Week of Aug. 27, 2007/US$10.00

PennWell

OIL&GAS JOURNAL®

International Petroleum News and Technology / www.ogjonline.com

New Directions in Middle East Processing

Industry needs fresh approach to petroleum engineer training
Lampasas gets first commercial field in Fort Worth basin
Systems approach combines hybrid drilling cost functions
Net WAGP economic benefit requires Ghana development

OIL&GAS JOURNAL®

Aug. 27, 2007
Volume 105.32

New Directions in Middle East Processing

Middle East condensate production will complicate refining operations 48
Michael Corke, Narayanaswamy Ravivenkatesh

Identifying sources key to detailed troubleshooting of amine foaming 56
Mater A. Al-Dhafeeri

Regular Features

Newsletter 5
Letters 12
Calendar 12
Journally Speaking 17
Editorial 19
Area Drilling 38
Equipment/Software/Literature 74
Services/Suppliers 74
Statistics 76
Classifieds 80
Advertisers' Index 83
Editor's Perspective/Market Journal 84

Cover

Luberef II is the second of two lube oil plants operated by Saudi Aramco Lubricating Oil Refining Co. (Luberef), a joint venture of Saudi Aramco (70%) and ExxonMobil Corp. (30%). Standing next to Aramco's Yanbu refinery, the plant started up in 1999 with capacity to produce 2.1 million bbl/year; it boosted Luberef's total refining capacity to 4 million bbl/year. A special report on advances in Middle East processing begins on p. 48 with a Purvin & Gertz analysis of how the condensate market in the region is likely to develop and whether investments in processing are likely. Following this article is an account of efforts to reduce foaming in two Aramco amine sweetening plants. Photograph from Aramco.

OIL&GAS JOURNAL Previous Page | Contents | Zoom In | Zoom Out | Front Cover | Search Issue | Next Page qMags

General Interest

Editorial: Restating temperatures 19
COMMENT: Industry needs fresh approach to petroleum engineer training 20
D. Ronald Harrell
'Measured' approach needed for US fuels development, task force says 24
Nick Snow
WATCHING THE WORLD: Environmental impacts 26
Chinese NOCs double domestic upstream spending 28
MMS Lease Sale 204 attracts $290 million in apparent high bids 30
COMPANY NEWS: Transocean, GlobalSantaFe agree to merger of equals 30
PERSONNEL MOVES AND PROMOTIONS: ConocoPhillips announces management changes 32

Exploration & Development

Lampasas gets first commercial field with Strawn gas in Fort Worth basin 34
John Sobehrad, Ralph Dozier

Drilling & Production

ESTIMATING DRILLING COSTS–Conclusion: Systems approach combines hybrid drilling cost functions 39
Mark J. Kaiser, Allan G. Pulsipher

Processing

Special Report: Middle East condensate production will complicate refining operations 48
Michael Corke, Narayanaswamy Ravivenkatesh
Special Report: Identifying sources key to detailed troubleshooting of amine foaming 56
Mater A. Al-Dhafeeri

Transportation

Net WAGP economic benefit requires Ghana development 68
Joseph Essandoh-Yeddu, Felix Asante, Gürcan Gülen

Oil & Gas Journal (ISSN 0030-1388) is published 48 times per year by PennWell Corporation, 1421 S. Sheridan Rd., Tulsa, Okla., Box 1260, 74101. Periodicals postage paid at Tulsa, Okla., and at additional mailing offices. Oil & Gas Journal and OGJ are registered trademarks of PennWell Corporation. **POSTMASTER:** send address changes, letters about subscription service, or subscription orders to P.O. Box 3497, Northbrook, IL 60065, or telephone (800) 633-1656. Change of address notices should be sent promptly with old as well as new address and with ZIP code or postal zone. Allow 30 days for change of address. Oil & Gas Journal is available for electronic retrieval on Oil & Gas Journal Online (www.ogjonline.com) or the NEXIS® Service, Box 933, Dayton, Ohio 45401, (937) 865-6800. **SUBSCRIPTION RATES** in the US: 1 yr. $60, 2 yr. $85, 3 yr. $109; Latin America and Canada: 1 yr. $64, 2 yr. $100, 3 yr. $135; Russia and republics of the former USSR, 1 yr. 1,500 rubles; all other countries: 1 yr. $109, 2 yr. $175, 3 yr. $250, 1 yr. premium digital $59 worldwide. These rates apply only to individuals holding responsible positions in the petroleum industry. Single copies are $10 each except for 100th Anniversary issue which is $20. Publisher reserves the right to refuse non-qualified subscriptions. Oil & Gas Journal is available on the Internet at http://www.ogjonline.com. (Vol. 105, No. 32) Printed in the US. GST No. 126813153. Publications Mail Agreement Number 602914. Return Undeliverable Canadian Addresses to: P.O. Box 1632, Windsor, ON N9A 7C9.

PennWell, Houston office

1700 West Loop South, Suite 1000, Houston, TX 77027
Telephone 713.621.9720 / Fax 713.963.6285 / Web site www.ogjonline.com

Editor Bob Tippee, bobt@ogjonline.com
Chief Editor-Exploration G. Alan Petzet, alanp@ogjonline.com
Chief Technology Editor-LNG/Gas Processing Warren R. True, warrent@ogjonline.com
Production Editor Guntis Moritis, guntism@ogjonline.com
Drilling Editor Nina M. Rach, ninar@ogjonline.com
Refining/Petrochemical Editor David N. Nakamura, davidn@ogjonline.com
Pipeline Editor Christopher E. Smith, chriss@ogjonline.com
Senior Editor-Economics Marilyn Radler, marilynr@ogjonline.com
Senior Editor Steven Poruban, stevenp@ogjonline.com
Senior Associate Editor Judy R. Clark, judyrc@ogjonline.com
Senior Writer Sam Fletcher, samf@ogjonline.com
Senior Staff Writer Paula Dittrick, paulad@ogjonline.com
Survey Editor Leena Koottungal, lkoottungal@ogjonline.com
Associate Editor Angel White, angelw@pennwell.com
Editorial Assistant Linda Barzar, lbarzar@pennwell.com

Petroleum Group President Michael Silber, msilber@pennwell.com
Vice-President/Group Publisher Bill Wageneck, billw@pennwell.com
Vice-President/Custom Publishing Roy Markum, roym@pennwell.com

PennWell, Tulsa office

1421 S. Sheridan Rd., Tulsa, OK 74112
PO Box 1260, Tulsa, OK 74101
Telephone 918.835.3161 / Fax 918.832.9290
Presentation/Equipment Editor Jim Stilwell, jims@ogjonline.com
Associate Presentation Editor Michelle Gourd, michelleg@pennwell.com
Statistics Editor Laura Bell, laurab@ogjonline.com
Illustrators Alana Herron, Kermit Mulkins, Mike Reeder, Kay Wayne
Editorial Assistant Donna Barnett, donnab@ogjonline.com
Production Director Charlie Cole

London

Tel +44 (0)208.880.0800
International Editor Uchenna Izundu, uchennai@pennwell.com

Washington

Tel 703.963.7707
Washington Correspondent Nick Snow, nsnow@cox.net

Los Angeles

Tel 310.595.5657
Senior Correspondent Eric Watkins, hippalus@yahoo.com

OGJ News

Please submit press releases via e-mail to: news@ogjonline.com

Subscriber Service

P.O. Box 2002, Tulsa OK 74101
Tel 1.800.633.1656 / 918.831.9423 / Fax 918.831.9482
E-mail ogjsub@pennwell.com
Circulation Manager Tommie Grigg, tommieg@pennwell.com

PennWell Corporate Headquarters

1421 S. Sheridan Rd., Tulsa, OK 74112

P.C. Lauinger, 1900-1988
Chairman Frank T. Lauinger
President/Chief Executive Officer Robert F. Biolchini

Member Audit Bureau of Circulations & American Business Media

OGJ Newsletter

Aug. 27, 2007

International news for oil and gas professionals
For up-to-the-minute news, visit www.ogjonline.com

General Interest — *Quick Takes*

Industry seeks more time to meet fuel rules

The Western States Petroleum Association (WSPA) on Aug. 13 petitioned the California Air Resources Board (CARB) for a more reasonable timeframe for meeting new fuel rules approved by the board earlier this summer. CARB has 30 days to respond.

CARB on June 14 amended California's reformulated gasoline rules to permit increased use of ethanol and lower-carbon fuels. The new rule gives refiners 2 years to comply or face punitive and costly penalties.

WSPA Chief Operating Officer Cathy Reheis-Boyd said, "We are not asking the board to change the new fuel specifications. We are simply asking the board to take into account that refiners also must comply with many other environmental regulations and construction realities when making major refinery changes; and that takes more time than the current rules provided."

In addition, the California Energy Commission (CEC) testified that based on its detailed modeling and surveys, it could take more than 4 years to complete the modifications. In fact, other major changes in California fuel formulations have taken at least 4 years to implement: California's cleaner-burning gasoline introduced in 1996 took 51 months, and California's Phase 3 cleaner-burning gasoline introduced in 2000 took 48½ months.

Reheis-Boyd said, "Our industry is committed to meeting these new fuel rules and is already working towards meeting them. But our companies need a reasonable timeframe to build the required facilities, given the lengthy process required to comply with numerous state and local regulations."

CEC also said a more reasonable timeframe "would minimize the risk of supply difficulties and associated price spikes for California consumers and businesses."

Philippines to vary energy sources, use more gas

Recently appointed Philippines' Energy Secretary Angelo T. Reyes has promised to make more use of natural gas to vary the country's energy sources and lessen its dependence on imported oil, estimated at some 325,000 b/d during 2006.

"Natural gas is the fuel of the future. [It] provides energy independence, stable and secure energy supply, and clean and efficient fuel. We are currently using this for power alone, but we need to promote it in the transport, industrial, and commercial sectors," Reyes said. He said several gas projects earmarked for construction will require $5 billion in investment during the next 7 years.

Among the projects Reyes said his department proposes is conversion of the Sucat, Limay, and Malaya coal-thermal power plants to gas-fired power facilities and construction of the 100-km Batangas-Manila I and 140-km Bataan-Manila II gas pipelines.

Plans also are under way for construction of new gas facilities in Central Luzon, Cebu, Agusan and Davao, and Palawan, while compressed natural gas facilities could be built in Luzon in areas such as Batangas, the Clark economic zone, and Cavite.

Reyes said gas constituted 29% of the country's power generation mix in 2006, while coal and oil made up 27% and 8%, respectively.

Iran oil minister replaced, caretaker appointed

Iranian President Mahmoud Ahmadinejad has removed Kazem Vaziri Hamaneh as the country's oil minister and appointed Gholamhossein Nozari as the caretaker until further notice. Analysts have interpreted the move as stamping his authority on one of the country's major industries that generates lucrative revenues.

Ahmadinejad did not give a reason for replacing Hamaneh, but in a letter announcing his replacement, the head of state-owned National Iranian Oil Co., Ahmadinejad thanked Hamaneh for his efforts to date. A spokesman from the Iranian oil ministry told OGJ that Hamaneh would serve the president in an advisory role on oil and gas affairs. He had held the role of oil minister for the last 2 years.

Iranian press said that Ahmadinejad was unhappy with Hamaneh's performance in attracting foreign investment and with the unrest in the country following gasoline rationing in June. Critics also said Iran had sold gas too cheaply to India and Pakistan via the proposed 2,300 km pipeline under development.

Ahmadinejad will need to introduce a candidate before Iran's parliament for the appointment to become official, the ministry spokesman added. He was unable to give a timetable on when this would happen and if indeed Nozari would be presented. ✦

Exploration & Development — *Quick Takes*

Tullow makes deepwater oil find off Ghana

Tullow Oil PLC has discovered a light oil accumulation with its Hyedua-1 well on the deepwater Tano license in 1,530 m of water off Ghana.

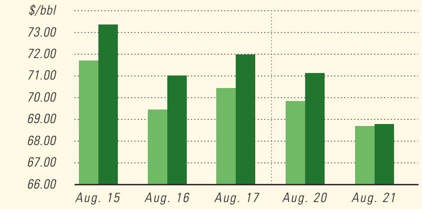
As the initial exploration well on the license, Hyedua-1 targeted the equivalent Santonian turbidite sandstones found in the Mahogany-1 discovery well, drilled about 5.3 km to the northeast on the adjacent West Cape Three Points license.

Hyedua-1, drilled to 4,002 m TD by the Fred Olsen Energy ASA Belford Dolphin deepwater drillship, encountered a 202 m gross reservoir interval containing 108 m of high-quality stacked reservoir sandstones and net hydrocarbon-bearing pay of 41 m.

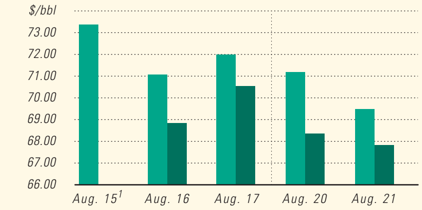
Logs and pressure tests indicate the strong likelihood that the reservoir sands are in communication with those at the Mahogany

Industry Scoreboard

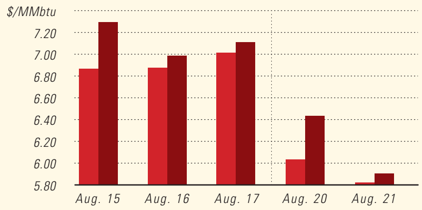
IPE BRENT / NYMEX LIGHT SWEET CRUDE



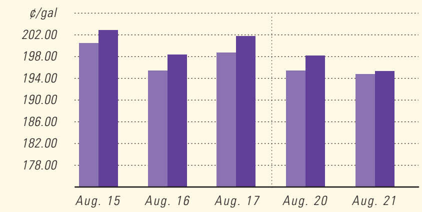
WTI CUSHING / BRENT SPOT



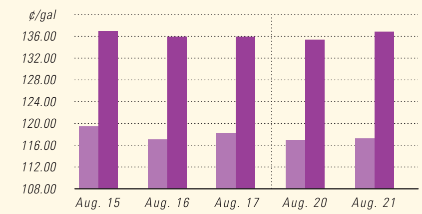
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



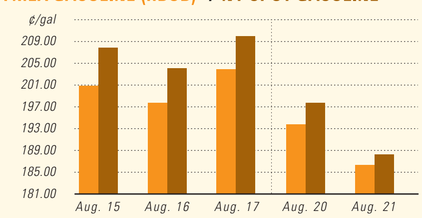
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



NYMEX GASOLINE (RBOB)[2] / NY SPOT GASOLINE[3]



[1]Not available. [2]Reformulated gasoline blendstock for oxygen blending. [3]Nonoxygenated regular unleaded.

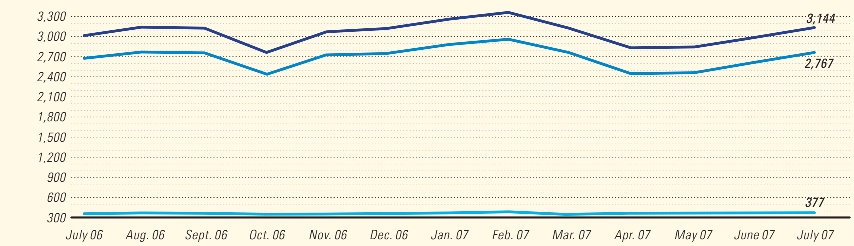
US INDUSTRY SCOREBOARD — 8/27

Latest week 8/10	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	9,624	9,584	0.4	9,296	9,187	1.2
Distillate	4,105	4,005	2.5	4,233	4,145	2.1
Jet fuel	1,617	1,672	–3.3	1,624	1,618	0.4
Residual	729	693	5.2	761	717	6.1
Other products	4,959	4,866	1.9	4,855	4,859	–0.1
TOTAL DEMAND	21,034	20,820	1.0	20,769	20,497	1.3
Supply, 1,000 b/d						
Crude production	5,181	5,166	0.3	5,186	5,098	1.7
NGL production[2]	2,430	2,367	2.7	2,375	2,185	8.7
Crude imports	10,104	10,277	–1.7	10,114	10,061	0.5
Product imports	3,547	3,810	–6.9	3,572	3,594	–0.6
Other supply[3]	954	1,263	–24.5	930	1,130	–17.7
TOTAL SUPPLY	22,216	22,883	–2.9	22,177	22,068	0.5
Refining, 1,000 b/d						
Crude runs to stills	15,902	15,900	—	15,227	15,221	—
Input to crude stills	16,065	16,124	–0.4	15,481	15,577	–0.6
% utilization	92.1	92.7	—	88.8	89.6	—

Latest week 8/10	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	335,228	340,395	–5,167	331,002	4,226	1.3
Motor gasoline	201,940	202,997	–1,057	205,393	–3,453	–1.7
Distillate	127,669	127,516	153	133,170	–5,501	–4.1
Jet fuel-kerosine	41,400	41,340	60	40,659	741	1.8
Residual	36,977	38,607	–1,630	42,648	–5,671	13.3
Stock cover (days)[4]			Change, %		Change, %	
Crude	21.1	21.5	–1.9	21.2	–0.5	
Motor gasoline	21.0	21.0	—	21.4	–1.9	
Distillate	31.1	31.2	–0.3	33.0	–5.8	
Propane	51.2	48.1	6.4	6s7.8	–24.5	
Futures prices[5] 8/3			Change		Change	Change, %
Light sweet crude, $/bbl	72.17	71.91	0.26	71.93	0.24	0.3
Natural gas, $/MMbtu	6.90	6.41	0.49	6.79	0.11	0.5

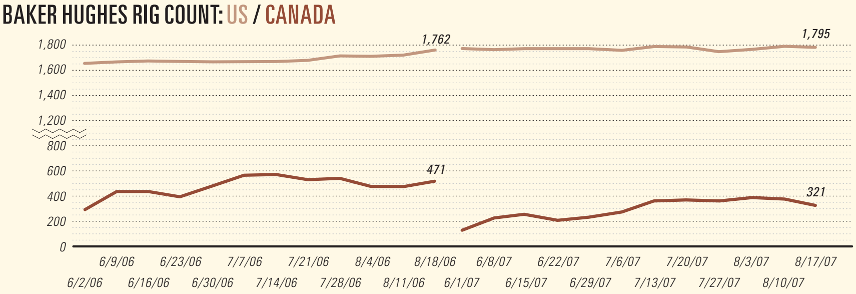
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average of daily closing futures prices.
Sources: Energy Information Administration, Wall Street Journal

BAKER HUGHES INTERNATIONAL RIG COUNT: TOTAL WORLD / TOTAL ONSHORE / TOTAL OFFSHORE



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

Why we should be on your radar

Weatherford wireline services has surprising capabilities and advantages, including the economy of flexibility.

It may be news to you that Weatherford offers worldwide a full suite of evaluation and intervention tools, imaging services and the industry's broadest array of conveyance options. Here's more news:

More flexibility for job-matched economy

Flexibility enables us to provide the most efficient answer to your specific operational and budgetary objectives. You don't pay for what you don't need.

EarthView imaging flexibility

View your wellbore and formation in multiple ways in any application—including coalbed methane and heavy-oil wells. Our geoscience experts can interpret your images while drilling or post-drilling.

Conveyance flexibility for any contingency

The unique Compact™ system gives you comprehensive formation evaluation capabilities, with or without wireline. Running in memory mode, the tools can be conveyed in many ways, including well shuttle, thru-drillpipe and non-electric line.

Our *Compact* system and our standard tools give you the industry-exclusive ability to log wellbores from 2-3/4 to 36 inches.

More options. More service.

There are many reasons we should be on your radar—and on your job. Visit www.weatherford.com, or contact your Weatherford representative.

Our business is built **All Around You.**

Drilling | **Evaluation** | Completion | Production | Intervention

Weatherford®

Create Your Career Future. Visit us at www.weatherford.com/careers.

discovery. Well data results further suggest that the Hyedua-1 and Mahogany-1 wells could represent a continuous accumulation with combined hydrocarbon columns in excess of 361 m within a single continuous trap extending across the West Cape Three Points and Deepwater Tano blocks, the company said.

Hyedua-1 will be sidetracked, prior to casing, to acquire core data over the reservoir interval and suspended for potential use as a development well.

Tullow will now appraise the accumulation. Suitable vessels have been identified to carry out a 910 sq km 3D seismic survey, covering the combined feature on both blocks, and a program of up to three additional appraisal wells late this year.

Tullow operates the Tano license with a 49.95% interest and holds 22.9% interest in the West Cape Three Points license.

InterOil gauges gas at Elk-2 appraisal well

InterOil Corp., Toronto, said it has achieved positive results from its Elk-2 appraisal well on PPL 238 in Papua New Guinea.

"We are now confident that the Elk structure contains sufficient gas to underpin the first train of an LNG plant, which will be built by Liquid Niugini Gas Ltd. adjacent to our refinery [planned at Port Moresby], and sufficient oil shows to justify sidetracking to confirm an oil leg," said InterOil Chairman and Chief Executive Phil Mulacek. The Elk-2 well was programmed to test the entire 2,000 ft Puri and Mendi limestone section in a downdip position of the discovery well 2.9 miles away (OGJ Online, Feb. 13, 2007).

Drilling and testing at Elk-2 confirmed 4,452 ft of indicated hydrocarbon column from the highest known gas in Elk-1 to the lowest indicated hydrocarbons in Elk-2, InterOil said. Mud logs indicated multiple gas zones, and there were multiple oil shows throughout a 594 ft column. In addition, the well had flowed gas and gas liquids during a drillstem test, the company said.

The target Puri and Mendi limestone reservoirs are much thicker than predrill estimates, it added.

The company intends to drill the Elk-2 well to total depth, log it, complete it, and test it.

"We will then sidetrack the well to intersect the potential oil leg structurally higher in the porous Mendi limestone section," Mulacek said.

InterOil has been designated as the preferred natural gas supplier for the planned Port Moresby LNG project, which consists of a two-train, 9 million tonne/year liquefaction plant having a nominal processing capacity of 1.6 bcfd of condensate and gas liquids, handling and storage facilities, and a gas pipeline from supply sources.

InterOil's Elk and Antelope structures are the key gas resources for the project (OGJ, Nov. 20, 2006, Newsletter).

LNG production is still on track to begin in 2012, InterOil said.

Total farms into offshore Vietnamese block

Total SA has received approval from the Vietnamese government to acquire a 35% interest in the production-sharing contract for offshore exploration Block 15-1/05. The French company will work alongside PetroVietnam Exploration & Production, which serves as block operator with 40%, and South Korea's SK Corp., with 25%.

Block 15-1/05, which covers 3,840 sq km, is about 40 km off Vietnam in 40 m of water. It lies in Cuu Long basin near four recent discoveries—Su Tu Den, Su Tu Vang, Su Tu Trang, and Su Tu Nau. The partners have already shot 2D seismic surveys on the block.

Phase 1 exploration, which will be launched before yearend, will include 800 sq km of 3D seismic data acquisition and the drilling of two wells.

Total's agreement with Vietnam also calls for stepped-up international cooperation between the French firm and PetroVietnam, particularly in the area of exploration. In 2006 the Asia-Pacific region accounted for about 253,000 boe/d, or 11%, of Total's production. Total is mainly active in Indonesia, where it has operated Mahakam block with partner Inpex since 1970 and is one of the country's leading producers of LNG. It also has gas production operations in Thailand and Myanmar as well as offshore operations in Brunei.

Total diversified its assets with the recent acquisition of interests in a number of exploration projects in Australia, Indonesia, and Bangladesh. It also acquired a 24% stake in Australia's Ichthys LNG project, in partnership with Inpex (OGJ Online, Feb. 2, 2007). It also has signed a contract with China National Petroleum Corp. to appraise, develop, and produce gas from China's South Sulige block (OGJ, Dec. 11, 2006, p. 18).

Southern Michigan gets TBR oil discovery

Continental Resources Inc., Enid, Okla., plans to drill two offsets in November to an Ordovician Trenton-Black River discovery in Hillsdale County, Mich., 60 miles southwest of Detroit.

The McArthur 1-36 tested at a rate of 20 bbl/hr of oil with 240 psi flowing tubing pressure on a ¾-in. choke. The well cut 182 ft of potential pay at 3,400-4,020 ft.

Continental has 83% working interest in the discovery and has identified other opportunities modeled after Albion-Scipio field in the area, where it holds 13,280 net acres of leasehold. McArthur 1-36 is the company's first well in Michigan.

Hillsdale County adjoins Indiana and Ohio. ✦

Drilling & Production — *Quick Takes*

Oil production starts from Kikeh field off Malaysia

Murphy Oil Corp. has started oil production from Kikeh field, 5 years after making the discovery in 4,400 ft of water 110 km off Sabah, Malaysia.

Predrilled wells in the field will continue to be placed on stream during the remainder of 2007, Murphy Pres. and Chief Executive Officer Claiborne P. Deming said.

Meanwhile, Kikeh field development is continuing with additional wells expected to come on stream throughout 2008. Plateau production from the field is expected to reach 120,000 b/d of oil. Deming said.

Kikeh is being developed as a stand-alone facility with oil being produced from both subsea and dry tree wells on board a spar facility—the first application of its kind outside the Gulf of Mexico (OGJ Online, Jan. 30, 2007). The development also uses a floating production, storage, and offloading vessel.

Murphy also expects first sales of its associated natural gas via a dedicated pipeline to Labuan in the first part of 2008, Deming said.

Murphy is operator and holds 80% interest in Kikeh field. Petronas Carigali Sdn. Bhd. holds the remaining 20%.

Providence to start gas flow from High Island A2

Providence Resources PLC expects to start natural gas production from the lowest reservoir level in its A2 well at High Island A268 in the Gulf of Mexico by the end of August. The well was drilled to a deviated 6,863 ft TVD, targeting potential gas accumulations.

Predrill gross recoverable volumes from the block range 3.5-5.8 bcf of gas.

The well encountered two high-quality gas-bearing sands in A2, assessed in an analysis of the well log and sidewall core data. Providence said its predrill expectations were met in the combined net gas pay. The well was drilled from the newly installed High Island A268 "A" platform using the Todco 250 jack up. Providence said the A2 well TD bottomhole location is about 1 mile east of the A1 well discovery.

This production will compliment gas from A1, announced in January, from which production will start in mid-September. The A2 discovery further underpins the economic justification for the project, which had been sanctioned with gas from the A1 well alone. After completion of A2, the Todco 250 jack up will move back to the A1 well to complete operations.

The partners are completing operations on the production liner across the reservoir intervals.

A production platform, with the capability to process the gas and export it via nearby existing infrastructure, has been successfully installed on High Island A268 to process gas from the A1 well.

NAOSC to produce bitumen from Leismer project

Statoil ASA subsidiary North American Oil Sands Corp. (NAOSC) will produce 10,000 b/d of bitumen from its Leismer demonstration project in Canada by late 2009 or early 2010.

Bitumen production will come from 22 horizontal well pairs linked to four well pads and a processing facility will generate steam for underground injection to make the heavy oil less viscous.

The Alberta Energy and Utilities Board has already given the Leismer project the go ahead.

NAOSC operates 1,110 sq km of oil sands leases in the Athabasca region of Alberta, northeast of Edmonton, which is one of the largest heavy oil provinces in the world. Statoil acquired NAOSC earlier this year for $2 billion (OGJ Online, Apr. 27, 2007).

"The Leismer demonstration project is the first lease to be developed in the NAOSC portfolio. The NAOSC portfolio is expected to yield more than 200,000 b/d at the end of the next decade," Statoil said. ✦

Processing — *Quick Takes*

OMV to upgrade European refineries

OMV AG, Vienna, planning a program of upgrades in its European refineries, said it will shut down its 69,280 b/d Petrobrazi refinery in Romania for upgrades sooner than originally planned—in this year's fourth quarter instead of first quarter 2008.

In Germany, it plans to install an expanded cracker and new metathesis plant at its 72,000 b/d Burghausen refinery, work that will take 6 weeks in the fourth quarter. "Additional propylene will be delivered to Borealis, feeding the new Borstar propylene plant coming on stream at the same time," OMV said. In addition, the 262,300 b/d Bayernoil refinery in Germany will be restructured to improve plant configuration, OMV said.

In Austria the company will construct a thermal cracker in its 208,600 b/d Schwechat refinery in Vienna so it can process more heavy crude and reduce the amount of heavy fuel oil in the product slate.

A company spokeswoman told OGJ that OMV's strategy is to build on two hubs: a Western hub comprised of Schwechat, Burghausen, and Bayernoil that would have a refining capacity of 18.4 million tonnes/year and an Eastern hub of Petrobrazi and Arpechim in Romania, with a capacity of 8 million tonnes/year (OGJ Online, Oct. 12, 2006). Arpechim is operated by OMV's Romanian unit Petrom.

OMV said it also will begin preparations to construct a 360-km ethylene pipeline in southern Germany from Munchsmunster to Ludwigshafen that will connect the southeast Bavarian chemical triangle with the northwest European ethylene network at Ludwigshafen. The pipeline will be completed in third quarter 2008.

OMV upstream priorities for 2007 are to develop Strasshof gas field in Austria, Maari oil field in New Zealand, Komsomolskoe oil field in Kazakhstan, Block S2 in Yemen, and oil discoveries in Libya and to complete Pohokura gas field development in New Zealand, said OMV Chief Executive Wolfgang Ruttenst at a press conference Aug. 16.

In Romania, the company will continue its modernization of production facilities to enhance efficiency and reduce production costs.

Coffeyville Resources restarts flooded units

Coffeyville Resources Refining & Marketing LLC said it has restarted most of the operating units at its 100,000 b/cd refinery in Coffeyville, Kan., after a record flood of the Verdigris River caused the shutdown of the facility in early July.

Process operations that have been restarted include two crude units, two vacuum units, one naphtha hydrotreater, a catalytic reformer, two distillate hydrotreaters, a fluid catalytic cracking unit, the alkylation unit, the isomerization unit, the delayed coking unit, and sulfur recovery facilities. Remaining units are in varying stages of start-up.

The company also said the refinery would be fully restored ahead of its earlier mid-September projection. It cautioned, however, that mechanical challenges created by the flooding that reached more than 6 ft deep will require the company to carefully monitor all equipment as it increases throughput to full production after start-up. In addition, truck rack sales from the company-owned terminal in Coffeyville could resume as early as next week, Coffeyville Resources said. It has been shipping product via pipeline from preflood inventory.

The company's adjacent nitrogen fertilizer plant, which was also flooded but sustained less damage than the refinery because it sets on higher ground, was restarted and began shipping product 2 weeks after the flood (OGJ Online, July 23, 2007).

Slavneft-Yanos eyes Russian refinery upgrade

Slavneft-Yanos, owned by TNK-BP and Gazpromneft, has let a consulting support contract to a unit of Jacobs Engineering Group Inc. for a planned upgrade of its 300,000 b/sd refinery in Yaroslavl, Russia.

The project involves converting refinery residue into high-value products that meet European specifications.

Jacobs Consultancy UK Ltd. will carry out the work from its Marble Arch, UK, office, supported by in-house process experts from Houston.

The contract's value was not disclosed. ✦

Transportation — *Quick Takes*

Hammerfest LNG plant processes first Snohvit gas

Statoil ASA said the gas processing facility at the Hammerfest LNG plant in northern Norway has received gas from Snohvit field on Aug. 21. The plant at Hammerfest is Europe's first export facility of its kind.

Gas lifted from Snohvit field previously flowed as far as the slug catcher, but this is the first time gas has reached the processing facility, Statoil said.

The company is expected to begin sending LNG exports from the Snohvit LNG project in the fourth quarter (OGJ Online, May 17, 2007).

Interests in the project are operator Statoil with 33.53%, Petoro SA 30%, Total E&P Norge 18.4%, Gaz de France 12%, Amerada Hess Norge 3.26%, and RWE Dea Norge 2.81%.

New JV proposes Pacific Northwest pipeline

Palomar Gas Transmission LLC, a newly formed joint venture of TransCanada Corp. and Northwest Natural Gas Co. (NNG), propose to build and equally own a natural gas pipeline that would serve Oregon, the Pacific Northwest, and the western US. If approved, the transmission line could begin service in late 2011.

As proposed, the project would include 220 miles of 36-in. pipe extending from northwestern to north-central Oregon, connecting TransCanada's existing Gas Transmission Northwest (GTN) system with NNG's distribution system near Molalla, Ore., 30 miles southeast of Portland.

The project design includes an extension option that would serve the Bradwood Landing LNG terminal proposed by NorthernStar LLC on the Colombia River.

The main section of the project is a 110-mile eastern portion that accounts for $300-350 million of the total project cost estimated at $600-700 million.

NNG's utility operation has agreed to contract for about 100 MMcfd of capacity on the pipeline. The company currently depends on a single interstate pipeline for its supply, two thirds of which comes through the Columbia Gorge.

TransCanada's GTN system will operate the Palomar pipeline, and has yet to request preliminary environmental approval for the project from the Federal Energy Regulatory Commission. Even before that filing is made, Palomar will begin the public engagement process, the company said.

Proposed LNG terminals in France face problems

A local environmentalist group and a handful of residents near Antifer are opposing construction of the proposed 9 billion cu m/year Gaz de Normandie LNG terminal, regasification unit, and pipeline at Antifer near the Le Havre oil port in Normandy, France (OGJ Online, Oct. 10, 2006).

Another problem, which is the "Not in my backyard," or Nimby, syndrome is threatening construction of a 6 billion cu m LNG receiving-regasification terminal that the Netherlands company 4 Gas plans at Verdon, 100 km south of Bordeaux at the mouth of the Gironde River (OGJ, Aug. 21, 2006, Newsletter).

Concerning the Gaz de Normandie LNG project, the environmental group, which reportedly has collected 7,500 signatures on an internet petition, wants the project scrapped, saying the project's purpose is profit and not because France needs more gas—a "fossil fuel which produces carbon dioxide"—according to environmentalist leader Francois Auber.

GDN Pres. Jean-Luc Poyer, in charge of the project for the main shareholder Poweo, told OGJ that there also were supporters of the project and that public input is scheduled for Sept. 14 through Dec. 14. The National Commission for Debates had asked Poyer to avoid polemics until then, he said.

GDN is a €500 million LNG regasification terminal project led by energy supplier Poweo 34%, in joint venture with E.On AG of Germany 24.5%, Austrian utility Verbund 24.5%, and the oil storage and port firm CIM 17%.

Concerning the Verdon terminal, France's State Secretary for Transport Dominique Bussereau wants the €400 million terminal transferred from its proposed location on a 700-ha industrial site to La Rochelle, north of Bordeaux beyond the mouth of La Gironde. His constituency faces Verdon on the other side of the Gironde River mouth, and he said the terminal will spoil a "tourist area."

A public debate is scheduled to begin in mid-September and end in December on the terminal, after which acceptance or rejection of the site will be decided, said 4 Gas General Manager for France Henk Jonkmal.

The final decision will rest with State Minister for Ecology and Sustainable Development Jean-Louis Borloo, who also is responsible for Transport and Energy. ✦

Letters

Correction: Camisea project

The July 23, 2007, edition of Oil & Gas Journal has a listing of major oil and gas projects being developed (OGJ, July 23, 2007, pp. 43-60).

On p. 58 of the project table, an entry under "Peru" reports for "Camisea gas/Peru LNG SRL" a peak year of 2009 and gas production of 1,300 MMscfd. It lists the operator as Hunt Oil and under "Development type" shows: "Blocks 56 and 88, 700-km gas pipeline, 575-km liquids pipeline."

I'm afraid that O&GJ's database on these projects contains pieces of wrong information. As the manager responsible for one portion of the project (gas production) I would like to offer you some clarification:

- Camisea gas: right.
- 1,300 MMscfd: partly right. We are increasing gas treatment capacity from nominal 440 MMscfd to 1,160 MMscfd in a project expected to be ready by mid-2008 with peak investments in 2007-08.
- Blocks 56 and 88: right. But operator of both blocks is Pluspetrol Peru Corp. (not Hunt Oil, as stated).
- 700-km gas pipeline and 575-liquids pipeline: wrong. Both pipelines are already built and working (as part of the initial start-up of Camisea in 2004). These pipelines are property of TGP (Transportadora de Gas del Peru).
- Peru LNG SRL: right. Under development, operator is Hunt Oil. Hunt Oil is also a shareholder of TGP and a nonoperator partner in Blocks 56 and 88.

Norberto M Benito
General Manager
Pluspetrol Peru Corp. SA

Calendar

✦ Denotes new listing or a change in previously published information.

OIL&GAS JOURNAL online

Additional information on upcoming seminars and conferences is available through OGJ Online, Oil & Gas Journal's Internet-based electronic information source at http://www.ogjonline.com.

2007

AUGUST

IADC Well Control of the Americas Conference & Exhibition, Galveston, Tex., (713) 292-1945, (713) 292-1946 (fax); e-mail:

info@iadc.org, website: www.iadc.org. 28-29.

SEPTEMBER

Brasil Subsea Conference & Exhibition, Rio de Janeiro, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwellpetroleumgroup.com. 1.

SPE/EAGE Reservoir Characterization and Simulation Conference, Muscat, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 3-5.

Rocky Mountain Crude Oil Market Dynamics Summit, Denver, (405) 525-3556, (405) 525-3592 (fax), e-mail: iogcc@iogcc.state.ok.us, website: www.iogcc.state.ok.us/events.html. 4-5.

Power-Gen Asia Conference, Bangkok, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwell.com. 4-6.

Offshore Europe Oil & Gas Conference and Exhibition, Aberdeen, +44 (0) 208 439 8890, +44 (0) 208 439 8897 (fax), e-mail: oe2007@spearhead.co.uk, website: www.offshore-europe.co.uk. 4-7.

Black Sea Oil & Gas Summit, Istanbul, +90 312 454 00 00-1412, +90 312 454 00 01, e-mail: bsogs2007@flaptour.com.tr, website: www.bsogs2007.org. 5-6.

Iraq Petroleum Conference, Dubai, +44 (0)20 7978 0075, +44 (0)20 7978 0099 (fax) website: www.thecwcgroup.com. 8-10.

Corrosion Solutions Conference, Sunriver, Ore., (541) 926-4211, ext. 6280, website: www.corrosionconference.com. 9-13.

Global Refining Strategies Summit, Houston, (416) 214-3400, x3046, (416) 214-3403 (fax), website: www.globalrefiningsummit.com. 10-11.

PIRA Understanding Natural Gas Markets Conference, New York, 212-686-6808, 212-686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 10-11.

Annual LNG Tech Global Summit, Rotterdam, +44 (0) 20 7202 7511, e-mail: anne.shildrake@wtgevents.com, website: www.lngsummit.com. 10-12.

SPE Asia Pacific Health Safety Security Environment Conference, Bangkok, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 10-12.

Turbomachinery Symposium, Houston, (979) 845-7417 (979) 845-1835 (fax), e-mail: turbo@turbo-lab.tamu.edu, website: http://turbolab.tamu.edu. 10-13.

Oil Sands Trade Show & Conference, Fort McMurray, *Alta.*, (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 11-12.

EXPOGAZ Gas Congress, Paris, 01 41 98 40 25, e-mail: lberthier@etai.fr, website: www.congresdugaz.fr. 11-13.

European Gas Forum, Paris, 01 41 98 40 25, e-mail: lberthier@etai.fr, website: www.congresdugaz.fr. 12-13.

AAPG Annual Eastern Meeting, Lexington, (859) 257-5500, ext. 173, website: www.esaapg07.org. 16-18.

United States Association for Energy Economics/IAEE North American Conference, Houston, (216) 464-2785, (216) 464-2768 (fax), website: www.usaee.org. 16-19.

API Fall Refining and Equipment Standards Meeting, San Antonio, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 17-19.

Annual American School of Gas Measurement Technology Event, Houston, (972) 224-5111, (972) 224-5115 (fax). e-mail: asgmt2007@aol.com, website: www.asgmt.com. 17-20.

IOGCC Annual Meeting, New Orleans, (405) 525-3556, (405) 525-3592 (fax), e-mail: iogcc@iogcc.state.ok.us, website: www.iogcc.state.ok.us. 23-25.

Society of Exploration Geophysicists (SEG) Annual Meeting, San Antonio, (918) 497-5500, (918) 497-5557 (fax), e-mail: web@seg.org, website: www.seg.org. 23-28.

Calendar

Russia & CIS Petrochemicals Technology Conference & Exhibition, Moscow, +44 (0) 20 7357 8394, e-mail: Conferences@EuroPetro.com, website: www.europetro.com. 25-26.

Annual Engineering & Construction Contracting Association Conference, Colorado Springs, Colo., (877) 484-3322, (713) 337-1644 (fax), e-mail: Twilson@EventsiaGroup.com, website: www.ecc-association.org. 26-29.

Annual Engineering & Construction Contracting Association Conference, Colorado Springs, Colo., (877) 484-3322, (713) 877-8130 (fax), e-mail: registration@ecc-association.org, website: www.ecc-association.org. 27-28.

Russia & CIS Refining Technology Conference & Exhibition, Moscow, +44 (0) 20 7357 8394, e-mail: Conferences@EuroPetro.com, website: www.europetro.com. 27-28.

OCTOBER

IPLOCA Convention, Sydney, +41 22 306 0230, e-mail: info@iploca.com, website: www.iploca.com. 1-5.

Well Control Gulf of Mexico Conference, Houston, (979) 845-7081, (979) 458-1844 (fax), e-mail: jamie@pe.tamu.edu, website: www.multiphasre-research.org. 2-3.

ISA EXPO, Houston, (919) 549-8411, (919) 549-8288 (fax) website: www.isa.org. 2-4.

Rio Pipeline Conference and Exposition, Rio de Janeiro, +55 21 2121 9080, e-mail: eventos@ibp.org.br, website: www.ibp.org.br. 2-4.

ISA EXPO, Houston, (919) 549-8411, (919) 549-8288 (fax) website: www.isa.org. 2-4.

Kazakhstan International Oil & Gas Exhibition & Conference, Almaty, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 2-5.

Regional Deep Water Offshore West Africa Exploration & Production Conference & Exhibition, Luanda, +31 (0)26 3653444, +31 (0)26 3653446 (fax), e-mail: g.kreeft@energywise.nl, website: www.dowac.com. 2-6.

GPA Rocky Mountain Annual Meeting, Denver, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 3.

IFP Symposium The Capture and Geological Storage of CO2, Paris, +33 1 47 52 70 96 (fax), e-mail: patricia.fulgoni@ifp.fr, website: www.ifp.fr. 4-5.

IPAA OGIS West, San Francisco, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org/meetings. 7-9.

Annual European Autumn Gas Conference, Düsseldorf, +44 (0)20 8241 1912, +44 (0)20 8940 6211 (fax), e-mail: info@theeagc.com, website: www.theeagc.com. 9-10.

IADC Drilling HSE Europe Conference & Exhibition, Copenhagen, (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 9-10.

NPRA Q&A and Technology Forum, Austin, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 9-12.

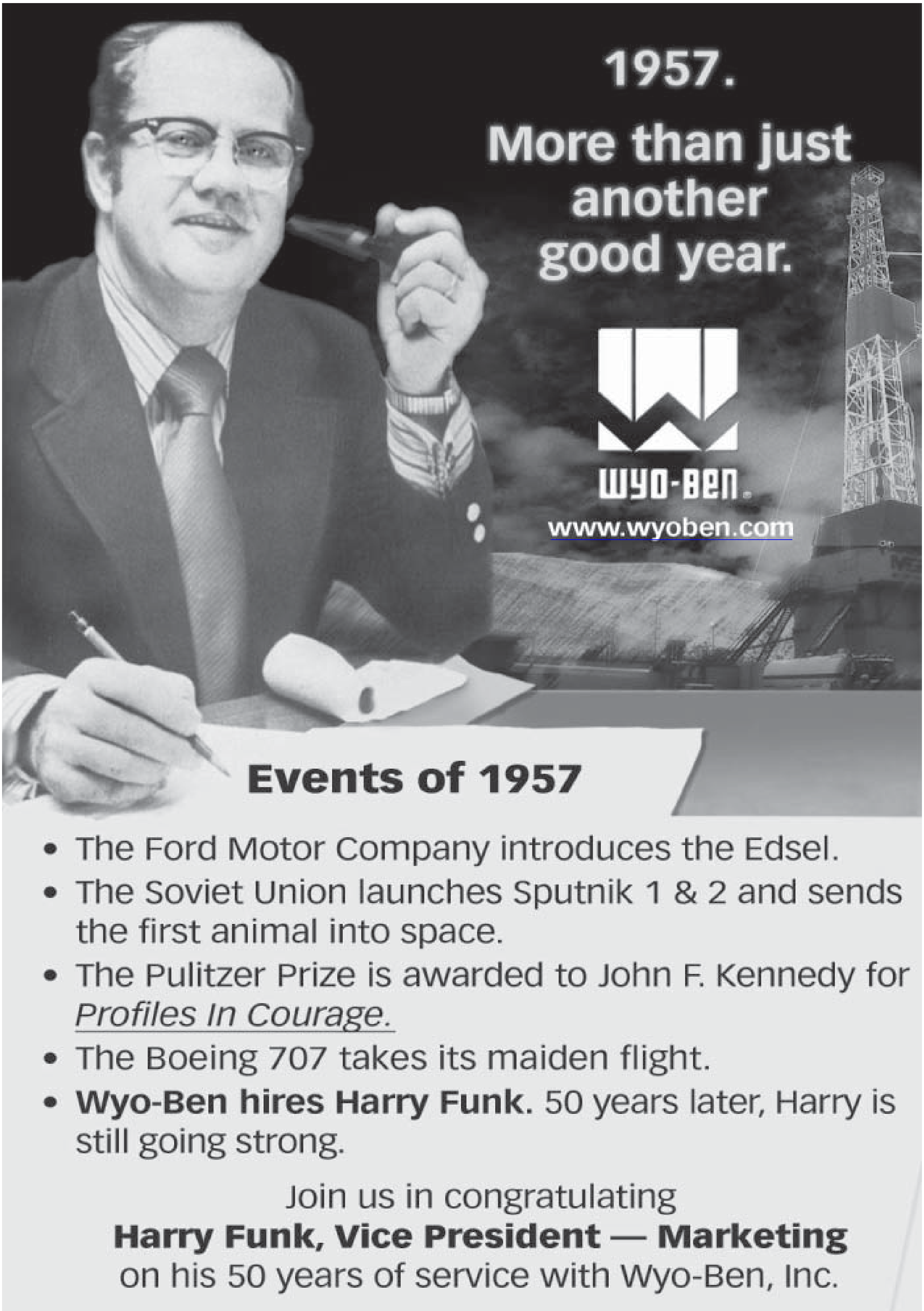
Deep Offshore Technology (DOT) International Conference & Exhibition, Stavanger, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepoffshoretechnology.com. 10-12.

International Bottom of the Barrel Technology Conference & Exhibition, Athens, +44 (0) 20 7357 8394, e-mail: Conferences@EuroPetro.com, website: www.europetro.com. 11-12.

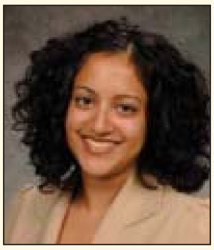
The Athens Summit on Global Climate and Energy Security, Athens, +30 210 688 9130, +30 210 684 4777 (fax), e-mail: jangelus@acnc.gr, website: www.athens-summit.com. 14-16.

ERTC Petrochemical Conference, Brussels, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 15-17.

Oil Shale Symposium, Golden, Colo., (303) 384-2235, e-mail: jboak@mines.edu, website: www.mines.edu/outreach/cont_ed/oilshale. 15-19.


1957.
More than just another good year.
WYO-BEN.
www.wyoben.com
Events of 1957
• The Ford Motor Company introduces the Edsel.
• The Soviet Union launches Sputnik 1 & 2 and sends the first animal into space.
• The Pulitzer Prize is awarded to John F. Kennedy for Profiles In Courage.
• The Boeing 707 takes its maiden flight.
• Wyo-Ben hires Harry Funk. 50 years later, Harry is still going strong.
Join us in congratulating
Harry Funk, Vice President — Marketing
on his 50 years of service with Wyo-Ben, Inc.

Ethics survey



Leena Koottungal
Survey Editor

In a time when media reports focus largely on the negative aspects of business news—corruption, unethical behavior, and the like—it was nice to see some positive news recently.

Ethisphere Magazine, a US publication dedicated to identifying the correlation between ethics and increased profits, recognized ethical companies worldwide for its 2007 report in May. Several oil and gas companies were recognized for their efforts to focus on ethical business behavior.

Ethisphere researched 5,000 companies focusing on 30 industries. Among the companies that made the list were Suncor Energy and Royal Dutch Shell PLC (oil and gas), Scottish & Southern Energy, Duke Energy, and FPL Group (energy and utilities), Akzo Nobel (chemicals), Fluor (engineering and construction), Koch Industries Inc. and Wesfarmers (diversified industries), and Alcoa (metals and mining).

"This was a rigorous process that identified a select group of companies that were unequalled in their industries for their commitment to ethical leadership and corporate social responsibility," wrote Alex Brigham, executive editor of Ethisphere. "These organizations go beyond making statements about doing business ethically; they translate those words into action."

Eight steps

Screening consisted of a sequential analysis:

1. Litigation, controversy, and conflict.
2. Ethical tone.
3. Innovation and industry leadership.
4. Corporate citizenship.
5. Pan-industry effort participation.
6. Governance and transparency.
7. Public and trade partner perception.
8. Ethics and compliance programs and systems.

Results of the first six steps narrowed candidates to finalists. They were then notified of their standing.

Step No. 7 examined outside stakeholders' reputation and perception of each company. Ethics audit letters were sent to customers and suppliers. Input was gathered from nearly two dozen nongovernmental organizations and socially responsible investment firms.

The final step analyzed internal ethics and compliance activities by using Ethisphere's database on companies' ethics and compliance programs. Also, the magazine interviewed CEOs and chief ethics officers of the finalists about their ethics and compliance systems. If a company did not participate in Step No. 8, Ethisphere relied on available third-party information. If such information was not obtainable, the highest score given was "neutral" regarding internal systems, a heavily weighted criterion. A neutral rating defined the difference between winning and losing.

Scoring consisted of nine weighted criteria: citizenship, 15%; industry leadership, 15%; internal systems, 15%; legal and regulatory, 15%; executive leadership, 10%; innovation, 10%; perception and reputation, 10%; governance, 5%; and transparency, 5%.

The completed analysis separated into 30 industries based on standard industrial classification codes. Within each industry, companies with a higher aggregate score made Ethisphere's list of the world's most ethical.

Industry highlights

Suncor achieves its vision by placing value on safety leadership, people and relationships, high performance, sustainability, and accountability to exceed expectations and deliver on commitments. It was also selected as one of the most respected corporations in Alberta in 2007 by Alberta Venture magazine.

Duke Energy's Code of Business Ethics provides guidance on social and ethical issues and offers information on the international EthicsLine through which employees can anonymously report unethical corporate conduct and ask questions to resolve dilemmas within the organization without fear of retaliation.

Nine of the 10 members of Fluor's board are nonemployee directors, independent from management. The CEO is the only board member who is an employee. The members meet at least quarterly without management present. The lead independent director acts as a liaison between the independent directors and management and also consults with the chairman and CEO.

Alcoa provides its code of conduct to suppliers so they understand policies and expectations. "If a vendor's values or policies differ drastically from Alcoa, chances are they won't be doing business with us," said Perry Minnis, director of ethics and compliance. "The most important thing is our values. We have a set of values and policies that is consistent across the company, and we train all employees to adhere to and uphold those values."

Lastly, Koch practices the market-based management business philosophy developed by associates working for and with Koch. It is a value system and guide that encourages employees to think and act like principled entrepreneurs through five dimensions: vision, virtue and talents, knowledge processes, decision rights, and incentives. ✦

Restating temperatures

Too much can be made about mistakes in US surface-temperature data from the Goddard Institute for Space Studies (GISS). Too little can be made about them, too.

Conservative commentators overreacted to revelations that GISS had erred in ways that stoked alarm about global warming. GISS is run by James Hansen, one of the first scientists to issue warnings about human contributions to observed warming and a longstanding ally of Al Gore in the former vice-president's crusade for aggressive response. When a Canadian mathematician pressed for and won a downward correction to GISS temperature data, bloggers and radio talk-show hosts pounced. One of them, Rush Limbaugh, called the correction evidence that "this whole global warming thing is a scientific hoax."

That's an overstatement. But so, evidently, was Gore's claim in his award-winning scare movie, "An Inconvenient Truth," that 9 of the 10 hottest years in US history have occurred since 1995.

Restated data

The inconvenient Canadian, Steven McIntyre, found errors in GISS temperatures for the US after January 2000. This month, the agency restated the data to show an overall decrease of 0.15° C. After the change it no longer can be claimed that 1998 was the hottest year in the US temperature record. That distinction now goes to 1934. Several other 10 hottest years receded in history after the adjustment.

The shift undercuts alarmist talking points more than it does the proposition that Earth's surface has warmed in the past century. While US temperature readings are among the best available, they represent a small part of the global whole. Hansen has pointed out that the change is barely distinguishable in global data, which show warming. McIntyre and others nevertheless are pressing their scrutiny of US temperature data and what US problems might mean to observations elsewhere.

Without question, potential lapses in the quality of temperature data deserve attention. Chances are low, however, that whatever new errors might come to light will show Earth to have been cooling. Even if that happened, no one would believe it. Young energy consumers and voters have been taught that their parents overheated the planet by driving to work and that anyone with doubts must be under an evil spell cast by oil companies.

In any event, it's no hoax that carbon dioxide of human origin is accumulating in the atmosphere. The central issue of the brittle global warming debate should be the extent to which the gas accumulation causes the temperature rise. Serious scientists can be found on both sides of the question. The unfortunate habit of politics is to note the coincidence of CO_2 and temperature gains, to assume causation, and to insist that people do anything imaginable to halt the trend, starting now.

In fact, the CO_2 and temperature records don't correlate perfectly; in the US, the correlation is worse now than it was before the GISS changes. Timing discrepancies have long been a source for doubt—Gore and his fans call it denial—about the ability of people to affect global temperature by cutting CO_2 emissions.

Other questions remain. By how much can people hope to alter global temperature with behavior changes, for example, when they account for only 1% of atmospheric CO_2, which itself represents no more than 0.04% of the atmosphere and is not, contrary to popular opinion, the most potent greenhouse gas? Hansen and others answer in part by postulating a cascade of self-amplifying catastrophes that will occur if the CO_2 concentration reaches an imminent "tipping point." Maybe they're right.

One scenario

Their gloomy scenario, however, is just one among a range of scientifically defensible possibilities—not all of them dire—about a complex system that so far has been mercilessly unpredictable. So maybe Hansen and his allies aren't right.

At best, this setback to the Hansen-Gore foreboding, however minor, should moderate the zealotry that has closed the global warming debate to questions that need answers. If so, it will have served human interests. Meanwhile, oil and gas companies should keep finding ways to cut the CO_2 emitted by their work. ✦

COMMENT

Industry needs fresh approach to petroleum engineer training

D. Ronald Harrell
Ryder Scott Co. LP
Houston

As I contemplate attending the Oct. 13 homecoming at Louisiana Tech University to be recognized as a member of the graduating class of 1957, I look back with fond memories. My experiences involving professors and classmates, particularly those in the Department of Petroleum Engineering (PE), are now a half a century old, but indelible in my mind.

On further reflection, however, even I have a bit of difficulty in appreciating the contrast between how petroleum engineers were educated then and now. So, what is the current level of undergraduate preparation? How should academic programs evolve to meet the ever-changing needs of the upstream petroleum industry?

My opinions are from the viewpoint of a petroleum engineer who earned a BS degree in petroleum engineering in 1957 and who has been in continuous professional practice since that time. I also have the added perspective as the grandfather of an enthusiastic young man entering Texas A&M University this fall to study petroleum engineering.

My comments are not intended to express a lack of respect for the dedicated, learned professional academic staffs in the various outstanding US and overseas universities with petroleum engineering programs. Indeed, I understand and appreciate their daily challenges with budgets, staff, equipment, and the university and government bureaucracies that continually limit their dreams and aspirations.

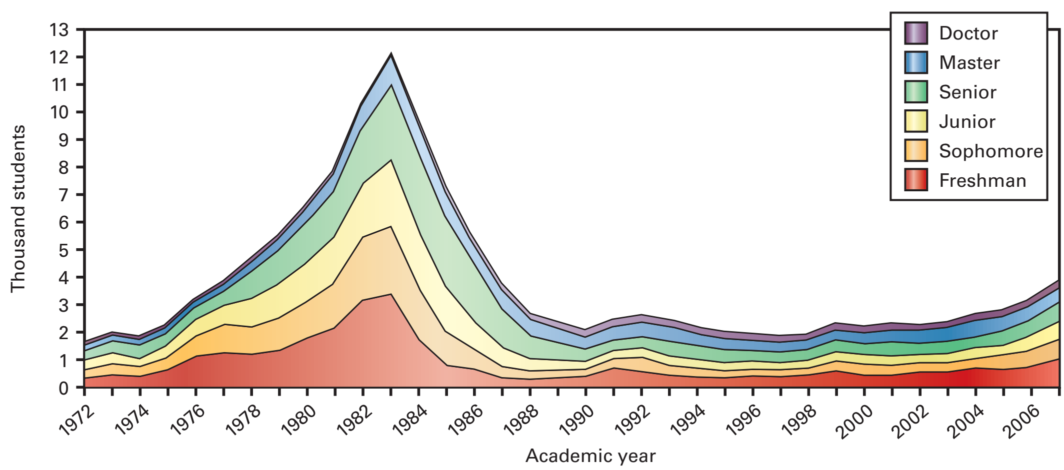
I refreshed my recollections by reviewing my college transcripts, and, sure enough, my 4-year degree plan required 145 hr of coursework with 0 electives. That included 19 hr in math, 25 hr in chemistry and physics, 11 hr in engineering drafting, and 5 total hr for pattern-making, machine shop, welding, and surveying. Civil engineering courses totaled 16 hr with 9 hr devoted to electrical engineering subjects.

I was required to take six geology courses plus labs for a total of 20 hr. My eight petroleum engineering courses combined for 26 hr of college credit. The remaining courses varied from mechanical and industrial engineering courses, English, technical writing, speech, and economics. I had no courses in humanities, business, or in statistics and statistical analysis.

Department constraints

PE departments across the US are caught in the squeeze between the politics of state governments and their universities for financial budgets, facilities, and curriculum control. Constraints similar to this are likely in non-US universities as well. The average 4-year bachelor of science

US PETROLEUM ENGINEERING ENROLLMENT



Source: Lloyd Heinze, Texas Tech University petroleum engineering chairman, for SPE

PE degree now requires about 132 hr, a portion of which is dedicated to some of the "softer" subjects related to the humanities, government, and health. US-based ABET Inc. establishes minimum standards for engineering degrees awarded by US and some international universities. Several states, including Texas, continue to encourage its institutions to reduce their curricula to a maximum of 120 hr for 4-year degree plans. Students and parents may favor that reduction in time and effort, but this is not in the long-term interests of the industry or any engineering student.

Many curriculum plans are influenced by engineering advisory boards that typically consist of PE alumni who are active in the upstream and service industry and are willing to contribute their insightful views about industry needs and the talents most valued in new graduates. On the other hand, many alumni continue to believe their undergraduate degrees equipped them well for their industry careers and are reluctant to urge changes except for occasional technology updating.

My informal and largely unscientific survey of several US universities offering petroleum engineering shows how much (or how little) is expected of entering freshmen in areas of math, chemistry, and physics. The average PE student today takes about 24 hr in those subjects, whereas my curriculum required 44 hr. There are some professors today who believe many incoming engineering freshmen should be exposed to additional science and math fundamentals because of the declining emphasis and quality of instruction they received in many public high schools.

Several US universities now limit the number of entering freshmen because of space and faculty limitations. This is not necessarily good news for the industry but does allow these universities to select the best and brightest applicants.

The role of geology in PE degree plans continues to be reduced over time in most US universities to about 6-12 hr. Given the increasing requirement for geoscientists and engineers to work closely together in describing and "unlocking the secrets" of some of today's challenging reservoirs, particularly the ones we refer to as being "unconventional," that is a serious deficiency. The wealth of the petroleum industry is contained in these underground reservoirs, and we must continue our quest for better reservoir description and understanding. Undergraduate participation in integrated geoscience-engineering projects is useful and necessary to establish and demonstrate the interdependence between the two disciplines.

A collateral problem is how do we find individuals who have the background to develop and teach courses about unconventional reservoirs? More about the staffing concerns later.

Modifying curricula

A professor from one of the leading US PE universities told me the school has not made any significant changes to its curriculum in 15 years. This particular university continues to provide the fundamentals of science and engineering that its administrators believe a petroleum engineer should understand, all within the 4-year curriculum guidelines mandated by the state and approved by ABET.

However, other professors at this same university and other universities on other continents are strong advocates for a greater emphasis in teaching petroleum engineers to both recognize and "manage uncertainty." Reidar Bratvold and Stephen Begg[1] recommend that "a petroleum engineering program should introduce uncertainty and decision-making early to develop a thorough understanding and comfort with these topics. The focus should be on teaching the decision analysis and probability concepts most relevant to decision-makers and decision-analysts in the petroleum industry. Although there may be room for a traditional statistics course in the curriculum, the emphasis should be on courses taught by engineers that leverage relevant examples with a practical, petroleum-oriented focus."

The authors, both of whom are respected academics, further say that "the uncertainty understanding thus developed at an early stage then should be used as a common thread through the entire set of subsequent engineering courses." Again, the availability of qualified staff to accomplish this is a present-day limitation.

These observations and recommendations by Bratvold and Begg are fully appreciated by this writer, who has spent a career in estimating and evaluating petroleum reserves and resources while continually struggling with assessing the true range of both technical uncertainty and commercial risk associated with resource classification and categorization. Can we continue to produce top quality petroleum engineers in a traditional 4-year academic cycle? My belief is that we cannot. Universities across the US and other countries are working very hard to produce qualified young men and women to serve as petroleum engineers, and I applaud their noble and worthy efforts.

However, I believe industry and academia must come to recognize that the unique and expanding challenges facing the petroleum industry this century demand even better-trained individuals. Many would say that the industry-academia cooperation to which I refer is alive and well and has been for a long time. I refer to a recent statement attributed to John Hofmeister, president of Shell Oil Co., where he said "Just as the oil and gas industry faces the 'great crew change,' it is also gearing up to meet a rising global demand for energy. These dual challenges require many new engineers with next-generation skill sets—and their education will take creative thinking and unprecedented partnerships between industry and academia."

According to data compiled by Lloyd Heinze, Texas Tech University petroleum engineering department chairman, undergraduate enrollments continue to grow, as shown in the table.

It clearly shows the impact of this spiraling growth rate on the undergraduate student-faculty ratio. This ratio cannot continue to expand without seriously impacting the quality of the graduating students and the continually increasing workload on the undergraduate faculty. The graduate programs seem to have a relatively constant student-faculty ratio, at least for now.

The chart on p. 20 illustrates the steady growth in US petroleum engineering students over the 5-year period ending in 2007. This contrasts with peak enrollment from around 1982.

Resolving dilemma

My suggestion goes far beyond the current level of industry-academia cooperation, advancing into a program where industry partners can and must become a vital part of the undergraduate program through university-industry designed summer intern programs. Students could earn 9-12 hr of college credit during a summer while providing meaningful work for his or her employer and earning income. The effective transfer of some of the basic PE courses in production, drilling, petrophysics, and reservoir studies (as examples) into a hands-on intern program would open university curriculum spaces during the academic year to incorporate topics such as (but not limited to) additional math and science fundamentals, uncertainty management, applied statistics, data management and "data mining," advanced petroleum economics, finance, accounting, business law, and geopolitics. An added benefit would be the opportunity to augment the current undergraduate petroleum engineering faculty with nonengineering instructors and professors.

Under this proposed plan, a student can obtain a BS degree in 4 years while earning 150 hr. Some universities might consider awarding a master's degree at this level or with only a few more credit hours. Certain universities might allow students to opt for the traditional 4-year degree or the expanded summer intern-college credit program.

This ambitious program cannot be accomplished overnight, as much work will be needed to develop the courses that can be effectively taught in an intern program and to obtain sustaining industry commitments to assist in this initiative. Many readers will simply assume this is too much trouble and will take too much time to create and manage. I believe we must give it a try. Some of our finest teachers are employed in industry, and many are willing to serve their company and their industry in a joint effort as described above.

The current and evolving university curricula have served to provide the US and the world with quality engineers for many decades, even though improvements are always necessary.

The most innovative undergraduate curriculum I reviewed is being developed by the University of Houston. UH has not offered a BS degree in petroleum engineering for about 30 years. The formal launching of this new degree plan at UH awaits final university approvals but has been endorsed by the current engineering dean and university provost.

Proposed courses make up a 130-hr curriculum that offers electives in nontraditional courses such as data mining and database structures, energy law, emerging technologies, optimization and control, and business simulation. A required leadership-and-entrepreneurship module consists of 9 hr in basics in finance, accounting, and economics; engineering effectiveness in modern technical environment; and project management.

Additionally, the module concept is included in three 9-hr modules in reservoir engineering, production engineering, and unconventional resources. Students will be required to complete two of these modules. This innovative degree plan grew out of dozens of interviews with industry leaders and a separate group of young petroleum engineers with 5 years or less industry experience.

Clearly, however, the curriculum could be strengthened even further through additional credits earned through a qualified summer intern program.

The Society of Petroleum Engineers[2] reports 111 schools and universities offer education courses in petroleum engineering or related disciplines. These schools are distributed globally: North America 37, South America 22, Europe 18, Asia 23, Africa 9, and Australia 2.

Faculty challenge

Attracting qualified faculty is a major challenge as salaries and bonuses for new engineering hires and engineers already in industry are growing rapidly and far outstrip what universities can typically offer for younger staff members. There is no satisfactory answer to this, unfortunately, but industry grants—in the form of endowed chairs,

US PETROLEUM ENGINEERING ENROLLMENT

Academic year	2003	2004	2005	2006	2007
Freshman	540	683	657	752	1044
Sophomore	377	370	510	580	687
Junior	346	368	388	532	641
Senior	410	437	547	613	707
Undergraduate	1,673	1,858	2,102	2,477	3,079
Master	526	579	494	496	537
Doctoral	194	225	238	241	253
Graduate	720	804	732	737	790
Total	**2,393**	**2,662**	**2,834**	**3,214**	**3,869**
Faculty	137	143	141	142	147
Student-faculty ratio					
Undergraduate students-faculty	12.2	13.0	14.9	17.4	20.9
Graduate students-faculty	5.3	5.6	5.2	5.2	5.4
Total students-faculty	17.5	18.6	20.1	22.6	26.2

Source: Lloyd Heinze, Texas Tech University petroleum engineering chairman, for SPE

Made in the USA and Canada.
From the oil sands to the deepwater Gulf of Mexico,
Tenaris is serving the North American energy industry.

At our mills in North America, we produce a broad range of OCTG, line pipe and coiled tubing products. And now, with Hydril, we have a range of premium connections to cover the widest array of demanding applications. We're investing to streamline production processes and set new standards in product quality. We're building an integrated supply chain to make our products and services readily available with the support of a distributor network. Combined with our global strengths, Tenaris can serve better than ever all your needs, from shallow wells to the most complex offshore environments.

Tubular technologies. Innovative services.

www.tenaris.com

Tenaris

other forms of endowments, structured fellowships, and funding of research projects—constitute the minimum level of support to be underwritten by the industry—a sector that desperately needs quality graduates and is the prime beneficiary of the program. The exploration and production industry has little obvious enthusiasm for grant programs. Companies seem more interested in contributing through scholarships and intern programs. I find it interesting that several of the very large integrated companies have a public position that they are adequately staffed, whereas my conversations with many of their employees paint a fairly grim picture about increased workloads and employee turnover.

As reported in a recent article, "Industry Working Together to Address 2007 Faculty Shortage," 19 PE departments in the US had 42 faculty vacancies.[3] The article also expressed concern about the "threatened cessation" of US Department of Energy funding for oil and gas research. The DOE now underwrites as much as 40% of the research conducted by professors and graduate students in PE departments.

Many US universities have benefited from time to time from invaluable contributions provided by adjunct professors, many of whom are actively employed in industry but are willing to contribute their professorial talents one or more days each week. Sadly, their compensation is not much more than gasoline money. No university can effectively create and effectively manage an undergraduate program staffed primarily by adjuncts. However, the students greatly benefit from those programs and genuinely seem to appreciate the efforts made by adjuncts to teach real-life engineering skills. This is only a partial solution because many universities are not favorably located, meaning close to metropolitan areas where petroleum engineers work in the upstream petroleum industry.

Distance learning through video conferences, internet, and possibly other means may meet the immediate needs of some companies, departments, or individuals, but this clearly is not a long-term solution for the primary education of petroleum engineering students.

Most large oil and gas producers and some of the larger service providers have training regimens for new engineering hires, but, in general, those programs are much less intensive than those of 25 or more years ago. Several industry professional organizations are redoubling their efforts to serve their constituencies and are increasing their roles in training beyond what the industry typically provides. Mentoring is a common practice in many companies, but its effectiveness is reduced if reduced staff numbers limit the time between mentor and mentee.

Industry must cultivate a skilled, young workforce of petroleum engineers to replace the retiring baby boomers. That requires sowing seeds for the future by supporting university PE programs through advisory programs to develop new course curricula. Industry also should support grant programs, internships, and adjunct teaching opportunities through volunteer efforts and financial subsidies. Participation requires breaking a myopic corporate mindset that demands results now. Current and future engineering students will become the lifeblood of the industry as oil and gas become harder to find and develop. Industry support of university PE programs now will show a high return on investment in the not-so-distant future. ✦

References

1. Bratvold, R.B., Begg, S.F., "Education for the Real World: Equipping Petroleum Engineers to Manage Uncertainty," SPE No. 103339, September 2006.
2. www.spe.org.
3. "Industry Working Together to Address 2007 Faculty Shortage," SPE Gulf Coast Section Newsletter, June 2007.

The author

D. Ronald Harrell is chairman emeritus of Ryder Scott Co. LP. He joined the consulting firm as a reservoir engineer in 1968, became vice-president in 1970, director in 1980, president in 1998, and chief executive officer in 2000. He retired as chairman in April 2006 after relinquishing his position as chief executive officer in March 2005. Harrell has managed reservoir engineering and geological studies worldwide, including property evaluations for acquisitions and divestitures, financing, reservoir management, gas supply analysis, gas storage studies, and litigation support. He graduated magna cum laude with a BS degree in petroleum engineering from Louisiana Tech University and was named its Distinguished Engineering Alumnus in 2002. He has been active in issues concerning reserve reporting requirements of the US Securities and Exchange Commission. Harrell is past chairman of the Society of Petroleum Engineers Oil and Gas Reserves Committee and currently sits on that committee as an observer. He is presently an SPE Distinguished Lecturer and will be recognized as an SPE Distinguished Member in November. His e-mail is rharrell7@comcast.net.

'Measured' approach needed for US fuels development, task force says

Nick Snow
Washington Correspondent

The US government must use its authority to stimulate timely technical advances and industry investment if it expects to use the nation's unconventional fuel resources before the overall economy is harmed by global oil supply and demand imbalances, competition for supplies, and higher prices, a government task force concluded.

A "measured" approach, in which government actively responds to or

Environmental impacts

Environmentalism has long hindered development of the oil and gas industry. But now—in a variety of places around the world—it also has become the means of taking projects away from their developers and putting them into altogether different hands. Consider Kazakhstan, which is using alleged environmental violations as a threat to revoke the license of a consortium led by Italy's Eni SPA unit Agip to develop the vast offshore Kashagan field.

Nurlan Isakov, the country's environment minister, said the work of the Agip KCO consortium, which includes Royal Dutch Shell PLC, ExxonMobil Corp., and ConocoPhillips, could be stopped because of environmental concerns. His remarks came as Eni and the Kazakh government began talks on the project's future.

Isakiv said if the obligations Agip has taken upon itself are not complied with, Kazakhstan is by law obliged to revoke the permit because further operations will cause even more ecological damage. Work at Kashagan may be stopped altogether, he said.

Deja vu

Does that remark sound familiar? If not, compare it to statements issued by the Russian government when it sought control of Shell's Sakhalin-2 oil and gas venture. According to one analyst, Isakiv wants to increase pressure on the consortium and change the terms to favor the Kazakh government.

According to reports, the consortium understands that the complaints raised by the Kazakh authorities are intended to raise the pressure on the group in talks over the Kashagan contract. To underscore the consortium's determination, Eni Chief Executive Paolo Scaroni is likely to arrive in Kazakhstan for talks this week. But any agreement could take months.

One consortium spokesperson said there should not be any surprises as KazMunaiGaz, the Kazakh national oil company, is a member of the consortium. That may be, but there may be other issues—and other parties—at play here.

Enter China

Just days before Kazakhstan issued its warning to the Eni-led consortium, it also signed an agreement to build pipelines to carry oil and gas from fields near the Caspian Sea to China. "The Caspian will be linked to western China," Kazakhstan President Nursultan Nazarbayev said after a meeting with Chinese leader Hu Jintao in the Kazakh capital of Astana on Aug. 18. According to one report, the agreement marks a setback for the European Union and the US, both of which have urged Kazakhstan to export oil and gas across the Caspian to western markets. Be that as it may, the Kazakhs clearly feel they have greater interests in serving nations to the east, mainly China.

Last year, Kazakhstan and China completed a pipeline from a field owned by Chinese National Petroleum Corp. in the central part of the republic to China's Xinjiang province.

Funny, no one seems to recall reading about any environmental impact reports prior to the construction of that line or, for that matter, any mention of environmental problems during its construction. ✦

mitigates major impediments and uncertainties to investment—could result in several million new barrels per day of production by 2035, reported the Task Force on Strategic Unconventional Fuels.

By contrast, it added, a "base case" approach, which assumes the current rate of development, existing laws, processes, and fiscal regimes, would make it "unlikely that significant investment in, or production of, unconventional fuels will occur in the foreseeable future."

An "accelerated" development approach would require government's sharing of considerable investment and risk with industry "but could perhaps double the incremental production achievable in the same timeframe," it said.

Primary uncertainties include access to resources on public lands; technology performance and efficiency; capital investment and operating costs; price and market risks; federal and state fiscal regimes; environmental standards, permitting processes, and timelines; infrastructure requirements; water requirements and availability; and socioeconomic impacts of development, the report said. It is posted at the task force's web site, www.unconventionalfuels.org.

Task force's origin

US Sec. of Energy Samuel W. Bodman established the task force in March 2006 as mandated under the 2005 Energy Policy Act. In addition to Bodman, it included the US Interior and Defense secretaries; governors of Colorado, Wyoming, Utah, Kentucky, and Mississippi; and representatives from three potentially affected communities. Gov. Jon Huntsman of Utah and Gov. Ernie Fletcher of Kentucky transmitted the initial report of its findings, recommendations, and options to Congress and the White House on Aug. 13.

The report said that, of the more than 2 trillion boe locked in domestic oil shale (including the Green River formation's 1.5 trillion boe in Colorado, Utah, and Wyoming), as much as

800 billion boe could be recoverable, depending on technology and economics, at around 25 bbl/ton. Production potentially could exceed 2.5 million b/d within 30 years, it added.

A strong response to the US Department of the Interior's 2005 offering of oil shale research, demonstration, and development leases on federal lands "signals that private industry may once again be ready to aggressively pursue the potential of the nation's oil shale resources," the report said.

It said US heavy oil resources in place are estimated at 60-100 billion bbl, with 2 billion bbl proved reserves and another 20 billion bbl potentially recoverable. With current production using enhanced recovery around 302,000 b/d (increased to 500,000 b/d when other processes are included), the report suggested that another 500,000 b/d of domestic heavy oil production could be achieved.

About 11 billion bbl of tar sands appear recoverable from the estimated 54 billion bbl of domestic resources in place, it said. Most of the deposits, about 32 billion bbl, are in Utah, with another 18 billion bbl in Alaska. The balance are in Alabama, Texas, California, Kentucky, and other states. Unlike Alberta's tar sands, those in the US are often consolidated or cemented and are "hydrocarbon-wet" instead of "water-wet," requiring new recovery technology, according to the report.

It said that while oil production from US tar sands currently is limited to minor volumes from a few California deposits, output could approach 200,000-300,000 b/d by 2025 with higher oil prices "and public actions to encourage projects."

CO_2 enhanced recovery

Carbon dioxide already is being used domestically in enhanced recovery at 82 projects to produce about 237,000 b/d from the estimated 300 billion bbl of conventional crude left behind in US reservoirs after primary and second production, the report said. Economics, CO_2's price, and relatively scarce infrastructure to deliver CO_2 to candidate oil fields currently constrain growth, it continued.

If delivery and other problems could be overcome, the report said that another 90-200 CO_2 enhanced recovery projects at $30-50/bbl oil prices could add 2.7-2.9 billion bbl of reserves and 350,000-400,000 b/d of production from 2010 to 2030. The projects would consume 400-600 bcf/year of CO_2, it said.

It estimated that first generation US coal-to-liquids plants would have capital costs of $70,000-100,000/b/d of capacity, or $3.5-5 billion for a 50,000 b/d plant. Produced fuels would be competitive at a $45-60/bbl world crude oil price, excluding costs for carbon capture and sequestration and tax credits for other subsidies, the report said. Plants smaller than 50,000 b/d would likely cost more, it added.

Most of the task force's recommendations in the report attempt to address major unconventional resource development impediments. It calls on Congress and the administration to:

- Provide an effective land tenure system.
- Develop an inclusive regulatory and permitting system that provides a predictable schedule.
- Create a fiscal regime to attract private development capital and a fast-track technology program to generate investment.
- Formulate effective and integrated local infrastructure plans.
- Establish a program to handle local social and economic impacts (including consideration of ways to direct mineral revenues to area communities).
- Develop an effective governmental structure at federal, state, and local levels.

The group also recommended international collaborations on unconventional fuels development, including forming a partnership with Alberta on oil sands and with other countries on oil shale. It also called on the federal government to work with affected states and communities in creating project development processes and conducting initial evaluations of investments which will be necessary to handle social and economic impacts.

The task force said that its next step will be to complete an EPACT-mandated program plan for commercializing US unconventional fuels—including detailed proposed objectives, strategies, key activities, and timelines—which will provide the basis for subsequent program implementation planning. ✦

Chinese NOCs double domestic upstream spending

Upstream spending on oil and gas operations in China by that country's three national oil companies jumped to $21.5 billion in 2006 from $12.6 billion in 2004, a greater increase than all of their international spending last year, including acquisitions.

While industry attention has focused on increased international activity by China's NOCs, the domestic expansion of PetroChina, CNOOC Ltd., and Sinopec is of greater importance in their competition with international oil companies, said Wood Mackenzie Ltd., Edinburgh, in a recent report. "All three companies have dramatically increased their expenditures on domestic exploration and production activities over the last 5 years to the extent that each company is now investing at a greater rate than most of the major IOCs," said Norman Valentine, senior corporate analyst for Wood Mackenzie.

Chinese NOCs' spending on field development has increased beyond most of the larger international companies. "At almost $9.40/boe, PetroChina's domestic upstream field development investment rate in 2006 was substantially higher than the average rate of the international majors at $7.50/boe," Valentine said. "Sinopec's and CNOOC's domestic investment rates of around $12/boe were also greater than the average rate of the international large caps, at $11/boe. In terms of activity, the differences are probably greater, as China has to some extent been sheltered from the full impact of the recent inflationary environment affecting upstream capital costs due to the lower costs of domestically sourced labor and materials."

The increased spending has paid off in several major discoveries by the Chinese companies. "PetroChina's multibillion-barrel Nanpu oil and gas field and Sinopec's giant Puguang gas discovery significantly strengthen the companies' portfolios, which are dominated by established and maturing producing fields," Valentine said. "Increased domestic expenditure has also increased liquid output from onshore legacy fields. For example, PetroChina has increased production from enhanced oil recovery projects in the Daqing field, while Sinopec has halted production declines from its Shengli area."

Wood Mackenzie said these discoveries are likely to maintain China's long-term production levels rather than trigger much of an increase in current production. However, analysts said the impact on China's gas development over the next 5-10 years is potentially more dramatic because of the large scale of gas reserves in the Sichuan basin and in Nanpu field. It could mean the NOCs will be more selective in pursuing some of the speculative overseas LNG opportunities and major international gas import pipeline developments, instead concentrating on the development of indigenous gas resources.

"Focusing E&P investment on China in our view provides the best opportunity for value creation for each of the NOCs. We expect the companies' heavy investment to continue until at least the end of the decade," Wood Mackenzie reported. Meanwhile, Chinese NOCs will continue searching out overseas acquisition opportunities as they seek to develop into larger, more internationally competitive organizations.

Much industry commentary has been devoted to the increase in overseas expenditure of China's NOCs, with their increasing appetite for multibillion-dollar asset acquisitions drawing much attention. "According to our analysis, total overseas expenditure by the three companies has indeed increased substantially over the last 2 years and reached $8 billion in 2005 and 2006," they said. ✦

MMS Lease Sale 204 attracts $290 million in apparent high bids

Apparent high bids totaling nearly $290 million were offered for 282 tracts in the western Gulf of Mexico at Lease Sale 204, reported the US Minerals Management Service Aug. 22 from New Orleans.

MMS officials received 358 bids totaling $369.5 million from 47 companies at the sale. Interest in deepwater and ultradeepwater tracts was high. Of the tracts receiving bids, 108 blocks were in 800-1,600 m of water, 43 were in 1,600-2,000 m of water, and 30 were in more than 2,000 m of water.

The latest sale offered 3,338 blocks covering 18 million acres in the western gulf's Outer Continental Shelf planning area off Texas.

Based on the number of total apparent high bids submitted, BP Exploration & Production Inc. topped the list with 91 bids totaling more than $31 million.

Statoil Gulf of Mexico LLC, however, placed 36 high bids totaling nearly $139 million—the highest total sum offered—and it held second place after BP for total number of apparent high bids submitted. All of these leases were in the Alaminos Canyon and Keathley Canyon areas of the gulf.

Statoil captured seven of the top 10 single highest bids submitted. It submitted the highest single bid of $37.6 million for Alaminos Canyon Block 810, which lies in more than 2,000 m of water.

Statoil Senior Vice-Pres. Oivind Reinertsen said, "These deepwater leases are promising acreage [that] we look forward to developing in the years to come, and they will contribute to securing our long-term commitment in the area."

The third highest single bid was submitted by Devon Energy Production Co. LP for Keathley Canyon Block 94. Devon, along with partner Petrobras America Inc., submitted more than $15.1 million for the tract, which lies in 800-1,600 m of water.

LLOG Exploration Offshore Inc. held the seventh highest spot for its $8.6 million bid on a tract in High Island, Area 138. Bois d'Arc Properties LP held the tenth highest spot for its $5.7 million bid for Alaminos Canyon Block 943. ✦

Top 10 companies by sum of apparent high bids

Table 1

Company	Total high bids	Sum of high bids, $
1. Statoil Gulf of Mexico LLC	36	138,889,688
2. BP Exploration & Production Inc.	91	31,015,727
3. Petrobras America Inc.	34	29,268,100
4. Devon Energy Production Co. LP	26	20,035,500
5. ConocoPhillips	24	12,341,000
6. Hydro Gulf of Mexico LLC	12	9,991,510
7. LLOG Exploration Offshore Inc.	3	9,401,880
8. Bois d'Arc Properties LP	2	6,115,000
9. Shell Offshore Inc.	3	4,442,426
10. Anadarko Petroleum Corp.	9	4,093,940

Source: US Minerals Management Service

Top 10 tracts by high bid

Table 2

Company	Block	Water depth, m	High bid, $
1. *Statoil Gulf of Mexico LLC	Alaminos Canyon 810	>2,000	37,588,800
2. *Statoil Gulf of Mexico LLC	Alaminos Canyon 811	>2,000	27,588,700
3. *Devon Energy Production Co. LP Petrobras America Inc.	Keathley Canyon 94	800-<1,600	15,128,500
4. *Statoil Gulf of Mexico LLC	Keathley Canyon 178	1,600-2,000	13,008,340
5. *Statoil Gulf of Mexico LLC	Keathley Canyon 136	800-<1,600	11,011,360
6. *Statoil Gulf of Mexico LLC	Keathley Canyon 135	800-<1,600	9,011,880
7. *LLOG Exploration Offshore Inc.	High Island Area 138	0-<200	8,635,575
8. *Statoil Gulf of Mexico LLC	Alaminos Canyon 767	>2,000	6,588,800
9. *Bois d'Arc Properties LP	Alaminos Canyon 943	>2,000	5,710,000
10. *Statoil Gulf of Mexico LLC	Keathley Canyon 405	>2,000	5,187,960

*Denotes the submitter.
Source: US Minerals Management Service

COMPANY NEWS

Transocean, GlobalSantaFe agree to merger of equals

Offshore drilling contractors Transocean Inc. and GlobalSantaFe Corp. agreed to a merger of equals, creating a company valued at about $53 billion.

In other recent company news:

- Houston-based drilling contractor Pride International Inc. has entered into a definitive agreement to sell its Latin America land drilling and workover and exploration and production services businesses to Brazilian private equity firm GP Investments Ltd. for $1 billion in cash.
- El Paso Exploration & Production Co., a subsidiary of El Paso Corp., Houston, reported plans to acquire Peoples Energy Production Co. for $875 million.
- PetroFalcon Corp., which has oil and gas operations in Venezuela through

its wholly owned Caracas subsidiary Vinccler Oil & Gas, has agreed to buy Lundin Latina de Petroleos SA (Lundin LDPSA), Caracas, for $41 million in a cash-stock transaction. Lundin LDPSA is the wholly owned Venezuelan subsidiary of Swedish firm Lundin Petroleum AB.

• Toreador Resources Corp. has sold all of its US properties for $19.1 million to RTF Realty Inc. of Dallas and plans to focus on its operations in the Black Sea off Turkey.

Transocean-GSF merger

The combined company, to be known as Transocean Inc., will retain principal offices in Houston. It will have a global fleet of 146 rigs and provide a full range of offshore drilling services in the world's key regions. It will have a substantial presence in ultradeep and deepwater drilling and additional growth from newbuild rigs.

Robert L. Long, who will continue as chief executive officer of Transocean, said, "This transaction will enhance our high-end floater fleet, including five newbuild ultradeepwater units, while growing our position in the worldwide jack up market, especially in the Middle East, West Africa, and North Sea."

Under terms of the agreement, Transocean shareholders will receive $33.03 in cash and 0.6996 share of the combined company for each Transocean share. GlobalSantaFe shareholders will receive $22.46 in cash and 0.4757 share of the combined company for each GlobalSantaFe share.

The aggregate total cash paid to both companies' shareholders will be $15 billion, which will be funded through a bridge loan due 1 year after closing, which is expected by yearend, subject to the approval of both companies' shareholders, regulatory clearances, receipt of funds under the committed financing, and other closing conditions.

Transocean has received a commitment letter from Goldman, Sachs & Co. and Lehman Bros. Inc. providing for this financing. Transocean expects to refinance the bridge loan with a mix of bank loans and debt securities.

The new company also will have a $33 billion revenue backlog. And the company intends to dedicate its first 2 years of free cash flow to reducing debt.

Following the merger, GlobalSantaFe Chairman Robert E. Rose will serve as chairman of Transocean, Transocean's Chief Executive Officer Robert L. Long will continue in his role, and Jon A. Marshall will assume the position of president and chief operating officer.

Pride sells LatAm units

Pride's sale of its Latin American businesses is expected to close by the end of the third quarter, subject to customary closing conditions, including a working capital adjustment of the purchase price.

The company's Latin America land business is comprised of 73 land drilling rigs, 135 workover rigs, and two lake-drilling barges. Its E&P services business provides various services to complete, maintain, and enhance production from oil and gas wells.

Pride reported combined 2006 revenues of $823.9 million for the two business units, which operate in eight countries in Latin America.

Following the close of the transaction, Pride's remaining land-based drilling and workover operations will consist of five land drilling and workover rigs in Chad along with two other land rigs in Kazakhstan and Pakistan.

Pride said proceeds from the sale, expected to be largely tax exempt, could be used for general corporate and strategic purposes, including potential funding for the construction of two ultradeepwater drillships and for future growth opportunities.

Pride recently placed a $680 million order with Samsung Heavy Industries Co. Ltd. for a newbuild drillship with advanced and dual-activity capability for use in ultradeep water (OGJ, July 16, 2007, Newsletter).

The drillship will be capable of drilling to a TVD of 40,000 ft in water as deep as 12,000 ft. It initially will be equipped for drilling in 8,000 ft of water, Pride said.

El Paso-Peoples deal

Peoples, which is a unit of Integrys Energy Group, owns an estimated 305 bcf of gas equivalent of proved reserves and owns 72 MMcfd of production.

The assets involve properties in Arkansas, Louisiana, Texas, and Mississippi.

El Paso expects to close the transaction in the third quarter.

El Paso said it will finance much of the acquisition with proceeds from its previously announced divestiture program covering 220-270 bcf, or 10% of total reserves. Integrys said the sale fit into its strategy to sell noncore assets.

PERSONNEL MOVES AND PROMOTIONS

ConocoPhillips announces management changes

ConocoPhillips has announced changes in several management positions effective Sept. 1.

Bill Berry, executive vice-president for E&P in Europe, Asia, Africa, and the Middle East, has elected to retire in January 2008 after 31 years of service. He will serve in a transition role from Sept. 1 until January.

John Lowe, executive vice-president, commercial, will become executive vice-president, E&P, and **Ryan Lance**, currently senior vice-president, technology, will become president, E&P for Europe, Asia, Africa, and the Middle East.

Other moves

Chevron Corp. has named **John S. Watson** executive vice-president, strategy and development, a new position effective Jan. 1, 2008.

In his new position, Watson will oversee business development, mergers and acquisitions, strategic planning, and Project Resources Co., which supports the development of major capital projects within Chevron.

Watson currently serves as president of Chevron International E&P, a role he has held since December 2004. He joined the company in 1980 as a financial analyst and has served in various roles, including president of Chevron Canada Ltd. and vice-president, strategic planning, for Chevron. Watson also served as the integration executive for the merger of Chevron and Texaco Inc., and in October 2001 was named vice-president and chief financial officer of the company.

Associated with this appointment, Chevron announced that it will restructure its global upstream operations into four operating companies. The new organizational structure for Chevron's worldwide E&P group expands from two companies—Chevron International E&P and Chevron North America E&P—to four: Africa and Latin America; Asia-Pacific; Eurasia, Europe, and Middle East; and North America.

Newfield Exploration Co. has approved several executive promotions.

David F. Schaible was named president and chief operating officer. Schaible will continue to report to **David A. Trice**, who will retain the title of Newfield chairman and chief executive officer.

Schaible was one of the founders that joined **Joe B. Foster** in 1989 when the company began operation and since has held positions of increasing responsibility within Newfield. Prior to this promotion, Schaible served as Newfield's executive vice-president, operations and acquisitions.

Lee K. Boothby will be named senior vice-president, acquisitions and business development, effective Oct. 1, and will relocate to the company's headquarters in Houston. He currently is vice-president, Midcontinent.

George T. Dunn will be named vice-president, Midcontinent, and will be relocating to Tulsa, effective Oct. 1. Dunn was most recently vice-president, Gulf Coast.

John H. Jasek will become vice-president, Gulf Coast, effective Oct. 1. Jasek was previously vice-president, Gulf of Mexico.

St. Mary Land & Exploration Co. has appointed **Stephen Pugh** senior vice-president of the company and regional manager of the ArkLaTex region, which includes the company's operations in Shreveport, La.

Pugh succeeds **David Hart**, who is retiring after 15 years.

Pugh most recently served as managing director for Scotia Waterous in Houston. Previously, he worked for Burlington Resources Inc. and its successor ConocoPhillips. Pugh began his career in 1981 at Superior Oil Co.

Separately, St. Mary has promoted **Greg Leyendecker** to vice-president of the company and regional manager of the Gulf Coast region.

Prior to this appointment, Leyendecker had managed the Gulf Coast region on an interim basis. He joined the company in late 2006 as operations manager for the Gulf Coast region. He previously has worked for Unocal Corp. and its successor owner Chevron in technical and management positions.

Oneok Partners LP has reported several executive appointments associated with the partnership's plan to begin in the third quarter to report its financial results in four segments: two in natural gas—gathering and processing, and gas pipelines—and two in natural gas liquids—NGL gathering and fractionation, and NGL pipelines.

Norton

The partnership has promoted **Pierce H. Norton II** to executive vice-president, natural gas.

Spencer

Separately, **Terry K. Spencer** has been

PetroFalcon-Lundin LDPSA deal

Following these transactions, Lundin Petroleum will become the largest shareholder in PetroFalcon, holding 42.5% of the shares.

Lundin plans to have two representatives on the board of PetroFalcon, a Venezuelan company. Lundin Petroleum is a Swedish independent oil and gas company with assets in Europe, Africa, Russia, and the Far East.

PetroFalcon will issue about 64 million shares to Lundin Petroleum, and PetroFalcon will receive Lundin Venezuela's 5% interest in the Baripetrol joint venture in Venezuela, as well as $30 million in cash from the acquisition and private placement.

Baripetrol operates the Colon unit in western Venezuela and has gross production of 10,500 b/d of oil and 5 MMcfd of gas.

The agreements are subject to the negotiation of a sales agreement and to all required regulatory approvals, including the approval of the Venezuelan Ministry of Energy and Petroleum.

RTF buys Toreador assets

Toreador said it wanted to concentrate on developing Black Sea gas discoveries in the South Akcakoca subbasin's (SASB) deeper water and on exploration in the sea's Thrace basin.

The US properties, which consist primarily of nonoperated working interests in about 700 wells in five states, had proved reserves of 700,000 bbl of oil and 4.1 bcf of gas at yearend 2006, Toreador said.

The book value of the properties is about $10.3 million, Toreador said—about 4% of the aggregate book value of the company's total oil and gas properties.

The deal is expected to close by Aug. 31 and the cash sale is effective from Sept. 1.

The properties have been sold on an "as is, where is" basis. Net proceeds from the sale will be added to Toreador's working capital and used for possible modest debt repayment and for other strategic initiatives.

Toreador has begun preliminary planning to bring gas discoveries in the deeper portion of the SASB into production as soon as possible. It has just spudded an exploratory well in the Thrace portion of the Black Sea with its 50:50 Turkish industrial partner Hema Endustri AS. ✦

promoted to executive vice-president, NGL.

Garth Johnson, chief financial officer of TAG Oil Ltd., has been appointed chief executive officer, effective Sept. 1.

On that date, Johnson's predecessor **Drew Cadenhead** will resign as chief executive, president, and director of the company. Cadenhead will remain with the company in a consulting role during an agreed transition period. TAG Oil's board will be evaluating the company's executive management needs.

Johnson, a certified general accountant, has extensive experience in financing, accounting, and regulatory reporting for both US and Canadian companies. He has been a director for several upstream oil companies operating in New Zealand and Papua New Guinea.

Jon Hrobsky has been elected deputy director of the US Department of the Interior's Minerals Management Service. He joins MMS deputy director **Walter Cruickshank**, but each will oversee specific programs.

Hrobsky will assist MMS Director **Randall Luthi**, who was recently nominated to his post (OGJ, Aug. 6, 2007, p. 5).

Hrobsky formerly served as deputy director in Interior's Office of Congressional and Legislative Affairs. Previously, he worked as legislative director and senior legislative assistant with two congressmen from Colorado.

Hrobsky's work has included helping MMS in the development of rules and regulations for the Energy Policy Act of 2005, the Gulf of Mexico Energy Security Act of 2006, and the 5-Year Leasing Program for 2007-12.

OIL&GAS JOURNAL Previous Page | Contents | Zoom In | Zoom Out | Front Cover | Search Issue | Next Page qMags

...mpasas gets first commercial field ...ith Strawn gas in Fort Worth basin

John Sobehrad
Geo-Logic
Temple, Tex.

Ralph Dozier
Intrepid Exploration & Production Co.
Blooming Grove, Tex.

The Fort Worth basin was noted for prolific oil and gas production long before the discovery of Newark East field in 1981 and the extensive Barnett shale gas play (Fig. 1).

In 1917, the discovery of Ranger field stimulated one of the largest exploration and development drilling "booms" in Texas.[1] Ranger field produces from the Atoka-Bend formation, a sandstone-conglomerate reservoir that directly overlies the Barnett formation.

Operators drilled more than 1,000 wildcat tests in and around the Fort Worth basin attempting to duplicate the success of Ranger field. These wildcat efforts resulted in the discovery of more oil/gas fields and production from numerous other reservoirs including Strawn fluvial/deltaic sandstone, Atoka-Bend fluvial/deltaic sandstone and conglomerate, Marble Falls carbonate bank limestone, Barnett siliceous shale, and Ellenburger dolomitic limestone (Fig. 2).

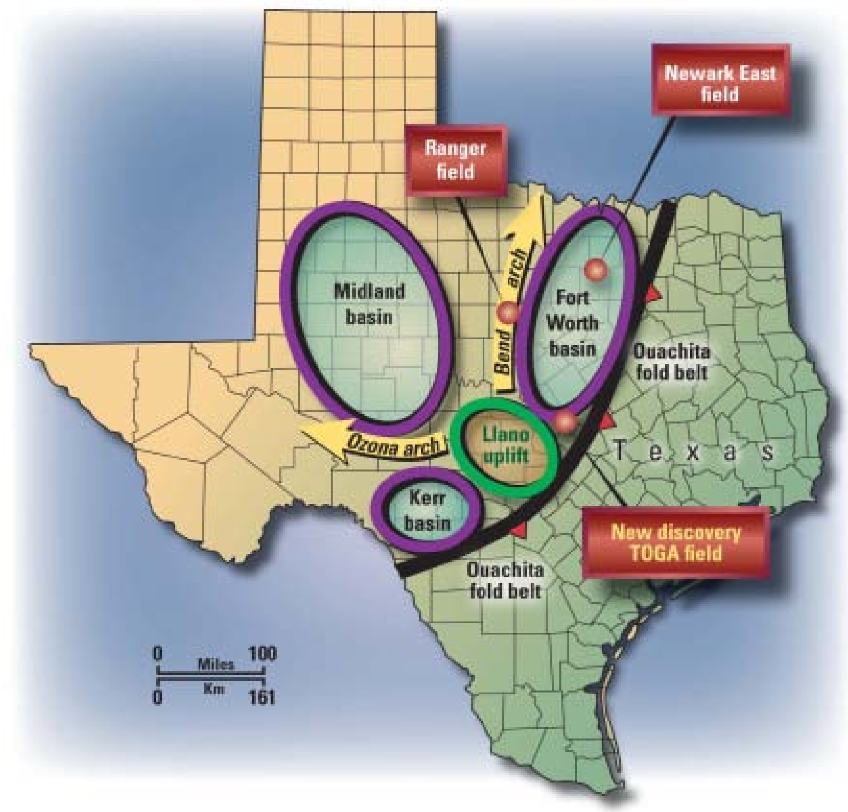
While most companies are concentrating on the Barnett gas play, Scully Energy Corp., private Salado, Tex., independent, focused on the productive reservoirs above and below the Barnett. Scully Energy in mid-2006 discovered an important gas field, TOGA (for Texas Oil and GAs), in southeastern Lampasas County, Tex. TOGA field produces from two of multiple Strawn reservoirs and has 55-65 bcf of gas or more recoverable by the first author's estimate.

TOGA is the first commercial oil or gas field in Lampasas County.

In addition to the Strawn reservoirs, Scully Energy encountered significant oil and gas shows in the Atoka-Bend, Marble Falls, and Ellenburger formations. Subsequent geological work indicates potential traps and the possibility for additional new discoveries.

GENERALIZED STRUCTURAL FEATURES

Fig. 1



Drilling history

Scully Energy's interest in the southern part of the Fort Worth basin is the result of two key wells drilled in 1918 and 1949.

The 1918 well, New York Syndicate/Tienert No. 1, is one of the 1,000-plus wildcat tests drilled in an effort to extend the Ranger Atoka-Bend play to the south along the southeastern flank of the Bend arch. Tienert-1 encountered oil shows in the Marble Falls and Ellenburger formations at 3,400 ft. Records indicate the "well penetrated a 30 foot oil bearing zone and showed considerable oil and much gas." However, the Tienert-1 well was deemed noncommercial and was plugged.

The 1949 well, Susman/Gotcher No. 1, was drilled to 1,450 ft and penetrated only the upper portion of the Strawn section.

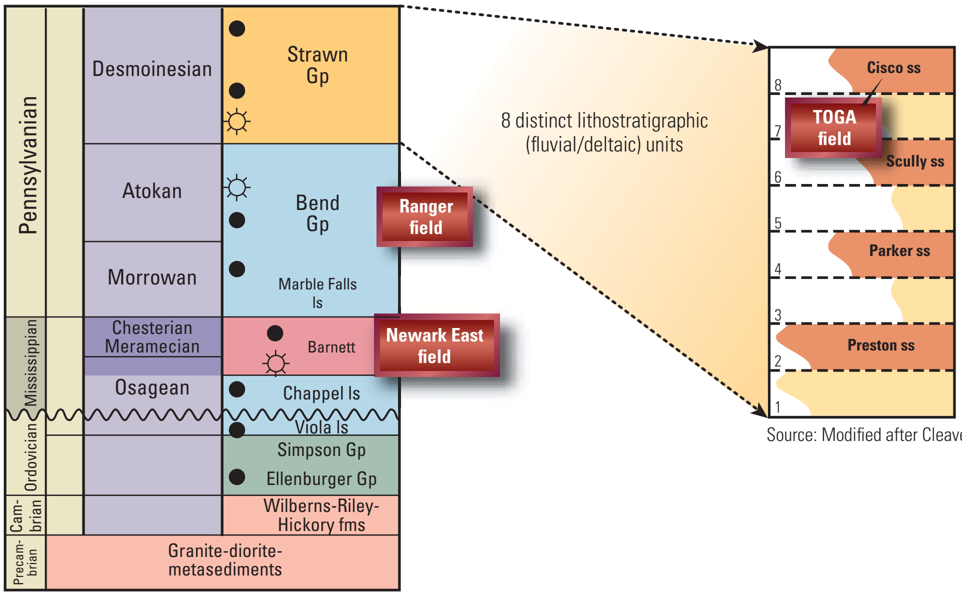
Records indicate a shut-in gas well from the Strawn reservoir that tested 2 MMcfd of gas. The well was eventually plugged due to lack of a gas market and infrastructure.

The TOGA field discovery well, Scully/Gotcher No. 1, was drilled offset to the Susman/Gotcher-1 well.

Scully Energy was drilling TOGA field's seventh well as this article went to press, and one well is within a few hundred feet of the Coryell County line. Three wells have been placed on 72-hr tests, and the start of gas production awaits installation of a 6-mile pipeline along right-of-way as yet not selected.

Fort Worth basin generalized stratigraphy

Fig. 2



Source: Modified after Montgomery et al., 2005

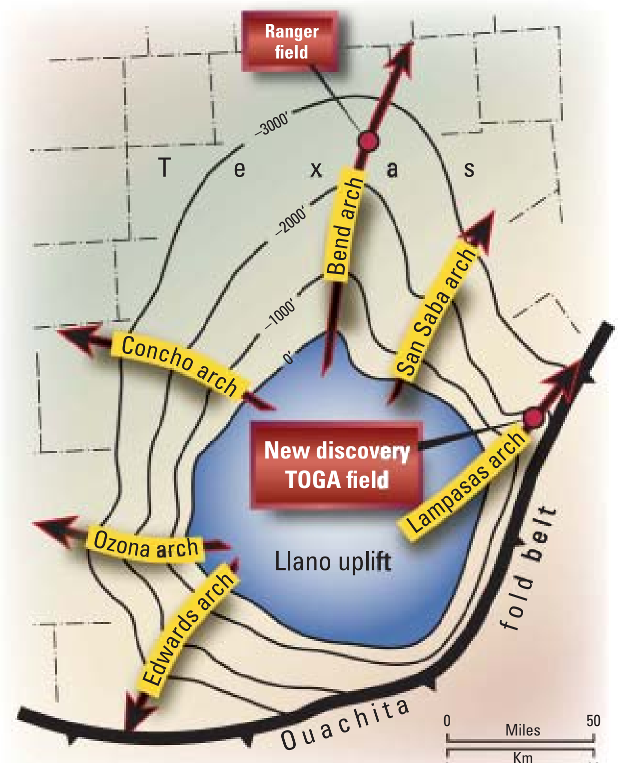
Source: Modified after Cleaves,1975

Geological setting

TOGA field is located on the Lampasas arch at the juncture of the south Fort Worth basin, the western edge of the Ouachita fold belt, and the northeast flank of the Llano uplift (Fig. 1). All

Llano uplift generalized geology on base Barnett

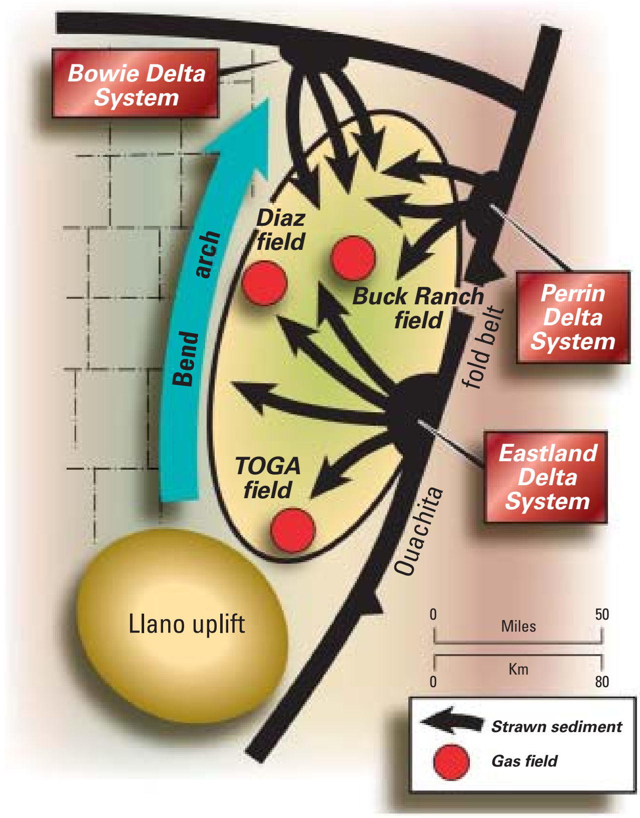
Fig. 3



Source: Modified after Woodruff et al., 1975, and Cheney, 1940

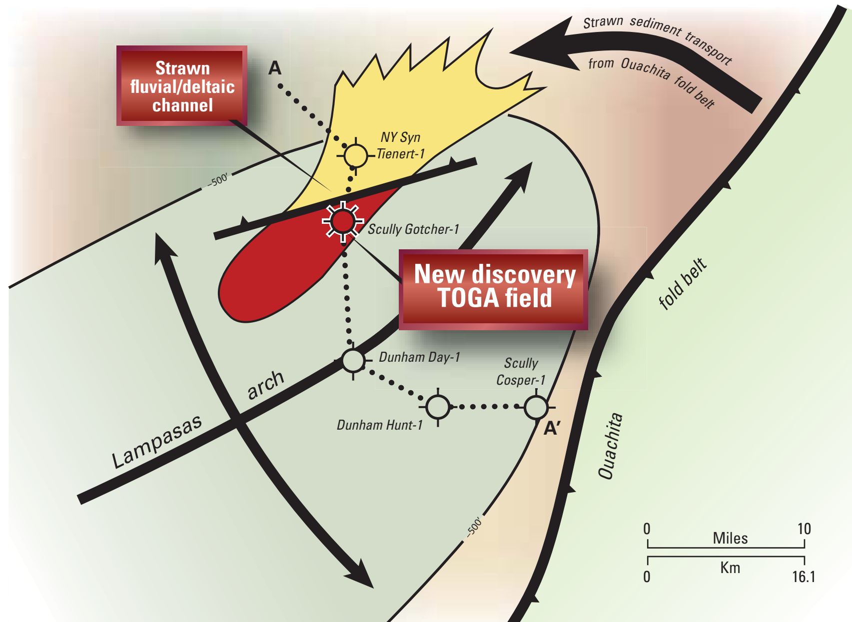
Fort Worth basin generalized delta systems

Fig. 4



Generalized geology, top Strawn reservoir, Toga field

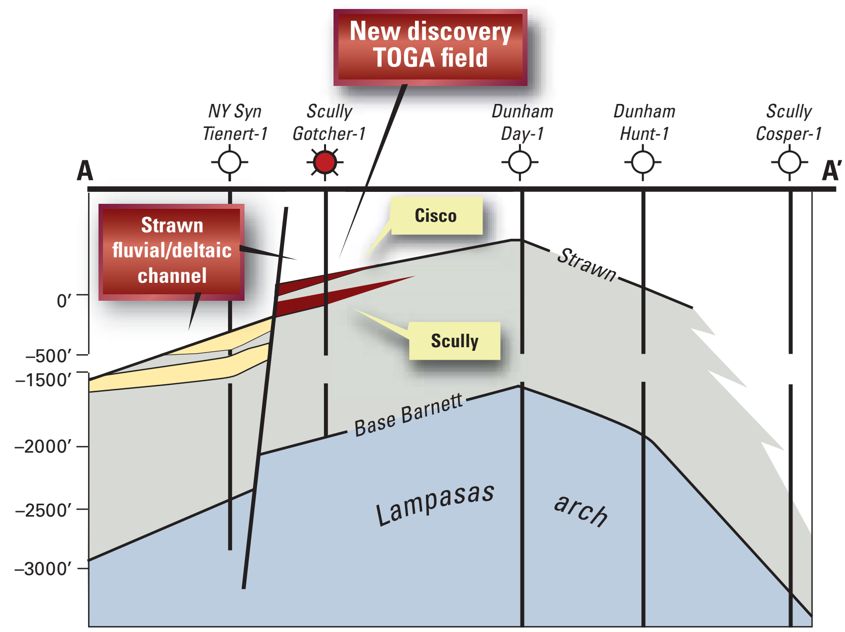
Fig. 5



Source: Modified after Smith, 1980, and Flawn, 1961

Cross section through TOGA field, Lampasas arch

Fig. 6



three structural features are important components to the development of the TOGA field reservoir and trap.

The Fort Worth basin is classified as a foreland basin associated with the Ouachita orogeny. The Ouachita orogeny is a major thrust fold belt that began during the Mississippian and continued throughout the middle to late Pennsylvanian.[2]

The resulting Fort Worth basin is a north-south elongated trough that is parallel and bounded by the Ouachita fold belt on the east, bounded on the west by the Bend Arch, and bounded by the Llano uplift to the south.[3] The Strawn sediments in the Fort Worth basin were derived from the rising forelands of the Ouachita fold belt.

The Llano uplift occurred during Pennsylvanian time and is also associated with the Ouachita orogeny (Fig. 3). The Llano uplift is ovate in shape and is structurally complex with numerous faulting and structural folding or arches that developed in a radial pattern around the uplift. It is along these arches where major oil and gas fields have been discovered, such as Ranger field and subsequently TOGA field.

Strawn deposition

Three major delta systems dominated Strawn deposition in the Fort Worth basin (Fig. 4).[4]

Depositional thickness of the Strawn sediments ranges from 4,500 ft in the north part of the basin to 1,500 ft in the southern part of the basin. The Eastland Delta system filled the south Fort Worth basin and is associated with numerous oil and gas fields, including TOGA field.

The westerly prograding Eastland Delta system deposited Strawn sediment from the rising Ouachita fold belt into the Fort Worth basin. The orogeny of the Llano uplift and subsequent Lampasas arch were contemporaneous with Strawn deposition and controlled the accumulation of the sediments.

The Strawn sediments were funneled and deposited along the north flank of the Lampasas arch (Figs. 5 and 6). Surface geology[2] corroborates the depositional direction from the Ouachita fold belt. The Llano uplift acted as a barrier to the southwest where the Strawn sediment thins appreciably.

Strawn stratigraphy

Previous detailed subsurface work indicates eight distinct lithostratigraphic units throughout Strawn deposition in the Fort Worth basin (Fig. 2).[4 5]

The Strawn sediments are related to fluvial-deltaic and fan-delta systems. Each lithostratigraphic unit represents a depositional cycle of the progradational delta. All eight depositional cycles are recorded in the northern part of the Fort Worth basin, whereas only four of the depositional cycles are noted in the southern part of the basin.

The initial TOGA field Strawn reservoir, termed the "Cisco," is associated with the last unit or depositional cycle. The "Scully" Strawn reservoir (Unit 6) is also productive and is waiting production testing. The last two units, "Parker" and "Preston," are prospective and have excellent production potential.

Strawn trap and reservoir

The trap for TOGA field is a combination stratigraphic and faulted anticline (Figs. 5 and 6).

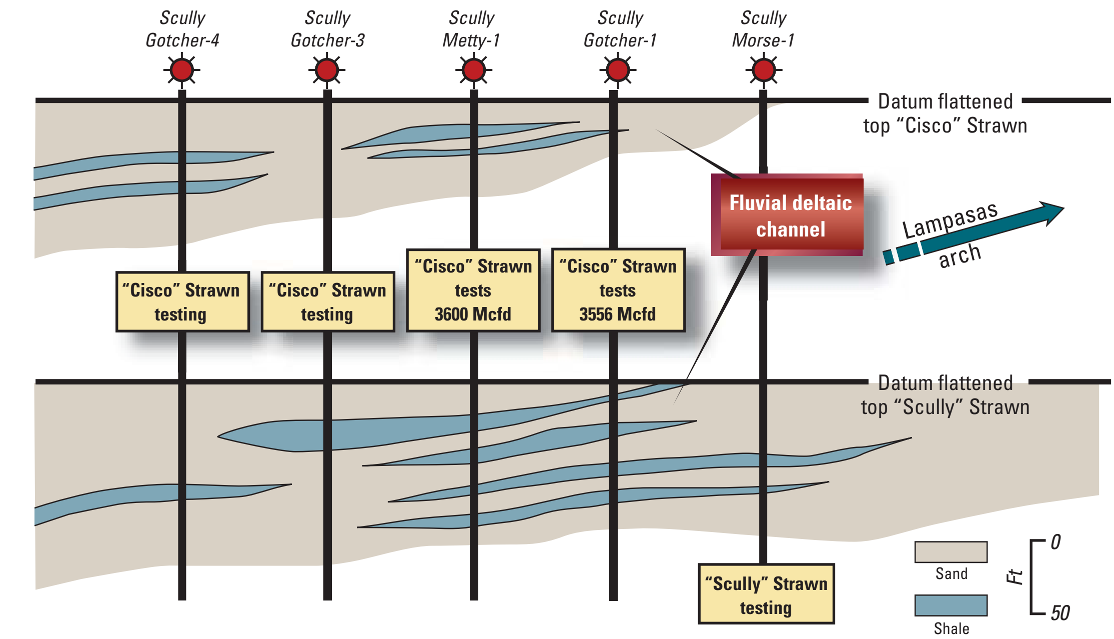
This type of trap is most common in the Strawn reservoirs of the Fort Worth basin and is also associated with the largest Strawn fields.[4]

The Strawn reservoirs are classified as fluvial/deltaic sediments and were deposited in a shallow basin environment.[5] The log profiles of the Strawn reservoirs from TOGA field wells exhibit the type of geometry from a fluvial/deltaic system and are more specifically interpreted to be delta front facies and distributary channel sands (Fig. 7).

The reservoirs of Diaz (Erath County, 1971) and Buck Ranch (Parker County, 1975) fields are analogous to the reservoirs of TOGA field (Fig. 4). The reservoir of Diaz field is from the Eastland

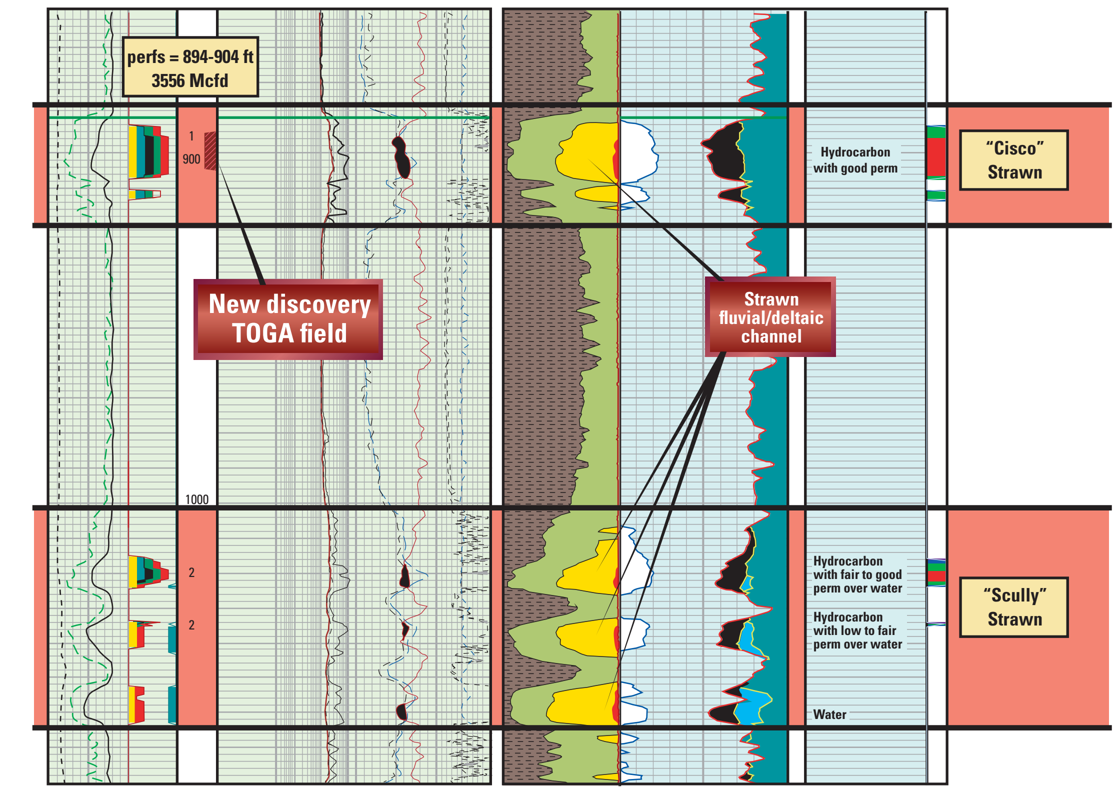
TOGA FIELD CROSS SECTION

Fig. 7



TYPE LOG, GOTCHER-1, TOGA FIELD

Fig. 8



Delta System, and the wells produce 1+ bcf from a 25-30-ft zone. The reservoir of Buck Ranch field is from the Perrin Delta System, and those wells produce 600+ MMcf from a 15-20-ft zone.

The TOGA Strawn reservoir is fine-medium grained sandstone with a porosity of 15-20%. The thickness ranges from 30 to 80 ft (Fig. 8). The dominant drive mechanism for the Strawn reservoirs in the Fort Worth basin is solution gas. It is assumed the drive mechanism for TOGA field will also be solution gas.

Reserve analysis for the Cisco Strawn reservoir indicates a recoverable 35+ bcf. The Scully Strawn reservoir is waiting on testing, but preliminary estimates indicate a recoverable 20-30+ bcf. ✦

References

1. Matteson, W.G., "A Review of the Development in the New Central Texas Oil Fields During 1918," AAPG Bull., Vol. 3, No. 1, 1919, pp. 63-211.

2. AbdelWahab, M.M., "Stratigraphy of the Strawn (Pennsylvanian), Colorado River Valley, North-Central Texas," unpublished master's thesis, University of Texas, 1980.

3. Montgomery, S.L., et al., "Mississippian Barnett Shale, Fort Worth basin, north-central Texas: Gas-shale play with multi-trillion cubic foot potential," AAPG Bull., Vol. 89, No. 2, 2005, pp. 155-175.

4. Cleaves, A.W., "Upper Desmoinesian-Lower Missourian Depositional Systems (Pennsylvanian), North-Central Texas," unpublished PhD dissertation, University of Texas, 1975.

5. Wandling, D.E., "The Geometry and Stratigraphic Relationship of Fluvial/Deltaic and Shallow Marine Facies in the Upper Part of the Upper Strawn Group (Pennsylvanian)," unpublished bachelor's thesis, Baylor University, 1984.

Bibliography

Cheney, M.G., "Geology of North-Central Texas," AAPG Bull., Vol. 24, No. 1, 1940, pp. 65-118.

Flawn, P.T., et al., "The Ouachita System," University of Texas Bureau of Economic Geology Pub. No. 6120, 1961.

Smith, S., "The Stratigraphy of the Travis Peak Formation across the Lampasas Arch, Central Texas," unpublished bachelor's thesis, Baylor University, 1980.

Woodruff, C.M., et al., "Lineaments of Texas—Possible Surface Expressions of Deep-Seated Phenomena," Geothermal Resource Assessment for the State of Texas, University of Texas Bureau of Economic Geology, 1984.

The authors

John Sobehrad (sobehrad@sbcglobal.net) is an independent geological/geophysical consultant and owner of the company Geo-Logic. He began his career in the late 1970s and has held various positions from wellsite geologist to chief exploration geologist and president. His experience has been onshore in Texas, Oklahoma, Louisiana, Mississippi, Montana, North Dakota, and Morocco. Offshore experience includes the Gulf of Mexico and the Atlantic basins of Morocco. He has BS in geology from the University of Wisconsin-Eau Claire.

Ralph Dozier is a geophysicist and owner of Intrepid Exploration & Production Co. He began his career in 1952 working for Precision Exploration Co. on a seismograph crew in the Williston basin, Permian basin, South Texas, and the Gulf Coast. In 1961, he became chief geophysicist for Cabot Corp. and worked worldwide. In 1975, he became director of domestic geophysics and later exploration manager for Union Texas Petroleum. In 1984, he began work as a consultant for Edwin L. Cox Co. in Corpus Christi. He majored in geology at the University of Houston.

Tajikistan

Tethys Petroleum Ltd., Guernsey, Channel Islands, said it is negotiating a production sharing contract with the Tajikistan government covering the large Kulibsky (Kulob) area in the Afghan-Tajik basin in southwestern Tajikistan.

The company expects to have a PSC or similar agreement in place by the fall of 2007. That will allow field rehabilitation to start and seismic data to be shot to firm up several attractive leads.

The company said the Kulob area has existing discoveries in a proven hydrocarbon system with several source and reservoir rocks and large structures created by tectonic activity and active salt movement.

California

Tri-Valley Corp., Bakersfield, spudded a well to shallow Upper Vaca tar sands at its Pleasant Valley project near Oxnard in California's Ventura basin.

After taking a vertical core, the company plans to drill 1,500 ft horizontally and inject 600° steam to repressurize the reservoir.

The Upper Vaca is as thick as 500 ft compared with the Canadian tar sands that typically occur in 60-ft stringers, Tri-Valley said.

The plan is to drill multiple wells to Upper Vaca before drilling deeper into the Lower Vaca. The company also intends to drill a 10,000-ft exploration well to appraise at least seven other oil-bearing zones in the Ventura basin, which as one of the world's deepest basins contains sediments to about 65,000 ft.

Pennsylvania

Atlas Energy Resources LLC, Philadelphia, and its investment partnerships have drilled seven vertical wells to the Devonian Marcellus shale in western Pennsylvania, six of which have been completed with results that pleased management.

The black, organic rich Marcellus shale is 100-150 ft thick at 7,000-8,500 ft on the company's leases, which total 213,000 acres.

The company plans to drill several more vertical wells in the next few months followed by a full gas development program starting in the fourth quarter of 2007.

ESTIMATING DRILLING COSTS—Conclusion

Systems approach combines hybrid drilling cost functions

Mark J. Kaiser
Allan G. Pulsipher
Center for Energy Studies
Louisiana State University
Baton Rouge

Drilling costs can be estimated with a combination of established, analytic techniques. This article, concluding a three-part series, presents a general framework to estimate costs with a formalized systems perspective.

This framework combines regression-based techniques, as employed in the joint association survey, with the multidimensional attributes of drilling, as incorporated in the mechanical risk index (MRI), directional difficulty (DDI), and difficulty index (DI) models (OGJ, Aug. 6, 2007, p. 39; Aug. 13, 2007, p. 46). A generalized methodology to frame the drilling cost estimation problem is presented and illustrated with an example from the Gulf of Mexico.

Drilling objectives

The objective in drilling a hydrocarbon well is to make hole as quickly as possible subject to the technological, operational, quality, and safety constraints associated with the process. These objectives are frequently conflicting and depend on factors that interrelate; vary with respect to time, location, and personnel; and are subject to significant private and market uncertainty.

Drill rates are often constrained by factors that the driller does not control and in ways that cannot be documented. In many situations, the causes of dysfunction are complex, occurring simultaneously, where effective solutions have not been developed.

Evaluation of drilling performance commands a high degree of visibility across oil and gas companies, and over the past few decades, various methods have been proposed to evaluate drilling cost and complexity. Understanding the drilling process requires isolating the factors of drilling and quantifying their interaction.[1-4] There is no way to identify all of the characteristics of drilling that might be important, but we can observe many characteristics, and in practice it is usually sufficient to consider a set of factors that adequately represent the technical aspects of drilling conditions.

Well characteristics are measured directly, while operator experience and wellbore quality frequently need to be represented by other variables. Many unobservable factors also affect drilling performance, such as well planning and preparation, project management skills, communication and training,[5-10] but these variables are usually outside the scope of analysis.

The premise of a systems approach to cost estimation is that process characteristics from several wells will allow the factors that influence drilling cost to be discovered. We first outline the drilling performance benchmarks and estimation techniques common in industry. Main factors that characterize the drilling process are then defined. The generalized functional approach is specified and calibrated, and an example is used to illustrate the procedure.

Performance benchmarks

Two methods are commonly used to benchmark drilling performance.

The first method is based on experimental design and controlled field studies. Typically, one or more parameters of the drilling process are varied and the impact of the variable(s) on output measures such as the rate of penetration (ROP) or cost/ft (CPF) examined.

The second method to study factor effects is based on an aggregate assessment of well data. In this method, data that characterize a set of wells are collected, and relationships are established between the variables based on empirical modeling techniques.

The aggregate approach to analysis uses a set of drilling data and seeks to discover relationships between vari-

Based on material published in SPE's Drilling & Completion Journal, June 2007.

ous factors of drilling and the cost and complexity of the well bore. In this approach, wells drilled under a wide variety of conditions provide the raw data to explore the manner in which factors contribute to drilling cost.

In the Gulf of Mexico, the joint association survey (JAS) and the mechanical risk index (MRI) are popular methods used to evaluate drilling cost and complexity. The JAS estimates drilling cost using survey data and quadratic regression models constructed from four descriptor variables. The MRI is a risk index that employs six primary variables and 14 qualitative indicators to characterize wellbore complexity. For additional details on these metrics, see the first two parts of this series (OGJ, Aug. 6, 2007, p. 39; Aug. 13, 2007, p. 46).

Factors

There are many factors and events that affect the time and cost to drill a well. Measurable factors include the physical characteristics of the well, geology, and drill parameters; indirect characteristics, such as operator experience and wellbore quality, are represented through other variables.

Factors such as well planning and execution, team communication, leadership, and project management skills will also affect drilling performance but are often considered beyond the scope of analysis.

Associated with every well w is a vector of dependent variables, φ(w), and a matrix of observations of independent variables, X(w). The matrix of observations is used to explain the dependent variables and is selected based on the underlying engineering and mechanical processes associated with drilling, the choice of dependent variable, data availability, and the level of classification.

There is no way to identify all the relevant characteristics of drilling, but we can identify many factors, and in practice it is only necessary to identify the set of factors that describe the primary elements of the process.

Equations

$$HL = \{\sum_{i=1}^{l} L(S_i) \mid A(S_i) \geq 85°, i = 1,\ldots,l\} \qquad (1)$$

$$HS = \frac{\sum_{i=0}^{k} D_i L_i^*}{\sum_{i=0}^{k} L_i^*} \qquad (2)$$

$$VR = \pi \sum_{i=0}^{k} R_i^2 L_i^* \qquad (3)$$

$$CI = \begin{cases} 1, FP > 10{,}000 \text{ psi or } T > 300°F., \\ 0, \text{otherwise} \end{cases} \qquad (4)$$

$$HR = \frac{HL}{DI} \qquad (5)$$

$$AR = \frac{HD}{VI} \qquad (6)$$

$$ER = \frac{TD}{VD} \qquad (7)$$

$$MWA = \frac{\sum_{i=0}^{k} MW(L_i^*) L_i^*}{\sum_{i=0}^{k} L_i^*} \qquad (8)$$

$$MWMX = \max_{L_i^*} MW(L_i^*) \qquad (9)$$

$$ROP = \frac{TD}{DHD} \qquad (10)$$

$$CPF = \frac{DHC}{TD} \qquad (11)$$

$$\Omega = \{(X_1,\ldots, X_p) \mid A_i \leq X_i \leq B_i\} \qquad (12)$$

$$\varphi(\Omega) = \alpha_0' + \sum_{i=1}^{q} \alpha_i' X_i \qquad (13)$$

Nomenclature

HL	=	Length of horizontal section of well
L	=	Casing length
S_i	=	Segment of casing string
$A(S_i)$	=	Angle of segment
D	=	Depth
HS	=	Hole size
VR	=	Volume of rock removed
R	=	Wellbore radius
FP	=	Formation pressure
CI	=	Complexity index
HR	=	Horizontal ratio
AR	=	Aspect ratio
ER	=	Extended reach ratio
MW	=	Mud weight
MWA	=	Average mug weight
MWMX	=	Maximum mud weight
ROP	=	Rate of penetration, ft/day
CPF	=	Cost/ft, $/ft
Ω	=	Design space

Well characteristics

A wellbore is a three-dimensional tubular structure that is described in geometric terms with respect to the length, diameter, and curvature of the hole's trajectory. The drilled interval (DI) is the difference between the total depth (TD) and the spud depth (SD), DI = TD – SD, while the vertical interval (VI) is the difference between the vertical depth (VD) and spud depth, VI = VD – SD. The spud depth is the distance from the rotary table to the seabed.

A well consists of segments of casing string S_i oriented at the angle $A(S_i)$ relative to a reference coordinate system. The maximum angle of the wellbore is computed as $MA = \max_i A(S_i)$. If MA ≥ 85°, the well is categorized as a horizontal well under the indicator variable HW: HW = {1, MA ≥ 85°; 0, otherwise}. If $L(S_i)$ denotes the length of well section S_i, then the total length of the horizontal section of a well is denoted as HL, Equation 1.

Each casing section has a diameter $D_i = D(S_i)$ and radius $R_i = R(S_i)$, and length $L_i = L(S_i)$ measured from the rotary table. If k = NS represents the number of strings associated with the well, then a well is characterized by the vectors $D = (D_1, D_2, \ldots, D_k)$ and $L = (L_1, L_2, \ldots, L_k)$. The incremental well casing length is denoted by $L^* = (L_1^*, L_2^*, \ldots, L_k^*)$, where $L_i^* = L_i - L_{i-1}$, for i = 1, ..., k, and $L_0^* = 0$.

Operators generally prefer the production casing to be as large as possible to maximize production, but large production casing requires a large wellbore, which is typically more complicated and expensive to drill. Average hole size and volume removed characterize the geometry of the final drilled well. The average hole size (HS) of the wellbore is determined by the weighted average diameter of the casing string, Equation 2, while the volume of rock removed (VR) without washout is defined by Equation 3.

Well complexity

Complex wells arise from diverse factors, including the nature of the geologic formation, depth of the target, size of the reservoir sands, trajectory of the wellbore, experience of the contractor, and technology applied. Well

complexity is difficult to quantify and frequently ambiguous because practices, opinions, and experiences among drilling contractors vary so dramatically.

High-pressure/high-temperature (HP/ HT) wells must be planned and drilled with significantly less formation data than shallower and cooler wells. If the formation pressure (FP) exceeds 10,000 psi or temperature (T) exceeds 300° F. anywhere along the wellbore, then a binary indicator will classify the well as complex (Equation 4).

The ratio of the horizontal length to the total footage drilled describes the percentage of the well's footage drilled under horizontal conditions, Equation 5. The aspect ratio, AR (Equation 6), measures the aggregate curvature of the well trajectory, and the extended reach ratio, ER, is the ratio of total depth to total vertical depth, Equation 7. All of these metrics provide, with some degree of correlation, alternate measures of well complexity.

Site characteristics

Primary wellsite characteristics include geographic location and, for offshore environments, distance to the nearest onshore service station and water depth at the site. Water depth and environmental conditions expected to be encountered is a primary determinant in selection of the rig required for drilling.

As the water depth increases and environmental conditions become harsher, larger and more robust rigs are required with extra hoisting capacity, mud-circulation systems, mooring systems, etc. The region and country in which a well is located is an important consideration in obtaining government regulations and permits, customs, port handling, and transportation.

The maturity of the infrastructure support services and the knowledge and experience of the operator will also play a role in determining drilling cost.

Operator preference

The operator decides not only where to drill, but also how to drill, and how to let the contract. The contract type (day rate, turnkey, combination) and duration, job specification (one well, multiple wells), supply and demand conditions at the time and negotiating strategies are important factors in determining drilling time and cost.

Many different rigs can be used to drill an offshore well; rig selection depends upon such technical factors as type of well being drilled, water depth and environmental criteria, vessel availability, type and density of seabed, expected drilling depth, and load capacity. Equipment selection involves tradeoffs that balance weather risk and the potential cost of delay.

Drilling program

Different types and sizes of bits are used according to the hardness of formations, pressure regime, and drilling plan. The final bit size is denoted FBS.

Mud weights vary over each well section. The average mud weight is defined by Equation 8, where $MW(L_i^*)$ represents the mud weight applied to the well section L^*_i, i = 1, ..., k. The maximum mud weight employed in the drilling program is the maximum weight over the entire well as shown in Equation 9. To the extent that high-pressure wells are more complex to drill, MWA and MWMX represent well complexity.

Formation evaluation

Formation evaluation is a critical step in exploration because it is the stage in which information about the presence or absence of hydrocarbon-bearing reservoirs is acquired. Time spent coring, logging, reaming, and testing is "flat" time, however. Therefore, for all other things equal, if a well requires more extensive formation evaluation, then its drilling performance metrics will not look as favorable if time is not adjusted for this activity.

A common decision in offshore operations involves the use of logging while drilling (LWD) vs. wireline (WL) techniques. Adding LWD to a directional well can add a few hours to each hole section for rig up and servicing, while drill pipe-conveyed WL logging may take days leaving the rig idle. Total formation evaluation cost may be less with LWD in cases where the well is deep and highly deviated, rig day rates and penetration rates are high.

Exogenous events

Offshore drilling may be subject to significant delays caused by weather; weather downtime can play an important factor in the total cost of the operation.

It can affect offshore drilling operations in various ways: Weather too severe for operations involving supply boats may lead to delay if stock levels on the rig decline to a critical level; weather may slow anchoring up and moving time; weather may be too severe for drilling to occur; extreme weather may result in damaged or lost drill strings and risers; etc.

If operating limits are exceeded because wave heights, ocean currents, or eddies are too strong, drilling operations will be temporarily abandoned and resumed when conditions fall within the operating capabilities of the equipment. Waiting on weather (WOW) needs to be considered separate from the drilling performance metrics to normalize for conditions beyond the control of the operator.

Many problems during drilling may require suspension of the activity. Most contracts specify a certain amount of "free" downtime (24 hr/month is typical), but outside this allowance, the contractor does not receive payment for the time the rig is inactive. Delays that are not directly accountable to the driller are usually charged at a reduced rate.

One of the most common problems in drilling a hole is that something breaks inside the well, such as a piece of bit or drill string, or something falls down the wellbore, such as a wrench or other tool. If fishing is unsuccessful, the hole will either be sidetracked or the driller will set a whipstock, and in the worst case, a new hole may need to be spudded.

Other drilling problems include stuck pipe, sloughing shale, lost mud circulation, formation damage, embrittlement, and abnormal pressure. Rig equipment failure, lost circulation, weather, and stuck pipe are the main causes of trouble time in the Gulf of Mexico.

Dependent variables

The time to drill a well is described by the number of the dry-hole days, DHD, defined as the number of days from the spud date to final well depth, plus any time spent batch setting, pre-installing or pre-setting casings. Dry-hole days normally includes time for all operations essential to well construction, such as tripping, running casing, and cementing (known as "flat time"), as well as interrupt and weather time and time spent on sidetracking. Time spent coring, logging, or other evaluation techniques are excluded.

Total number of days from the rig arrival on location until the rig is released is the total site days, TWD. This time includes the time for mooring and demooring, where applicable, completion and testing, suspension and plug and abandonment activities. Normal dry-hole days is DHD excluding all nonproductive time such as freeing stuck pipe, repairing equipment, and WOW.

The cost of operations during the dry-hole day period plus the casing batch set, preset period is denoted DHC. The definition of DHC will vary with each operator but will normally include the cost of operations, plus overhead, base operations, incentive payments, logging, transport, materials supply, marine vessel support, marine supply base, port facility, and warehousing. The cost of wellheads and technical and mechanical sidetracks are also normally included.

The costs for completion and well test operations, production strings and liners, trees, completion equipment, long-term daily rental of completions equipment, well design, site survey and preparation, rig mobilization and demobilization, well suspension and reentry, and plug and abandonment are not included in DHC. The total well cost TWC is the dry-hole costs plus all the cost that were specifically excluded.

Primary drilling performance metrics include the rate of penetration ROP and the cost per ft CPF drilled, shown in Equations 10 and 11.

Unobservable variables

Many variables known to influence drilling performance, such as well planning and preparation, project management, and technology are difficult but not impossible to quantify. The significance of these factors cannot be overstated, but because the manner in which these variables influence the drilling program are difficult to ascertain, such factors are not usually incorporated in analysis.

Functional model

The generalized functional model is best viewed as a generalization and synthesis of the benchmark indices used in industry. We combine the regression methodology used in the JAS with the multidimensional attributes of drilling incorporated in the MRI, DDI, DI, and related metrics.

Methodology

Regression analysis provides a standard and transparent analytic framework to establish relationships between performance and cost metrics and drilling variables. The functional approach to drilling cost estimation follows four basic steps, shown in Box 1 on this page.

Generalized functional model methodology

Box 1

Step 1. Select the descriptor variables of the drilling process in terms of the component vector $(X_1, \ldots, X_p)$.

Step 2. Define the design space Ω as a subset of wells that satisfy bounds on individual parameters:

$$\Omega = \{(X_1, \ldots, X_p) \mid A_i \le X_i \le B_i\}$$

where the values of A_i and B_i, $i = 1, \ldots, p$, are defined by the user.

Step 3. Construct a regression model based on the component vectors $(X_1, \ldots, X_p)$ and well data that comprise the category Ω,

$$\varphi(\Omega) = \alpha_0' + \sum_{i=1}^{p} \alpha_i' X_i$$

and test the model coefficients $(\alpha_0', \alpha_1', \ldots, \alpha'_p)$ for statistical significance.

Step 4. Maintain the significant variables and other factors of interest, reestimate the model specification,

$$\varphi(\Omega) = \alpha_0 + \sum_{i=1}^{q<p} \alpha_i X_i$$

and report the final model results.

Design space

Drilling data need to be categorized before assessment. Selecting the "appropriate" level of categorization depends upon the problem requirements, the amount and quality of information available, and the nature of the question under consideration.

Various levels of categorization may be defined, such as "deepwater wells" or "shallow water deep gas wells" or more specifically, through specification of constraint sets, such as 13 ppg ≤ MXMW ≤ 16 ppg, TD ≥ 15,000 ft, 500 ft ≤ WD ≤ 1,000 ft, etc. This is formalized through the design space Ω and the set of descriptor variables X_i shown in Equation 12.

Selection of the values of A_i and B_i, $i = 1, \ldots, p$, is specified by the user. If all available wellbore data are used to generate the design space, then the volume would be unconstrained (i.e., $A_i = 0$, $B_i = \infty$), and the model results would likely exhibit significant variability because the sample data are highly heterogeneous. A trade-off exists between capturing the right amount of data variability within the design space vs. the ability to generalize the model results from the constructed functions.

The manner in which drilling factors influence performance is frequently

Previous Page | Contents | Zoom In | Zoom Out | Front Cover | Search Issue | Next Page

incorporated through a weight term associated with the occurrence of the event. The weight is a numerical measure, either a constant or a functional expression, and often subjective in nature.

A more general approach is simply to note the presence or absence of the drilling factor, or its magnitude, and to infer the appropriate weight through the model structure. This not only eliminates the subjective element introduced by the user, but also allows the significance of individual factors to be determined in relation to other factors and wellbores.

The procedure to incorporate drilling factors in the model is to let variable X_i indicate the presence of the term: (1, ith condition/factor present; 0, otherwise), and then to analyze the regression model to determine the impact of the factor. Any factor believed to affect drilling performance can be considered, and the only restriction is that the factors should not be redundant or strongly correlated with other variables, in accord with standard regression protocol.

Specification

A preliminary assessment of well data determines the factors that serve as useful descriptor variables. Typically, 10-20 variables will suffice to characterize the drilling process.

The initial model $\varphi(\Omega)$ shown in Equation 13 is constructed for the design space Ω for each of the reported output variables DHD(Ω), DHC(Ω), and TWC(Ω), and the coefficients (α_0', α_1', ..., α'_q) are estimated for each output measure. After the initial model is computed and the statistical significance of the variables determined, the variable set is refined and the model reestimated. Usually, only variables with p-values <0.05 are maintained, but other criteria may also be applied. The final reestimated model is specified with all the regression coefficients reported.

Average DHD and DHC for GOM sample set

Box 2

DHD = –23.5 + 1.83WT + 0.21WD + 1.1DI –0.66HD + 13.7AR + 6.36NS

DHC = –13.9 + 1.79WT + 0.56WD + 0.3DI –0.48HD + 6.5AR + 3.25NS

Example drilling time, cost

Box 3

The average time and cost to drill an exploratory well (WT = 1) in the Gulf of Mexico in 220 m of water (WD = 2.2) with a 1,500 m drilling interval (DI = 15), 250 m horizontal displacement (HD = 2.5), 0.2 aspect ratio (AR = 0.2) and four strings (NS = 5) is estimated using the functional relations, as follows:

DHD= 28.1 days, DHC= $10.4 million, and TWC= $15.1 million

Calibration

The database employed in the model calibration consists of 50 wells drilled in the Gulf of Mexico, 2000-03. The sample set is meant to be illustrative, rather than representative, and given a more comprehensive database, more general models are readily established. The quality and completeness of well data varied widely, and, where possible, the data was checked for consistency with public sources.

The restricted time window minimizes the impact of inflation, technological improvements, and volatility in the market rates of rigs, but if these factors were considered relevant, they could be examined separately. Only project data representing actual cost were processed, and to minimize the influence of scale effects, batch and campaign drilling operations were excluded from consideration.

Further, only "new" wells were considered; sidetracks, slot recovery or enhancement, and multilateral wells were excluded. All the wells in the sample set were drilled with day rate contracts with water and synthetic fluids, and none of the wells was horizontal or drilled underbalanced. The hole's size, volume removed, well status, and average mud weight were not available for analysis.

Construction

Functional relations for DHD and DHC were computed based on the sample set described.

The initial factor set included 13 variables: {WT, WD, DI, HD, VD, AR, CR, HL, MA, FBS, NS, MXMW, SALT}. The design space was unconstrained and defined by Ai = 0, $B_i = \infty$, i = 1, ..., 13. All the variables are numeric, except well type and salt section, which are categorical: WT = 1, exploratory well; WT = 0, development well; SALT = 1, salt section encountered while drilling; SALT = 0, no salt section encountered.

The quantitative factors include water depth (WD, in 100 m), drilled interval (DI, in 100 m), horizontal displacement (HD, in 100 m), vertical depth (VD, in 100 m), aspect ratio (AR, unitless), complexity ratio (CR, unitless), horizontal length (HL, in 100 m), maximum angle (MA, °), final bit size (FBS, in.), number of casing strings (NS, integer valued), and maximum mud weight (MXMW, in specific gravity).

Expected signs

The expected signs of the coefficients are easy to ascertain in most instances and provide a first check on the veracity of the model results. If the signs of the coefficients do not follow the expected pattern and the variables are statistically significant, then additional structural issues may need to be investigated.

Exploratory wells are expected to take more time to drill because of the potential risk involved, and because greater water depth means additional complexity, technical and environmental complications, the water-depth coefficient is expected to be positive.

The drilled interval is the length of the wellbore, and all things being equal, it is clear that the greater the drilled interval the longer the time (and the greater the cost) of drilling. The drilled interval is expected to be a primary explanatory variable across all model types.

The vertical interval is expected to be correlated to the drilled interval for exploratory wells, but for horizontal

wells, the correspondence is expected to be weaker.

The sign of the horizontal displacement, aspect ratio, and extended reach ratio is uncertain. The aspect ratio and extended-reach ratio describe the geometry of the wellbore trajectory, and because they are strongly correlated, only one of the variables needs to be included in the regression model.

The coefficient of the final bit size is expected to be positive because a large wellbore should take more time to drill and cost more than a small wellbore. The number of casing strings directly indicates the complexity of the well; and the maximum mud weight positively correlates with the pressure profile. Increasing the number of casing strings or applying greater mud weight is expected to be associated with slower drilling time and greater costs.

Statistical analysis

Table 1 depicts the average dry-hole days, dry-hole cost, and total well cost for the sample set. Derived measures such as the rate of penetration (ROP), dry-hole cost/day (CPD), and dry-hole and total cost/meter (DHCPM, TWCPM) also appear.

The average dry-hole days/well was 35; the average dry-hole cost was $11.2 million/well. The average rate of penetration over the drilling cycle was nearly 100 m/day. Observe that the standard deviation of the performance statistics is in most cases only slightly less than the average values, indicating that the data spread is significant. Total well cost is nearly $1,000/m more than the dry-hole drilling cost. The dry-hole and total well cost data are strongly correlated, $\rho(DHC, TWC) = 0.94$, with weaker but still significant correlations between dry-hole days and cost: $\rho(DHD, DHC) = 0.72$, $\rho(DHD, TWC) = 0.76$.

PERFORMANCE STATISTICS, GULF OF MEXICO, 2000-03 — Table 1

Metric	Mean	Standard deviation
DHD, days	34.7	19.2
DHC, $ million	11.2	6.6
TWC, $ million	13.6	10.2
ROP, m/d	98.3	60.5
CPD, $1,000/d	273.1	93.1
DHCPM, $/m	3,111.8	1,575.2
TWCPM, $/m	4,144.2	2,528.3
DHC/DHD, $1,000/day	325.6	111.3
TWC/DHC	1.21	0.31

Table 2 presents drilling factor statistics. The factors exhibit significant variability and a low level of correlation, with one notable exception—the extended reach and aspect ratio—indicating that the two measures provide roughly the same information about the well geometry and do not both need to be incorporated in the model.

Model results

Table 3 shows functional relations for DHD, DHC, and TWC. The average dry-hole days and dry-hole cost are estimated as shown in Box 2.

Most of the variables are statistically significant and of the expected sign, and the most significant variables for DHD include drilled interval and number of strings, for DHC and TWC, water depth, drilled interval, and number of strings. The statistical significance of the variables and model fits appears reasonable considering the modest sample size. Box 3 provides an example of the use of the model. ✦

References

1. Brett, J.F., and Millheim, K.K., "The drilling performance curve: A yardstick for judging drilling performance," SPE 15362, 61st Annual Technical Conference and Exhibition of the Society of Petroleum Engineers, New Orleans, Oct. 5-8, 1986.

2. Schreuder, J.C., and Sharpe, P.J., "Drilling the limit—A key to reduce well costs," SPE 57258, SPE Asia Pacific Improved Oil Recovery Conf., Kuala Lumpur, Oct. 25-26, 1999.

3. Mannon, D.C., "Reducing wells cost by increasing drilling efficiency," AADE 01-NC-HO-35, AADE National Drilling Technical Conf., Houston, Mar. 27-29, 2001.

4. Jones, J.A., and Poupet, P., "Drilling the limit—a practical approach to breakthrough performance," SPE/IADC 59207, IADC/SPE Drilling Conference, New Orleans, Feb. 23-25, 2000.

5. Rowe, S.J., Grittner, S., Walters, G., Shilling, R., and Brendling, W.J., "Using risk-based simulation models to assist in planning deepwater exploration and production programs, west of Shetland and in the Gulf of Mexico," OTC 12952, Offshore Technology Conference, Houston, May 1-4, 2000.

6. Holland, D., Pritchard, D.M., and Anand, P., "Seven drilling myths—managing successful drilling operations," Journal of Petroleum Technology, Vol. 55, No. 9, pp. 44-48, 2003.

7. Cayeux, E., Genevois, J-M., Crepin, S., and Thibeau, S., "Well planning

GULF OF MEXICO SAMPLE STATISTICS, 2000-03 — Table 2

Metric	Mean	Standard deviation	Min.	Max.
WT	0.53	0.43	0	1
WD, m	1,032	542	5	2,402
DI, m	3,417	1,129	1,018	7,327
HD, m	844	734	0	2,562
VD, m	4,265	1,310	1,510	7,948
AR	0.34	0.36	0	1.5
ER	1.1	0.2	1	1.7
HL, m	426	636	0	4,893
FBS, in.	10.4	2.2	6	14.8
NS	4.3	1.1	2	6
MXMW, sp gr	1.5	0.3	1.1	2.0

DRILLING TIME, COST MODEL RESULTS — Table 3

$$\varphi(\Omega) = \alpha_0 + \alpha_1 WT + \alpha_2 WD + \alpha_3 DI + \alpha_4 HD + \alpha_5 AR + \alpha_6 NS$$

	DHD	DHC	TWC
α_0	–23.5 (–3.8)	–13.9 (–4.7)	–10.34 (–3.0)
α_1	1.83 (2.2)	1.79 (1.2)	1.73 (1.9)
α_2	0.21 (1.1)	0.56 (4.8)	0.63 (4.7)
α_3	1.09 (8.1)	0.33 (4.9)	0.35 (4.3)
α_4	–0.66 (–2.1)	–0.48 (–1.6)	*–0.26
α_5	13.67 (1.5)	6.50 (1.8)	5.12 (2.1)
α_6	6.36 (3.7)	3.25 (3.1)	3.33 (2.4)
R^2	0.66	0.59	0.48

*Indicates t–statistic <1.

OIL&GAS JOURNAL | Previous Page | Contents | Zoom In | Zoom Out | Front Cover | Search Issue | Next Page | qMags

quality improved using cooperation between drilling and geosciences," SPE 71331, SPE Annual Technical Conf. and Exhibition, New Orleans, Sept. 30-Oct. 3, 2001.

8. Kaminiski, D.H., Pellerim, N.M., and Williams, J.H., "A new data integration and work process system for providing online real-time drilling collaboration," SPE 78343, SPE Europec Conf., Aberdeen, Oct 23-25, 2002.

9. Leendert, J.U., Williams, J.H., Pellerin, N.M., and Kaminiski, D.H., "Real time operations centers; the people aspects of drilling decision making," IADC/SPE 79893, IADC/SPE Drilling Conf., Amsterdam, Feb 19-21, 2003.

10. Harris, B.W., "Drilling cooperatives: one strategy for reducing drilling cost and risk," SPE 56459, SPE ATCE, Houston, Oct. 2-6, 1999.

The authors

Editor's note: The biography for Mark J. Kaiser appeared with Part 1 of this series, OGJ, Aug. 6, 2007, p. 39.

Allan G. Pulsipher (agpul@lsu.edu) is executive director and Marathon Oil Co. professor at the Center for Energy Studies at Louisiana State University. Before joining LSU in 1980, he served as chief economist for the Congressional Monitored Retrievable Storage Review Commission, chief economist at the Tennessee Valley Authority, a program officer with the Ford Foundation's division of resources and the environment, and on the faculties of Southern Illinois University and Texas A&M University. He has a PhD in economics (1971) from Tulane University.

Middle East condensate production will complicate refining operations

Michael Corke
Purvin & Gertz Inc.
Dubai

Narayanaswamy Ravivenkatesh
Purvin & Gertz Inc.
Singapore

Condensate production, especially in the Middle East, will rise substantially in the next few years. Some concerns about the effect of increased production on the marketability and prices of condensate have led producers to consider investing in condensate processing capacity as an alternative to being at the mercy of the condensate market.

This article examines how the condensate market is likely to develop and whether investments in processing are likely.

Definitions

Condensate is a generic term that many use to describe a variety of light petroleum streams that range from NGLs to light crude oil. Strictly speaking, a condensate is a mixture of hydro-

carbons that exists in a gaseous state in an underground gas reservoir but condenses under atmospheric conditions.

This article principally addresses these condensates, which are extracted directly from well fluids (field condensates). It does not consider lighter natural gasoline-type condensates that are frequently recovered from gas-processing operations.

To assist the definition, Fig. 1 shows a typical gas production and processing chain.

The definition of condensate became highly political within the Organization of Petroleum Exporting Countries because condensates do not fall within OPEC quotas. In 1998 OPEC agreed, for quota purposes, that 50° API was the break point between light crude oils and condensates.

Most condensates are used as refinery feedstocks for the manufacture of products for the fuels markets. Some condensates, however, particularly paraffinic condensates (those with high paraffin content), are suitable as feedstocks for the manufacture of ethylene. Paraffinic condensates used in this way compete with naphtha for this end-use market.

Condensate disposition

In essence, a condensate producer has three main disposition options. The condensate could be:

- Commingled into a local crude oil stream.
- Exported as a segregated stream.
- Processed and the resulting products, mainly LPG, naphtha, and middle distillates from typical condensates,

OIL&GAS JOURNAL Previous Page | Contents | Zoom In | Zoom Out | Front Cover | Search Issue | Next Page qMags

could be exported.

Commingling into crude oil is generally the favored option where possible. Most North Sea crude is handled this way. Condensate may enhance the value and marketability of a crude stream, although with limits.

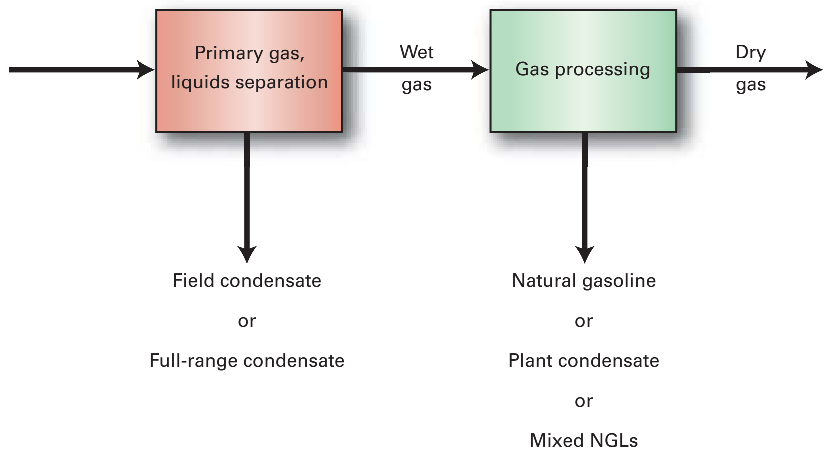
If condensate addition results in a crude that becomes difficult to process because its yields of light ends or naphtha are too high or its yields of fuel oil are too low, then condensate addition can depress the value of the crude. If crude value is plotted vs. API, value tends to increase with increasing API, but this trend can reverse for crudes with API gravities in the mid and higher 40s.

Processing a condensate by simply splitting it, or splitting and treatment or other processing of the derived products, can be attractive in some circumstances. Certainly it limits condensate supply and produces products that can be sold into deep and established markets.

Finally, the condensate can be exported without any processing and treatment.

GAS PRODUCTION, PROCESSING

Fig. 1



Supply outlook

The market for condensates is unusual within the oil industry because, like LPG, it is a supply-driven market. Most markets, including those for crude and most refined products, are demand-led. Condensate, however, is produced as a by-product of gas production and must be moved into the market.

In most cases, secure offtake is more important than price maximization. The question, therefore, for condensate is not whether there is sufficient supply, but whether there is sufficient capacity to absorb the condensate at reasonable prices.

In 2006 gross worldwide production of field condensates was about 3.6 million b/d; 2.7 million b/d of this total was segregated. About 1.2 million b/d was processed locally and 1.5 million b/d was exported to other locations (Fig. 2).

Our outlook is for global condensate production to rise strongly, primarily due to increasing gas production. The Middle East is expected to account for more than half of this increase (Fig. 3).

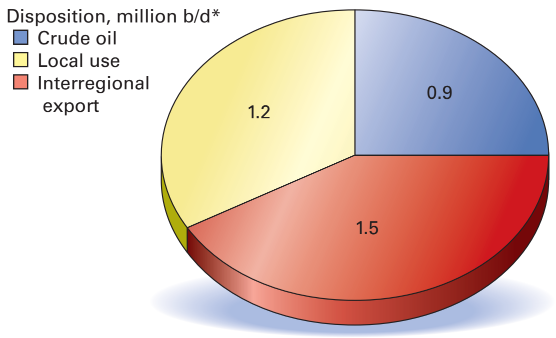
Considerable uncertainties surround this outlook. In particular, major uncertainty relates to the future development of gas-based projects in Qatar, given the current development moratorium and the timing and impact of Abu Dhabi's sour gas project is also unclear.

Further uncertainty is due to the general difficulty of predicting how Iranian gas projects will develop and uncertainty concerning the extent to which the Saudi gas initiative will result in substantial increases in domestic gas and condensate produced.

Currently segregated condensate production accounts for about 3% of total refining industry feed on a global basis. Most of the remainder is crude. During 2005-20, segregated condensate production will increase to about 4.7 million b/d from about 2.1 million b/d, but this increase will still leave condensate as only around 5% of refinery intake by 2020 (Fig. 4).

CONDENSATE DISPOSITION

Fig. 2



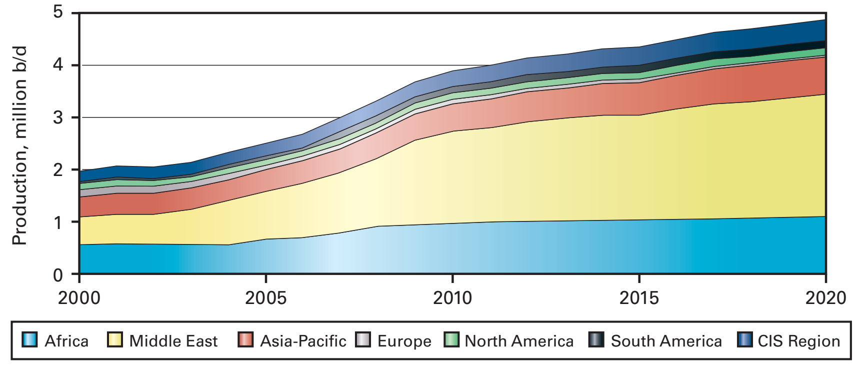
*2006 estimates.

Because condensate is a relatively small proportion of total refinery intake, we have no doubt that condensate will continue to move into the market without undue difficulty. This is not to say, however, that this increase could not have pricing implications.

To a considerable degree, Middle East condensate exports have been sold to buyers that preferred to have some condensate in their feedstock slate. Typically such buyers would have a desire to boost naphtha yields, perhaps because of having associated ethylene-cracking operations.

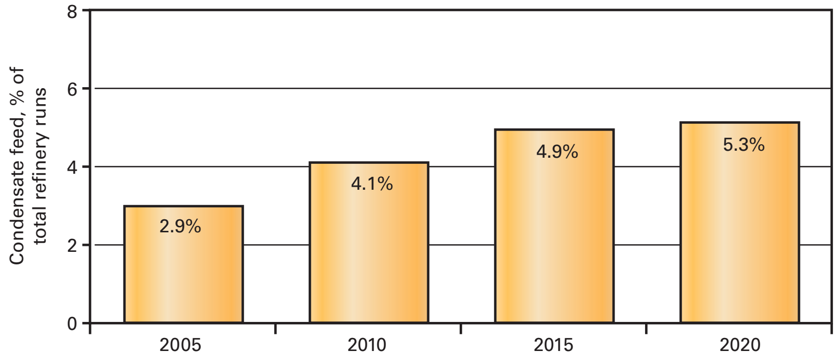
SEGREGATED CONDENSATE PRODUCTION

Fig. 3



CONDENSATE AS REFINERY FEED

Fig. 4



When condensate production rises, it is likely that producers will have to sell condensate to refiners that have no specific interest in taking condensate and may need to be encouraged to do so by being offered a discount. In this context, a discount is defined as being a discount relative to the theoretical refining value of a condensate.

Condensate processing

The most basic condensate processing is simply to split the condensate through a simple distillation operation and carry out a minimal amount of treating, typically sweetening the LPG and naphtha that contain hydrogen sulfide. Historically, Asian market gas-oil sulfur specifications have been fairly lax, allowing untreated gas oil to be sold as finished product directly into the market.

European and US distillate markets are changing rapidly, however, with the European Union diesel market having to meet a 10-ppm specification by 2009. Although Asian distillate markets are in some cases lagging this trend, the overall shift towards low-sulfur products is ongoing. Fig. 5 shows that high-sulfur distillate demand should fall to 30% of total demand during the next 10 years from about 51% in 2006.

Distillate hydrotreating is therefore a natural addition to a condensate-splitting project. Similarly, conversion of naphtha into gasoline may be an option, as would the use of naphtha as feedstock to an aromatics production facility or an ethylene cracker. Both of these options, however, are major investments that would dwarf that for a simple condensate splitter.

The extent to which a producer may wish to invest in condensate splitting or condensate refining will, to considerable degree, reflect how the whole condensate would be priced in the market.

Pricing, processing economics

Although some condensates may be used as direct feed to ethylene crackers, by far most condensates are unsuitable for this and will be used as refinery feedstocks. The price-setting mechanism for most condensates is therefore as competition to crudes as a refinery feedstock.

The refining value and, consequently, the market price of a condensate is generally higher than the refining value and market price of a typical light Middle East crude.

Fig. 6 compares distillation yields for a typical condensate and Dubai crude.

A typical condensate consists of about 65% naphtha, 30% middle distillates, and 5% LPG. LPG is rarely higher than this because otherwise the condensate would be too volatile to ship in standard tankers. In contrast, these components account for around 57% of the yield of Dubai crude, with low-value fuel oil accounting for the remainder.

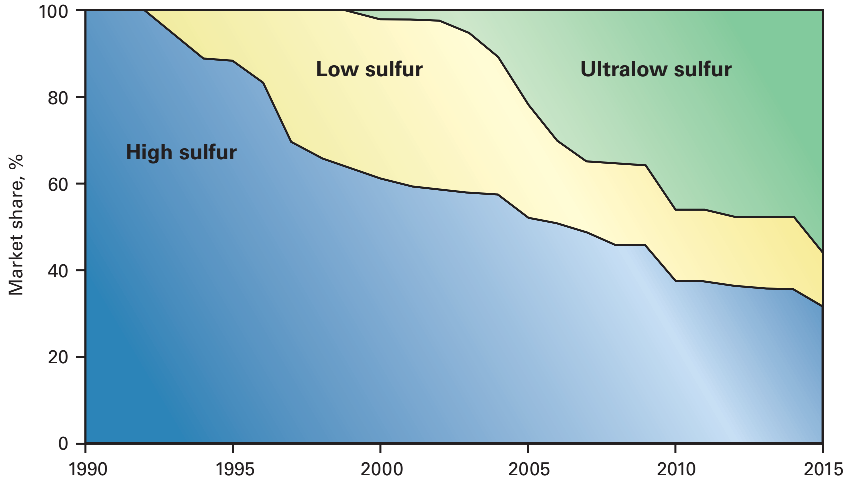
This simple distillation yield comparison shows why the value of condensate is typically higher than that of a typical crude. Also, the value difference between the two is sensitive to market price differentials between light products such as naphtha, gasoline, and middle distillates on the one side, and heavy fuel oil on the other. When oil prices rose and light-heavy price differentials widened in 2004-06, value differentials between typical Middle East condensates and typical Middle East light crudes, such as Dubai, widened to about $6/bbl from $2-3/bbl.

Naturally, simple distillate distillation yields do not tell the whole story. The chemical nature of condensate, crude, and individual cut qualities also affect values and, therefore, market prices. These are, however, generally of secondary importance in value terms.

Although refining values largely determine the price of condensates relative to crudes, another element is also significant. Refineries are generally designed to process crudes, not condensates. For most refiners, processing condensate as a high fraction of the

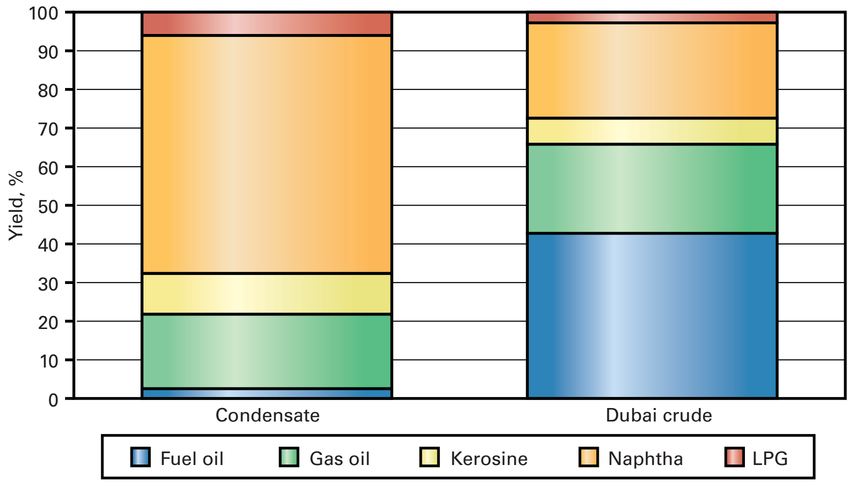
ASIAN DIESEL MARKET

Fig. 5



YIELD COMPARISON

Fig. 6



feedstock slate is technically impossible.

Condensates include too much light material and too little heavy fuel oil. This overloads the overheads systems and inadequate heat input results. Typically, therefore, condensates must be coprocessed with crudes, with the condensate 10-20% of feed.

This means that condensate must be segregated and injected into a refinery feed stream on a ratable basis. This can tie up refinery tankage and reduce operating flexibility.

For a refiner without a specific desire to boost naphtha yields, this is typically an inconvenience that requires some incentive. The incentive is a market discount relative to refining value for the condensate.

An historical analysis shows that refiners in Asia interested in processing feedstocks with high naphtha yields typically processed Middle East condensates. These refiners are favorably inclined towards processing condensate and are willing to pay full refining value. When condensate production increases, it becomes necessary to market condensate to refiners without such interests. Market discounts are therefore likely to appear. With limited production, discounts are nonexistant or minor; these would deepen if production increased substantially.

Deep discounts are not sustainable. They would encourage refiners to invest in additional flexibility to process condensate and would also encourage condensate producers to invest in condensate processing facilities of their own. Long-term discounts are therefore expected but will not be severe.

The naphtha market also affects the pricing of condensates and specifically the extent to which a market discount will apply at any point in time. When the naphtha market is strong and naphtha buyers are concerned about supply security, condensate demand will increase and market discounts, if any, will decline.

The outlook for the naphtha market is also therefore important to the outlook for condensate markets. Asia is a huge importer of naphtha because its olefin business is largely naphtha-based, although the use of LPG feedstock is likely to increase.

Little distillate is used as olefin cracker feedstock in Asia. Naphtha accounts for about 80% of Asian ethylene cracker feed and Asia accounts for almost half of total global light naphtha demand.

It is interesting to track the yield of naphtha from Asian refineries. Fig. 7 shows that this is approaching a level that represents the technical maximum yield of naphtha from the region's refineries.

Demand for naphtha in Asia will continue to rise and refinery production will increase much more slowly; Asia naphtha imports will therefore surge during the next few years. During 2006-08, regional naphtha supply deficit will rise to 47 million tonnes from 29 million tonnes.

This will result in a firm short-term market for naphtha, and consequently good demand for condensate. In the slightly longer term, the market will ease due to increasing Middle East naphtha and condensate production and increased use of LPG feedstock in the Asian olefin cracking industry.

Clearly, these trends will have an

important bearing on the economics of condensate processing investments. In the longer term, increasing condensate production will result in discounts relative to refining values, though not unduly deep discounts.

In the short term, firm naphtha and condensate markets are more likely; however, the factor not yet discussed is location. A location with local demand for products from a condensate processing operation will have a strong economic advantage compared with a location where most, if not all, of the products must be exported. This is simply a result of tanker transportation economics, which can result in FOB prices for exports of $20/tonne or more below the price at which product can be imported. (FOB: free-on-board; buyer pays freight and insurance costs.)

The most favorable circumstances for a condensate processing operation are for a location that has local condensate available (FOB pricing) and a local deficit in terms of product supply. A location that has the opposite situation will find it difficult to cover cash operating costs.

An extension of this analysis suggests that condensate processing should always occur in a product-importing location rather than a product-exporting location. Typically, condensate from the Middle East is transported to markets in Asia as part cargoes on very-large crude carriers (VLCCs), whereas products from refining and condensate processing operations are typically transported in smaller ships, normally long-range (LR-1; Panamax) and medium-range tankers.

In 2006, for example, transportation in a VLCC was cheaper than transportation in an LR-1 by as much as $1.50/bbl and cheaper than transportation in a medium-range tanker by as much as $2/bbl.

Future considerations

It is difficult to generalize about the attractiveness of condensate processing as a producer option. Location and the existence of local demand for products are important. Timing is also important—general levels of refining margins, which will affect condensate refining or processing margins, also vary with time, as do condensate market discounts and processing facility investment costs.

Investment costs are currently extremely high as a result of supply tightness for construction materials, equipment, and engineering and construction services.

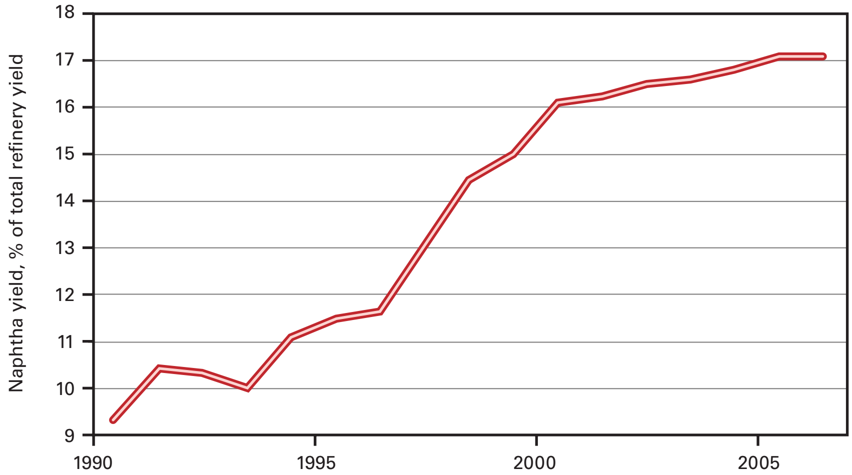
A condensate producer may find local processing strategically desirable, particularly where it is important to guarantee the offtake of condensate. Although marketing condensate is not unduly difficult, selling finished products into deep, liquid product markets will be easier. In any case, a careful evaluation of project economics is clearly essential.

Finally, a conundrum related to condensate discounts must be recognized. If all produced condensate is sold into the market, discounts will occur at a certain level. If producers instead invest in a certain amount of condensate-processing capacity, discounts for the remaining condensate will be reduced. The resulting smaller discounts would then result in reduced returns on the investments made.

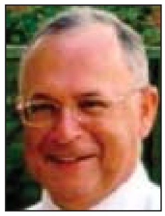
The optimum solution may be to encourage others to invest in condensate processing capacity, then to continue to sell condensate at close to its full refining value. ✦

ASIA REFINERY NAPHTHA YIELDS

Fig. 7



The authors



Michael Corke (mjcorke@purvingertz.com) is senior vice-president and manager for Purvin & Gertz Inc., Dubai, responsible for the firm's consulting activities in the Middle East. Before joining Purvin & Gertz' London office in 1985, Corke worked for British Petroleum and Murphy Eastern Oil Co., a subsidiary of Murphy Oil Corp., where he was involved in oil trading, refinery construction, joint venture refinery management, and North Sea operations. He holds a BSc in chemical engineering from Leeds University, UK.

Narayanaswamy Ravivenkatesh is an associate consultant for Purvin & Gertz Inc., Singapore, with responsibility for the firm's Asian Petrochemical Feedstock Market Outlook service. Before joining Purvin & Gertz in 2005, Ravivenkatesh held numerous positions at ExxonMobil Corp.'s Singapore complex in refining, supply, and petrochemicals. He has also held various positions at Hindustan Petroleum Corp. Ltd. including field, process control, and shift supervisory roles. Ravivenkatesh holds a BE in chemical engineering from Bangalore University, India, and an MBA from Southern Illinois University.

Why Attend:

The Houston Energy Financial Forum is the first opportunity for you to hear E&P company's current third quarter results. There is no fee to attend this event if you are an analyst or institutional investor.

This is a unique opportunity to network with executives, analysts, senior industry leaders, and others who are part of the financial sector.

The venue for this event is Hotel ZaZa. This newly-opened hotel is an unexpected blend of history, business and fashion, brilliantly located in Houston's beautiful Museum District. Hotel ZaZa is a great new place to stay while attending a great new event!

Why Present:

The Houston Energy Financial Forum is your only opportunity to present in Houston. Reach out to analysts and potential institutional investors while presenting information to help shore up stock prices. Be sure to arrange other business while you are there and reap the full benefits of this opportunity!

Why Sponsor:

A sponsorship gives your company premium exposure and recognition. This is an excellent chance to foster new relationships and build on current ones in this industry.

Join these 2007 Houston Energy Financial Forum sponsors today.

Hosted by: CIT

Event Sponsors: American Stock Exchange, Cameron, Canaccord Adams, Enertia Software, Flotek, Gardere, Texas Capital Bank, Weaver and Tidwell L.L.P.

Participating Sponsor: energycapitalsolutions

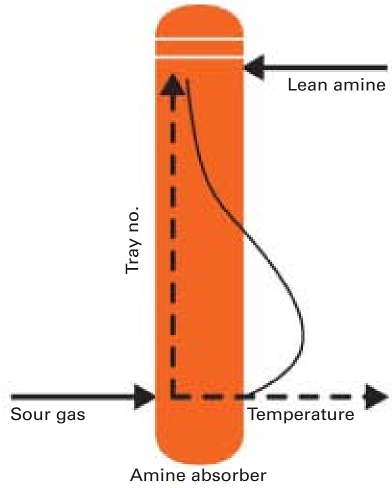
The following companies are proud presenters at the 2007 Houston Energy Financial Forum:

Addax Petroleum
American Oil & Gas
Anterra Energy
ATP Oil & Gas Corp.
Aurora Oil & Gas
Basic Energy Services
Bayou Bend Petroleum
Boots & Coots
BPZ Energy
Callon Petroleum
Cameron
CANO Petroleum
Carrizo Oil & Gas
Cimarex Energy
Core Labs
Devon Energy
Double Eagle Petroleum
Endeavour Intl Corp
Energy XXI
Exxel Energy
Far East Energy
Flotek Industries
Foothills Resources
FX Energy
Gastar Exploration
GMX Resources
Kodiak Oil & Gas
Max Petroleum
Megawest Energy
New Frontier Energy
NGAS Resources
Panhandle Oil & Gas
Parallel Petroleum
Petro Resources Corp.
Petro Search
Petroleum Development Corporation
Petroquest Energy
Pinnacle Gas Resources
PRB Energy
Rancher Energy
Samson Oil & Gas
Southwestern Energy
Sterling Energy
Stormcat Energy
TXCO
W&T Offshore

To reserve your sponsorship for the 2007 Houston Energy Financial Forum, contact:

Nicole Durham — *Office:* 713.963.6234 | nicoled@pennwell.com
Mark Immekus — *Office:* 713.963.6263 | marki@pennwell.com

TYPICAL CONTACTOR TEMP. PROFILE Fig. 1



Identifying sources key to detailed troubleshooting of amine foaming

Mater A. Al Dhafeeri
Saudi Aramco
Dhahran

Investigation and troubleshooting of foaming in two Saudi Aramco amine sweetening facilities reduced reliance on continuous antifoam injection at the company's Berri gas plant by identifying the source of the problem. At the Shedgum gas plant, however, economics dictated continuing antifoam injection.

Both case studies revealed that liquid hydrocarbon carryover with sour feed gas was the main foam promoter. A lesson learned from these two cases was to focus on defining the foaming problem. This allowed a better understanding of the problems and provided the least expensive solution to abate foaming or reduce its severity.

Diglycolamine (DGA) is the most widely used amine-sweetening agent in Saudi Aramco's plants. As with other amines such as monoethanolamine (MEA), diethanolamine (DEA), and methyl diethanolamine (MDEA), foaming is a major concern especially in high-pressure systems.

This article will demonstrate the benefits of proper troubleshooting to identify sources of amine foaming in the two Aramco gas plants. It will also provide some general information about amine foaming, causes, symptoms, and troubleshooting guidelines.

Foaming

Amine-solvent foaming has been widely discussed in the gas processing industry and in the literature. Foaming continues to occur in amine facilities because various factors induce foaming and a lack of operational knowledge exists for troubleshooting foaming incidents.

Many operational practices regarding foaming problems try to solve what caused such incidents rather than develop a strategy to track the sources of foaming and alleviate them or reduce their impact. High capital losses occur annually due to foaming in amine systems. Such losses derive from the temporary loss of sour-gas processing capability and hence a reduction in sales and fuel-gas production, solvent loss, and violation of environmental regulations.

Foaming in any Saudi Aramco treating plant generates serious revenue loss due to the huge size of the gas-sweetening units that treat about 7 bscfd of sour gas using DGA. Continuous antifoam injection has been the most common method to suppress foaming. Although use of antifoam injection is well known and documented, it is only recommended as a last resort and then only intermittently.

Because most of antifoams are surface active, high dosage could aggravate foaming problems. Besides, some recent findings suggest that antifoam reduces the absorption capacity of CO_2 by 40-55%. Those findings, however, were based on use of MDEA.[1]

To reduce reliance on antifoams and increase operational confidence in high-pressure amine systems, the central engineering group of Saudi Aramco, working with field and operation engineering in two gas plants, decided to focus on identifying the sources of foam and eliminate them rather than trying to suppress the foam.

Foaming in amine systems

Pauley defines foaming as "a result of a mechanical incorporation of a gas into a liquid, where the liquid film surrounds a volume of gas creating a bubble."[2] Two key characteristics are needed to present a foaming concern:

1. Solution tendency to foam—the ease with which a solution forms a foam bubble.

2. Foam stability—foam resistance to break into continuous liquid phase. The higher the foam tendency and stability, the higher the possibility of a foaming problem.

Surface tension is the primary indication of foaming tendency. Lower surface tension leads to more solution susceptibility to foam. The major source of reduced surface tension of an amine solution is solution contamination with surface-active agents, which include liquid hydrocarbons.

Surface tension is also affected by operating conditions; higher temperature and pressure tend to reduce surface tension. Temperature has the upper hand in impacting surface tension of an aqueous amine solution.

Higher pressure, to a lesser extent, affects solution-foaming tendency. At higher pressures, the solubility of liquid hydrocarbons in the amine solution increases, thereby changing the surface structure of the aqueous solution and rendering a lower surface tension and hence increased system tendency to foam.[3]

That is exactly what has been observed in Saudi Aramco's gas processing facilities where most of the current foaming concerns are in the amine plants that are operating at high pressures. Having a low surface tension does not indicate a stable foam and hence a foaming problem.

Stability, related to the nature of the surface layer, is the other key factor of having a foaming concern. Foam stability depends on three characteristics: elasticity, gelatinous layer formation, and film drainage.[4]

- Having higher elasticity, and therefore resistance to thinning, generates lower foaming stability. The major function of most antifoam is to increase the solution elasticity and hence reduce the foam stability.
- Gelatinous or plastic layer is a surface structure related to the nature of molecular composition of the aqueous solution; solutions that are prone to form gelatinous layers tend to have higher foaming stability.[4] Secondary (DEA) and tertiary (MDEA) amines form this layer more easily than primary (MEA and DGA) amines. They are, therefore, more susceptible to foam. Contaminants, such as amine degradation products, induce the formation of the gelatinous layer.
- Faster film drainage reduces foam stability. Fine particulates, however, such as iron sulfide, tend to retard film drainage and hence increase foam stability.

Foam inducers

Clean uncontaminated amine does not form stable foam. Amine system foaming results from contaminants either introduced to the system through the feed gas, make up water, and recycled streams or generated in the system, such as degradation and corrosion products. Here are the most common causes of foaming:[5-8]

1. Liquid hydrocarbon introduced by sour feed gas is the primary cause of foaming problems in gas-sweetening plants. Liquids can be introduced as mist entrainment or carryover or can be formed inside the column if the lean amine entering the column is cooler than the sour-gas dewpoint.

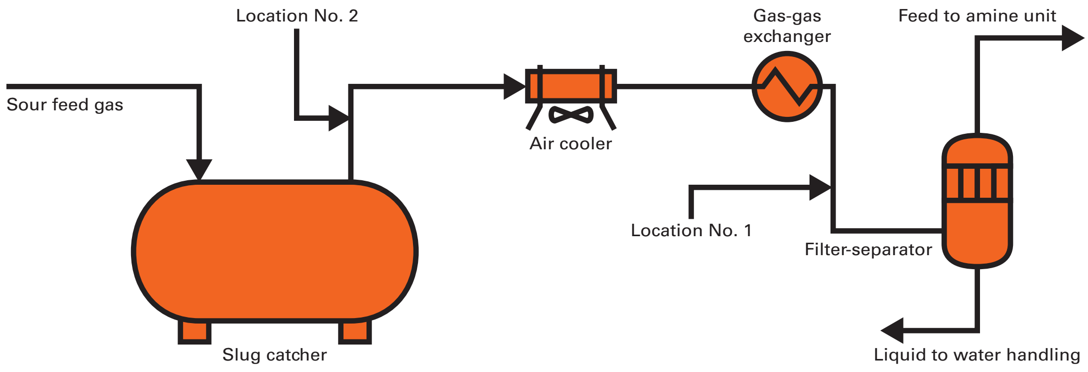
The impact of liquid hydrocarbon comes from its solubility in the aqueous amine solution, which therefore reduces its surface tension. Secondary and tertiary amines, more than primary amines, tend to foam in the presence of liquid hydrocarbons due to the higher solubility of liquid hydrocarbon in secondary and tertiary amines.

One of the tasks is the removal of liquid hydrocarbon droplets of aerosol size. Droplet sizes greater than 3μ are generally controllable; smaller sizes require careful filter-separator and coalescer design. Some plants were able to reduce the liquid carryover by installing 0.3μ coalescers upstream of the amine absorber columns.[9]

2. Solid particulate contamination, especially iron sulfide, is one of the major causes of foaming. Iron sulfides, as very fine particulates, are difficult to remove by conventional mechanical filters, tend to concentrate in liquid-gas interface, and hence increase foaming stability. Iron sulfide, a by-product of corrosion activities of hydrogen sulfide and carbon steel piping, could be carried over from the sour feed gas or

SAMPLE COLLECTION LOCATIONS

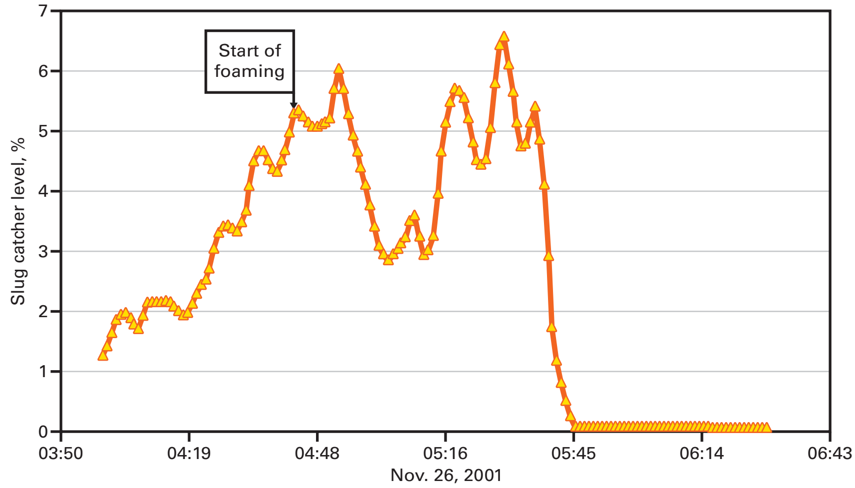
Fig. 2



OIL&GAS JOURNAL | Previous Page | Contents | Zoom In | Zoom Out | Front Cover | Search Issue | Next Page | qMags

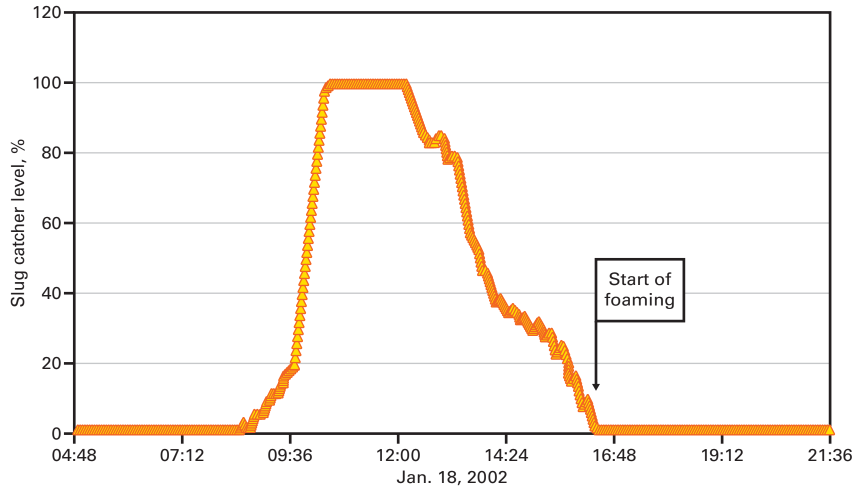
Berri slug catcher: first incident

Fig. 3



Berri slug catcher: second incident

Fig. 4



generated in the amine solution due to such reasons as high solution acid-gas loading, high velocities, and formation of acidic degradation products.

3. Water-soluble surfactants such as corrosion inhibitors, well-treating compounds, and excessive antifoam agent tend to dissolve in aqueous solutions and reduce surface tension. Such contaminants are often much more problematic than liquid hydrocarbons, if an appreciable amount exists in the sour gas, due to their higher solubility in amine solution.

4. Amine degradation products lead to changes in the amine solution's structure and may increase the foaming tendency. Degradation products are compounds formed either by direct reaction of the amine and constituents in the feed gas (such as CO_2, COS, CO, O_2, and CS_2) or by thermal decomposition of the amine. Conversion of the amine, irrespective of the mechanism, represents a loss of active and valuable amine.

5. Heat-stable salts not only tend to reduce the system's sweetening capability, but also increase the amine solution's corrosivity. Corrosion products, mainly iron sulfide, and changes in solution physical properties tend to increase the foaming stability and tendency, respectively.

Because heat-stable salts are not thermally regenerable, they accumulate in and contaminate the circulating amine solution. Such heavy salts are products of amine reaction with other anionic species or stronger acidic components (other than H_2S and CO_2) present in the sour feed gas.

6. Oxygen ingress in the feed or amine solution, even at parts-per-million levels, leads to the formation of carboxylic acids that react with amine to form heat-stable salts and hence increases the system's tendency to foam. Positive pressure is always required to avoid any accidental oxygen leakage to the system. One area that needs to be monitored is the amine storage tank that should normally be protected by an inert-gas blanket, usually of nitrogen.

7. Makeup water could be another source of introducing various contaminants to the system. The main source of the makeup water is the utility plant where various chemical additives are introduced to treat it before it is fed to the steam boilers. Such chemicals include corrosion inhibitors and boiler-feed-water chemicals. Demineralized water could provide a very safe source of makeup.

Foaming symptoms

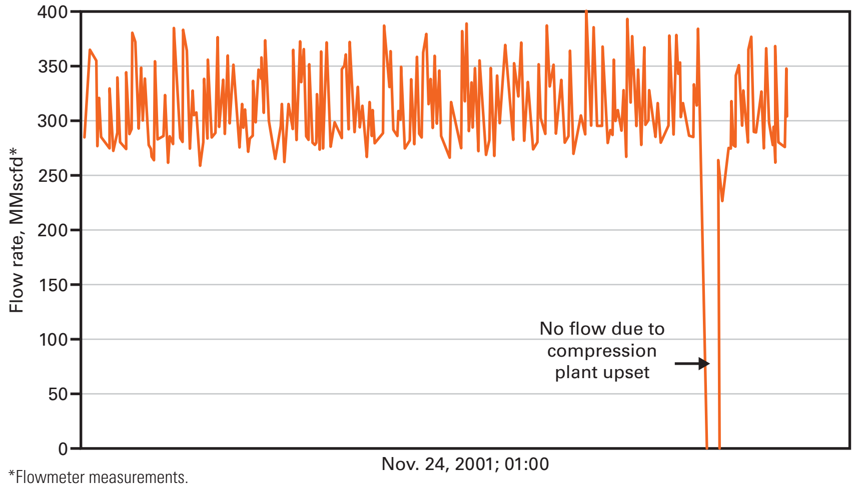
An amine system subjected to foaming exhibits the following behavior:

• Sudden increase in the column's differential pressure is the first alarming sign of a foaming system. Normally, amine absorber columns come equipped with differential pressure cells to monitor system abnormalities. When the contactor faces foaming and as the foam height increases, the void volume inside the column is reduced, which leads to higher pressure drop.

• Off-specification sweet gas results from the loss of some absorption capacity of amine solution. Foaming reduces the vapor-liquid contact area, generating a reduced effective mass-transfer zone and hence less acid gas is picked up by the amine.

OFFSHORE COMPRESSION FLOW: FIRST INCIDENT

Fig. 5



*Flowmeter measurements.

Most of the gas processing plants are equipment with an online analyzer to detect H_2S concentration in the sweet gas to avoid producing an off-specification sales or fuel gas. Unexpectedly high H_2S content in the sweet gas indicates possible foaming.

- Amine carryover to downstream equipment is a late warning of foaming in the column and could be indicated by erratic or abnormal levels in the downstream knockout drums.
- Loss or reduction in the rich-amine flow rate is accompanied by an erratic or abnormal level indication in the absorber column's bottom section.
- Abnormal absorber column's temperature profile can be another indicator. A typical temperature profile has a shape of a pregnant woman; the bulge (maximum) temperature is in the lower trays where the main reaction between acid gas and amine solution occurs (Fig. 1). During foaming, the bulge temperature normally shifts from the lower trays to the upper trays, especially if foaming was caused by contaminated sour gas.

Antifoam injection

Antifoam does not eliminate foaming; rather, it reduces its severity. Most antifoams tend to increase the surface layer's elasticity, allowing it to resist film thinning.[7] Once antifoam injection ceases, the system becomes vulnerable to foaming at any time because the foam-inducing contaminants are still in the system. Relying solely on antifoam to avoid foaming allows to contaminants to build up in the system. This buildup leads to such other serious problems as amine degradation, solvent losses, and corrosion.

Excessive antifoam dosing reverses its function and makes it a foam promoter. This phenomenon has been clearly demonstrated by Saudi Aramco Research & Development Center, which found that silicon based antifoam increases its foam-reducing power in a DGA system up to a concentration of 25 ppm; nothing was gained beyond that. At 9,000 ppm, antifoam begins to stabilize the foam and therefore increases the foaming severity.[10]

Another side effect that has yet to be fully proven for the primary amines is the impact of antifoam on the reduction of the mass transfer rate. One study concluded that the presence of antifoam renders lower diffusion of the acid gases into the amine solution, hence reducing amine-absorption capacity.[1]

Because of these reasons and the extra cost associated with antifoam chemicals, antifoam should be the last option. Consequently, preventing contaminants and maintaining a good quality amine should be the primary target.

Case studies

Foaming in high pressure gas-treatment facilities at Saudi Aramco has been a concern since their start-up. Currently there are seven high-pressure treatment trains in Saudi Aramco that are using DGA as the sweetening solvent: Five are processing nonassociated sour gas in the southern area and two at the Berri gas plant treat high-pressure offshore associated gas.

Continuous antifoam is being extensively used in the southern plants. In the Berri plant, antifoam injection underwent various changes from batch injection to continuous injection as a reaction to some foaming incidents in which the plant management could tolerate no further reduction in gas supply. Central engineering group decided to tackle the foaming problem in two locations where there have been elevated concerns regarding foaming.

The main target of the troubleshooting was to identify the source of foaming rather than relying on the practice of optimizing the antifoam injection rate. Listed below are the two case studies with some background on the plants, causes of the problems, and recommendations to abate foaming or reduce its severity.

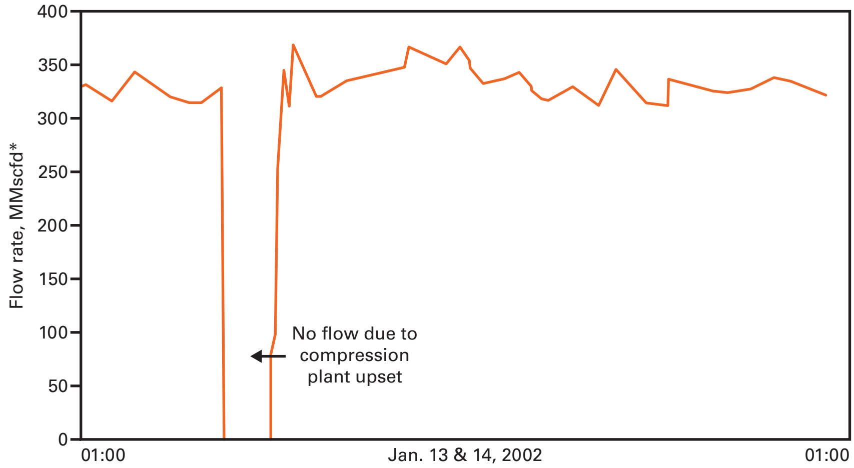
Shedgum—history

Foaming in the high-pressure amine contactor has been a problem since start-up of the plant. Sour nonassociated Khuff gas was first introduced to the unit in 1991 with the amine being regenerated in one of the low-pressure gas treatment plants. Maximum throughput attained at that time was 280 MMscfd. (Design rate is 440 MMscfd.) Even at that rate, the system did not stabilize due to the onset of early foaming symptoms.

The commissioning tests indicated that foaming in the HP contactor was caused by some contaminants in the amine system. Therefore, activated-car-

OFFSHORE COMPRESSION FLOW: SECOND INCIDENT

Fig. 6



*Flowmeter measurements.

bon beds were installed temporarily to remove dissolved hydrocarbons.

After applying three batches of activated carbon, which were exhausted within 35 days, the plant was only capable of processing 250 MMscfd of sour gas. No more activated carbon was added and the system was dismantled for economic reasons.

With the continuous antifoam injection of 0.72 ppm (vol), the train was able to process a maximum sustainable sour-gas rate of 460 MMscfd.

Since then, the plant has been using continuous antifoam. With time, its processing capacity has declined and symptoms of foaming have occurred when the plant has been operating around the design rate even with continuous antifoam injection.

Table 1 shows the basic information about the HP unit.

The team formed to resolve the problem focused on three major areas. Two of them address potential causes of foaming; the third explores possible options to reduce the foaming. The areas are:

- Amine solvent quality.
- Sour feed-gas pretreatment.
- Areas of improvements.

Amine solvent quality

Amine solution quality is crucial in predicting and preventing foaming. The first step taken was to check the lean-amine solution's quality. Analyses showed a detailed breakdown of the solution's constituents but did not show the content of either the dissolved hydrocarbon or dissolved solids, which were expected to be the major cause of foaming in the plant.

The results revealed 15 wt % degradation products in the solution. The conventional titration method was showing an amine concentration of around 40-50 wt % before the detailed analysis. It was found, however, to be <34 wt %. Table 1 shows the complete analyses results.

This is a clear sign that there is a poor amine quality circulating in the system. The main reason was the system's configuration at that time when a common regenerator was used for the HP and LP trains. Investigators speculated that hydrocarbons were in an appreciable amount due to the amine filtration system that does not contain activated-carbon beds.

Existing filtration consists of precoat filter (1µ rating) and a mechanical cotton-fiber filter (5µ rating) designed to process 10% of the circulating amine solution. Earlier studies showed that when activated-carbon beds were installed, they were exhausted in less than 35 days. This indicated that amine was severely contaminated with dissolved hydrocarbon introduced by the sour feed gas.

Sour-gas pretreatment

The HP unit is equipped with a slug catcher for removing bulk liquids and two vertical three-phase filter-separators for removing liquid aerosols and solid particulates with diameters of >0.5µ.

The filters were equipped with two separate compartments, 42 filter-coalescing elements, and vane pack. Estimated clean pressure drop (criterion for replacing the filter element) across the filter separator was 1.25 psi. A high pressure drop has never been a concern in the plant since the unit start-up.

We concluded that the presence of solids in the gas phase was not a major concern and, therefore, decided to inspect the filter separator for mechanical damage to the filter elements. Most of the filter elements were found to be in good mechanical condition except for three elements that had some cracks that could have been caused by improper installation or damage during the removal process.

Another important issue we looked at was to verify

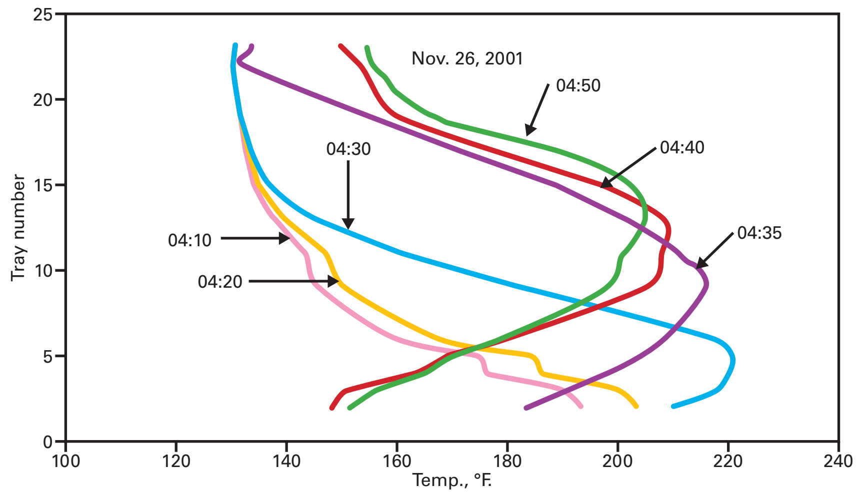
BERRI, SHEDGUM PLANT DATA

Table 1

	Operating gas plant — Berri	Operating gas plant — Shedgum
Process variables		
Sour gas, MMscfd	270	440
H_2S, mole %	2.2	3.2
CO_2, mole %	2.8	3.7
Pressure, psig	550	990
Amine circulation rate, gpm	2,100	3,400
Lean-amine solution analyses		
Amine, wt %	39	34
Water, wt %	58	52
Degradation products, wt %	3	15
Organic acids, ppm (wt)	50	80
Inorganic acids, ppm (wt)	15	20
Heat-stable salts anions, ppm (wt)	65	100
Lean loading, mole/mole	0.08	0.07
Sample recovery, %	99	98

CONTACTOR TEMP.: FIRST INCIDENT

Fig. 7



the liquid loading inside the filter separator. To do that we collected samples from locations No. 1 and No. 2 (Fig. 2).

We used samples from No. 2 as simulation input and analyzed samples from No. 1 for liquid loading to confirm the simulation results. In No. 1, we collected samples from the vertical segment of the pipeline to have a representative sample. The collection point was carefully chosen to be as close as possible to the exit nozzle of the heat exchanger to minimize liquid settling.

We use No. 2 to collect gas stream samples where the possibility of having liquid is minimal. We used the results of an analysis of this stream in the simulation to estimate the liquid formation downstream of the heat exchanger. A combination of both methods provided a good representation of the liquid loading.

Simulated cases showed a liquid loading of 320 gpm, while the design rate for each filter-separator was 62 gpm. Liquid loading measured from No. 1 showed variations from as low as 15 gpm to as high as 320 gpm. This indicated that the filter-separators were well under-designed for handling the high liquid loadings due mainly to the plant being operated under an inlet-gas composition that differs from the design.

Areas of improvement

It was clear that high liquid loading that exceeds the design of the exiting filter-separator is the main cause of foaming in the plant. Nonetheless, the high capital cost of installing additional filter-separators and of the commissioning of a new regeneration system for the HP unit led to the decision to continue using continuous antifoam injection as the primary option to suppress foaming.

Several low-cost modifications and operational practices were adapted to improve the unit performance and reduce the foaming severity, including:

- Retrofitted perforated liquid surface-protection plate above the maximum liquid level. This will reduce agitation activities at the liquid surface and hence the liquid carryover rate.
- Modified the level-control system to have one controller for both liquid hydrocarbon and water levels. This will allow faster drainage of the liquid and reduce carryover.
- Enhanced operational awareness of some of the important practices, such as routine skimming of hydrocarbon liquids from the flash and the reflux drums, eliminating the oxygen ingress to the amine storage facilities, and operating the flash drum at pressures as low as possible to flash more hydrocarbons.

Berri gas plant—background

Treatment of an offshore high-pressure sour gas at two amine treating units at the Berri gas plant was commissioned in 1998 and 2000, respectively (Table 1). Since their start-up, the units were hit by a series of foaming incidents during the winter season. During each incident, the plant used batch antifoam to control the problem. Some recent incidents, however, have led to continuous antifoam injection being practiced.

The two high-pressure trains use activated-carbon beds to treat the amine solution with upstream and downstream guard filters. Being surface active, the activated-carbon beds absorb the antifoam and hence are exhausted quickly.

It was a common practice to have the beds offline during antifoam injection. Having them offline leads to the dilemma of not having a sink source for the antifoam. Continuous antifoam injection means continuous buildup of the antifoam agent in the system that could after time reverse the functionality of antifoam.

Continuous antifoam at Berri has a more severe impact on the system than at Shedgum. That plant is equipped with a precoat filter that acts as a sink for the antifoam agent.

Our laboratory found that silicon-based antifoam (100 ppm) was completely removed from the amine solution by one pass through 1-in. precoat filter media. The lab estimated that the precoat filter at the plant removed 70% of the antifoam.[10]

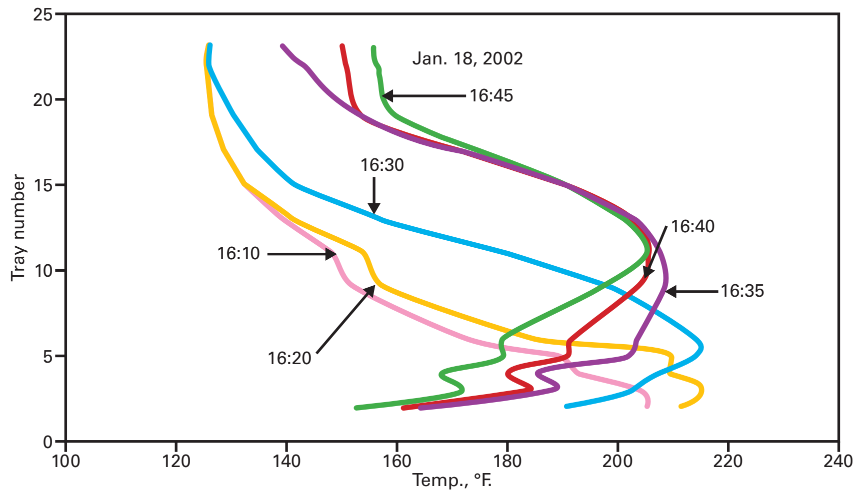
Therefore, identifying the causes of foaming was imperative to convince plant management to stop practicing continuous antifoam injection. Answering a series of questions will review the two recent foaming incidents, foaming in the HP system, its causes and recommended remedies:

- ***What went wrong in the Berri gas plant's HP amine unit?***

The main cause of the foaming incidents was liquid carryover with the sour-gas stream mainly as a result of

CONTACTOR TEMP.: SECOND INCIDENT

Fig. 8



liquid condensation in the pipeline after an upset in the offshore gas producing facilities.

The upstream facilities use a refrigeration system to control the hydrocarbon dewpoint at about 60° F. to condense heavy hydrocarbons and hence avoid their condensation along the pipeline.

Immediately preceding the last two foaming incidents, the upstream gas compression plant and the refrigeration systems were shutdown temporarily. This upset resulted in hydrocarbon condensation and liquid buildup in the pipeline that was carried to the Berri slug catcher. Inadequate drainage of the slug catcher's liquid level caused liquid carryover to the HP contactor.

- ***How did we identify the causes?***

Several indications showed that the cause of foaming was liquid carryover resulting from an upset in upstream operation. Following are these indications:

—*High level indication in Berri's slug catcher.* There was a sharp increase in the slug catcher's level indicator reading immediately before each foaming incident (Figs. 3 and 4) that is abnormal for the dry sour feed gas. The sour gas is a dry gas because of the removal of heavy hydrocarbons by the dewpoint-control unit. It is concluded from this that a rapid increase in the slug catcher's level is very remote except during upsets in the upstream operation or during pipeline scraping activities.

—*Outage in upstream compression plant.* Before each of the two recent foaming incidents, there were upsets in the upstream gas compression plant where gas flow through the subsea pipeline to Berri ceased (Figs. 5 and 6). No flow into the subsea segment of the pipeline and continuous withdrawal of gas by Berri caused pipeline pressure to decrease.

Because of the retrograde nature of the gas, pressure reduction leads to an increase in the gas dewpoint temperature.[11] Low ambient temperature, therefore, caused the stagnant gas to reach dewpoint temperature resulting in condensation in the pipeline.

An examination of the two foaming incidents revealed a time lag between shutdown of compression plant and onset of foaming in HP amine system because gases travel faster than the bulk liquids accumulation due to condensation. Gas residence time in the high-pressure gas pipeline is 13-16 hr; liquids will travel more slowly, however, depending on their quantities.

This also explains the time difference between the two incidents in the shutdown impact in the form of foaming. The Nov. 26 foaming took place 2 days after compression plant shutdown, while the Jan. 18 foaming was observed 5 days after the shutdown. This is attributed to longer shutdown duration during the Jan. 18 case that resulted in more liquid condensation and accumulation.

—*Contactor temperature profile.* The temperature inside the contactor during both foaming incidents increased as we moved up the column (Figs. 7 and 8). The reaction between amine and sour gas is exothermic and usually the first contact trays have the highest temperatures.

In foaming systems, major reactions take place at the interface of the foam due to the holdup of amine by the foam. As the foam moves upward, the exothermic reaction will move upward and be reflected by higher temperatures on the upper trays. Such a trend appeared during the foaming incidents, which indicates that sour feed gas has introduced foaming promoters to the system.

—*Berri HP system operating experience.* Operating experience in Berri HP amine plant showed no foaming tendencies during summer. High temperature is the best environment for inducing foaming, as it reduces the amine surface tension and makes it susceptible to foaming. Troublefree operation during summer proves that the HP DGA system should be able to handle normal operating conditions during cold weather if the same sour-gas feed quality is maintained.

—*Amine quality.* Amine quality has not been a problem in Berri's HP DGA system. The plant was able to operate adequately during summer operations. In addition, the HP amine system is equipped with the recommended conventional filtration system of mechanical and activated carbon, which are designed to maintain high amine quality. detailed analysis confirmed the good amine quality (Table 1).

- ***What is recommended to alleviate foaming reoccurrence?***

Troubleshooting the amine foaming problem and operational experience revealed that this problem is periodic and could be controlled without major modification to the exiting system.

Therefore, it was decided to stop the continuous antifoam injection practice.

It was found that the most cost-effective method to abate foaming is to have better coordination between the upstream facilities and the gas processing plant. Producing facilities should alarm the gas plant to take the proper action whenever upsets occur in any of the following systems: gas refrigeration, gas dehydration, and gas compression.

Implementing this practice will allow gas-treatment operations personnel to inject antifoam (batch) to the amine solution and closely monitor plant operation. In addition, added benefits could be attained by installing a gap-action control valve in the slug catcher liquid drainage system to prevent high liquid build up.

Effective troubleshooting of foaming is vital in achieving a resolution to amine foaming. Operations engineers should be aware of several things in order to do an effective trouble shooting:

- Understand the foaming concept, symptoms, and potential causes.
- Check amine quality and treatment methods that include filtration or reclamation.
- Examine sour-gas quality and pretreatment equipment.
- Review operational practices of the amine sweetening plant.
- Respond proactively to the activities in upstream facilities that have the potential to cause problems in the amine system. ✦

References

1. Linga, H., Hinderaker, G., and Tykhelle, B., "The Effect of Hydrocarbon Condensate and Antifoaming Agents on the Performance of CO_2 Absorption with Activated MDEA," 52nd Annual Lawrence Reid Gas Conditioning Conference, Norman, Okla., Feb. 24-27, 2002.
2. Pauley, C.R., Hashemi, R., and Caothien, S., "Analysis of Foaming Mechanisms in Amine Plants," 39th Annual Lawrence Reid Gas Conditioning Conference, Norman, Okla., Mar. 6-8, 1989.
3. Al Ghamdi, A.M., "Study Underscores Effectiveness of Antifoaming Agent in DGA Sweetening Process," OGJ, May 20, 2000, p. 62.
4. Pauley, C.R., Hashemi, R., and Caothien, S., "Ways to Control Amine Unit Foaming Offered," OGJ, Dec. 11, 1989, p. 67.
5. Kohl, Arthur L., and Nielsen, Richard, Gas Purification, 5th Edition, Houston: Gulf Publishing Co., 1997.
6. Pauley, C.R., "Face the Facts About Amine Foaming," Chemical Engineering Progress, July 1991, pp. 33-38.
7. Von Phul, S.A., "Sweetening Process Foaming and Abatement," 51st Annual Lawrence Reid Gas Conditioning Conference, Norman, Okla., Feb. 25-28, 2001.
8. Von Phul, S.A., "Sweetening Process Foaming and Abatement Part II: Case Studies," poster, 52nd Annual Lawrence Reid Gas Conditioning Conference, Norman, Okla., Feb. 24-27, 2002.
9. Khatib, Z.I., "Reduction of Entrainment of Aerosols in Gas Streams," 47th Annual Lawrence Reid Gas Conditioning Conference, Norman, Okla., Mar. 2-5, 1997.
10. Harruff, L.G., "Saudi Arabian Experience with DGA Units and Related Sulfur Plants," 48th Annual Lawrence Reid Gas Conditioning Conference, Norman, Okla., Mar. 1-4, 1998.
11. Katz, D.L., "Retrograde Condensate in Natural Gas Pipelines," 23rd Annual Lawrence Reid Gas Conditioning Conference, Norman, Okla., Mar. 15-16, 1973.

The author

Mater A. Al Dhafeeri is a senior gas processing engineer for Saudi Aramco, joining in 1995. He has worked in most of Saudi Aramco's gas processing facilities and NGL parts of the refineries. Al Dhafeeri holds a BS in chemical engineering from Tulsa University and an MS in natural gas engineering and management from the University of Oklahoma.

Net WAGP economic benefit requires Ghana development

Joseph Essandoh-Yeddu
Energy Commission of Ghana
Cape Coast

Felix Asante
ISSER
University of Ghana at Legon
Accra

Gürcan Gülen
Center for Energy Economics
University of Texas
Houston

Ghana needs to complete its domestic pipeline infrastructure before start-up of the 470-MMcfd West African Gas Pipeline if the country is to take full advantage of the new high-volume access to natural gas WAGP will provide. Although the initial pipeline systems to be laid are small and therefore can be constructed fairly quickly, there will inevitably be delays associated with acquisition of rights of way, the import of equipment, or other contingencies.

Ghana also must finalize commercial arrangements between industrial users and the supply company and between the supply company and both the West Africa Pipeline Co. and natural gas producers in Nigeria. Beyond the foundation volume, no agreements for additional volumes for Ghana exist, even as demand for Nigerian natural gas grows both domestically and internationally.

Natural gas that will flow to Ghana through WAGP offers a competitive and clean alternative to current fuels, especially for power generation and industrial purposes. The ability to absorb foundation volumes when the pipeline starts operating is important in keeping down the cost of natural gas for all users. No incentives, however, are necessary to induce industrial users in Tema and Takoradi to switch to natural gas from oil products, so long as oil prices stay greater than $30/bbl.

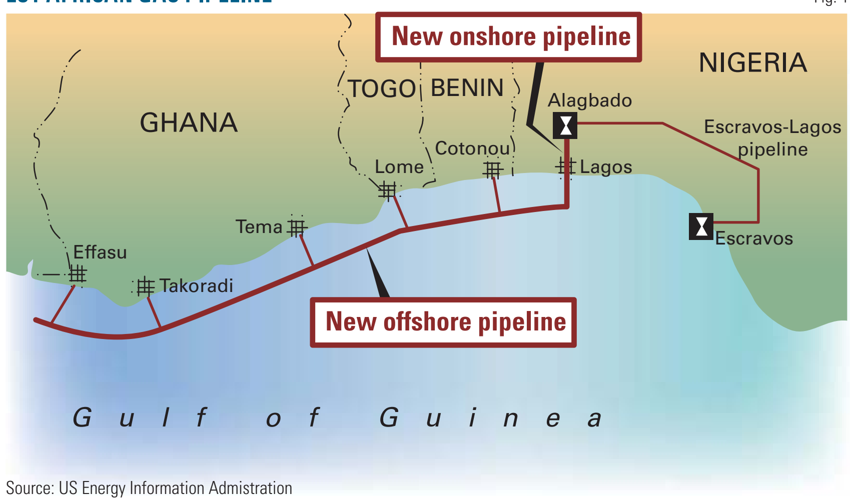
In addition to the typical industrial uses of generating heat or steam, natural gas also opens up the possibility of economically competitive cogeneration of electricity, helping Ghana meet its electrification goals more quickly, reliably, and cheaply. Reduced demand for oil products will also help equalize Ghana's trade balance, as payments for oil imports go down, and, in the long-run, may even help Ghana become an exporter of oil products if its refining capacity is expanded.

This article examines the factors affecting natural gas' large-scale introduction to the Ghanian energy market both in preparation for and upon WAGP's entering service.

Based on a presentation to the West African Power Industry Convention 2006, Accra, Ghana, Nov. 7-9, 2006.

WEST AFRICAN GAS PIPELINE

Fig. 1



Source: US Energy Information Admistration

Background

Natural gas is to start flowing from Nigeria through WAGP to Benin, Togo, and Ghana later this year. Ghana will buy 75% of the line's 134 MMcfd start-up volume and initially use the gas primarily as feedstock for the Takoradi thermal power plant in the country's western region (Fig. 1). The 550-Mw plant will provide a foundation market for Nigerian gas in the region. Initial demand from the plant will total 100-110 MMcfd, enough to generate 5 Tw-hr of electricity at 85% utilization. Plans call for the plant to be upgraded to 660 Mw.

Other industries in Tema and Takoradi, Ghana, are early candidates for switching to natural gas from oil products. As elsewhere in the world, natural gas provides a fuel that is cleaner, more efficient, and more stable in pricing than oil products, allowing its use not only for typical industrial purposes but

OIL&GAS JOURNAL | Previous Page | Contents | Zoom In | Zoom Out | Front Cover | Search Issue | Next Page | qMags

also for generating on site electricity either for self-sufficiency or backup.

Cogeneration of heat-steam and electricity maximizes natural gas' energy content. The sale of excess power to the national grid from cogeneration or self-generation facilities can also improve system reliability and lower electricity costs.

Once industrial and electrical demand in Tema and Takoradi has been met, however, Ghana offers little else in the way of small commercial or residential demand. Laying pipelines to serve dispersed residential and small commercial customers will yield an expensive service per unit of natural gas, testing customers' ability to afford it.

The most likely manner of providing natural gas to smaller users is the incremental expansion of pipelines in Tema to currently planned communities once the system to meet industrial demand has been put in place. This possibility lies at least 5-10 years in the future.

The transport sector is responsible for 21-22% of Ghana's energy use, and accounts for 85% and 99% of diesel and gasoline consumption respectively, creating additional opportunities for natural gas use, particularly if oil prices remain high. Compressed natural gas is a low-cost alternative fuel for vehicles, especially in countries that have a gas infrastructure. CNG vehicles are roughly 10% more efficient than gasoline vehicles and are as efficient as diesel fuelled vehicles.

Evaluating the potential natural gas penetration of Ghana's industrial and transportation sectors requires looking at the demand structure in each sector and estimating both cost of distribution infrastructure development and final cost of delivered gas to end users, relative to their current fuel supplies

Potential demand for natural gas by industrial and other large users is limited in Ghana. Tema and Takoradi, with their concentration of industrial activities, including the Tema oil refinery, Volta Aluminium Co., and Ghana cement works, provide the areas where pipeline systems can most easily be developed to allow industrial users to switch to natural gas early in the market development process. Past studies to determine natural gas demand in Tema and Takoradi have established a broad range of 4-20 MMcfd.

Takoradi and Tema also host Ghana's only two international seaports.

RESIDUAL FUEL OIL DEMAND FORECAST, GHANA — Table 1

Year	Economic growth scenarios, %/year	Fuel oil demand, without access to natural gas (1,000 tonnes)	Fuel oil demand, with access to natural gas (1,000 tonnes)	Implied natural gas use, MMcfd
2008	>7	197-198	66-70	13-14
	5-7	124-125	41-42	8-9
2012	>7	214-17	71-75	14-15
	5-7	134-136	44-45	9
2015	>7	236-237	78-90	15-18
	5-7	146-147	48-50	9-10
2020	>7	255-260	95-115	18-23
	5-7	156-159	52-54	10-11

Source: "Strategic National Energy Plan 2006-20," Energy Commission, Ghana, 2006

Demand potential

Until Ghana builds a national natural gas pipeline network, introduction of natural gas into the economy will not necessarily displace all fuel-oil demand. Even absent such a network, however, natural gas will to displace about two-thirds of the country's fuel-oil demand by 2020, especially in Tema and Takoradi, assuming industrial growth of more than 6%/year by 2020.

Ghana's economic growth has exceeded 5%/year since 2003. Current government development plans call for the country to become a middle level developing country with real gross domestic product of $1,000 per capita by 2015, from the current level of about $600 per capita. This growth rate, however, would require expansion of more than 7%/year.

Displacing this amount of residual fuel oil would require 8-14 MMcfd of natural gas in 2008 and as much as 23 MMcfd by 2020 (Table 1). If the necessary pipeline systems can be built in Tema and Takoradi, and industrial users in these areas switch to natural gas at expected rates, demand for natural gas in industrial heating could easily be closer to the 14-MMcfd end of the projected 2008 range.

Electricity

The industrial sector has accounted for 9% of the national diesel consumption demand on average since 2000. Industry uses diesel largely for backup power generation. Diesel consumption by industry rose to almost 97,000 tonnes in 2004 from about 61,000 tonnes in 2001. Based on diesel-demand forecasts provided by the Energy Commission of Ghana and Tema oil refinery, projected natural gas demand for backup generation, assuming it replaces diesel entirely, will exceed 20 MMcfd by 2020 (Table 2). Added to demand for heating, initial demand for natural gas in 2008 could reach 18-26 MMcfd.

It may not be too meaningful, however, to talk about backup power in terms of daily demand for natural gas because backup generation does not have a constant demand. On days when the system is constrained or there are rolling blackouts, the need for electricity may be several times greater than the amount shown in Table 2. At other

DIESEL, NATURAL GAS DEMAND FORECAST; BACKUP ELECTRICITY GENERATION — Table 2

	2008	2012	2015	2020
Total diesel demand, 1,000 tonnes	1,100-1,300	1,500-1,600	1,800-2,000	2,300-2,500
Diesel demand for backup electricity, 1,000 tonnes	99-117	135-144	162-180	207-225
Natural gas requirement, MMcfd*	10-12	13-14	16-18	20-23

*Assumes 100% replacement of diesel by natural gas.
Source: "Strategic National Energy Plan 2006-20," Energy Commission, Ghana, 2006

Natural gas delivered cost[1]

Table 3

	$/MMbtu
Oil indexation	[2]0.20-1.00
Cost of gas in Nigeria	0.55
Gas sales handling fee	0.10
Escravos-Lagos pipeline tariff	0.25
WAGP cost	[3]1.90-5.00
Distribution tariff in Ghana	0.20
Conversion cost	0.05
Total cost	**3.25-7.15**

[1]Data taken or estimated from various studies on WAGP by the World Bank, or calculated by the authors. [2]Oil price range, $30-60/bbl. [3]Low value yields 15% return to the pipeline assuming a gas demand profile of 100 MMcfd in 2007 reaching almost full capacity in 2026. High value yields 15% return assuming a gas demand profile of 25 MMcfd in 2007 reaching about 225 MMcfd in 2026.

times, when the electricity from the grid is reliable, industry might use no natural gas at all for power generation.

This fluctuation in load may cause problems for the natural gas distribution company. Demand for storage could emerge, increasing the cost of gas. Industrial facilities could also retrofit their backup systems to be able to switch between diesel and natural gas, depending on the relative costs of each.

The best long-term option for industry, however, may be ongoing natural gas-fueled self-generation, or cogeneration, which would allow it to take advantage of cleaner, more efficient gas turbines for power while meeting heat and steam needs at the same time. Excess power could be sold back to the national grid, once Ghana fully implements electricity unbundling, easing the urgency of expanding generation capacity in the rest of the country.

Transportation

A city like Accra would need at least 5-10 CNG filling stations to make CNG-fuelled vehicles practical. Regulated vehicle conversion shops would also be needed.

The cost of 5-10 filling stations would total $5-10 million. Placing these stations efficiently along the roads would require expansion of the gas pipeline network as well, increasing initial investment and hence the cost of natural gas to everyone.

Private investors are unlikely to take such risks in the absence of a CNG fleet. Even assuming low-cost gas ($3-3.5/

MMbtu) and high-cost oil ($50+/bbl), it would take 3-4 years for individuals to recover the cost of converting their vehicles to CNG.

Per capita income in Ghana ranges $450-600. The average Ghanian citizen is therefore unlikely to spend the $700 or more required to make the CNG conversion. Even those who can afford it would have to find the surrounding infrastructure convenient enough to make the change worthwhile. The likelihood of any large increase in demand for natural gas from the transportation sector is therefore low.

Secondary system

Addressing the demand potential described in this article requires timely development of pipeline systems in Tema and Takoradi and a low final cost of delivered gas to industrial users. Given the compactness of the distribution areas and proximity of most major potential customers, the local pipeline systems would be fairly short, consisting of a main trunk linking WAGP to a larger diameter backbone pipeline and smaller laterals feeding end users.

Major customers in the Tema and Takoradi areas would require two pipeline networks of roughly 20-25 km each in the early stages. These systems would be fairly quick and inexpensive to build. A discounted cash flow model using sensitivity analyses can calculate the per-unit cost impact of building distribution systems in Tema and Takoradi.

Economic assumptions

A system including all necessary pipelines to take natural gas from WAGP and deliver it to customers will most likely include a combination of steel and plastic pipes. Steel pipelines of 8-in. OD and greater are most appropriate for the section taking the gas from WAGP and bringing it to the service area, since the volumes will be relatively large and pressure will be high.

High-density polyethylene pipe of 4-6 in. OD will be most appropriate for laterals because it is far cheaper and easier and faster to lay. HDPE pipes have proven effective and durable for pressures less than 100 psi.

Steel pipes cost about $25,000/OD in./km. Value-added tax (12.5%), import duty (~10%) and port handling and haulage fees (~3.5%) will increase this cost by roughly 26%, to $31,500.

HDPE pipes cost about $3,100 and $4,200/OD in./km for 4 and 6-in. OD pipes, respectively. Including various taxes and fees, the total imported cost per inch becomes $4,000 and $5,300 for 4 and 6-in. pipelines, respectively.

The local distribution companies that this article assumes will be licensed to operate the Tema and Takoradi franchises will most likely generate revenues through charging tariffs to carry natural gas in their distribution networks to end users, rather than through sale of gas itself. The LDCs' revenues will therefore depend heavily on the volume of gas they distribute.

A discounted cash flow model yields an optimum return on distribution tariff of 15% for each LDC. LDCs around the world are typically regulated and return 8-12%; but a higher rate in Ghana will make investment in these small systems attractive.

Several scenarios of various pipeline OD and lengths yielded a distribution tariff of similar magnitude. Only a summary of the results follows.

The base assumption for Tema includes a 22-km pipeline network consisting of 15 km of 6-in. HDPE pipe and 7 km of 12-in. steel pipe. The base assumption for Takoradi includes a 20-km pipeline network consisting of 5 km of 12-in. steel pipe and 15 km of 6-in. HDPE pipe.

These assumptions yield total costs of almost $2.4 million for Takoradi and $3.1 million for Tema. The estimate for Takoradi, however, does not include the cost of extending WAGP from the power plant to downtown Takoradi, about 15 km away. Building the additional 12-in. steel pipeline could double or even triple distribution tariffs unless demand for gas in Takoradi is much larger than initial estimates of 4-7 MMcfd.

Both networks can be constructed

Estimated comparative costs

Table 4

Crude oil $/bbl	LPG	Residual fuel oil	Diesel	Natural gas	
	$/MMbtu, average				
60	10.30	15.40	8.25	14.40	4.05–7.15
45	7.75	12.30	6.60	11.00	3.70–6.75
30	5.51	8.80	4.60	7.70	3.30-6.30

Electricity generation, cost comparison

Table 5

Cost	Distributed generation Natural gas	Diesel	Average grid distribution tariff Industrial	Commercial
	$/kw-hr			
Maximum	8.50	22.00	7.50	11.0
Minimum	5.50	16.60	4.50	9.6

in less than 3 months. Using 6 and 12-in. pipelines, as opposed to 4-in. HDPE and 8-in. steel pipes, will lead to pipeline capacities that may not initially be supported by the market, increasing the capital cost of the infrastructure and leading to a higher distribution tariff for the same target rate of return of 15%.

Oversizing the pipelines makes sense on both engineering grounds and an optimistic view of future demand. Increasing size only adds incrementally to cost, as most other variables (rights of way, labor, equipment, etc.) are already covered, and adds the ability to accommodate future increases in load.

Calculating an upper limit for the distribution tariff is also desirable. If natural gas is competitive at this upper limit, it will also be competitive at lower cost. A 15% return requirement also helps establish this upper limit.

Tema network calculations assume initial natural gas delivery rates of 7 MMcfd, increasing 5%/year. The growth rate equals Ghana's industrial growth rate since 2000.

Takoradi system calculations assume initial natural gas delivery rates of 4 MMcfd in 2007 and the same annual growth rate. These assumptions are fairly conservative, given initial demand estimates of 18-26 MMcfd. This analysis uses lower demand values to help establish the upper limits of the distribution tariff, so that improvements in switching and penetration rates will lead to declines in the tariff and make natural gas more attractive.

This analysis also calculates the cost incurred by new users of natural gas in installing or retrofitting the necessary equipment (burners, boilers, furnaces, etc.). Uniform average annualized cost for conversion—including investment, operation, and maintenance—total roughly $22,000. Conversion costs range between $0.005 and $0.06/MMbtu for consumption of 1-11 MMcfd of natural gas per customer.

Results

The distribution tariff for Tema equals $0.20/MMbtu. If industrial users in Tema are more enthusiastic about natural gas and switch quickly in 2007, for example at a rate of 12 MMcfd rather than 7 MMcfd, the tariff may fall to $0.12/MMbtu. Takoradi, a smaller system, will need a distribution tariff of $0.28/MMbtu. Increasing the initial load to 7 MMcfd from 4 MMcfd reduces the tariff to $0.16/MMbtu.

The starting load in 2007 is important, but even with low starting load and potentially oversized pipeline systems, the tariffs are not a significant component of the total cost of gas delivered through WAGP (Table 3). WAGP cost covers a wide range because the tariff is set to yield 12% on a foundation volume of 134 MMcfd and 15% for additional customers. To keep WAGP's cost as low as possible, Ghana needs to be ready to take its share of the foundation volume, and preferably more, once WAGP is able to ship them.

The gas cost range of $3.25-7.15/MMbtu leaves a lot of room for sensitivity to the price of oil. The higher the crude oil price, the more attractive a switch to gas becomes. The switch becomes less attractive to residual fuel oil users as crude falls below $45/bbl. Table 4 provides estimated costs compared to existing fuels at crude prices of $30, $45, and $60/bbl.

The low end of the natural gas price range reflects a relatively high use of natural gas by Ghana in 2007, and the high end reflects a low-use scenario. As long as the oil price stays greater than $45/bbl, natural gas will remain competitive with oil products even in low-use scenarios. The more gas Ghana takes from the pipeline when gas starts flowing, the more competitive gas will be.

Even at oil prices of $30/bbl, gas can remain attractive to RFO users (Table 4), placing a premium on the readiness of distribution pipelines to serve industrial customers before WAGP starts delivering foundation volumes. New combined-cycle generation will produce electricity at roughly $0.045-0.075/kw-hr at a natural gas price of $3.25-7.15/MMbtu. A retrofitted Takoradi plant, however, should produce at rates $0.01-0.015/kw-hr cheaper because its prices would not reflect the capital cost of building a new facility.

Should industry decide to cogenerate, electricity generation costs would equal about $0.055-0.085/kw-hr, based on single-cycle gas turbine technology, making it less competitive to generate power than to buy it from the grid (Table 5). Most cogeneration units today, however, use more efficient combined-cycle technology.

The value of heat-steam used by other industrial processes also figures into any accounting of relative costs, as does the increased reliability made available by self-generation. Finally, to the extent cogenerators can sell excess power into a market or to other users, they will reduce the cost of their own consumption even further.

These cost advantages make it easy to imagine cogeneration as competitive with electricity from the grid at $0.045/kw-hr. The accounting becomes even more straightforward for large commercial and service entities like hotels and cold stores; even at the high end, $0.085/kw-hr, the cogeneration prices are lower than the distribution tariff. ✦

The authors

Joseph Essandoh-Yeddu (jeyeddu@yahoo.co.uk) heads the strategic planning and policy division of the Ghana Energy Commission, a regulatory body. He has more than 15 years' experience in the energy sector of Ghana. He was the program manager for Ghana's solar energy program until 1998 and led a national team that produced Ghana's Strategic National Energy Plan 2006-20. He has been a member of Ghana's negotiating team to the UN Climate Change Convention and the Kyoto Protocol meetings since 2005. Essandoh-Yeddu holds a BS in physics and an MS engineering degree in environment and energy from Chalmers University of Technology, Gothenburg, Sweden. He is currently pursuing a PhD at the University of Cape Coast, Ghana.

Felix Ankomah Asante (fasante@ug.edu.gh) is a senior research fellow and coordinator of the Resource Center for Energy Economics and Regulation at the Institute of Statistical, Social, and Economic Research, University of Ghana, Legon. He holds a PhD (2002) in development economics from the University of Bonn, Germany.

Gürcan Gülen (gurcan.gulen@beg.utexas.edu) is a senior energy economist at the Center for Energy Economics, Bureau of Economy Geology, Jackson School of Geosciences, University of Texas at Austin. Gülen comanages a 5-year cooperative agreement with the US AID, focusing on capacity building in energy sectors of emerging economies in Africa. He served as president, vice-president, and secretary of the Houston chapter of the US Association for Energy Economics 1998-2001. He is currently vice-president for conferences for the USAEE. Gülen received a PhD in economics from Boston College and a BA in economics from Bosphorus University, Istanbul.

Equipment/Software/Literature

New 200,000 lb lift side boom

Here's a newly engineered 200,000 lb side-boom attachment for a Caterpillar Inc. D9H tractor body.

The new unit has a maximum lift of 200,000 lb and a maximum working load of 117,600 lb.

The new M594C attachment includes hydraulic pilot controls, an upgraded hydraulic system with load-sense pressure compensated piston pump, offset 35 in. track shoes (9,240 sq in. of ground contact area), a gross machine weight of 128,300 lb, and a 132 in. track length. Modifications were also made to the D9H case and frame by the addition of rear track to frame supports, a stiff bar, and the addition of fish plates to strengthen the sideboom mounting structure. Winches are planetary with two-speed high efficiency piston motor and dual brake system. The load winch has free fall function.

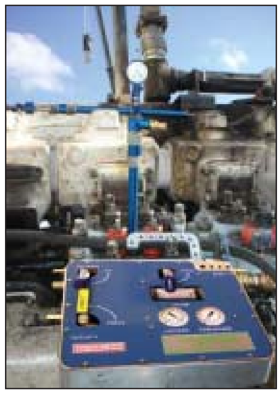
Source: **Midwestern Mfg. Co.,** 2119 S. Union Ave., Tulsa, OK 74107-2703.

Predictive maintenance engine inspection tool

DynaProbe, introduced jointly by Dynalco Controls Inc., Fort Lauderdale, Fla., and Beta Machinery Analysis Ltd., Calgary, is an engine inspection tool that helps reduce maintenance costs, minimize overhaul downtimes, and decrease the chance of a catastrophic failure occurring.

Data obtained can also be trended, and predictive wear rates can be determined as more inspections are performed. The tool is designed to be used by spark-ignited and diesel engine mechanics to measure:

- Power cylinder condition and wear—liners, rings, ports, head, valves.
- Valve sink and train setting.
- Wrist pin and connecting rod clearances (wear and trend).
- Ignition system condition.
- Cylinder leakage rate.
- Blow-by.



Source: **Dynalco Controls Inc.,** 3690 NW 53rd St., Fort Lauderdale, FL 33309.

Services/Suppliers

Pure Group AS

Stavanger, has announced that it will merge with Montreal-based Torr Canada Inc.

Torr Canada Inc. develops and manufactures proprietary water treatment solutions for use in the upstream oil and gas industry.

Pure Group AS, jointly held by Statoil Innovation AS and Hitec Vision Private Equity, is comprised of the companies ProPure AS, ProSep Technologies Inc., and Pure Group Asia Pacific. The group offers a comprehensive suite of services, solutions, and process systems for water treatment, oil and gas separation.

Aker Kværner ASA

Lysaker, Norway, has announced the appointment of Pål Helsing as executive vice-president for its field development business area. Helsing, who has been with Aker Kværner since 1993, holds degrees from Glasgow University and the Norwegian School of Management.

Aker Kværner ASA is a leading global provider of engineering and construction services, technology products, and integrated solutions for several industries, including oil & gas, and refining & chemicals.

Cæsar Petroleum Systems LLC

Houston, has announced that Donald Zmick has joined the company as vice-president of client services. Zmick previously held positions with Chevron, Amoco, Murphy Oil, NBD Bank, and most recently with Decision Strategies Inc. He earned his BS degree, magna cum laude, from Texas Tech University, and an MBA from the University of Chicago.

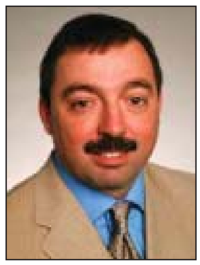
Zmick

Cæsar Petroleum Systems LLC serves the worldwide petroleum industry with integrated business simulation software tools, training, support, and on-site consulting. Its anchor product, Petroleum Ventures & Risk (PetroVR) software, was introduced in 1997.

InterAct PMTI

Houston, has named Brent Boudreaux as director of marine operations.

Boudreaux earned a BS degree in mechanical engineering at McNeese State University, and an MBA from Texas A&M University. He has more than 15 years of industry experience, primarily in marine construction/decommissioning.



Boudreaux

InterAct PMTI, formerly Pacific Management Technologies Inc., was acquired by Acteon, the UK-based leader in seabed-to-surface technology, in mid-June. InterAct PMTI provides services to the oil and gas industry worldwide, focusing on four main areas: regulatory affairs, drilling support services, project management, and subsea rental services.

Statistics

IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4 8-10 2007	Districts 1-4 8-3 2007	District 5 8-10 2007	District 5 8-3 2007	Total US 8-10 2007	Total US 8-3 2007	Total US *8-11 2006
	1,000 b/d						
Total motor gasoline	1,154	1,335	59	62	1,213	1,397	1,388
Mo. gas. blending comp.	796	973	52	32	848	1,005	1,027
Distillate	218	256	14	47	232	303	261
Residual	173	396	0	6	173	402	277
Jet fuel-kerosine	84	78	147	169	231	247	300
Propane-propylene	121	82	1	0	122	82	251
Other	416	61	13	148	429	209	325
Total products	**2,962**	**3,181**	**286**	**464**	**3,248**	**3,645**	**3,829**
Total crude	**8,509**	**9,136**	**1,364**	**862**	**9,873**	**9,998**	**10,022**
Total imports	**11,471**	**12,317**	**1,650**	**1,326**	**13,121**	**13,643**	**13,851**

*Revised.
Source: US Energy Information Administration
Data available in OGJ Online Research Center.

Additional analysis of market trends is available through **OGJ Online**, *Oil & Gas Journal's* electronic information source, at http://www.ogjonline.com.

OGJ CRACK SPREAD

	*8-17-07	*8-18-06	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	84.84	82.51	2.33	2.8
Brent crude	70.03	72.23	–2.21	–3.1
Crack spread	14.82	10.28	4.54	44.2
FUTURES MARKET PRICES				
One month				
Product value	83.60	84.61	–1.01	–1.2
Light sweet crude	72.06	71.93	0.13	0.2
Crack spread	11.54	12.68	–1.14	–9.0
Six month				
Product value	82.61	84.61	–2.00	–2.4
Light sweet crude	70.47	71.93	–1.47	–2.0
Crack spread	12.15	12.68	–0.53	–4.2

*Average for week ending.
Source: Oil & Gas Journal
Data available in OGJ Online Research Center.

PURVIN & GERTZ LNG NETBACKS—AUG. 17, 2007

Receiving terminal	Liquefaction plant Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	6.73	4.69	5.92	4.59	5.28	5.90
Everett	5.47	3.48	5.09	3.58	3.96	5.76
Isle of Grain	3.48	1.93	2.98	1.90	2.15	2.96
Lake Charles	4.13	2.54	3.88	2.69	2.86	4.74
Sodegaura	4.94	7.06	5.14	6.77	6.11	4.41
Zeebrugge	5.91	4.10	5.31	4.01	4.49	5.33

Definitions, see OGJ Apr. 9, 2007, p. 57.
Source: Purvin & Gertz Inc.
Data available in OGJ Online Research Center.

CRUDE AND PRODUCT STOCKS

	Crude oil	Motor gasoline Total	Motor gasoline Blending comp.[1]	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane-propylene
	1,000 bbl						
PADD 1	15,399	53,596	25,645	10,554	52,018	13,586	4,061
PADD 2	65,735	47,799	14,964	7,076	27,526	1,347	20,725
PADD 3	183,748	64,038	27,106	12,870	33,462	16,326	24,970
PADD 4	13,914	6,040	2,129	539	2,958	364	[1]2,018
PADD 5	56,432	30,467	22,120	10,361	11,705	5,354	—
Aug. 10, 2007	**335,228**	**201,940**	**91,964**	**41,400**	**127,669**	**36,977**	**51,774**
Aug. 3, 2007	**340,395**	**202,997**	**92,604**	**41,340**	**127,516**	**38,607**	**50,354**
Aug. 11, 2006[2]	**331,002**	**205,393**	**89,238**	**40,659**	**133,170**	**42,648**	**61,841**

[1]Includes PADD 5. [2]Revised.
Source: US Energy Information Administration
Data available in OGJ Online Research Center.

REFINERY REPORT—AUG. 10, 2007

District	Refinery operations Gross inputs	Refinery operations Crude oil inputs	Refinery output Total motor gasoline	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane-propylene
	1,000 b/d		1,000 b/d				
PADD 1	1,469	1,475	1,897	87	475	102	48
PADD 2	3,276	3,266	2,118	228	891	50	180
PADD 3	7,765	7,623	3,467	642	1,943	301	691
PADD 4	603	599	289	28	179	14	[1]139
PADD 5	2,908	2,820	1,500	438	612	187	—
Aug. 10, 2007	**16,021**	**15,783**	**9,271**	**1,423**	**4,100**	**654**	**1,058**
Aug. 3, 2007	**15,920**	**15,791**	**9,151**	**1,408**	**4,098**	**737**	**1,135**
Aug. 11, 2006[2]	**15,912**	**15,578**	**9,242**	**1,465**	**3,896**	**689**	**1,027**
	17,447 operable capacity		**91.8% utilization rate**				

[1]Includes PADD 5. [2]Revised.
Source: US Energy Information Administration
Data available in OGJ Online Research Center.

OIL&GAS JOURNAL | Previous Page | Contents | Zoom In | Zoom Out | Front Cover | Search Issue | Next Page | qMags

OGJ GASOLINE PRICES

	Price ex tax 8-15-07	Pump price* 8-15-07	Pump price 8-16-06
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	239.1	278.8	302.2
Baltimore	228.2	270.1	307.5
Boston	225.4	267.3	305.9
Buffalo	223.3	283.4	308.8
Miami	237.7	288.0	314.5
Newark	231.5	264.4	300.4
New York	223.2	283.3	319.2
Norfolk	225.0	262.6	293.7
Philadelphia	231.2	281.9	322.6
Pittsburgh	227.4	278.1	298.7
Wash., DC	243.3	281.7	323.1
PAD I avg.	230.5	276.3	308.8
Chicago	239.0	289.9	347.7
Cleveland	209.6	266.0	291.0
Des Moines	239.6	280.0	280.8
Detroit	233.4	282.6	301.0
Indianapolis	235.6	280.6	287.8
Kansas City	232.5	268.5	294.6
Louisville	252.0	288.9	297.5
Memphis	242.2	282.0	289.1
Milwaukee	233.1	284.4	316.2
Minn.-St. Paul	229.6	270.0	296.5
Oklahoma City	226.8	262.2	286.8
Omaha	223.0	269.4	300.4
St. Louis	251.2	287.2	296.3
Tulsa	226.1	261.5	282.9
Wichita	237.6	281.0	289.0
PAD II avg.	234.1	276.3	297.2
Albuquerque	239.8	276.2	298.8
Birmingham	228.6	267.3	290.8
Dallas-Fort Worth	227.1	265.5	292.9
Houston	232.4	270.8	291.9
Little Rock	226.9	267.1	290.0
New Orleans	232.5	270.9	292.3
San Antonio	226.9	265.3	285.0
PAD III avg.	230.6	269.0	291.7
Cheyenne	245.6	278.0	289.5
Denver	247.9	288.3	297.8
Salt Lake City	246.9	289.8	294.7
PAD IV avg.	246.8	285.4	294.0
Los Angeles	225.0	283.5	322.9
Phoenix	246.7	284.1	291.2
Portland	239.0	283.2	305.1
San Diego	237.7	296.2	331.7
San Francisco	234.7	293.2	329.9
Seattle	226.3	278.7	318.0
PAD V avg.	235.1	286.5	316.5
Week's avg.	**233.6**	**277.2**	**301.8**
July avg.	**251.6**	**295.2**	**295.2**
June avg.	**265.9**	**309.4**	**288.4**
2007 to date	**228.4**	**271.9**	—
2006 to date	**222.3**	**265.7**	—

*Includes state and federal motor fuel taxes and state sales tax. Local governments may impose additional taxes.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

REFINED PRODUCT PRICES

	8-10-07 ¢/gal		8-10-07 ¢/gal
Spot market product prices			
		Heating oil	
Motor gasoline		No. 2	
(Conventional-regular)		New York Harbor	196.25
New York Harbor	198.05	Gulf Coast	193.62
Gulf Coast	192.55	Gas oil	
Los Angeles	192.05	ARA	195.53
Amsterdam-Rotterdam-		Singapore	193.33
Antwerp (ARA)	181.94		
Singapore	179.19	Residual fuel oil	
Motor gasoline		New York Harbor	130.07
(Reformulated-regular)		Gulf Coast	135.12
New York Harbor	199.80	Los Angeles	152.65
Gulf Coast	202.80	ARA	138.14
Los Angeles	206.05	Singapore	137.42

Source: DOE Weekly Petroleum Status Report.
Data available in OGJ Online Research Center.

BAKER HUGHES RIG COUNT

	8-17-07	8-18-06
Alabama	4	4
Alaska	4	4
Arkansas	50	28
California	38	35
Land	37	30
Offshore	1	5
Colorado	117	93
Florida	1	0
Illinois	1	0
Indiana	4	0
Kansas	14	16
Kentucky	9	6
Louisiana	178	197
N. Land	58	54
S. Inland waters	24	21
S. Land	31	42
Offshore	65	80
Maryland	1	0
Michigan	3	3
Mississippi	12	11
Montana	19	21
Nebraska	0	0
New Mexico	86	91
New York	6	7
North Dakota	42	34
Ohio	14	6
Oklahoma	190	195
Pennsylvania	17	16
South Dakota	3	2
Texas	837	809
Offshore	6	13
Inland waters	1	3
Dist. 1	25	22
Dist. 2	33	27
Dist. 3	57	60
Dist. 4	83	96
Dist. 5	186	147
Dist. 6	135	115
Dist. 7B	33	48
Dist. 7C	57	43
Dist. 8	113	107
Dist. 8A	18	20
Dist. 9	33	31
Dist. 10	57	77
Utah	35	44
West Virginia	32	28
Wyoming	68	108
Others—NV-2; TN-5; VA-2; WA-1	10	4
Total US	**1,795**	**1,762**
Total Canada	**321**	**471**
Grand total	**2,116**	**2,233**
Oil rigs	309	330
Gas rigs	1,480	1,427
Total offshore	73	99
Total cum. avg. YTD	**1,754**	**1,605**

Rotary rigs from spudding in to total depth.
Definitions, see OGJ Sept. 18, 2006, p. 42.

Source: Baker Hughes Inc.
Data available in OGJ Online Research Center.

SMITH RIG COUNT

Proposed depth, ft	8-17-07 Rig count	8-17-07 Percent footage*	8-18-06 Rig count	8-18-06 Percent footage*
0-2,500	59	8.4	44	2.2
2,501-5,000	109	52.2	82	36.5
5,001-7,500	233	23.6	228	21.9
7,501-10,000	437	4.1	380	5.2
10,001-12,500	428	0.9	419	1.9
12,501-15,000	279	0.3	287	—
15,001-17,500	106	—	107	—
17,501-20,000	70	—	68	—
20,001-over	35	—	29	—
Total	**1,756**	**7.9**	**1,644**	**6.6**
INLAND	43		36	
LAND	1,643		1,543	
OFFSHORE	70		65	

*Rigs employed under footage contracts.
Definitions, see OGJ, Sept. 18, 2006, p. 42.

Source: Smith International Inc.
Data available in OGJ Online Research Center.

OGJ PRODUCTION REPORT

	[1]8-17-07	[2]8-18-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	19	20
Alaska	752	636
California	665	676
Colorado	50	60
Florida	6	7
Illinois	30	28
Kansas	96	98
Louisiana	1,336	1,397
Michigan	14	14
Mississippi	49	48
Montana	92	100
New Mexico	163	162
North Dakota	104	112
Oklahoma	165	174
Texas	1,333	1,364
Utah	43	49
Wyoming	143	141
All others	60	71
Total	**5,120**	**5,157**

[1]OGJ estimate. [2]Revised.

Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

US CRUDE PRICES

$/bbl*	8-17-07
Alaska-North Slope 27°	62.00
South Louisiana Sweet	76.75
California-Midway Sunset 13°	62.50
Lost Hills 30°	70.30
Southwest Wyoming Sweet	65.98
East Texas Sweet	68.00
West Texas Sour 34°	62.70
West Texas Intermediate	68.50
Oklahoma Sweet	68.50
Texas Upper Gulf Coast	65.25
Michigan Sour	61.50
Kansas Common	67.50
North Dakota Sweet	66.00

*Current major refiner's posted prices except North Slope lags 2 months. 40° gravity crude unless differing gravity is shown.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

WORLD CRUDE PRICES

$/bbl[1]	8-10-07
United Kingdom-Brent 38°	71.87
Russia-Urals 32°	69.73
Saudi Light 34°	68.92
Dubai Fateh 32°	67.93
Algeria Saharan 44°	73.78
Nigeria-Bonny Light 37°	74.69
Indonesia-Minas 34°	75.71
Venezuela-Tia Juana Light 31°	67.69
Mexico-Isthmus 33°	67.58
OPEC basket	70.90
Total OPEC[2]	69.98
Total non-OPEC[2]	69.74
Total world[2]	69.87
US imports[3]	68.09

[1]Estimated contract prices. [2]Average price (FOB) weighted by estimated export volume. [3]Average price (FOB) weighted by estimated import volume.
Source: DOE Weekly Petroleum Status Report.
Data available in OGJ Online Research Center.

US NATURAL GAS STORAGE[1]

	8-10-07	8-3-07	Change
	bcf		
Producing region	919	932	–13
Consuming region east	1,573	1,544	29
Consuming region west	411	406	5
Total US	**2,903**	**2,882**	**21**
	May 07	**May 06**	**Change, %**
Total US[2]	**2,179**	**2,310**	**–5.7**

[1]Working gas. [2]At end of period.
Source: Energy Information Administration.
Data available in OGJ Online Research Center.

WORLD OIL BALANCE

	-2007- 1st qtr.	2006 4th qtr.	2006 3rd qtr.	2006 2nd qtr.	2006 1st qtr.	-2005- 4th qtr.
	Million b/d					
DEMAND						
OECD						
US & Territories	21.07	21.01	21.14	20.87	20.75	21.14
Canada	2.35	2.26	2.26	2.14	2.24	2.33
Mexico	2.05	2.00	1.96	1.98	2.05	2.10
Japan	5.39	5.29	4.75	4.72	5.89	5.46
South Korea	2.35	2.32	2.04	2.04	2.29	2.23
France	1.97	1.95	1.93	1.87	2.09	1.96
Italy	1.69	1.71	1.68	1.65	1.89	1.78
United Kingdom	1.80	1.81	1.78	1.82	1.91	1.84
Germany	2.42	2.71	2.75	2.59	2.60	2.63
Other OECD Europe	7.30	7.46	7.43	7.21	7.40	7.49
Australia & New Zealand	1.09	1.10	1.07	1.05	1.06	1.10
Total OECD	**49.48**	**49.62**	**48.79**	**47.95**	**50.17**	**50.06**
NON-OECD						
China	7.53	7.53	7.24	7.30	7.02	7.07
FSU	4.43	4.38	4.18	4.20	4.35	4.66
Non-OECD Europe	0.75	0.71	0.66	0.71	0.75	0.69
Other Asia	8.60	8.70	8.42	8.59	8.50	8.89
Other non-OECD	14.62	14.51	14.74	14.47	14.27	15.02
Total non-OECD	**35.93**	**35.83**	**35.24**	**35.27**	**34.89**	**36.33**
TOTAL DEMAND	**85.41**	**85.45**	**84.03**	**83.22**	**85.06**	**86.39**
SUPPLY						
OECD						
US	8.43	8.46	8.48	8.35	8.18	7.74
Canada	3.43	3.40	3.32	3.16	3.29	3.28
Mexico	3.59	3.52	3.71	3.79	3.80	3.75
North Sea	4.80	4.76	4.51	4.71	5.11	5.05
Other OECD	1.47	1.52	1.52	1.41	1.41	1.51
Total OECD	**21.72**	**21.66**	**21.54**	**21.42**	**21.798**	**21.33**
NON-OECD						
FSU	12.58	12.45	12.23	12.03	11.78	11.97
China	3.84	3.83	3.83	3.85	3.83	3.75
Other non-OECD	11.43	11.67	11.87	11.67	11.49	11.75
Total non-OECD, non-OPEC	**27.85**	**27.95**	**27.93**	**27.55**	**27.10**	**27.47**
OPEC*	**34.52**	**35.94**	**36.62**	**36.16**	**36.33**	**36.70**
TOTAL SUPPLY	**84.09**	**85.55**	**96.09**	**85.13**	**85.22**	**85.50**
Stock change	**–1.32**	**0.10**	**2.06**	**1.91**	**0.16**	**–0.89**

*Includes Angola.
Source: DOE International Petroleum Monthly
Data available in OGJ Online Research Center.

OECD TOTAL NET OIL IMPORTS

	Apr. 2007	Mar. 2007	Feb. 2007	Apr. 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	–1,388	–1,241	–1,459	–1,219	–169	13.9
US	12,583	12,634	10,795	11,951	632	5.3
Mexico	–1,497	–1,667	–1,726	–1,790	293	–16.4
France	2,284	1,311	1,960	1,723	561	32.6
Germany	2,026	2,139	2,358	2,336	–310	–13.3
Italy	1,635	1,650	1,714	1,423	212	14.9
Netherlands	991	838	1,014	934	57	6.1
Spain	1,662	1,488	1,670	1,564	98	6.3
Other importers	3,674	3,614	4,055	3,649	25	0.7
Norway	–2,274	–2,476	–2,395	–2,435	161	–6.6
United Kingdom	–206	13	–165	74	–280	–378.4
Total OECD Europe	**9,792**	**8,577**	**10,211**	**9,268**	**524**	**5.7**
Japan	4,802	5,013	5,382	5,116	–314	–6.1
South Korea	1,875	2,615	2,087	2,252	–377	–16.7
Other OECD	654	1,027	792	1,012	–358	–35.4
Total OECD	**26,821**	**26,958**	**26,082**	**26,590**	**231**	**0.9**

Source: DOE International Petroleum Monthly
Data available in OGJ Online Research Center.

OECD* TOTAL GROSS IMPORTS FROM OPEC

	Apr. 2007	Mar. 2007	Feb. 2007	Apr. 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	436	380	304	391	45	11.5
US	5,977	6,296	5,342	5,896	81	1.4
Mexico	21	28	23	—	21	—
France	821	534	821	814	7	0.9
Germany	465	330	351	501	–39	–7.7
Italy	1,187	1,230	1,316	1,076	111	10.3
Netherlands	538	521	660	540	–2	–0.4
Spain	632	627	797	783	–151	–19.3
Other importers	1,250	972	1,465	1,298	–48	–3.7
United Kingdom	264	248	251	182	82	45.1
Total OECD Europe	**5,157**	**4,462**	**5,661**	**5,197**	**–40**	**–0.8**
Japan	4,024	4,788	4,382	4,896	–872	–17.8
South Korea	2,136	2,485	2,080	2,294	–158	–6.9
Other OECD	741	706	700	577	164	28.4
Total OECD	**18,492**	**19,145**	**18,492**	**19,251**	**–759**	**–3.9**

*Organization for Economic Cooperation and Development.
Source: DOE International Petroleum Monthly
Data available in OGJ Online Research Center.

US PETROLEUM IMPORTS FROM SOURCE COUNTRY

	Apr. 2007	Mar 2007	Average YTD 2007	Average YTD 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	1,000 b/d					
Algeria	798	727	718	528	190	36.0
Angola	526	708	571	463	108	23.3
Kuwait	135	305	196	143	53	37.1
Nigeria	948	1,346	1,135	1,211	–76	–6.3
Saudi Arabia	1,488	1,244	1,379	1,433	–64	–4.4
Venezuela	1,412	1,286	1,311	1,485	–174	–11.7
Other OPEC	670	681	631	121	510	421.5
Total OPEC	**5,977**	**6,296**	**5,941**	**5,394**	**547**	**10.1**
Canada	2,479	2,305	2,425	2,266	159	7.0
Mexico	1,572	1,749	1,601	1,805	–204	–11.3
Norway	198	164	150	205	–55	–26.8
United Kingdom	386	292	285	252	33	13.1
Virgin Islands	322	349	353	283	70	24.7
Other non-OPEC	2,962	2,740	2,667	3,079	–412	–13.4
Total non-OPEC	**7,919**	**7,599**	**7,481**	**7,890**	**–409**	**–5.2**
TOTAL IMPORTS	**13,896**	**13,895**	**13,422**	**13,284**	**138**	**1.0**

Source: DOE Monthly Energy Review
Data available in OGJ Online Research Center.

OIL STOCKS IN OECD COUNTRIES*

	Apr. 2007	Mar. 2007	Feb. 2007	Apr. 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million bbl					
France	190	179	188	196	–6	–3.1
Germany	291	291	292	283	8	2.8
Italy	135	134	135	132	3	2.3
United Kingdom	105	106	105	102	3	2.9
Other OECD Europe	667	660	675	648	19	2.9
Total OECD Europe	**1,388**	**1,370**	**1,395**	**1,361**	**27**	**2.0**
Canada	179	182	181	169	10	5.9
US	1,688	1,677	1,666	1,701	–13	–0.8
Japan	615	615	631	618	–3	–0.5
South Korea	149	156	147	144	5	3.5
Other OECD	107	101	103	108	–1	–0.9
Total OECD	**4,126**	**4,101**	**4,123**	**4,101**	**25**	**0.6**

*End of period.
Source: DOE International Petroleum Monthly Report
Data available in OGJ Online Research Center.

Classified Advertising

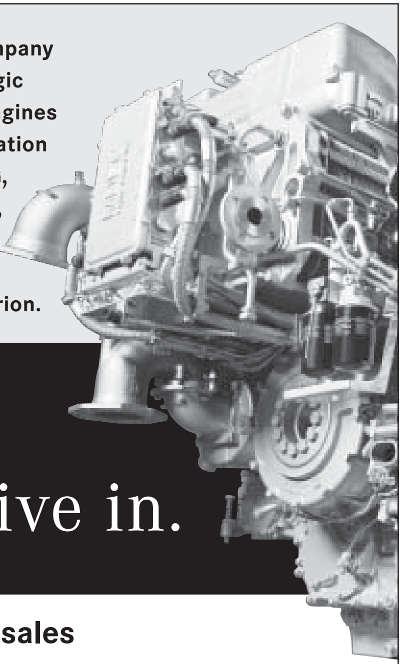
Your marketplace for the oil and gas industry

DEADLINE for CLASSIFIED ADVERTISING is 10 A.M. Tuesday preceding date of publication. Address advertising inquiries to CLASSIFIED SALES, 1-800-331-4463 ext. 6301, 918-832-9301, fax 918-831-9776,
email: glendah@pennwell.com.

- *DISPLAY CLASSIFIED: $350 per column inch, one issue. 10% discount three or more CONSECUTIVE issues. No extra charge for blind box in care. Subject to agency commission. No 2% cash discount.*
- *UNDISPLAYED CLASSIFIED: $3.50 per word per issue. 10% discount for three or more CONSECUTIVE issues. $70.00 minimum charge per insertion. Charge for blind box service is $50.50 No agency commission, no 2% cash discount. Centered heading, $8.75 extra.*
- *COMPANY LOGO: Available with undisplayed ad for $75.00. Logo will be centered above copy with a maximum height of 3/8 inch.*
- *NO SPECIAL POSITION AVAILABLE IN CLASSIFIED SECTION.*
- *PAYMENT MUST ACCOMPANY ORDER FOR CLASSIFIED AD.*

EMPLOYMENT

MTU Friedrichshafen GmbH is the core company of Tognum AG which combines, as a strategic holding manufacturers of diesel and gas engines as well as complete drive and power-generation systems. Under the umbrella of Tognum AG, the well-known brands MTU, Detroit Diesel, Mercedes-Benz industrial engines, Katolight, MDE, CFC Solutions and L'Orange as well as the Business Unit Rotorion.



We **power** the world we live in.

Specialist, gas engine systems sales

Your tasks:

You are responsible for the sale of gas engine systems, analysis of tendering specifications and monitoring of international invitations to tender. Furthermore, you are responsible for customer recruitment as well as for comprehensive customer support and ensuring customer satisfaction.

Your qualifications:

University degree in electrical or mechanical engineering, knowledge of gas engines, practical knowledge of project management, negotiating skills, knowledge of contract law, experience in international project systems business and a high proficiency in English.

Your contact:

Marianne Blumer · +49 75 41 / 90 29 19 · marianne.blumer@mtu-online.com

MTU Friedrichshafen GmbH · Personalservice (PBT) · 88040 Friedrichshafen

Ein Unternehmen der Tognum-Gruppe

Top-Arbeitgeber 2006/07 trendence Wirtschafts Woche Deutsches Absolventenbarometer

mtu

PROJECT COORDINATOR

Manage offshore deepwater engineering projects for the M/V Fugro Explorer. Coordinate vessel mobilization, demobilization, and activities. Responsible for project budget, bids and schedule. Lead field investigators & provide direction to project engineers. Conduct internal audits. Liaison between company departments, sister companies, 3rd party contractors and client on project. MS in Civil Engineering plus 3 yrs experience as project engineer of offshore engineering projects.

Send resume to:
Fugro McClelland Marine Geosciences Inc.
Attn: Erica Auguillard
6100 Hillcroft, 4th Flr
Houston, TX 77081
EOE

Smith International, Inc in Houston, Tx seeks qualified Designer – Engineering System Development to lead standardization and automation of programming CMM (Computerized Coordinate Measurement) machines based on DMIS programming language standard in order to insure proper manufacturing inspection of roller cone and fixed cutter bits and assure equality on complex geometry. Implement PC DMIS off-line programming based on ProE integration module of PC DMIS software. Qualified applicant must possess exp. in ProE and CMM programming and inspection. Mail resume to Smith International, Inc, 16740 Hardy St., Houston, TX 77032. Include job code DESENGHOU to resume.

Smith International, Inc in Houston, Tx seeks qualified Integration Engineer to work with design and manufacturing departments to develop CAD modeling processes to be used in both departments without duplication or remodeling. Create web application and user interfaces to facilitate consistent data among design families and in all CAD models. Define PDC (Polycrystalline Diamond Cutter) drill bit design and manufacturing process. Customize Pro/ENGINEER software to handle the intricacies of advanced cutting structure design. Qualified applicant must possess a Masters degree in Mech. Eng, Manufacturing Eng. or Eng. Technology plus exp. Mail resume to Smith International, Inc, 16740 Hardy St, Houston, TX 77032. Include job code INTENGHOU on resume.

BUSINESS OPPORTUNITIES

LOOKING TO BUY OR SELL AN OILFIELD RELATED BUSINESS? CALL HEBERT PROPERTIES 337-257-1819. 40 YEARS OF OIL FIELD EXPERIENCE AND CONTACTS

EQUIPMENT FOR SALE

Solar Taurus 60

5.2 MW • Mobile Gen Sets
FOR SALE

- Solar Maintained - Low Time
- 13 Units (Gen 1) & (Gen 2)
- 8 Natural Gas - 5 Dual Fuel
- Low Nox 25 ppm
- Complete Packages
- Mobile PCR U.G. Switchgear
- 60 Hz ○ 13.8 kV
- 50 Hz Conversion Available

Mid America Engine, Inc.
662-895-8444 · Fax: 662-895-8228
Keith: keith@maegen.com
Art: art@maegen.com

SURPLUS GAS PROCESSING/REFINING EQUIPMENT

NGL/LPG PLANTS:10 - 600 MMCFD
AMINE PLANTS:10 – 2,700 GPM
SULFUR PLANTS:10 - 180 TPD
COMPRESSION:100 - 20,000 HP
FRACTIONATION:1000 – 25,000 BPD
HELIUM RECOVERY:75 & 80 MMCFD
We offer engineered surplus equipment solutions.

Bexar Energy Holdings, Inc.
Phone 210 342-7106
www.bexarenergy.com
Email: matt.frondorf@bexarenergy.com

Process Units
Crude Topping Units
~~6,000 BPSD~~ SOLD
10,000 BPSD
14,000 BPSD
Condensate Stabilizer
6,500 BPSD
Catalytic Reformer
3,000 BPSD
Naphtha Hydrotreater
8,000 BPSD
HF Alkylation Unit
2,500 BPSD
Butane Isomerization
3,700 BPSD
Sulfur Recovery Plant II
22T/D
Tail Gas Plant
Amine Treating
300 GPM
FCCU UOP
17,000 available
BASIC EQUIPMENT
Please call: 713-674-7171
Tommy Balke
tbalkebasic1@aol.com
www.basic-equipment.com

EQUIPMENT FOR SALE

REFRIGERATION AND J.T. PLANTS

7.5 MMSCFD, 1000 PSI, NATCO
4.0 MMSCFD, 1000 PSI, NATCO
6.5 MMSCFD, 1250 PSI X 400 PSI, H&H J.T.
2.0 MMSCFD, 1000 PSI, PROCESS EQPT.
OTHERS AVAILABLE
PLEASE CALL 318-425-2533, 318-458-1874
regardres@aol.com

AUCTION

LARGE OIL & GAS ROYALTY AUCTION
FOR U.S. BANKRUPTCY COURT of OKLAHOMA

Wed, Sep 12, 2007 @ 2:00 PM
200 NW 114th St, Okla. City, OK
For Complete Brochure & Info for online bidding, see Website or Contact

DAKIL AUCTIONEERS, INC
405 751-6179
www.dakil-auction.com

REAL ESTATE

Carroll Real Estate Co
Wanted ... ranch / recreational listings
Texas, Oklahoma, New Mexico
903-868-3154

CONSULTANTS

Brazil: EXPETRO can be your guide into this new investment frontier.
Effective strategic analysis, quality technical services, compelling economic/regulatory advice, and realistic approach regarding Brazilian business environment - 120 specialists upstream, downstream, gas and biofuels. Email: contato@expetro.com.br. Web: www.expetro.com.br - Rio de Janeiro, Brazil.

E-mail your ad to: glendah@pennwell.com

Advertising Sales / Advertisers Index

Houston
Regional Sales Manager, Marlene Breedlove, 1700 West Loop South, Suite 1000, Houston, TX 77027; Tel: (713) 963-6293, Fax: (713) 963-6228, E-mail: marleneb@pennwell.com. Regional Sales Manager, Charlene Burman; Tel: (713) 963-6274, Fax: (713) 963-6228; E-mail: cburman@pennwell.com

Southwest / South Texas/Western States/ Gulf States/Mid-Atlantic
1700 West Loop South, Suite 1000, Houston, TX 77027; P.O. Box 1941 Houston, TX 77251; Regional Sales Manager; Marlene Breedlove, Tel: (713) 963-6293, Fax: (713) 963-6228; E-mail: marleneb@pennwell.com

Northeast/New England/Midwest/North Texas/ Oklahoma/Alaska/Canada
1700 West Loop South, Suite 1000, Houston, TX 77027; Tel: (713) 963-6244, Fax: (713) 963-6228; Regional Sales Manager, Charlene Burman; Tel: (713) 963-6274, Fax: (713) 963-6228; E-mail: cburman@pennwell.com.

Scandinavia/The Netherlands/Middle East/Africa
David Betham-Rogers, 11 Avenue du Marechal Leclerc, 61320 Carrouges, France; Tel: 33 2 33 282584, Fax: 33 2 33 274491; David Betham-Rogers, E-mail: davidbr@pennwell.com.

United Kingdom
Carole Winstanley, ADBIZ MEDIA LTD, 252 Union Street, Aberdeen, AB10 1TN, Scotland, United Kingdom; Tel: +44 (0) 1224 791178; Fax: +44 (0) 5601 151590; E-mail: adbizmedia@btconnect.com.

France/Belgium/Spain/Portugal/Southern Switzerland/Monaco
Daniel Bernard, 8 allee des Herons, 78400 Chatou, France; Tel: 33 (0)1 3071 1224, Fax: 33 (0)1 3071 1119; E-mail: danielb@pennwell.com, France, Belgium, Spain, Portugal, Southern Switzerland, Monaco.

Germany/Austria/Denmark/Northern Switzerland/Eastern Europe/Russia
Verlagsburo Sicking, Emmastrasse 44, 45130, Essen, Germany. Tel: 49 0201 77 98 61, Fax: 49 0201 781 741; E-mail: wilhelms@pennwell.com. Wilhelm F. Sicking, Germany, Austria, Denmark, Northern Switzerland, Eastern Europe, Russia, Former Soviet Union.

Japan
e. x. press Co., Ltd., Hirakawacho TEC Building, 2-11-11, Hirakawa-cho, Chiyoda-ku, Tokyo 102-0093, Japan, Tel: 81 3 3556 1575, Fax: 81 3 3556 1576; E-mail: manami.konishi@ex-press.jp; Manami Konishi

Brazil
Grupo Expetro/Smartpetro, Att: Jean-Paul Prates and Bernardo Grunewald, Directors, Ave. Erasmo Braga 22710th and 11th floors Rio de Janeiro RJ 20024-900 BRAZIL; Tel: (55-21) 3084 5384, Fax: (55-21) 2533 4593; E-mail: jpprates@pennwell.com.br and bernardo@pennwell.com.br

Singapore/Australia/Asia-Pacific
Singapore, Australia, Asia Pacific, 19 Tanglin Road #09-07, Tanglin Shopping Center, Singapore 247909, Republic of Singapore; Tel: (65) 6 737-2356, Fax: (65) 6 734-0655; Michael Yee, E-mail: yfyee@singnet.com.sg

India
Interads Limited, 2, Padmini Enclave, Hauz Khas, New Delhi-110 016, India; Tel: +91-11-6283018/19, Fax: +91-11-6228928; E-mail: rajan@interadsindia.com. Mr. Rajan Sharma.

Italy
Vittorio Rossi Prudente, UNIWORLD MARKETING, Via Sorio 47, 35141 PADOVA - Italy; Tel:+39049723548, Fax: +390498560792; E-mail: vrossiprudente@hotmail.com

A

Aramco Services Company 27
www.aramco.jobs/OGJ

B

Baker Hughes Incorporated
Baker Atlas .... Back Cover
www.bakerhughes.com
BCCK Engineering Inc. .... Inside Front Cover
www.bcck.com

C

Carbone Lorraine 31
www.carbonbrush.com /
www.elec.carbonelorraine.com
Chevron 41
www.chevron.com/careers.com
CONVERTEAM 29
www.converteam.com

D

Det Norske Veritas 18
www.dnv.com/energy

E

ESRI 13
www.fmctechnologies.com
Exterran 2
www.exterran.com

G

GE Oil & Gas .... Inside Back Cover
www.ge.com/oilandgas

H

Hydro 25
www.hydro.com

I

Industrial Rubber, Inc. 12
www.iri-oiltool.com
IPAA 51
www.ipaa.org

N

Noram Resources Inc. 33
amilton@noramresources
flytle@noramresources.com

O

Oil & Gas Asset Clearinghouse LP 13
www.ogclearinghouse.com
Oil and Gas Regulatory Authority 73
www.ogra.org.pk

P

PennEnergy 79
www.pennenergy.com
Petrobras 45
www.ibp.org.br/pipeline.com
Polyguard Products 71
www.polyguardproducts.com
PennWell
Deep Offshore Technology 59
www.deepoffshoretechnology.com
Houston Energy Financial Forum 54-55
www.accessanalyst.net
Offshore Asia 2008 63
www.offshoreasiaevent.com
PennEnergyJOBS 61, 82
www.PennEnergyJOBS.com
PennWell Corporation 65
www.ogjonline.com
www.BuyOGJ5.com
Subsea Tieback Forum & Exhibition 75
www.subseatiebackforum.com

Q

Qatar Airways 11
www.qatarairways.com

S

Society of Petroleum Engineers 14, 47
www.spe.org/atce/2007
Stallion Oilfield Services 4
www.stallionoilfield.com

T

Tenaris 23
www.tenaris.com

W

Weatherford International 7
www.weatherford.com/careers
WECEC Kuwait 15
www.wecec-kuwait.com
Wyo-Ben 16
www.wyoben.com

This index is provided as a service. The publisher does not assume any liability for errors or omission.

Chavez wrong on price path, cutoff threat

Hugo Chavez says the darnedest things.

At a meeting of Caribbean government leaders in Caracas Aug. 11, the Venezuelan president first observed that oil prices "are headed straight to $100/bbl." Then he repeated a threat to cut oil supplies to the US.

He's wrong on both counts.

The day before he spoke, the spot price of Brent crude was $69.57/bbl, nearly $10/bbl below its peak of the prior month and more than $5/bbl below its level of the same time a year earlier. This is not the trajectory Chavez described.

The Editor's Perspective

by Bob Tippee, Editor

Someday, the crude price might reach $100/bbl. But to say it's "headed straight" to triple digits is incorrect.

It's also untrue that Venezuela will cut oil flow to the US.

For starters, the condition Chavez specified—"if they attack us again like they did in April of 2002"—won't materialize.

The US didn't attack Venezuela in 2002. Yes, discerning Americans cheered that year's coup attempt against Chavez, which, alas, ultimately failed. But attack? Please. And the US wouldn't attack a country just for having a president given to shrill utterance.

What's more, cutting oil sales would further squeeze a state oil company on which Venezuela's economy depends. Petroleos de Venezuela, increasingly forced to sell oil cheap to satisfy presidential promises, would have to find new buyers for heavy crude. And its Citgo subsidiary would have to scramble for alternative feedstock for its refineries on the US Gulf Coast.

While PDVSA and crude buyers in the US could adjust to a Chavez cutoff, PDVSA would have the harder time of it. Venezuela needs US sales more than the US needs Venezuelan oil.

In fact, the Venezuelan need for oil sales to nearby buyers paying full price grows with each soft deal Chavez makes to ingratiate a neighboring government. His audience for the $100/bbl forecast, for example, was in Caracas for a meeting of Petrocaribe, the group of nations to which Venezuela supplies oil under conciliatory credit terms.

High oil prices paint over serious corrosion at work in the Venezuelan oil industry. As damage spreads, it's perversely amusing to wonder what darned thing its cause will say next.

(Online Aug. 17, 2007; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

It's just Erin and Dean, not Katrina and Rita

On Aug. 19 as Dean, the first hurricane of the 2007 season, pounded Jamaica's south coast, residents of Houston some 1,427 miles away were emptying grocery shelves of bread, bottled water, and other essentials on the remote chance that the storm might come ashore in their vicinity.

E-mails were circulating in the city warning recipients to "fill up your car tanks and keep them topped off" because gasoline prices might spike to $6/gal if Dean hit the Texas Gulf Coast. A run on gasoline in the country's fourth-largest urban area just 2 weeks before the long Labor Day weekend that historically marks the end of the summer driving season could do more to drive up gasoline prices than some distant storm.

Meanwhile, most computer weather models showed Dean, then a Category 4 hurricane, would hit Mexico's Yucatan Peninsula Aug. 21. Most forecasters expected it to make landfall in north-central Mexico on Aug. 22. However, government officials in Texas and Louisiana were preparing in case Dean turned north.

Officials in Cameron County, Tex., were urging residents to evacuate "out of the kill zone" ahead of the storm. State officials gathered 1,300 school and commercial buses in San Antonio, as Texas Gov. Rick Perry activated a plan to evacuate elderly and special-needs residents from the Rio Grande Valley if Dean veered northward.

The Texas National Guard already had deployed water rescue teams along the coast before Tropical Storm Erin—downgraded to a tropical depression—made landfall Aug. 16, 25 miles northeast of Corpus Christi. A flashflood watch was issued for 33 Texas counties through Aug. 17 as that storm dumped 4-10 in. of rain along a corridor between San Antonio and Austin. Remnants of Erin poured 7 in. of rain on parts of Houston, causing some flooding and triggering 70 high-water rescues.

David Paulison, director of the Federal Emergency Management Agency, activated that agency's hurricane-response plan, with disaster teams set in San Antonio and more standing by. FEMA and Louisiana officials were sharply criticized for the haphazard initial government response to Hurricane Katrina, which flooded New Orleans in August 2005. Determined to avoid such condemnation when Hurricane Rita threatened the Texas Coast in September 2005, state and local officials triggered a massive evacuation that produced gridlock on Houston area freeways; people were stranded in summer heat with no water, no food, and no gasoline as the hurricane came ashore more than 100 miles to the east, leaving Houston untouched.

Industry planning

Meanwhile, oil and gas companies have stuck to their long-proven strategy of evaluating risks before reacting to storms. As Erin approached Texas, Shell Oil Co. evacuated 188 workers from offshore facilities and shut in 5 MMcfd of natural gas production from the North Padre Island 927 field. Valero Energy Corp.'s 340,000 b/d refinery in Corpus Christi continued operations "as planned," with no disruption.

On Aug. 20, the US Minerals Management Service said personnel were evacuated from 10 of the 834 manned production platforms and 24 of the 101 rigs in the US sector of the gulf. Officials said 41,967 b/d of oil (3.2% of normal gulf crude production) and 100 MMcfd of natural gas (1.3% of normal production) were shut in.

Analysts in the Houston office of Raymond James & Associates Inc. said, "Most of the majors are not evacuating platform workers, and others are keeping all essential employees in the gulf. The forecasts now suggest that the US oil and gas infrastructure in the gulf are safe as the Category 4 storm heads towards Mexico."

Shell officials evacuated 380 offshore workers on Aug. 18, and were scheduled to bring ashore another 200 on Aug. 19. However, a company spokesman said Aug. 20, "Due to high confidence in the Hurricane Dean storm track over the next several days, we are suspending any further personnel evacuations at this time."

Shell shut in gulf production of 39,000 b/d of crude and 97.5MMcfd of gas. However, Shell said no additional shut-ins were expected. Meanwhile, officials would continue monitoring Dean, as well as Tropical Disturbance No. 37 that "may potentially impact portions of the eastern Gulf of Mexico late this week into next week."

On the other hand, the storm forced Petroleos Mexicanos, Mexico's national oil company, to shut down 140 offshore units and move 1,300 workers to land. "It is expected to move towards the Bay of Campeche, where 66% of Pemex's oil production is located," said Raymond James analysts Aug. 20.

(Online Aug. 20, 2007; author's e-mail: samf@ogjonline.com)