Petroleum news

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North America's source for oil and gas news

Week of January 4, 2004 • $1

page 4 Alaska Railroad sees money in gas line tax-exempt bonds

Diving into the deep end

COURTESY MURPHY OIL

J. Ray McDermott delivered a 14,064 ton truss spar hull last month for Murphy Oil's Front Runner project in Green Canyon offshore Louisiana. Above the hull is being loaded out onto a heavy lift vessel from Dubai, United Arab Emirates, where it was fabricated. McDermott will install the floating production system in more than 3,521 feet of water. The platform will be able to handle 60,000 barrels of crude and 110 million cubic feet of gas per day from Front Runner and other nearby Gulf of Mexico prospects coming on line in the second quarter.

ExxonMobil says Point Thomson not viable as standalone project

The Point Thomson bubble has apparently burst — at least until there is a natural gas pipeline from Alaska's North Slope to take gas to market.

Field operator ExxonMobil, speaking for itself and other major owners of the undeveloped eastern North Slope field — BP Exploration (Alaska), Chevron U.S.A. and ConocoPhillips Alaska — told the Alaska Division of Oil and Gas in mid-December that "a standalone project prior to gas sales is not economically viable under the current fiscal system."

ExxonMobil told the state that "completion of engineering

see POINT THOMSON page 15

Alberta eager to aid flow of Arctic gas; Smith promises to untangle regulatory knots

Alberta Energy Minister Murray Smith

Prodded by industry leaders, the Alberta government is planning to unveil regulatory changes that will offer easier access to its natural gas pipelines by out-of-province suppliers.

Energy Minister Murray Smith said the streamlining will apply to interested parties in Alaska, the Northwest Territories and British Columbia.

Speaking to conferences over the final quarter of 2003, he pledged efforts by the

see ALBERTA page 19

BREAKING NEWS

WASHINGTON, D.C.

A cloudy forecast

EIA analysts cut 2025 crude production estimate by 660,000 barrels per day

By ALLEN BAKER

Petroleum News Contributing Writer

Federal energy analysts are taking off their rose-colored glasses when it comes to projecting Alaska's future oil production. In the recently released Annual Energy Outlook 2004, Energy Department experts cut their estimate of Alaska production in 2025 by 660,000 barrels a day, to a daily production of just 510,000 barrels. That's just over half of the current number.

The Energy Information Administration estimates, out Dec. 16, now align more closely with the figures from the Alaska Department of Revenue. Gone are optimistic expectations published last year that Alaska production would climb to 1,280,000

"The North Slope could actually be producing pretty much a million barrels a day until 2025 if some of the heavy oil fields go into production. That would be like adding a couple of billion-barrel fields."
—EIA analyst Philip Budzik

JUDY PATRICK

Mark Myers, director of the Alaska Division of Oil and Gas, thinks EIA's assessment is unduly pessimistic and is missing a significant component.

see FORECAST page 19

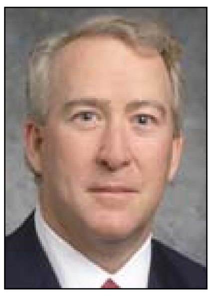
OKLAHOMA CITY

Chesapeake changes its view on Permian basin potential

Independent buys $510M in assets where it had considered pulling up stakes

PETROLEUM NEWS

Deal-minded Chesapeake Energy has dramatically strengthened its position in the U.S. Permian basin, a region of the country where not long ago the predominantly natural gas producer said it would pull up stakes to focus on its prize exploration and development area, the U.S. Midcontinent.



Chesapeake CEO Audrey McClendon

Of the $510 million in property acquisitions announced by the Oklahoma-based independent in late December, roughly three-quarters of "the deal" involved the Permian basin of West Texas and northeastern New Mexico, Audrey McClendon, Chesapeake's chief executive officer, told analysts in a conference call.

Only about 15 percent of the assets being purchased by Chesapeake in three separate deals are located in the Midcontinent and the rest in South Texas and onshore Gulf Coast, he said.

In late 2002, Chesapeake said it wanted to sell or trade its Permian assets, which the company had inherited in previous deals and had no real interest in keeping. But when the company "put it all together" and "hired a good team" to look at the Permian,

see CHESAPEAKE page 16

ALBERTA

Oil sands poised for gusher

Study projects 5 million barrels per day by 2030, 20% of continent's demand

By GARY PARK

Petroleum News Calgary Correspondent

Certain that North America's dependence on crude oil will extend to at least 2050, the Alberta Chamber of Resources sees a future for the province's oil sands that will stagger even the most starry-eyed optimists.

By 2030, the chamber estimates the oil sands could be producing 5 million barrels per day, or 20 percent of the continent's demand, assuming that technological advances can unlock more than the current 175 billion barrels of oil thought to be recoverable with known methods.

"Technology development and adoption has rapidly reduced supply costs and increased the economic viability of oil sands development with world crude prices at sustained levels at or above US$20 per barrel," the chamber said in the draft of an Oil Sands Technology Roadmap, released for comment in

Just doubling output to 2 million bpd in the 2010-2012 period dangles the prospect of 32,000 new jobs, while achieving the 5 million bpd level would require spending of C$30 billion for each increase of 1 million bpd.

see GUSHER page 16

Alaska - Mackenzie Rig Report

*The Alaska - Mackenzie Rig Report as of December 31, 2003.
Active drilling companies only listed.*

**TD = rigs equipped with top drive units WO = workover operations
CT = coiled tubing operation SCR = electric rig**

This rig report was prepared by Wadeen Hepworth

Alaska Rig Status

North Slope - Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Milne Point, drilling MPF-88	BP
Sky Top Brewster NE-12	15 (SCR/TD)	Stacked, Endicott Island	Available
Dreco 1000 UE	16 (SCR)	Stacked, Deadhorse	Available
Dreco D2000 UEBD	19 (SCR/TD)	Alpine, drilling CD2-43	ConocoPhillips
OIME 2000	141 (SCR/TD)	Meltwater, drilling 2P-424	ConocoPhillips
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Stacked, Prudhoe Bay	Available
Dreco 1000 UE	2-ES (SCR)	Going to DS-7 by end of year	BP
Mid-Continent U36A	3-S	Stacked at Prudhoe Bay	Available
Oilwell 700 E	4-ES (SCR)	Prudhoe Bay, working	BP
Dreco 1000 UE	7-ES (SCR/TD)	Prudhoe Bay, S pad	BP
Dreco 1000 UE	9-ES (SCR/TD)	Prudhoe Bay, V pad	BP
Oilwell 2000 Hercules	14-E (SCR)	Moving to location	Total
Oilwell 2000 Hercules	16-E (SCR/TD)	Stacked, Prudhoe Bay	Available
Oilwell 2000	17-E (SCR/TD)	Stacked, Point McIntyre	Available
Emsco Electro-hoist -2	18-E (SCR)	Stacked, Deadhorse	Available
OIME 1000	19-E (SCR)	Stacked, Deadhorse	ConocoPhillips
Emsco Electro-hoist Varco TDS3	22-E (SCR/TD)	Stacked, Milne Point	Available
Emsco Electro-hoist Canrig 1050E	27-E (SCR/TD)	Stacked, Deadhorse	Available
Emsco Electro-hoist	28-E (SCR)	Stacked, Deadhorse	Available
OIME 2000	245-E	Stacked, Kuparuk	ConocoPhillips
Nordic Calista Services			
Superior 700 UE	1 (SCR/TD)	DS-15, well 33b	BP
Superior 700 UE	2 (SCR)	DS-15, well 04	BP
Ideco 900	3 (SCR/TD)	1Y pad, Feb. 1 start up	ConocoPhillips

North Slope - Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Nabors Alaska Drilling			
Oilwell 2000	33-E (SCR/TD)	NS-27, Northstar	BP

Cook Inlet Basin – Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Marathon Oil Co. (Inlet Drilling Alaska labor contractor)			
Taylor	Glacier 1	Cannery Loop Unit #7	Marathon
Inlet Drilling Alaska/Cooper Construction			
Kremco 750	CC-1	Stacked, Kenai	Forest Oil
Nabors Alaska Drilling			
Rigmasters 850	129	Marathon gas field	Marathon
National 110 UE	160 (SCR)	Stacked, Kenai	Available
Continental Emsco E3000	273	Kasilof, KS1	Marathon
	51	Steelhead platform, done 12-1-03	Unocal
Aurora Well Service			
Franks 300 Srs. Explorer III	AWS 1	Stacked, Nikiski	Available
Evergreen Resources Alaska			
Wilson Super 38	96-19	Stacked in yard	Evergreen Resources Alaska Corporation
Engersol Rand	1	Stacked in yard	Evergreen Resources Alaska Corporation
Water Resources International			
Ideco H-35 KD		Trading Bay, spud Nov. 4 Dec. 12 at 3517' TD Idle, waiting for breakup	Pelican Hill

Cook Inlet Basin – Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
XTO Energy (Inlet Drilling Alaska labor contract)			
National 1320	A	Idle	Idle
National 110	C (TD)	C22-23 workover	XTO
Nabors Alaska Drilling			
IDECO 2100 E	429E (SCR)	Rigging down, demobilizing to Kenai	Forest Oil
Unocal (Nabors Alaska Drilling labor contractor)			
Not Available			
Kuukpik	5	Relased on Dec. 26, demobilizing off platform and will stack in Kenai	idle

Mackenzie Rig Status

Mackenzie Delta-Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
AKITA Equtak Drilling Ltd.			
Oilwell 500	62	Stacked, Tuktoyaktuk, NWT	EnCana
Dreco 1250 UE	63 (SCR/TD)	No specifics provided	Chevron Canada
	64	Stacked, Inuvik, NWT	Available

Central Mackenzie Valley

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
AKITA/SAHTU Drilling Ltd.			
Oilwell 500	51	Drilling in the Colville lake area	Apache Canada
	40	Drilling near Tulita, NWT	Northrock Resources
Nabors Canada			
	62	Stacked, Norman Wells	Available

Christy loading platform in Cook Inlet Courtesy Offshore Divers

Baker Hughes North America rotary rig counts*

	December 23	December 19	Year Ago
US	1,114	1,112	862
Canada	308	495	277
Gulf	101	103	108

Highest/Lowest

US/Highest	4530	December 1981
US/Lowest	488	April 1999
Canada/Highest	558	January 2000
Canada/Lowest	29	April 1992

*Issued by Baker Hughes since 1944

Rig start-ups expected in next 6 months

AKITA/SAHTU Drilling Ltd.

55 Will be drilling for EnCana near Tulita, NWT. January 2004 start-up.

AKITA Equtak Drilling Ltd.

62 Will be drilling for EnCana this winter in the Mackenzie Delta. January 2004 start-up.

The Alaska - Mackenzie Rig Report is sponsored by: ConocoPhillips

ALASKA

State of Alaska receives winter seismic, core hole applications for Cook Inlet, Nenana, Holitna basins

The state of Alaska has received applications for winter seismic programs in the Cook Inlet and Nenana basins, and a core hole application in the Holitna basin.

The seismic applications, on the south Kenai Peninsula, on the west side of Cook Inlet and in the Nenana basin, are from Veritas DGC Land.

Veritas said the Cook Inlet programs, approximately 100 miles of two-dimensional seismic, would be shot between the end of January and May 1.

The south Kenai program is southeast of Ninilchik and north of Anchor Point. The crew will stay in Ninilchik.

The west side survey is from the Moquawkie area straddling the Beluga River and continuing south to North Foreland and Trading Bay. The crew will stay in the VECO camp in Beluga.

The Nenana basin survey is approximately 200 miles of 2D seismic. Veritas said that work would be done from Jan. 15 through May 15, with mobilization of equipment out of Anchorage in January. Accommodations will be on site at a mobile remote camp.

Core holes in Holitna basin

The application for the core hole program is from Naniq Energy Co. LLC of Eagle River, Alaska, to drill two core holes in the Holitna basin some 15 miles southeast of

see APPLICATIONS page 4

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Petroleum news

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● ALASKA

Alaska Railroad sees money in gas

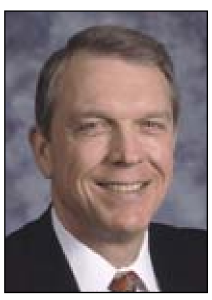
Company would use tax-exempt bond issuance fee for gas line to finance track upgrades

By LARRY PERSILY

Petroleum News Juneau Correspondent

The Alaska Railroad Corp. says it would need to upgrade its track and traffic capacity to handle the heavy load of a natural gas pipeline construction project, and it figures it could help pay for the work by charging a fee to project developers if they use the corporation's tax-exempt bonding status to finance the pipeline.

The fee could be worth tens of millions of dollars if project sponsors are able to use the railroad to issue billions of dollars of bonds for the proposed project, estimated to cost up to $20 billion.



"We're told to go out and be profitable so we don't have to draw on the state." —Patrick Gamble, Alaska Railroad Corp. president and chief executive officer

Charging a fee to issue so-called conduit bonds for a natural gas pipeline assumes the Internal Revenue Service would agree with the state's assumption that the railroad corporation can issue tax-exempt debt for such a privately owned project. Tax-exempt bonds could be attractive to project developers because of the lower interest rates charged on such debt.

Railroad officials have discussed the possibility of negotiating a fee in exchange for letting developers save money with lower interest rates, but "only in the most general sense," said Patrick Gamble, the corporation's president and chief executive officer.

The heavy, constant loads of steel pipe and other construction material would put a strain on tracks and could clog busy summer traffic, Gamble said. Better tracks would mean trains could go faster, resulting in more handling capacity, he said. Improved communication links also would allow the railroad to handle pipeline freight at the same time as heavy summer passenger traffic, Gamble said.

Track upgrades needed

Regardless of whether the pipeline project moves ahead, the railroad has a five-year plan for upgrades, starting in 2004, with federal funds to cover much of the work, but not all of it, Gamble said.

If North Slope producers or others decide to build a natural gas pipeline, and pay a fee to the railroad corporation for issuing bonds, the extra money would pay to speed up the corporation's track improvement plan, he said.

Although the railroad is owned by the state, it does not get state money for its capital improvements. "We're told to go out and be profitable so we don't have to draw on the state," the CEO said.

There is some sentiment, however, that the railroad — because it is owned by the state — should not charge a fee if it issues bonds for a natural gas project, Gamble said.

"We view it completely different. We are a private corporation for all intents and purposes," Gamble said, explaining that the state law governing the corporation tells it to be entrepreneurial. Any money made on the bond deal would benefit the state and its residents by paying for needed track improvements, he said.

Valdez issued such bonds in the '70s

The city of Valdez did much the same thing when it sold bonds to help finance construction of the trans-Alaska oil pipeline terminal more than 25 years ago. Valdez charged the oil companies a 1 percent fee for issuing voter-approved, tax exempt bonds for the terminal, raising about $13 million for the city over the years, said John Kelsey, a former Valdez mayor and city council member.

"They'd logically be entitled to a reward," Kelsey said of the railroad corporation.

The natural gas pipeline developers, not the railroad, would be responsible for the bond payments, just as the oil companies, and not the city of Valdez, are responsible for the debt service on the oil terminal.

Charging a fee to issue bonds for a natural gas pipeline assumes the Internal Revenue Service agrees with the state's assumption that the railroad corporation can issue tax-exempt debt for such a privately owned project.

A provision in the law that transferred the railroad from the federal government to the state more than 20 years ago might allow the railroad to serve as a conduit for issuing bonds exempt from federal taxation on the interest paid to investors. If allowed to finance the project with tax-exempt debt, the companies could save as much as $1 billion in interest payments over the life of the bonds, according to estimates prepared by the state in 2002.

Corporation's bonding authority uncertain

Federal law, however, is unclear on whether the corporation's tax-exempt bonding ability extends beyond railroad projects. The law says the corporation may issue tax-exempt debt even when the money is used to finance business activities that normally would not qualify for a tax exemption, but it is uncertain how far the provision might extend.

The clearest answer would be to ask Congress to give the railroad explicit authority to issue tax-exempt debt for the gas line project. Another option would be to seek a ruling from the Internal Revenue Service, based on the existing law.

Gamble said the railroad has been asking around to learn "what's kind of normal for an issuer fee." He attended a recent course on public finance in Washington, D.C., and said he learned 0.5 to 0.75 percent would be within the range of market-rate fees for assisting in such financing, though he was quick to state that is not the railroad's official position or a starting point in negotiations.

"We realize we would have to go to the table with the state and producers," Gamble said.

In addition to a fee for issuing the bonds, the corporation would want to talk about arbitrage — the income made from investing bond sale proceeds before needing to spend the money on construction work. Arbitrage, the spread between the interest owed on the borrowed money and the income earned on investing the money until it's needed, could be substantial on such a large project.

All subject to negotiation

Gamble posed the question: "Should the railroad get that or should the state get that? Our argument is that would be up for negotiation as well."

Whether North Slope producers or other potential gas pipeline developers would want to use railroad bonds would depend, in part, on whether Congress passes the pending energy bill that includes federal loan guarantees for the project. Because a developer generally could not have both a federal loan guarantee and the savings of tax-exempt financing, the companies would need to decide which is more advantageous to their finances.

A federal guarantee could knock half a percent or more from the interest rate on private, taxable debt, with some industry estimates putting the savings at closer to a full percent. ●

CANADA

Husky joins NWT drilling program

Husky has signed a farm-in agreement with four other companies to drill an C$18 million well in the Central Mackenzie Valley of the Northwest Territories.

The operator of the Wilma Summit Creek B-44 well is Northrock Resources (a wholly owned unit of Unocal Oil), with EOG Resources Canada, Pacific Rodera and International Frontier Resources as the other partners along with Husky.

Road and lease construction is taking place and the well is expected to spud around mid-January, targeting a depth of about 9,800 feet and three potential hydrocarbon-bearing zones.In October, construction equipment, drilling supplies and 360,000 liters of fuel were barged up the Mackenzie River.

International Frontier, with a 5 percent interest in the lands, separately announced it will make a private placement of 600,000 common flow-through shares at a price of 60 cents each to accredited investors and directors of the company.

The proceeds will be used to incur Canadian exploration expenditures on the company's Northwest Territories exploration program.

—GARY PARK, Petroleum News Calgary correspondent

continued from page 3

APPLICATIONS

Sleetmute. Equipment will be moved up the Kuskokwim River from the Red Devin airstrip in January to build an ice strip on Big Lake. A Hercules C-130 aircraft will transport two truck-mounted drill rigs and supplies to the Big Lake ice strip, and the equipment will be moved cross country to the drill sites.

The two core holes will be drilled to a depth not exceeding 3,500 feet, and the holes will be logged and the cuttings put down the holes.

The core hole locations are in sections 7-35 of township 17 north, range 42 west, Seward Meridian, and sections 6 and 8 of T16N-R42W, SM.

The crew will stay in Red Devil and be taken to the sites by helicopter. Naniq estimates approximately 90 days of work.

—PETROLEUM NEWS

● CANADA

Canadian pipelines chase U.S. markets

Calgary-based Enbridge buys Shell assets; Vancouver-based Terasen accelerates timetable for Express

By GARY PARK

Petroleum News Calgary Correspondent

Enbridge and Terasen, Canada's two largest crude oil pipeline companies, have ratcheted up the scramble to secure greater access for Canadian oil in U.S. markets.

Operating largely through its U.S. unit, Calgary-based Enbridge announced deals Dec. 22 that include 615 miles of pipelines and 9.5 million barrels of storage in Oklahoma and Illinois, while Vancouver-based Terasen unveiled plans to raise capacity by 60 percent on its 172,000 barrels per day Express line from Alberta to Wyoming.

In the latest of a flurry of U.S. acquisitions, Enbridge will pay Shell-owned companies US$140.5 million for a bundle of assets, subject to regulatory approvals and rights of first refusal.

The purchases are highlighted by the 433-mile Ozark pipeline from Cushing, Okla., to Wood River, Ill., which has capacity of 252,000 bpd, but is currently operating at about two-thirds of that level.

Enbridge believes it can increase Ozark volumes once it completes the purchase a 90 percent stake in the Cushing-to-Chicago crude pipeline from BP, which has capacity of 300,000 bpd plus 4.3 million barrels of tankage.

By the end of 2004, Enbridge expects to have reversed the flow of that pipeline, which will be renamed Spearhead, to open up a new marketing area for Canadian heavy oil.

Among the other assets, Enbridge will gain 58.8 percent of the 135-mile Osage line from Cushing to El Dorado, Kansas, a system that is currently moving 110,000 bpd, 10,000 bpd below capacity; the 47-mile, 65,000 bpd West Tulsa pipeline; and a 60 percent interest in the 310,000 bpd Woodpat line from Wood River to Patoka.

Terasen boosting Express capacity

Terasen, meanwhile, is accelerating its timetable to boost Express capacity to 280,000 bpd, less than a year after acquiring the line from EnCana for C$1.18 billion.

Initially, it planned a two-stage expansion, but the response to an open season has convinced Terasen to combine the phases when it seeks National Energy Board approval early in 2004, targeting spring 2005 for the upgrade.

The project, which President and Chief Executive Officer John Reid has indicated could cost about C$100 million, is eagerly awaited by refineries in the U.S. Rocky Mountain region, where production is starting to slide.

Express, which covers more than 700 miles, connects at Casper, Wyo., with the Platte system and opens up markets in southern Illinois.

Reid said last month that increasing supply from the Alberta oil sands along with growing U.S. demand are "creating exciting future growth opportunities." ●

ARCTIC

Map offers unified look at Arctic vegetation

A new map of Arctic vegetation has made it easier for researchers to study the area.

University of Alaska Fairbanks researcher Donald "Skip" Walker led a team of some 35 scientists from five countries who worked for 11 years developing the "Circumpolar Arctic Vegetation Map."

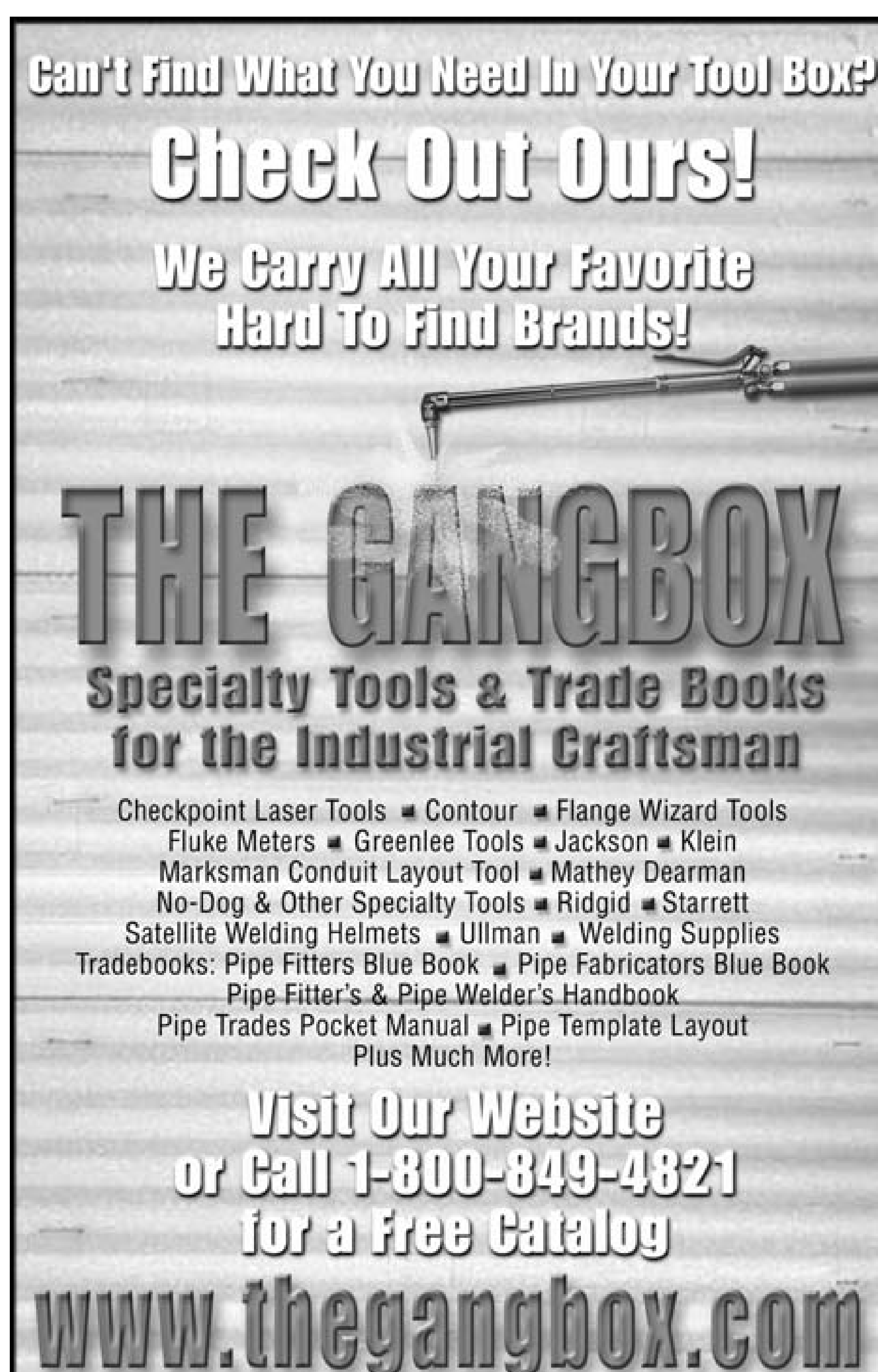
The problem the map addresses is that mapping of Arctic vegetation had been done in varying scales, legends, language and coverage, providing at best a fragmented picture of the Arctic. The map, published in October, provides the first chance for everyone from scientists to educators to residents of Arctic communities to use vegetation as a common factor in analyzing the entire region, according to Walker.

"We're beginning to see the Arctic as a whole system with a lot of common characteristics and cultural and social issues," he told the Fairbanks Daily News-Miner. "A map on vegetation really helps address a lot of these issues."

Walker said developing the map involved mapping vegetation in areas where sufficient data wasn't available and combining existing maps into a common view of the Arctic. The project, funded by about $700,000 in National Science Foundation money, also presented plenty of logistical challenges in trying to coordinate efforts from scientists spread throughout the world.

Once all the maps had been assembled, UAF researcher Martha Raynolds started the process of synthesizing them into a common image. Raynolds used an infrared image of the Arctic region as seen from the North Pole as a base map, then added data from the mapping of individual areas to produce the completed product.

The finished map offers a more complete picture of the variety of Arctic vegetation than do the satellite images used for analyzing vegetation, she said.



ALLAKAKET, ALASKA

FBI looks for men who booked flight to village near trans-Alaska pipeline

Amid heightened national security, the FBI is looking for a man who booked a flight to a remote village near the trans-Alaska oil pipeline.

A man had requested a charter to the Koyukuk River village of Allakaket using a known alias of Zaman Muhammad, but he and a travel companion didn't show up for the flight. The air carrier then contacted the FBI.

"We cannot connect them with any type of criminal activity at this time," said Bob Burnham, assistant special agent in charge for the FBI in Anchorage. "As far as we know, there could be a completely innocent explanation to all of it."

Saying new intelligence data suggested the possibility of terrorist attacks during the holidays, federal officials Dec. 21 raised the national security threat level to "orange," the highest notch below an actual attack. Alaska Gov. Frank Murkowski raised the state's level to orange Dec. 22.

Burnham said employees at the air carrier became suspicious about a stranger asking to travel to Allakaket, 190 miles northwest of Fairbanks, in winter. The flight path parallels the pipeline part of the distance, but doesn't cross it.

The agent would not say who contacted the FBI about the flight or comment on how the agency knew the person may have used an alias.

"It's the orange alert that caused us to look at this a little more quickly," Burnham told the Anchorage Daily News. "It's a great example of somebody trying to do the right thing."

The operations manager at Warbelow's Air Ventures called the FBI sometime over the weekend about two passengers who had booked seats on the Dec. 21 regular Sunday flight to Allakaket using a reservation service, said owner Art Warbelow. They hadn't chartered their own flight, however.

Seeing two strangers giving Middle Eastern names heading to the Athabascan village of 97 seemed odd, especially since the flight carries regulars, Warbelow said. The passengers never showed up.

"We're in a little different situation from most of the big airlines because we know all of our customers," Warbelow added.

—THE ASSOCIATED PRESS

● HOUSTON, TEXAS

U.S. independents' earnings could drop despite higher prices

Analysts expect fourth quarter earnings to decrease by 12%

PETROLEUM NEWS

Analysts expect the leading U.S. exploration and production independents to report 2003 fourth quarter earnings roughly 12 percent below the third quarter, a surprise considering prices for natural gas rose 12.7 percent and oil 3.5 percent during the same period.

However, the consensus among analysts who follow the 15 independents tracked by Petroleum News also is that 2003 fourth-quarter earnings should increase about 40 percent compared to the same period in 2002 when commodity prices began to strengthen.

Early consensus for the 2004 first quarter projects that earnings will increase 5.6 percent from the 2003 fourth quarter, due largely to normal seasonal demand for energy.

Because independents are heavily dependent on income from production, oil and natural gas prices generally play a crucial role in shaping quarterly financial results. And with just a few trading days remaining in the 2003 fourth quarter, U.S. gas prices were averaging $5.42 per thousand cubic feet compared to $4.82 in the third quarter. Oil prices during the same period averaged $31.15 per barrel versus $28.01 in the prior quarter.

Despite the increase in commodity prices quarter-over-quarter, the consensus among analysts is that many independents will make less profit in the 2003 fourth quarter than in the previous quarter.

That could be because of declining production, a problem that has plagued industry in the United States for several years, or to hedging production at oil and gas prices that ended up being lower than average spot market prices for the quarter. Gas prices also increased dramatically during the first weeks of December, following a period of declining prices due to a rapid build in storage that began to wane in the final month of the year.

Natural gas surplus declined rapidly

"What had been a rapidly building surplus suddenly encountered some seasonally cold weather and as a consequence, declined by 58 billion cubic feet in three weeks," said Stephen Smith of Stephen Smith Energy Associates. Although a sizeable surplus of 199 bcf remained after the draw down, he added, "the gas price (still) increased by over 50 percent in two to three weeks time."

Companies tracked by Petroleum News for the purpose of gauging earnings in the independent sector are Pioneer Natural Resources, Kerr-McGee, Anadarko Petroleum, Devon Energy, Unocal, Apache, Chesapeake Energy, XTO Energy, EOG Resources, Noble Energy, Burlington Resources, Newfield Exploration, Forest Oil, Tom Brown and Evergreen Resources.

According to consensus estimates among analysts polled by Thompson/First Call, only Kerr-McGee, Chesapeake and Tom Brown were expected to post earnings increases in the final quarter of 2003. However, earnings estimates are adjusted as reporting day approaches, and generally there are companies that regularly miss or beat consensus estimates.

Investment bank Lehman Brothers argues that investors today tend to penalize companies that spend their excess cash on drilling and reward those that curtail spending and use their extra cash for debt reduction, acquisitions, stock buy backs and shareholder dividends.

"In the past investors were focused on production growth, even if that growth was uneconomic and if it came at the cost of rising debt and increased shares outstanding," Lehman said, adding that these days investor focus is on "capital discipline."

"If 2003 is a guide, investors may reward those companies that generate the most cash flow in the new year," Lehman said. "Our expectations," Lehman said, are that XTO, Pioneer, Apache and Burlington stand to generate the most free cash flow among U.S.-based independents in 2004.

Lehman's analysis supports other studies showing that U.S. natural gas production, the mainstay of most independents, has been shrinking at the rate of 2 to 3 percent a year, ushering in a growing import market for liquefied natural gas.

Nevertheless, "this indicates to us that companies that have exhibited capital restraint have actually performed better in delivering volume growth results on a per share basis," Lehman concluded. ●

DENVER, COLO.

Tom Brown sets capital budget, production targets for new year

Exploration and production independent Tom Brown said it plans to spend $250 million to $300 million on exploration and development in 2004 compared to $245 million to $255 million in 2003.

Seventy to 80 percent of the budget this year is earmarked for development activities and the remainder for leasing and exploration, the company said, adding that it expects cash flow to "significantly exceed" its capital spending and that it intends to use the extra cash to reduce debt, acquire properties or possibly finance additional drilling.

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"Our capital spending program is designed to achieve strong reserve and production growth and return on capital," Jim Lightner, Tom Brown's chief executive officer, said Dec. 18.

The Denver-based company projected that 2004 production would range between 114 billion cubic feet and 117 bcf of natural gas equivalent, or about 20 percent higher than 2003 output. Production is 85 percent natural gas.

Tom Brown said its 2004 capital budget excludes any property acquisitions or divestitures the company might do during the year, as well as production gains from any drilling successes.

—PETROLEUM NEWS

EL DORADO, ARK.

Murphy warns of lower fourth quarter profits

Murphy Oil said Dec. 30 it expects income before special items for the fourth quarter to be 55-60 cents per diluted share. Production during the quarter is estimated to average 124,000 barrels of oil equivalent per day. Expected average crude oil and natural gas sales volumes for the quarter should be 127,000 boe per day. Arkansas-based Murphy said in a statement that it expects dry hole charges for the fourth quarter to be "in the range of $19-$22 million with total worldwide exploration expense averaging between $35 million and $40 million."

In the worldwide downstream business, Murphy expects to post a loss of approximately $10 million for the quarter "reflecting the erosion of Gulf Coast refining margins as well as reduced U.S. refinery runs during the start up of the Meraux refinery including new units brought online with the completion of the Clean Fuels project."

Corporate charges are expected to rise to $15 million in the fourth quarter "reflecting the reduction in capitalized interest as the Medusa and Habanero developments in the deepwater Gulf of Mexico and the Clean Fuels project at the Meraux refinery are now completed."

The company said "earnings may also vary based on prices, volumes and the timing of actual liftings" of some of Murphy's oil production.

HOUSTON, TEXAS

Noble Energy launches first natural offshore production in Israel

Natural gas production has begun from the Mari-B field in the Mediterranean Sea offshore Israel, project operator Noble Energy said, noting that Mari-B is the first offshore gas production facility in Israel.

"The startup ... is an important milestone for the company," Charles Davidson, Noble's chief executive officer, said Dec. 24. "This project will contribute consistent and substantial production volumes, cash flow and income for years to come."

Houston-based Noble and its partners have an 11-year contract to supply 636 billion cubic feet of natural gas to Israel Electric for the utility's electrical power plants.

Noble's Mari-B partners include Avner Oil Exploration Limited Partnership (23 percent), Delek Drilling Limited Partnership (25.5 percent) and Delek Investments and Properties (4.441 percent). Noble holds a 47.059 percent stake in the field, estimated to contain more than 1 trillion cubic feet of gas reserves.

Noble said that as it expects gross production at Mari-B to reach 100 million cubic feet per day in 2004, about 40 million cubic feet per day net to Noble, as Israel Electric fires up boilers for a new gas turbine. Ultimate gross production under the contract is planned to reach 170 million cubic feet per day. Noble said it expects to market additional gas as Israel develops its infrastructure.

Noble also has an undeveloped offshore discovery, Noa, which is estimated to contain more than 200 billion cubic feet of gas reserves. Noa eventually will be tied back to the Mari-B platform, Noble said.

—PETROLEUM NEWS

Two Houston companies want U.S. sanctions against Libya lifted

Executives of two Texas oil companies are already making plans to take advantage of a possible end to an embargo with Libya.

Representatives of ConocoPhillips and Marathon Oil Corp. haven't made a trip to Libya since 1986, when President Reagan imposed sanctions on Libya because of terrorist activity.

But company officials say that could change. The Bush administration Dec. 22 dangled the prospect of improved economic relations with Libya. The country agreed Dec. 19 to dispose of its weapons of mass destruction and open the door for inspections.

"The events that took place on Friday are very encouraging, but we are still held to U.S. sanctions," Susan Richardson, spokeswoman for Marathon Oil, said in Dec. 23 editions of the Houston Chronicle.

Before the sanctions ConocoPhillips, Marathon Oil and New York City-based Amerada Hess, part of the Oasis Group, produced about 850,000 barrels of oil a day in Libya.

Fadel Gheit, senior energy analyst with Oppenheimer & Co., in New York City said without the sanctions Libya could produce up to 3 million barrels per day.

"That would make Libya among the largest oil-exporting countries," Gheit said.

He said President Bush could lift sanctions in early 2004.

Richard Boucher, U.S. State Department spokesman, said the United States is looking at Libya's changes.

"As Libya's policy changes, Libya's behavior changes, Libya's circumstances change, we'll be willing to look at those things," Boucher said. "And at some point, we may be in a position to make some changes."

The oil companies are eager to start doing business with Libya because concessions they hold with the country expire in 2005 and Libya could transfer the leases to Europe.

The United Nations also sanctioned Libya, but the ban was lifted when Libya accepted responsibility for a 1988 bombing of a Pan Am jet over Lockerbie, Scotland.

—THE ASSOCIATED PRESS

● LIBYA

Petro-Canada could benefit from Libya's course correction

By GARY PARK
Petroleum News Calgary correspondent

With Libyan leader Moammar Gadhafi close to shedding his global bad-boy status, oil giants are salivating at the prospect of once more gaining access to proved reserves of about 30 billion barrels.

If the North African country delivers on its pledge to give up weapons of mass destruction and the United States ends 17 years of economic sanctions, ConocoPhillips, Marathon Oil, Amerada Hess and Occidental Petroleum are all eager to return to oil fields they were forced to abandon.

A dearth of exploration has held Libyan production to about 1.5 million barrels per day, or 2 percent of world supplies, but that could progressively be doubled by 2020, helping both the United States and Europe reduce dependence on Saudi Arabia.

For now, most of the international ventures in Libya have been run by Total of France, ENI of Italy and OMV of Austria., while the National Oil Company of Libya reached a $100 million agreement in December with a group formed by Woodside Petroleum of Australia, Repsol of Spain and Hellenic Petroleum of Greece to develop several fields.

Also well positioned are almost 20 Canadian-based companies, with E&P, service and consulting interests in Libya, led by Petro-Canada.Through various acquisitions, Petro-Canada has engaged in exploration and production of nine concessions, most of them in the onshore Sirte basin.

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Operations are conducted by a joint venture company, Veba Oil Operations, owned by Libya's National Oil Co. (51 percent) and Petro-Canada's subsidiary Veba Oil Libya (49 percent).

With interests in more than 20 producing fields, notably the giant Amal field, Petro-Canada ended 2002 with average production of 43,500 bpd from reserves of more than 100 million barrels.

In 2003, the En Naga field come on stream and Petro-Canada has been weighing other new opportunities in Libya — a process that will likely be accelerated if Libya maintains its current course and doesn't impose unacceptable conditions on foreign companies.

The one encouraging sign already is that Libya refrained from nationalizing the assets that U.S. companies left behind in 1986.

Wood Mackenzie Consultants of the United Kingdom has described Libya as "highly underexplored" and ready to profit from advanced drilling techniques that could boost recovery rates from aging fields. ●

SOUTH KOREA

BP takes 35% interest in power station

BP, already selected to supply liquefied natural gas to SK Power's electrical generating plant under construction in South Korea, announced Dec. 23 it will take a 35 percent ownership stake in the project.

SK Corp., a South Korean oil refiner, had held 100 percent ownership of SK Power, but will drop its share to 65 percent.

SK Power is building the 1,074-megawatt, gas-fired power station at the Port of Gwangyang, about 200 miles south of Seoul on South Korea's southern coast. The power station is estimated to cost $600 million, with start-up scheduled for 2006, BP said. The power plant will consume almost 90 million cubic feet of natural gas a day, which will be imported from BP's Tangguh LNG project in Indonesia.

The power plant will be next door to another consumer of Tangguh gas, a new LNG receiving terminal being developed by POSCO, the world's second largest steelmaker. POSCO, a South Korean company, will take its own 90 million cubic feet per day of Tangguh LNG.

Tangguh, with more than 14 trillion cubic feet of proven reserves, also will supply Sempra Energy's proposed LNG receiving terminal on Mexico's Baja Peninsula and a terminal in China. The combined flow of the three projects in Mexico, China and South Korea will total almost 1.1 billion cubic feet per day.

—LARRY PERSILY, Petroleum News Juneau correspondent

natural gas

UNITED STATES

LNG imports to more than offset declining Canadian gas volumes

Net imports of natural gas from Canada will edge upwards over the next six years to 3.68 trillion cubic feet, then start a long decline over at least 15 years to about 2.5 tcf, the U.S. Energy Information Administration forecasts.

In the meantime, liquefied natural gas imports will grow to 2.16 tcf by 2010 and grow by about 16 percent a year to 4.8 tcf in 2025, the agency predicts. U.S. domestic production will increase fractionally from 19.05 tcf in 2002 to 20.5 tcf in 2010 and 21.62 tcf in 2015, while well head prices in the United States (measured in 2002 dollars) will average $3.40 per thousand cubic feet in 2010 and $4.19 in 2015.

COOK INLET, ALASKA

Aurora, Forest looking at two prospects at Three Mile Creek

Aurora Gas and Forest Oil are looking at two natural gas prospects in the Three Mile Creek unit on the west side of Cook Inlet in Southcentral Alaska.

Aurora filed an application with the Alaska Division of Oil and Gas to form the Three Mile Creek exploration unit, on the west side of Cook Inlet about four miles from the Beluga River unit. The unit would be smaller than the proposal described in a Petroleum News story Dec. 7 — 8,156 acres rather than 9,200 acres.

The application proposes the state and Cook Inlet Region Inc. jointly manage the Three Mile Creek unit agreement. The state owns 5,596 acres in the proposed unit and CIRI owns 2,560, 68.61 percent and 31.39 percent, respectively. Aurora holds 100 percent working interest ownership in 6,455 acres, including the CIRI acreage and one of the state leases, while Forest owns 100 percent working interest ownership in the other state lease, 1,701 acres, giving Aurora approximately 79 percent of the unit and Forest 21 percent.

The state said the applicants have identified two natural gas prospects within the Three Mile Creek unit area, and plan to acquire new seismic data over the unit area and drill an exploration well in each prospect during the three-year term of the unit agreement.

In the first two years of the plan, before Jan. 31, 2006, Aurora would drill the first exploration well or acquire at least 20 miles of new 2D seismic. The first well would be on state lease ADL 388233, owned by Aurora. Either the first well or the seismic acquisition must be completed in the first year or the unit terminates and the owners pay the state $8 an acre for the state leases.

Both the well and the seismic must be completed by Jan. 31, 2006, or the unit will terminate and the owners will pay the state $8 an acre for the expired state leases for each of the two years.

A well is required in the third year, unless the companies decide to shoot at least 15 additional miles of 2D seismic "over acreage not previously shot to better delineate the prospective trend."

If the seismic option is exercised, Aurora will pay the state $8 an acre for the state acreage comprising the 15 lines miles of seismic for each of the three years, "gaining one additional year within which to commence drilling" the second well.

● UNITED STATES

Risk part of LNG growth

Producers expected to share price risk in supplying LNG to U.S.

By LARRY PERSILY

Petroleum News Juneau Correspondent

Producers will likely find themselves sharing the price and volume risks as they move strongly into the growing U.S. market for imported liquefied natural gas, says a report by Cambridge Energy Research Associates.

As the U.S. market for LNG grows, the report says, suppliers will need to "bridge the gap" between North America's history of volatile gas prices and short-term contracts vs. the stability of longer-term LNG supply contracts traditionally demanded by producers and lenders for other markets.

Attracting the billions of dollars in new investments for upstream supplies, LNG tankers and receiving terminals will require that sellers and buyers find an affordable middle ground between the risks to their respective bottom lines.

"Producers will … have to accept some of the price risks and volatility that are part and parcel of the U.S. market," said the CERA report, The Incoming Tide: LNG Surges into North America.

> *"Producers will … have to accept some of the price risks and volatility that are part and parcel of the U.S. market."*
> —Cambridge Energy Research Associates report

Other industry reports see the same shift toward a new financial structure for U.S. markets, with producers and buyers each giving up some security.

Long-term contracts not the norm for U.S.

Long-term contracts were a fixture of not only the Asian LNG market in past years, but Europe, too, was willing to sign up for guaranteed supply. "Unlike may U.S. power developers, the European developers do not have an adversity to signing long-term firm contracts for supply," said a 2003 report from Wood Mackenzie, a worldwide oil and gas consulting firm.

Moving away from the rest of the world's accept-

see GROWTH page 12

● UNITED STATES

Lower costs help boost United States LNG trade

Federal report estimates 2.2 tcf of LNG imports to U.S. by 2010

By LARRY PERSILY

Petroleum News Juneau Correspondent

Liquefied natural gas imports into the United States will more than quadruple by 2010, aided by falling prices for new liquefaction plants and tankers, according to a federal report.

The estimated 2.2 trillion cubic feet of LNG brought into the country in 2010 would equal about 8 percent of domestic gas consumption, exceeding the production from any single gas-producing state except Texas, said the U.S. Energy Information Administration.

"The combination of higher gas prices, lower LNG production costs, rising gas import demand, especially in North America, and the desire of gas producers to monetize their gas reserves is setting the stage for increased LNG trade in the years ahead," said the Dec. 16 report titled, The Global Liquefied Natural Gas Market: Status & Outlook.

"Costs of liquefying, transporting and regasifying LNG have fallen significantly over the past 20 years," with some of the biggest savings coming in lower tanker construction costs, the report said.

More LNG than four largest U.S. natural gas fields combined

If the projection for 2.2 tcf of imported LNG in 2010 is correct, it would exceed today's combined natural gas production from the nation's four most

see TRADE page 10

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TRADE

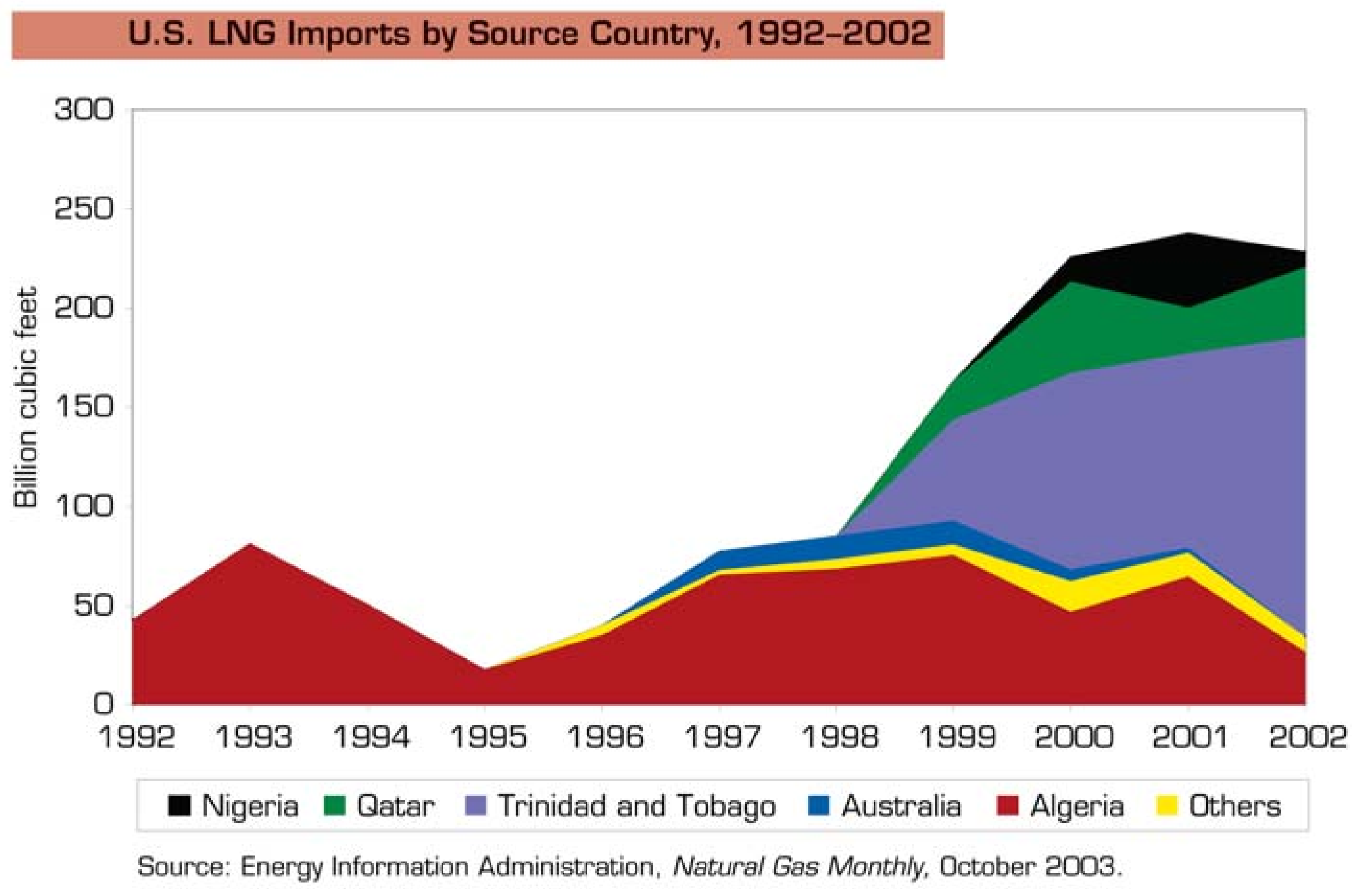
prolific fields: the Blanco/Ignacio-Blanco field across Colorado and New Mexico; the Basin field in New Mexico; the Hugoton gas area across Texas, Oklahoma and Kansas; and the Powder River basin in Wyoming.

LNG imports in 2002 totaled 229 billion cubic feet, or about 1 percent of the nation's gas consumption, the report said. By the time the numbers are added up for 2003, the total is projected to more than double to 540 bcf, the federal agency said.

And, if the agency's projections are right, expansion of all four existing LNG receiving terminals and construction of at least four new terminals would accommodate more than quadrupling U.S. imports to 2.2 tcf by 2010.

The report forecasts that total to double again by 2020, to more than 4 tcf per year, or more than 11 bcf per day.

A fleet of new tankers is scheduled to come online over the next several years to help move all that gas around the world.

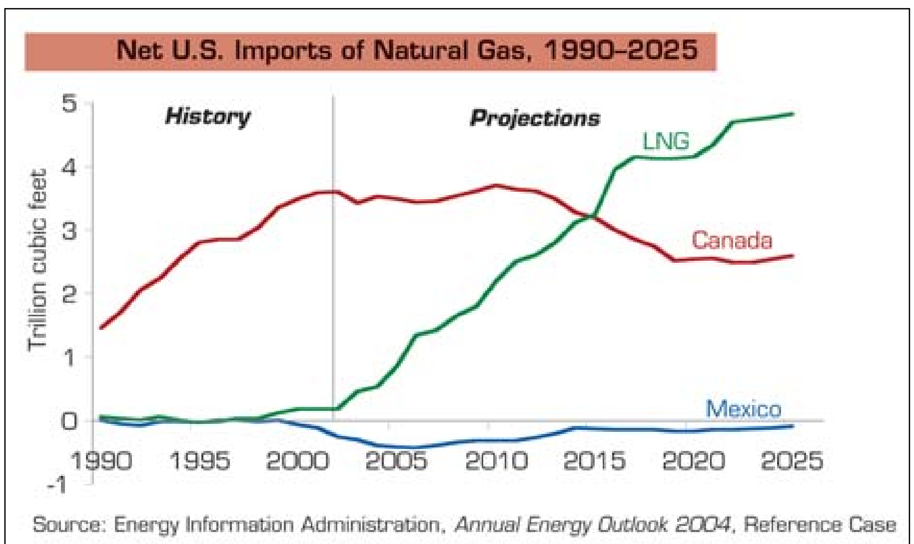


Shipyards building 55 new LNG tankers

"As of late 2003, there were 151 LNG tankers in the world fleet with 55 tankers under construction," the report said. The new ships will increase the total carrying capacity of the fleet at full load from 366 bcf in 2003 to 527 bcf by 2006, with even more ships expected later in the decade to meet the rising demand not only in the United States but around the Pacific Rim and Europe.

Meanwhile, tanker construction costs are dropping. "Building costs for LNG tankers have decreased from about $280 million (nominal) in the mid-1980s to about $155 million in late 2003," the report said.

"The main factor driving down prices is an increase in the number of shipyards that can build LNG tankers, which enhances competition."



Competition among shipyards

In addition to the eight shipyards in Japan, South Korea and Europe currently building LNG tankers, the report noted that India, China and Poland are also looking to get into the tanker construction business.

No U.S. shipyard has built an LNG tanker since 1980.

Although the federal report did not calculate savings from lower tanker costs on a per-mcf basis, Jim Jensen, a Massachusetts-based natural gas consultant with 30 years experience, offered just such a calculation for a Nigerian LNG project in an October presentation to the National Association of Petroleum Investment Analysts. The shipping cost savings between when the project was proposed in 1998 and when it was brought back for another look in 2003 added about 28 cents per mcf to the netback value of natural gas, he said.

Liquefaction costs dropping, too

Lower liquefaction costs over the same five years added 31 cents to the netback value of the gas, with 17 cents more in value coming from better economics of building larger plants, Jensen said.

Even without the per-mcf numbers, the federal report offers the same conclusions as Jensen. "Major economies of scale have been achieved by increasing the size of liquefaction trains," the report said.

In the early days of LNG, the report said, the norm was liquefaction trains with an annual capacity of 50 billion to 100 billion cubic feet of gas. "Today, trains with annual capacities of 242 bcf are under construction, and a 380-bcf-per-year train is planned for Qatar."

A recent report from Asia Pacific Energy Research Centre in Tokyo estimated liquefaction costs for a 2000 expansion of LNG production facilities at Qatar at about half the cost of Malaysia's 1983 project at Tiga. Shipping costs also dropped by about half between the 1983 and 2000 projects, the research office said.

Costs vary between facilities

The Energy Information Administration report acknowledges that costs vary widely, depending on whether it is a new project or expansion of existing facilities.

In addition to anticipating expansion of all four existing U.S. LNG import terminals by 2006, the report said at least four new terminals will open by 2010, although it did not go so far as to predict the exact location of each new plant.

The report also provided a breakdown of price components in an LNG project:

• Gas production, from the reservoir to the liquefaction plant; 15 to 20 percent of total costs.

• Liquefaction, storage and loading; 30 to 45 percent.

• Shipping; 10 to 30 percent, mostly depending on distance. (For example, it is about 2,500 miles from Venezuela to the gulf coast of Texas vs. 13,000 miles from Qatar to Texas.)

• Receiving terminal costs and regasification; 15 to 25 percent. ●

● UNITED STATES

Pessimism emerges over gas production

Higher numbers from independents unable to reverse near-term forecast

By LARRY PERSILY

Petroleum News Juneau Correspondent

Regardless how many more drilling rigs poke holes in the ground and how much independent producers try to pick up the pace, the fear is growing that U.S. natural gas production will slip further behind in meeting rising demand.

U.S. gas production fell about 2 percent from 2001 to 2002, with production expected to hold pretty much flat through 2006, according to the federal Energy Information Administration.

Meanwhile, the percentage of new reserves booked to replace gas drawn down for production also is slipping, the agency said.

All of which explains the increasing look to imported liquefied natural gas to meet the nation's growing demand for at least the next several years.

"The root of the problem," according to Simmons & Co., an international investment bank specializing in oil and gas, was that the nation ignored flat North America supply over the past decade. That supply line didn't jump much despite rapid growth in coalbed methane and tight sand gas, Canada's Maritime and Ladyfern production, and Gulf of Mexico deepwater gas, Matt Simmons, the company's chairman, reported at a natural gas conference in Houston in November.

"Conventional U.S. natural gas production actually peaked 30 years ago!" Simmons told his audience.

A lot of work is needed

And just to fulfill projections of holding overall domestic production steady — much less building supply — assumes new supplies from the deepwater Gulf and Rocky Mountain region, new technologies and a lifting of the federal ban on offshore drilling, Simmons said.


PIONEER NATURAL RESOURCES

Offshore drillers Diamond Offshore, Noble and Ensco International have the same headache when it comes to troublesome rig markets in the Gulf of Mexico. Pictured above is Noble's Homer Ferrington, currently drilling for Nexen at Green Canyon (243) in the Gulf. Noble moved rigs out of the Gulf of Mexico in 2003 in search of more lucrative markets in Mexico and abroad.

He is not the only one sounding skeptical of meeting the growing demand for gas.

"Much like in the 1970s, when oil production continued to fall, regardless of how many rigs were drilling, we think we are nearing (if not at) a similar crossroads in the U.S. natural gas supply picture," said Wayne Andrews, oil and gas stock analyst for Raymond James & Associates' Houston office.

"Given the inherent rate of decline in U.S. natural gas wells today, combined with what is still a muted response to drilling activity, we expect domestic natural gas production levels to continue trending south for the next several quarters," Andrews said in a recent briefing report.

"While this trend will almost certainly be led by the majors, the independents may not be able to reverse it as fast as many people may have thought."

Others also see increased pressure on smaller companies to help cover falling production. Cambridge Energy Research Associates reports the nation's 10 largest gas producers saw a significant drop in output from 2002 to 2003, with the next 34 companies able to cover almost 70 percent of that loss.

"The net effect for all the companies listed is still negative, but the decline is not as dramatic as the numbers from only the largest companies would lead one to believe," Cambridge Energy Research said in its November briefing on natural gas supplies.

"We and others would love to increase natural gas production in the United States," John Watson, chief financial officer for ChevronTexaco, told industry analysts in November. "The reality is, it's difficult to do that with the kinds of reservoirs that we have today."

Most of the nation's gas production comes from mature fields, making it even more important that companies find new reserves to replace what they're taking out of the ground. But there, too, the United States seems to be falling short, said the Energy Information Administration.

Reserve replacement dropping

Reserve additions averaged 107 percent of annual production from 1994 to 1997, the federal agency said. The gas shortage and price spike of the winter of 2000-2001 led to increased drilling and a 152 percent reserve replacement rate in 2000. But since then the rate has fallen each year, dropping to 118 percent in 2002.

The largest gas producing state is Texas, which supplies about 21 percent of North American production — about equal to the combined flow from Louisiana, Oklahoma, Wyoming and New Mexico.

And while domestic gas production has climbed just 1 percent since 1996, the combined flow from African, Middle East and Asian Pacific nations has jumped more than 40 percent to overtake the United States in production. ●

● COOK INLET, ALASKA

Natural gas work continues on Kenai Peninsula

Marathon applies to drill at southern end of Ninilchik unit, Unocal will drill up to nine Happy Valley wells

By KRISTEN NELSON

Petroleum News Editor-in-Chief

Natural gas exploration is continuing on Alaska's Kenai Peninsula, with both Marathon Oil Co. and Unocal applying for work which will expand areas of known gas accumulations.

Marathon has applied to drill exploration wells from a new pad at the southern end of the Ninilchik unit to test the Paxton exploration play. Ninilchik unit operator Marathon and its partner Unocal have been delivering natural gas from drilling pads in the northern portion of the unit since this fall. The company told the state in early December that if exploration is successful, it "will seek the necessary approvals and permits to install a lateral pipeline that will supply gas to the existing Kenai Kachemak Pipeline."

The Paxton pad will be used to test the southern portion of the structure at the Ninilchik unit, Marathon said, because the southern portion of the unit "cannot be reached from the Dionne Pad located approximately 1.8 miles northeast of this location."

The Paxton pad, on private land, is some three miles north of Ninilchik and is accessed from the Sterling Highway.

Marathon said it plans to drill, using Nabors Drilling Rig No. 129, on or before Feb. 23 and complete operations in early April.

"Paxton Pad will be constructed to allow the drilling of two to three exploration wells and will be approximately 200 by 300 feet," the company said. Water for drilling will be from a new water well to be drilled on the pad.

Marathon said the well, which will be drilled to a bottom hole on state oil and gas lease ADL 384372 from the pad on private land, is "to confirm the presence of recoverable gas reserves in the southern portion of the Ninilchik Unit."

Unocal working at Happy Valley

Unocal is working at Happy Valley, some seven miles southeast of Ninilchik, where it announced a natural gas discovery in November. First production is planned for November 2004.

Unocal told the state of Alaska in mid-December that it plans up to four wells at the Happy Valley pad "to delineate the Happy Valley gas field." The pad is on private property owned by the Ninilchik Native Association, but proposed bottom holes for the wells are on state oil and gas lease ADL 0384380 or Cook Inlet Region Inc. lease C-061590.

"Depending on the results of the delineation," Unocal told the state, "an additional five wells may be drilled across 2005 and 2006." Production activities will begin once the field has been delineated.

Unocal said its "goal is to have four to five wells online and flowing through a production facility by Nov. 1, 2004."

The pad is some six miles east of the Sterling Highway and is accessible by Oil Well Road with a short gravel road extension to the pad. Unocal said the Kenai Kachemak Pipeline (which it owns in partnership with Marathon) will extend the pipeline along Oil Well Road to the drill site.

Unocal said it plans an unmanned operation at Happy Valley, with operational support from the manned field office in Ninilchik approximately nine miles away with inspections of the drill site at Happy Valley at least twice a day.

The planned schedule is for three wells to be drilled between January and March, with testing from February to April. Facilities will be installed from June to October, with commissioning and startup in October and first gas planned for Nov. 1, 2004. ●

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GROWTH

ance of long-term contracts — where the buyers take most if not all of the risk — and entering the hazards of the U.S. market will take some getting used to as producers look to sell a growing volume of LNG in the years ahead.

The United States consumed about 4 percent of the world's LNG deliveries in 2002, with strong demand estimates leading to projections that the U.S. market could exceed 20 percent of worldwide LNG consumption by 2010.

U.S. could pass Japan as top LNG importer

"Within 10 years, the United States could surpass Japan as the largest LNG importer in the world," the Cambridge Energy report said.

Feeding that growth will take billions of dollars in investment in upstream and downstream facilities. And, of importance to producing company shareholders, it could mean sharing more of the price risk of new development projects than in the past.

"Producers that wish to sell LNG according to the practices and terms of the old LNG paradigm (of long-term contracts) are not likely to penetrate the U.S. market," CERA said.

That old paradigm placed a higher value on long-term supply, to the financial benefit of producers.

Buyers took more of the risk

"Traditional (non-U.S.) LNG contracts focused on security of supply," said the U.S. Energy Information Administration in a December report on LNG markets. "Take-or-pay clauses shifted the volume risk to the buyer," providing more protection to the producers.

Changes away from long-term, take-or-pay LNG contracts in the Far East have been under way for several years, and are accelerating as a growing oversupply chases after a demand that isn't growing nearly as fast. It's becoming a bit of a buyer's market.

"Recent changes in the LNG market have trended toward increased flexibility," the federal report said. "Contracts have loosened terms on both price and volume, and can be negotiated for shorter periods of time."

It's always been different in the United States, the report said, where short-term contracts and bouncing gas prices made it difficult if sellers — and their lenders — were looking to lock in a steady revenue stream.

Volatile U.S. markets make it harder

"Importers and exporters involved in U.S. LNG transactions are exposed to a significant level of risk given the high degree of price volatility in U.S. natural gas markets," the federal report said.

It's all about who is going to take how much of the painful risks: that prices might fall, if you are the seller; or that they might rise, if you are the buyer.

"A significant part of the market risk appears to have migrated upstream," said natural gas consultant Jim Jensen, of Jensen Associates in Weston, Mass. "The real governing force for LNG growth is upstream, where the largest and riskiest investments are concentrated," Jensen said at an October meeting of petroleum investment analysts.

Bringing global LNG supplies to the United States is a "contracting conundrum," said CERA.

"A way must be found to bring to bring together a global gas market characterized by long-term, take-or-pay contracts … with a North American market with a bias toward shorter-term deals," the report said.

"The softening of the LNG paradigm (long-term contracts) and the rise of North America as a market for LNG are mutually reinforcing developments. CERA expects continued movement on both fronts, driven by economic necessity." ●

NPR-A

Conoco permits new NPR-A well

ConocoPhillips Alaska has permitted a new well in the National Petroleum Reserve-Alaska, the Carbon No. 1. The well is proposed as an almost vertical hole in section 4, township 10 north, range 1 east, Umiat Meridian, some five miles north-northwest of ConocoPhillips' Spark discovery well, one of five wells and one sidetrack ConocoPhillips and partner Anadarko Petroleum announced as discoveries in May 2001.

All of the discoveries were in the Alpine producing horizon, the companies said. Spark was the well with the sidetrack, so both Spark No. 1 and Spark No. 1A were listed as discoveries. The companies said they did extensive testing at the Spark drilling location, and the Spark No. 1A well tested 1,550 barrels per day of liquid hydrocarbons and 26.5 million cubic feet per day of natural gas.

—PETROLEUM NEWS

CANADA

Canada to top 20,000 wells

Canada will pass a landmark 20,000 well completions in 2003, eclipsing its previous high of 18,184 in 2001.

Industry statistics show 19,979 wells were rig released in the first 11 months, 17 percent ahead of the same period in 2002.

Exploratory wells accounted for almost 5,000 of the total, 37 percent up from the previous year, and development drilling surged 43 percent to 14,987. Alberta claimed 13,125 of the well completions, of which 9,612 were targeting natural gas prospects, followed by Saskatchewan at 3,706 (2,071 listed as gas wells), British Columbia 709 (577 gas), Manitoba 88 and Northern Canada eight (five gas and three dry holes), with Eastern Canada logging 95, 60 of them listed as gas wells.

—GARY PARK, Petroleum News Calgary correspondent

Calpine boosts Canada spending

Calpine Natural Gas Trust, a recently created Canadian spin-off from U.S. power giant Calpine, is targeting a modest increase in capital spending this year. The board of directors has approved a 2004 capital program of C$9.3 million, with C$6.8 million earmarked for drilling and completions, compared with C$8.5 million in 2003, of which C$4.6 million went to drilling and completions.

The CNG Trust assets were expected to yield an average 33 million cubic feet of gas equivalent per day in 2003, weighted 69 percent to natural gas with the 2004 forecast at 30 million to 34 million cubic feet equivalent.

Calpine set up a Canadian headquarters almost three years ago through a C$1.8 billion purchase of Encal Energy, then three months ago joined the stampede to the ranks of income trusts by converting proven reserves of 83 billion cubic feet of gas equivalent.

The trust has hedged 100 percent of the gas production from its initial properties for a minimum price of C$7.35 per thousand cubic feet with a wholly owned subsidiary of Calpine.Participation in CNG Trust is viewed by Calpine as a means to increase its competitiveness in the acquisition and development of additional gas reserves in Canada to fuel its power generation portfolio in North America.

—GARY PARK, Petroleum News Calgary correspondent

● ROCKY MOUNTAINS

Flood of permits strains BLM in the Rockies

In energy bill Bureau of Land Management would receive an additional $1.5 million to reduce the permit backlog in western states

By ROBERT GEHRKE

Associated Press Writer

Oil and gas companies eager to drill in the Rocky Mountain West appear to have an ally in the Bush administration, which is approving wells at a pace well ahead of the Clinton administration and looking to get even faster.

An Associated Press review of thousands of applications to drill on Bureau of Land Management land since 1998 shows a 34 percent increase in the number of wells approved under Bush when compared with the last three years of the Clinton administration.

Patricia Morrison, BLM's principal deputy assistant secretary for land and minerals

The vast majority of the permits, 94 percent since 2001, are clustered in five states: Colorado, Montana, New Mexico, Utah and Wyoming — a key region in the administration's push to open more public land for energy development.

BLM has received nearly 26,000 applications to drill wells and approved nearly 19,000 since 1998 — almost three of every four. BLM land and other federal land managed by the Interior Department contain an estimated 68 percent of the nation's gas reserves and 74 percent of oil resources. The Associated Press review covered detailed BLM records over the last three years and summary information dating to 1998.

A flood of permits has strained BLM's meager resources, creating a backlog of applications industry officials say is leading to shortages and higher gas prices.

Interior seeking to speed up process

To answer the critics, the Interior Department is seeking to speed up the process.

"We are blessed with vast resources. We have a stewardship responsibility to produce it and I think the American public expects us to produce it," said Patricia Morrison, the agency's principal deputy assistant secretary for land and minerals.

BLM controls 262 million acres of land and 700 million acres of subsurface rights, with an annual budget of about $2 billion and 10,000 employees — but it isn't enough these days.

The BLM field office in Buffalo, Wyo., has been swamped by the oil and gas stampede. It handles permits for the frenzied coalbed methane development of the Powder River Basin, where the agency expects to issue 3,000 permits in the coming year and methane is so shallow wells can be punched with rigs used to drill for water.

Four years ago, 23 people worked at the Buffalo office. The number has more than tripled to 76 to handle the demand, more than 4,000 permit applications in the last three years.

Dennis Stenger, field manager of the office, said his staff has been aggressive in trying to get faster, issuing permits to clusters of wells to avoid redundant environmental and cultural studies. That practice and others were adopted BLM-wide in a series of directives issued in April aimed at improving the permit process.

Regulations call for permit processing in 30 days

Without unforeseen delays, the office can generally get permits processed in 46 days, Stenger said. "You can't streamline much more" without changing the environmental laws, he said.

Federal regulations, however, say BLM is supposed to process permits in 30 days or less. The industry notes that a state like Colorado can often process permits to drill on state lands in as little as 10 days.

The Associated Press review found it takes BLM much longer — an average of 89 days over the last three years, excepting applications still pending at the end of the 2003 budget year.

Morrison said the numbers don't reflect delays caused by companies amending or withdrawing an application. But she conceded that permits are taking too long to handle for the liking of industry — and government.

"That's exactly what we're trying to address," Morrison said.

Volume of applications growing

The Associated Press review found that, during

see PERMITS page 14

FORT WORTH, TEXAS

Range pays $85M for Texas properties

Range Resources, an exploration and production independent headquartered in Fort Worth, Texas, said it has completed the purchase of West Texas oil and gas properties for about $85 million.

The properties encompass 32,000 net acres and are situated adjacent to Range's Conger field properties in Sterling County. The deal included more than 500 wells with current production of 14 million cubic feet of gas equivalent per day and proved reserves of about 80 billion cubic feet of equivalent.

A 400-mile gathering system that collects and transports from the properties also was acquired, Range said, adding that a development program would be initiated in 2004 to increase production over a three-year period.

"With this acquisition, Range becomes the largest operator in the Conger field with a concentration of 800 wells in the area," Range President John Pinkerton said Dec. 23. He said that with the acquisition, Range expects to increase production by 10-to 15 percent in 2004.

—PETROLEUM NEWS

NORTH DAKOTA

Veritas looking for oil and gas on 179,000 acres in western North Dakota

A Texas company is sweeping large tracts of western North Dakota in search of undiscovered oil and gas reserves.

Veritas DGC Inc. is conducting seismic testing north of Tioga, and recently completed tests east of Watford City.

Future tests are planned west of Fairfield in Billings County. Some 65 percent of the Billings County area is in the Little Missouri National Grassland.

All three searches will cover about 179,000 acres of private and public land.

"It's probably one of the larger shots we've had in some time," said Dave Hvinden, with the state Industrial Commission's Oil and Gas Division.

The largest previous testing project was in 1998 near Kenmare. That project involved about 80,000 acres.

The search areas already have several oil wells, but officials say Veritas' testing employs a more advanced method that measures shock waves to provide a three-dimensional underground map.

In some areas, the waves are generated by setting off five-pound explosive charges.

The Billings County tests are scheduled for this winter. Elmer Nordsven, area mineral manager for the Dakota Prairie Grasslands, said officials were pleased with the project near Watford City.

"(Veritas) did an excellent job," he said. "They were very conscientious."

—THE ASSOCIATED PRESS

● CANADA

Company testing the waters with new oil sands technology

By GARY PARK

Petroleum News Calgary Correspondent

The Canadian oil sands subsidiary of an Israeli-U.S. engineering and manufacturing company is gearing up to take the plunge early in 2004 into equity and debt markets to finance its share of a C$3.2 billion project in northern Alberta.

OPTI Canada is a joint partner with Nexen in the Long Lake project which will include a field upgrading facility incorporating a patented OPTI technology that will eliminate the need to purchase natural gas and electricity, one of the heaviest cost burdens in the oil sands sector.

Based on a demonstration project that was launched in spring 2001, OPTI has calculated that it can produce synthetic crude at a cost of C$6-$7 a barrel, at least C$5 below other projects that integrate extraction with upgrading.

OPTI is now poised to test investor confidence in its technology by seeking financial backing for what is described as one of the largest packages — C$500 million initial public offering, C$800 million in debt financing and C$400 million in private equity — for a start-up resource company.

Final decision likely in February

Nexen has indicated it will likely make a final decision in February on whether to proceed with Long Lake, which is expected to come on stream in 2007 at 70,000 barrels per day and double that output by 2011, tapping into a lease with 5 billion barrels of oil-in-place.

OPTI's parent company is the Ormat Group of Companies, which trades on the Tel Aviv Stock Exchange and is considered a world leader in remote power generation systems using renewable energy sources.

The technology converts bitumen into partially upgraded sour crude oil and asphaltenes, which can in turn be converted into hydrogen-rich, low energy fuel gas.

As part of the deal, Nexen has a 50 percent interest in the bitumen property, the exclusive right with OPTI to use its technology in the Athabasca oil sands region and the right to use the technology elsewhere in the world.

OPTI President and Chief Executive Officer Sid Dykstra has said large-scale oil sands developments offer "great economics when combined with a low cost fuel source and an upgrading solution." ●

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PERMITS

the first 33 months of the Bush administration, the BLM approved 9,876 wells, or about 299 per month. In the final 40 months of the Clinton presidency, 8,934 wells were approved, or 223 per month.

The volume of permit applications has also grown fairly steadily, from 3,790 in 1998 to 4,715 in 2003. The number approved has fluctuated some, but has generally increased as well.

Billions of dollars are at stake: A recent industry study by IHS Energy estimated an additional 264 million cubic feet of natural gas per day could be in production by August 2004 if BLM were able to wipe out its backlog in six months and begin consistently processing permits in 45 days. The Energy Department has estimated that, over the next two decades, gas consumption will grow by more than 50 percent, while production would grow by just 14 percent if it continues at its current rate.

In the energy bill Republicans expect to revive next year, BLM would receive an additional $1.5 million to reduce the permit backlog in Colorado, Montana, New Mexico and Utah during the coming year. There are other provisions intended to speed things up, including the creation of a White House task force to coordinate energy projects, initiatives targeting the most crowded offices and tighter deadlines. ●

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POINT THOMSON

and resource evaluation work during the past year has confirmed that development of the resource at PTU (Point Thomson unit) is challenged."

Resource evaluation work has "resulted in a significant reduction in liquid resources," the company said. On the cost side, engineering design work and "better identification of permitting and environmental requirements" added costs to the project, although that was balanced because "a cost reduction effort identified changes in scope that reduced costs" back to within the original cost range.

ExxonMobil said the Point Thomson owners have not given up on development and have begun discussions with the state "to explore ideas that could result in a commercially viable project."

Companies exploring alternatives

ExxonMobil said the Point Thomson owners have not given up on development and have begun discussions with the state "to explore ideas that could result in a commercially viable project."

But because the project is not currently economic, the Point Thomson owners are proposing a change in their agreement with the state, which mandates a $10 million payment to the state if the owners determine by Jan. 15, 2004, to relinquish the expansion area.

In the 2001 agreement expanding the unit, the amount was $8 million and the deadline was June 30, 2003. The state extended that deadline in exchange for an increase to $10 million.

The companies are now proposing a sliding deadline: from Jan. 15, 2004, until the required date for the beginning of development drilling, June 15, 2006, the major working interest owners "may at any time provide notification of their election to contract the expansion acreage" and pay the state $10 million, plus an added amount equal to one-twelfth of $4 million for each full month beginning Jan. 16, 2004.

ExxonMobil said the owners' proposal is "consistent with the basis for the payment schedule" in the state's 2001 decision approving the unit expansion, "which recites that the payment is intended to compensate the state for delay in receiving bonus payments from leasing the acreage that was not relinquished."

The proposal would also, ExxonMobil told the state, align the interests of the owners and the state, giving the owners an incentive for early relinquishment of the acreage "if conditions warrant," an incentive which "is not present if there is a fixed payment that does not increase with time." Early relinquishment would make the acreage available sooner for the state to offer in an oil and gas lease sale.

Point Thomson resource

While ExxonMobil said evaluation had led to a "significant reduction" in the estimate of liquid resources at Point Thomson, it did not make the new estimates public.

The Alaska Division of Oil and Gas has listed the Point Thomson resource as 435 million barrels of oil and 8 trillion cubic feet of gas in its last two annual reports, and any information on new reserve estimates provided to the state by the owners in unit discussions is confidential.

Numbers from ExxonMobil earlier this year are in line with the state's recent published numbers. Houston, Texas-based ExxonMobil spokesman Bob Davis told Petroleum News in August that the field contains roughly 400 million barrels of recoverable condensate, which Davis said is a liquid much like kerosene, plus the 8 tcf of gas.

Davis said in December that the owners were not releasing revised resource figures.

Point Thomson is a high-pressure condensate field, and initial development plans called for producing the oil and reinjecting the gas into the reservoir.

Project estimate exceeds a billion dollars

Davis told Petroleum News Dec. 31 that the owners spent more than $50 million this year completing engineering and evaluation work for Point Thomson, and have had "preliminary discussions with the state on the project status."

The owners estimate project costs at in excess of a billion dollars for facilities, infrastructure and drilling, Davis said, in addition to the hundreds of millions of dollars already spent at Point Thomson, which is in its 20th plan of development.

He said that, as the owners have told the state, based on costs, the resource and estimated revenue from the project, it is not economic.

"We do anticipate additional discussions with the state with the goal of identifying a commercial project," Davis said.

Leases held since 1970s

There has been a Point Thomson unit since the late 1970s, allowing leaseholders to retain oil and gas leases even though there is no production, until there is a pipeline to take the field's resources to market.

There have been various expansions and contractions in the unit since it was formed.

The most recent was in 2001, when the unit owners negotiated with the state to expand the unit to include adjacent leases close to expiration, in exchange for a number of commitments, including a long-term plan of development for the unit, development drilling beginning by June 15, 2006, and completion of seven development wells by June 15, 2008.

In exchange for expansion of the unit to include the additional leases, the unit's owners agreed to pay the state to make up for money the state could have earned by offering the expansion area leases in state oil and gas lease sales if they didn't meet the agreed-upon development schedule for the unit.

The companies made the first such payment in 2002 when they decided not to deepen the Red Dog No. 1 well in a portion of the expansion acreage and instead paid the state $940,000, and relinquished leases on the western edge of the unit.

Unit alignment almost complete

Progress is being made on another front.

Alignment of major interests at the field, agreed to by ExxonMobil, BP and Chevron in 2000, and subsequently by ConocoPhillips, is nearing completion, ExxonMobil told the state.

The company said cross assignments are being executed, and said it would submit them to the state for approval as soon as all of the companies had signed.

—**KRISTEN NELSON,** Petroleum News editor-in-chief

CANADA

Canadian seismic halts 10-year slide

A rebound in seismic activity provides another pointer to the scorching upstream pace in Canada.

The three largest producing provinces — Alberta, Saskatchewan and British Columbia — are either ahead of or close to passing 2002 levels, according to government statistics.

The three largest producing provinces — Alberta, Saskatchewan and British Columbia — are either ahead of or close to passing 2002 levels, according to government statistics.

By early December, Alberta had handled 925 seismic applications, which was "slightly ahead" of comparative 2002 figures; 284 companies filed permit applications in Saskatchewan, 11 more than 2002; and British Columbia logged 148 permits applications to mid-November, just 14 behind the total for the previous year.

Even so, the region will be well short of record levels, as E&P companies continue to trim their seismic budgets as conventional production slides in the Western Canada sedimentary basin.

But the reversal of a 10-year downward trend in seismic bodes well for 2004, given the usual 12-month lead time to drilling.

The hottest plays attracting seismic activity are northeastern British Columbia, northern Alberta and the Estevan, Swift Current and Kindersley areas of Saskatchewan.

—**GARY PARK,** Petroleum News Calgary correspondent

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CHESAPEAKE

Chesapeake decided it liked what it already had and began to look for more, McClendon said. He also said that several new players had moved into the Midcontinent and "moved acquisition values a little higher than we like."

However, the Midcontinent will remain Chesapeake's primary core area, where about 90 percent of the company's current assets are located. "Our focus will be on the Midcontinent," McClendon emphasized, adding that Chesapeake would continue to shop for properties in the Midcontinent, as well as in the Permian and Gulf Coast regions.

In its latest transactions, Chesapeake said it would buy privately owned Concho Resources for $420 million and two smaller properties from unidentified sellers for $90 million. The combined assets hold an estimated 320 billion cubic feet of gas equivalent and produce a combined 70 million cubic of equivalent per day, Chesapeake said.

Oil and gas reserves grow to more than 3.4 tcf of gas equivalent

The three deals increased the company's total oil and gas reserves to more than 3.4 trillion cubic feet of gas equivalent, while pushing expected 2004 production to about 890 million cubic feet of equivalent, a 9 percent increase from prior estimates. The company also adjusted its anticipated 2004 capital budget to between $725 million and $775 million, up from earlier guidance of $675 million to $725 million.

Chesapeake said that the $420-million Concho acquisition, expected to close at the end of January, would rank Chesapeake among the 20 largest producers in the Permian basin, with 350 billion cubic feet of gas equivalent. Concho, based in Midland, Texas, was founded in association with New York-based Yorktown Energy Partners. In 2002, Concho bought the assets of Oklahoma-based exploration and production independent Ricks Exploration, which formed the core of Concho's assets in both the Permian Basin and Midcontinent.

> *In late 2002, Chesapeake said it wanted to sell or trade its Permian assets... But when the company "put it all together" and "hired a good team" to look at the Permian, Chesapeake decided it liked what it already had and began to look for more.*
>
> **—Audrey McClendon, Chesapeake Energy CEO**

Of the $90 million involved in the two smaller transactions, $25 million was for properties in the Permian and $65 million for properties in Goliad County, Texas, Chesapeake said, adding that one of the deals already had closed and that the other was expected to close in January.

Chesapeake said it would realize an additional $150 million value net to the company over the next two years because of strong hedging positions placed on the production it was acquiring.

"The dramatic increase in oil and natural gas prices during the past few weeks has given us the ability to lock in 100 percent of our anticipated gas production volumes from (these) acquisitions at prices well above the price decks we used to purchase these properties," Chesapeake's McClendon said. ●

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GUSHER

December.

Just doubling output to 2 million bpd in the 2010-2012 period dangles the prospect of 32,000 new jobs, while achieving the 5 million bpd level would require spending of C$30 billion for each increase of 1 million bpd.

In turn, an additional 1 million bpd would pump C$15 billion into Canada gross domestic production, which currently stands at C$1 trillion. An additional 3 million bpd would inject a further C$45 billion, with an overall boost to GDP of 4-5 percent.

Each direct oil sands job is forecast to generate three additional jobs in a wide range of support fields.

The chamber is made up of 170 members, drawn from corporations, government agencies and educational institutions.

The document says the oil sands "will increasingly be seen as a versatile energy source, expanding from the two-product industry today.

"Achieving the level of development envisaged during the decline in conventional oil and gas reserves will also see an expanded role, with multiple marketable productions."

Conserving natural gas important

The draft says that to conserve natural gas — currently a major building block in oil sands development — will require the sector to become "internally self-sufficient in energy and hydrogen, or use other abundant external sources.

"The oil sands industry does not want to contribute to a 'bidding war' for this clean energy source, nor threaten supply to the petrochemical industry.

"Oil sands byproducts will maintain feedstock supply security and offer future growth opportunities in petrochemicals."

In a general conclusion, the chamber says oil sands development "is a project of enormous potential benefit, not just in Alberta but also across (Canada). Furthermore, exports of products that are upgraded to the maximum possible extent in Canada, provides an unparalleled opportunity for wealth and job creation and infrastructure development.

"With the right technology, the oil sands will provide a sustainable bridge between non-renewable fossil fuels and cleaner energy options for the future."

Numerous challenges to expanding oil sands production

But the challenges presented by the chamber's vision are not brushed aside.

COST STRUCTURE

Newer technology that is currently being tested should continue a "positive trend" to lower the oil sands cost structure and help withstand "any cyclical changes or a future downturn in crude prices."

But, in only the last 20 years, the costs of mining and upgrading have plunged from C$40 a barrel to about C$17, while the in-situ recovery of deeply buried bitumen deposits has been trimmed from about C$22 per barrel to C$13.

EXPANDED MARKETS

Although oil sands production will offset the overall North American decline in conventional light volumes and the expected increased demand for refined petroleum products, there will be the need to extend traditional U.S. markets for extra Canadian output.

A start has been made in that direction with the introduction of Synbit — a blend of synthetic crude and bitumen — which has the ability to compete against medium sour crude oils and grow in volume from essentially zero to several hundred thousand bpd by 2010.

The next biggest opportunity is to open up transportation routes to the U.S. Gulf Coast and resolve the issue of competition with foreign crude sources.

Relatively new markets such as California and Pacific Rim countries might also take up to 1 million bpd.

UPGRADING AND FUELS OF THE FUTURE

The document says that upgrading "not only provides an opportunity to increase the value of finished products but also an opportunity to respond to changing downstream refining pressures to produce cleaner burning fuels."

But weighed against the benefits and future potential capabilities of upgrading are the risks and unknown costs "going into the future," which means Canada "will need to realize sufficient economies of scale to make such an investment attractive."

PIPELINE INFRASTRUCTURE

Currently, up to 80 percent of heavy oil and bitumen blends produced in Canada are shipped to the United States through existing pipelines, but a transportation constraint looms by 2007 at the latest.

However, the pipeline industry is already immersed on discussions with oil sands producers to plan the right "mix" of future capacity, including the need to transport ultra-low sulfur products without major reprocessing.

KICKING THE NATURAL GAS DEPENDENCY

The heavy reliance on natural gas for upgrading is reflected in the current consumption of 1,000 cubic feet of gas for every barrel recovered from in-situ projects, while upgraders consume as much as 700 cubic feet per barrel of synthetic crude for energy and hydrogen.

Based on current rates, gas usage would rise from 10 percent of Western Canada sedimentary basin, coalbed methane and Mackenzie Delta supply by 2012 to an "unthinkable" 50 percent by 2030, assuming oil sands output of 5 million bpd.

"Such a demand level, combined with competition from other markets in the face of dwindling reserves, will help drive price increase," the chamber warns.

"The 'business-as-usual' case is clearly unsustainable and uneconomical.

"The solution is energy and hydrogen self-sufficiency, either through use of residues, or external energy alternatives, such as coal or nuclear energy."

ENVIRONMENT

The Kyoto Protocol is just one of many challenges as social and regulatory pressures build on the oil sands sector to reduce its overall environmental footprint.

The chamber concedes that the cumulative effect of oil sands development and operations is "relatively unknown," which puts pressure on the industry to invest in developing and applying the right technologies to improve on the existing environmental record.

That includes strategies or technologies to reduce greenhouse gas emissions such as carbon dioxide, sulfur dioxide, nitrogen oxides, hydrogen sulfide, carbon monoxide and methane.

As well, the industry is urged to continue striving for minimum water use at a time of dwindling water supplies and rapidly growing industries and population in Alberta. ●

● DELTA JUNCTION, ALASKA

Initial permits issued for Pogo gold mine

Developer still waiting for EPA permits, plans to start mobilization, minor road work after receiving state authorization

By PATRICIA JONES
Petroleum News Contributing Writer

Alaska regulators issued state permits Dec. 18 allowing development of the Pogo gold mine located about 40 miles northeast of Delta Junction in Interior Alaska.

The U.S. Army Corps of Engineers wetlands permit is expected to follow soon, according to Ed Fogels, project manager for the Alaska Department of Natural Resources.

Pogo developers Teck-Cominco and Sumitomo Metal Mining are still waiting for permits from the Environmental Protection Agency, which are expected to be issued in late February, Fogels said.


"They operate a little slower than I would like down there. But I have no reason to believe these permits will not be forthcoming." —Alaska Gov. Frank Murkowski

"Consequently, Teck-Pogo plans to limit themselves to mobilization and minor roadwork until the NPDES permit is issued," he said.

Pogo developers first submitted a development plan and permit applications to regulators in August 2000. A final environmental impact statement was released by agencies three years later, on Sept. 19.

EPA serves as the lead agency for the environmental review and authorization of the Pogo project. The disposal permit is required for mine operation.

"They operate a little slower than I would like down there. But I have no reason to believe these permits will not be forthcoming," Alaska Gov. Frank Murkowski said, following release of state permits.

One of the first steps for the $250 million hard rock gold development is constructing a 50-mile all-season road to the site from the Richardson Highway. Teck-Pogo officials said that winter road construction and preliminary surveying and site preparation is expected to begin immediately.

Construction is expected to take about two years, and the work force could peak at 500. Once complete, the underground gold mine is expected to employ about 300 full-time workers to produce 375,000 ounces of gold a year, for at least 11 years.

Teck battles with EPA

Mining industry analysts question whether the permitting delay is linked to Teck's ongoing debate with EPA regarding drainage from a British Columbia mining project into a lake in Washington state.

According to a Reuters news report, Teck's battle with the EPA centers on a planned study into the environmental health of Lake Roosevelt on the Columbia River, which carried million of tonnes of smelter waste from Teck's Trail mine processing site across the border from British Columbia into Washington for nearly a century.

Slag, a waste by-product of the smelting process, is classified as a non hazardous substance in Canada and the United States, Teck said. The firm said the traces of metals left in the glassy substance are generally not released.

Teck, which believes the health risk from the dumped slag to be minimal, has agreed to pay for an ecological risk assessment. but refuses to do it under the aegis of the EPA.

The miner objects on the grounds that a U.S. agency has no jurisdiction over a Canadian operation — a debate that could draw in the Canadian government as it could have wider cross-border authority ramifications.

But Doug Horswill, Teck's environmental vice president, said his company's key objection to being ruled by U.S. "Superfund" law was that the scope of the EPA-required investigation and clean-up was considerably wider, going beyond the immediate geography and metal damage.

The EPA has asked a U.S. court to force Teck to comply with its order. Teck, which accuses the EPA of releasing misleading and wrong information on the lake's contamination, said it would appeal if the ruling went against the firm. ●

NUNAVUT TERRITORY

Nunavut sparkling over diamond prospects

Nunavut Territory is one step closer to joining its Northwest Territories neighbor in the diamond mining business.

The Inuit of western Nunavut and Tahera Corp. reached an agreement-in-principle that is essential to development of the Jericho diamond mine.

The deal guarantees benefits to the region's 4,500 Inuit, including jobs, training and business opportunities, said Charlie Evalik, president of the Kitikmeot Inuit Association.

He said mining is "one of the sectors we need to pursue for economic opportunities for the Inuit people.

"The jobs and contracts that Inuit and Inuit firms receive from the mine will create a lot of economic wealth for the Kitikmeot Inuit."

A Tahera spokesman welcomed the historic agreement which is required under the Nunavut Land Claim that was the basis of creating the territory before any mine project can proceed.

He said it represents the "birth of the diamond industry" in Nunavut.

The agreement also covers special considerations and compensation from Tahera for traditional, social and cultural concerns and the impact on Inuit water rights.

The Ekati and Diavik diamond mines are already producing in the Northwest Territories and the Snap Lake project is scheduled to start full production in 2007.

—**GARY PARK,** Petroleum News Calgary correspondent

SEATTLE

New president for Nevada Star

Gerry Carlson stepped down from the president's position with junior-sized Nevada Star Resource Corp. earlier this fall, due to time constraints with other mining exploration and business ventures.

Robert Angrisano, a senior principal technologist with Microsoft Corp. and a major shareholder of Nevada Star, is currently serving as the company's interim president, Carlson told Petroleum News in a telephone interview Dec. 16. Angrisano took on the executive responsibilities Nov. 1. Board chairman Monty Moore serves as interim chief executive officer of the company.

Robert Angrisano, a senior principal technologist with Microsoft Corp. and a major shareholder of Nevada Star, is currently serving as the company's interim president, Carlson told Petroleum News in a telephone interview Dec. 16.

"I will keep Nevada Star strategically focused on the discovery and development of significant sources of metals in high demand, to maximize value for our shareholders," Angrisano said in an Oct. 31 press release announcing the leadership changes.

The company said the board of directors will be looking for someone with a strong background in both mining and business to take over as president and CEO.

Carlson remains involved with Nevada Star as a shareholder and a board director.

"It really required a full-time president, and I was not able to commit enough time to the position," he said.

Carlson, who continues to direct Vancouver, British Columbia-based Copper Ridge Exploration, is well known within the Alaska mining industry. He formerly headed LaTeko Resources, which at one time owned the Ryan Lode Mine on Ester Dome just west of Fairbanks, and had a share of the True North gold deposit northeast of Fairbanks.

Kinross Gold, which acquired most of LaTeko's land assets in 1999, is currently producing gold from True North at its Fort Knox mill and conducted an extensive exploration program at Ryan Lode this summer.

Carlson's Copper Ridge holds properties in the Yukon Territories and a grassroots exploration property in east central Alaska, near the Pogo gold deposit.

—**PATRICIA JONES,** Petroleum News contributing writer

Companies involved in North America's oil and gas industry

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

Petroleum news

Business Spotlight

By PAULA EASLEY

FORREST CRANE

Gene Carlson, Vice President, Heavy Haul Division

Carlile Transportation Systems

Carlile Transportation Systems provides transportation and logistics services within the Continental United States and Canada. It recently added an airplane hangar to the Prudhoe Bay Logistics Center. It maintains two other Alaska North Slope terminals serving air carriers and passengers. Services include LTL, TL, bulk, steamship, barge, rail, heavy haul, third-party logistics, hazmat/waste and freeze/chill transportation.

Gene Carlson has been in the Alaska transportation and logistics field since 1980, joining Carlile in October 1995. He thrives on complex logistical challenges, especially the movement of modules and specialized equipment. Active in University of Alaska athletics, Alaska Trucking Association, Republican Party of Alaska, Alaskans for Drugfree Youth, the Alaska Outdoor Council, SPCA and NRA, he and wife Darlene take time out for hunting, fishing and hockey. They have three children.

HEATHER YATES

Christopher Owens, CNC Foreman

Unique Machine Inc.

Alaska's largest machine shop, in business 28 years and counting, is located at 5839 Old Seward Highway in Anchorage. Unique Machine provides fast turnaround and high-production support of full-length tubing and casing to oilfield clients and general machine shop and welding services to Alaska's construction, fishing and mining industries.

For five years CNC foreman Chris Owens worked as a traveling machinist, doing everything from aerospace prototype work to job shop repair, in six states. Then a bolt of lightning named Simone hit, and Chris settled down with her in Anchorage. He's been with Unique Machine for six-plus years. The couple has a son, Tyle age 2, and daughter Whitney, a month old. Chris and Simone love traditional archery shooting and kayaking.

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FORECAST

barrels daily in 2021, and stay at that level through 2024.

Philip Budzik crunched the numbers this year, taking over for another analyst who left the agency.

"The 2003 projections are way more optimistic than anyone else's," says Budzik. "It's difficult for me to say what factors went into such a completely different assessment.

Top-to-bottom review

"When I was given that responsibility (for the Alaska projections), I did a top-to-bottom review of the existing oil fields and what USGS (Geological Survey) says, and the new forecast reflects that," Budzik said. Neither estimate includes any production from the Arctic National Wildlife Refuge.

With the adjustments, says Alaska state oil economist Charles Logsdon, the EIA numbers "are very compatible with what we have now."

The EIA forecast is still a bit more optimistic, predicting Alaska will pump 930,000 barrels of oil daily in 2015, about 10 percent more than the Alaska Revenue Department is expecting for that year. In their most recent revision, state economists cut their future projections by about 4 percent compared with their numbers a year ago.

Myers disagrees with EIA

But Mark Myers, director of the Alaska Division of Oil and Gas, disagrees with EIA's assessment.

"I think that the overall view of investment levels by the three majors would lead you to their (EIA's) conclusions. I think that the part that is missing is an understanding of the potential for onshore stratigraphic plays and the Beaufort Shelf and the recent activity and interest by independents. If Alaska is able to attract independent investment and enough wells were drilled, the production estimate could be increased fairly dramatically. The secrets are the economy of scale of more robust exploration programs with fit to purpose equipment and the ability to develop fields that are less than 200 million barrels of oil on a regular basis," Myers told Petroleum News Dec. 29.

Opportunities elsewhere

Oil company enthusiasm for putting money into Alaska has dampened as other opportunities arose, say the EIA analysts.

"A lot of the players who are there (in Alaska) are simply not maintaining the investment they were doing a few years ago," said Paul Holtberg, director of the EIA's demand and integration division. "The pessimism has really surged in the last couple years. Looking at specific plays and activity levels there, we concluded our expectations were too high."

"There's definitely been a sea change in the petroleum industry's attitude toward the North Slope," agrees Budzik, the EIA analyst who put together the new numbers.

"Probably most important is how much the rest of the world is opening up to private development," he says. "In the early '70s, the only frontier areas with a lot of promise were the North Slope and the North Sea, plus the Gulf of Mexico to a lesser extent.

"Now you have the former Soviet Union, China, West Africa, particularly offshore, and even the OPEC countries are sort of opening up to private development," he said, noting the expanding opportunities in Qatar and Algeria.

"The problem with the North Slope is that they've found most of the oil that they expect. If you go west, they expect more gas. If you go east, into ANWR, the largest field they expect to find is only about a billion barrels."

There have also been some recent disappointments in Alaska, such as Badami, he noted.

Steady flow through 2016

Still, the current EIA projections call for relatively little decline over the next decade or so. The production levels remain about 900,000 barrels per day through 2016.

"The good news is there is still a lot of production potential on the North Slope," Budzik notes. "The North Slope could actually be producing pretty much a million barrels a day until 2025 if some of the heavy oil fields go into production. That would be like adding a couple of billion-barrel fields."

While the current EIA projection assumes a natural gas pipeline to Lower 48 markets coming into operation around 2018, Budzik says that may not add much to the flow of liquids down the trans-Alaska oil pipeline. Gas liquids could well flow down the gas line for use in petrochemical plants in Alberta or near Chicago, he said.

His EIA colleague, Holtberg says that "if you build a gas pipeline, you might get some offsetting oil at the same time" as new fields such as Point Thomson become profitable.

Cloudy crystal ball

Projecting two decades into the future is always a tough proposition, as technology continues to change, prices rise and fall, and other economic factors come into play. The EIA report also lowered its expectation for offshore oil in 2025 by 120,000 barrels a day, citing new figures on the cost of offshore production.

From the U.S. fields in total, the government agency expects an average annual decline of 0.9 percent each year between now and 2025, cutting the current number by about a million barrels a day to 4.6 million barrels daily by that year. ●

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ALBERTA

government to work with industry in developing a single-window approval process.

The objective will be to aid the efforts of suppliers to move gas from the North Slope and Mackenzie Delta to the Lower 48 states, Smith said.

Patrick Daniel, chief executive officer of Enbridge, made a vigorous case for streamlining approvals and removing barriers, which he has described as the "Achilles heel of gas development."

Daniel said a joint review process by Canada's National Energy Board and the U.S. Federal Energy Regulatory Commission for the proposed Alaska Highway project would help accelerate northern development.

He also suggested that the 13 agencies and governments involved in the Mackenzie Valley pipeline opens the door for special interest groups to raise issues that are not necessarily relevant to the permitting and facilities issues.

Smith acknowledged the current difficulties "for people to walk through the regulatory maze" in Alberta, involving the provincial energy and environment departments and the Energy and Utilities Board.

To overcome that confusion, the government commissioned a former deputy energy minister to look for regulations that could be eliminated.

He said the Energy and Utilities Board has "very good jurisdictional expertise in Alberta and we can tie in through commercial agreements these tie-ins with the Alberta network."

—**GARY PARK,** Petroleum News Calgary correspondent