Looking for more

ConocoPhillips works base production at Kuparuk; 3-D to identify targets

By KRISTEN NELSON
Petroleum News Editor-in-Chief

Development at West Sak, the heavy oil accumulation at the Kuparuk field on Alaska’s North Slope, is in the news a lot these days (see story and maps in E&P section of this issue), but Kuparuk operator ConocoPhillips Alaska is also doing some innovative work to find oil targets at the field’s main reservoir.

The development team at Kuparuk is responsible for new developments such as West Sak, Matt Fox, ConocoPhillips Alaska greater Kuparuk area development manager, told Petroleum News in mid-December, but the team doesn’t “take our eye off the base production.”

Production from the main Kuparuk reservoir is some 150,000 barrels per day, Fox said, with the rest of the production coming from West Sak. Tar, Melwater and Tabasco. Alaska Department of Revenue figures show total production from the field for December averaged 198,179 bpd.

Production at Kuparuk, the second largest field on the slope after Prudhoe Bay, began in 1981. As of November, the most recent month for which data is available from the Alaska Oil and Gas Conservation Commission, 1.97 billion barrels had been produced from the main reservoir.

**Better bet for B.C.**

Oil sands pipelines, LNG terminals hold more immediate promise than offshore oil and gas development; Enbridge, Terasen in tight race

By GARY PARK
Petroleum News Calgary Correspondent

For all the huffing and puffing over the uncertain future of offshore oil and gas development, Enbridge Energy’s Rupert or Kitimat, while two little-known companies are vying for rights to build a liquefied natural gas receiving terminal in the same area.

With a candor that is rare among industry executives, Enbridge President and Chief Executive Officer Pat Daniel, although confident his company has an edge over Terasen, conceded to the Globe and Mail that the battle for the hearts and wallets of shippers and

**Gulf’s Blackbeard wildcat**

well headed to 32,000 feet

Searching for deep gas in structure possibly as large as the state of California

By RAY TYSON
Petroleum News Houston Correspondent

Perhaps the most closely watched exploration well of the New Year is about to begin an arduous six-mile journey that if completed would rank it among the deepest wells ever drilled on Planet Earth.

Owners of the Blackbeard prospect, situated in the relatively shallow waters of the Gulf of Mexico’s continental shelf, have finally selected a date and location to launch drilling: Jan. 15 on South Timbalier block 168.

“We’d love to see it work,” quipped Steve Rowan plans to use its newest rig, the Tarzan jack-up class Scooter Yeargain, for the Blackbeard project

COURTESY ROWAN
ON DEADLINE

Crude futures fall on rising U.S. supplies

By BRAD FOSS
Associated Press Business Writer

Crude oil futures prices fell Jan. 5 after the U.S. government reported larger-than-expected increases in winter fuel supplies, sending heating oil prices tumbling.

Light sweet crude for February delivery dipped 52 cents to settle at $43.39 per barrel on the New York Mercantile Exchange, where heating oil futures fell 2.82 cents to $1.2184 per gallon. Brent crude was down 53 cents at $40.51 a barrel on London’s International Petroleum Exchange.

The U.S. Energy Department’s statistical arm reported Jan. 5 that supplies of distillate fuel, which include heating oil and diesel, grew by 2 million barrels last week to 121.1 million barrels. It was a sharply higher increase than was expected, though it still leaves inventories 11 percent below year ago levels, according to the Energy Information Administration. High-sulfur distillates used for heating oil increased by 1.2 million barrels to 50.1 million barrels, about 9 percent below year ago levels.

Northeast not as cold as feared

The tight-but-growing supply of heating oil comes as winter weather in the U.S. Northeast, the main consuming region, has not been as cold as originally feared.

“Their story is on the slip. I’m not willing to fly that flag any more in the province,” said the short-fused Williams.

Flags down, swimsuits off in royalty feud

THE CANADIAN FLAGS ARE DOWN

By BRAD FOSS
Associated Press Business Writer

The American Stock Exchange, which produces less than 3,000 barrels of oil equivalent per day, is gearing up in royalty feud

The sticking point is Williams’ demand that the offshore revenues, projected to total billions of dollars, should be paid without any impact on federal equalization payments made to Canada’s economically weaker provinces.

To date, the region is producing oil from the Hibernia and Terra Nova fields, White Rose is due to start operations within a year. Hibernia sportswear company has even withdrawn a line of swimwear that resembles the Canadian flag.

“Those are some of the stories,” said the short-fused Williams.

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The American Stock Exchange, which produces less than 3,000 barrels of oil equivalent per day, is gearing up for what could be the first to leave.
State’s ANWR stratigraphic test well project alive and well

The state of Alaska’s plan to drill a stratigraphic test well offshore the 1002 area of the Arctic National Wildlife Refuge is “alive and well,” the governor’s senior adviser on energy, mining and the environment told Petroleum News Jan. 6. (See related stories on page 4 and page 14 of this issue.)

Mike Menge said Gov. Frank Murkowski had hoped to drill the well this winter but uncertainty around the presidential and U.S. Senate elections this past fall made oil companies wary about signing on to the project, which was designed to involve a consortium of companies with the actual drilling done by a division of ASRC Energy Services, a subsidiary of Arctic Slope Regional Corp. ASRC is the Native regional corporation for Alaska’s North Slope and is headquartered in Barrow.

“In my opinion, if the election this past fall had gone another way — if Bush and (Sen. Lisa) Murkowski had not been elected — then I think there would have been a very small chance of ANWR being opened,” Menge said.

“We only had one major company willing to sign up (before the election) but they were concerned about the opening of ANWR, … which looks a lot more likely now. … As we move closer to the opening I think we’ll see a lot more oil companies interested in joining” the drilling consortium, he said.

A well drilled offshore the eastern portion of ANWR’s coastal plain could provide valuable information about the geologic potential of both the coastal plain and offshore federal and state waters, Alaska Division of Oil and Gas Director Mark Myers told Petroleum News in a past interview.

“The governor wants to accelerate oil and gas exploration and development and this is just one part of that effort. This is an area that has been under-evaluated and this … well could provide the data, the catalyst for more frontier exploration,” he said.

—KAY CASHMAN
NEW ORLEANS

McMoRan acquires remaining interest In Gulf of Mexico production facility

Exploration and production independent McMoRan Exploration has agreed to acquire K1 USA Energy Production’s 66.7 percent interest in production facilities and related oil reserves on Main Pass block 299 in the Gulf of Mexico. McMoRan said Dec. 29 the deal gives McMoRan a 100 percent stake in the so-called K-Mc Venture. McMoRan said it will repay the venture’s $8 million debt and release K1 USA from its 29.3 percent interest in the so-called K-Mc Venture. The deal gives McMoRan a 100 percent stake in the so-called K-Mc Venture. McMoRan said it will repay the venture’s $8 million debt and release K1 USA from its 29.3 percent interest in the so-called K-Mc Venture. McMoRan said it will repay the venture’s $8 million debt and release K1 USA from its 29.3 percent interest in the so-called K-Mc Venture.

Oil production from Main Pass 299 is currently shut-in due to extensive damage caused by Hurricane Ivan last September to a third-party offshore terminal facility, which provided throughput services for Main Pass 299 sour crude oil. Before the hurricane, the Main Pass 299 field produced about 2,800 barrels of oil per day. McMoRan said it was evaluating alternative plans for the future sale of Main Pass 299 production.

WASHINGTON, D.C.

Greens claim credit for Conoco’s withdrawal from Arctic Power

This is a significant win for America’s Arctic, and we commend ConocoPhillips for listening to their shareholders and the American people and dropping out of Arctic Power. It appears that ConocoPhillips and BP are鼻子在 the coastal plain, “has implied the exact opposite. Both companies are currently drilling in the Arctic. What’s the difference between drilling in NPR-A,” where ConocoPhillips is currently exploring “and drilling in ANWR’s coastal plain? Physically and environmentally there is absolutely no difference at all.”

Hand was quick to point out that ConocoPhillips has been “a good supporter of Arctic Power over the years” and that Alaska employees of the company continue to be involved in the association. “This is a transparent effort on the part of the environmentalists to create a false impression of a lack of support in Alaska that coincides with the new Congress. It is a desperate grasp to change the focus from the issue of responsible development to the merits to something else.”

Hand said more than “75 percent of Alaskans support environmentally sensitive development of ANWR.”

Roger Herrera, Arctic Power

Kevin Hand, Arctic Power

PIRG targeting Chevron, Exxon

Since 1998, PIRG’s Arctic Wilderness Campaign and its partners have targeted four of the major oil companies that have expressed interest in drilling in ANWR. PIRG’s press release said the campaign has filed 15 shareholder resolutions and “generated more than 65,000 e-mails, phone calls, and letters” to BP, ConocoPhillips, ExxonMobil, and ChevronTexaco.

“Resolutions have also been filed this year at ChevronTexaco and ExxonMobil that ask each company to report on the risks of operating in sensitive areas such as the Arctic Refuge. These resolutions will be voted on at each company’s 2005 annual meeting.” PIRG said in its release.

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Don’t know about it? You should.

In 2005, Petroleum News is publishing the first comprehensive guide to Alaska’s oil and gas basins and business environment. The purpose of the guide is to give potential oil and gas investors the information they need to make investment decisions – or point to where they can find the information.

The 18 chapters include everything from securing leases to permitting to Alaska service company profiles. A chapter analyzing efforts made to reduce the ‘fear factors’ that underlie the belief you can find lots of oil in Alaska but you can’t make money there spawned the guide’s title, Dispelling the Alaska Fear Factors.

Guide Facts

- A draft online version of the guide will be posted at www.PetroleumNews.com/AlaskaFearFactors.pdf January 31, 2005
- First print edition and final online version will be released in late March 2005
- Purpose is to attract oil and gas companies to Alaska as operators or as partners to invest in Alaska projects
- Guide will be 8 & 1/2 by 11” with spiral binding
- Printed in full color, will include maps, well data, outcrops, etc.
- No ads in guide; companies will buy pages to run their profiles
- Guide will be free to all oil company and investment group employees
- Guide eBook on Petroleum News’ web page will be updated as needed
- Guide eBook will be posted on government and company web pages

Companies, Communities, Agencies Invited to Participate

- Oil companies, landowners can tout prospects, exploration and production success
- Service and supply companies can talk about their Alaska experience in a profile
- Communities can promote their advantages as a good place to live and work
- Government agencies can point to policies and programs of interest to industry

Want to Know More?
Contact: LAURA ERICKSON
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e-mail: lerickson@PetroleumNews.com

Alaska Fear Factors Staff

Kay Cashman  Laura Erickson  Alan Bailey

An annual publication Petroleum News 2005
HOUSTON

Contango to reap $50 million from Texas property sale

Contango Oil & Gas has completed the sale of nearly all of its South Texas natural gas and oil interests to independent Edge Petroleum for $50 million, the companies said Dec. 29.

Contango said that after adjustments it would net about $35 million in sale proceeds, adding that adjustments were made for taxes and net revenues that Contango received for production occurring after July 1, the effective date of sale, up to the closing date of Dec. 29.

The proceeds will provide working capital for ongoing operations and will allow Contango to continue investing in onshore exploration programs and to maintain its 10 percent limited partnership interest in the Freeport LNG plant, including any potential expansion in the plant's capacity.

Contango said it plans to participate in about 20 onshore wells in 2005, adding that sale proceeds also would enable the company to consider investing in offshore Gulf of Mexico exploration opportunities developed by its two partially owned subsidiaries, Republic Exploration and Contango Offshore Exploration.

—RAY TYSON

MIDLAND, TEXAS

Parallel expands stakes in West Texas fields

Parallel Petroleum has purchased an additional 13.2 percent working interest and 10 percent net revenue interest associated with the independent’s producing properties in the Means Queen unit and Contango’s San Andres fields in the Permian basin of West Texas, the company said Dec. 31.

The additional interests were purchased from 17 unaffiliated parties for a combined purchase price of about $2.85 million. The 17 purchases represent a combined estimated 500,000 barrels of oil equivalent of proved oil and gas reserves, with current production of roughly 50 barrels per day net to Parallel.

The properties are in Andrews and Gaines counties and produce from the Queen and San Andres formations at depths of about 4,200 to 4,900 feet, and consist of 25 leases covering about 5,160 contiguous acres, with 67 producing oil wells.

Parallel’s average working interest in the West Texas properties increased from 56.6 percent to 69.8 percent and the company’s average net revenue interest increased from 43.8 percent to 53.8 percent.

—RAY TYSON

* YELL O W SPR IN G S , O H I O *

Talk of oil decline moving into the mainstream

Hubbert theorized global oil would peak between 1990, 2000; experts disagree on when peak will occur; Ohio conference on peak oil aimed at laymen

By JAMES HANNAH

Associated Press Writer

Until about five months ago, Mel Hutto had never heard of “peak oil,” the belief that global oil production will decline and never return to the levels that have nourished American lifestyles.

Now the 66-year-old retired business consultant says he will change his lifestyle and campaign in his hometown of Bellingham, Wash., about the need to reduce reliance on oil.

“We’re going to be without oil. The whole industrial culture will at some point start breaking down,” said Hutto, who, out of curiosity attended a conference on the topic in the southwest Ohio town of Yellow Springs. “I tried to think this wasn’t real and wasn’t really going to happen.”

Talk of peak oil is moving from obscure energy workshops and technical journals into the social consciousness via books, National Geographic and other magazines and college curriculum.

“It is beginning to move more to the mainstream of public discussions,” said Frank Lard, associate professor of technology and public policy at the University of Denver’s Graduate School of International Studies. “There is a lot of unease about oil and energy.”

Oil experts divided

The notion began in the 1950s when geophysicist M. King Hubbert predicted that global oil production would peak between 1990 and 2000. The prediction — based on production profiles and estimates of oil reserves — was largely confined to scientific circles.

Paul Thiers, assistant professor of political science at Washington State University Vancouver, has added the topic to his natural resources class. He said the fighting in Iraq and rising gasoline prices are generating interest in the subject.

The world uses about 80 million barrels of oil a day, and consumption continues to increase. U.S. consumption alone is expected to grow nearly 50 percent in the next 20 years.

How soon production will begin to decline is dividing oil experts. Some believe it is imminent. They say discoveries of oil have slowed and that there is little left to be found. Others believe oil will be abundant for at least several decades and that new technologies to extract oil will help ensure plentiful supplies for a long time.

“I can’t deny it’s coming. What I do deny is it’s around the corner. It’s not peaking,” said Robert Ebel, a petroleum geologist and head of the energy program at the Center for Strategic and International Studies, a liberal-leaning village and home to Antioch College, which has a history of social activism and civil disobedience.

The main speaker, Richard Heinberg, believes oil production will peak within five years. Once production begins to decline, the oil-reliant U.S. economy will begin to shrink, and transportation, power and other oil-dependent products and services will become much more expensive, he said in an interview.

“It means the undermining of the whole way of suburban life that has been developed in America,” said Heinberg, who wrote “The Party’s Over,” a book describing the imminent decline of peak oil.

The conference was hosted by Community Service Inc., a Yellow Springs group founded in 1940 and dedicated to developing a nation where the population is distributed in small self-sustaining communities.

see DECLINE page 7

Tuntutuliak to Timbuktu

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GULF OF MEXICO

U.S. to combine Eastern, Central Gulf of Mexico lease sales

Minerals Management Service says logistics, economics, behind decision; last Eastern sale drew only 16 bids

By RAY TYSON
Petroleum News Houston Correspondent

The U.S. Minerals Management Service, due in part to反对 of the last Eastern Gulf of Mexico lease sale, has decided to combine the next sale with the much larger Central Gulf lease sale on March 16 in New Orleans.

“There are a lot of practical reasons,” MMS spokesman Caryl Fagot said Jan 4. “It’s strictly convenience, logis-
cically easier and more economic to do
them all at once.”

Eastern Gulf Lease Sale 189, held in December 2003, took less than five minutes to complete and generated just $8.4 million in high bids. There were only 16 bids on 14 of the 138 blocks offered, compared to 190 bids on 95 blocks two years earlier, when the region was reopened to oil and gas leasing, generating a whopping $340.5 million in high bids in Sale 181.

“We certainly aren’t offering that many tracts … so the sale won’t take that long at all,” Fagot said.

Upcoming Eastern Gulf Sale 197 will consist of just 124 blocks covering about 714,240 acres, according to MMS. That compares to 4,043 blocks encompassing 213.1 million acres to be offered in Central Gulf Sale 194 on the same day.

Spiderman discovery in Eastern Gulf

Nevertheless, Sale 197 could attract some interest, particularly from explorers looking for additional acreage to expand or protect discoveries made since a small portion of the vast Eastern Gulf region was reopened to leasing in 2001.

Significant discoveries since the Eastern Gulf was reopened are Spiderman, Atlas, Atlas NW, Jubilee and San Jacinto. They consist of both shallow near-shore and deepwater acreage production hub that also will include the Thunder Horse complex operated by BP.

Central Gulf area both shallow and
deepwater acreage

In contrast, the Central Gulf sale area consists of both shallow near-shore and deepwater acreage spread over a wide area offshore Louisiana, Mississippi and Alabama. Water depths range from just a few feet to more than 11,000 feet.

The Central Gulf also is home to some of the largest oil discoveries in the entire U.S. Gulf, including the 1.5 billion barrel Thunder Horse complex operated by BP.

MMMS estimates that upcoming Central Gulf Sale 194 alone could result in the discovery and production of 276- to 654 mil-

lion barrels of oil and 1.5- to 3.3 trillion cubic feet of natural gas.

Last year’s Central Gulf Sale 190 gener-
ated a surprising $568.8 million in high bids, attracting a total of 829 bids on 557 blocks, the largest number of bids submit-
ted for a Central Gulf offering in six years. The prior year’s sale netted just $297.6 mil-
lion.

Of the 4,043 blocks to be offered in the next Central Gulf sale, 1,180 blocks are in water depths of less than 1,312 feet and carry five-year lease terms; 125 blocks are in water depths ranging from 1,312 to 2,624 feet and carry eight-year terms; and 2,738 blocks are in water depths of less than 1,312 feet and carry ten-year terms.

Central Gulf Sale 194 and Eastern Gulf Sale 197 also will offer popular government drilling incentives for both deep and shallow waters, primarily involving suspension of federal royalties on initial production from qualified leases.

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Companies face potential cleanup liability

BLM says the risk is small; Bush administration say they don't want high bonds to discourage exploration in midst of energy crunch

By DAVID PACE
Associated Press Writer

Bonds posted by companies with federal oil and gas leases cover only a small fraction of the projected costs of plugging wells and restoring land once the fuel is extracted, leaving taxpayers with the potential for huge cleanup bills, an Associated Press analysis of federal records shows.

The Bureau of Land Management has collected just $132 million in bonds from oil and gas companies responsible for more than 100,000 wells on federal lands. The government estimates it costs between $2,500 and $75,000 to cap each well and restore the surface area.

In the past five years, the BLM has spent $2.2 million to clean up 167 wells where operators defaulted on their bonds.

At that average rate of $13,066 per well, the shortfall between the bonds and the actual cleanup costs could leave taxpayers with as much as a $1 billion potential liability if companies reneged on their cleanup responsibilities, the AP analysis found.

The Bush administration this fall quietly shelved an eight-year effort to increase the minimum bond requirements for oil and gas drilling on federal lands.

The current rates were set in 1960, and oil and gas companies are the only federal mineral lease holders that aren’t required to post full reclamation bonds. Coal and hard rock mineral companies must post bonds equivalent to the estimated cleanup costs.

Bush administration officials say they don’t want high bonds to discourage oil and gas exploration on federal lands in the midst of an energy crunch and believe the risks are minimal given that relatively few companies have reneged on cleanup obligations in recent years.

BLM calls risk ‘small’

In the past five years, 17 companies defaulted on their cleanup, causing their bonds to be revoked.

“There is a small risk here,” said Bob Anderson, the BLM’s deputy assistant director for minerals. “And it’s a risk that we think is an equitable one.”

But others, including landowners struggling to get older, non-producing wells plugged, believe it is unfair.

Eric Barlow, a Wyoming rancher who’s been trying for years to get two nonproducing oil wells on his 18,000-acre spread plugged and abandoned, said the BLM’s current bonding requirements are little more than “window dressing.” Barlow owns the land but the government owns the rights to the minerals underneath and leases those.

The Bush administration concluded this fall that rather than raise the minimum bonds for all oil and gas leases, they would use existing authority to selectively impose higher bond requirements on those companies they deem risky.

BLM could increase bonding requirement

“The BLM has reviewed its policies and procedures and believes that the existing regulations … already provide the needed authority to increase bonds when the BLM determines that operators pose a risk on federal oil and gas leases,” BLM Director Kathleen Clark and Assistant Secretary of the Interior Rebecca Watson wrote Sept. 30.

In the past five years, Anderson said the agency has increased 35 bonds, requiring operators to post an extra $3.6 million. The increases account for less than 3 percent of total oil and gas bonds.

The September decision amounted to an about-face. A year earlier, Watson told a Denver newspaper that increases in a proposed new bond rule would take effect “sooner rather than later.”

Interior Secretary Gale Norton, Watson said at the time, “has a firm view that companies are responsible for land reclamation, not individual taxpayers.”

The 1960 regulations require that an operator post a minimum bond of $10,000 per lease, regardless of how many wells will be drilled on that lease. Alternatively, a company can choose to post a minimum $25,000 bond for statewide drilling, or a $150,000 nationwide bond.

The bonds are intended to ensure that oil and gas wells are plugged and the surface area restored once production has ceased. Without such reclamation, abandoned wells can pose a pollution threat to groundwater if well casings fail.

Bond increase rule on hold

Following a critical 1996 inspector general’s report, the BLM in 1998 proposed a rule change that would have increased the minimum lease bond to $20,000 and the minimum statewide bond to $75,000. At the time, the agency said increases just to cover inflation since 1960 would require a lease bond of $50,000 and a statewide bond of $135,000.

The rule change was ready for final publication when Bush took office in 2001 and ordered a government-wide halt to all pending rule changes. The bond rule appeared to be back on track when the BLM’s implementation plan for the recommendations of Vice President Cheney’s energy task force in 2002 called for its completion.

But none of the four bond-related tasks in that implementation plan have been completed, while eight tasks related to speeding up drilling permit approvals and opening more federal lands to oil and gas development have been finished. BLM issued 5,824 drilling permits in five Rocky Mountain states during fiscal 2004, a 63 percent increase over 2003.

Critics say risk to taxpayers growing

Environmentalists and ranchers critical of the agency say the risk to taxpayers is growing as larger, more established oil and gas companies sell their lease holdings to smaller, less financially viable firms.

The explosive growth of coalbed methane exploration in Wyoming and Montana also poses increased risks, they argue, because it requires far more wells and surface disturbances than traditional oil and gas activities.

The number of idle wells on federal lands also is growing. BLM data obtained with a Freedom of Information request show that more than 1,500 oil and gas wells are no longer producing, and in some cases haven’t been for decades.

That’s 25 percent more than the 1,200 “temporarily abandoned” or “shut-in” wells the BLM told Congress existed on federal lands four years ago.
Canada’s drilling rig count falls by 25, U.S. down 14 this week

The number of rotary rigs operating in North America during the week ending Dec. 31 decreased by 14 from the previous week but increased 117 vs. the same period last year. Compared to the previous week alone, land rigs fell by 12 to 1,117 and offshore rigs fell by two to 105. Inland water rigs were unchanged with 21.

Of the total number of rigs operating in the United States during the recent week, 1,058 were drilling for natural gas and 183 for oil, while two were being used for miscellaneous purposes. Of the total, 803 were vertical wells, 312 directional wells and 128 horizontal wells.

Among the leading U.S. producing states, Texas was hardest hit during the recent week, down by 14 to 532 rigs. Oklahoma’s rig count decreased by two to 145, while Alabama’s decreased by one to nine and Louisiana’s decreased by one to 169. Wyoming picked up one rig for a total of 76. New Mexico was unchanged with 75 rigs, as well as California with 27 rigs.

—RAY TYSON

Alaska North Slope production stays steady in December

Alaska North Slope crude oil production averaged 981,072 barrels per day in December, up less than a tenth of a percent from November’s average of 980,690 bpd. The Alaska Department of Revenue’s Tax Division reported that production at Endicott was disputed Dec. 5-7 by the cleanup of a glycol spill in a gas module, Northstar production dipped Dec. 21-22 when a compressor went down and overall North Slope production was prorated 50 percent Dec. 26 due to a remote gate valve closure at Pump Station 4 on the trans-Alaska pipeline. The volume dropped from 972,526 bpd Dec. 25 to 966,469 bpd Dec. 27.

The BP Exploration (Alaska)-operated Endicott field had the largest drop in production, averaging 21,223 bpd in December, down 8.85 percent from an average of 23,284 bpd in November. BP-operated Lisburne averaged 46,239 bpd in December, down 0.3 percent from a November average of 46,393 bpd. Lisburne production includes Point McIntyre and Niakuk.

The ConocoPhillips Alaska-operated Alpine field averaged 115,847 bpd in December, down 0.3 percent from a November average of 116,197 bpd. The BP-operated Milne Point field averaged 52,438 bpd in December, almost flat with a November average.

The technology advances that allowed 1E and 1J to be commercial “have been rapid and they’ve been dramatic. The knowledge sharing across the slope … — and across the world in fact — has been very leveraging … And we’re actively working on the next technology breakthrough we need to get to the even more viscous stuff.”
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—Matt Fox, ConocoPhillips Alaska greater Kuparuk area development manager

More technology breakthroughs will be needed if more of 23 billion barrels of heavy oil at West Sak-Schrader Bluff, Ugnu is to be developed combined with the shallower Ugnu formation, accounts for 23 billion barrels of oil in place in Fox said: a volume of oil equivalent to the original oil in place at Prudhoe Bay.

Low rates, low recovery, low price

But, he said, the viscous oil suffers from “a triple whammy effect: you’ve got the low rates, the
low recovery factor and the low price.”

This oil isn’t just heavy oil, he said, it is “cold heavy oil, and that means it’s extremely viscous.” The reservoirs are shallow, from roughly 3,000 feet below the surface down to some 4,500 feet, and they lie under some 1,800 feet of permafrost, so the reservoir temperatures vary from about 40 degrees Fahrenheit to about 90 degrees F, “and that combination of these cold temperatures and the relatively low API means that we have extremely high viscosities.”

Prudhoe Bay and Kuparuk oil have about the same viscosity, ability to flow, as water, Fox said. West Sak has about the same viscosity as olive oil. Ugnu has about the same viscosity as maple syrup. In terms of production this is a big whammy: West Sak is about 100 times as viscous as water. The flow rate of oil is “indirectly proportional to viscosity, so if viscosity increases by a factor of 100, which is what we have here going from the Kuparuk to the West Sak, rates will decrease by a factor of 100.”

In addition, recovery rates are lower, because the West Sak oil is very difficult to move out of the pore spaces in the formation, “it’s very difficult to displace because of its viscosity.”

And refineries pay less for lower API oil than for Prudhoe Bay or Kuparuk oil.

**Rapid changes in last few years**

While the North Slope producers have been trying to make the shallow accumulations commercial for two decades, Fox said, the things that finally made the best of this oil commercial have all been recent developments, since the late 1990s.

Well types changed from vertical to horizontal multilateral; drilling reach changed from moderate to extended reach; the recovery mechanism has changed from waterflood to waterflood enhanced by lean gas injection; and the method of dealing with sand has changed.

The West Sak-Schrader Bluff and Ugnu reservoirs are unconsolidated, poorly cemented, and sand is produced with the oil. In the late 1990s, the focus was on keeping the sand in the reservoir by using sand screens in the well bores. Fox said there were three problems with this: some of the West Sak sand is as fine as flour and you couldn’t devise a screen that could keep it back; restricting sand with screens restricted the flow rate and “was exacerbating the viscosity problem;” and the screens were costly.

The solution was to focus on flow rate and deal with the sand that came to the surface by re-injecting it, Fox said. Well spacing has also changed from 1,100 feet to 1,250 feet. It may not look like a big deal, he said, but the more distance you can put between wells, the fewer you have to drill, “And that’s a big deal for pushing down the cost.”

**Keeping the oil flowing**

Another thing that’s changed is keeping the oil flowing. Electric submersible pumps are used to move the heavy oil to the surface, but they break down, and because Kuparuk doesn’t have a fulltime workover rig, wells could be shut in for six months at a time. “And that would kill the economics of the project because of the level of the failures,” Fox said.

They are still using electric submersible pumps, but now they are building in backup: the ability to use gas lift when the pumps fail, “so we can keep some level of production going, and that made a surprisingly big difference to the economic viability.”

An oil-based mud system replaced a water-based mud system for drilling, improving both drillability and productivity.

And how the oil is handled at the surface changed, he said.

The initial plan was just to mix West Sak production with Kuparuk production, since both occur on the same drill pads, but experimentation showed that wasn’t enough, Fox said, and so heaters are being added at the drill sites and chemicals are being added to allow the sand to drop out of the oil.

And the volume of oil that can be accessed from a single well has changed because extended reach multilateral wells are now possible because of “new technologies like rotary steerable systems and more efficient torque reduction tools (and) more efficient mud systems…” increasing production from some 200 barrels per day from 1980s vertical wells to 2,500 to 3,000 bpd from long tri-lateral wells.

**Waterflood plus gas**

The viscous oil is difficult to displace from the rock pores because of its viscosity, Fox said. With waterflood, a recovery rate of some 18 percent is possible. In the deeper North Slope conventional oil
reservoirs miscible gas injection is used for enhanced oil recovery, a type of gas injection where the gas injected mixes with the oil in the reservoir. But viscous oils “don’t lend themselves to a miscible process,” Fox said, so instead of miscible gas, lean gas will be used. This is in pilot testing now, he said.

The gas doesn’t mix with the oil, but “some molecules in the gas link to the oil and very little exchange is enough to drop the viscosity dramatically,” for example from 60 centipoise (centipoise is a measure of viscosity) to 10 centipoise, which produces “a significant increase in the displacement.”

The expected increase in recovery with lean gas injection is 20 percent over waterflood, increasing total recovery to about 22 percent.

**Slope-wide sharing**

“The only way we were really able to exploit these technology advantages is because we made a concerted effort to share knowledge across the slope and within the operating companies,” Fox said, and called the level of knowledge sharing “unprecedented.”

The North Slope viscous team included technical staff from ConocoPhillips and BP, with some ExxonMobil participation.

One thing the team was asked to do was to improve the ability to predict rates. “We had a track record of over-promising and under-delivering and it was killing our creditability outside Alaska when we would go looking for funds.” Sand control was another issue the viscous team tackled, as was depletion planning, getting the oil out of the ground, “and that team came up with the idea of doing viscosity-reduction gas injection,” Fox said.

The North Slope viscous team is continuing to work, he said, learning from implementations and looking at what can be done next.

**What about the rest?**

Of the 23 billion barrels in place, some 15-16 billion barrels are at Kuparuk, with 1C and 1D, the experimental pads, developing about half a billion barrels and the 1E and 1J pads exploiting oil in place of about a billion barrels.

West Sak because the sands are too thin, but it might work in the thicker Ugnu formation, and “we’re running laboratory experiments and reservoir simulation experiments to try and see if we can make this viable,” Fox said. “But there are some big challenges in this environment: we have 1,800 feet of permafrost (and) pumping steam through that — that has to be thought through.”

The technology advances that allowed 1E and 1J to be commercial “have been rapid and they’ve been dramatic,” Fox said. “The knowledge sharing across the slope ... and across the world in fact — has been very leveraging ... And we’re actively working on the next technology breakthrough we need to get to the even more viscous stuff.”

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**Exploration & Production**

age of 52,442 bpd. Milne Point production includes Schrader Bluff heavy oil.

Production from the ConocoPhillips-operated Kuparuk River field averaged 198,179 bpd in December, up 0.2 percent from a November average of 197,767. Kuparuk production includes West Sak heavy oil, and satellite production from Tabasco, Tarn and Melwater.

BP-operated Prudhoe Bay averaged 472,908 bpd in December, up 0.4 percent from a November average of 470,872. Prudhoe includes production from the field’s western satellites, Midnight Sun, Aurora, Polaris, Borealis and Orinoco.

BP-operated Northstar averaged 74,238 bpd, up 0.7 percent from a November average of 73,735 bpd.

Cook Inlet production averaged 22,763 bpd, up 1.3 percent from a November total of 22,467 bpd.

The North Slope temperature at Pump Station No. 1 averaged -7.1 degrees Fahrenheit in December, compared to a three-year temperature average of -3.9 degrees F; the November temperature averaged 2 degrees F.

—KRISTEN NELSON
Pipeline leak forces shutdown of Canyon Express gas system

The Canyon Express pipeline, which serves three deepwater gas fields in the Gulf of Mexico, has been shut down because of a troublesome leak in the methanol delivery system that keeps hydrates from clogging sub-sea production wells.

Production from the King’s Peak, Aconcagua and Camden fields actually was halted in early December but not announced until Jan. 5.

“We really expected to find the leak without it having a material impact on production,” said Susan Spratlen, a vice president of Canyon Express user Pioneer Natural Resources.

Pioneer said the impact to its average daily production alone during the 2004 fourth quarter is expected to be about 5,000 barrels of oil equivalent, leaving total production for the quarter at the lower end of the company’s previously forecasted range of 190,000 to 205,000 barrels of equivalent per day.

France’s Total operates the Canyon Express gas system on behalf of fellow producers BP, Marathon Oil, Mariner Energy and Pioneer.

Spratlen said that while the exact cause of the leak was still being investigated, it is believed the methanol pipeline could have been struck by an object. “There is evidence something hit the line on the ocean floor,” she added.

A key technology employed at Canyon Express, among the deepest pipelines in the Gulf of Mexico, is said to be the recovery and reuse of methanol as a hydrate inhibitor. At water depths of 7,200 feet, temperatures below 400 degrees can cause hydrates to form at the wellhead. Canyon Express facilities include the storage, regeneration and distribution of 1,900 barrels per day of methanol.

—RAY TYSON

New life in aging basin

Shell Canada, Talisman gas discoveries give hope for Western Canada Sedimentary basin, but pressure on big explorers to drill more wildcats

By GARY PARK

Peters News Calgary Correspondent

Canada exited 2004 with word of two of the biggest onshore natural gas finds on record.

At a time when all the talk was of fading prospects for the Western Canada Sedimentary basin and industry observers were bemoaning that lost art of wildcatting, the discoveries by Shell Canada and Talisman Energy were greeted enthusiastically.

But even more important than the size of the new plays was where and how they were achieved.

Shell made its breakthrough under a limestone shelf in the eastern foothills of the Canadian Rockies, raising hopes for others whose pockets are deep enough to absorb costs of up to C$10 million a well.

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Just a month earlier, almost unheralded, Pioneer said the impact to its average daily production alone during the 2004 fourth quarter is expected to be about 5,000 barrels of oil equivalent, leaving total production for the quarter at the lower end of the company’s previously forecasted range of 190,000 to 205,000 barrels of equivalent per day.

Drilling the Delta

Chevron/BP, EnCana-led partnership spuds two exploratory wells on Mackenzie Delta, regulators OK third well, hunting for supplies to fill pipeline

By GARY PARK

Petroleum News Calgary Correspondent

wo exploratory gas wells of special interest to the Mackenzie Gas Project are now being drilled on the Mackenzie Delta, helped by an early freezeup in the area, and a third is on the schedule for the current winter.

An EnCana-led partnership with Anadarko Canada and ConocoPhillips Canada spudded exploratory Umak N-05 well on Jan. 7, just three weeks after a Chevron Canada Resources-BP Canada Energy joint venture started the Olivier H-01 well, which should reach its targeted depth of about 11,500 feet by late March or early April.

In addition, Chevron and BP have regulatory authorization to drill another exploratory well, Olivier 2H-01, to a depth of 10,300 feet.

At stake are the hopes of finding new supplies to fill the proposed Mackenzie Valley pipeline to

see BASH page 13

see DELTA page 13
DELTA

its initial capacity of 1.2 billion cubic feet per day.

Akita Drilling’s No. 63 rig is contract-
ed for both Chevron-BP wells and No. 62 is drilling Umik N-05.

Encouraging hydrocarbons found

The N-05 well on Richard’s Island is only two kilometers from Umik N-16 which was drilled to a depth of about 10,200 feet last winter and encountered hydrocarbons that were described as “encouraging.” EnCana spokesman Alan Boras told Petroleum News. N-16 is due for testing this winter to assess its commercial value.

EnCana is not disclosing the projected depth and cost of N-05 on Exploration License 384, although drilling is expected to last six weeks. However, National Energy Board frontier statistics set the targeted depth at about 11,900 feet. Boras said the freezeup allowed work to be completed ahead of normal on an ice road to the drill site. Chevron-BP got an even faster start by barging supplies and equipment to the Olivier site in late sum-

N-16, with EnCana holding 37.5 percent, Anadarko 37.5 percent and ConocoPhillips 25 percent, was shut down in mid-April and is scheduled for testing this winter to determine its commercial value.

It was the first pure exploration well by EnCana in the Delta region and is viewed by the big Canadian independent as part of its strategy to build long-term reserves.

EnCana finds Arctic attractive

Given the gas supply/demand outlook, EnCana believes the Arctic is now a much more attractive prospect. ConocoPhillips is already a key player on the Delta, as one of four owners of anchor fields on the Delta that underpin the Mackenzie application — an asset it picked up in its C$6.9 billion takeover of Gulf Canada Resources.

It holds 75 percent of the 1.8 trillion cubic foot Parsons Lake find, with ExxonMobil Canada controlling the remaining 25 percent. Anadarko purchased its 37.5 percent working interest in two exploration licenses adjacent to the Parsons Lake field from Alberta Energy Co. (one of the two founding companies of EnCana) in 2000.

The licenses, covering 530,000 acres, augmented Anadarko’s previous acquisi-
tion of Canadian Arctic holdings, consist-
ing of interests ranging from 3.4 percent to 24 percent in 10 significant discovery licenses and six production license, with a combined area of 142,000 acres.

BASIN

Talisman notched an equally significant success in the Monkman Pass area of northeastem British Columbia.

Shell's Foothills strike in west-central Alberta is estimated to contain 500-800 billion cubic feet, although the sulfur con-
tent could shrink the salable gas to 360-400 billion cubic feet — still enough to match almost two year’s of the company's current production.

Clive Mather, Shell Canada's president and chief executive officer, could barely hide his delight, given the company's steady slide over the years from the top rung on Canada's gas production list. He said the Foothills exploration pro-
gram, designed to arrest that decline, could actually “take us beyond that objec-
tive and contribute to the future growth of our natural gas business.”

Talisman calculated its discovery at more than 200 billion cubic feet of gas in place, with the potential for more hits that could raise the cumulative total to 2 trillion cubic feet.

The Monkman well has started produc-
ing at 40 million cubic feet per day and has the capability to exceed 75 million cubic feet per day — enough for Talisman to pay off the C$16 million cost of the well within about three months, according to Chris Theal of Tristone Capital.

Talisman Chief Executive Officer Jim Buckee believes there is clear potential for many finds on the same scale in an area that could hold 2 tcf or more.

The independent, which is also employing gains in 3-D seismic, expects to spend up to C$600 million in 2005 on another four wells and has identified 30 potential drilling targets at depths of about 13,100 feet with potential of 35 billion cubic feet well or greater.

Straddling the northern foothills across the British Columbia-Alberta border, EnCana could overshadow both of its rivals in the Cuthbank Ridge play, where it has posted 33 successes from 34 wells that were drilled to only about half the depth of the Shell and Talisman wells. It plans to drill up to 1,800 wells and hopes to recover 10 tcf.

Foothills’ production entering 2004 was dominated on the eastern side by Shell at 554 million cubic feet per day and on the western side by Talisman at 181 million cubic feet per day.

Although the region is a “big boys” game at a time when not many big boys are exploring,” the successes by Shell and Talisman could ease a “creeping feeling” that the Western Canadian Sedimentary basin is in irreversible decline, said Wilf Gobert, vice chairman of Calgary-based investment dealer Peters & Co.

Shell drilled a horizontal hole

Although unable to disclose competi-
tive details about Shell’s new seismic pro-
cessing techniques, spokesman Jan Rowley gave some insight into the high-
techn methods used.

She told Petroleum News that the hori-
zontal hole was drilled to a total depth of 16,800 feet using powerful computer pro-
gams to help interpret the seismic read-

ings obtained from complex strata. Rowley said the same technology will be applied to drill a follow-up well sometime in 2005 to determine if the find is part of a broader regional play.

Buckee said the shortage in Canada of “truly undervalued assets or companies” is forcing E&P companies to return to exploration basics.

Others embarking on high-risk chal-
lenges include Anadarko Petroleum, Burlington Resources, Canadian Natural Resources, Devon Energy, Husky Energy and Petro-Canada, which all have the financial means to test their belief that technology can unlock more of the Western Canadian Sedimentary basin’s potential.

Burlington Chief Financial Officer Steven Shapiro told analysts last year that project economics are “very robust” in Canada, where Burlington’s Canadian division has more than 2 tcf of drilling inventory and plans to build momentum in 2005 and 2006.

Those companies are vital players in opening up 2-3 tcf of undiscovered gas, excluding coalbed methane, that the Geological Survey of Canada estimates is locked in the Western Canadian Sedimentary basin — more than four times the current market gas reserves the Canadian Association of Petroleum Producers has identified for all of Canada — although about 95 tcf is associated with “conceptual plays” that are beyond current drilling technologies.

Call for revival of exploration

Of the more than 400,000 wells drilled in the sedimentary basin in the past decade, less than one third were listed as exploratory and an even smaller fraction were high-risk, according to analysts

Steve Hager at Canadian Discovery and Roger Smith at Sunco Energy.

Because high-risk, high-reserve oppor-
tunities have been neglected for years much of the sedimentary basin is under-
developed, Smith said, while adding that further work will inevitably see undiscover-
ged resources grow beyond previous esti-
mates.

He said the reluctance to tackle higher-
risk exploration stems from the “quarter-
by-quarter” mentality of shareholders that has seen company leaders become more risk-averse and transfer their emphasis to short-term results.

The challenge for E&P companies in the Western Canadian Sedimentary basin is a revival of exploration, speakers told a Conference Board of Canada forum in December, given that only 25 percent of last year’s wells were designated as wild-
cat and few were in the high-risk catego-
ry.

Glen Gradem, president of Rosetta Exploration, said there is an “impending and very real crisis” between the rising demand for hydrocarbons and the shrink-
ing output.

He said that requires a shift from the “just-in-time” supply of gas that has emerged over the last 20 years in Western Canada and the less predictable focus on the creation of genuine new wealth.

Failure to return to “serious explo-
rataion” will lead to a “rocky ride over the next 20 years,” Gradem said.

“Canada has a huge remaining hydro-
carbon potential, a proven, but somewhat mature basin … what we seem to lack is the belief that there is more supply to be had,” he said.
**WASHINGTON, D.C.**

Murkowski meets with Norton, ANWR, Kenai National Wildlife Refuge discussed

Alaska Gov. Frank Murkowski met with U.S. Secretary of the Interior Gale Norton in early January to discuss a variety of Alaska issues, including legislation authorizing oil and gas development in the 1002 area of the Arctic National Wildlife Refuge and the impediments to further oil and gas development in the Kenai National Wildlife Refuge.

“...The Interior Department controls vast areas of Alaska and thus impacts the lives of Alaskans,” said the governor after the meeting. “I am gratified by the secretary’s openness to resolving conflicts and to working cooperatively on issues affecting us all. I am committed to protecting the rights of Alaskans, and I am glad to have a secretary in Washington willing to listen.”

According to a Jan. 5 press release from the governor’s office, in the meeting the secretary and the governor agreed to work together and with members of Congress to seek legislation authorizing oil and gas development in ANWR.

“The governor also provided an update on Alaska’s progress to date on the development of a natural gas pipeline and expressed his frustration about impediments to further oil development in the Kenai National Wildlife Refuge,” the release said.

“Alaska can make a great contribution to the nation through its oil and gas reserves — and provide jobs and a hopeful future for Alaskans,” Murkowski said. “We will continue to work with the Interior Department on these critical energy issues.”


**AOGCC proposes changes to workover rules, reporting**

Lists of planned workovers weren’t used by commission, will be eliminated, replaced with weekly reports of work done

By KRISTEN NELSON

Petroleum News Editor-in-Chief

The Alaska Oil and Gas Conservation Commission is working on changes to its rules for reporting development well workovers.

Commission Chairman John Norman said at a Jan. 4 public hearing that the commission has been reviewing the reports it requires to “determine those reports that are necessary and to also determine if any reports or paperwork” required by the commission are “no longer useful to the commission” and to see about eliminating any that aren’t useful.

One area identified for review was workovers, and commission staff worked on this area with industry representatives.

The intent “was to update and revise orders that had been issued by the commission pertaining to operations generally known as workovers,” commission senior reservoir engineer Tom Maunder said at the hearing. Workovers, he said, include activities such as “a major entry into a well bore, or minor other activities that could be likened to changing the oil or checking the oil in an automobile.”

The commission waived requirements for pre-approvals for workovers in conservation orders for fields issued beginning in 1990. Maunder said, but those waivers were not extended as new pools were added at some fields, so there is inconsistency in requirements for pre-approvals for workovers.

**Task force established**

A task force of commission staff and representatives of the Alaska Oil and Gas Association was established and met beginning last April. The task force developed what Maunder called a “task matrix” of workover operators to identify tasks which require pre-approval from the commission and tasks that would be “considered routine” and do not require prior approval. The task force also identified a third type of work, Maunder said: tasks that are so routine that requirements for approvals and subsequent report of the work “would be burdensome to both the operator and the commission.”

The task force developed two task matrices, he said, one for production wells and one for injection wells. The proposed changes in the commission’s conservation orders would apply the same standards to all fields in the state.

“By putting this task matrix out there, to be used by the operator, it literally puts everybody on the same page as to requirements of what activities they need to seek approval on and any follow-up reports that are necessary,” Maunder said.

There may be some increased paperwork, Maunder said, but the proposed changes provide “a consistent approach across the major oil fields in the state.”

**Report also changed**

A workover report required by the commission will also change, Maunder said.

The report required now is a list of workover operations planned for the following week. The new report will be a list of workovers done in the prior week. The planned work list wasn’t useful, he said, because plans often changed and some workover operations were deferred.

The new report, a list of completed work, would be useful to the commission in its compliance effort, he said, because it could...
be used to verify that required follow-up reports had been received.

Commissioner Dan Seamount asked Maunder about the potential for increased paperwork, and Maunder said there was mention in the task force that there would be some increase in paperwork. The goal, he said, “is to make sure we were getting the reports that were required and to grant the relief to the additional fields” where conservation orders do not grant waivers.

Seamount asked what the new weekly reports would include, and Maunder said samples he has seen include well identification, work performed, if a sundry approval was required prior to the work and what follow-up report was required.

Any paperwork increase hard to quantify in advance

The Alaska Oil and Gas Association participated on the task force for industry and staff engineer Harold Engle of BP Exploration (Alaska), a task force member, told the commission industry appreciated the opportunity to work with the commission on the issues, and said the association supports the changes proposed and the effort and wishes to continue working with the commission.

On the potential for increase in paperwork, it is tough for industry to quantify any increase now, Engle said. Industry would like to see the process work for a while and then “evaluate any increases” that result from the changes, he said, and come back to the commission if there are problems.

Seamount also asked about required follow-up reports for workovers requiring approvals. As the commission looked at its records, he said, it found that required workover reports weren’t always received within 30 days as required, and asked Engle if he thought the proposed changes would solve the issue of late reports.

Engle said requirements for reports had evolved over the years and said the task force effort has clarified “what activities need reports to be filed” and when.

Will paperwork increase?

Norman asked Engle if he thought there was anything in the commission’s proposed changes that “unnecessarily increases the reporting or paperwork burden on industry?”

Engle said there may be more paperwork required for work in the field, but he didn’t think it would be significant. He suggested the task force continue on and evaluate any increases at a later date.

Norman asked Maunder if anything in the changes would lessen safety or protection against waste. Maunder said no. In fact, Maunder said, alteration of casing in a workover operation will require pre-approval from the commission under the proposed changes. This had been waived from pre-approvals in the conservation orders that are being amended, he said. “In looking at events that have happened in the last couple of years where casings have been compromised,” this type of workover was changed to require pre-approval. This will require more paperwork, he said, but he said this type of work isn’t a frequent occurrence.

Norman said the record will be left open for two weeks for any additional comments and said he anticipates that following closing of the record the commission will act on the proposal. He said the commission would “expect full compliance” as soon as the changes are adopted. "If for any reason full compliance proves to be impractical, then we will expect you to contact the commission immediately,” Norman said, and the commission will take another look at the requirements.

AOGCC

Alyeska required to improve spill training

Alyeska Pipeline Service Co. will be required to make improvements in its spill-response training program for trans-Alaska oil pipeline employees.

The Bureau of Land Management is requiring Alyeska implement the changes recommended recently in an audit done after a longtime Alyeska spill-response coordinator brought forward concerns. Alyeska operates the 800-mile pipeline and has already started making many of the required changes.

The report spelling out how the changes will be implemented was published by the Joint Pipeline Office. The BLM requirements include establishing a minimum level of spill-response training before new employees are sent into the field, creating uniform methods to document employee training and reviewing training materials to ensure they are current. Hands-on training also will be increased with spill-response equipment and review sessions scheduled of the approximately 60 spill-response training exercises conducted every year.

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—THE ASSOCIATED PRESS
Feds may have funds for shale plant cleanup

Federal royalties already in hand from gas wells on the Roan Plateau may be enough to pay for the cleanup of a former oil shale research facility on the south cliffs of the plateau. A draft analysis by the federal Bureau of Land Management estimates that cleaning up the Anvil Points facility in Rifle in Western Colorado will cost $4 million to $8.7 million. More than $10 million has been set aside from the federal royalties. BLM spokesman Steven Hall said.

Anvil Points was decommissioned in 1984 after operating for 40 years, sometimes under private management and sometimes under the federal government. The government is responsible for the cleanup, Hall said.

The BLM is also studying ways to deal with a 1,000-foot-long, 350-foot-high pile of spent oil shale below the defunct plant. It contains arsenic and other dangerous heavy metals. Government and private researchers have tried for decades to find economical methods of extracting oil from shale. Nationwide, an estimated 2.6 trillion barrels of oil are locked in shale, including 1.5 trillion barrels in the Green River formation, most of which is in Western Colorado.

—THE ASSOCIATED PRESS

Russia goes to the sea with Siberian pipeline

Russia is trying to beef up its export pipeline system to boost its role as a major oil supplier for the world. The nation currently exports around 7 million barrels a day, most of it through its pipeline network, and consumes about 2.5 million internally. The nation expects to more than double its pipeline exports by 2020.

Despite heavy lobbying from China, the Russian government has picked a pipeline route that will take oil from eastern Siberia to the ocean, where it can be exported to Japan and other countries.

The decision to choose that alternative over a cheaper line to China alone came Dec. 30.

The pipeline will end at the port of Nakhodka, on the Sea of Japan about 110 miles from Vladivostok. Nakhodka, with a population of 225,000, has been gaining as a major Far East port because it has fewer ice problems than Vladivostok. The oil will enter the 2,600-mile pipeline at Taisht in eastern Siberia.

The 1.6-million-barrel-per-day line will be built by OAO Transneft, a state-owned firm. Construction is expected to take three to six years.

Cost estimates vary all over the map, from around $11 billion to $16 billion or more. A detailed project plan is expected by May, with better numbers.

As part of its lobbying for the pipeline to come to the Pacific, Japanese officials offered to help with financing for the huge project. Japan wants to reduce its dependency on the Middle East, which now provides 85 percent of the country's oil.

Yukos stake for China

Meanwhile, Russian officials also said that the Yukos unit auctioned off earlier in December would not go to giant Gazprom along with state-owned Rosneft. Instead, Yuganskneftegaz will be spun off as a separate government-controlled oil company.

The Gazprom-Rosneft merger will go ahead later this month, with the share swap giving Russia's government majority control of Gazprom.

Industry and Energy Minister Viktor Khristenko also said Dec. 30 that state-owned China National Petroleum Corp. could purchase up to 20 percent of the old Yuganskneftegaz. That division, the former core of Yukos, holds 17 percent of Russia's oil reserves and produces around 1 million barrels a day.

China's rising demand

China, now the world's second-largest oil consumer, imports 2.5 million barrels a day while producing 3.5 million barrels daily. Its thirst for oil has been increasing dramatically. A deal for nearby Siberian reserves would likely be welcome.

China had been hoping the Siberian pipeline would go to its aging petroleum center at Daqing, where it could be distributed to Chinese refineries. That route would have been much shorter and cheaper, but it would have left the Russian exporters with just one market, rather than an opening to tanker shipments around the Pacific Rim. And Yukos officials had pushed that alternative, which didn't help its chances in the political arena.

Russia is trying to beef up its export pipeline system to boost its role as a major oil supplier for the world. The nation currently exports around 7 million barrels a day, most of it through its pipeline network, and consumes about 2.5 million internally. The nation expects to more than double its pipeline exports by 2020.

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China's national oil companies have been out shopping the world for new reserves, recently signing major agreements with Iran and with partners of the North West Shelf venture that holds huge natural gas reserves off Australia. But Western companies already have tied up the best prospects, and China is bidding against fellow rising power India, which also wants to ensure its energy supplies.

Chine's rising demand

It was purchased by a front company for $9.6 billion, with that company later revealing it was controlled by Rosneft. Just where the $9.6 billion will come from isn't clear. The government could provide the funds directly, given all the political heat it has taken already over the Yukos saga.
Companies involved in North America's oil and gas industry

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Pacific Rim Institute
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All of the companies listed above advertise on a regular basis with Petroleum News.

Business Spotlight

Doug Hestes, sales manager

Oil & Gas Supply Co.

Oil & Gas Supply, celebrating its 10th anniversary in 2005, is an industrial and Automotive Premier hydraulic hose and fitting distributor with production facilities in Anchorage and Kenai. The company also does exporting for hard-to-find parts. With more than 75 years experience combined, O & G Supply finds what you want when you want it.

Doug Hestes has been in the business since 1981. In 2001 he joined Oil & Gas Supply and has helped customers from Prudhoe Bay to Dutch Harbor. In addition to being a NASCAR fan (he attended the 2001 Daytona 500), Doug likes all motor sports. Most weekends you can find Doug and girlfriend Sheila at Big Lake. He’s fully recovered from last summer’s heart attack.
ConocoPhillips Alaska’s latest report to the Alaska Division of Oil and Gas on Kuparuk field development plans estimates that production from the main Kuparuk reservoir at the field will peak in 2006 at some 158,000 barrels per day, and then decline, averaging 137,000 bpd in 2007, 129,000 bpd in 2008 and 121,000 bpd in 2009.

The Department of Revenue’s fall forecast estimates that Kuparuk main reservoir production will drop in 2005 to some 144,000 bpd, while satellites will contribute 55,000 bpd, for an expected average of 199,000 bpd from the unit. In 2006, a total of 207,000 bpd is expected to include 141,000 bpd from Kuparuk and 66,000 bpd from satellites. By 2012, Revenue estimates that the main Kuparuk reservoir will be averaging 102,000 bpd, while the satellites will be producing some 100,000 bpd. The department’s list of Kuparuk satellites includes those presently under production: West Sak, Tabasco, Tarm and Melwater.

ConocoPhillips Alaska said the 3-D seismic that will be shot this winter uses “new technology that’s designed to allow us to image in the reservoir where the oil and gas are” allowing the company to target sidetracks.

Foiled by the complex geology at Kuparuk, he said, “we can’t slow the decline down” as a result of the new 3-D, which will have higher frequency content, closer spacing and longer offset, it expects “significant improvement in stratigraphic and structural resolution at all horizons, both producing and non-producing intervals."

ConocoPhillips is also drilling sidetracks to allow us to get the most from Kuparuk, whether it’s through base management or whether it’s through development," Fox said.

ConocoPhillips is building a new full-field reservoir simulation model at Kuparuk, challenging “because of the complexity of the field.” The combination of new 3-D seismic, coiled tubing drilling and the new reservoir simulation model, “are going to allow us to get the most from Kuparuk, whether it’s through base management or through new development,” Fox said.

ConocoPhillips is looking for additional drilling opportunities in the Kuparuk reservoir. This winter, Fox said, “we’re running a new 3-D seismic survey across the Kuparuk” field.

Kuparuk, he said, “is one of the most complex fields in the world from a geological perspective, from a faulting perspective — it’s just incredibly complex. You combine that with the fact that we’re doing a miscible gas-injection enhanced oil recovery. You can’t go many years in the world and find anything more challenging than this.”

Because Kuparuk is so complex, there are still opportunities there, Fox said.

In addition to the new seismic, ConocoPhillips is also experimenting with coiled tubing drilling techniques.

Coiled tubing drilling has been used successfully at Prudhoe Bay, Fox said, “but the geology at Kuparuk makes coiled tubing drilling more of a challenge…”

In addition to 3-D and coiled tubing, ConocoPhillips is “building a new full-field reservoir simulation model at Kuparuk, challenging “because of the complexity of the field.” The combination of new 3-D seismic, coiled tubing drilling and the new reservoir simulation model, “are going to allow us to get the most from Kuparuk, whether it’s through base management or through new development,” Fox said.

“Horizontal wells

Coiled tubing wells will also increase rates, Fox said, because they are drilled as horizontal sidetracks. Coiled tubing can’t achieve the lateral lengths a rotary rig can, “but we don’t need those lengths because it’s quite a tight well spacing in Kuparuk anyway. What we need is the accuracy, the ability to see it and then get after it with the coiled tubing.”

Fox said ConocoPhillips plans to put the 3-D it shoots this winter to work before the end of this year and is doing some preparatory work so that the seismic can be very efficiently processed.

Once the seismic has been interpreted, he said, it will be used to identify targets for infill drilling at Kuparuk for the next several years.

ConocoPhillips told the Division of Oil and Gas that the 3-D seismic survey will be 155 square miles “of full-field data, covering nominally one-half” of the Kuparuk River unit. The company said original 3-D datasets were acquired between 1988 and 1990, and as a result of the new 3-D, which will have higher frequency content, closer spacing and longer offset, it expects “significant improvement in stratigraphic and structural resolution at all horizons, both producing and non-producing intervals…”

ConocoPhillips is also drilling a sidetrack lateral on the eastern edge of Kuparuk, the 3-D-101L, from the 1D pad in ADL 25661, to test Kuparuk C4, C3, C2 and C1 sands in lease ADL-26248, outside the boundary of the existing participating area, although inside the Kuparuk River unit. The company said that if the sidetrack, being drilled as a single-trip operation, is successful, the working interest owners will apply for an expansion of the participating area.

ConocoPhillips plans one-half rotary rig per year for Kuparuk drilling and infill drilling at Kuparuk for the next five years with five to seven new penetrations per year. Approximately five coiled tubing drilling wells are planned in 2005 and 2006, the company said, then 10 coiled tubing wells per year for 2007-09, the remaining years of this five-year plan.

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customers is “definitely a competition.”

Terasen, in setting a Jan. 26 deadline for “expressions of interest,” is equally certain it is the front-runner because of the options it is offering — a view that Credit Suisse First Boston analyst Dominique Barker endorses because of the opposition she expects Enbridge will encounter from aboriginal groups along its right of way in British Columbia.

Applications need to be filed this year

The consensus among industry observers is that regulatory applications will need to be filed this year if either company is to capitalize on an expected increase of 2 million barrels per day of oil sands production by 2010.

Greg Stringham, vice president of the Canadian Association of Petroleum Producers, told the Globe and Mail that the contest is “getting to the crunch point.”

The association itself is also getting into the act, with plans to unveil its own report this month on the competing pipeline proposals and the outlook for markets in Asia, California and the U.S. Midwest to refine oil sands output.

Given that more pipeline capacity to eastern North America is also likely to be needed, Stringham suggested that regardless of who is first in the race to the British Columbia coast, the ultimate demand for transportation should benefit both companies.

Enbridge focus is Gateway

Enbridge is pinning its hopes on the Gateway project, a 400,000 bpd system costing C$2.5 billion, with 75-80 percent of the volume capacity of 250,000 bpd (likely China) and the rest to California.

Enbridge has already secured an interim agreement with Nexen and OPTI Canada, joint partners in the Long Lake oilsands project covering 60,000 bpd over a 50-month term, starting in late 2006.

That also requires expansion of Enbridge’s 330-mile Athabasca pipeline from its current capacity of 250,000 bpd to 350,000 bpd, tapping into various phases of the ConocoPhillips-Total Surmont project, Devon Canada’s Jackfish scheme, Canadian Natural Resources’ Horizon Phase 1, plus Long Lake Athabasca, which links Fort McMurray with the Enbridge mainline at Hardisty in central Alberta, has an eventual design capacity of 570,000 bpd.

Also on Enbridge’s drawing boards is its 30-year lease with the Prince Rupert Port Authority and Galveston LNG has raised C$550 million, about one-tenth of what it estimates is needed to construct a terminal.

WestPac’s lease gives it exclusive rights for an LNG project on 250 acres of industrial land on Ridley Island near Prince Rupert.

It opens the way for WestPac to move forward on other aspects of its C$200 million venture to ship LNGs from possible sources in the Middle East, Australia, Indonesia and Russia. Plans call for daily volumes of 300 million cubic feet per day, starting in 2009.

Galveston is aiming to begin operations in 2008 and handle 340 million cubic feet per day, using its Kitimat terminal as a distribution hub for markets in Canada and the United States.

It hopes to follow the C$50 million financing, about one-third from an unidentified investment company in Boston, with another C$100 million in the first half of 2005.

Galveston has also filed for regulatory approval and claims to have the backing of the Town of Kitimat, where residents are more interested in its chances of an economic infusion than mounting environmental opposition.

The company has also made progress in lining up customers, such as utilities and industrial companies, and is confident it can secure supplies. But Gordon Hart, who sold his C$350 million plan to build an LNG terminal in Nova Scotia to Anadarko last summer, cautions that small LNG promoters like Galveston face difficult obstacles, partly because of the distance from British Columbia to U.S. markets.

He also said the terminal covers 10 percent or less of the cost of LNG. The bulk is needed for liquefaction and shipping. Without assurances of strong markets, long-term supply contracts pose a challenge, while large players in the LNG shipping business will have no interest in glutting the markets, Hart said.

Leading players

The consensus among industry observers is that regulatory applications will need to be filed this year if either company is to capitalize on an expected increase of 2 million barrels per day of oil sands production by 2010.

A second stage costing C$480 million would add 195 miles of new 30-inch pipe, more than doubling Trans Mountain to 850,000 bpd.

The Northern Option proposed more than 600 miles of new pipe to offer 500,000 bpd of heavy and light crude to either Prince Rupert or Kitimat, which Enbridge says would accommodate more than fivefold to 5 million bpd over the next 25 years.

Terasen offering options

While Enbridge juggles its various elements, Terasen is offering a different set of options in a bid to lure current and prospective customers.

The strategy is “all about options, choice and flexibility,” said Terasen President Rich Ballantyne.

The documents start with plans for an initial “anchor loop” on the Trans Mountain pipeline from Edmonton to British Columbia’s Lower Mainland, spending C$570 million to hike volumes to 300,000 bpd from 225,000 bpd by 2008, offering tolls of C$1.40 per barrel.

From that phase, Terasen is pitching either a Southern Option or Northern Option.

The first would involve a 300-mile, 30-inch-diameter pipeline, costing C$900 million and boosting Trans Mountain capacity to 400,000 bpd by 2009.

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continued from page 1

WILDCAT

Campbell, head of investor relations for Blackbeard partner Newfield Exploration.

The Blackbeard well is a true frontier venture, headed to the 32,000-foot level and perhaps beyond in search of what some explorers believe could harbor giant reserves containing trillions of cubic feet of natural gas. Geologic structures that make up this “ultra-deep” play on the Gulf’s continental shelf are said to be as large as the state of California.

However, the curious will have to wait a spell for Blackbeard’s results. “The well will take nine months to a year to complete, and we’ll wait a spell for Blackbeard’s results. We’ll then have to find another partner willing to absorb the full cost of drilling,” Campbell said.

Rowan will drill with jack-up

Rowan, which has drilled two-thirds of all deep wells below 18,000 feet on the continental shelf, was selected for the Blackbeard project.

The company plans to use its newest rig, the Tarzan jack-up class Scooter Yeargain, and stands to reap $28 million to as much as $35 million for the job, depending on how long the rig is employed.

The super powerful Scooter Yeargain was designed specifically to withstand the “high pressure, high temperature” environment associated with deep drilling, said Danny McNeece, Rowan’s chairman and chief executive officer.

Blackbeard would be one of the few exploration wells to penetrate the so-called “ultra-deep” zone below 25,000 feet on the Gulf’s continental shelf. Shell was the first with its Shark wildcard, which turned out to be a dry hole. The major is said to be currently drilling a 26,000-foot well on its Joseph prospect offshore East Texas.

Newfield, an independent exploration and production company based in Houston, had tried for several years to find a partner willing to absorb the full cost of drilling an ultra-deep well on its Treasure Island property, which houses the Blackbeard prospect. The company hit the jackpot in April 2004 when it signed on major ExxonMobil and BP and Brazil state-owned oil company Petrobras.

ExxonMobil is serving as operator of the huge Blackbeard prospect, which actually covers multiple blocks in both the South Timbalier and Ship Shoal areas offshore Louisiana. Under terms of the deal, Newfield retains a 25 percent carried working interest in Blackbeard and will not have to spend a dime on the exploration well.

Newfield also signed a letter of intent with Petrobras to drill one firm exploration well with an option to drill a second well to earn a 30 percent interest in all of Newfield’s 27 Treasure Bay leases.

Newfield also has a stake in 60 blocks associated with the nearby Treasure Bay project, another area on the Gulf’s continental shelf thought to have ultra-deep potential.

CBM

Peters & Co. said Apache Canada, EnCana, MGV Energy and Trident Exploration will lead the coalbed methane charge in 2005, with Apache raising its well total as much as 800 from its current 300 and more than tripling its volumes to 142 million cubic feet per day.

EnCana, with a current tally of 450 wells, will add another 1,000 in 2005, the report predicted, while MGV, the wholly owned unit of QuickSilver Resources, will more than double its well count to 750 in 2005 and make a three-fold gain in production to 100 million cubic feet per day.

Trident, which had targeted 300 gross wells in 2004, will add another 500 to 800 in 2005, pointing to a quantum leap in volumes from its reported 11 million cubic feet per day in September.

1,500 coalbed methane completions expected in 2004

Peters & Co. expects Canada to notch 1,500 coalbed methane well completions this year, achieving year-end production of 150 million cubic feet per day, or 1 percent of Canada’s total gas volumes.

Compared with the United States, coalbed methane is still in its infancy in Canada, but the potential is huge.

The Geological Survey of Canada has estimated coal seams hold 182 trillion to 553 trillion cubic feet, 60 percent located in the Alberta plains.

But Peters & Co. noted that most experts rate the ultimate recoverable resource at 20 to 100 tcf.

For the entire gas sector, the Alberta Energy and Utilities Board issued 13,502 permits for conventional gas wells for the first 11 months of 2004, 17 percent ahead of last year’s pace, while licenses for coalbed methane-targeted wells more than tripled to 1,397.

More than 20,000 gas permits expected for 2004

Canada-wide, regulators expect to issue 20,000 plus permits this year, having already exceeded 18,000 by the end of November in Alberta, British Columbia and Saskatchewan.

Leading the percentage gains was northeastern British Columbia where licenses were approved for 1,468 gas wells, 264 ahead of the January-November period of 2003.

The license count totaled 25,355 at the end of November, 8.6 percent above the 2003 record, with November alone claiming 3,221 new permits.

Industry records to the end of November show about 14,760 gas wells were completed across Canada, or 73 percent of the total 20,224 of which oil wells accounted for 20.5 percent, with the balance reported as service wells and dry holes.

Based on that performance, the Canadian Association of Oilwell Drilling Contractors expects rig utilization and its member companies will average 62 percent for all of 2004, matching the record set in 2003, although this year has seen the fleet expand by 124 rigs to 702.

Fleet utilization for early November in western and northern Canada was 80 percent.

—GARY PARK