending Nov. 19 to 1,677.

Houston-based Baker Hughes Inc. said 936 rigs were exploring for natural gas and 731 for oil. Ten were listed as miscellaneous. A year ago this week, the rig count stood at 1,113.

Of the major oil- and gas-producing states, Texas gained seven rigs and Arkansas, Colorado and North Dakota each gained two. Oklahoma lost eight rigs, Louisiana lost five, New Mexico and Pennsylvania each lost three and Wyoming lost two. Alaska, California and West Virginia remained unchanged.

The rig count tally peaked at 4,530 in 1981 and fell to a record low of 488 in 1999.

—THE ASSOCIATED PRESS

● PIPELINES & DOWNSTREAM

Alaska regulators OK tariff settlement

After 259 percent rate increase provokes a fight, Cook Inlet Pipe Line Co. and small oil producer Cook Inlet Energy talk it out

By WESLEY LOY
For Petroleum News

A dispute over a sharp hike in the cost to ship oil through a pipeline along Alaska's Cook Inlet has ended peaceably with a settlement.

The Regulatory Commission of Alaska blessed the settlement with a Nov. 19 order accepting the deal between Cook Inlet Pipe Line Co. and small oil and gas producer Cook Inlet Energy LLC.

The settlement ends a dispute raised after CIPL filed a 259 percent rate increase for 2010, pushing its rate from $4.06 per barrel of oil to $14.57.

The RCA allowed the higher rate to take effect at the start of the year, but only temporarily and subject to refunds.

Cook Inlet Energy, which operates wells on the western side of Cook Inlet, complained the rate hike was excessive. But CIPL said it was reasonable, blaming the increase on reduced throughput and damage to its system resulting from eruptions of Redoubt volcano in 2009.

Five-year deal

Early on, the dispute between CIPL and Cook Inlet Energy was pretty testy.

Cook Inlet Energy complained the timing of the rate hike was terrible, as the newly formed company had only acquired its oil and gas properties in late 2009. It filed a formal protest calling the increase "excessive, unjust, and unreasonable."

But CIPL argued it operated "a very small pipeline … on nearly a non-profit basis." The company added it had "no responsibility to subsidize" Cook Inlet Energy's oil field investment.

With the help of a settlement judge the RCA appointed, the two sides negotiated over several months and ultimately reached the agreement.

Under the five-year deal, Cook Inlet Energy will pay CIPL a rate of $8 per barrel for the remainder of 2010. In coming years, the rate will be determined by dividing CIPL's agreed annual revenue requirement of $17.28 million by the total number of barrels shipped through the pipeline.

As part of the settlement, Cook Inlet Energy will pay CIPL to transport at least 260,063 barrels of oil in 2010 and 346,750 barrels each year thereafter, regardless of whether it actually ships the volumes.

CIPL, partly owned by Chevron subsidiary Unocal, runs a 42-mile pipeline on the west side of Cook Inlet between Granite Point and the Drift River Oil Terminal, where tankers load.

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

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ANWR ADVICE

anniversary and asking Obama to "grant the Arctic Refuge the strongest possible protections."

All the senators are Democrats with the exception of the first signer, Sen. Joe Lieberman, a Connecticut independent. Other signers included Sen. Mark Udall of Colorado and both senators from Washington state, Patty Murray and Maria Cantwell.

"The Arctic National Wildlife Refuge is truly one of America's greatest wild places," the letter says. "Its Coastal Plain hosts an amazing diversity of wildlife including polar bears, grizzly bears, muskoxen, wolverines, and over a hundred thousand caribou. This 'biological heart' of the Refuge is connected to the entire country, as well as to countries all around the world. Every year, birds that begin their lives on the Coastal Plain migrate to all 50 states and across six continents, before heading back to the Arctic, where the cycle of life begins again."

Language in the letter mirrors that in a Nov. 18 letter environmental groups sent Obama.

Alaska's senators, Republican Lisa Murkowski and Democrat Mark Begich, immediately ripped the letter from their Senate colleagues.

"We've seen proposals to lock up ANWR before and they all share a total disregard for our nation's energy security and economic responsibilities," Murkowski said in a Nov. 19 press release. "When a small area in Alaska holds the promise of being able to produce a million barrels of oil a day, it's irresponsible to suggest permanently barring access to that resource."

The focus, said Begich, should be on using directional drilling to tap ANWR with minimal surface disturbance and cutting U.S. dependence on foreign oil, not writing letters painting the refuge as "this last bastion of wilderness."

Murkowski is the ranking Republican on the Senate Energy and Natural Resources Committee.

"The vast majority of ANWR is already off limits to development," Begich said. Lieberman and others are just trying to appease environmentalists, he said.

The focus, said Begich, should be on using directional drilling to tap ANWR with minimal surface disturbance and cutting U.S. dependence on foreign oil, not writing letters painting the refuge as "this last bastion of wilderness."

The U.S. Fish and Wildlife Service, which manages the refuge, has said it might recommend new wilderness designations for ANWR including the highly prospective coastal plain. Any new wilderness would need congressional approval.

But presidents can, and often do, declare national monuments, and this could doom ANWR drilling just as wilderness designation would.

—WESLEY LOY

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ESCOPETA

two decades, allowing for drilling of several underexplored offshore Cook Inlet prospects, including its prospects in the Kitchen Lights unit.

Davis said the day-rate on the Spartan rig is low — "much less than $100,000" — and that his contract gives him the option to buy the rig.

State gives Escopeta green light

The status of the Kitchen Lights unit is just as critical to Escopeta's plans as securing funding and a rig.

The state placed the unit in default in July, a ruling Escopeta appealed in September.

Since Escopeta filed its appeal, the deadline to cure the default passed, and so Escopeta recently asked the Alaska Superior Court for a stay until the matter is resolved.

With its drilling program now funded and contracted, the company asked the state to lift the default and increase by one month the timeline for drilling deadlines approved in July.

According to Kevin Banks, director of the state's Division of Oil and Gas, the default has been lifted and the new deadlines approved.

Banks told PN Nov. 23, the state "has a signed agreement with Escopeta that basically says we withdraw our default and Escopeta withdraws its litigation."

The default was withdrawn "as of today."

The state took the action based on "several representations by Escopeta," including Escopeta "having a contract with Spartan Offshore Drilling, Escopeta preparing to enter into a heavy life vessel contract, and having $15 million on deposit in a U.S. bank account."

Banks, who has seen a copy of the Spartan contract, said the state recently "received a letter from a Texas bank saying that Escopeta had the money. He (Davis) says he will be obtaining additional funding if we withdraw the notice of default, which we have."

Per the agreement, Escopeta "has to have a drilling rig mobilized, under way, by March 30, 2011, … and has until Oct. 31, 2011, to drill its first well," Banks said.

Escopeta, Davis said, will need help from the state to make sure the company gets the rest of the state and federal permits it needs to drill: "We have everything except the spill plan and rig-specific permits, but once we get the rig to Alaska we don't want it sitting around waiting."

A gas bonanza?

The first well Escopeta plans to drill is Kitchen Lights Unit No. 1, located northwest of the SRS No. 1 well that Shell drilled in 1962 to a total depth of 16,375 feet.

The 83,394-acre Kitchen Lights unit includes Kitchen, East Kitchen and two other prospects, Northern Lights and Corsair.

Davis believes the Kitchen and East Kitchen prospects might contain 7.5 trillion cubic feet of natural gas and 1.7 billion barrels of oil.

Those estimates, if correct, would make Kitchen Lights the largest Cook Inlet gas and oil play. The gas estimate alone is similar to the recoverable natural gas reserves that ExxonMobil estimates it has in its Point Thomson field, the second largest known gas deposit on Alaska's North Slope.

Escopeta plans to drill 16,000-17,000 feet into the Jurassic. The company needs to drill into a pre-Tertiary zone, such as the deep Jurassic, to take advantage of tax credits available from the state. That depth would allow Escopeta to test both the gas and the deeper oil potential of the region.

Jones Act waiver not deal-killer

To use the Dockwise vessel, Escopeta needs a waiver of the federal Jones Act, which requires goods bound for U.S. ports to be carried on ships flagged and built in the U.S.

Without a waiver, Escopeta would be forced to pay a fine, which is what Rowan, the last jack-up rig operator in Cook Inlet, did.

Escopeta received a waiver in 2006, during an earlier attempt to bring a jack-up rig to Alaska, but recently asked the Obama Administration to reaffirm that Bush-era document. The administration asked Escopeta to apply for a new waiver, which the company is doing. Regardless of the outcome of that new application, though, Davis noted that the 2006 waiver has "never been revoked or cancelled."

Banks sent a letter Nov. 23 to U.S. Immigration and Customs supporting Escopeta's application for a waiver.

The other jack-up

Escopeta is one of two companies trying to bring a jack-up rig to Cook Inlet.

The other, Buccaneer Alaska, wants the Alaska Industrial Export and Development Authority to issue a mix of bonds and financing to help buy, rather than lease the rig. (See related Buccaneer story on page 5 of this issue.)

There is an incentive for both companies to be the first to drill a well with a jack-up.

Under a new tax credit created this year, the first company to drill an offshore well in Cook Inlet using a jack-up rig would get 100 percent of its costs, up to $25 million, paid for by the state. The state would also pay for 90 percent of the second well, up to $22.5 million, and 80 percent of the third well, up to $20 million. The three wells must be drilled by three different companies, but must also be drilled using the same jack-up rig.

Therefore, if both Escopeta and Buccaneer successfully bring jack-up rigs to the Cook Inlet, only the first company to drill a well would be eligible for the tax credit.

Currently, Escopeta plans to begin drilling in April while Buccaneer plans to drill by July. ●

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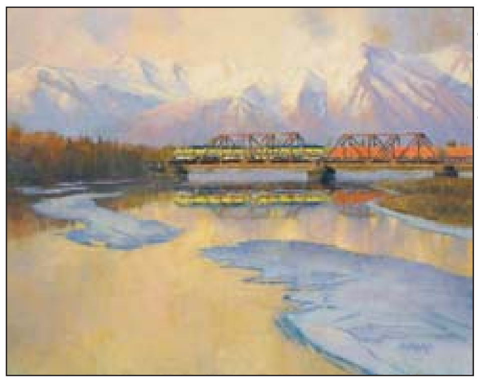
Petroleum news

Oil Patch Bits

AKRR sets annual print sale and signing event



ALASKA RAILROAD

The Alaska Railroad said Nov. 17 that it will release its 2011 annual prints and posters during two public sale-and-signing events in December, each featuring artist Douglas Girard who will be on hand to sign the prints and posters.

Both events will be held from 10 a.m. to 2 p.m., the first one at the Anchorage Historic Depot, Saturday Dec. 4 and the second at the Fairbanks Depot Saturday Dec. 18. Entitled Northbound Over the Matanuska Bridge, the artwork depicts a freight train crossing the rail bridge over the Matanuska River. Girard says he was inspired by a scene that he passes almost daily during the commute from his home in Palmer to work as a graphic artist in Anchorage. The 2011 Alaska Railroad print costs $55, posters cost $30 and pins cost $5. Following the signing events, prints, posters and pins will remain on sale at the Anchorage Historic Depot and the Fairbanks Depot, and may also be purchased online via the Alaska Railroad Gift Shop website at www.AlaskaRailroadGiftShop.com/.

Solstice names O'Toole account tech, receptionist

ELIZABETH O'TOOLE

Solstice Advertising, an Anchorage-based full-service advertising agency, said Nov. 11 it recently underwent a significant expansion and is pleased to announce the addition of Elizabeth O'Toole as accounting tech and receptionist. O'Toole holds a BA in business management with an emphasis in accounting from Charter College in Anchorage. She is also a Level 3 certified tax advisor with years of experience preparing tax documents for H&R Block. Though she loves working with numbers, she also has a strong desire to work with people, which makes her a perfect fit at Solstice, where she will be juggling numbers and customer relations every day.

Iditarod announces Donlin as sponsor of 2011 race

The Iditarod Trail Sled Dog Race said Nov. 16 that Donlin Creek LLC is a Principal Partner

see **OIL PATCH BITS** *page 14*

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

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

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NIKAITCHUQ

we were sitting in the back of the bus, anxious to learn how to do projects in Alaska," he said.

Then in 2007, Eni acquired Kerr-McGee's 70 percent interest (Kerr-McGee had been acquired by Anadarko Petroleum in 2006).

Eni plans 52 wells at Nikaitchuq, 26 producers, 21 water injectors, three water source wells and two disposal wells, with 22 wells planned onshore and 30 offshore.

Nikaitchuq has facilities onshore at Oliktok Point and offshore at a drilling island, with the processing facilities at Oliktok Point.

"The facilities that we built are for 40,000 barrels a day notionally of viscous crude and they employ a lot of technology tha t you don't find in the normal production and processing facility," Moles said.

Production drilling has begun onshore and the civil work is complete at the offshore drilling pad, including foundations for the modules that will be installed later.

Drilling challenge

Moles said drilling at Nikaitchuq is a challenge because the reservoir is about 4,000 feet true vertical depth with targets at some distance from the drilling pads.

Referring to an illustration comparing vertical depth to step out — the distance from the drilling pad to the target — Moles said "our drillers are going to be doing some world-class wells in a marginal field at very shallow depths to produce cold viscous crude."

There are about 45 people in Eni's local office, Moles said, "and for a $2 billion project, that's not a lot of people; and these guys work selflessly and have done a great job getting us to where we are."

Eni also has 42 people on the North Slope managing construction.

"And then of course we're supported by the other 560 contract staff that are up there every day living in our camp, putting the thing in."

Nikaitchuq will be produced with waterflood, using water from the Ivishak formation and produced water. That Ivishak water is 185 to 200 degrees, Moles said, and will be used for waterflood, but will also be mixed with the crude oil coming back from offshore "because the crude's about 87 degrees" and for it to move through the subsea pipeline to the processing facility "it needs some energy and some temperature to ensure the flow."

Heaviest flowline bundle

The flowline bundle between the offshore drilling pad and shore includes an outgoing pipe to take water to the drilling pad, a line for diesel for the rig and cables for power and fiber optic, he said.

When development was being discussed there were some who favored using the natural Spy Island so Eni wouldn't be putting another island in the Beaufort; others argued that Spy Island should be left in its natural state.

"We chose to keep it off the island and keep it far enough away that we wouldn't induce any currents that would erode the island," Moles said.

The offshore flowline bundle was installed in 2008 and the onshore flowline in 2009.

Liquids move to and from the island in a "pipe in a pipe: That helps us with some heat retention and some capability for leak detection," he said. While the pipe in a pipe "was quite a challenge … it gives us a second barrier to the sea."

Hot water goes out to the drilling pad in a concrete-coated pipe.

Moles said the pipe bundle to the offshore drilling pad is only 3.8 miles long, not the longest ever installed, "but it's by far and away the heaviest bundle that's been installed in the Arctic."

Well containment shelters

Like Oooguruk, where Eni is a partner to field operator Pioneer Natural Resources, Nikaitchuq has well containment modules, so that any spills during drilling are "captured by the shelters and

see **NIKAITCHUQ** *page 14*

Eni gets Schrader Bluff pool rules

The Alaska Oil and Gas Conservation Commission has issued pool rules for the Schrader Bluff oil pool at Nikaitchuq.

While initial wells are being drilled from a drilling pad at Oliktok Point, the entire Nikaitchuq unit is offshore in East Harrison Bay, approximately centered around Spy Island.

The commission said the Nikaitchuq Schrader Bluff oil pool is the accumulation of hydrocarbons correlating to the interval between the measured depths of 3,530 and 3,867 feet in the Kigun No. 1 well southwest of Spy Island.

The Nikaitchuq Schrader Bluff includes two sands, OA (3,780 to 3,822 feet in the Kigun well) and N (3,627 to 3,663 feet); only the deeper OA sand will be developed initially.

"Four distinct lobe deposits are currently interpreted by the operator, and these lobes are separated by layers of siltstone, calcite-cemented siltstone, or mudstone. The OA and N sands appear to persist through the Nikaitchuq Unit," the commission said in its Nov. 19 order.

Gross thickness for the OA sand ranges from 30 to 40 true vertical feet.

OA sand

API gravity for the OA sand varied from 16 degrees API to 19 degrees in samples from four wells.

Original oil in place for the OA sand is estimated at 800 million to 930 million barrels, with 4-5 percent (30-45 million barrels) estimated recoverable through primary recovery, and 120 million to 200 million barrels estimated recoverable through primary and waterflood, a total of 15 to 22 percent of original oil in place.

The commission said production over a projected life of 30 years is expected to average some 7,000 barrels per day, with a peak production rate of about 28,000 bpd and 2.2 million cubic feet of gas per day early in the project life.

The N sand reservoir is estimated to contain between 300 million and 600 million barrels and "may be developed later depending upon drilling results," the commission said.

Twenty-six production wells are planned, with the horizontal sections of the wells ranging from 4,000 to 8,500 feet within the reservoir. Producers will alternate with injectors "in a line-drive flood pattern flanked by outboard production wells."

—KRISTEN NELSON

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NIKAITCHUQ

that liquid can be put back into the system."

Because Nikaitchuq will use waterflood, Moles said it's "going to be a large water cycling project."

The processing facilities are designed to handle 40,000 bpd of crude oil, but will circulate 100,000 to 120,000 bpd of water at peak, water used to "sweep what oil we can out of the reservoirs after the early flow."

The project includes two grind and inject facilities, a permanent one onshore and a temporary one on the offshore drilling island.

Moles said that initially the facilities will grind and inject cuttings from the drilling rig, "but in the long term, we're not managing sand downhole; we're bringing the sand to the surface."

"Sand's maybe a misnomer — it's more like a heavy flour. And that will be accumulated in the process facilities, managed," and sent to the grind and inject facility to be further pulverized and re-injected, he said.

Offshore next

A rig has been contracted for the offshore drilling pad and that will go offshore next summer, Moles said. Drilling of the offshore wells will continue into 2014.

Onshore modules are in place — two large modules built in Louisiana, one the processing facilities and the other the utilities. In addition, Moles said, "we had a very large number of pipe rack and other process modules built here in Alaska."

The offshore drilling pad will have quarters for 120 and power distribution for the wells.

All the wells require electric submersible pumps, he said: "These wells won't flow without some help. So we have a large power and management distribution component in this development."

Onshore modules are in place — two large modules built in Louisiana, one the processing facilities and the other the utilities. In addition, Moles said, "we had a very large number of pipe rack and other process modules built here in Alaska."

All of the offshore modules are being built in Alaska, and those are now being built at local fabrication shops. ●

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FINANCE & ECONOMY

Oil rises to near $82 amid mixed signs

Oil prices rose slightly to near $82 a barrel Nov. 24 in Asia as an upward revision of U.S. economic growth and a report showing an unexpected jump in crude inventories provided mixed signals on demand.

Benchmark oil for January delivery was up 37 cents to $81.62 a barrel at mid-day Singapore time in electronic trading on the New York Mercantile Exchange. The contract lost 49 cents to settle at $81.25 on Nov. 23.

The American Petroleum Institute said Nov. 23 that crude inventories rose 5.2 million barrels the week ending Nov. 19 while analysts surveyed by Platts, the energy information arm of McGraw-Hill Cos., had forecast a drop of 1.9 million barrels. Inventories of gasoline and distillates fell, the API said.

Oil prices were supported by an upward revision of third quarter gross domestic product growth. The Commerce Department said Nov. 23 that the economy expanded at a 2.5 percent annual rate in the July-September quarter, up from the 2 percent pace initially estimated.

"The better than expected GDP figures that can easily conjure up ideas of stronger than expected oil demand growth," Ritterbusch and Associates said.

In other Nymex trading in December contracts, heating oil rose 1.2 cents to $2.26 a gallon and gasoline added 1 cent to $2.14 a gallon. Natural gas was down 1.2 cents to $4.25 per 1,000 cubic feet.

In London, Brent crude rose 33 cents to $83.58 a barrel on the ICE Futures exchange.

—THE ASSOCIATED PRESS

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OIL PATCH BITS

sponsor of the 2011 Last Great Race, contributing $285,000 to the historic event. Donlin and Iditarod representatives were present at the Resource Development Council's conference to officially announce their joint efforts in support of this cherished Alaska tradition. A sponsorship ceremony was held Nov. 17 in the Donlin Creek booth in the Dena'ina Civic and Convention Center.

"Donlin Creek is proud and honored to now be part of the Iditarod family with this contribution to the historic race," said Doug Nicholson, general manager of Donlin Creek LLC.

Both mining and mushing have been historically tied throughout Alaska's heritage. On the first Saturday of March every year, teams from all walks of life begin the 1,049 mile trek to Nome on the Iditarod Trail and will pass through some of Alaska's most scenic panoramas along the Kuskokwim River.

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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HOPE

prices in Alberta, Canada, will climb to somewhere between $5 and $7 per thousand cubic feet by 2020, with prices continuing to climb thereafter. And with a possible fee of $3.50 per thousand cubic feet for treating North Slope gas and carrying it by pipeline to Alberta, those gas prices could make a North Slope gas line viable, Antony Scott, a commercial analyst with Alaska's Division of Oil and Gas, told Petroleum News Nov. 22.

DNR wanted an authoritative set of data, against which to benchmark the gas line project and had obtained funding from the Alaska Legislature for the Black & Veatch study, said Mark Myers, Alaska Gasline Inducement Act coordinator.

"This is a very robust study," Myers said. "It's like no other study we've seen out there in the literature."

And Scott emphasized that the study tried to be unbiased in its views of future gas markets and, if anything, had underestimated the future cost and pricing of shale gas.

Technical breakthrough

Shale gas technology involves the extraction of natural gas from the impervious rocks where gas forms, rather than using the conventional approach of drilling into porous and permeable reservoir rocks that have trapped gas as it bubbles through subsurface rock strata. The use of high-tech horizontal drilling techniques that allow a well bore to pass for long distances through a shale gas horizon, coupled with the use of water and chemicals to fracture the rock, thus releasing the gas from the rock lattice, have been key enabling technologies in shale gas development.

The coupling of technical breakthroughs in shale gas production with the realization that vast areas of gas shale underlie various regions of the United States and Canada has triggered the shale gas revolution and caused a massive uptick in estimates of North American natural gas resources.

However, despite much hype about shale gas, with implications of vast gas supplies at rock-bottom prices, shale gas development still only has about a 10-year track record, with most of that record relating to one shale unit, the Barnett shale in Texas, Scott explained.

"It's really important to recognize that outside of the Barnett we're in extremely early days of the shale gas story," Scott said.

But, after assessing various natural gas scenarios, the Black & Veatch analysts have concluded that shale gas production would figure large in any future North American natural gas supply situation.

"No matter what, there's an awful lot of shale gas that is going to be relatively inexpensive to produce," Scott said.

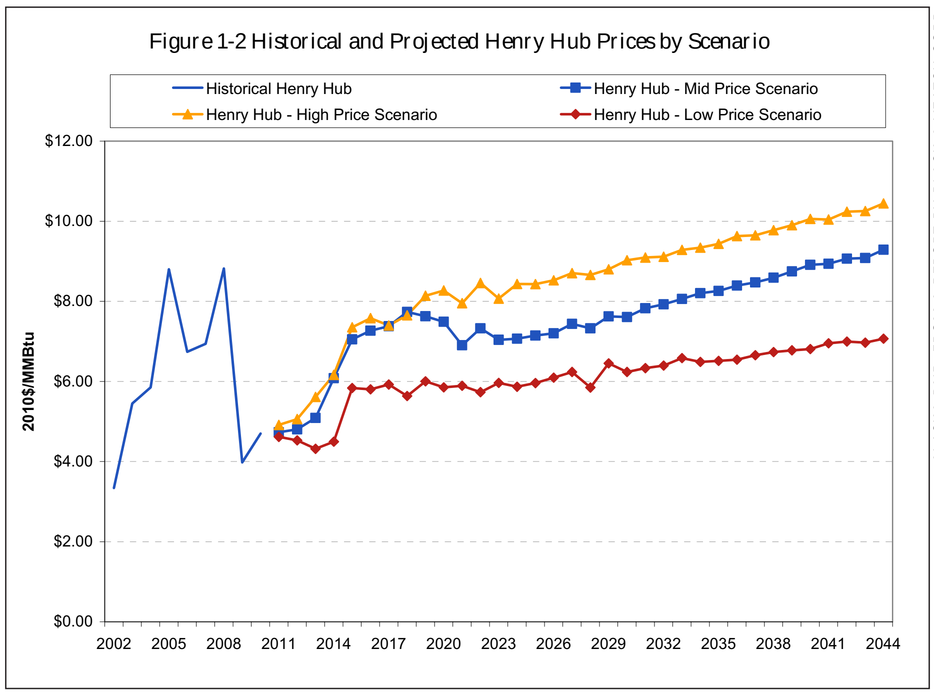
Price impact

The arrival of shale gas in the North American gas market, converting tightening production from conventional gas fields to a growing gas glut, caused gas prices that had climbed to levels approaching $8 per thousand cubic feet by 2008 to suddenly collapse, dropping to below $4 currently.

And the import of liquefied natural gas into the Lower 48, thought just a few years ago to be an inevitable growth industry as domestic supplies of natural gas decline, has now been pushed into the background.

"If you look at the price environment … it becomes hard to tell a story in which LNG finds an attractive home in North America," Scott said.

Key drivers behind Black & Veatch's view of future Lower 48 natural gas markets are the assumptions that the now-known abundant supplies of North American natural gas, coupled with an environmental preference for the use of gas rather than coal as a fuel, will push up the use of natural gas for electricity generation. On the other hand, while there are major uncertainties regarding future gas demand levels, there are also major uncertainties in estimates of the future costs of developing new shale gas resources.



ALASKA DNR, FROM A REPORT BY BLACK & VEATCH CORP.

Projected future Henry Hub natural gas prices from a new Black & Veatch assessment of the implications of shale gas development for North American gas pricing. The 2008 peak in historic prices was driven by tightening supplies of conventional gas resources, while the burgeoning shale gas industry caused the subsequent gas price drop. Black & Veatch thinks that cost and demand pressures will drive prices higher in the future, with prices reaching a range of $6 to $8 per thousand cubic feet at Henry Hub in 2020. The corresponding price range in Alberta would be $5 to $7.

For example, the supply of water for shale fracturing and the subsequent treatment and disposal of water produced from gas wells has represented a fairly modest cost element in the development of the Barnett shale, but will likely become a major cost factor in the development of shale gas in other basins.

Inconsistent data

But inconsistencies in the way in which finding and development costs for shale gas are reported make it difficult to assess whether those costs are compatible with current gas price levels, and Black & Veatch thinks that current prices may be artificially low.

"Current market prices for natural gas in North America may not provide adequate return for full development of shale resources in North America," the Black & Veatch report says. "Significant levels of current shale production appear to be driven by requirements to drill to maintain acreage positions."

Published shale gas finding and development costs in the Lower 48 range from $2.06 to $2.35 per thousand cubic feet, but these numbers do not appear to include factors such as land lease costs and water costs. Estimated costs of $3.25 to $4.25 per thousand cubic feet in western Canadian basins are likely nearer the full cost, although there are differences between cost reporting rules in Canada and the United States, Black & Veatch says.

And an examination of the production history of the Barnett shale provides some revealing insights into possible future shale-gas cost trends.

Essentially, Barnett shale production has seen a series of significant technical breakthroughs, each of which has caused a sudden jump in gas production. But the rate of increase in production has dropped back sharply after each technology-induced spike. And, contrary to popular belief, the cost of finding and developing additional volumes of Barnett shale gas appears to have increased rather than decreased over time.

Rising cost

The explanation for this conundrum seems to lie in the production characteristics of shale gas resources. In essence, a shale gas well achieves high initial production rates as the fractured shale rapidly releases its gas content. But, with the rock being relatively impermeable, that initial production rate drops off quite rapidly, requiring increasing effort to stimulate existing wells and the drilling of new well bores to sustain overall production levels.

The result is a production cost profile that curves upwards as more and more of the gas resource is accessed, until a law of diminishing returns places an upper cap on the total volume of gas that can be viably extracted from a particular shale gas resource, the Black & Veatch analysts concluded.

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HOPE

Recognizing the importance of individually considering the unique characteristics of each shale gas basin, the Black & Veatch analysts applied the upward curving cost model to each of the various U.S. and western Canada basins, to assess future gas production costs in different basin scenarios. Estimated water costs factored high in the distinctions between the scenarios — potential situations ranged from unlimited water access and the disposal of untreated water down wells, as for a Barnett shale development, to limits on water supplies and the need for the treatment of produced water, as would be required for developments in the Marcellus shale in Pennsylvania.

Additional costs, all subject to significant uncertainty and regional variation, include land access and government taxes.

Rising demand

But future demand for natural gas in North America should support the anticipated gradual rise in shale gas costs.

Black & Veatch has its own Lower 48 gas demand forecast that assumes gas demand for electricity generation will rise at an annual rate of 3.2 percent, with greenhouse gas regulation tending to drive the replacement of coal-fired generating capacity by gas-fired power plants. In 2010 the Energy Information Administration, apparently barred from considering potential changes in government energy policies, came up with a lower growth rate of 0.5 percent, on the assumption that there would be no future restrictions on greenhouse gas emissions.

And although the Black & Veatch projection of total demand from all uses of gas through to 2035 also exceeds the equivalent EIA projection, the Black & Veatch projection is "within the fairway" of several independent gas demand forecasts, Scott said.

"Power generation demand is going to be a really big story," he said. "It's going to matter a lot."

Then, when it comes to the interplay between gas costs, gas demand and gas prices, the actual level of gas demand and the actual finding and development costs would appear to be the likely dominant future drivers of gas prices. And Black & Veatch assembled low, medium and high gas price scenarios, using a standard North American gas model to project, for each scenario, likely annual gas prices at different market hubs, together with likely annual production volumes from each shale gas basin, through to 2040.

Price scenarios

The low-price scenario assumes the relatively low EIA projection of future gas demand, together with low water costs; low finding and development cost escalation, along the lines of conventional gas fields; and modest tax rates. The medium-price scenario uses Black & Veatch's shale-gas cost escalation model, together with Black & Veatch's projection of future gas demand. The high-price scenario adds in increased environmental restrictions over access to shale gas resources, somewhat higher tax rates and relatively high water costs.

The low-price and high-price scenarios projected into 2020 result in the $5 to $7 per thousand cubic feet price range that may come into play in Canada at around the time when completion of a North Slope pipeline could be in the offing.

"Except in very extreme events we believe the Alaska (gas line) project — given what we know about the tariff structure today, the cost of producing gas at Prudhoe and Point Thomson — it looks like it should work," Myers said. ●

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GAS EXPORTS

period.

Expansion out of Rockies

But the immediate concern stems from expansions of pipeline systems out of the U.S. Rockies region.

The opening next summer of El Paso's Ruby pipeline to Malin, Ore., will see Rockies producers take a slice of the Canadian baseload market in California.

TransCanada's Bison pipeline from the Powder River basin in Wyoming to the company's existing Northern Border system in North Dakota will also claim about 400 million cubic feet per day of the Midwestern markets, taking a portion of the Venture, Iowa, market away from Canadian suppliers, Bentek says.

A looming flood of production from the Marcellus shale in the Appalachian basin has triggered a number of U.S. Northeast pipeline expansions, many designed to ship gas directly to Ontario, a mainstay of TransCanada's 4 bcf per day mainline system.

Bentek says this "big squeeze" will have severe impacts on U.S. and Canadian flows, base relationships and ultimately on the Canadian supply and demand balance.

The firm predicts that Canadian production will drop by almost 1 bcf per day over the next five years as unconventional production growth from the Montney and Horn River shale plays in British Columbia fail to counter significant declines in conventional volumes from Alberta.

Changes in prices, flow patterns

By increasing takeaway from the Rockies directly to California and the Midwest markets, the Ruby and Bison pipelines will change prices and flow patterns across the West and deep into Canada, it says.

By next summer, Rockies producers will have an incremental 1.5 bcf per day of westbound capacity on Ruby, which will compete directly against Pacific Gas and Electric's premium market in the West.

NEB statistics for the first eight months of 2010 estimated Canadian exports to the California market of 342 bcf, up 89 bcf from the same period of 2009.

Overall exports from Canada have been flat compared with 2009 at about 7 bcf per day.

Bentek says Marcellus production has already started redirecting Canadian imports out of the region and planned pipeline expansions will have capacity for 14 bcf per day to support further growth of the Marcellus play and other unconventional plays in the Southeast-Gulf of Mexico and Rockies.

Greg Lohnes, president of natural gas pipelines at TransCanada, told investors it is "very difficult to build new infrastructure," but his firm has existing depreciated infrastructure which allows it to "move gas an awfully long way for what it costs to build a very short pipeline through a very congested area." ●

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