Petroleum news

page 2 Oil Patch Insider: Cosmopolitan unit leases set to expire

Vol. 9, No. 35 • www.PetroleumNews.com — North America's source for oil and gas news — Week of August 29, 2004 • $1.50

Devlan to drill rare summer well

COURTESY OF AKITA DRILLING

Devlan Exploration is joining the hunt for oil in the central Mackenzie Valley of the Northwest Territories. (See story on page 11.) Pictured above is the Akita/Sahtu Drilling rig that is being used by Devlan this summer. This photo was taken last winter at another location.

Mackenzie gasline project not a slam-dunk, says Imperial

Partners in the Mackenzie Gas Project intend to file their regulatory applications at an early date, but even then the C$5 billion undertaking is "by no means a certainty," said a spokesman.

And much work has yet to be completed just to reach the filing stage, which has fallen behind because of a delay in receiving final instructions on how to prepare the environmental assessment, said Hart Searle, of Imperial Oil, the lead partner in the project.

see **MACKENZIE** *page 15*

Kerr-McGee confirms North Slope JV talks with Pioneer

Exploration and production independents Kerr-McGee and Pioneer Natural Resources are indeed considering a possible joint development of their oil discoveries on Alaska's North Slope, Kerr-McGee confirmed in an Aug. 25 conference call with industry analysts.

"We have begun discussions with Pioneer to explore potential develop-

see **JV TALKS** *page 15*

"We have begun discussions with Pioneer to explore potential development synergies in Alaska."
—Rick Buterbaugh, Kerr-McGee

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INTERNATIONAL

Benevolent landlord

Alaska, Norway get best deal from oil, gas; Canada doesn't, says think-tank

By GARY PARK
Petroleum News Calgary Correspondent

Alaska has been lauded for ensuring that its citizens get their money's worth from their oil and natural gas riches, while jurisdictions in western and northern Canada have been lambasted for selling their resources too cheaply.

The findings come in a study released Aug. 17 by the Pembina Institute for Appropriate Development, an Alberta-based think-tank titled When the Government is the Landlord.

The authors also said the Canadian governments were "making poor use of the revenues they do generate, using them to fund current expenditures rather than making long-

see **LANDLORD** *page 16*

GULF OF MEXICO

Apache, Morgan Stanley grab Anadarko's U.S. shelf acreage

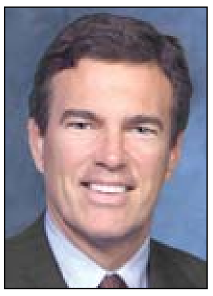
By RAY TYSON
Petroleum News Houston Correspondent

Exploration and production independent Apache Corp. is scooping up yet more oil and gas properties on the U.S. Gulf of Mexico's continental shelf in a $1.3 billion transaction said to be a win-win deal for seller Anadarko Petroleum and buyers Apache and investment bank Morgan Stanley.

Anadarko said it signed a separate purchase and sale agreement for the divestiture of its Phase 1 Canadian properties to Advantage Oil & Gas for $142 million.

The U.S. Gulf transaction marks Anadarko's exit from the Gulf's continental shelf, where the company pioneered tricky sub-salt exploration resulting in such noted discoveries as Mahogany, Hickory and Tanzanite.

As part of an on-going restructuring effort, Anadarko's $1.3 billion in property sales on the shelf also represents a huge leap in the company's goal to divest $2.5 billion of properties.



Anadarko CEO James Hackett

"By exiting the shelf, we can focus our Gulf program on the deepwater," James Hackett, Anadarko's chief executive officer,

see **APACHE** *page 18*

COOK INLET

Escopeta Oil's search for Cook Inlet's 'missing giants'

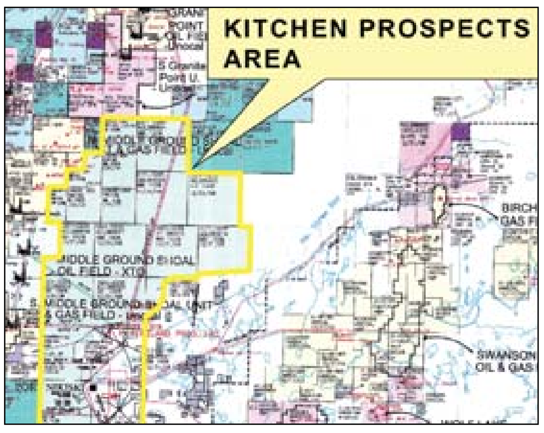
Independent shopping offshore Alaska prospects, using new seismic technology

PETROLEUM NEWS

The U.S. Department of Energy's recently published report on Alaska Cook Inlet natural gas hypothesizes that there are missing giants — large oil and natural gas fields — that remain to be found in Cook Inlet. And U.S. Geological Survey scientists have theorized that only 4 percent of the oil which could have been generated by Cook Inlet basin source rocks has ever been identified.

Houston-based independent Escopeta Oil, one of the inlet's largest state oil and gas leaseholders, thinks it has identified two of these missing giants in

see **GIANTS** *page 8*



Novice company joins oil sands fold; Cosmopolitan unit leases set to expire

TOSS ANOTHER NAME into the oil sands mix.

Deep Well Oil & Gas has doubled its oil sands holdings to almost 40,000 acres in the lightly developed Peace River area of northwestern Alberta.

With a former Alberta cabinet minister Horst Schmid as its chairman, Calgary-based Deep Well is following the lead of Blackrock Ventures, which expects to produce 15,000 barrels per day later this year from its Seal lease in the Peace River area.

The Deep Well bitumen deposit is estimated to be about 115 feet thick and could hold 2 billion barrels of recoverable reserves.

JUDY PATRICK

Aerial photo of Nabors Alaska rig 129 on the Red Pad in Unocal's Nikolaevsk exploration unit on Alaska's southern Kenai Peninsula. The photo was taken on Aug. 13. Unocal has drilled and is evaluating two exploration gas wells at Nikolaevsk, the Red No. 1 and the Red No. 2. (See story in last week's Petroleum News.)

Cosmopolitan federal leases set to expire

TWO FEDERAL LEASES in the Cosmopolitan unit on Alaska's southern Kenai Peninsula are set to expire. The Minerals Management Service would like to see a firm work commitment for the joint state-federal unit before it grants a lease extension – something unit operator ConocoPhillips has not yet applied for.

"The leases are being maintained under an approved suspension of operations until this November. The SOO was issued to enable ConocoPhillips to complete a number of geologic and reservoir studies on the economic potential of the prospect," Alaska Regional Director John Goll told Petroleum News in a written response Aug. 25.

ConocoPhillips' first well at the prospect was spud in October 2001. A sidetrack was drilled in 2003. Since that time ConocoPhillips has been evaluating the prospect for possible development.

A former executive with Forest Oil, a working interest partner in Cosmopolitan, told Petroleum News it would take a jack-up rig to really test the prospect. (Pennzoil found oil and gas in the area in 1967, drilling offshore with a jackup.)

There are no jackup rigs in Alaska, although a number of companies, including Escopeta Oil (see page 1 story) have been talking about bringing one in for a few years.

JUDY PATRICK

JOHN GOLL

Continuance of the suspension of operations, Goll said, will depend on the findings from ConocoPhillips studies "and future work commitments," which he said "could include additional seismic surveys to better delineate the prospect before drilling another well."

Both MMS and the state of Alaska have to approve "the scope and nature of any future work commitments," Goll said. "If MMS does not approve a continuance of the SOO before the current SOO expires … the federal leases will expire."

ConocoPhillips spokesperson Dawn Patience said Aug. 25 that it was "too soon to tell" if the company was going to file for extension or bring in a jackup as part of its work commitment.

Cook Inlet running low on propane

ALASKA PROPANE SUPPLIERS are currently shipping it in from Canada by rail because propane production has dropped off at Unocal's Swanson River field in the Cook Inlet basin.

"Swanson has our highest BTU producers, highest propane producers. It is in a natural decline but the reason for the recent drop-off was well work we did at the field," Unocal spokesperson Roxanne Sinz told Petroleum News recently.

The well work — coiled tubing velocity string inserts – was finished three weeks ago but production from the Hemlock, she said, has still not come back on.

"It was unforeseen that these wells would be slow in coming back around. … We're still trying to get them back on. … It forces the wholesalers to buy from Canada," Sinz said. ●

CANADA

Canadian gas exports bounce back

Canada is on track for a modest turnaround in natural gas exports to the United States, pulled along by a stronger demand for gas-fired power generation.

Against a background of agency forecasts of an irreversible decline in Canadian shipments south of the 49th parallel, National Energy Board's latest report on Aug. 20 showed that May volumes to the United States rose to 281.5 billion cubic feet, up 4.2 percent from a year earlier, pushing the five-month total to 1.49 trillion cubic feet compared with 1.47 tcf a year earlier.

Exports were higher to all regions in May, with the U.S. Northeast posting a 3.2 percent rise to 86.7 bcf and the dominant Midwest market rising by 1.1 percent over a year earlier to 125.4 bcf.

Might end two year slide in exports

If the trend continues, it could end a two year slide in exports that followed 14 straight years of record growth.

Earlier this year, the U.S. Energy Information Administration estimated that net pipeline imports would hold at the 2002 level of 3.6 tcf through 2010, and then go into decline to 2.6 tcf in 2025. It based that forecast on NEB estimates of total production to 5.9-7.1 tcf by 2015, down sharply from the regulator's previous forecast of 8.1-9.0 tcf.

The NEB reported export prices for May averaged US$5.43 per million British thermal units and $5.40 over the January-May period, compared with $5.01 and $5.56 respectively last year.

In Canadian currency, exports fetched an average $6.97 per gigajoule in May, up 7.9 percent from May 2003, but the five-month level dropped to $6.72 from $7.64.

Revenues from exports climbed in May to C$2.12 billion (about US$1.63 billion) from C$1.89 billion (US$1.24 billion). The five-month tally dropped to C$10.8 billion (US$8.3 billion) from C$12.2 billion (US$9.4 billion).

—GARY PARK

ALASKA

Potential Alaska, federal oil gas lease sales

Agency	Sale and Area	Proposed Date
DNR	North Slope Areawide	Oct. 27, 2004
DNR	Beaufort Sea Areawide	Oct. 27, 2004
MMS	Sale 195 Beaufort Sea	March 30, 2005
DNR	Cook Inlet Areawide	May 2005
DNR	Foothills Areawide	May 2005
BLM	NE NPR-A	June 2005
DNR	North Slope Areawide	October 2005
DNR	Beaufort Sea Areawide	October 2005
DNR	Alaska Peninsula Areawide	October 2005
MMS	Sale 199 Cook Inlet	2006
MMS	Sale 202 Beaufort Sea	2007
MMS	Chukchi Sea/Hope Basin	interest based
MMS	Norton Basin	interest based

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

This week's lease sale chart sponsored by:

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Petroleum news

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Dee Cashman	CIRCULATION REPRESENTATIVE

ADDRESS
P.O. Box 231651
Anchorage, AK 99523-1651

EDITORIAL
Anchorage
907.522.9469

EDITORIAL EMAIL
publisher@petroleumnews.com

BOOKKEEPING & CIRCULATION
907.522.9469
Circulation Email
circulation@petroleumnews.com

ADVERTISING
907.770.5592
Advertising Email
scrane@petroleumnews.com

CLASSIFIEDS
907.644.4444

FAX FOR ALL DEPARTMENTS
907.522.9583

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NEWS IN BRIEF

Yukon seeks bids for area inside Arctic Circle; spur to Mackenzie gasline possible

The Yukon government has invited bids to explore for oil and gas in the Peel Plateau, next to the Yukon-Northwest Territories border just inside the Arctic Circle.

The call area covers almost 100,000 acres and is part of the Peel Plateau and Plain area where the gas potential has been estimated at 2.8 trillion cubic feet. A major discovery could eventually open the way to a spur line connecting with the proposed Mackenzie Valley pipeline.

The call area covers almost 100,000 acres and is part of the Peel Plateau and Plain area where the gas potential has been estimated at 2.8 trillion cubic feet. A major discovery could eventually open the way to a spur line connecting with the proposed Mackenzie Valley pipeline.

Energy, Mines and Resources Minister Archie Lang said the Yukon government hopes to expanded the potential for finds by opening up relatively unexplored prospects.

Prior to the call, the government reduced the disposition area by two-thirds and designated 25 percent of the parcel as an "area of special consideration" to meet environmental concerns.

The deadline for bids is October 20.

Alberta has sights on the stars

Forget what you heard two weeks ago, the Alberta government should rake in more than C$9 billion in resource revenues in 2004-05, predicts analyst Peter Linder of DeltaOne Energy Fund.

That's C$1 billion better than Energy Minister Murray Smith predicted in mid-August, certain that new oil and gas price levels will be around for a while.

Given the price outlook and the rapid expansion of oil sands projects, Alberta government officials believe revenues from oil alone could soar to C$13.5 billion by 2017, putting the combined resource returns close to C$20 billion.

Alberta land sales surpass C$700 million mark

Alberta continues to enjoy a land sales bonanza in 2004, reaching almost C$707 million from auctions of petroleum, natural gas and oil sands rights, compared with C$533 million at the same time in 2003.

The Aug. 18 sale generated C$39 million from almost 365,000 acres. The top bid went to broker Township Land, which paid C$763,788 for 5,700 acres at an average C$134 per acre, compared with the auction average of C$107 per acre.

To date this year, bidders have accumulated 5.09 million acres, up from last year's 4.89 million acres, with average per acre values climbing by 27 percent.

—GARY PARK

Allenergy snatches prime 'Kelly Lease' in Oklahoma

Independent producer Allenergy said it purchased a 430-acre premium gas lease in Okmulgee County of northeastern Oklahoma known as the "Kelly Lease" from an undisclosed seller.

The parcel contains 10 wells, two of which are free-flowing and eight that are fully equipped, shut-in and ready to be brought online and into production, Allenergy said Aug. 25, adding that eight to 10 additional development sites also are located on this lease.

The property is adjacent to the highly-productive Okfuskee County area, which has multiple producing zones and where the new "Caney Shale" zone is currently being tested, Allenergy noted.

The Kelly lease was purchased on a three-year note that will be paid with 15 percent of gross production, Allenergy said.

The company said it is in negotiations on other leases.

—RAY TYSON

ALASKA

XTO buys tiny piece of Kuparuk

XTO Energy closed this month on a tiny piece of the Alaska North Slope's Kuparuk River oil field, part of a larger acquisition outside Alaska from ChevronTexaco and not reported when the larger deal was announced in May.

KYLE HAMMOND

The Alaska purchase – one-tenth of one percent of Kuparuk – was "an incidental part of the acquisition, not something we were targeting," Kyle Hammond, XTO's vice president of operations for Alaska and the Permian basin, told Petroleum News Aug. 26.

The ConocoPhillips-operated Kuparuk River unit averaged 185,921 barrels of oil per day in July. Hammond said XTO's share will be about 200 barrels per day.

He also said XTO is not actively seeking properties on the North Slope.

More Cook Inlet wells

XTO, however, continues to stay active in looking for new oil in old places in the Cook Inlet basin of Southcentral Alaska.

Hammond said April 1 that XTO planned to drill one, possibly two, wells from its platforms at Middle Ground Shoal this year – the only offshore wells planned for the inlet in 2004.

On Aug. 26 he said the company now has four wells planned, all sidetracks; two to three wells are planned for this year; the rest early next year.

Oil production at Middle Ground Shoal, a mature field XTO acquired from Shell in 1998, has slipped from 3,900 barrels in the first quarter of this year to 3,700 barrels per day recently. Hammond expects the new wells to have a "positive impact" on production.

XTO is scheduled to begin work on the first sidetrack in a couple of weeks.

—KAY CASHMAN

finance&economy

FRISCO, TEXAS

Comstock acquires Ovation assets

Exploration and production independent Comstock Resources has agreed to buy nearly all the assets of Ovation Energy for $62.5 million, Comstock said Aug. 25. The properties are located in the East Texas, Arkoma, Anadarko and San Juan basins.

Frisco, Texas-based Comstock estimated the properties contain proved reserves of 42.7 billion cubic feet of gas equivalent, consisting of 99 percent natural gas. Sixty-six percent fall into the proved developed category, the company added.

The Ovation properties include 161 active wells. Comstock said it would operate 69 of the wells. The properties currently produce about 7 million cubic feet of natural gas equivalent per day. The transaction is expected to close on Oct.1 of this year.

Comstock said it also hedged a portion of its natural gas production in 2005 and 2006 related to the acquisition and to its recently expanded East Texas drilling program.

—RAY TYSON

CALGARY

Penn West board recommends switch to energy income trust

In a moment of rare insight into his character, Canadian oil patch wizard Murray Edwards said “there are no eras … we’re all just sands in time. There’s no permanency to anything.”

That was intended to signal his lack of emotional attachment to Calgary-based Penn West Petroleum, a company he has been instrumental in building from a C$3 stock in 1992 to about C$66 today with a market capitalization of C$3.6 billion and a senior producer, pumping 107,000 barrels of oil equivalent per day, including 330 million cubic feet of natural gas.

Against a backdrop of rumors that he was fighting tooth-and-nail to preserve Penn West as a traditional exploration and production company and prevent a switch to the burgeoning income trust ranks, Edwards insisted he was “indifferent” to the trust structure that now holds 30 oil and natural gas producers.

Under mounting pressure

His comments came on the afternoon of Aug. 20 when, amid considerable tension among shareholders at Penn West’s annual meeting, the board of directors recommended moving all of the company’s assets into a trust, setting Penn West up for a possible C$1 billion market gain and creating easily the largest energy trust.

The company has been under mounting pressure over the past year from big institutional investors, including Salida Capital,

see **PENN WEST** *page 6*

● OKLAHOMA CITY

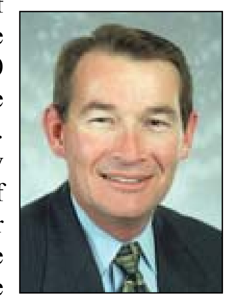
Kerr-McGee forecasts more oil from Gulf on strong results from Nansen field

By RAY TYSON

Petroleum News Houston Correspondent

Deepwater player Kerr-McGee has raised its 2004 third-quarter oil production forecast for the Gulf of Mexico by as much as 10 percent because of a surprisingly strong performance from the company-operated Nansen field on East Breaks Block 602.

Earlier projections had called for Kerr-McGee’s total production in the Gulf of Mexico to average between 52,000 and 56,000 barrels per day during the current quarter ending Sept. 30. That outlook has now been increased to a range of 58,000 to 62,000 barrels per day, a daily 6,000 barrel spike on the upside of the range that presumably is coming largely from Nansen.



“Performance from the deeper oil-bearing sands continues to exceed our expectations.” —Rick Buterbaugh, Kerr-McGee’s vice-president of investor relations

Performance from deeper oil sands

“Performance from the deeper oil-bearing sands continues to exceed our expectations,” Rick Buterbaugh, Kerr-McGee’s vice-president of investor relations, said Aug. 25 in a third quarter interim conference call. “Therefore we have increased our projected oil volumes in the Gulf for the third quarter.”

In fact, Nansen is performing so well on the oil side that Kerr-McGee and 50 percent partner Devon Energy have “intentionally delayed” the recompletion of wells into shallower gas zones until this year’s fourth quarter, Buterbaugh said.

“This increases the overall value of the Nansen field, but accordingly reduces the near-term gas volumes,” he explained.

San Jacinto discovery added to Eastern Gulf of Mexico gas hub

Production from the San Jacinto discovery in deepwater Eastern Gulf of Mexico would be tied to a proposed central processing facility in Atwater Valley, along with six other previously disclosed natural gas fields in the area, San Jacinto partner Kerr-McGee said Aug. 25.

The planned hub is expected to be sanctioned by the Atwater Valley Producers Group in the “next several months” with initial production anticipated for mid-2007, said Rick Buterbaugh, Kerr-McGee’s vice-president of investor relations.

“This group is making good progress on an overall plan of development for numerous gas discoveries in the area,” he added.

Along with San Jacinto, the most recently announced discovery in the Eastern Gulf region, Merganser, Vortex, Spiderman, Jubilee, Atlas and Atlas Northwest would be tied to the hub. None of the fields qualifies as

see **SAN JACINTO** *page 6*

Proved reserves jump to 200 million BOE

The original project was sanctioned in 2000 on a gross proven reserve base of 55 million barrels of oil equivalent and a gross proven plus probable resource of about 120 million barrels of equivalent. But following development drilling, the addition of Navajo field satellites, and better than anticipated production performance, Kerr-McGee said it now expects to produce more than 200 million barrels of equivalent proven and probable resources.

Production through the Nansen truss spar at

see **KERR-MCGEE** *page 6*

continued from page 5

KERR-MCGEE

mid-year 2004 was averaging about 30,000 barrels of oil per day and 165 million cubic feet of natural gas per day.

"Individual wells and reservoirs have generally performed well above expectations," Kerr-McGee spokeswoman Debbie Schramm said. Kerr-McGee achieved first production at Nansen in early 2002. The field, located in 3,700 feet of water, was developed with the world's first truss spar. Production is derived from nine Nansen dry-tree wells on the spar and six sub-sea wells of which three produce the Nansen field and three produce the Navajo satellites.

Having less luck at Boomvang field and elsewhere

However, Kerr-McGee is having less luck bringing into production two recently drilled and completed satellite development wells at its Boomvang field, located just nine miles from Nansen in East Breaks. Installation of a sub-sea pipeline to service the wells has been delayed a month because of damage to a pipe laying vessel enroute to the field, Buterbaugh said. He said first production from the wells is now expected during the fourth quarter.

The company also has encountered gas production snags or temporary delays elsewhere, including the Wattenberg field in northeastern Colorado, the Greater Natural Buttes area in northeastern Utah and the Skene field in the North Sea, where gas production will be shut during September to upgrade a compressor that should extend the field's life.

Kerr-McGee is experiencing some higher condensate at Wattenberg and therefore lower gas yields, Buterbaugh said. In the Greater Natural Buttes area, gas volumes are "constrained" due to plant maintenance at the main station, he said, adding that the plant turnaround was expected to be completed by Sept. 1.

Adding insult to injury, roughly 1,000 barrels per day of oil equivalent were lost in the third quarter from Kerr-McGee's Red Hawk and Neptune fields due to pipeline shutdowns as hurricanes Bonnie and Charley swept through the Gulf of Mexico in early August.

Ahead of schedule at China's Bohai Bay

On a brighter note, Buterbaugh said oil production from China's Bohai Bay is ramping up ahead of schedule with the first two cargoes successfully offloaded from the FPSO, or floating production, storage and offshore loading system. The company also was expecting the millionth barrel of production on Aug. 25, just five weeks after field startup.

Moreover, current oil production of 25,000-30,000 barrels per day from Bohai Bay is expected to increase to 35,000 barrels per day in the fourth quarter as additional development wells come on steam, Buterbaugh said. Also, he said gas production from the company's Red Hawk field in the Gulf of Mexico, launched in mid-July, already has ramped up to a full rate of 120 million cubic feet per day.

All the ups and downs in production have caused Kerr-McGee to alter its forecasted oil-gas mix for the third quarter while maintaining previous guidance of 333,000 to 360,000 barrels per day of combined equivalent production for the period.

The company is now projecting slightly higher oil production of 156,000-170,000 barrels per day and slightly lower gas production of 1.060-1.140 billion cubic feet of natural gas per day during the current quarter. ●

continued from page 5

SAN JACINTO

a stand-alone development, primarily because of their remote locations in "ultra-deep" waters of the Gulf exceeding 7,000 feet.

The San Jacinto discovery on DeSoto Canyon Block 618 is just six miles west of Spiderman, among the largest announced discoveries thus far in the Eastern Gulf planning area. The two discoveries alone are said to hold combined estimated gas reserves of around 500 billion cubic feet.

Kerr-McGee holds a 20 percent interest in the Dominion E&P-operated San Jacinto prospect. Spinnaker Exploration, another exploration and production independent, has a 27 percent stake in the prospect. Dominion owns the remaining interest. The discovery well is located in 7,800 feet of water about 95 miles southeast of Venice, Louisiana.

Dominion plans to spud an exploratory well in this year's third quarter on the West Raptor prospect at DeSoto Canyon Block 445, Kerr-McGee's Buterbaugh said. West Raptor is also operated by Dominion. But in the event of a commercial discovery, any subsequent developments would be operated by 33 percent owner Kerr-McGee.

Also participating in Atwater Valley Producers Group

In addition to Kerr-McGee, Dominion and Spinnaker, Devon Energy, Anadarko Petroleum and Australia's BHP Billiton are participating in the Atwater Valley Producers Group.

Anadarko holds 100 percent interests in the Jubilee, Atlas and Atlas Northwest discoveries and operates Spiderman with a 45 percent interest. Dominion holds a 36.67 percent stake in the prospect and Spinnaker an 18.33 percent interest.

In addition to San Jacinto, Kerr-McGee holds an interest in Merganser together with long-time deepwater partner Devon. Devon also holds an interest in the BHP-operated Vortex discovery. Merganser, Vortex and Jubilee are located in Atwater Valley just outside the Eastern Gulf planning area.

continued from page 5

PENN WEST

CanFund VE Management and the C$75-billion Ontario Teachers Pension Plan Board.

Edwards, who is believed to hold 6.5 percent of Penn West shares and is a co-owner of the Calgary Flames franchise in the National Hockey League, said his only priority is to build shareholder value as much as possible.To that end, he suggested trusts can "serve a purpose at times" and can be "abused at times."

"I think they have a role to serve at the right time with the right structuring. Are they the perfect model? No."

In a bull cycle

Continuing on his philosophical path, Edwards said "you go through transitions and cycles. Right now, none of us in Calgary are as smart as we think we are ... $47 oil means a lot of us look pretty smart.

"We are in a bull cycle and as much as we are in a bull cycle, we will have challenges and we are going through a phase right now in Western Canada."

Penn West president Bill Andrew, conceding shareholder pressure was a consideration in the board recommendation, said Penn West had reached a point "where a different way of looking after the shareholders" was needed.

Apparently, less than a majority of shareholders wanted to take the plunge into the trust pool.

Not yet a done deal

A proposal to seriously consider the trust model was defeated by 52 percent of shareholders at the annual meeting.

But the conversion is not yet a done deal. The board said that unless it gets a favorable ruling from the Canadian government on a number of "complex" but unspecified tax issues, Penn West "will continue as an oil and gas exploration and development company while it examines its strategic alternatives."

A formal review started six months ago, with three options on the table: Trust conversion, outright sale or merger, or maintaining the status quo, although Andrew is reported by insiders to have said the review was not started to choose a do-nothing strategy. The trust stable now holds 30 energy companies, of which 24 reported total production of 630,000 barrels of oil equivalent per day in the second quarter and distributed C$2.29 billion to unit-holders, or 71 percent of their cash flow.

That share of cash flow was down from earlier trust days when upwards of 90 percent was distributed, showing that more trusts are turning to traditional exploration rather than acquisitions to maintain production volumes.

But, unlike some recent trust converts, Penn West chose not to recommend spinning a portion of its output into a junior E&P.

—GARY PARK

● BRITISH COLUMBIA

Time for a turnaround, says think-tank report

Government accused of undermining B.C.'s energy security; Neufeld says industry is vital source of employment, revenue

By GARY PARK

Petroleum News Calgary Correspondent

Just as British Columbia is battling headwinds in its efforts to tap coalbed methane and offshore oil and gas deposits, it has been buffeted from the side by a report that argues the province's energy policies should be concentrated on conservation and security, not the extraction and export of resources in fragile eco-systems.

A 60-page report commissioned by two think-tanks – the Canadian Centre for Policy Alternatives and the David Suzuki Foundation – accused B.C.'s government of being fixated on shipping as much oil and gas as quickly as possible to the United States.

Dale Marshall, author of Running on Empty: Shifting to a Sustainable Energy Plan for British Columbia, said the province needs to make a dramatic change to the way it produces, consumes and exports energy.

The report noted the government of Premier Gordon Campbell released a plan in 2002 that promoted the objectives of sustainability and security.

But Marshall said that it is now clear the government is ready to undermine energy security, by ignoring the dangers of climate change and making only token gestures towards conservation and renewable energy.

He said the strategy is focused more on building new coal and gas-fired power plants, and building transmission systems to export oil, gas and electricity to the United States, along with developing coalbed methane.

The result, he said, is the loss of jobs across the Canada-U.S. border and the production of greenhouse gases that the study links to drought, declining salmon stocks, insect infestations and forest fires.

Based on Environment Canada statistics, the report concludes that greenhouse gas emissions from electricity rose by 175 percent from 1990 to 2001 and by 45 percent from the hydrocarbon sector.

Neufeld makes no apologies

B.C. Energy Minister Richard Neufeld replied that British Columbia is actually a net importer of oil and consumes 45 percent of its natural gas, with the balance going to the United States and Eastern Canada.

He made no apologies for the incentives offered to oil and gas companies to entice them to the province and generate "solid employment and a good revenue stream for social programs."

Even so, Neufeld insisted the government has put a high priority on renewable and clean energy sources by urging "anyone marketing electricity ... to get 50 percent of their new energy from clean sources. B.C. Hydro has managed to meet that so far, in fact, has beat it."

He said the greenhouse gas emission figures cover the previous left-wing New Democratic Party government's time in office, while the numbers have gone down since the current Liberal government was elected in 2001.

Neufeld brushed aside as "left-wing talk," the report's recommendation that all oil and gas subsidies should be eliminated, royalties should be increased and a permanent fund should be set up paralleling those of Alaska, Alberta and Norway.

He said programs to encourage horizontal, deep and summer drilling are not subsidies, but have "benefited British Columbia hugely."

The permanent fund concept was rejected in favor of eliminating a budget deficit and retiring a "pretty large debt."

Meanwhile, the government's push to exploit its estimated 90 trillion cubic feet of coalbed methane reserves is colliding with more than just opposition from the Montana government, which objects to the auctioning of drilling rights to two large blocks of land in southeast British Columbia because of the dangers to water being pumped from coal beds and finding its way to the Flathead River Basin.

Coalbed methane development not imminent

Some experts say that only 20 percent of the coalbed methane reserves can be extracted economically and others suggest commercial development is far off in the future.

While most of neighboring Alberta's coalbed methane is in dry coal fields, B.C.'s fields would produce large volumes of water along with the gas, creating environmental problems like those associated with coalbed methane production in the United States.

Alberta has the added advantage of an extensive network of roads and pipelines in its coalbed methane areas. B.C.'s infrastructure is minimal.

Tom Ebbern, an analyst at Tristone Capital, said the fact that no company has yet present plans for commercial coalbed methane development in British Columbia suggests no one has figured out how to do it economically.

But it is not all bad news for the B.C. government. A report issued Aug. 9 by the B.C. Business Council said the resource sector, including, energy, mining and forestry, accounts for 13 percent of the province's gross domestic product, compared with 11.1 percent for the rest of Canada.

Resource-based goods make up 75 percent of British Columbia's merchandise exports, yielding C$22 billion in annual earnings and provide 180,000 direct jobs, or one in every 10.

B.C. Finance Minister Gary Collins, commenting on the critical dependence on resource extraction and processing said that sector "isn't going to go anywhere anytime soon," regardless of efforts to diversify.

He said regulatory and tax regimes would be kept competitive with neighboring jurisdictions, although the province would never "bail out a particular company." ●

NEW ORLEANS, LA.

Minerals Management Service moves three into management positions

The U.S. Minerals Management Service said it has appointed employees Jim Grant, Joe Gordon and Lars Herbst to management positions at MMS' Gulf of Mexico regional office in New Orleans.

Jim Grant was named chief of staff, office of the regional director. He began his career with MMS in 1984 in the Corpus Christi District in Texas and has served as chief of the technical assessment and operations support section; chief of the production, commingling and rate control section; and chief of the plans, platforms and pipelines section.

In his new position, Grant will serve as immediate advisor to Gulf Regional Director Chris Oynes on major programmatic, policy, and budget issues as well as organizational issues.

Joe Gordon was appointed deputy regional supervisor of field operations. His responsibilities include managing the technical functions of the regional activities within field operations. The office of field operations evaluates and approves operator proposals to install and modify platforms and pipelines on OCS leases, evaluates new technology to be used in the Gulf, reviews and approves exploration and development plans, and administers the Gulf's accident investigation and civil penalty programs.

Gordon joined MMS in 1988 as a staff engineer in the technical assessment unit in the Gulf region. He has served as the Lafayette district drilling engineer, the Lafayette district manager and, most recently, chief of the office of safety management.

Lars Herbst was appointed to the position of deputy regional supervisor for district operations in the office of field operations in the Gulf region. His duties include oversight of the five district offices located in New Orleans, Houma, Lafayette, and Lake Charles in Louisiana, and Lake Jackson, Texas. The primary functions of the district offices include permitting and inspection activities related to offshore operations, including drilling, workover, completion, well abandonment, and production operations.

Herbst began his career with MMS in 1983, after working for Schlumberger in the well testing group. At MMS, he started as a staff engineer in the technical assessment unit for the Gulf region. In 1990, Herbst was named drilling engineer in the New Orleans District, and in 1995, became the New Orleans district manager.

—RAY TYSON

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GIANTS

its Kitchen and East Kitchen prospects. Escopeta's executives believe their two prospects contain substantial amounts of oil and gas and are looking for a partner so that Escopeta can bring in a jackup rig and drill an exploration well.

Escopeta President Danny Davis told Petroleum News in July that the company hopes to have partners in place in time to begin permitting this fall and bring a jack-up rig to the inlet next year to drill the prospects, which are offshore the Kenai Peninsula, north of Nikiski.

The Kitchen and East Kitchen prospects are in 70 feet of water close to the Kenai industrial complex. They represent 10 years of work by the company, including studies by geologists with Cook Inlet experience and, more recently, the reprocessing of seismic by Houston-based Apex Metalink Inc. with its proprietary technology.

Prudhoe Bay happened

How could there be missing giants in Cook Inlet, a hydrocarbon basin which has been in production for nearly 50 years? A basin which sits on the doorstep of Anchorage, the oil company capital of Alaska?

"There were always a few questions that were unanswered when we were doing work in the inlet, in relation to the fields," said Bob Warthen, a consulting geologist working with Escopeta. Warthen has worked the inlet since 1967, first for Union Oil where he was a regional geologist for 26 years, and then as a consultant.

"And after Prudhoe Bay was discovered, the inlet became a stepchild, so the working scenarios in the inlet were strictly a development-type scenario — develop the existing properties. Consequently very little exploration work has been done," he said.

Geologists were reassigned and transferred away from work in the inlet, first to "Prudhoe Bay; then you had restructuring; then you had downsizing; then you had the oil problems in '85 and '86 — the oil price collapse; then more restructuring; then you had company mergers," Warthen said.

"And all of this translated to people: people were transferred out; they were furloughed; some of them migrated to other professions — they weren't coming back; some of them died. We've lost some significant talent in the inlet just because they passed away … Bob Levine … Charlie Selman. … I'm probably one of the few guys left working the inlet that started in the early days. There's very few of us remaining and actively exploring," he said.

Developing prospects

After Warthen took an early retirement from Unocal in 1992, he began working all the available data on the inlet, including well information and seismic, and looked at rocks, trying "to get a better understanding of the intricacies of the formations."

And he developed a basin map, "let's just call it an idea map, or as Danny (Davis) calls it, our 'play book'," he said.

That idea map, in different iterations, identified acreage acquired by Escopeta, which began looking for opportunities in Alaska in 1993 and bought its first leases in the state in 1994. The company now owns some 128,000 acres of state oil and gas leases in the Cook Inlet basin (see map on page 9).

An early prospect that Escopeta was involved in, and subsequently sold, was at Cape Starichkof, where ConocoPhillips Alaska drilled the Hansen wells at the Cosmopolitan unit.

Because Escopeta has worked on a number of prospects in the inlet, it took several years to do the work and assemble the leases for Kitchen and East Kitchen. "We basically had other things that required our attention in the inlet rather than some of the ideas that I had," said Warthen.

Reevaluating Cook Inlet

The work Warthen originated on the inlet was focused on the petroleum system and potential untested habitats and traps for hydrocarbons. In addition to Warthen, geologists Walter Wells and Frank Banar, retired from Mobil, contributed to Escopeta's "idea map," hiring on as consultants for Escopeta.

"Reservoir rocks are not a problem in Cook Inlet: every horizon has reservoir rocks with varying porosities and permeabilities that are basically reasonable," Warthen said. "Trapping was not really a problem either," since available seismic provides "a decent understanding of the style of traps and accumulation mechanisms."

Walter Wells did a search for everything written on the petroleum systems in the

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Excerpts from DOE's Cook Inlet basin gas study

The following information was taken from the executive summary of the U.S. Department of Energy's South-Central Alaska Natural Gas Study, which was released in June.

Summary conclusions

The Cook Inlet basin is the source for all of the natural gas used in south-central

Alaska. This gas supplies the residential and commercial demand for utility gas and electricity generation and two industrial facilities, Agrium's fertilizer plant and the ConocoPhillips/Marathon LNG plant, in Nikiski, Alaska on the Kenai Peninsula.

• The current remaining proven reserves represent about a 9-year supply at current demand rates.

• The estimated ultimate recovery for existing Cook Inlet gas fields is approximately 8.5 trillion cubic feet.

• Ninety-five percent of the gas was found before 1970 during exploration for structurally trapped oil.

• There was no gas-focused exploration until the late 1990s.

The Cook Inlet basin lacks numerous medium to large gas fields when viewed from the geologic expectation of a lognormal distribution of field size and reserves. A total Cook Inlet gas resource endowment of 25 to 30 trillion cubic feet original-gas-in-place … is postulated.

• The potential exists for an additional 13 to 17 tcf of conventionally recoverable gas in the Cook Inlet basin in addition to the 8.5 tcf recoverable gas already discovered. …

• These resources are expected to be largely biogenic gas in stratigraphic or combination traps.

• No exploration has yet occurred for stratigraphic accumulations. …

Proven reserves in known fields are forecast to meet demand until 2012 for the base case, which assumes the Agrium fertilizer plant shuts down in 2005 as a result of lack of sufficient quantities of low-cost gas and that LNG export ends when the current contract and export license expires in the first quarter of 2009.

A shortage will occur by 2009 unless new reserves are found and developed, or industrial use is curtailed. Large seasonal swings in demand and very limited gas storage could lead to seasonal shortages before 2009. …

New gas is being discovered and developed as a result of the stimulus being provided by higher prices and market demand. …

• Reserves growth is expected to occur in response to an increase in real prices. A recent contract has indexed prices to a 36-month average of Lower 48 reference prices (Henry Hub).

See DOE's report on web site http://www.cookinletoilandgas.org/

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GIANTS

inlet, Warthen said. “When we started looking at the three things that you need for a prospect — the trap, the reservoir and the charge — we started really focusing on the petroleum system, on the migration path, the generating area, and we looked at a lot of the seminal USGS reports from some of the real experts in that field, and even interviewed some of them.”

The theory on migration of oil, Warthen said, is that the migrating oil finds a path, and then travels along that path, not deviating from it.

“When it leaves the source area, it migrates up dip and fills the deepest traps first,” he said. “As these are filled the oil continues to migrate up dip filling the shallowest traps in turn.”

Only 4% of oil identified

U.S. Geological Survey geologists have theorized that only 4 percent of the volume of oil that theoretically generated from Cook Inlet source rock has ever been identified.

Some of the oil could have leaked out of the basin, Warthen said. And there has been a theory that the basin tilted and the oil remigrated. If the basin tilted, he said, some traps would be pretty well filled and others are going to be only 15-20 percent filled.

But the known traps are filled between 58 and 65 percent, except Middle Ground Shoal, which Warthen said was filled 80 to 85 percent.

The Escopeta acreage position at Kitchen and East Kitchen is “just to the east of Middle Ground Shoal and situated directly overlying the Tertiary/Mesozoic depocenter and we believe the early oil is migrating in an east-west direction,” Warthen said.

Because of the known migration path of oil in the inlet, it is believed that oil migrated into the Kitchen prospect traps, filled those, and subsequently migrated on to Middle Ground Shoal and then into other fields, and “that’s the reason why Middle Ground Shoal is about 80 to 85 percent filled and the rest of these (farther along the migration path) are less (filled),” Warthen said. “We believe that these prospects are among the ‘missing giants’ postulated by the U.S. Department of Energy,” he said.

Warthen said the Kitchen prospect got its name “because we kept referring to this area here as the area where the oil was ‘cooked’, i.e. being the ‘kitchen’.”

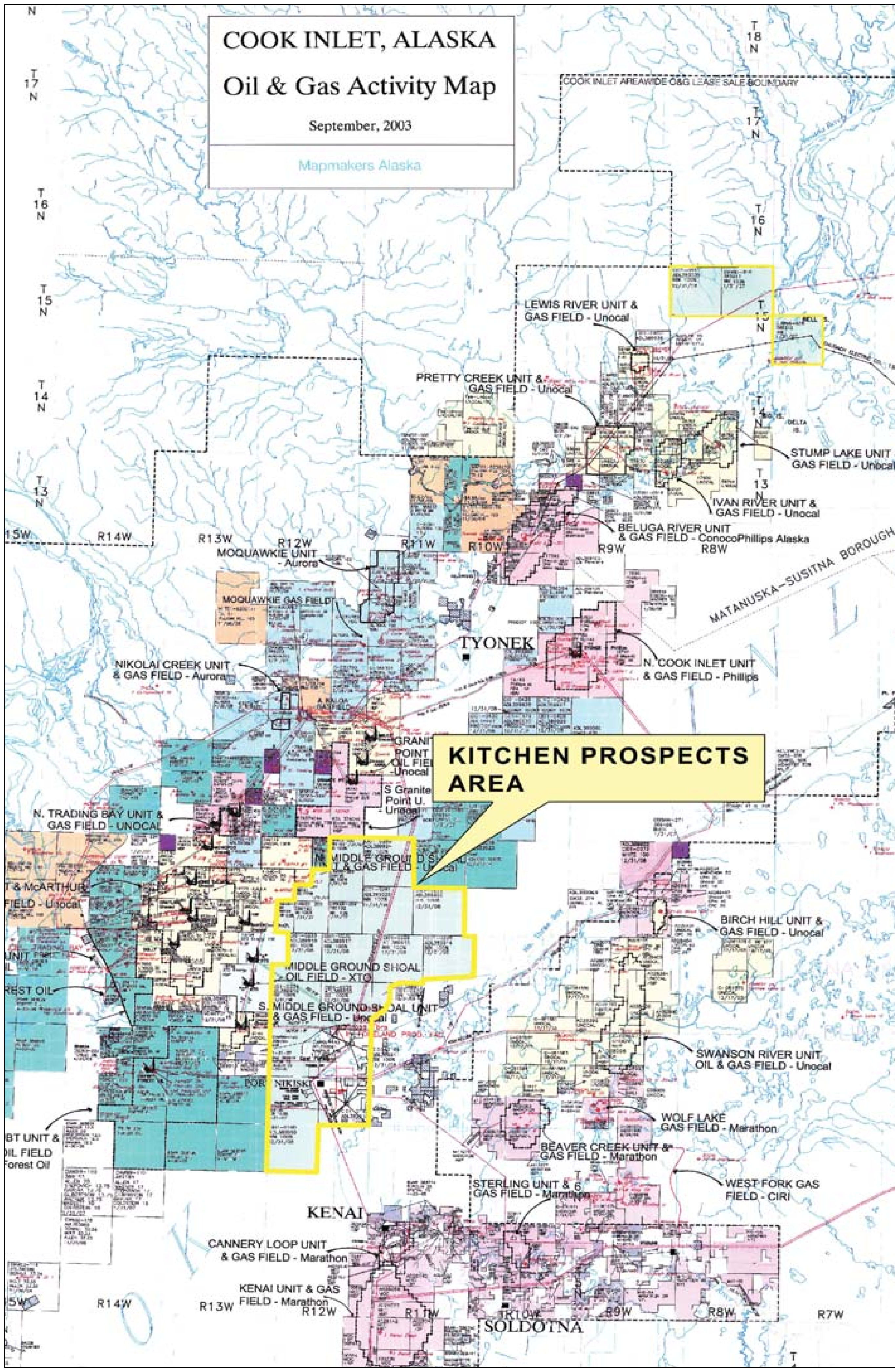
Reprocessing and remapping

Escopeta has not shot any proprietary seismic, but it has purchased existing seismic from a number of companies and used those lines to delineate the area, to look at the prospect from “a structural standpoint,” Warthen said.

Escopeta has had the seismic lines it acquired reprocessed and based on that reprocessing it has remapped the Kitchen complex area.

The southern part of the prospect that contains East Kitchen has never been identified, Davis said, “and this feature extends another eight miles beyond the original tested anticline.” The South Cook Inlet anticline has been remapped and is now “about 15 to 16 miles long and about three to four miles wide,” he said. The Shell SRS No. 1 well on the northern flanks tested 360 barrels of oil per day from a lower Tyonek sand, he said, however other prospective pays were never tested due to collapsed casing.

“The southern half of the anticline is what we’re calling our East Kitchen prospect, and it has never been drilled. In effect, it is a major anticline with demonstrated hydrocarbons that have not been adequately tested,” Davis said.



COURTESY OF ESCOPETA

“We took 1980’s seismic data and applied some new techniques to it: reprocessing, petrophysical studies on the rocks, sophisticated log analysis on the logs … gravity magnetic data, to back up our regional studies,” Warthen said.

So what do the combined studies indicate to Escopeta about potential Kitchen and East Kitchen reserves?

Escopeta consultants estimate potential reserves at East Kitchen as 2.33 trillion cubic feet of gas and 457 million barrels of oil, Davis said. For Kitchen the numbers are 3.95 tcf of gas and 829 million barrels of oil.

A new processing technique

One very important thing Escopeta did, said Frank Banar, was to have the data reprocessed using a process called wavelet energy absorption, which has been used in Asia, West Africa and Siberia. In China, he said, the process was used in basins which have both coal and gas, and where the gas needed to be identified on the seismic.

Because Cook Inlet has both coal and gas, the process seemed appropriate, “and so we were the first ones to do that here in Alaska,” Banar said. In addition to the seismic processing for gas, Apex Metalink also have a process for fluids identification.

The wavelet energy absorption processing “showed some significant gas reserves on the Kitchen and East Kitchen structures, especially in the Tertiary section, where abundant coal beds have generated major dry gas reserves,” Banar said.

Current Cook Inlet production is from Tertiary formations: dry gas from Sterling, Beluga, and upper Tyonek; oil from the lower Tyonek and Hemlock. There is no production from the older Cretaceous and Jurassic in the upper Cook Inlet basin, although surface oil seeps are known from the Jurassic Tuxedni formation. The Tuxedni, said Warthen, has been identified by the USGS as the source rock for all of the oil present in the Hemlock.

Davis said potential deep gas below the Tertiary is a separate prospect. The objectives at Kitchen and East Kitchen are the major producing Cook Inlet formations, the Sterling, Beluga, Tyonek and Hemlock. Escopeta does not attribute any reserves to pre-Tertiary, he said, but considers them a very viable future target based upon present seismic interpretations.

Big structure south of old well

One of the things the Department of Energy report notes, said Davis, is that the inlet has been explored for structural traps but not for stratigraphic traps. “There was no concentrated exploration for stratigraphic-type plays or potential below where they’ve found everything in the Hemlock (formation).” East Kitchen is a structural trap, he said, while Kitchen is a

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faulted stratigraphic trap first proposed by the USGS.

Looking at seismic, Davis said, just a few miles south of the Shell No. 2 SRS, "we had a large anticlinal structure there, and we couldn't figure out why it hadn't been drilled." One interesting thing about Kitchen, he said, is that seismically it looks very much like the Beluga River field.

Escopeta had Core Lab of Houston do a petrophysical analysis of the Shell South Cook Inlet No. 2 well, one and a half miles north of Escopeta's East Kitchen location. This well was drilled in 1965, had numerous oil and gas shows and casing was set, however the well was suspended and never tested in 1965, Escopeta said. No core data was available from the well, but Core Lab said core was available from the North Cook Inlet Unit No. B-01 well, and a "porosity permeability relationship was derived and the model applied" to the Shell No. 2 well. The lab said "results indicate that the South Cook Inlet No. 2 well appears to indicate some hydrocarbon potential," and estimated 252 feet of gas pay and 303 feet of oil pay which was bypassed.

First partners, then a jackup

At one time, Davis said, Forest, ConocoPhillips, Prodigy and Escopeta were interested in working together to bring a jackup rig into the inlet. Collectively, "we had nine wells identified to be drilled with the jackup rig, unfortunately we were not able to move forward together."

Escopeta doesn't have any three-dimensional seismic, but Davis said that at this point, he wants to put money into drilling, rather than into 3D, "as 3D will not change the size of our structure, but will be an excellent tool for field development."

Davis said that if drilling at East Kitchen confirms Escopeta's interpretation, the plan is to set a production platform over the well so that the location could be produced.

Companies unfamiliar with Alaska

Davis said Escopeta needs partners to go ahead, however, he said, "finding partners for Alaska is a unique search."

Some say the project is too costly, some want 3D seismic shot before they commit.

But most Lower 48 companies are just not familiar with Alaska, Davis said.

"They don't know the potential. It's not their operating backyard. They haven't seen what I've been able to see through Bob's, Frank's and Walter's eyes."

What is the attraction for Escopeta? Cook Inlet has major reserves and an existing gas market.

"In my opinion," Davis said, "there's more current potential in what we have identified here than what some independents are pursuing on the North Slope."

If they find gas on the North Slope, he said, they have no market, while in Cook Inlet, "it's approaching a five-dollar market right now."

Davis said companies also ask: "If we get up there, what else can we do?" If Escopeta is right about the reserves in the Kitchen and East Kitchen prospects, he said, "they'll be drilling out here for the next 30 years. Because you're going to set a platform on East Kitchen and probably two on Kitchen: that's plenty for a company to do," he said, referring to a map of the area.

"Plus, Bob (Warthen), Frank (Banar) and Walter (Wells) have other ideas, and we have other projects that we're going to chase so there's a lot, a lot more to do."

Is there production to purchase?

One thing Cook Inlet apparently doesn't currently offer, Davis said, is production that can be purchased. "One big independent in Houston said, 'look, if you had some production we could buy up there, we'd buy the production and then we could combine that and we could drill your wells'."

But, Davis said, "at today's prices of $45 oil and $4.74 gas, it is time to drill wells, especially those that will lock up major reserves, and not buy production."

What Escopeta is doing matches up with the Department of Energy report's description of two-phase exploration history in mature basins, first exploration for structural traps like the company's East Kitchen prospect, Davis said, and then a second phase focused on stratigraphic plays like the company's Kitchen prospect.

"At this point in time Cook Inlet exploration is still in the structural prospect phase," he said. "Few if any exploration plays have been pursued and drilled solely on stratigraphic trapping concepts. Based on exploration results in basins elsewhere, this implies as much as 50 percent or more of the basin's reserve potential has not been investigated," Davis said.

That's what Escopeta is doing at Kitchen, he said, and the new seismic interpretation shows what the company believes is major oil and gas accumulations.

"Major companies have had success drilling behind WEA (wavelet energy absorption) and I think it works," Davis said of the new APEX Metalink seismic processing technique. "We spent considerable money on processing and we're the first ones to use that process here in the Cook Inlet basin chasing stratigraphic traps and that's what we're doing in the Kitchen prospect."

Davis said Escopeta can take the results of the well drilled at East Kitchen, relate the logged oil and gas pays directly to the wavelet energy absorption and wavelet fluid absorption processed seismic anomalies "and get a very strong idea of what to expect at our Kitchen prospect, thus greatly reducing risk." He said the East Kitchen prospect "is very similar to ConocoPhillips' Cosmopolitan discovery. "We are drilling on an anticline up dip from actual tests for oil, 57 bopd at Cosmo and 360 bopd for East Kitchen with large upside potential for natural gas up hole."

Davis said that Wells, Banar and Warthen's "geological predictions were right on target for the successful Hanson well at ConocoPhillips' Cosmopolitan prospect. I think we are getting ready to do the same exact thing again at East Kitchen, with the only difference being (that) the reserve potential at East Kitchen is almost three times as big."

The Kitchen prospect, he said, is a 25,000-acre stratigraphic trap "that holds possible 3.9 tcf (of gas) and 829 million barrels of oil.

"I think there is plenty of oil and gas in our Kitchen prospects for any company large or small to be participating in for years to come," Davis said. "Escopeta has been actually doing business in the Cook Inlet basin for over 10 years. We were in the right place, at the right time, with our own in-house geological studies and resources to build an exploration opportunity of a lifetime," he said.

"Alaska", said Davis, "is definitely the place to explore for world-class oil and gas reserves." ●

Editor's note: Kay Cashman, Petroleum News publisher and managing editor, and Kristen Nelson, Petroleum News editor-in-chief, conducted the interview for this story.

NORTH AMERICA

Rig count jumps by 32 to 1,621

The number of rotary drilling rigs operating in North America during the week ending Aug. 20 totaled 1,621, an increase of 32 rigs from the previous week and an increase of 143 rigs compared to the same period last year, according to rig monitor Baker Hughes.

The Canadian rig count alone came in at 391 during the recent week, up by 34 from the prior week but down by two versus the year-ago period.

The number of rigs operating in the United States slipped by a net two to 1,230 from the previous week but was up by 148 versus the same period last year. Compared to the previous week, land rigs alone fell by two to 1,115, while the number of inland water rigs slipped by one to 20. The offshore count increased by one to 95 rigs.

Of the total number of rigs operating in the United States during the recent week, 1,055 were drilling for natural gas and 174 for oil, while one was being used for miscellaneous purposes. Of the total, 756 were vertical wells, 324 directional wells, and 150 horizontal wells. Among the leading U.S. producing states, Texas took the biggest single hit in the recent week, falling by 15 from the previous week to 507 rigs. Louisiana's rig count was down by four to 167, while Alaska's slipped by one of 10 rigs. However, New Mexico picked up seven rigs for a total of 66. Wyoming picked up three rigs for a total of 86. And Oklahoma picked up three rigs for a total of 170. California was unchanged with 25 rigs.

—RAY TYSON

ALBERTA

Oil sands operators boost first-half volumes by 28%

Output from Alberta's three big-scale oil sands projects nudged 100 million barrels in the first half of 2004, easily topping 500,000 barrels per day.Financial results to the end of June from Syncrude Canada, Suncor Energy and the Shell Canada-led Athabasca facility showed combined production of 98 million bpd, an increase of 21.8 million bpd over the same period last year, with all three plants reporting major gains.

The giant Syncrude consortium climbed to 241,000 bpd from 200,000 bpd for the first six months of 2003, with operating costs down sharply to C$17.94 per barrel from C$24.11 last year.

Suncor raised its first-half average to 212,400 bpd from 199,650 bpd a year earlier, although it has trimmed its 2004 forecast to 220,000 bpd from an original 225,000-230,000 bpd because of maintenance work in April. Operating costs dropped to C$12.15 per barrel from C$12.80.The Athabasca venture, which only came on stream at the start of 2003, has made solid gains through the break-in period. Average output for the January-June period this year was 83,400 bpd, compared with 18,200 bpd in the same period of 2003, with this year's operating costs averaging C$20.40 per barrel. The partnership is targeting staged expansion to 155,000 bpd.

—GARY PARK

● NORTHWEST TERRITORIES

Devlan Exploration to drill rare summer well

Junior E&P gives impetus to search for oil in the central Mackenzie Valley

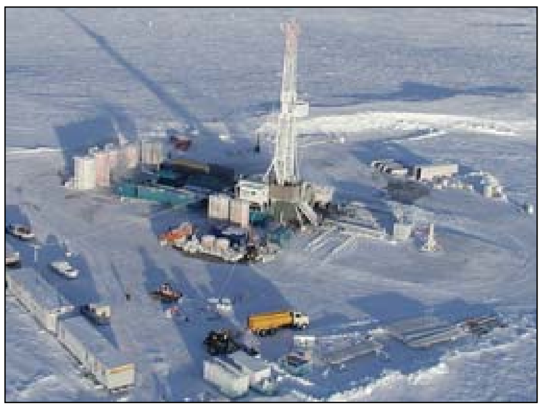
By GARY PARK

Petroleum News Calgary Correspondent

Devlan Exploration, a Canadian-based junior oil and gas producer, is joining the hunt for oil in the central Mackenzie Valley of the Northwest Territories. With the exception of the wells Imperial Oil has drilled on the manmade island near Norman Wells, it will be the first summer drilling in the region for many years.

Having received National Energy Board approval, Devlan is ready to proceed with drilling in the Grandview Hill area, 165 miles northwest of Norman Wells. It is expected to take one month to reach total depth of 2,600 feet on its wholly-owned Exploration License 413.

see DEVLAN page 12


COURTESY OF AKITA DRILLING

Pictured above is the Akita/Sahtu Drilling rig that is being used by Devlan this summer in the Grandview Hill area, 165 miles northwest of Norman Wells. This photo was taken last winter at another drilling location near the Colville River.

● KENAI PENINSULA

North Fork project closer to development

Southern Kenai Peninsula unit gets funding for second well, gasline north to KKPL

By KAY CASHMAN

Petroleum News Publisher & Managing Editor

As reported in last week's Oil Patch Insider, Alliance Energy of Tulsa, Okla. has agreed to fully fund development of NorthStar Energy Group's North Fork unit on Alaska's southern Kenai Peninsula, including 'fast-tracking' a pipeline north to connect the gas field with the Kenai Kachemak Pipeline.

Under a farmout agreement between Alliance and NorthStar, development of the North Fork field east of Anchor Point includes drilling a second well, No. 41-36, "as soon as January 2005,"

see NORTH FORK page 13


JUDY PATRICK

Unocal acquired 100 percent working interest in the Nikolaevsk exploration unit, north of NorthStar and Alliance's North Fork unit, late last year, leaving former unit operator Alliance with an over-riding royalty interest in Nikolaevsk. Pictured above, left to right, at Unocal's Red Pad in the Nikolaevsk unit in August are Gary White, Willbros Pipeline Engineers; Tom Alexander, Willbros; Barry Foote, Alliance; Sam Nappi, Alliance; and Keith Summar, Alliance.

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DEVLAN

The company said Aug. 19 that equipment and rig hands are moving to the site, about 560 yards from the banks of the Mackenzie River. The equipment includes an Akita/Sahtu Drilling rig, which has been carried by barge. The first barge arrived Aug. 23, Akita/Sahtu Senior Vice President Rob Hunt told Petroleum News.

Plastic mat road used

"They were able to drill in the summer because they're using a board road" from the barge landing to the drill site, Hunt said. The road is approximately 300 kilometers in length.

The mats, he said, were first used in the swamps in Louisiana and brought into Canada about eight years ago.

"There are a lot of environmental issues" in the area, demanding "zero ground disturbance," he said.

The mats are made from "a unique, very strong plastic; they're interlocking and very light." Wood mats, Hunt said, tend to absorb water, and "become very heavy and thus expensive to move around."

Once the well is completed, the land tenure requirements for the 201,160 acre license will be fulfilled until 2009.

Devlan said it will then be able to take a measured approach to its future exploration spending and also take advantage of the Mackenzie Valley natural gas pipeline, which is targeted for completion before 2010.

The Arctic pipeline proposal is expected to include a second line to carry liquids from the Mackenzie Delta to Norman Wells, where it would feed into the under-utilized Enbridge pipeline from a long-established oil field to northern Alberta.

Looking at deeper targets

Devlan said that in addition to the shallow target for its Devlan Moose Lake D-07 well it has been examining the deeper potential underlying the exploration license.

For the second quarter, Devlan reported net earnings of C$1.66 million, down 11 percent from the year earlier, although production was up 12 percent to an average 2,713 barrels of oil equivalent per day.

Heavy oil is making a stronger contribution, with output of 378 bpd in the three months, based largely on drilling success from 11 wells in Saskatchewan.

The junior's net debt dropped to C$20 million by June 30, with company President Martin Cheyne noting that the "improved balance sheet will enable us to pursue both our Alberta and Northwest Territories drilling prospects this summer."

Speculation of Northrock discovery, EnCana dry hole

Meanwhile, results are being eagerly awaited from an oil-targeted well drilled last winter by Northrock Resources, a subsidiary of Unocal. The well was drilled to almost 10,000 feet about 50 miles south of Norman Wells.

Speculation of a discovery has intensified in recent weeks, but there has been no confirmation from Northrock, or its partners Husky Energy, EOG Resources Canada, Pacific Rodera or International Frontier Resources.

EnCana also completed an oil exploration well in the central Mackenzie in February, but has yet to answer reports that it was a dry hole. ●

● NATIONAL PETROLEUM RESERVE-ALASKA

Alaska one step closer to building road to NPR-A

State issues RFP for Colville River Road; timetable calls for construction to start in 2007 and finish in 2009

By KAY CASHMAN

Petroleum News Publisher & Managing Editor

The state of Alaska is one step closer to building a road to the National Petroleum Reserve-Alaska. On Aug. 24, the Northern Region office of the Alaska Department of Transportation and Public Facilities released a request for proposals for an environmental impact statement for the Colville River Road project. The year-round, gravel road will connect the petroleum reserve with the North Slope road system and help fuel growth in Alaska's oil and gas industry, the mainstay of the state's economy.

The EIS, estimated to cost "in the range of $1 million or greater," is scheduled to be finished by December 2006, "with final design complete by March 2007," Mike McKinnon, project manager for the department, told Petroleum News Aug. 24.

Road construction is expected to start with staging in the summer of 2007 and be finished by the end of 2009.

Connect with Spine Road

The new road will connect with the Spine Road that runs through the Prudhoe Bay and Kuparuk River oil fields. It will connect at the Spine's western most point which is at the Tarn/Meltwater Road junction; then head west 15 miles, cross the Colville River, and end on Native land in NPR-A. There a connecting 2-3 mile road will be built to the village of Nuiqsut.

After looking at four possible crossing sites the decision to locate the bridge about three miles below Nuiqsut and 11 miles south of ConocoPhillips' operations at Alpine, was "driven by the Colville River hydrology," McKinnon said.

"The proposed crossing is closest to the most active zones of development. The project will also include opening of one or two new material sites in the area," the department said in its project description.

The 18-mile long, 32 foot wide road

*see **ROAD** page 19*

GULF OF MEXICO

Current Deepwater Activity

Operator	Area/ Block	OCS Lease	Rig Name	Prospect Name	Water Depth (ft)
Shell Offshore Inc.	LL 399	G23480	TSF DEEPWATER NAUTILUS	Cheyenne	8,951
Shell Offshore Inc.	AC 857	G17565	TSF DISCOVERER DEEP SEAS	Great White	8,220
BP Exploration & Production Inc.	WR 724	G17011	D.O. CONFIDENCE	Das Bump	7,591
Exxon Mobil Corporation	KC 919	G21447	GSF EXPLORER	Hadrian	7,316
BP Exploration & Production Inc.	GC 743	G15607	T.O. DEEPWATER HORIZON	Atlantis(GC)	6,830
Union Oil Company of California	KC 681	G20949	DISCOVERER SPIRIT	East Sardinia	6,345
BP Exploration & Production Inc.	MC 778	G09868	TSF DISCOVERER ENTERPRISE	Thunder Horse South	6,037
Dominion Exploration & Production, Inc.	MC 773	G19996	PRIDE 1503	Devil's Tower	5,610
Kerr-McGee Oil & Gas Corporation	GC 768	G21817	T.O. DEEPWATER MILLENNIUM	Deep Blue	5,257
Mariner Energy, Inc.	VK 962	G15444	DIAMOND OCEAN AMERICA	Swordfish	4,673
BHP Billiton Petroleum (GOM) Inc.	GC 653	G20084	GSF C.R. LUIGS	Shenzi	4,340
Anadarko Petroleum Corporation	GC 608	G18402	NABORS POOL 140	Genghis Khan	4,287
Anadarko Petroleum Corporation	GC 518	G21801	ENSCO 7500	K2 North	4,049
Anadarko Petroleum Corporation	GC 518	G21801	NOBLE PAUL ROMANO	K2 North	4,035
Chevron U.S.A. Inc.	GC 640	G20082	T.O. CAJUN EXPRESS	Tahiti	4,017
Eni Petroleum Co. Inc.	GC 562	G11075	GSF CELTIC SEA	K2	3,925
BP Exploration & Production Inc.	VK 915	G06894	NOBLE JIM THOMPSON	Dorado	3,460
Shell Offshore Inc.	GC 248	G15565	NOBLE MAX SMITH	Glider	3,440
Eni Petroleum Co. Inc.	GC 298	G08010	D.O. VALIANT	Allegheney(South)	3,305
Shell Offshore Inc.	VK 956	G06896	H&P 205	Ram-Powell	3,214
Kerr-McGee Oil & Gas Corporation	GB 668	G17407	NABORS MODS RIG 150	Gunnison	3,152
Nexen Petroleum U.S.A. Inc.	GC 243	G20051	T.O. MARIANAS	Aspen	3,065
Kerr-McGee Oil & Gas Corporation	GB 669	G15927	NOBLE AMOS RUNNER	Gunnison East	2,962
Shell Offshore Inc.	GB 426	G07493	AUGER	Auger	2,862
Kerr-McGee Oil & Gas Corporation	VK 869	G13065	D.O. STAR	Triton	2,410
Murphy Exploration & Production Company	MC 582	G16623	MODS 141	Medusa	2,215
Chevron U.S.A. Inc.	VK 786	G10944	ENSCO 25	Petronius	1,754
BP Exploration & Production Inc.	VK 989	G09771	NABORS POOL 143	Pompano I	1,295

Total Deep Water Prospects with Drilling/WO Activity 28

New Deepwater Activity

Exxon Mobil Corporation	KC 919	G21447	Hadrian	7,316
Kerr-McGee Oil & Gas Corporation	GC 768	G21817	Deep Blue	5,257

continued from page 11

NORTH FORK

NorthStar President Barry Foote told Petroleum News Aug. 19. (The lion's share of the North Fork field is held by field operator Gas-Pro, which is owned by NorthStar.)

Homer agreement with Enstar gets approved

Foote also said the Regulatory Commission of Alaska issued final approval in early July for the gas sales agreement between Enstar Natural Gas Co. and NorthStar, which would bring natural gas from North Fork to the community of Homer. (See related article in the April 11 edition of Petroleum News.)

The agreement provided for 20 years of natural gas delivery from North Fork via a pipeline that Enstar would build to Homer.

Dan Dieckgraeff, Enstar's manager of finance and rates, told Petroleum News a year ago, when the companies first announced the agreement, that following RCA approval it would probably take a year and a half to two years to begin delivering gas to Homer. Commission approval, he said, was just the first step.

Foote said Aug. 19 that he would be interested "in talking to Enstar" about his company building the pipeline to Homer.

There is a single well at the North Fork field, drilled in 1965. RCA's approval was contingent on NorthStar drilling at least one additional well to raise proved reserves at the field from 12 billion cubic feet to 14.5 bcf.

Willbros, ENSR handling pipeline north

Alliance has engaged Willbros Pipeline Engineers and ENSR "to permit and build the pipeline north" to connect with the KKPL, Foote said.

The North Fork unit is on its 39th plan of development with the U.S. Bureau of Land management. The delay in development to date has been because there has

Foote said Aug. 19 that he would be interested "in talking to Enstar" about his company building the pipeline to Homer.

been no market for southern peninsula gas. But that situation recently changed with the construction of the KKPL and its recent extension (under construction) to Unocal's discoveries in the Deep Creek unit on the southern peninsula north of North Fork.

"We're very pleased about NorthStar's plans because we want to monetize this asset for the state," Steve Martinez at BLM told Petroleum News after a recent visit from NorthStar and Alliance executives. ●

Want to know more?

If you'd like to read more about the North Fork unit go to Petroleum News' web site and search for these articles, published in the last few months.

Web site: www.PetroleumNews.com

2004

- **Aug. 22** Oil Patch Insider: North Fork development, gaslines get green light
- **May 23** Cook Inlet sale a burner
- **May 16** Pipelines plugging progress
- **April 11** Commission conditionally OKs gas sales agreement
- **Feb. 15** Unocal moves forward on Kenai gas exploration

2003

- **Dec. 21** Unocal buys out Alliance
- **Nov. 9** New independent files for Kenai Peninsula unit
- **Aug. 31** NorthStar wants to expand North Fork unit

● FAR EAST

Yukos sells stake in gas producer to TNK-BP

FAREAST report

TNK-BP has obtained the majority stake in a Siberian gas venture from beleaguered OAO Yukos in a convoluted deal, according to Russian sources. Yukos received $357 million for its share of Rospan International. TNK-BP had been the minority partner in the Rospan venture, according to an article in the Kommersant daily.

Assets of Yukos have been frozen by the Russian government, but the Rospan stake was held by an overseas subsidiary. TNK-BP announced early in August that it was buying the Rospan assets, where it is the operator.

Yukos, the country's biggest oil producer, faces an escalating tax bill in Russia, which says the company owes more than $3 billion in back taxes for 2000 alone.

Two banks reportedly pull plug on TNK-BP loan

A BANK LOAN TO TNK-BP that would have given the joint venture about $600 million has been scaled back after two big European investors pulled out, according to the Financial Times in Great Britain.

The loan was to be secured by future export receivables and have a maturity in five years. BP has a 50 percent stake in the venture, which ranks third in oil production among Russian firms.

But Societe Generale and ING have apparently pulled out over fears that property rights in Russia might not be secure, according to the Financial Times. Eight banks were originally involved in the loan, which may now be cut to $400 million or so.

Husky Energy signs deal for exploration in South China Sea

HUSKY ENERGY HAS SIGNED a deal to explore for oil in a block of the South China Sea covering about 3,900 square kilometers, or roughly 964,000 acres.

The agreement with the China National Offshore Oil Corp., announced Aug. 16, calls for Husky to drill a well in the deepwater block next year, subject to rig availability, and to drill two additional wells before 2011.

Husky will pay all the costs, with CNOOC having the right to back into the development with a 51 percent interest.

Average water depth on the block about 180 miles southeast of Hong Kong is about 4,300 feet. CNOOC has shot significant amounts of 2-D seismic on the block already, and it is considered to have good potential.

Husky already has a 40 percent working interest, in partnership with CNOOC, in the successful Wenchang field off China, which is expected to yield 18,000 to 20,000 barrels daily net to Husky over the course of the current year.

Husky now has a total of about 6.2 million acres of exploration acreage in the South China Sea and the East China Sea.

Russian government to sell OAO Lukoil shares by year's end

THE 7.59 PERCENT OF OAO LUKOIL held by the Russian government will be sold by the end of the year, according to a Russian minister quoted by the news agency Itar-Tass on Aug. 19.

Andrei Sharanov said the package of 64.6 million Lukoil shares would be sold in a lot at auction. The government has set a minimum price of $1.26 billion for the shares.

ConocoPhillips has been considered the leading contender to buy the stake, and executives of that company met recently with Russian officials.

—ALLEN BAKER, PETROLEUM NEWS

● BRAZIL

Brazil getting with the rhythm

Foreign firms swallow doubts, join Brazil's pursuit of oil self-sufficiency, but state-owned Petrobras keeps most blocks under its control

By GARY PARK

Petroleum News Calgary Correspondent

Global oil giants seem to have decided that there's more than an "awful lot of coffee in Brazil,' but they're not quite ready to samba.

In what was billed as a key test of the investment climate under the left-leaning government of President Luiz Inacio Lula da Silva (better known simply as Lula), they took an active part in Brazil's sixth government licensing round Aug. 17 and 18.

The sale attracted $704 million for 154 blocks, far eclipsing the dismal results in 2003, which generated only $9 million for the government.

The round is anticipated to generate $26 billion in new investments and boost Brazil's oil reserves by 1.3 billion barrels to 14 billion barrels, overtaking the current South American leader, Venezuela, which has 8.3 billion barrels.

The round is anticipated to generate $26 billion in new investments and boost Brazil's oil reserves by 1.3 billion barrels to 14 billion barrels, overtaking the current South American leader, Venezuela, which has 8.3 billion barrels.

It is also expected to close the gap between Brazil's output of 1.6 million barrels per day and its consumption of 1.8 million bpd, setting the stage to meet the government's goal of 500,000 bpd in net exports by 2012.

But doubts still hang over the South American country.

Despite the vote of confidence by such foreign operators as Shell, Devon Energy, EnCana, Kerr McGee, El Paso, Spain's Repsol YPF, Norway's Statoil and South Korea's SK, most of the big players continued giving a wide berth to the licensing round.

Their misgivings were reinforced by the confusion stemming from a Brazil Supreme Court ruling prior to the sale, the fact that Brazil's state-owned Petrobras took a role in 107 of the 154 blocks that were sold and indications from government officials that Brazil will skip the 2005 round, after holding a tender every year since 1999 when it opened its oil industry to private companies.

The mines and energy ministry's oil and gas secretary Maria das Gracas Foster told the opening day of Round 6 that as Brazil gets close to self-sufficiency "we need to better plan the development of our reserves."

Foreigners might not be able to export oil

She said that although foreign and private companies can explore and produce, a decision on whether they can export their production will hinge on the government's strategy and national consumption trends.

That thinking echoed an August 16 Supreme Court ruling that foreign operators of auctioned blocks should not be allowed to own the oil they produce and might not be able to export it. They would also be required to obtain federal approval for all of their development plans.

Although the ruling was overturned by the Supreme Court president August 17 and das Gracas Foster declared the "problem solved," the bidding companies think it is likely the dispute is far from over.

Shell, for instance, currently exports about 55,000 bpd from its Brazil operations because it views the Petrobras pricing policy as uncompetitive.

Repeated calls from the private sector for Brazil to make its investment terms more attractive have also gone unheeded, prompting consultant Wood Mackenzie to note last year that the government of Rio de Janiero, which controls the key Campos Basin, has a tax regime that leaves "existing and potential investors extremely wary of Brazil."

However, there has been a hint of movement, with the federal government extending a tax exemption on imported capital goods used in the offshore to 2009 from 2007.

Paulo Kastrup Netto, an attorney representing several of the bidding compa-

see BRAZIL page 15

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JV TALKS

ment synergies in Alaska," said Rick Buterbaugh, Kerr-McGee's vice-president of investor relations.

Pioneer CEO Scott Sheffield told Petroleum News in early August that such a joint venture was possible, but Kerr-McGee declined to comment. However, Pioneer said additional drilling and review of well logs and other geological data would be necessary before serious talks could begin with Kerr-McGee.

In the conference call, Buterbaugh said Kerr-McGee expects to drill two appraisal wells this winter on its Northwest Milne acreage "to confirm deliverability and to establish the aerial extent of the reservoir." He said the company also expects to drill at least one exploratory well this winter on its West Milne Point acreage.

In the conference call, Buterbaugh said Kerr-McGee expects to drill two appraisal wells this winter on its Northwest Milne acreage "to confirm deliverability and to establish the aerial extent of the reservoir."

The two Northwest Milne wells are in the Nikaitchuq unit and the exploratory well is in the Tuvaaq unit, immediately to the west of Nikaitchuq. (See initial story on Kerr-McGee's North Slope drilling plans in the July 18 edition of Petroleum News.)

—RAY TYSON

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BRAZIL

nies, told the Financial Times that although the federal government has stripped some regulatory agencies of their policymaking powers it "recognized the important role they can and should play."

Shell, Kerr-McGee, EnCana top foreign bidders

Shell was the top foreign bidder in Round 6, spending $23 million, followed by Kerr McGee $13 million, EnCana $10.6 million, Devon $8.6 million and Repsol $6 million.

Shell, Repsol and El Paso bid in tandem with Petrobras, acquiring equity stakes but leaving Petrobras with majority interests and the operator role.

A Devon-led group including EnCana, Kerr McGee and SK opted to go it alone on one block in the Sergipe Alagoas Basin, which has strong light oil prospects and was acquired for $16.4 million.

An EnCana spokeswoman told the Financial Post that the Canadian independent, based on five years experience in Brazil, feels the country is "politically stable and has good exploration opportunities."

EnCana plans to take a role in six wells over the next four years, with its eye on adding Brazil to its other South American interest in Ecuador, where it produces 68,000-74,000 bpd. ●

continued from page 1

MACKENZIE

The 70-page terms of reference were released Aug. 18 by the Canadian Environmental Assessment Agency, more than six weeks behind the original target.

That puts into doubt the partners' hopes of filing the main regulatory applications for field development, gathering systems and the main pipeline before the end of summer on Sept. 21.

Not fixated on a certain date

However, Searle noted that "from the get-go we have made a commitment to do things right," which means the proponents are not fixated on a certain date.

He said the intention is to file "as soon as we are ready," while adding that "we can't offer a date."

A filing "will be a milestone, but the project is by no means a certainty," Searle told Petroleum News, noting that we are asking the owners "to put billions of dollars on the table" when the uncertainty of gas prices makes the economics difficult.

Earlier this month, Hal Kvisle, chief executive officer of TransCanada, sent up a similar warning flare.

If the regulatory and approval processes take too long, allowing the development of Alaska gas or liquefied natural gas projects to proceed first, the window could slam on the Mackenzie scheme, he said.

Unprecedented terms of reference for EIS

The terms of reference for the environmental impact statement are all the proof, if any was needed, of the challenges ahead.

What is required by the three jurisdictions that make up a joint review panel is probably unparalleled in scope for any Canadian project, although Searle said the questions to be answered are within the range of expectations of the Mackenzie partners.

For example, the joint review panel will require the applicants to describe how climate change as a direct or indirect result of human activity that "alters the composition of global atmosphere" – quite apart from natural climate variability – could affect the project over its 30-year lifespan.

The terms of reference say that for "certain portions of the project area it may be necessary to identify changes in water levels and storm surges, fire, permafrost conditions and changes to other landscape and waterscape processes that could occur because of climate change."

Environmental contingent gathering force

While having to deal with a barrage of questions, the Mackenzie consortium is also facing a gathering storm of opposition and concern from environmental groups.

The Canadian Arctic Resources Committee and the Sierra Club of Canada plan to make the case that the project is planned for one of the most sensitive regions on the planet, where the rate of warming is already taking its toll.

In addition, Dene Youth Alliance, which sees gas development as potentially being incompatible with aboriginal culture and traditions, has joined the ranks of those uneasy about a pipeline.

Where gas goes outside scope of review

But any attempts by opponents to open up the issue of using Arctic gas as a fuel source for the extraction and processing of bitumen in the Alberta oil sands have been rejected by the joint review panel.

There have been suggestions that all or most of the Mackenzie Delta gas would go directly to the oil sands.

Although the Delta gas owners – Imperial, Shell Canada, ConocoPhillips Canada and ExxonMobil Canada – are all involved in oil sands and heavy oil projects, they have said that decisions on where Arctic gas might finish up are outside the scope of the environmental review.

The environmental review is expected to take up to 14 months as part of an anticipated two-year regulatory process.

It will be conducted by a seven-member panel, chaired by Vancouver-based consultant Robert Hornal and will combine the oversight responsibilities of the National Energy Board, the Northern Gas Project Secretariat, the Canadian Environmental Assessment Agency and the Mackenzie Valley Environmental Impact Review Board.

Hornal, who served as director of the federal Indian Affairs' Program, said in a statement that politics has no role in the panel's assigned task of examining the environmental and social consequences of the project.

In addition to the environmental review, the project faces public hearings involving 12 federal, Northwest Territories and aboriginal agencies as part of more than 4,000 licenses, permits and agreements needed for the planning, construction and start-up phase.

That list includes benefits and access agreements with aboriginal communities, along with agreement covering matters such as wildlife compensation, land use, surface tenure and water use.

Searle said "we are still grinding away on benefits and access agreements," in challenging discussions to "move the yardsticks forward."

—GARY PARK

continued from page 1

LANDLORD

term investments."

They said such a policy "creates a fragile situation whereby the funding of core government services is vulnerable to uncontrollable and volatile shifts" in commodity prices.

In a news release accompanying the report, the institute said "big machinery, shiny logos and business suits often overshadow the fact that provincial oil and gas reserves (in Canada) are public – not corporate – resources."

It accused the Canadian jurisdictions of undercharging companies for the development of the resources, failing to set aside revenues for the future and allowing negative environmental impacts of industry activities to steadily rise.

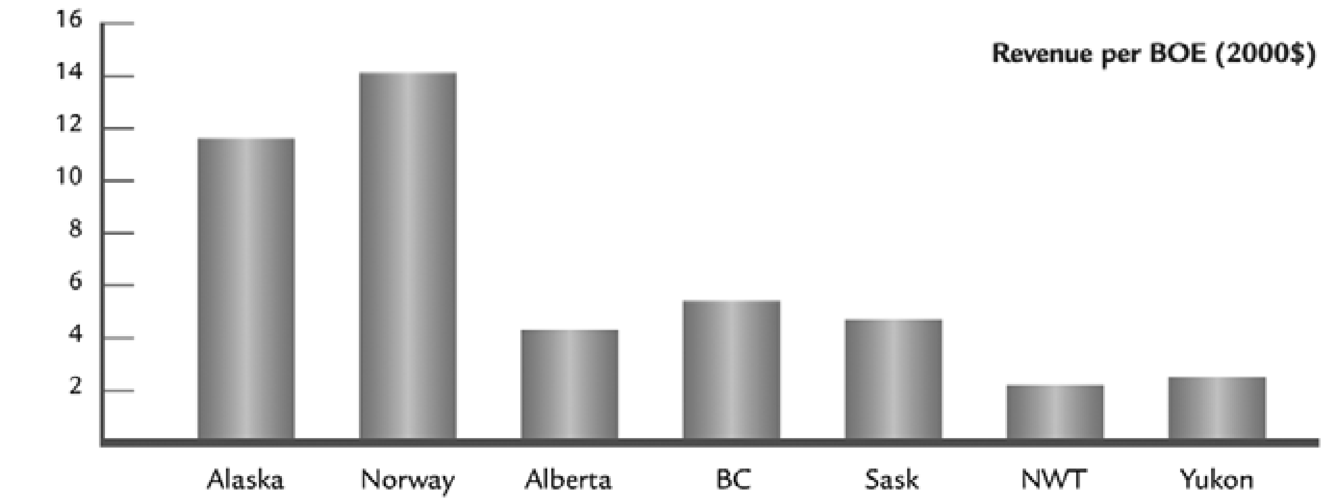


Figure 1 Average government revenues from oil and gas developments (2000$/barrel of oil equivalent)

PEMBINA INSTITUTE

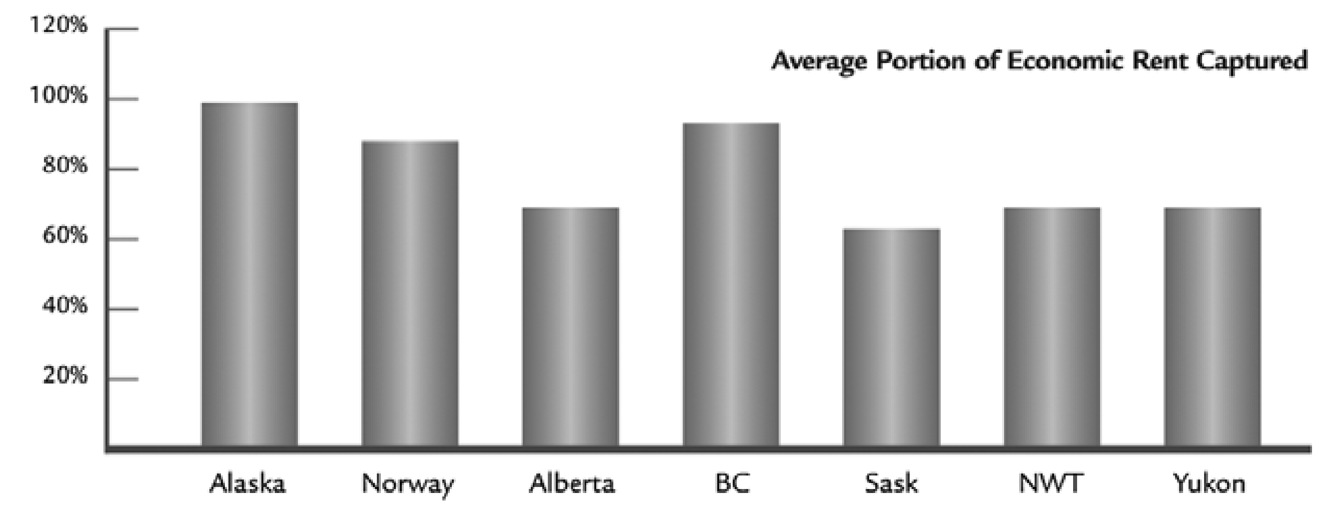


Figure 2 Average portion of economic rent captured by governments

PEMBINA INSTITUTE

Saskatchewan Industry and Resources Minister Eric Cline … said Saskatchewan does not compete with Norway, "we compete with other Canadian provinces" – a sentiment echoed by Greg Stringham, vice-president of the Canadian Association of Petroleum Producers, who noted that the average well in Western Canada yields only 30 bpd, compared with 6,000 bpd in Norway and 600 bpd in Alaska.

The governments are "not providing maximum compensation to the citizens of these regions for the development of oil and gas resources," said lead author Amy Taylor.

Covering the period from 1995 to 2002, the report said Norway collected C$14.10 per barrel of oil equivalent and Alaska C$11.70, overshadowing the Canadian take of C$5.40 in British Columbia, C$4.70 in Saskatchewan, C$4.30 in Alberta, C$2.50 in the Yukon and C$2.20 in the Northwest Territories (although some of the differences were attributed to regional differences in production costs and value of the resources).

But even allowing for those differences, the institute said the bulk of Canadian regions lagged behind in the portion of available revenue they collect.

Table 7-1 International comparison of revenue generation from oil and gas production, 1995 to 2002 (2000$/BOE)

REGION	1995	1996	1997	1998	1999	2000	2001	2002
BC	2.6	3.7	3.7	2.7	4.1	8.6	10.1	8.1
AB	3.1	3.2	3.1	3.1	2.1	4.2	8.5	6.8
SK	4.5	4.4	4.7	3.5	2.7	5.0	6.6	5.9
YT	1.2	2.7	1.8	1.6	1.1	2.2	4.9	4.5
NWT	1.2	2.6	1.7	1.2	1.3	2.2	2.5	4.5
Alaska	13.3	10.5	12.2	10.5	8.7	13.7	13.0	10.5
Norway	7.9	12.8	14.8	6.8	6.7	19.7	26.1	18.1

PEMBINA INSTITUTE

Alaska recovers 99%, B.C. 93%, Norway 88%

Alaska was estimated to recover 99 percent, British Columbia 93 percent, Norway 88 percent, Alberta, the Northwest Territories and the Yukon 69 percent and Saskatchewan 63 percent.

Despite the low returns, development and environmental impacts are on the rise, the study found.

For example, in British Columbia it said the number of well completions increased by more than 50 percent and the amount of land disturbed by pipelines rose 271 percent. Toxic emissions were also up: Nitrous oxides by 78 percent, sulfur dioxide by 20 percent and greenhouse gases by 47 percent.

Government and industry leaders in Canada were quick to retaliate.

Comparing apples with bananas?

Saskatchewan Industry and Resources Minister Eric Cline said the report oversimplified the complexity of developing oil and gas projects, while his Alberta counterpart Murray Smith said the Pembina Institute was dead wrong.

Cline challenged any suggestion that his government could just "jack up its rates and still have activity in the oil patch."

He said Saskatchewan does not compete with Norway, "we compete with other Canadian provinces" – a sentiment echoed by Greg Stringham, vice-president of the Canadian Association of Petroleum Producers, who noted that the average well in Western Canada yields only 30 bpd, compared with 6,000 bpd in Norway and 600 bpd in Alaska.

Cline also said the idea of channeling energy revenues into a "rainy day" fund is out of the question, given Saskatchewan's economic plight after years of drought.

Smith said Alberta has found the right balance that ensures Albertans get their "fair share of rent and royalties," while competing for world capital.

Smith noted that the province's price-sensitive royalty model and the surge in commodity prices has seen royalties from the past four previous match those for the previous 10 years.

He said the royalty calculation for Alberta is based on widely-dispersed oil and gas deposits, unlike the concentrated pools in Norway.

Stacking Alberta up against Norway is "like trying to compare an apple and a banana," he said.

Taylor said the Pembina Institute was not suggesting that Canadian governments should obtain 100 percent of the available "economic rent," but was not convinced that 69 percent in Alberta was adequate.

The report called on governments to impose special taxes on oil and gas companies to build a fund to pay for any environmental damage.

"They could be taxes levied on sulfur dioxide emissions or greenhouse gas emissions or waste or water consumption," the report said.

The institute also recommended Canadian governments change the mix and level of royalties, taxes and tax credits to obtain maximum compensation for the development of oil and gas.

In addition, jurisdictions were urged to quickly establish non-renewable permanent resource savings funds and build the value of those funds as resources are depleted.

Alberta Industry and Resources Minister Murray Smith said the Pembina Institute was dead wrong. … Stacking Alberta up against Norway is "like trying to compare an apple and a banana," Smith said.

The study said such funds were especially important in the Northwest Territories and the Yukon, which are facing rapid development of their resources in areas that are particularly susceptible to boom and bust economic cycles.

It suggested that in excess of C$90 million was lost in the NWT because of inadequate resource royalties between the Canadian government and the producing companies.

"We've had a lot of concern over whether there is a fair return for the resources that are being extracted here, particularly in anticipation of the Mackenzie Valley pipeline," said Kevin O'Reilly of the Canadian Arctic Resources Committee, which contributed to the report and plans to work more closely with the NWT government and aboriginal groups to find "ways of trying to capture those revenues."

Taylor said that although lower royalty rates are "somewhat justified" due to higher production costs in the NWT and Yukon, much of the NWT development is occurring close to the Alberta and B.C. borders where production costs are similar, while the Yukon was paying a significant cost in environmental damage and lower revenues from gas projects.

Lewis Rifkind, of the Yukon Conservation Society, said that even though the Yukon government has full authority over oil and gas development "it has not yet established tax and royalty regimes to maximize economic returns" to it citizens. ●

Companies involved in North America's oil and gas industry

ADVERTISER PAGE AD APPEARS

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

Petroleum news

Business Spotlight

By PAULA EASLEY

COURTESY PHOTO

Joe Usibelli Jr., president

Usibelli Coal Mine

Long a household word in Alaska, Usibelli Coal Mine produces a million-plus tons of coal per year for instate use and export to the Pacific Rim. Emil Usibelli started the business 61 years ago; it now employs 85 people year-round in Healy and Fairbanks. Coal available in Healy can satisfy even greater demands far into the next century.

Joe Jr., a cancer survivor, believes "the best way to predict the future, is to create it." His engineering degree was earned at the University of Alaska-Fairbanks and today he serves on the University's Board of Regents. Individually and on behalf of the company, Usibelli supports numerous organizations that better peoples' lives. At the Black Diamond course in Healy, Joe's also becoming a halfway decent golfer. He and wife Marilyn have a baby daughter, Lexi.

FORREST CRANE

Larry Smith, president

Smith Consulting Services

Smith Consulting Services provides geophysical support to oil and gas operators, the only instate company using the Kingdom Suite seismic interpretation system. SCS runs on a portable PC, enabling on-the-road viewing and work sessions. The company offers a full range of tools for field planning and data integration, including ArcGIS mapping and ENVI satellite image processing.

Before moving to Anchorage in 1997, Larry spent 21 years in the oil business, living and working at projects around the globe. Bicycling and sea kayaking are favorite activities. His best trip? He and wife Christine cycled from Nanjing to Shanghai, China along the Yangse River. Christine's curly blond hair and Larry's beard were novel attractions. They have two sons, 18 and 15, and just celebrated their 25th anniversary.

continued from page 1

APACHE

said in announcing the deal Aug. 20.

Apache now one of largest shelf leaseholders

The deal also would transform Apache into one of the largest leaseholders on the shelf with 2.6-million acres covering 546 offshore blocks, which includes Anadarko's 241 leases that would make up nearly 45 percent of Apache's expanded shelf base once the transaction closes by the end of this year's third quarter.

Morgan Stanley Capital Group agreed to pay Anadarko $775 million to acquire an overriding interest in just 24 million barrels of proved oil equivalent reserves, using an investment tool known as Volumetric Production Payment, or VPP.

Anadarko's package consists of proved reserves totaling 98.6 million barrels of oil equivalent and current daily production of 46,000 barrels of equivalent, or about 11,000 barrels of oil and 199 million cubic feet of natural gas per day. It also includes the company's interest in 78 fields and 112 offshore platforms.

Upon completion of the sale, Anadarko would operate only one offshore platform, the recently commissioned Marco Polo facility at deepwater Green Canyon Block 608.

Apache said it would ante up $537 million of the $1.3 billion sale price to acquire a net 61 million barrels of the proved reserves and a hefty share of the daily production, plus the fields and platforms.

Morgan Stanley uses VPP investment tool

Morgan Stanley Capital Group agreed to pay Anadarko $775 million to acquire an overriding interest in just 24 million barrels of proved oil equivalent reserves, using an investment tool known as Volumetric Production Payment, or VPP.

"Any time you have a three-handed deal it's a bit of a circus," confessed Roger Plank, Apache's chief financial officer said in an Aug. 23 conference call with industry analysts. "But this one came together well and, frankly, quite quickly. The reason is because the deal makes sense for all parties."

In light of the high commodity price environment, Apache said it would pay a "reasonable" $8.83 per barrel of oil equivalent for its share of the deal, plus an extra $1.62 per barrel to produce and deliver Morgan Stanley's volumes, for a total of $10.45 per barrel in costs to Apache.

In contrast, Morgan Stanley would pay a steep $15.46 per barrel, obviously reflecting the firm's belief that oil and gas prices will continue strong. However, for its willingness to pay a reserve premium, Morgan Stanley would take its production up front over the four year-term of the VPP.

"The reason Morgan Stanley is paying a high price is because they get the first (production) out of the ground," Apache's Plank said. "So their production is lower risk and therefore worth more."

Shell deal used similar VPP approach

Actually, Morgan Stanley and Apache used a similar VPP approach to acquire Shell oil and gas properties on the shelf last year, a deal which Apache said has thus far proved successful. In the year since the properties were acquired, Apache said it already has recovered more than half its investment and added reserves through exploitation activities.

Still, Apache was cautious about entering into a deal with Anadarko given that "ski-high commodity prices have driven the acquisition market to very expensive levels," Steve Farris,

Morgan Stanley would pay a steep $15.46 per barrel, obviously reflecting the firm's belief that oil and gas prices will continue strong.

Apache's chief executive officer, said, noting that Apache was unwilling to pay the $15.46 per barrel asking price without finding a way to enhance company returns.

"Our rate of return is enhanced since we are not acquiring the lower-risk, higher unit cost reserves," he said.

Additionally, Morgan Stanley's production share would revert to Apache when the VPP expires in four years. Apache also retains sole rights to an additional 23 million barrels of estimated probable reserves.

"By structuring the transaction the way we have, we're able to exploit a $1.3 billion asset with a $537 million capital investment and retain all the future upside," Farris said.

He said that when Apache bought its first Shell package on the shelf in 1999, reserve life was estimated at seven years. After five years of exploitation activities, he added, the properties are still producing 16,000 barrels of oil and 54 million cubic feet of gas per day, roughly 50 percent of production at the time of purchase. And remaining reserves represent 62 percent of the reserves the company acquired in 1999.

"We expect these (Anadarko) assets to produce much longer than current reserve life would indicate," Farris said. "Our strategy on the shelf is to take what it gives us and not try to re-invest all that cash flow back into the assets."

Apache likes deal because it was a complete exit

In the past, Apache has shied away from purchasing large oil and gas packages from an exploration and production independent such as Anadarko.

"Quite frankly, we were drawn to this package because it was a complete exit by Anadarko from the shelf," Farris said, noting a major difference in company philosophies on the shelf.

"Anadarko's focus … has been to explore for larger fields and create value through discovery," he added. "Apache's focus in the Gulf is really quite different. We create value through exploitation in and around our existing property base with less focus on higher risk exploration."

Of the 241 blocks being acquired from Anadarko, 93 are undeveloped and also hold promise for additional reserves. Apache would operate 53 of the 78 producing fields along with 80 percent of the production and 85 percent of net reserves, assuring its control over the Anadarko assets.

Apache expects its share of daily production from Anadarko properties to average about 3,000 barrels of oil and 50 million cubic feet of gas during the 2004 fourth quarter, increasing to 6,500 barrels of oil and 70 million cubic feet of gas per day in early 2005 when the Tarantula discovery at South Timbalier 308 comes on line.

Apache said the Anadarko properties would increase the company's 2005 earnings by about $83 million or 25 cents per share. The company said it plans an additional $55 million in capital expenditures this year to achieve those results.

Apache using cash on hand, commercial paper

Because of substantial cash flow expected from Apache operations, the company said it intends to finance the deal with cash on hand and commercial paper. The transaction is expected to raise Apache's debt to 24 to 25 percent of capitalization, just a percent or two above the current level. "We expect to pay off that debt very quickly," Plank said.

Because some of the properties being acquired from Anadarko are subject to preferential rights by undisclosed third parties, the exact purchase price will not be known for about a month, Apache said.

Just days after announcing the sale of its Gulf shelf properties to Apache and Morgan Stanley, Anadarko said it signed an agreement with Advantage Oil & Gas to sell an estimated 9.9 million barrels of oil equivalent for $142 million.

The package was said to contain various assets in Central and Southern Alberta and Southeast Saskatchewan representing daily net production of about 4,500 barrels of equivalent. Both reserves and production are net after royalties.

Those assets include 35 fields covering about 130,000 net acres. Oil and natural gas production from the package is 60 percent operated by Anadarko.

"The completion of this first phase of our divestiture program in Canada is yet another step forward in the execution of our refocused corporate strategy," Anadarko's Hackett said.

Data room open

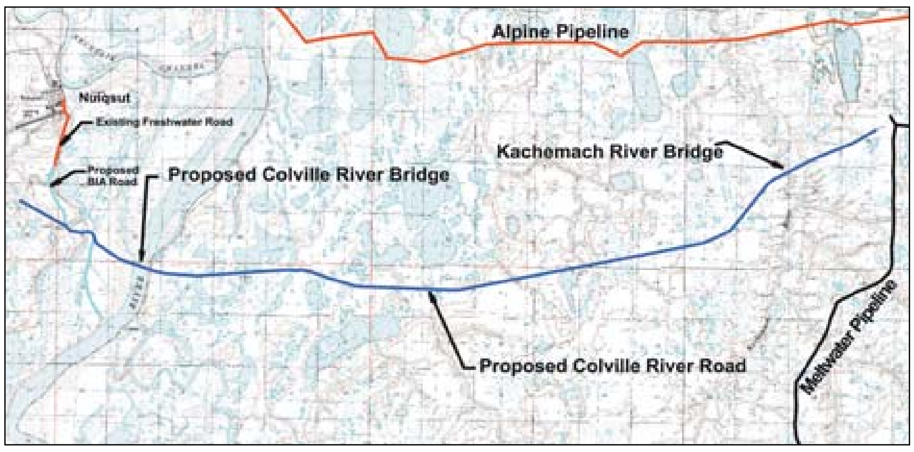
None of the properties sold by Anadarko in its divestiture program were in Alaska, Alaska spokesman Mark Hanley told Petroleum News.

Anadarko Canada President Mike Bridges said the data room for the company's Phase 2 Canadian package was to open the week of Aug. 22. "We anticipate at least as much interest in our Phase 2 package," he added. The Phase 1 transaction is expected to close by Sept. 30 with an effective date of July 1.

Data rooms already are open for all seven packages of Anadarko's U.S. onshore properties. Together, the remaining packages represent an estimated 230 million cubic feet of proved oil equivalent reserves, the company said.

Anadarko said it intends to use about $1.4 billion in proceeds from its $2.5 billion divestiture program to pay down debt with the remainder going primarily to repurchase its own stock.

"The sales agreements provide greater confidence that we will exceed our targeted minimum after-tax proceeds of $2.5 billion," said Jim Larson, Anadarko's chief financial officer. ●



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ROAD

would be built up with eight feet of gravel to protect the permafrost, McKinnon said.

While the review is under way, the department plans to work on preparing bid-ready designs for the construction work.

Approximately three-quarters of the total cost will go toward the Colville River bridge, McKinnon said.

How to pay for construction of the project, "developing a financial package, is part of the design effort that is currently underway," he said.

The Fairbanks office of Peratrovich, Nottingham and Drage is the design team that put the RFP together, and continues to work on the project, "providing the department with engineering design services for the project and collecting field data necessary for the design. This field data will be available for incorporation into the EIS," the department said.

Result of two-year investigation

In its public notice the department said the Colville River Road project was "the result of a two-year investigation of northern Alaska resource development opportunities" that identified the transportation infrastructure needed to make the developments feasible.

The need to improve access to oil and gas leases in NPR-A was determined to be the "most important investment" the state could make to promote resource development for Alaska's economy," the agency said.

Recent reductions in the North Slope ice road season and "a new generation of international oil and gas exploration opportunities combine to make all-season access important to continued development of North Slope oil and gas resources," the department said.

McKinnon said there are still concerns about security and the operational aspects of using the Spine Road as an arterial route to access NPR-A.

The state has made a commitment to oil industry representatives that "the design process will include security and operations management plans … to ensure that security and operations are not adversely affected by the new road," the agency said in its project description.

Road to Badami, Point Thomson

Another North Slope road project the state department of transportation is looking at is a road to the eastern Badami and Point Thomson fields, linking them with the existing North Slope road system.

"Within the next few weeks we will have our reconnaissance engineering and economic analysis from CH2M Hill and Northern Economics. After a DOT internal review we will make some public announcement about the findings," McKinnon said. ●

COURTESY BUREAU OF LAND MANAGEMENT

Ice roads cost an average of $100,000 per mile to build. Pictured above is an ice road under construction in NPR-A.