Petroleum news

page 4 Apache pumps up exploration & production investment

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Agrium wins battle, loses war

Agrium's nitrogen facility on Alaska's Kenai Peninsula

Arbitration panel awards Agrium $38.5 million-plus

An arbitration panel tasked with determining Unocal's natural gas supply obligations to Agrium's nitrogen facility in Alaska ruled July 23 that Unocal owes Agrium $36.5 million plus $2 million interest for under-delivery of gas between July 2002 and April 2004. The panel directed determination of additional damages to June 30, 2004, and it ordered Agrium to reimburse Unocal $5 million for royalties paid to the state of Alaska.

Unocal sold Agrium the nitrogen facility in 2000. The ruling applied to the two companies' gas purchase and sale agreement under which Unocal would continue to supply natural gas to the Nikiski plant until June 30, 2009, at $1.20 per thousand cubic feet, subject to annual adjustment dependent on gas

see AGRIUM page 16

Alaska to lease offshore ANWR, MMS Beaufort Sea sale advances

The state of Alaska said in late July that it will add tracts offshore the Arctic National Wildlife Refuge to Oct. 27 Beaufort Sea areawide oil and gas lease sale. The 26 tracts had been deferred in previous areawide lease sales.

In a late July legal notice the state Division of Oil and Gas said it had developed "a new mitigation measure to ensure that exploration, development and production activities within tracts 1 through 26 are conducted in a manner that prevents unreasonable conflicts between oil and gas activities and subsistence whale hunting."

Under Mitigation Measure 18, the lessee has to consult with the North Slope Borough and the Alaska Eskimo Whaling Commission to discuss how the siting, timing and methods of proposed operations can be planned and carried out to avoid potential conflicts with subsistence whale hunting.

see ANWR page 9

BREAKING NEWS

7 **Microsoft co-founder takes over Plains Resources:** Vulcan Energy closes $460 million takeover merger

7 **Burlington does turnaround on Canada:** U.S. independent is pumping another $80 million into 2004 Canada E&P spending

11 **Cross-border CBM feud builds:** Montana governor warns B.C. premier she may ask Canadian government to intervene

NORTHERN CANADA / ALASKA

Glacial progress

TransCanada chief warns Alaska gas or LNG could return Canadian project to back burner; frustrated with pace of federal efforts to settle land claims

By GARY PARK

Petroleum News Calgary Correspondent

TransCanada CEO Hal Kvisle is so frustrated with Canada's "ponderous regulatory and approval processes" that he is warning against any assumptions that the Mackenzie Gas Project is a given.

"People shouldn't necessarily assume that the voracious market appetite will be there," he told a conference call July 23. "We should go ahead with this project while it's attractive to do so."

Kvisle said if Alaska gas gets to market first and a wave of liquefied natural gas projects are built,

TransCanada CEO Hal Kvisle said if Alaska gas gets to market first and a wave of LNG projects are built, the Mackenzie natural gas pipeline could be shelved.

the Mackenzie gasline project could be shelved as it was in the late 1970s.

"I would not like to see it go on the back-burner for another 25 years," Kvisle said.

Hart Searle, a spokesman for the Mackenzie project, told Petroleum News that the partners

see GASLINE page 16

INTERNATIONAL

Simmons hopes he's wrong

Leading energy analyst believes Saudi Arabia's crude oil supply near peak; calls for greater global reserve transparency to anticipate 'cataclysm'

By F. JAY SCHEMPF

Petroleum News Contributing Writer (Houston)

Matt Simmons hopes he is wrong.

But if he's right in his belief that Saudi Arabia's giant oil fields might already have peaked and could start into rapid decline in as few as three years, somebody better have a "Plan B" ready or there's no way, he says — absolutely no way — to avoid a world energy cataclysm.

Pretty strong words. Stronger, perhaps, than any uttered before about energy. Simmons spoke them, and more, at a July 9 Washington, D.C., presentation made at a meeting on Saudi Arabia's future. The Hudson Institute sponsored the meeting.

Simmons asked for anybody, including the Saudis themselves, to refute his claim. But so far, in his view, nobody's stepped up. He acknowledges, however, that the Saudis recently have been more forthcoming about their ability to supply all the extra oil the world will require from Saudi fields. But still, it appears that nobody is

see SIMMONS page 18

Leading energy analyst Matt Simmons believes Saudi Arabia's giant oil fields might already have peaked.

NORTHERN ALASKA

North Slope likely has 211 tcf undiscovered gas

USGS's Houseknecht predicts big increase in northern Alaska's undiscovered, recoverable gas resource estimate when agency submits final numbers late this year

By KAY CASHMAN

Petroleum News Publisher & Managing Editor

1 | 2 SERIES

When the U.S. Geophysical Survey releases its final numbers for northern Alaska's undiscovered, technically recoverable, natural gas the average estimate is likely to reach 211 trillion cubic feet.

USGS has already released its estimates for undiscovered, technically recoverable gas on federal lands and offshore state lands – 150 tcf. At the end of this year the agency will publish its estimates for onshore state and Native lands.

David Houseknecht, one of USGS's top research geologists, expects those numbers to be close to the average estimate for federal lands in the National Petroleum Reserve-Alaska, 61.4 tcf, bringing the average estimate of undiscovered, technically recoverable gas in northern Alaska to approximately 211 tcf. (USGS provides a range of undiscovered resources based on probability, the 'mean' or average number being the most likely.)

The 211 tcf estimate does not include the 33 to 35 tcf of known (proved) reserves in North Slope fields

see ESTIMATE page 19

Alaska - Mackenzie Rig Report

The Alaska - Mackenzie Rig Report as of July 28, 2004.
Active drilling companies only listed.

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

This rig report was prepared by Wadeen Hepworth

Alaska Rig Status

North Slope - Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Milne Point, reentry MPI-17	BP
Sky Top Brewster NE-12	15 (SCR/TD)	Deadhorse yard	Available
Dreco 1000 UE	16 (SCR)	W pad sidetrack W-09	BP
Dreco D2000 UEBD	19 (SCR/TD)	Alpine, drilling CD2-05	ConocoPhillips
OIME 2000	141 (SCR/TD)	Infield Kuparuk, drilling 1E-112 multilateral	ConocoPhillips
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Stacked, Prudhoe Bay	Available
Dreco 1000 UE	2-ES (SCR)	Prudhoe Bay, K-03B	BP
Mid-Continent U36A	3-S	Stacked, Deadhorse	Available
Oilwell 700 E	4-ES (SCR)	Milne Point, 24-AL1	BP
Dreco 1000 UE	7-ES (SCR/TD)	Prudhoe Bay, N-01A	BP
Dreco 1000 UE	9-ES (SCR/TD)	Prudhoe Bay, V-213I	BP
Oilwell 2000 Hercules	14-E (SCR)	Stacked, Deadhorse	Available
Oilwell 2000 Hercules	16-E (SCR/TD)	Stacked, Prudhoe Bay	Available
Oilwell 2000	17-E (SCR/TD)	Stacked, Point McIntyre	Available
Emsco Electro-hoist -2	18-E (SCR)	Stacked, Deadhorse	Available
OIME 1000	19-E (SCR)	Stacked, Deadhorse	Available
Emsco Electro-hoist Varco TDS3	22-E (SCR/TD)	Stacked, Milne Point	Available
Emsco Electro-hoist	28-E (SCR)	Stacked, Deadhorse	Available
OIME 2000	245-E	Stacked, Kuparuk	Available
Nordic Calista Services			
Superior 700 UE	1 (SCR/TD)	DS 7-32B	BP
Superior 700 UE	2 (SCR)	Summer maintenance	BP
Ideco 900	3 (SCR/TD)	Kuparuk, stacked at 1-Q	ConocoPhillips

North Slope - Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Nabors Alaska Drilling			
Oilwell 2000	33-E (SCR/TD)	Stacked, NorthStar	BP
Emsco Electro-hoist Canrig 1050E	27-E (SCR/TD)	Stacked at 12-acre pad	Kerr-McGee

Cook Inlet Basin – Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Aurora Well Service			
Franks 300 Srs. Explorer III	AWS 1	Rigging up on Long Lake #1 re-entry	Aurora Gas
Evergreen Resources Alaska			
Wilson Super 38	96-19	Mobilizing to workover 2 wells in the Pioneer unit	Evergreen Resources Alaska Corporation
Inlet Drilling Alaska/Cooper Construction			
Kremco 750	CC-1	Stacked, Kenai	Forest Oil
Kuukpik	5	Happy Valley #8	Unocal
Marathon Oil Co. (Inlet Drilling Alaska labor contractor)			
Taylor	Glacier 1	Rig maintenance	Marathon
Nabors Alaska Drilling			
Rigmasters 850	129	Kenai, Star #1	Unocal
National 110 UE	160 (SCR)	Stacked, Kenai	Available
Continental Emsco E3000	273	Stacked, Kenai	Available
	51	Steelhead platform, done 12-1-03	Unocal
IDECO 2100 E	429E (SCR)	Stacked, removed from Osprey platform	Available
Water Resources International			
Ideco H-35 KD		Prep to resume operations	Pelican Hill

Cook Inlet Basin – Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Cudd Pressure Control	340K	Workover, Osprey Platform	Forest Oil
Unocal (Nabors Alaska Drilling labor contractor)			
Not Available			
XTO Energy (Inlet Drilling Alaska labor contract)			
National 1320	A	Idle	XTO
National 110	C (TD)	Idle	XTO

Mackenzie Rig Status

Mackenzie Delta-Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
AKITA Equtak			
Dreco 1250 UE	62 (SCR/TD)	Stacked Tuktoyaktuk, NT	EnCana
Dreco 1250 UE	63 (SCR/TD)	Stacked, Lucas Point, NT	Chevron Canada
National 370	64	Stacked, Inuvik, NT	Available

Central Mackenzie Valley

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
AKITA/SAHTU			
Oilwell 500	51	Stacked in Norman Wells, NT	Available
Nabors Canada			
	62	Racked	Available

Nabors Alaska Drilling workers on a North Slope rig. JUDY PATRICK

Baker Hughes North America rotary rig counts*

	July 23	July 16	Year Ago
US	1,216	1,211	1,091
Canada	380	241	424
Gulf	94	92	104

Highest/Lowest

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

*Issued by Baker Hughes since 1944

Rig start-ups expected in next 6 months

Rig Owner/No.	Rig Location/Activity	Operator
XTO Energy		
A & C	The rig on platform C will be reactivated in August 2004.	XTO

The Alaska - Mackenzie Rig Report is sponsored by: ConocoPhillips

NORTH OF 60 MINING

Drilling complete at Gold Hill

Crews working for MAX Resource Corp. recently completed the company's first pass of 1,400 feet of core drilling on the Gold Hill property, located in Interior Alaska about 10 miles off the Denali Highway.

Spending about $200,000 for the work, crews drilled seven holes, each about 200 feet deep, according to Clancy Wendt, vice president of exploration for MAX Resource, a Vancouver, B.C.-based junior exploration company that has recently come out of dormancy. The drilling work was done to confirm past reverse-circulation drilling completed in the late 1980s which identified some high-grade gold intercepts, including one that assayed five feet grading .66 ounces of gold per ton of rock, according to the company's July 21 press release.

In addition, the recent drilling was completed to give geologists a better look at the mineralized trend, Wendt told Petroleum News on July 28.

MAX Resource announced in May its option agreement on the Gold Hill property with Zazu Exploration, Inc., a privately-held Texas corporation which holds a lease on the mining claims from General Crude Oil.

Wendt said MAX hopes to complete more core drilling this year, although that work depends on whether the company can secure a drill rig later this season. "Drill rigs are getting as scarce as hen's teeth," he said.

Plans call for an additional 12 holes to be drilled, for a total of 2,000 to 2,400 feet, Wendt said. That drilling may be held until next year, when additional airborne and ground geophysical work is also contemplated for the Gold Hill property.

The Gold Hill property includes 3,873 hectares (9,570 acres) of land located off the Denali Highway, roughly midpoint of the gravel road that stretches from Cantwell to Paxson through the heart of Alaska. Located 200 kilometers (124 miles) south of Fairbanks, access is by ATV from the Denali Highway or by helicopter.

Editor's note: For a more detailed report, see the August issue of North of 60 Mining News, a monthly supplement of Petroleum News.

— PATRICIA LILES

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NEW ORLEANS, LA.

Louisiana loses jobs in chemicals

As Louisiana failed to sustain much employment growth over the past year, two key economic and well-paying sectors — the oil support industry and chemical manufacturing — took major hits, the state labor department reported July 26.

Figures from the goods-producing sector, which had an overall loss of 5,900 jobs, reflected two situations slowing the economy: a lack of sustained drilling in the Gulf of Mexico, and layoffs in the chemical industry, which has been hurt by high natural gas prices.

Oil support firms lose 1,600 jobs

Oil support businesses lost 1,600 jobs from June 2003 to the end of last month, while chemical manufacturing — one of the highest average paying jobs in Louisiana — dropped 1,000 jobs.

The chemical industry already has warned that more layoffs are on the horizon. The domestic chemical business — inside and outside of Louisiana — has been dealing with foreign competition taking advantage of lower gas prices overseas.

—THE ASSOCIATED PRESS

GULF OF MEXICO

Current Deepwater Activity

Operator	Area/ Block	OCS Lease	Rig Name	Prospect Name	Water Depth (ft)
Shell Offshore Inc.	LL 399	G23480	R&B FALCON DEEPWATER NAUTIL	Cheyenne	8,951
BP Exploration & Production Inc.	WR 724	G17011	OCEAN CONFIDENCE	Das Bump	7,591
Chevron U.S.A. Inc.	WR 759	G17016	TSF DISCOVERER DEEP SEAS	Jack	6,965
BP Exploration & Production Inc.	GC 743	G15606	TSF DEEPWATER HORIZON	Atlantis(GC)	6,829
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	6,040
Dominion Exploration & Production, Inc.	MC 773	G19996	PRIDE 1503	Devil's Tower	5,610
Kerr-McGee Oil & Gas Corporation	GC 767	G24182	FALCON DEEPWATER MILLENNIU	Conquest	5,261
Mariner Energy, Inc.	VK 962	G15444	DIAMOND OCEAN AMERICA	Swordfish	4,673
BHP Billiton Petroleum (GOM) Inc.	GC 653	G20084	GLOMAR C. R. LUIGS	Shenzi	4,340
Anadarko Petroleum Corporation	GC 608	G18402	NABORS POOL 140	Genghis Khan	4,320
Anadarko Petroleum Corporation	GC 518	G21801	NOBLE PAUL ROMANO	K2 North	4,035
Chevron U.S.A. Inc.	GC 640	G20082	TRANSOCEAN CAJUN EXPRESS	Tahiti	4,017
Eni Petroleum Co. Inc.	GC 562	G11075	GLOMAR CELTIC SEA	K2	3,925
BP Exploration & Production Inc.	VK 915	G06894	NOBLE JIM THOMPSON	Dorado	3,460
Murphy Exploration & Production Company -	GC 338	G21790	NOBLE AMOS RUNNER	Front Runner	3,278
Shell Offshore Inc.	GC 248	G15565	NOBLE MAX SMITH	Glider	3,243
Eni Petroleum Co. Inc.	GC 254	G08010	DIAMOND OCEAN VALIANT	Allegheny	3,225
Shell Offshore Inc.	VK 956	G06896	H&P 205	Ram-Powell	3,214
Kerr-McGee Oil & Gas Corporation	GB 667	G17407	DIAMOND OCEAN STAR	Gunnison/Durango	3,152
Kerr-McGee Oil & Gas Corporation	GB 668	G17408	NABORS MODS RIG 150	Gunnison	3,152
Shell Offshore Inc.	GB 426	G07493	AUGER	Auger	2,862
TOTAL E&P USA, INC.	MC 243	G19931	SUNDOWNER XVI	Matterhorn	2,816
Walter Oil & Gas Corporation	MC 583	G16624	DIAMOND OCEAN LEXINGTON	Killer Bee	2,487
Murphy Exploration & Production Company	MC 582	G16623	MODS 141	Medusa	2,215
LLOG Exploration & Production Company	GB 415	G24491	DIAMOND OCEAN SARATOGA		2,072
Kerr-McGee Oil & Gas Corporation	GB 244	G15860	TRANSOCEAN MARIANAS	Basal Peak	1,946
Chevron U.S.A. Inc.	VK 786	G10944	ENSCO 25	Petronius	1,754
El Paso Production GOM Inc.	EW 1003	G06921	SUNDOWNER XI	Prince	1,483
BP Exploration & Production Inc.	MC 109	G05825	H&P 203	Amberjack	1,030
Total Deep Water Prospects with Drilling/WO Activity				30	

New Deepwater Activity

Kerr-McGee Oil & Gas Corporation	GC 767	G24182	Conquest	5,261
LLOG Exploration & Production Company	GB 415	G24491		2,072

● HOUSTON, TEXAS

Apache pumps up E&P investment

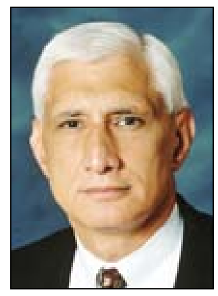
Earnings break record in Q2, spent $1 billion for E&D in first half of year, setting stage for even stronger second half

By RAY TYSON

Petroleum News Houston Correspondent

Big Houston independent Apache doled out $1 billion for exploration and development in the first half of the year, resulting in strong production and record income for the 2004 second quarter and setting the stage for what could be an even stronger second half.

Fueled by robust oil and gas prices and lower lifting costs, Apache's profit during the second quarter jumped 53 percent to $372 million or $1.13 per share on revenue of $1.247 billion from $243 million or 74 cents per share on revenue of $1.044 billion a year earlier, the company reported July 29.



Steve Farris, Apache president and CEO

Apache's earnings surpassed the previous quarterly record of $1.06 per share reported in the first quarter of 2004.

"The story in the second quarter was higher production, lower lifting costs and strong commodity prices," said Steve Farris, Apache president and CEO.

He said the $1 billion invested during first six months of the year increased the level of drilling activity and "is providing strong momentum for the second half."

Apache said its liquid hydrocarbon production during the 2004 second quarter averaged 234,788 barrels per day, up three percent from the first quarter and up six percent from the prior-year period. Natural gas production averaged 1.25 billion cubic feet per day, up 38 million cubic feet per day from the first quarter and a slight increase from the year- earlier period.

Operation highlights during this year's second quarter included a sequential three percent increase in U.S. gas production, due to exploitation of offshore blocks acquired from BP and Shell in 2003 and onshore South Louisiana fee acreage acquired in 2002, as well as continued success in the Deep Springer and Red Fork plays in the Anadarko Basin, the Styles Ranch area in North Texas and in East Texas.

Apache said its North Sea production increased seven percent from the first quarter to 47,179 barrels per day because of six new producing wells and increased field efficiency. In July, net production averaged about 55,000 barrels per day, the company said. Moreover, Apache's Egypt region set quarterly records for gross production of 100,828 barrels of oil per day and 276 million cubic feet of gas per day, the company said.

Apache said its 2004 second-quarter earnings included two unusual items that together reduced the per-share results by 19 cents — a $48 million after-tax reserve for a previously announced arbitration award, which Apache said it intends to contest, and the $14 million after-tax impact of the employee share appreciation plan.

Those items were partially offset by a lower effective tax rate, primarily from a reduction in Alberta provincial tax rates and the impact of favorable currency swings on deferred taxes, Apache said. The tax items totaled $35 million after tax or 11 cents per share.Cash from operations during this year's second quarter, before changes in operating assets and liabilities, totaled $721 million, up from $639 million in the year-earlier period.

Apache's debt-to-capitalization ratio declined to 23.2 percent at the end of the 2004 second quarter from 24.2 percent at the end of the first quarter. ●

NORTH POLE, ALASKA

H.C. Price lands contract to construct North Pole naptha-fired power plant

Interior Alaska's electric provider Golden Valley Electric Association announced July 28 it signed a $74.9 million contract with H.C. Price Co. to build a new 60 megawatt naphtha-fired power plant in North Pole. Work is scheduled to begin this summer and to be completed by April 2006.

The new power plant will be located within the security confines of the Flint Hills oil refinery. Feedstock comes directly from the Trans-Alaska Pipeline System, although the new power plant can be converted to natural gas, should that fuel become available in quantity in Interior Alaska, GVEA said.

GVEA needs new power generation to meet its future power needs, expected to grow more than 30 megawatts from the Strategic Missile Defense System, the Pogo Gold Mine and conversion to electric power at Alyeska's Pump Station 9, all in the Delta Junction area.

—PATRICIA LILES

● COOK INLET

Regulatory commission agrees to hear Cook Inlet gravity bank issue

Forest goes after Cook Inlet Pipeline, charging carrier's gravity bank provisions are discriminatory

By KRISTEN NELSON
Petroleum News Editor-in-Chief

The Regulatory Commission of Alaska said July 19 that it will hear a complaint by Forest Oil Corp. against Cook Inlet Pipeline Co. concerning handling of gravity bank issues.

The commission appointed Janis Wilson as the administrative law judge in the proceeding, set an Aug. 3 deadline for others wishing to intervene and scheduled a prehearing conference for Aug. 17.

The commission said Forest filed a complaint against the pipeline in April, asserting that the pipeline was not applying its gravity bank agreement equitably.

Forest told the commission that the pipeline, owned 40 percent by Forest, 40 percent by Unocal and 20 percent by Mobil Pipeline Co., is used by three shippers — Forest, Unocal and ExxonMobil — to move crude oil to the Drift River Terminal. Forest said the pipeline "transports crude oil from the Granite Point, McArthur River, West McArthur River, Trading Bay and Redoubt Shoal fields on the west side of Cook Inlet," and also said that Tesoro Alaska Co. is the sole purchaser of the crude transported by the pipeline.

The commission said the pipeline "established a gravity bank to adjust for differences in gravity among the crude oil produced from the various oil fields connected" to the pipeline. Provisions of the gravity bank are contained both in the tariff filed with the Federal Energy Regulatory Commission and in the tariff filed with the commission, although none of the oil is currently shipped outside of Alaska.

Crude oils have different American Petroleum Institute gravities, and oils of different gravity have different values. Gravity banks exist so that shippers of different oils are compensated, or charged, based on the API gravity of the oil they ship. Forest told the commission that the gravity bank methodology is "designed to facilitate equitable adjustment among shippers for gravity differentials arising from the common stream operation and that the intent of the gravity bank was to place each shipper in approximately the same economic position it would have been in had it been delivered the same crude oil that it originally tendered for shipment on" the pipeline. Forest told the commission that "the gravity bank was never intended to create a preference or advantage for certain shippers or a prejudice to others."

JUDY PATRICK

Forest told the commission that oil from Redoubt Shoal has a lower gravity than other Cook Inlet oil, "and that this should lower the overall gravity, and therefore the price, of the other commingled crude oils transported" on the pipeline.

Redoubt oil has lower gravity

Forest told the commission that oil from Redoubt Shoal has a lower gravity than other Cook Inlet oil, "and that this should lower the overall gravity, and therefore the price, of the other commingled crude oils transported" on the pipeline. But, Forest said, crude oil purchaser Tesoro told Unocal and ExxonMobil that it would not decrease the prices it paid them due to commingling of Redoubt Shoal crude. Forest said even though Unocal and ExxonMobil do not receive a reduced price for their commingled crude oil, Forest is charged by the gravity bank, creating a "windfall" to Unocal and ExxonMobil.

Forest told the commission that Cook Inlet Pipeline is not applying its tariff as written, because that tariff has provided, since 1986, "that the gravity differential adjustment value is 1 cent for each one-tenth degree of API below 40 degrees gravity…" Forest said that the pipeline's tariff requires oil with an API gravity higher than 40 degrees to be treated as 40 degree oil for purposes of calculating the gravity differential, but the company said it received calculations in January which indicated the pipeline was not complying with the 40-degree cap as required by the tariff, and said the pipeline confirmed that since 1989 the gravity differential had been applied to all crude oil, regardless of gravity. Forest said the pipeline told it that as of March 1, 2004, "the gravity differentials for all crude oils will be calculated only up to a maximum API gravity of 40 degrees."

Forest's request to the commission

The commission said Forest has requested that it suspend the pipeline's gravity bank methodology or require that any gravity bank payments be refundable until the commission issues its final order in this matter. Forest has requested that the commission investigate "whether applying the current gravity bank methodology to Forest's Redoubt Shoal crude oil provides an undue windfall, preference or advantage to Unocal and ExxonMobil or unreasonably prejudices

see **GRAVITY BANK** page 6

NEWS IN BRIEF

El Paso sells interest in Indonesian firm

El Paso Corp. has closed the sale of its stake in an Indonesian production company for $23.2 million, plus working capital.

The shares in Coastal Indonesia Sampang Ltd. were sold by El Paso subsidiary El Paso Production Co. and bought by Singapore Petroleum Co. Ltd.

Coastal Indonesia Sampang has a 40 percent working interest in the Sampang production sharing contract, which provides exploration rights in Indonesia.

Houston-based El Paso has been selling assets to cut its debt load, but ran into further trouble in February when it had to write down its reserves by 1.8 trillion cubic feet of gas equivalent.

Wind Dancer field gets BLM go-ahead

The Bureau of Land Management has reached a decision that the Wind Dancer gas field near Wamsutter, Wyo., will have no significant impact on the environment. The document came out July 28.

The BLM released its Environmental Assessment on the project for public review in June.

Two smaller independents, Cabot Oil and Gas Corp. and GMT Energy Corp., want to explore and develop 6,400 acres in northcentral Sweetwater County. The project is expected to involve up to a dozen natural gas wells, along with roads, pipelines and production facilities.

The BLM released its Environmental Assessment on the project for public review in June. Its Decision Record, which includes public comments on the assessment, is posted on the Rawlins BLM website at: http://www.wy.blm.gov/nepa/rfodocs/winddancer/index.htm

—ALLEN BAKER

PORLAMAR, VENEZUELA

Venezuela wants hike of OPEC price ranges

Venezuela will propose an increase in the oil price range established by the Organization of Petroleum Exporting Countries at the next meeting in September, Venezuela's oil minister said July 25.

"For the (upcoming September OPEC meeting) we've asked to have a technical evaluation of the price range" to determine the possibility of raising it from its current range of between US$22 and US$28, Ramirez said during a meeting between Venezuelan and Argentine business executives on Margarita Island.

Venezuelan officials haven't suggested what the new price range should be, Ramirez said. The OPEC meeting is Sept. 15 in Vienna, Austria.

"We've made an important effort in (increasing production), and that's why we've proposed reviewing the range because clearly we'll need important investments to continue supplying the level of demand," Ramirez said.

Other OPEC members, including Saudi Arabia, say they agree with the current price range. Venezuela, the world's No. 5 oil exporter, produces more than 3 million barrels of oil a day, according to the government. Critics say the number is closer to 2.5 million. Ramirez said OPEC would continue to monitor the market before deciding whether to increase the caps on production levels.

"The important thing to note is that OPEC members are now approaching their production capacities," Ramirez said. OPEC decided in June to raise production by 2 million barrels a day in July, and by an additional 500,000 barrels a day in August to lower oil prices that have been over US$40 a barrel this year.

But Venezuelan officials say that production hikes will not bring down oil prices, which are high because of the conflicts in the Middle East.

—THE ASSOCIATED PRESS

continued from page 5

GRAVITY BANK

and disadvantages Forest."

Forest wants the commission to declare the pipeline's gravity bank "unjust, unreasonable, unduly discriminatory and unlawful" when applied to Forest's Redoubt Shoal crude. It wants the commission to direct the pipeline to amend its tariff so that the gravity bank methodology does not apply to Redoubt Shoal crude.

It wants a refund of "gravity bank windfalls" it paid on Redoubt Shoal crude, an amount it has told the commission exceeds $300,000.

Forest wants the commission to find that it was subjected to "an unlawful rate, service, or practice in violation of the Alaska Pipeline Act," and direct that Forest receive a refund of excess gravity bank payments it made as a result of the pipeline's failure to adhere to its tariff, a sum which Forest told the commission amounts to more than $75,000 for 2003 alone.

Unocal the Cook Inlet operator

Cook Inlet Pipeline told the commission that it is currently operated by Unocal Pipeline Co., and has been since 1995 when Unocal took over from Mobil. The pipeline said separate divisions of Unocal manage the pipeline and ship crude oil on the system, respectively Unocal Midstream and Trade and Unocal Alaska.

The pipeline said its tariff provides that gravity payments are made between shippers, not through the pipeline, and said the shippers have a separate gravity bank agreement and Unocal Alaska is the gravity bank administrator. The pipeline said it calculates amounts and notifies each shipper of its debits and credits, but "it is the shipper's responsibility to ensure that the amounts are correctly paid and received." The pipeline said the gravity bank "is a zero-sum calculation" and payments made and received each quarter should be equal.

The pipeline told the commission that if Forest is at a disadvantage, it is because of its contract with Tesoro, not because of any discriminatory practices by Cook Inlet Pipeline. The pipeline said that if it acceded to Forest's request that the gravity bank not apply to Redoubt Shoal crude oil, then the gravity bank provisions would discriminate among shippers, thus, "Forest is seeking a preference which common carriers are not permitted to convey to shippers."

The pipeline told the commission "that if Forest is disappointed with the price it receives for its crude oil, it should renegotiate its contract with Tesoro."

Cook Inlet Pipeline said it began applying the 40-degree API cap on all shipments beginning March 1. The pipeline said it applied the 40-degree API cap from 1986 through 1989, but that in October 1989 it began to treat all crude by adjusting its value by 1 cent for each one-tenth degree difference in gravity. No shipper challenged the application of the 40-degree API cap until Forest raised the issue, the pipeline said. It also said "it cannot locate individuals who could explain the purpose of the original provision or why, starting in 1989, the 40-degree API cap was no longer applied."

The pipeline said the commission does not have the authority to issue refunds for past periods, that the 40-degree cap has been resolved going forward, and noted "that Forest, as an owner and shipper, could have requested an accounting of the 40-degree API cap calculations at any time but apparently chose not to do so."

The commission said Forest has argued "the underlying justification for the gravity bank no longer exists as to Forest's Redoubt Shoal crude oil." The company also said that just because a tariff provision has been in existence for some time does not make it "just and reasonable."

The commission said Forest has demonstrated there is good cause for it to investigate, and it has instituted an investigation.

Forest has alleged, the commission said, that the pipeline is being operated to the benefit of affiliated interests of shareholders owning a majority of the line (Unocal and Mobil), over the interests of a minority shareholder. "If that is the case," the commission said, the pipeline "is engaging in a discriminatory practice contrary to statute." A carrier must operate in accordance with its tariff, and has a duty to change a tariff that is discriminatory.

The commission said it has "good cause to investigate" whether the pipeline's "current gravity bank tariff provisions are just and reasonable and nondiscriminatory."

It also appears, the commission said, that the pipeline "may have violated its gravity bank tariff provision governing the calculation of gravity differentials." Since the calculation has been done in two ways, one of the ways may have been incorrect, or both ways of interpreting the provision may be correct and the tariff provision too vague. "In either case," the commission said, "there is good cause for us to investigate…" ●

finance&economy

DENVER, COLO.

Teton looking to expand outside Russia, notably North America

Teton Petroleum Co. has some change jingling in its pockets and is looking beyond the frontiers of Russia, where it has focused, for new opportunities — notably in North America.

"If the deal makes sense in Alaska we will look at it, or in any state in the Lower 48."
—Gillian Kane, Teton Petroleum's vice president for investor relations

The Denver-based company discussed its new strategy at the July 16 annual meeting, where shareholders approved the sale of Teton's 35.3 percent interest in Goloil, the Russian closed joint stock company, for $8.9 million. Teton will also be repaid about $6 million in loans it made to Goloil, for total proceeds of about $15 million.

Once the check comes in, Teton will have about $18 million in cash and no corporate debt. And while Teton intends to continue its focus on Russia and the territories of the former Soviet Union, other areas will also be considered, including Alaska.

"If the deal makes sense in Alaska we will look at it, or in any state in the Lower 48," said Gillian Kane, the company's vice president for

see **TETON** *page 9*

CALGARY, ALBERTA

Petro-Canada close to wrapping up C$719M Prima Energy deal

Petro-Canada's self-described step out of its North American natural gas business is now a done deal, with the formalities of its C$719 million takeover of Denver-based Prima Energy all but completed. The Calgary-based company reported July 23 that 93 percent of Prima's shares were tendered to its cash offer, made through indirect, wholly-owned subsidiary, Raven Acquisition.

Petro-Canada President and CEO Ron Brenneman said Prima is an "excellent fit with our long-term strategy to sustain and expand our core North American" gas operations.

He said Prima, with 55 million cubic feet equivalent of production per day, 1,600 drillable locations in the Powder River and Denver-Julesberg basins and 360,000 undeveloped acres, sets Petro-Canada up to "benefit from the growing unconventional gas segment."

Prima's production is more than 80 percent gas and 40 percent of that comes from coalbed methane, which accounts for the bulk of its 552 billion cubic feet equivalent of proved plus probable reserves.

In entering the realm of tight gas and coalbed methane in the U.S. Rockies region, Petro-Canada is following the lead of its Canadian rival EnCana, which has invested heavily in unconventional prospects, and even gone one step higher by paying about C$80,000 per flowing barrel for Prima compared with EnCana's C$65,000 for its Tom Brown acquisition.

—GARY PARK

● HOUSTON, TEXAS

Microsoft co-founder Allen takes over Plains Resources

By RAY TYSON
Petroleum News Houston Correspondent

Vulcan Energy, an affiliate of an investment company owned by Microsoft co-founder and billionaire Paul Allen, has closed its $460-million takeover merger of exploration and production independent Plains Resources, just days after shareholders approved a $17.25 per share offer for the company.


PAUL ALLEN

The deal also gives Vulcan a stake in a much bigger prize, fast-growing Plains All American Pipeline, a publicly traded master limited partnership (MLP) with over 7,000 miles of gathering and mainline pipelines in Texas, Oklahoma, California and Louisiana and the Canadian provinces of Alberta and Saskatchewan.

Plains Resources owns 44 percent of the general partnership and 12.4 million limited partnership units, which represents about a 24 percent aggregate ownership interest in Plains All American, which also is involved in marketing, terminaling and storage operations.

"We believe Vulcan will be a solid long-term partner and a valuable resource in the continued execution of our business plan," said Greg Armstrong, chairman and chief executive officer of Plains All American. "Paul Allen's Vulcan organization is one of the leading private investment firms in the nation."

Bid went up in response to offer from Leucadia National

A week prior to the July 22 merger vote, Vulcan agreed to increase its bid for Plains from $16.75 to $17.25 per share, following a competing offer from Leucadia National Corp. amounting to $17 per share.

Leucadia gain countered Vulcan with a revised

see **ALLEN** *page 9*

● HOUSTON, TEXAS

Burlington does turnaround on Canada cost-cutting

U.S. independent says must drill 900 to 1,000 wells a year in Canada to achieve production target, compared to 700-800 this year

By GARY PARK
Petroleum News Calgary Correspondent

Burlington Resources is making a course correction in Canada and going against the flow of other U.S.-based companies north of the 49th parallel by pumping another US$80 million into its 2004 Canadian capital spending.

"We believe we have a strong inventory – some 2 trillion cubic feet of economic projects in Canada," chief operating officer Randy Limbacher told a conference call July 22. "We're going to be ramping up our activity level heading into the winter of 2004-05."

Executives of the Houston-based independent conceded they had "overcorrected" when they trimmed their Canadian budget to about US$700 million from about US$735 million in 2003 because of a surge in the value of the Canadian dollar and higher costs.

The squeeze lowered Burlington's gas output in Canada to 834 million cubic feet per day in the second quarter from 868 million in the same period last year.

Chief financial officer Steven Shapiro said Burlington's Canadian division is now spending only about 50 percent of cash from its operations at a time when project economics are "very robust."

see **BURLINGTON** *page 9*

● OKLAHOMA CITY, OKLA.

Kerr-McGee's production up by 25% in third quarter

By RAY TYSON

Petroleum News Houston Correspondent

It all comes together for Kerr-McGee in the third quarter of this year its oil and gas production will rocket more than 25 percent, thanks in large part to new offshore field developments and a recent corporate merger.

That milestone will follow a highly successful second quarter in which Kerr-McGee's profit soared 59 percent to $110.6 million or $1.01 per share from $69.6 million or 68 cents per share in the year-ago period.

Capex expenditures down

Revenues of $1.1 billion in the second quarter were up slightly from the 2003 period, the company said, but capital expenditures were down to $289.2 million from $340.1 million a year earlier.

Oil production in the second quarter actually dropped 9 percent from the year-ago period to 140,500 barrels per day, due largely to the divestiture of non-core properties, while natural gas production for the comparable periods rose 6 percent to 740 million cubic feet per day.

Increase comes from deepwater Gulf, Bohai Bay

But the company said in a July 28 conference call with analysts that overall company output should increase by more than a quarter in this year's third quarter ending Sept. 30, as production continues to ramp up at the Red Hawk and Gunnison fields in deepwater Gulf of Mexico and from a new core area in China's Bohai Bay, and the full production benefit from the $3.4 billion Westport Resources merger earlier this year is realized.

Additional production from existing fields also is expected to contribute to Kerr-McGee's production increase in the 2004 third quarter, the company said.

In the Westport deal, Kerr-McGee gained proved reserves of 1.8 trillion cubic feet of natural gas equivalent, consisting of 76 percent natural gas and primarily located in the Rocky Mountain and Texas Gulf Coast areas. The transaction also included probable and possible reserves of 1.8 trillion cubic feet of natural gas equivalent, about 50 percent of which are located in and around the Natural Buttes field, in the Uinta basin of northeast Utah.

Second Red Hawk well to go online

Kerr-McGee's total daily production volume ultimately is expected to increase more than 34 percent, giving the new company daily production of about 1.2 billion cubic feet of natural gas and 160,000 barrels of oil.

Separately, production from Red Hawk, with an estimated resource base of about 250 billion cubic feet of natural gas, is expected to ramp up to a peak of 120 million cubic feet of natural gas per day in early August after the second well is placed on production.

In Bohai Bay, Kerr-McGee expects to have 10 wells on line by the end of July producing 15,000 to 20,000 barrels of oil per day. With additional wells, output is expected to peak at 40,000 to 45,000 barrels per day by mid-2005.

Kerr-McGee's debt to total capitalization at June 30, 2004 decreased to 46 percent compared with 58 percent at December 31, 2003. The company carried $4.4 billion in debt at the end of the recent quarter versus $3.7 billion at the end of the prior quarter. Kerr-McGee assumed about $1 billion in debt on June 25, 2004 upon completion of the merger with Westport Resources. ●

OIL COMPANY EARNINGS

Earnings from Top 35 North American E&P Capex Spenders

Earnings second quarter 2004 • Change from second quarter 2003
Liquids production second quarter 2004 • Change from second quarter 2003
Natural gas production second quarter 2004 • Change from second quarter 2003

Company	symbol	earnings	%	liquids	%	gas	%
BP	BP	$3,908	+23	2,518,000	+32	8,425	0
RD/Shell	RD						
EnCana	ECA	$250	-69	269,718	+31	3,037	+23
ExxonMobil	XOM	$5790	+39	2,581,000	+4	9,001	-3
Can. Natural	CNQ.TO						
ConocoPhillips	COP	$3,075	+75	1,012,000	–4	3,303	-5
El Paso	EP						
ChevronTexaco	CVX						
Anadarko	APC						
Devon	DVN						
Dominion	D	$251	+5	27,274	+8	1,034	-6
Burlington	BR	$379	+36	143,200	+38	1,899	+1
Occidental	OXY	$581	+55	440,000	+6	642	+4
Husky	HSE.TO						
Newfield	NFX	$67	+47	15,629	-10	521	+1
Petro-Canada	PCZ	C$393	-33	310,600	-5	868	+2
Unocal	UCL						
Kerr-McGee	KMG	$110	+59	140,500	-9	740	+6
EOG	EOG						
Nexen	NXY.TO						
Imperial	IMO						
Talisman	TLM	C$197	-2	229,579	+22	1,244	+17
Pioneer	PXD						
Apache	APA	$373	+53	224,602	+6	1,251	0
Marathon	MRO	$352	+42	178,000	-12	965	-17
Suncor	SU.TO						
Merit							
Williams	WMB						
Chesapeake	CHK	$86	+12	18,589	+37	850	+27
Pogo	PPP	$65	-18	58,423	-15	338	+12
Penn West	PWT.TO						
XTO	XTO	$99	+73	25,145	+31	803	+27
Spinnaker	SKE	$18	+76	6,400	+68	111	-1
Forest	FST						
BHP Billiton	BHP						

NOTE: Top 35 is based on Petroleum News research

continued from page 1

ANWR

The state said this "consultation may include negotiating a conflict avoidance agreement."

There will also be a state North Slope areawide lease sale in Anchorage on Oct. 27. Sealed bids must be received by the division by 4:00 p.m. (local time) on October 25.

The bidding method for both sales will be cash bonus, with a minimum bid of $10 per acre. North Slope lease terms will be seven years; Beaufort Sea leases will be both seven and 10 years, depending on location. For more details visit the division's website, www.dog.dnr.state.ak.us/oil

MMS says no new concerns

A new report by the U.S. Minerals Management Service says there are no new environmental concerns preventing a Beaufort Sea oil and gas lease sale from taking place next spring.

The proposed sale, tentatively scheduled for March 30, covers nearly 9.8 million acres off Alaska's northern coast from the Canadian border to Point Barrow.

MMS has released an environmental assessment of the area that would be affected by the sale, determining there would be "no new significant impacts" besides those previously assessed.

MMS completed a comprehensive environmental impact statement of drilling in the Beaufort Sea two years ago, when it developed its five-year leasing plan, which includes three Beaufort sales.

The report released at the end of July was conducted to determine whether another evaluation was necessary because of new or changed information on the region's birds, bowhead whales and subsistence hunters.

"Our view was that nothing had changed to make any new significant issues," said John Goll, MMS Alaska regional director.

The assessment will be open to public comment for 30 days. A proposed notice of sale is scheduled to go out in October and a final notice of sale 30 days before the sale date.

In the most recent Beaufort Sea sale, last September, three companies bid more than $10 million for leases on 181,000 acres. Next year's proposed sale covers the same territory. MMS proposes six alternatives to the plan, removing from the sale various areas used by subsistence whale hunters.

—THE AP CONTRIBUTED TO THIS STORY

continued from page 7

BURLINGTON

Building momentum for 2005, 2006

He said the goal now is to "build momentum for 2005 and 2006, while ramping up our organizational capability for somewhat higher project load."

Limbacher said Burlington needs to drill 900 to 1,000 wells a year in Canada to achieve growth, compared to the 700-800 expected this year, given that production from Canadian wells falls by 25-30 percent a year.

He said the company, faced with a 5 percent cost increase due to higher activity levels, is trying to secure better deals with service suppliers.

But coalbed methane does not figure highly in Burlington's plans, although the company is involved in more than two dozen wells.

Limbacher said the fact that Burlington is drilling so few wells across a wide area and that it takes up to five years to "see any kind of results" from coalbed methane means it will likely be "several more years before you start to make a real call on CBM plays in Canada for the industry as a whole." ●

continued from page 7

TETON

investor relations, in response to Petroleum News.

"Our goal is to replace Goloil with a balanced portfolio of properties, including some modest percentage of assets outside the (former Soviet Union)," said Igor Effimoff, Teton's chief operating officer. "We are focused on identifying and acquiring properties that are discounted to relative values in the market, have existing production, and have proven reserves which we can drill with relatively low risk in order to provide upside for our shareholders."

—**ALLEN BAKER,** Petroleum News contributing writer

continued from page 7

ALLEN

offer, in which the company said it would barrow about $175 million and use the proceeds to commence a tender offer to purchase Plains' common stock for $18 per share.

However, Plains' board of directors concluded that Leucadia's proposed leverage buyout would not result in "superior value" for Plains stockholders compared to Vulcan's cash deal. Holders of about 17 percent of Plains' outstanding common stock were contractually committed to vote for the new deal with Vulcan.

Flores, Raymond party to takeover

In addition to Microsoft's Allen, Plains chairman James Flores and company chief executive John Raymond, son of ExxonMobil chairman Lee Raymond, were party to the takeover merger through Vulcan Energy, an affiliate of Allen's Vulcan Capital.

"We are pleased to have completed the acquisition, Allen said, adding that Plains All American "is the premier crude oil MLP in the industry, with a world-class management team."

Vulcan's offer for Plains Resources was valued at around $460 million. The transaction was financed with equity from Vulcan Capital and Plains Resources' management, a $175 million term loan from Fleet National Bank and a $75 million term loan from Bank of America. Plains Resources is headquartered in Houston, Texas. ●

Letter from the Publisher

Dear reader,

We are changing the name of our annual magazine from "The Independents" to "The Explorers." The subhead will be: Oil and gas companies investing in Alaska's future.

We're doing this because our original intent was to feature the independents coming into Alaska to *explore* for oil and gas.

That is still our intention, BUT two of the new companies, Total and Petro-Canada, are majors, not independents.

By excluding the majors we also had to leave out one of Alaska's most active explorers – ConocoPhillips – which is trying to attract partners for its Alaska operations, many of which are independents. We also left out Marathon, another major, which has been an active explorer in the Cook Inlet basin.

We are still going to play up the increasing role of independents in Alaska, but with the new title we can include all the companies investing in exploration.

If you have any questions, please feel free to call me at 907 770-3505.

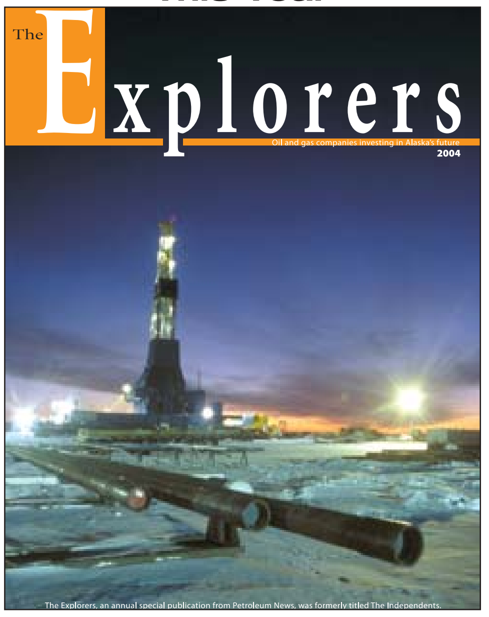
Thank you.

Sincerely,

Kay Cashman

Kay Cashman, publisher and managing editor

This Year



Last Year

LONDON

BP posts 35 percent rise in quarterly profit to $3.43 billion

Soaring oil and natural gas prices together with fatter profit margins in refining drove BP PLC's second-quarter earnings higher by 35 per cent.

The London-based company posted a profit of $3.43 billion for the three months ending June 30, up from $2.54 billion during the same quarter of 2003, BP said July 27. BP reported pro forma net profit, which the company said excludes losses or gains from the sale of assets or termination of operations, of $3.91 billion, up from $3.17 billion a year ago.


JUDY PATRICK

BP chief executive John Browne

The results came in slightly below market expectations for $4.14 billion, based on an average of eight analysts' forecasts compiled by Dow Jones Newswires.

Quarterly sales rose to $71.2 billion, compared to $54.8 billion for the same period last year.

The strong profit gains came largely on the back of higher oil and gas prices. The price of benchmark North Sea Brent crude averaged $35.32 a barrel in the second quarter — 38 per cent higher than last year and the highest of any quarter for more than 20 years, BP chief executive John Browne said in a statement.

Continued supply constraints among members of the Organization of Petroleum Exporting Countries along with steady growth in demand should keep oil prices firm, Browne said.

BP expected global economic growth to continue, noting momentum in Japan and signs of recovery in Europe. However, the pace of economic activity in the United States appeared to be easing, and the Chinese government was taking steps to try to cool the sizzling growth in China, he added.

BP's biggest business — exploration and production — saw second-quarter sales volumes increase by 18 per cent to 3.97 million barrels of oil equivalent a day. All the growth came from Russia, where BP formed its TNK-BP joint venture last year.

The Russian contribution offset declines in output elsewhere due to sales of assets, lower seasonal gas production in the North Sea, and unplanned shutdowns at facilities in the large Mars field in the Gulf of Mexico and at a field in Trinidad. Pro forma earnings from exploration and production jumped to $4.56 billion from $3.86 billion.

For the first six months of the year, BP's profit grew to $7.6 billion, from $5.96 billion in 2003.

● OKLAHOMA CITY, OKLA.

Chesapeake acquires $590M in properties

Company's aggressive nature has transformed it into the fifth largest independent producer of natural gas in the U.S.

By RAY TYSON

Petroleum News Houston Correspondent

Chesapeake Energy, whose production is soaring through both acquisitions and an exceptionally active drilling program, is acquiring another $590 million worth of oil and gas properties located in South Texas and the U.S. mid-continent from three separate private companies.

Chesapeake's aggressive nature has now transformed the Oklahoma-based company into the fifth largest independent producer of natural gas in the United States, with a record 76.5 billion cubic feet of output reported in the 2004 second quarter.

The company's total production in the recent quarter of 86.5 billion cubic feet equivalent was 88 percent weighted to gas and represented a 29 percent increase compared to the same period last year and a 10 percent increase from the previous quarter.

The company projected in a July 26 conference call with industry analysts that it expects additional 5 percent increases in production in this year's third and fourth quarters.

Chesapeake's latest transactions provide the company with additional estimated proved reserves of 310 billion cubic feet of natural gas equivalent, estimated probable and possible reserves of 453 billion cubic feet of equivalent, 50,000 acres of leasehold, and extra daily production of 60 million cubic feet of equivalent.

The proved reserves are 92 percent gas, 97 percent company-operated, 35 percent proved developed and have current lease operating expenses of just 29 cents per thousand cubic feet of equivalent, about 60 percent below the industry average.

"These very low lease operating expenses create unusually high economic values … and add to the attractiveness of Chesapeake's all-in acquisition cost of $1.68 per thousand cubic feet of equivalent," the company said.

The deals specifically involve the acquisition of Tulsa-based Bravo Natural and substantially all the assets of Houston-based Legend Natural Gas and Oklahoma City-based Tilford Pinson Exploration, Chesapeake said.

Bravo's assets consist of 20,000 acres located in the Granite Wash- producing Stiles Ranch and Allison Britt fields of the Anadarko Basin in Wheeler and Hemphill counties, Texas, and Roger Mills County, Okla. The Granite Wash, together with the deeper Cherokee/Atoka Washes, to date has produced more than 1.2 trillion cubic feet of gas equivalent from 10 major fields in the Anadarko Basin. The transaction is expected to close on August 2.

Legend's producing assets and 18,000 net acres of leasehold are located in the Roleta, Haynes, Comitas and En Seguido fields in the Zapata County portion of South Texas. The majority of Legend's assets are located three to seven miles south and east of the Zapata County assets Chesapeake acquired in October 2003 from Laredo Energy. The transaction is expected to close on August 31.

Tilford Pinson's producing assets and 12,000 net acres of leasehold are located primarily in the Arkoma Basin fields of Northwest Scipio, Northwest Reams and South Pine Hollow in Pittsburg County, Oklahoma. The deal already has been closed.

Chesapeake said it intends to finance the $590 million of new acquisitions using a 50-50 combination of senior notes and common stock issuance.

Chesapeake's average daily production rate for the 2004 second quarter was 951 million cubic feet of natural gas equivalent production, consisting of 841 million cubic feet of gas and 18,385 barrels of oil and natural gas liquids. It was Chesapeake's 12th consecutive quarter of production growth.

During the 2004 second quarter, Chesapeake generated net income of $85.8 million or 31 cents per share on revenue of $574.3 million, up from net income of $76.3 million or 31 cents per share on revenue of $429.6 million in the second quarter of 2003.

When excluding a $7.1 million loss from the company's hedging program, Chesapeake's net income in the 2004 second quarter would have been $92.9 million or 33 cents per share, the company said. ●

natural gas

CANADA

By end of May Canadian gas output was up 2.1 percent

Marketable natural gas production across Canada grew by 2.1 percent in the first five months of 2004, thanks to higher output in British Columbia and Saskatchewan, according to Statistics Canada, a government agency.

The volumes rose to 2.58 trillion cubic feet from 2.52 Tcf a year earlier, with British Columbia posting a 7 percent gain to 428 billion cubic feet and Saskatchewan climbing to 106 billion cubic feet from 101 billion in the first five months of 2003.

Alberta edged up only marginally to 1.96 Tcf from 19.5 Tcf, while Nova Scotia and northern Canada were both down.

The struggles in Nova Scotia were compounded July 22 when Shell Canada, a 31.3 percent owner of the Sable offshore field, reported that its second-quarter share of production slumped to 129 billion cubic feet from 142 billion.

At that rate production for 2004 would average about 412 million cubic feet per day for export to the U.S. Northeast, far from the short-lived peak of 550 million cubic feet per day and at the lower end of a forecast 400 to 500 million cubic feet per day for the year.

That is despite the introduction late last year of the Alma field, which has a targeted 120 million cubic feet per day. South Venture, with projected recoverable reserves of 300 billion cubic feet, is due on stream later this year.

Shell has led the way in dramatically slashing its estimates of Sable reserves, effectively lowering the total for the field, which started producing in 1999, to 1.35 trillion cubic feet from an initial 3.6 Tcf, and shrinking the projected lifespan by 10 years to 2014.

—GARY PARK

CALGARY, ALBERTA

Husky, Trident team up in coalbed methane deal

Husky Energy is seeking a role in the front ranks of companies developing coalbed methane in Alberta by signing a farmout and joint venture agreement with privately-owned Trident Exploration.

Husky is the first of Canada's five integrated oil companies to enter what president and CEO John Lau described as an "emerging energy sector in Western Canada."

The deal, announced July 27, extends an original 2002 venture between the two companies for exploration and development of coalbed methane in the Fenn Rumsey area of central Alberta.

It calls for 120 wells to be drilled over the next two years, with Husky paying 30 percent of an expected C$40 million for drilling and associated facilities to gain a 50 percent stake in production.

Husky and Trident say they have successfully completed 50 wells, of which 32 have been tied in and are producing 6 million cubic feet per day of natural gas.

Husky believes its lands in the Fenn Rumsey area have 500 billion cubic feet of gross natural gas resource in place.

see TEAM page 13

● ALASKA

Anadarko, BP offer conflicting gasline views

Explorer Anadarko is concerned about tariff rates, access to pipe; producer, likely gasline owner BP is worried about cost overruns, market prices

By KRISTEN NELSON

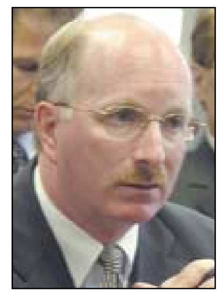
Petroleum News Editor-in-Chief

Parties can have different views on tariff issues, Alaska Division of Oil and Gas Director Mark Myers told members of the Alaska Legislature in mid-June. One of those differences is between companies with known gas reserves and those still exploring, legislators were told at a hearing held June 16-17 in Anchorage, the first of three planned by the Legislative Budget and Audit Committee and the Senate Resources Committee.

1 2 SERIES

Anadarko and BP represented companies with such different views.

Mark Hanley, Alaska public affairs manager for Anadarko Petroleum Co., said he wanted to give legislators some perspective from the viewpoint of a company which is still exploring and doesn't yet have any gas to put into a pipeline.



Mark Hanley, public affairs manager for Anadarko Petroleum Alaska

Depending on whether you are a producer, a pipeline owner, or a producer who is also a pipeline owner, you may want different things from a tariff, he said. The rules of the game for gas pipeline tariffs "are very fluid, there's a lot of ability to change those rules. And in fact, because of that we're going to sit back and watch," Hanley said.

Explorers want a gas pipeline, he said, but they are

see VIEWS page 13

● B.C. / MONTANA

Cross-border CBM feud builds

Montana governor warns B.C. premier she may ask Canadian government to intervene; Neufeld suggests dispute tied to gubernatorial election

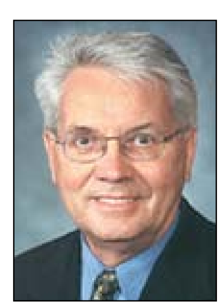
By GARY PARK

Petroleum News Calgary Correspondent

The cross-border tensions between British Columbia and Montana over coalbed methane development are moving to the highest levels, with Montana Gov. Judy Martz on the verge of asking the Canadian government to intervene.

Trouble started brewing last year when British Columbia put up for auction the drilling rights on two large chunks of land in the province's southeast corner between Fernie and the Montana border. The successful bidders will be unveiled Aug. 25.

Because of the volume of water that is pumped in association with coalbed methane production, Montana fears the waste water would eventually flow into the Flathead River Basin alongside the western boundary of Glacier National Park.



B. C. Energy and Mines Minister Richard Neufeld

The northern Flathead is designated a "wild and scenic river" that supports the largest population of grizzly bears in North America, outside of coastal regions.

Because of the tight timeframe to evaluate potential impacts of coalbed methane development, Martz said in a letter to B.C. Premier Gordon Campbell that she is "exploring the possibility of asking the Canadian government to conduct an environmental assessment ... prior to the sale of these leases."

B. C. Energy and Mines Minister Richard Neufeld, observing that Montana has 350 produc-

see FEUD page 12

● WEST COOK INLET

Aurora puts west Cook Inlet gas field online

Pleased with Kaloa well results, Moquawkie goes online, Texaco Long Lake No. 1 well next

By KAY CASHMAN

Petroleum News Publisher & Managing Editor

Aurora Gas LLC, a niche player in Alaska's Cook Inlet basin, said July 27 it is pleased with the results of its Kaloa No. 2 well and expects to put the Kaloa gas field online early in the fourth quarter. The company also said natural gas production has begun at its Moquawkie field.

Both fields are onshore on the west side of Cook Inlet.

Aurora said it "perforated and tested four separate intervals at a combined flow rate of approximately 10 million cubic feet per day" at the Kaloa well. The well, expected to produce at a rate of 5 million cubic feet per day for the first year before it sees any decline, is expected to come online "early in the fourth quarter," Aurora President G. Scott Pfoff told Petroleum News July 28.

He said the Moquawkie No. 1 well has a flow rate of 5 million cubic feet per day without compression.

Like Aurora's other two producing onshore Cook Inlet fields — Nicolai Creek and Lone Creek — Kaloa and Moquawkie contain natural gas deposits that were discovered in the search for oil in Cook Inlet that began in the 1950s.

Kaloa No. 2 was a re-drill of Kaloa No.1, an oil well drilled in 1967 by Pan American.

The Kaloa No. 1 "tested gas, and was put on production briefly; however, the operator shut it in almost immediately as a result of sand-up problems," Pfoff said. "However, we now have methods for controlling sand production and the demand for natural gas in Cook Inlet is high, making the development of smaller fields an economically attractive endeavor for Aurora."

At Moquawkie Aurora reestablished production by re-entering and re-completing the Mobil Moquawkie No. 1 well late last year.

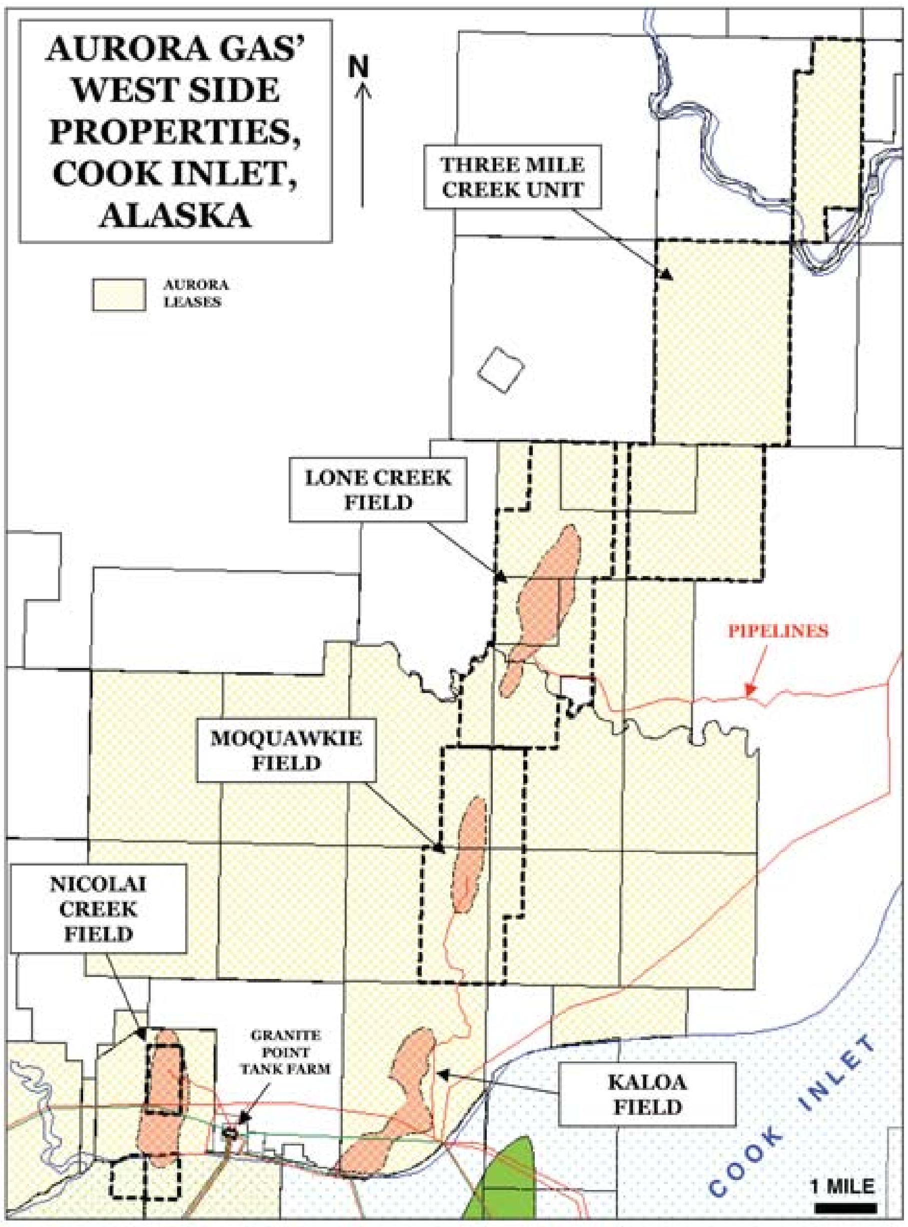
Ed Jones, Aurora Gas vice president of operations, told Petroleum News in a previous interview that there are more old wells in the Moquawkie area, some of which the company might re-enter "at some point."

Aurora is "built on the belief that tremendous amounts of economically recoverable shallow gas reserves exist on Cook Inlet's west side, much of which has already been discovered but is in need of development," Pfoff said in a previous interview.

When companies were exploring Cook Inlet for oil in the 1950s and 1960s, they found a lot of gas, "sometimes they knew it and they tested it, sometimes they didn't, they just blew right through it with heavy mud that invaded the zones," he said.

Aurora focuses on what is known, Pfoff said: "Our whole niche is to use those logs and the geology and the well control and then some of the seismic that's been shot since, and put together a puzzle to go back in and find low-risk opportunities to develop natural gas."

see **AURORA** *page 14*



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FEUD

ing coalbed methane wells, said his province has only a handful of wells that he characterized as experimental.

He suggested Martz is more concerned about the looming gubernatorial election than environmental concerns.

B.C. delegation blindsided

Neufeld said a delegation of B.C. coalbed methane regulators recently met with Montana officials "so they would be comfortable with how we were handling" the project.

Instead of a low-level information meeting, the delegation was confronted with a packed meeting.

"I think our folks got blindsided a bit because Montana let everyone in the country know who was coming," Neufeld said.

Steve Thompson, glacier program manager for the National Parks Conservation Association and a director of the Flathead Coalition, formed in the 1970s to challenge a coal mine on the B.C. side of the border, told the Vancouver Sun that before coalbed methane licenses are sold "we want a consultative process to look at all the potential impacts – air, water, wildlife and also some socioeconomic impacts."

He said British Columbia lacks data about water quality and flows in many of the feeder streams that would carry water from coalbed methane production.

But Neufeld countered that B.C. regulations are as stringent as Montana's, limiting the volume of water that can be discharged so it won't threaten fish habitat.

Pierre Alvarez, president of the Canadian Association of Petroleum Producers, said that some of the negative side-effects of coalbed methane development in the United States could not happen in Canada "because of the regulatory environment here."

Side-effects couldn't happen in Canada

Pierre Alvarez, president of the Canadian Association of Petroleum Producers, said that some of the negative side-effects of coalbed methane development in the United States could not happen in Canada "because of the regulatory environment here."

He said Canadian regulators have a better understanding of coalbed methane impacts based on what has happened over 15 years in the United States. ●

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VIEWS

in no position to build a line themselves, because they have no reserves. Neither are they in a position to invest the billions of dollars to explore for and develop gas reserves, "thinking it might get built."

Explorers need the lowest tariff possible, he said, but "the terms and conditions of the tariff" also "can affect whether people invest." The explorers face the exploration risk: "typically in an exploration company your biggest risk is in the geologic side, the underground side. Are you going to find the gas? Is it going to be in quantities, flowing enough and large enough size and close enough to infrastructure to make a commercial gas find?"

Bill Benham, vice president of regulatory affairs for BP Energy Co., BP's North America gas and power marketing and trading business

But, he said, "the biggest risk in Alaska right now is the aboveground risk, the commercial risk, the risk of the cost of tariffs being too high."

The producers, he said, face the risk of cost overruns on the pipeline, the risk of legal challenges and the market price risk.

"We face all those same kinds of issues: we also have the exploration risk," Hanley said.

Volumes must be nominated

Because gas pipelines are contract carriers, companies with gas to ship contract for specific amounts of space in the pipeline on a ship-or-pay basis. The explorers, who are yet to make discoveries, won't know for a number of years out how much gas they have, so won't be able to participate in the open season when nominations are made for space on the initial pipeline. That makes expansion terms critical for exploration companies, Hanley said.

Pipelines can be designed so that expansion is inexpensive or expensive, he said. With inexpensive expansion, the cost of expansion could be rolled into original rates, and could end up reducing rates for everyone.

But if the pipeline is not designed for inexpensive expansion, it could create a situation where there is only one way to get gas to market and that one way is controlled by those with original capacity, precluding new entrants.

The explorers, he said, will be focused on line expansion, and on tariff terms as well as on tariff rates.

The initial pipeline owners, for example, "can say we're taking the risk, we're doing this, so we have the right of first refusal on all expansion capacity."

Hanley also said that while producers should be aligned with explorers in wanting a low tariff and a high netback, "if you have a producer-owned pipe and they're aligned, there may be some incentive to shift … profits to the pipeline."

Well-established procedures

Bill Benham, vice president for regulatory affairs for BP Energy Co., BP's North America gas and power marketing and trading business, told legislators by phone from Houston that the process for developing and getting regulatory approval for both pipeline tariff rates and other elements of the tariff is "very well established in both the U.S. and Canada." The tariff rates, he said, reflect the cost of constructing and operating the pipeline.

"There is always going to be some concern about having underestimated capital and operating costs in relation to the rate that ends up being established," he said, "the concern being then that the resulting rate would not adequately recover those costs." That is "a key, key risk factor for the pipeline," he said.

On the shippers side, he said, concerns will be that the shippers may overpay for capacity because of "a loss of the market, a loss of supply or the supply source — in effect the situation where your capacity commitment does not match the actual throughput" for which you contracted. And if a shipper fails to reach a negotiated rate with the pipeline, the shipper may file with the FERC and get an increase in rates.

Sen. Scott Ogan, R-Palmer, asked Benham about open season disadvantages for explorers, and Benham said this is a situation they see in the Lower 48. Pipelines are generally looking to add throughput, he said, and it's to the benefit of the pipeline to add facilities to get more gas to market, and such expansion can be achieved in various ways.

A shipper coming in after an open season can also go to existing shippers and contract for unutilized capacity, either firm or interruptible, although he acknowledged that interruptible capacity is "probably not something that's very attractive to Alaska shippers."

What if line is full for years

Ogan asked about a situation where "producers could fill the line already for a number of years and potentially shut out others," while the state of Alaska has an interest in seeing new production brought online.

Benham said that typically pipelines are sized in anticipation of the resource capability of an area, and Dave MacDowell, BP Exploration (Alaska)'s gas project spokesman, said the producers' (BP, ConocoPhillips, ExxonMobil) proposal of a 52-inch diameter line was designed to be expandable, with production beginning at 4.5 billion cubic feet a day, and expandable to 5.5 bcf a day with compression. Expansion is in everyone's interest, he said, because "more volumes mean lower unit costs."

As for who would pay for an expansion, Benham told Ogan that FERC has "rules and regulations around this," but generally if the expansion is less than 5 percent of the original cost, then that would be rolled into the original rates. If the expansion cost is more than 5 percent, FERC looks at who benefits from the expansion, the whole system or just new users. If only new users benefit, then FERC may apply incremental pricing, which would put the expansion cost on "the new shippers, who are putting the new demand on the system." ●

continued from page 11

TEAM

Under the new arrangement, the companies will pursue prospects in east central Alberta from the coal seams of the Horseshoe Canyon formation, which the Alberta Geological Survey estimates holds upwards of 70 trillion cubic feet of gas resource.

Average well production rates of 120,000-180,000 cubic feet per day are projected for the joint venture land.

Trident, one of the most active coalbed methane exploration and production companies in Western Canada, has drilled 192 wells, including 94 in the Horseshoe formation and 72 in the Mannville formation.

—GARY PARK

CALIFORNIA

Startup Fidelis has a producing well

Fidelis Energy Inc. has announced its first successful well and plans several more to exploit a natural gas reservoir between Sacramento and Stockton, Calif.

The Archer-Whitney No. 1 well is initially expected to produce about 5 million cubic feet daily, after an open test produced gas at a rate of 12 million cubic feet a day. Drilling is expected to start on a second well in September, and as many as five production wells are expected.

Operator for the North Franklin project is Archer Longbow. Silver Star Energy has a 40 percent interest.

Fidelis, which began operations in November of 2000, holds a 35 percent interest after getting involved in the project in mid-April with a $250,000 investment. Three weeks later, Fidelis added $500,000 more to boost the company's interest in the property to the 35 percent.

Contracts have already been signed with a pipeline company and a gas purchaser, and a Fidelis spokesman says the company could have three producing wells by the end of the year.

The North Franklin project is in the Sacramento Basin along the productive "Eastside Winters stratigraphic trend." The gas reservoir at North Franklin is the Winters formation.

Fidelis, based in Tucson, Ariz., also has interests in Alberta and in Kern County, Calif., but no other producers at this point.

—ALLEN BAKER

NOVA SCOTIA

New Brunswick gas hopes boosted

Backed by a glowing evaluation, Corridor Resources, a Halifax-based junior E&P, wants to step up the pace of natural gas development in New Brunswick.

Consulting firms APA Petroleum Engineering and Petrel Robertson Consulting have estimated Corridor's McCully field may hold more than 200 billion cubic feet of gas, with a commercial potential of C$240 million.

If a 40-mile pipeline link is built to the Maritimes & Northeast system in 2006, the consultants believes 120 billion cubic feet (proved and probable reserves) and 164 billion cubic feet (proved, probable and possible reserves) could be recovered from "current and future wells drilled in the evaluation area."

To date, Corridor has pumped 800 million cubic feet from the field for use at a nearby potash mine owned by Potash Corporation of Saskatchewan, which owns half the McCully field. Corridor's net share of any gas sales from McCully would be 78 billion cubic feet from proved and probable reserves and 107 billion from proved, probable and possible – enough to prompt Corridor president Norm Miller to plan five more wells this fall at the field.

He suggested the field could be even larger if gas is found in several unexplored sections. Corridor believes it has cost data to make an "extremely attractive" case for exporting gas from New Brunswick.

But the consultants have cautioned that given McCully's production performance, when the reservoir has shown a tendency to fill with groundwater as the gas is removed, there is a "key technical uncertainty" to full-scale development.

—GARY PARK

ALBERTA

Deer Creek ready for initial offering

Deer Creek Energy is stepping up the pace of the planned expansion of its Joslyn project in northeastern Alberta.

In late July the oil sands startup announced approval from securities regulators across Canada for its initial public offering on the Toronto Stock Exchange of C$160.55 million and a commitment agreement for a C$65 million credit facility with two Canadian chartered banks.

This comes on the heels of a May approval from the Alberta Energy and Utilities Board for a second-phase expansion at Joslyn from 2,000 barrels per day to 12,000 bpd by mid to late 2007.Deer Creek said the operational plans for phase two are firmly on track as part of a multi-phase development of a lease with in-place reserves of 7.5 billion barrels and a production potential rated at 160,000 bpd.

Three projects, with potential reserves of 1.8 billion barrels, are under active consideration – two steam-assisted gravity drainage projects of 30,000 bpd each and one mining project of 100,000 bpd.

In April, Deer Creek reported the start of its steam-assisted gravity drainage operations after completing a 195-well program on schedule and under budget.

—GARY PARK

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AURORA

One more well for Kaloa, $3 per mcf

Aurora said Kaloa No. 2, drilled 60 feet from Kaloa No. 1 and producing from the Carya formation, was drilled to a total depth of about 3,700 feet and encountered 150 feet of net pay at depths between 3,158 and 3,552 feet.

"Aurora will install compression, dehydration and a short gathering line. Kaloa will utilize the existing interconnection with Beluga Pipe Line. The gathering line will be 4 inch pipe and be approximately one-half mile long," Pfoff said.

When asked about the reserves at Kaloa, he said the company would have a much better idea of the reserves after the field has come online. "I can tell you that we ran our economics assuming a minimum of 10 billion cubic feet recoverable."

Aurora plans to market the gas to Enstar Natural Gas Co. "pursuant to an existing contractual arrangement … at approximately $3 per mcf (thousand cubic feet) … and sell volumes above its Enstar commitment to other customers in south-central Alaska," Pfoff said.

Based upon Aurora's "current mapping of the reservoir, it appears at least one more well should be drilled at Kaloa," he said.

Pleased with progess on west side

Aurora previously announced that Moquawkie No. 1 had tested 7.6 million cubic feet per day, but said on July 27 that it expected it to produce at 5 million cubic feet per day. The company has been working on installation of production facilities, a 4.4 mile pipeline and an interconnection with the Marathon owned and operated Beluga Pipe Line. The Moquawkie No. 1 is currently the only well online in the field; however, Pfoff said Auroria will soon test the Simpco Moquawkie well and depending on the results, may have it on stream by the fourth quarter." He said Aurora is assessing the reserve situation at Moquawkie.

"We are extremely pleased with our progress on the west side," said Jones. "Our first few wells have had to justify and carry the economic burden of facilities, gathering lines and interconnections. Future wells will be much easier and less expensive to add to the system."

Texaco well next, encouraged by Three Mile seismic

The company is now in the process of mobilizing the Aurora Well Service Rig No. 1 to an exploratory re-entry of the Texaco Long Lake No. 1 well, which Texaco "drilled in 1973 looking for oil, but plugged and abandoned as a dry hole, therefore, it is not in a designated field," Pfoff said.

On the west side of Cook Inlet, the well is on a lease Aurora acquired in the 2002 lease sale held by the Mental Health Trust.

When asked about plans for drilling in the newly formed Three Mile Creek unit, Aurora Pfoff said he was "very encouraged by the seismic we shot over Three Mile Creek this past winter" and that Aurora is "working closely with our partner, Forest Oil, to determine if and when a well should be drilled." ●

● HOUSTON, TEXAS

Newfield scores large natural gas discovery

At 50-60 bcf it ranks among Newfield's largest finds in Gulf of Mexico's deeper zones

By RAY TYSON

Petroleum News Houston Correspondent

Newfield Exploration says it has found natural gas that appears to meet pre-drill reserve estimates of 50-60 billion cubic feet, ranking it among the largest discoveries Newfield has made this far in deeper zones of the Gulf of Mexico's continental shelf.

The West Cameron 77 No.1 well encountered about 120 feet of net gas pay in two zones between 16,800 and 17,600 feet, the company said July 26, adding that well was then deepened to 19,603 feet and encountered an additional zone that appears to have possible pay over a large gross interval.

Steve Campbell, Newfield's head of investor relations, said the deeper zone would be tested over the next few weeks and that any reserves would be in addition to the pre-drill estimates. "It was a surprise to find it," he said.

Newfield's deep-shelf gas discoveries have averaged about 40 billion cubic feet each.

He said Newfield is evaluating development plans for the discovery and expects first production from the field in early 2005. Depending on the depths of the pay sections completed in this well bore, the field would qualify for 15-25 billion cubic feet of royalty relief under rules established by the U.S. Minerals Management Service.

Steve Campbell, Newfield's head of investor relations, said the deeper zone would be tested over the next few weeks and that any reserves would be in addition to the pre-drill estimates. "It was a surprise to find it," he said.

The West Cameron 77 discovery is located about 10 miles offshore Louisiana in about 40 feet of water. Newfield has now drilled 12 successful deep shelf exploration wells out of 19 attempts to date. The Company expects to spud additional deep shelf tests in the remainder of 2004.

Newfield operates the West Cameron 77 discovery with a 45 percent working interest in a joint development area covering portions of West Cameron 77 and West Cameron 96. After payout, Newfield's interest, subject to a 25 percent back in by Seneca Resources would be 33.75 percent. The remaining interest is owned 30.95 percent by Australia's BHP Billiton, 13.75 percent by Houston Exploration and 10.3 percent by Ridgewood Energy. ●

NORTH AMERICA

Rig count jumps by 144 to 1,596, Canada accounts for 96 percent of the increase

The number of rotary drilling rigs operating in North America during the week ending July 23 jumped to 1,596, up 144 from the previous week and up 81 compared to the same period last year, according to rig monitor Baker Hughes.

Canada accounted for 96 percent of the increase, soaring by 138 rigs to 380 versus the previous week but still down by 44 rigs compared to the same weekly period a year ago. The number of rigs operating in the United States during the recent week increased by five to 1,216 compared to the prior week and was up by 125 rigs compared to the year-ago period. Compared to the prior week, land rigs alone increased by three to 1,097, while offshore rigs increased by two to 99. Inland waters rigs were unchanged at 20.

Of the total number of rigs operating in the United States during the recent week, 1,047 were drilling for natural gas and 168 for oil, while one was being used for miscellaneous purposes. Of the total, 757 were vertical wells, 333 directional wells, and 126 horizontal wells.

Among the leading producing states in the United States, Oklahoma saw the largest increase in rigs during the recent week, jumping by nine to 178. Texas gained six rigs for a total of 508. Louisiana picked up two rigs for a total of 168. And New Mexico gained one rig for a total of 66. Wyoming's rig count fell by three to 80, while California's dropped by two to 25. Alaska lost one rig for a total of 10.

—RAY TYSON

ALBERTA

Shell adds to oil sands portfolio

Shell Canada's growing belief in the future of Alberta's oil sands was reflected in its recent decision to buy two leases from EnCana. Terms were not disclosed.

The leases are about 12 miles northwest of the Muskeg River mine, the core of the Athabasca project operated by Shell. Lease 9 holds an estimated 1 billion barrels of recoverable bitumen, enough to support a mine producing up to 100,000 barrels per day. Until more drilling is done, it is not known if Lease 17 has enough potential to make a mining project feasible.

Neil Carmata, Shell Canada's senior vice-president of oil sands, said the "high quality resource fits well with our long-term plans to grow our Athabasca sands business." Athabasca, a joint venture by Shell 60 percent, Chevron Canada 20 percent and Western Oil Sands 20 percent, come on stream at the start of 2004 and is moving progressively to its peak output of 155,000 bpd.

New drilling on property adjacent to the Muskeg River mine allowed Shell to boost its proven reserves by 8.5 percent to 651 million barrels.

The company has also received approval from a federal-provincial review panel to move ahead with a second mine at Athabasca.

The C$2 billion Jackpine Mine will not be in operation until 2010, but is aiming for 200,000 bpd.

—GARY PARK

continued from page 1

GASLINE

"appear to be on track" to file the main regulatory applications for field development, gathering systems and the main pipeline later this summer, as planned.

Without being drawn into commenting on Kvisle's reference to the "glacial" pace of regulatory progress, Searle said meetings will be held at some point with ministers in the new federal cabinet who are directly involved in Mackenzie issues, such as newly-appointed Indian Affairs and Northern Development Minister Andy Scott and reappointed Natural Resources Minister John Efford.

However, Searle said the decisions on land claims and rights-of-way are between the federal government and the First Nations.

"Most definitely, we would like to see the negotiations come to fruition," he said. "Would we like to see greater progress? Yes, I think we would."

Aboriginal land claims still not resolved

If all goes well, TransCanada can build a pipeline down the Mackenzie Valley within 18 months of receiving a regulatory green light, but the "big question is how long it will take to get that green light," Kvisle said.

He noted that although the proponents believe it will take only two years to complete the regulatory phase, assuming applications are filed this year, it has taken "several years just trying to get into the regulatory process."

In addition to negotiating the maze of boards and agencies in the Northwest Territories, the Mackenzie partners are also waiting for the Canadian government to resolve aboriginal land claims and right-of-way issues, Kvisle said.

He said the Inuvialuit and Gwich'in in the northern NWT communities continue to support the C$5 billion project, but right-of-way access is unresolved with the Sahtu in the central Mackenzie Valley and there is no sign of a breakthrough in the land claim negotiations with the Deh Cho, who occupy the lower third of the pipeline route.

Kvisle said it is possible the Mackenzie partners might seek a different timetable on building the pipeline and settling the land claim, but added "that's a big if."

The Deh Cho First Nation reiterated a month ago that it will launch a court action blocking the pipeline unless it gets a seat on the environmental review panel.

Deh Cho Grand Chief Herb Norwegian said his 4,500 residents need environmental guarantees because there is no land claim to protect their interests.

Vacuum at the federal policy level

Kvisle said the stumbling block in dealing with the aboriginals is a "vacuum at the federal policy level. We can do nothing, other than encourage the federal government to treat the problem seriously."

In pointing a finger at the government, he said it is easier for TransCanada to build a pipeline across private land in Ontario than across federal lands in the Arctic.

Until the First Nations matters are clarified "the project is not going ahead," he said.Meanwhile, Imperial Oil, Shell Canada, ConocoPhillips Canada and ExxonMobil Canada, owners of the anchor gas fields on the Delta, are "doing everything possible" to meet their timetable.

Kvisle, referring to community opposition that scuttled TransCanada's hopes of partnering in an LNG project in Maine, said the "glacial pace" of approvals will only have repercussions on the marketplace.

"It is going to take longer rather than shorter (to get approvals) and commodity prices will be higher rather than lower for the foreseeable future," he said. ●

Alaska maybe, Canada nothing doing

TransCanada is open to conveying its rights to carry natural gas from North Slope producers across Alaska, but when it comes to those same rights in Canada – forget it.

That was the message July 23 from the Canadian pipeline company's CEO Hal Kvisle, who said "I think it is," when asked by one analyst if the Alaska Highway project is a competitive process.

Noting that TransCanada is the only company to hold certificates to build a pipeline in both Alaska and Canada, he questioned whether rivals who "show up from time to time" in Alaska have the technical ability or "financial horsepower" to actually take over the project.

Over the past two months, since renewing discussions with the Alaska government, TransCanada is moving ahead with processing its application for a pipeline right-of-way across state lands.

Given that any decision in Alaska requires the support and involvement of North Slope producers, Kvisle said TransCanada "would be pleased to convey" the certificates it was granted 25 years ago to the producers so long as an appropriate commercial agreement could be negotiated.

But he said that TransCanada, through its wholly-owned subsidiary Foothills Pipe Lines, has "spent significant dollars" on the so-called pre-build legs in Alberta, British Columbia and Saskatchewan.

The pre-build portions from central Alberta to the western and eastern U.S. and designed for eventual tie in with the Alaska Highway pipeline, cost a combined C$1.5 billion in the 1980s and deliver 3.3 billion cubic feet per day of gas from Western Canada.

—GARY PARK

continued from page 1

AGRIUM

reserves in specified Cook Inlet fields.

A third, independent party was tasked with assessing the gas reserves in those fields and adjusting them annually. If reserves fell, then the amount of gas that Unocal had to supply dropped.

According to a July 2002 interview with Unocal spokeswoman Roxanne Sinz, adjustments had been negative, so Unocal thought it should be able to cut its supply of gas but Agrium has not wanted it to do so because gas prices had increased and Agrium would be forced to buy gas at higher prices from other suppliers. At that time Unocal was receiving $2.75 per mcf for gas sales to Enstar, subject to adjustment depending on Henry Hub prices and inflation. As of June of this year, Unocal is receiving as much as $4.74 per mcf from fields not dedicated to Agrium under the two companies' 2000 gas purchase and sale agreement.

The panel agreed with Unocal on the major point of contention between the two firms when it determined that the gas purchase and sale agreement was a reserves-based contract limited to specified reserves that were specifically dedicated to Agrium in the 2000 agreement.

The $36.5 million damage assessment was levied because Unocal's full production from the dedicated properties did not meet the schedule of deliveries as interpreted by the arbitration panel.

The panel set Unocal's annual supply obligation for the contract years ending June 30, 2005, June 30, 2006, and June 30, 2007, at 48.7 billion cubic feet, 36.3 bcf and 18.6 bcf, respectively.

"Either party to the contract may request a reserve certification annually which could increase or decrease delivery obligations after June 30, 2005," Agrium said.

Although the gas purchase and sale agreement runs through June 30, 2009, Agrium said the forecast for gas supplies from the dedicated properties shows a "decline to a nominal amount" after June 30, 2007. And since the arbitration panel decided Agrium could only expect to receive gas from those properties specified in the original agreement, the fertilizer facility will not be able to count on Unocal for low-cost gas after that time.

The agreement sets a cap of $50 million on liquidated damages for the life of the contract, but Agrium said the panel "specifically reserved for further determination whether Unocal's liability for damages is limited to $50 million should Unocal fail to deliver the specified contract quantities after June 30, 2005."

Unocal said it believes the cap will be enforceable.

Additional litigation related to the asset purchase and sale agreement is pending in California Superior Court in Los Angeles County. Unocal said trial on those issues is expected to begin late this year.

—KAY CASHMAN

Companies involved in North America's oil and gas industry

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Business Spotlight

By **PAULA EASLEY**

FORREST CRANE

Bill Richards, inside sales representative

U. S. Bearings and Drives

U.S. Bearings and Drives, formerly BESCO, has excelled in supplying hard-to-find power transmission products to a diverse customer base – from the aggregate field, to the oil industry, to the fishing fleet. It has operated in Alaska since 1952, and continues to offer quality components through its highly qualified personnel.

Bill Richards joined the firm a year ago following 15 years in the automotive aftermarket business. He says his Alaska customers are the most diverse and interesting he's ever encountered. Bill's summer leisure activities include lots of hiking and bike trips. In the fall he becomes a wildly enthusiastic Texas Longhorn fan and ardent supporter of local Alaska breweries. Bill, divorced, is father to Tyler, living in Texas, and Daisy, in Anchorage.

FORREST CRANE

Erwin L. Long, president

Arctic Foundations Inc.

Launched in 1972, Arctic Foundations manufactures passive, active and hybrid thermosyphons for ground freezing to stabilize permafrost foundations, for the formation of frozen barriers to confine hazardous waste; and to create impervious dams. It is also a pressure vessel code shop; products are metal sprayed and fusion coated.

Prior to becoming owner and president of Arctic Foundations, Erv Long was chief of the foundations and materials branch of the U.S. Army Corps of Engineers. He's a specialist in permafrost geotechnical engineering and is dedicated to enlarging the science of this engineering field. Erv and his wife Gloria have two sons, Norman and Stephen, and two daughters, Leslie and Allison. He moved to Alaska in 1947 and loves challenging outdoor activities.

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SIMMONS

willing to counter his specific charges.

Simmons knows whereof he speaks. He views the world oil supply picture from the vantage point of 30 years' experience as founder of Simmons & Company International, Houston, which today is one of the world's largest energy investment banking groups. Since opening the company's first office in Houston back in 1974, Simmons and his group have guided a broad client base to complete more than 500 oil and gas investment banking projects with a combined dollar value of some $58 billion. The company now has additional offices in Boston, London and Aberdeen, Scotland.

A few fields produce almost all Saudi oil

But all the investment capital in the world won't be much help if, as Simmons suspects, Saudi Arabia can no longer open the tap wider at its key oil fields as the world's "plug" producer in meeting steadily increasing world oil demand. Contrary to widespread opinion, the "gift" to the world of Saudi Arabia's oil, in Simmons' view at least, is not one that will keep on giving.

Despite recent comment by Saudi Aramco that it has discovered 85 oil fields in the country and has so far developed just 23 of them, Simmons says only a handful of fields account for virtually all Saudi Arabian oil production. The largest, Ghawar — the world's single largest oil field — has accounted for about 60 percent of all the oil the country ever produced, he said. Today, he added, Ghawar still produces about 5 million barrels per day of the current Saudi oil output of 7.5 to 8 million bpd. Five other fields produce the remainder, he said: Abqaiq, Safaniyah, Zuluf, Berri and Shaybah.

But all six of these fields, he noted, are more than 30 years old. Abqaiq was discovered in 1940, Ghawar in 1948, and Safaniyah in 1951. The last three were discovered in the mid-1960s.

There's no Act 2

Normally, Simmons said in a July 23 interview with Petroleum News, Saudi fields would be subject to the same decline curves as those experienced by any of the world's oil fields, once reservoir pressure begins to dwindle. The difference is, he said, Saudi Aramco doubled up to catch up, almost from the start, by keeping reservoir pressures — and individual well flow rates — as high as possible, seemingly for as long as possible.

In simple terms, says Simmons, the Saudis have produced their fields under simultaneous primary and secondary recovery, having instituted huge waterflooding programs relatively soon after completing field development.

"All of these fields are old," he pointed out, "but Saudi Aramco has managed them in a 'gold standard' fashion by instituting careful and rigorous water injection to maintain very high reservoir pressures. They're effectively sweeping the reservoirs until the easily recoverable oil is gone. In so doing, they have defied the standard decline curves. With water injection, they've maintained reservoir pressures above the bubble point. The trouble is, once they finally finish the sweep, they've done both primary and secondary depletion. There isn't any Act 2."

Apparently, detailed knowledge of this double dipping has not been common. Saudi production figures and field statistics have been regarded largely as state secrets since the 1980s. Nevertheless, said Simmons, most world oil supply studies assume that Saudi production is nearly inexhaustible and can be increased almost effortlessly by whatever world demand dictates.

No new giant oil fields in Saudi Arabia

But according to Simmons, enough data exists in the public domain today that, when combined and analyzed, reveals a much different picture.

During the past decade or so, he said, the lack of hard field data from most producing countries, particularly from OPEC member countries and even more particularly from Saudi Arabia, made it extremely difficult for his company to plan various energy investment scenarios for its clients.

So, Simmons instituted a 12-month study of technical presentations on Saudi Arabian oilfield activity made before various meetings around the world of the Society of Petroleum Engineers, beginning in 1961 and going through 2003. The study amassed more than 200 such tech papers, he said, delivered largely by oilfield service companies and dealing with highly technical aspects in all six of the Saudi giant fields.

"Each individual paper doesn't tell you a lot," he said. "But, by going through this incredible stack and then going back and isolating each by the specific field they dealt with, chronologically, you could see the history of what had been going on in Saudi Arabia during that time."

While the study revealed a "whole litany" of surprises, said Simmons, the most important one is that while the six Saudi Arabian giant fields have accounted for everything Saudi Arabia has produced so far, there is sufficient evidence to argue that once those fields are in decline, the Saudis won't have much else in the way of new oil from which to draw.

Saudi Aramco has explored the country thoroughly, Simmons said, and no new 'giant' fields have resulted.

"Meanwhile, Saudi Aramco's senior management are adamant that their existing oil fields are in great shape and can reliably produce as much as 15 million bpd for another 50 years," said Simmons. "They also insist that their proved reserves are actually conservative and there are still another 200 billion barrels of oil yet to be found in various unexplored pockets of Saudi Arabia." The world has only the company's word on this, said Simmons.

New technology won't do it

He added that Saudi Aramco senior managers also believe "with some passion" that the technological tools they are now employing would contain the rise of water in existing fields. Such tools, he noted, include horizontal and extended-reach wells and multi-lateral well completions, among others.

"My worry is that too many other oil companies around the world also believed these same tools would allow them to steadily grow their production from a reduced amount of wells drilled," he said. "Instead, it turned out that virtually every key oil producer using these same tools sadly ended up seeing their production growth peter out."

While the tools did extract more oil per well, he explained, they also accelerated the recovery of economical oil. In turn, this created decline rates never seen before in existing production.

Simmons has taken his study's findings and conclusions and currently is writing a book, which he plans to self-publish late this coming fall.

Calls for mandatory oil reserves transparency

But regardless of who's right or who's wrong, Simmons said, the solution to deter-

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ESTIMATE

such as Point Thomson and Prudhoe Bay.

"The largest accumulations we expect in the National Petroleum Reserve-Alaska are approximately the same size as the known gas reserves in the Point Thomson field. They are pretty substantial accumulations," Houseknecht said in his presentation at the legislative gas hearings in Anchorage on July 28.

"Every one of those four major gas plays in NPR-A extends across the Colville River into Native and state lands. They extend all the way eastward to the pipeline corridor.

"So even though we have not finalized our estimates for state and Native lands and I therefore cannot be specific, the geology on state and Native lands is essentially identical to that of the National Petroleum Reserve-Alaska and it would not surprise me if, in a few months from now, we are releasing numbers that are the same order of magnitude as our NPR-A estimates," he said. USGS estimates in NPR-A were 40.4 tcf to 85.3 tcf, with an average undiscovered, technically recoverable, gas resource of 61.4 tcf.

"The upside potential could be much greater," Houseknecht said.

According to a chart supplied by Mark Myers, director of the state Division of Oil and Gas, for his presentation at the gas hearings, with 150 tcf of gas reserves you could fill a gas pipeline delivering 5.6 billion cubic feet a day for 75 years.

Nonconventional gas not included

Houseknecht's gas resource estimates for northern Alaska do not include undiscovered nonconventional natural gas. He said there are "huge nonconventional gas resources" in northern Alaska, such as gas hydrates and coalbed methane and that "a significant proportion" of these resources are located under or within easy reach of existing North Slope infrastructure.

USGS is ignoring unconventional resources in their current estimates because their "recoverability potential has not been established," Houseknecht said.

He cautioned that USGS's gas resource estimates, although based on sound science, have not been confirmed by drilling. Proved gas reserves, however, are resources that have "been shown to exist in known reservoirs" and can be "expected to be produced."

Although USGS assessments are done independent of state governments, there is cooperation between the two in terms of sharing available geological and geophysical data, Myers said.

"Resource assessments are always ongoing. As you get more information, as you get more understanding. Traditionally, assessments on the North Slope focused on oil. Now we're seeing a more dedicated effort to look at gas resource potential," he said.

Does Myers think Houseknecht's gas resource estimates for northern Alaska are accurate?

"I think … its' highly probable the gas resources are there," he said.

How do northern Alaska's undiscovered gas reserves compare to the deepwater Gulf of Mexico, a major contender for oil and gas capex spending?

The U.S. Minerals Management Service estimates there is "as much as 55 tcf of undiscovered natural gas" in the deepwater frontier of the Gulf (water depths greater than 7,000 feet). ●

Editor's note: See part two if this story in the Aug. 8 edition of Petroleum News.

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mining whether Saudi fields can meet ever-climbing demand is a simple one: Adopt a far higher standard of petroleum data transparency and begin reporting timely field-by-field production statistics, supported by the average number of producing wells in each field, and have it verified by a reliable third party.

"I'd also like to see them update their estimates, by field, of original oil in place, by estimated ultimate recovery, and by cumulative production," he said. "Once you have those data, any analysts can determine in one day whether everything's fine in Saudi Arabia, or whether its 'Katy, bar the door! This field is just about to go into very steep decline."

He noted that a mandatory requirement for greater oil reserves transparency should be ordered on a global basis. However, so far only the Paris-based International Energy Agency currently is working to set up such a program. Though voluntary, the program at least calls for greater transparency from oil producing nations, he said.

Nevertheless, without such information and without it being handed over quickly, the world could be in for a huge surprise, said Simmons. In his opinion, great crises come out of ignoring great problems, and the sooner the world is aware of a problem, the sooner a solution — "Plan B" — can be reached. He said that with greater oil supply transparency, the current oil price probably would not gyrate the way it has in the past. "The increased knowledge of what's really going on in the energy business versus the perception of what we thought was going on will help people understand that we need to get used to high energy prices and that $40 per barrel oil is not dangerous," said Simmons.

What's dangerous, he said, is $40 per barrel oil being too cheap.

Difference can't be filled from elsewhere

But the outlook is still extremely grave, he said.

"If I'm correct about my concerns, Saudi Arabia is now producing more than they should to sustain their oil output," he deadpanned. "The harder you pull a field in its production, the faster you bring on the end of its reservoir pressure. So, I could argue that for the well-being of the world, Saudi Arabia probably ought to back off and start producing 3 to 4 million bpd so that their oil might last another 30 to 50 years. However, they may already have peaked in their ability to grow oil production, and if that's so, the world has peaked, as well."

Could the difference be made up from other world oil-producing areas? Again, Simmons is dubious. Not from West Africa, he said. Not from Russia, either. And currently, alternative fuels won't do it, either. Not natural gas, the available global supply statistics on which are even murkier than those for oil. Not hydrogen fuels, since they require a basic energy feedstock. Not even nuclear power, which he said would take decades to add, with scarcely a clue as to how much uranium remains throughout the world.

"There isn't any case you could make, by any stretch of the imagination, based on anything we know, that you could go elsewhere to make up the difference," said Simmons. "This could become the biggest energy issue the world has ever faced."

Among all the ramifications of a worldwide energy shortage, Simmons said, the geopolitical implications are perhaps the most severe, particularly since the United States imports 25 percent of Saudi Arabia's total oil exports, which average about 6 million bpd.

"I have oftentimes said that I would not want to be part of any energy delegation charged with the responsibility of having to tell the leaders of either India, or particularly of China, that their exciting emergence into prosperity is over because we have no spare energy to fuel their great dreams."

Meanwhile, Matt Simmons is waiting — and hoping — for someone to prove him wrong. ●

’Tis the season for forest fires — again

It’s fire season again in Alaska. As usual, the 800 mile trans-Alaska oil pipeline from Prudhoe Bay to the Valdez terminal is in the middle of more than one forest fire.

The pipeline, built to withstand much higher temperatures than those generated by a forest fire, has fared well again this year with only minor external damages, Mike Heatwole Petroleum News July 28.

Heatwole is corporate communications manager for Alyeska Pipeline Service Co. which was established in 1970 to design, build, operate and maintain the Trans-Alaska Pipeline System, commonly referred to as TAPS.

“We’ve had only minor external damage this year. As has happened in multiple years in the past, we’ll go back in after the fire season is done” to make further assessments and repair the damage. … We have a lot of people in the field and, as usual, are taking a lot of precautionary measures,” Heatwole said.

Alyeska does something called “brushing,” which means clearing brush and trees away from the pipeline so “there’s not a fuel source under the pipeline,” he said.

If a forest fire jumps the pipeline and is burning on both sides, the company will often go in and clear out more trees, he said.

“We work closely with the fire fighters, sometimes offering equipment, assistance,” Heatwole said.

Rhea DeBosh Rhea, information officer for the Joint Pipeline Office, told Petroleum News July 28 that it “takes an awful to get through all the material around the pipe.”

“When you look at the pipeline, you’re not really seeing pipe. … There is a protective coating on the outside and underneath that it is protected by a variety of different materials. … The pipe is very heat resistant, very strong. It would be extremely difficult to expose the pipe without some type of major catastrophe. The forest fires simply do not burn hot enough.”

—PETROLEUM NEWS