Week of Oct. 16, 2006/US$10.00

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Pipeline Report

FACTS: Oil market suffering from investment lull of 1990s
Drilling confirms radar-mapped atmospheric seepage anomalies
Best practices limit fluid effects on CRA tubulars
Best practices improve ethylene plant controller performance

OIL&GAS JOURNAL®

Oct. 16, 2006
Volume 104.39

PIPELINE REPORT

REGULAR FEATURES

COVER

The construction of new gas and liquids pipelines, such as this 42-in. line in East Texas, comprises only the first step in effectively bringing these materials to market. In addition to building and operating such systems safely, operators strive to operate their pipelines as efficiently as possible once in service. This issue's special Pipeline Report, beginning on p. 56, features articles addressing the efficient operation of liquids pipelines; the first focuses on developments in drag-reducing agents, while the second evaluates models for determining the viscosity of crude oil blends. Photo from Willbros USA Inc. by Lindy King.

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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Oct. 16, 2006

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General Interest — Quick Takes

Hostages released from Nigerian Shell facility

Most hostages taken Oct. 10 from a Royal Dutch Shell PLC facility in southern Nigeria have been released, authorities said Oct. 11, adding that a further 8 workers are due to be set free later in the day.

Around 60 oil workers were seized when attackers wielding automatic rifles occupied the Shell facility at Oproma in Bayelsa state after overrunning the nearby navy base. The attackers initially demanded that Shell tackle erosion problems, in addition to supplying electrical light and water to the community.

Hafiz Ringim, the police commissioner for Bayelsa state, said an agreement had been reached between the government and militant leaders following discussions on Oct 10. He did not detail the conditions that had been agreed.

News of the release came as senior security officials in Nigeria said they were laying down strategies to limit the impact of militant attacks in the oil-producing delta. The officials met after militants claimed to have killed 30 members of the armed forces in gun battles with government gunboats and attack helicopters in the creeks of the eastern Niger Delta last week.

MMS publishes guidelines for coastal state aid

The US Minerals Management Service has published guidelines under which six states can receive financial help under the Coastal Impact Assistance Program.

The program, which was authorized under Section 384 of the 2005 Energy Policy Act, authorizes the US Secretary of the Interior, as delegated to MMS, to distribute $250 million/year to Alabama, Alaska, California, Louisiana, Mississippi, and Texas from fiscal 2007 through 2010.

All CIAP funds will be distributed through grants, MMS said.

The states must use all funding received under CIAP for coastal programs and activities, including implementation of a federally approved marine, coastal, or comprehensive conservation management plan; mitigation of impacts from Outer Continental Shelf activities through funding of onshore infrastructure projects and public service needs; and wetlands protection or restoration.

Each state has to submit a coastal impact assistance plan by July 1, 2008, to receive funding from the program, MMS said. They also have to submit individual grant applications as required and governed by the DOI's grant regulations.

Chevron, Petronas resolve Chad tax dispute

Chevron Corp. and Malaysia's state-owned Petronas have resolved a dispute with the government of Chad over the payment of taxes.

In a memorandum signed Oct. 6, Finance Minister Abbas Mahamat Tolli and Chevron's Africa Director Frederick Neilson, representing the two companies, agreed to pay $289 million in taxes.

In August, Chad President Idriss Deby accused Chevron and Petronas of failing to pay taxes and ordered the two companies to leave the country (OGJ Online, Aug. 28, 2006). ✦

Exploration & Development — Quick Takes

Petrobras group encouraged by oil find off Brazil

A group led by Brazil's Petroleo Brasileiro SA (Petrobras) agreed to accelerate its exploration program based on results from a light oil discovery on Block BM-S-11 in a frontier section of the Santos basin 150 km off Rio de Janeiro, said partner BG Group PLC.

The Tupi well, in 2,126 m of water, flowed 4,900 b/d of 30° gravity crude and 4.3 MMscfd of gas from a deep presalt reservoir through a ⅝-in. choke. Tupi involves a large structure that requires appraisal drilling and evaluation.

Petrobras, operator, has a 65% stake in the frontier block. BG Group holds 25% interest, and Petrogal 10% interest.

Tullow, Hardman to explore Ugandan Block 2

The Ugandan government, Hardman Resources Ltd., and Tullow Oil PLC have agreed under a new memorandum of understanding to progress the appraisal and development activities for Block 2 on the Ugandan side of the Albertine Graben.

The companies want to realize the full potential of existing discoveries and "provide time for the continuing active exploration of the remainder of the block."

The partners plan to spud the Nzizi-1 well, an updip appraisal well to the southwest of the Mputa oil discovery, by early November.

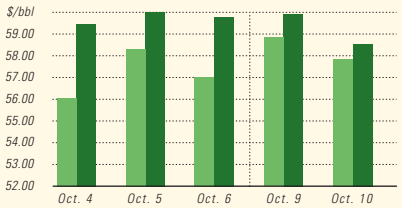
They will also carry out further 3D and 2D seismic surveys to better define the volumes of the existing discoveries, develop infill locations, and explore the northern area of the block to identify drilling prospects in 2007-08. The partners are currently evaluating the most effective way to drill offshore prospects in Lake by the end of 2007.

The partners and the government are keen to start early production with the discoveries already made. If their investigations prove to be technically and commercially feasible, the petroleum development could use the oil discovered to fuel a potential 50-Mw local electric power station and supply a small refinery. This would be significant for Uganda, which has no oil production.

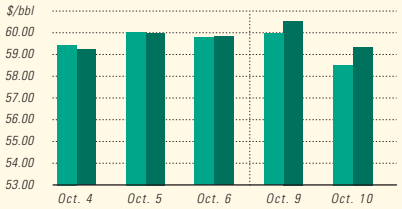
Simon Potter, Hardman chief executive officer and managing

Industry Scoreboard

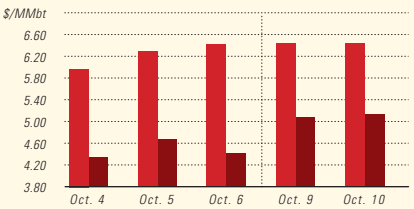
IPE BRENT / NYMEX LIGHT SWEET CRUDE



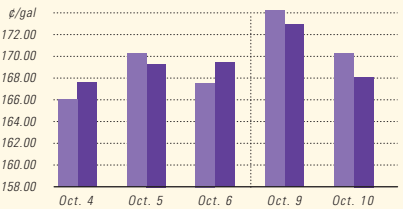
WTI CUSHING / BRENT SPOT



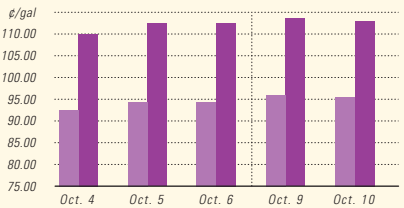
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



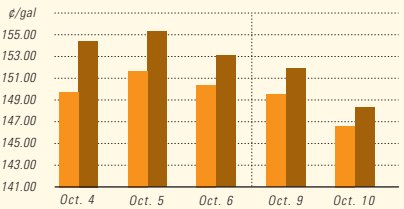
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



NYMEX GASOLINE / NY SPOT GASOLINE[1]



[1]Nonoxygenated regular unleaded.

SCOREBOARD

Due to the holiday in the US, data for this week's industry Scoreboard are not available.

director, said, "Confidence in the existing resource base and the market potential allows us to consider an early production scheme.

Hardman has a 50% interest in Block 2 via its subsidiary Hardman Petroleum Africa Pty. Ltd., which is operator. Tullow holds the remaining 50%.

Aramco to start work on Manifa oil field

Saudi Aramco will start development of offshore Manifa oil and gas field in first quarter 2007 with a production target of 900,000 b/d of Arab Heavy crude.

It expects to let a lump-sum, turnkey contract by yearend for construction of a causeway to shallow-water parts of the field. The causeway will have a 21-km main artery and branches totaling 20 km to 27 drilling islands.

In addition to the causeway, the project will include a central processing facility; a primary gas-oil separation plant; utility and water supply plants; a water-injection facility with capacity of 1.74 million b/d; offshore platforms including jackets, platforms, and electric submersible pumps; offshore crude and water-injection trunklines, flowlines, and electrical cables; pipelines to the Khursaniyah gas plant and Ras Tanura and Juaymah oil terminals; and an upgrade at Khursaniyah to handle 120 MMscfd of Manifa gas.

The completion target is mid-2011. Aramco has received bids for the front-end engineering and design of onshore parts of the project and hopes to let the contract by the end of October. It plans to award offshore lump-sum bid packages early in 2007.

Heritage prepares to test Kingfisher well in Uganda

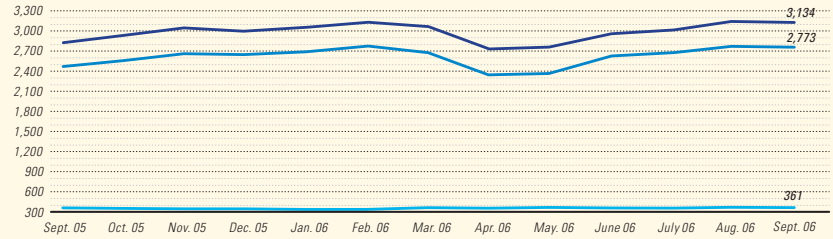
Heritage Oil Corp., London, has temporarily suspended drilling at its Kingfisher-1 exploration well on Block 3A in Uganda in preparation for a testing program.

The production test, expected to begin in about 30 days, is scheduled to take about 3 weeks.

Heritage plans to test as many as four intervals in the well. The intervals have a total net pay of 37 m in a stacked sand and shale sequence typical of the Albert Graben basin.

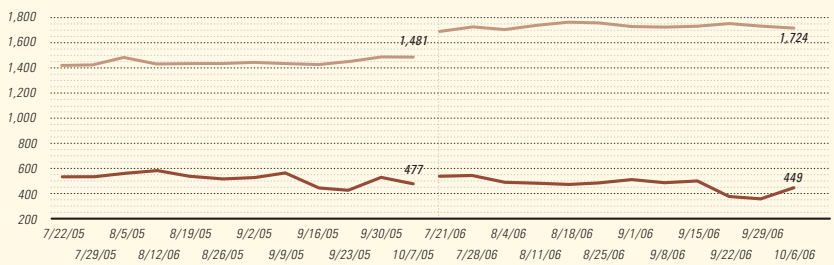
Kingfisher-1 has been drilled to 2,125 m, and wireline logs and formation pres-

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

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Drilling | Evaluation | Completion | Production | Intervention

sure testing and sampling have shown encouraging indications of hydrocarbons, Heritage said.

The well encountered hydrocarbons in a section above the primary objective, and drilling to the primary objective is scheduled to resume after this initial testing has been completed.

It could take an additional 60 days to reach the target depth of 3,000-4,000 m.

Kingfisher-1 is the first of a possible two-well initial drilling program on Block 3A, for which Heritage is the operator with a 50% interest; Tullow Oil PLC owns the remaining interest (OGJ Online, July 21, 2006).

Firms start exploration south of Mobile Bay

Private Corpus Christi, Tex., independent Royal Exploration Co. and Petsec Energy Ltd., Lafayette, are starting a two or three-well program for gas in Gulf of Mexico federal waters south of Mobile Bay.

The duo plans wells on Mobile Blocks 950 and 951 off the Mississippi-Alabama state line and Block 873 southeast of North Central Gulf gas field, which is near the mouth of the bay.

The wells, the first to be drilled on the portfolio of 33 leases acquired in August 2006, can be drilled in 12-15 days/well and, if successful, hooked up in within 4 months from completion of the drilling program, Petsec Energy said.

Inpex agrees to cut Azadegan field ownership

Japan's Inpex Corp. has agreed to reduce to 10% its concession in Iran's Azadegan oil field from the current 75%, with the outstanding 65% stake to be transferred to National Iranian Oil Co.

With the agreement, Japan will likely avoid withdrawing from the development project altogether. But the Japanese government will suspend planned financial assistance to the development project.

As a result, Iran, which is cash-strapped and has little technological expertise, is thought likely to attempt to transfer most of its concession to a third party.

NIOC Managing Director Gholamhosein Nozari has already suggested that Iran could transfer the 65% share to other companies, either Iranian or foreign. France's Total SA is considered one possibility, along with other unnamed Russian and Chinese firms.

Due to the threat of United Nations economic sanctions, however, it is uncertain whether NIOC will be able to find a new participating company among any international firms for the project.

Inpex, owned 29.35% by the Japanese government, signed a contract with NIOC in February 2004 to develop Azadegan. But development work for the field was delayed by the possibility of UN sanctions being imposed on Iran due to its nuclear program.

Also Inpex reportedly is requesting from NIOC a proportionate reimbursement of the substantial advance fee it paid for the development rights.

Azadegan, in southwestern Iran, was one of Iran's biggest oil finds when announced in 1999, with oil in place of 26 billion bbl and reserves pegged at 6 billion bbl.

The field is eventually expected to produce 260,000 b/d of crude oil, equivalent to 6% of Japan's total crude imports. ✦

Drilling & Production — *Quick Takes*

Heerema to remove North West Hutton platform

BP PLC has let a contract to Heerema Marine Contractors for the main decommissioning work on its North West Hutton integrated drilling, production processing, and accommodation platform 130 km northeast of the Shetland Islands in the UK North Sea. The platform sits in 140 m of water.

The field, discovered by Amoco Corp. in 1975, produced 125 million bbl of oil between 1983 and January 2003.

Heerema's contract covers offshore removal and onshore recycling and disposal. A heavy-lift vessel will remove the 20,000-tonne topsides and the 17,000-tonne steel jacket down to the tops of the footings (OGJ, June 20, 2005, p. 51). The units will be moved to the Able yard on Teesside for recycling and disposal.

About 97% of the material recovered will be recycled, according to BP. After this work is finished, Heerema and subcontractors will decommission the pipeline, clear debris, and inspect the platform site.

Detailed engineering for removal will begin immediately. Offshore removal is expected to begin in 2008 and to be completed by the end of 2009. A BP spokesman declined to tell OGJ the value of the contract.

BP said the contract "represents the largest remaining element of the total North West Hutton decommissioning project." BP has completed well abandonment and topsides cleanup.

According to BP, no company has tried to dismantle a steel jacket structure of this weight and in this water depth, meaning that new cutting tools are required to carry out the operation.

North West Hutton field is operated by BP (25.8%) on behalf of CIECO Exploration & Production (UK) Ltd. (25.8%), Enterprise Oil UK Ltd. (28.4%), and Mobil North Sea Ltd. (20%).

Hess lets contract for Songa drillship off Libya

Hess Corp. has let a contract to Songa Offshore for the Songa Saturn drillship.

This contract is for the drilling of one well off Libya in fourth quarter 2007. The contract will start after the Songa Saturn completes a contract with Noble Energy Inc. in Equatorial Guinea.

The revenue totals $17 million. The Songa Saturn is available for additional work in the Mediterranean at the completion of the Hess contact.

ADCO to boost oil output from three fields

Abu Dhabi Co. for Onshore Oil Operations (ADCO) let a front-end engineering and design contract to Foster Wheeler International Corp. to boost production from three mature oil fields.

The project involves the Sahil, Asab, and Shah (SAS) oil fields. The value of the contract was not disclosed. ADCO plans to increase total production from the fields to more than 1.8 million

b/d by 2010. Current production figures were not immediately available. ADCO is part of the Abu Dhabi National Oil Co. group of companies.

In addition to boosting production, the SAS field development is intended to enhance the environmental aspects of the fields and to provide facilities to enhance operation of the fields until 2040.

The contract is scheduled for completion in mid-2007. The project's commissioning is slated for 2010.

SAS fields are 180 km south of Abu Dhabi City. Production began in 1974 at Asab and was followed by Sahil and Shah.

Santos begins Maleo field production off Java

Santos Ltd., Adelaide, has begun natural gas production from Maleo field off eastern Java under a $550 million deal with Indonesia's state-owned PT Perusahaan Gas Negara (PGN).

Santos has agreed to sell 243 bcf of gas to PGN for 8-12 years.

The new gas supply is expected to reduce east Java's diesel fuel consumption by 6.75 million kl.

Gas will be supplied at a plateau rate of 110 MMcfd for 5-6 years, then tail down as the field depletes.

The $75 million development comprises a mobile offshore production unit supported by a new six-well wellhead platform connected to a 7.4-km spur line to the existing East Java Gas Pipeline. From there gas is distributed to the Surabya and Gresik gas grid.

The field was discovered in 2002 and contains proved and probable reserves of 240 bcf.

Santos has a 75% interest in the Maleo partnership, and Petronas subsidiary PC Madura holds the remaining 25%.

PTTEP to ramp up Arthit field gas production

Thailand's PTT Exploration & Production PLC (PTTEP) plans to increase production by as much as 45% from its Arthit gas field in the Gulf of Thailand, in the first 3 years of operation.

To meet rising domestic demand, PTTEP will produce an additional 120-150 MMcfd of gas from Arthit in addition to the earlier scheduled rate of 330 MMcfd.

The production increase is made possible with the help of a floating production, storage, and offloading vessel at the field, 230 km off the southern Thai province of Songkhla.

Following a series of delays caused by technical problems and equipment shortages, PTTEP has rescheduled the Arthit production start-up to first quarter 2008 (OGJ Online, May 4, 2006).

The company said it would discuss terms and conditions for the sales of additional gas supplies with state-owned PTT PLC.

PTTEP has an 80% stake in the field; Chevron Thailand Exploration & Production Ltd. holds 16% interest; and Moeco (Thailand), a Thai unit of Mitsui Oil Exploration Co., holds the remaining 4%. ✦

Processing — *Quick Takes*

EPA, API mark ULSD's arrival at retailers

The US Environmental Protection Agency marked the arrival of ultralow-sulfur diesel fuel at retail outlets with a ceremony at the Columbus, Ind., headquarters of diesel engine manufacturer Cummins Inc. on Oct. 10.

US refiners began to produce diesel fuel for highway use with a 15 ppm sulfur content on June 1, down from 500 ppm previously, under EPA orders. The federal agency said that the lower sulfur fuel will be used by more than 90% of the nation's trucks and buses. It estimates that this will cut nitrogen oxide emissions by 2.6 million tons/year and particular matter emissions by 110,000 tons/year.

American Petroleum Institute Pres. Red Cavaney, who also attended the ceremony, noted that while the change is arguably the most complex and costly transition ever experienced in US motor fuels history, its implementation has been smooth so far with no significant problems concerning supplies or vehicle performance.

Most retailers will complete the transition to ULSD by Oct. 15, he added. Only ULSD will be allowed for highway and virtually all off-road vehicles by 2010, and for nonroad, locomotive, and marine diesel engines by 2014.

Flexicoking unit due Elefsis refinery

Hellenic Petroleum SA has selected ExxonMobil Research & Engineering Co.'s flexicoking technology for an upgrade project at its 100,000 b/cd refinery in Elefsis, Greece.

ExxonMobil will supply a 20,000 b/d flexicoking unit, which will convert vacuum residue to lighter products.

Flexicoking integrates fluid bed coking and air gasification to eliminate petroleum coke. It allows refiners to process vacuum resid, atmospheric resid, oil sands bitumen, heavy whole crudes, deasphalter bottoms, or thermal cracked tar to produce higher-value liquid and gas products.

Flexicoking produces a clean low-sulfur fuel gas, which can be used economically in refinery furnaces and boilers, as well as by power plants to minimize nitrogen oxides and sulfur oxides emissions.

Husky taps Axens for Lloydminster upgrader

Husky Energy Corp., Calgary, has selected Axens NA of Princeton, NJ, to supply three technologies for a possible future expansion of Husky's 82,000 b/sd heavy oil upgrader at Lloydminster.

Axens has studied process configuration optimization to establish a firm technical basis for developing the basic engineering for the upgrader expansion. Such an expansion would increase production to 150,000 b/sd, enabling the unit to process additional heavy oil from operations in the Lloydminster area and the Tucker Oil Sands project at Cold Lake, Alta., 250 km away.

Axens will license a high conversion hydrocracker to convert vacuum gas oil into ultralow-sulfur diesel and additional high-quality distillates for synthetic crude production. A Prime-D unit also has been licensed to upgrade distillates to ULSD.

In addition, Axens will revamp the existing H-Oil hydrocracker

to process 100% deasphalted oil. This modification will achieve high conversion to quality distillates for direct blending into the synthetic crude oil pool.

Japanese firms plan pilot GTL plant

Six Japanese firms have announced plans to jointly establish a research entity and build a test plant for the production of gas-to-liquid fuel with an eye toward potential international development.

The six firms—Nippon Oil Corp., Inpex Holdings Inc., Japan Petroleum Exploration Co., Cosmo Oil Co., Nippon Steel Engineering Co., and Chiyoda Corp.—said they would begin by setting up a research organization later this month.

The group also said it hopes to finish construction of a test plant in Japan during fiscal 2008, and will conduct joint research through fiscal 2010.

The test facility, to be built in Niigata Prefecture, is due to produce 500 b/d of synthetic oil.

The consortium plans to conduct tests jointly with Japan Oil, Gas & Metals National Corp., aiming to study the potential for the construction of plants overseas. The group did not say when such construction might begin. ✦

Transportation — *Quick Takes*

Enterprise to lay pipeline for Shenzi oil

Enterprise Products Partners LP has signed definitive agreements with producers to build, own, and operate a pipeline connecting deepwater Shenzi oil and gas field in the Gulf of Mexico with existing systems.

The 83-mile, 20-in. pipeline will be able to carry as much as 230,000 b/d of crude. Shenzi field is in 4,300 ft of water, covering Green Canyon Blocks 609, 610, 653, and 654.

The new pipeline will connect a tension-leg platform under construction at the field with the Cameron Highway Oil Pipeline and Poseidon Oil Pipeline systems at Enterprise's Ship Shoal 332B junction platform.

The Shenzi TLP will have production capacities of 100,000 b/d of oil and 50 MMcfd of natural gas (OGJ Online, June 14, 2006). Production is to begin by the middle of 2009 from seven wells completed subsea and tied back to the platform. The field eventually will have as many as 15 wells.

Shenzi gas will move through a new lateral to the Cleopatra trunkline and on to Ship Shoal 332.

BHP Billiton Ltd. operates the field and holds a 44% interest. Repsol E&P USA Inc. and Hess Corp. hold 28% interests each.

Gazprom submits plans for Altai gas pipeline

Russia's OAO Gazprom has submitted to Russia plans for a segment of natural gas pipeline as part of a larger project aimed at transporting Russian gas to China.

The 54-km pipeline section would extend through Altai. An Altai government commission is expected to take 5 days to accept or reject the project.

If accepted, the pipeline route is to be approved by yearend, technical design is to be ready in 2007, and pipelaying would start in 2008.

The Altai line will link western Siberian fields and western China, where it will be connected with the projected 2,800-km West-East Chinese pipeline, through which gas will be supplied to Shanghai.

Under the general project, Russia intends to supply 60-80 billion cu m/year of gas to China through the proposed pipeline, which will be commissioned in 2011.

Electricite de France plans LNG terminal

Electricite de France (EDF), the partially state-owned French utility, plans to boost its gas presence in northwest Europe by building an LNG regasification terminal in northern France, taking capacity at the Gate LNG project in the Netherlands, and increasing its gas pipeline capacity through the Netherlands and Belgium. The plans are significant, considering EDF's previous focus on electricity within France and Europe.

Over the next 3 years EDF will investigate building and operating a 13.14 million-tonne/year LNG regasification terminal at Dunkirk Port in northern France. If the project proves feasible, EDF will start terminal operations by 2011.

EDF said the terminal's capacity under the first phase will be 4.38 million tonnes/year; it plans to expand this to 8.76 million tonnes/year in the second phase.

An EDF spokeswoman told OGJ that the terminal's regasified LNG under the first phase would go to France, the UK, Germany, and Belgium. "The EDF Group is looking to secure supplies for north Europe," she added.

The Dunkirk Port Authority, which focuses on the North Sea, is France's third largest third port, handling 6,300 ships a year and annual cargo traffic of more than 53.44 million tons. EDF beat four other candidates to win the LNG tender from the Dunkirk Port Authority.

EDF has also agreed with Gasunie, the Dutch gas transport network operator, to take a 10% capital stake in its Gate LNG regasification terminal in Rotterdam, which will become operational from 2010. Vopak, the Dutch terminal tank operator, will reserve for EDF 2.19 million tonnes/year of regasification capacity at Gate LNG.

Gasunie subsidiary GTS and Belgian transporter Fluxys have also agreed to reserve 3 billion cu m of long-term gas capacity for EDF through the Netherlands and Belgium. "These positions are in addition to the 2 billion cu m transport capacity already acquired by the group on the interconnection between mainland Europe and the United Kingdom," EDF said.

The company said all of the additional gas supplies were important for its subsidiaries in Great Britain, Germany, and the Benelux countries where EDF and the Dutch company Delta are developing an 870 Mw combined-cycle gas turbine power plant in southwest Netherlands by 2009. ✦

Calendar

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Biofuels in transportation

Angel White
Associate Editor

In pursuit of energy independence, the US government is promoting the use of biofuels as transportation fuels. The Department of Energy has set a goal of ethanol production equal to about 30% of the country's current gasoline demand by 2030, said Alexander Karsner, DOE's assistant secretary for renewable energy.

Karsner was one of several speakers representing key biofuel interests—government, automobile manufacturers, oil and gas companies, agricultural entities, and academia—at a recent conference at Rice University, Houston.

From the automobile industry, Susan M. Cischke, vice-president, environment and safety engineering for Ford Motor Co., said about 63% of transportation fuels are imported. Over the years Ford improved the gas mileage efficiency in its vehicle fleet, including cars, trucks, and sport utility vehicles, she said.

But Adam Schubert, US product strategy manager for BP Fuels Management Group, said transportation energy demand is projected to double by 2050.

According to Kyriacos Zygourakis, professor of chemical engineering and bioengineering, Rice University, the US needs about 60 billion gal of biofuels to replace just 30% of 2004 gasoline demand.

"It is a formidable task to provide a liquid alternative to transportation fuel," he said. "A broad portfolio of technologies is needed to provide a sustainable energy future."

Agriculture factor

According to a Sept. 15 report by Simmons & Co. International Ltd., "The National Corn Growers Association forecasts US corn supply will be sufficient to support 16 billion gal of ethanol by 2015-16, which could displace about 7% of US gasoline consumption on a btu-equivalent basis."

The report further stated that "while we do not expect alternative fuels to carry the lion's share of the transportation fuel burden, they can make a meaningful impact. In fact, current ethanol and biodiesel technologies should allow for displacement of 5-10% of current fuel consumption. Future technologies, such as cellulosic ethanol, could allow displacement of nearly 30%."

Additionally, it said, "The promotion of ethanol results in a shifting from political risk in the Middle East to agricultural/weather risk in the Midwest."

FFVs, E85

Sergio Trindade, International Fuel Technology Inc. director, science and technology, said, "There are definite limits to biofuels' ability to meet transportation fuels demand."

He added, "What's the point of flex-fuel vehicles without a flexible infrastructure?"

According to the Simmons report, "In the US, one drawback to these vehicles [which run on a high blend of ethanol and gasoline, such as E85] is the lack of available fueling stations. There are only 800 retail outlets in 37 states which offer E85 fuel. By comparison, there are about 180,000 gasoline/diesel refueling stations in the US."

Biodiesel

The biodiesel industry in the US is small but has great potential for growth, the report noted. Biofuels use a large variety of feedstock and, unlike ethanol, can be shipped via pipeline. They also have a favorable energy balance.

The report cited a DOE estimate that biofuels provide 3.2 units of energy for every one unit of fossil fuel required to make them.

Michael Pachero, director of the National Bioenergy Center for the National Renewable Energy Laboratory (NREL), addressed the growth potential of biodiesel recently in a statement prepared for the US Senate Committee on Energy and Natural Resources.

"The growth of [the biodiesel] industry is currently limited by a number of barriers to market penetration," he said. "Additional engine testing is needed to better understand the performance of B20 (20% biodiesel) and lower blends in the advanced emission-control diesel engines that will enter the market in the 2007-10 time frame in response to EPA regulations."

Biobutanol

NREL is teaming up with oil industry technology developers to explore options for integrating biomass streams into petroleum refineries.

This concept has been the basis of a joint effort by BP PLC and DuPont to develop biobutanol. This advanced biofuel, produced from the same agricultural feedstock as ethanol, can be added directly into refinery gasoline streams (OGJ Online, Sept. 29, 2006).

Schubert believes, "Biofuels is not a silver bullet but a valuable piece of the puzzle to attain a sustainable energy solution." ✦

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Editorial

New US diesel era

As US fuel consumers enter a new era of highway diesel fuel this week, the first and probably only thing many of them will notice is the price. It's down from the high levels of this past summer but higher than the price of gasoline. While hardly lacking in precedent, a diesel premium to gasoline tends to attract the attention of drivers of diesel-powered vehicles, who have been conditioned by history to think their fuel should be the cheaper of the two. It's also something to which truck drivers and other diesel users should accustom themselves.

Gasoline and diesel trade in disparate markets, of course. Because prices of both fuels move with the price of their raw material, a crude swoon since August explains much about their recent declines. Otherwise, the fuels have different demand and price influences. Gasoline is subject to seasonal driving patterns. Diesel prices, because the fuel is chemically so similar to heating oil, are sensitive to winter weather. Market differences like these keep the diesel-gasoline price relationship in flux and perhaps less relevant to economic analysis than, for example, crude-product price differentials.

Diesel premium

But gasoline and diesel prices are what appear on service station signs across the country. It's the difference between them that fuel consumers will notice—and complain to politicians about. And regulations taking effect this week lift chances that the diesel premium to gasoline will become more the norm than the exception. Oil industry officials, therefore, should prepare for questions from a driving public facing a new round of fuel-market changes.

Starting this week, 80% of the diesel produced or imported by all but the smallest refiners and sold at retail for road use must contain no more than 15 ppm sulfur. That's a 97% cut in diesel sulfur content. The Environmental Protection Agency mandated the ultralow-sulfur product to protect emission-control equipment required on diesel engines entering the market next year. When it proposed them in 2000, EPA said the engine and fuel changes would cut emissions of ozone precursors by 95% and of soot by 90%.

The refining industry spent an estimated $9 billion to install equipment needed for compliance. Beyond the capital costs, the industry's operating costs have increased for the hydrogen inputs, catalysts, processing severities, and other changes made necessary by the EPA diesel program. And there are indirect costs, such as new pressure on total oil supply as newly intense processing lowers product yields. Overall, therefore, the cost of making highway diesel has risen, although a crude-price slump now masks the effects.

In addition to the newly elevated manufacturing costs, diesel faces a market squeeze. Supply of ultralow-sulfur diesel in the US now largely depends on domestic and nearby hydrotreating capacity and availability of sweet crude. Because other countries also are lowering diesel sulfur content, competition for on-specification product in international trade will be intense, which means the price will be high. Meanwhile, US demand for highway diesel has a new and growing stimulus: the logistics of fuel ethanol, production of which is geographically diffuse and transportation of which requires trucks. Further boosts to demand for ultralow-sulfur diesel in the US will come from regulatory steps extending the requirement to 100% of highway diesel by 2010 and to off-road product in 2015.

Rising prices

Increased costs plus supply limits plus intensifying competition for international supply plus new demand add up to rising prices for highway diesel unless crude prices collapse. And no one expects crude prices to collapse. So the next few years might be very good to producers of diesel from biological feedstocks and natural gas, whose products are free of sulfur. But they may challenge consumers of diesel and of goods transported by diesel vehicles.

When regulations raise fuel costs, consumers ultimately bear the burden. In this case, the costs will yield health benefits associated with lower levels of air pollution. Those benefits are very important. But the costs can't be severed from them. The relationship must not be forgotten when questions arise about diesel prices, as they will. ✦

FACTS: Oil market suffering from investment lull of 1990s

Sam Fletcher
Senior Writer

The global oil market is suffering now from a lack of investments in the 1990s when oil prices were low and refining margins poor, said analysts at Fesharaki Associates Consulting & Technical Services Inc. (FACTS), Honolulu.

"Low excess upstream capacity and persistent threats to supply security have continued to keep [crude] prices high. Moreover, refining capacity has been tight due to low investments over the past decade, particularly in the upgrading capacity needed to refine heavy crudes into lighter products," said Jit Yang Lim, senior FACTS consultant, in a recent report.

The historically cyclical oil and gas industry is on a new plateau, said Lim. More crude is needed from the Organization of Petroleum Exporting Countries as non-OPEC supply growth falls further behind demand growth. But political, legal, and management problems are unlikely to allow OPEC to add new capacity large enough to respond to demand growth. "Furthermore, we expect the costs throughout the entire production chain to increase rapidly," Lim said.

"The key to the future oil market is US policy on domestic tax and auto standards."

Paris-based International Energy Agency earlier predicted a strong increase in non-OPEC crude production this year but has been forced to reduce its forecast month by month. In July, it expected the growth of crude supplies outside of OPEC to accelerate to 1.7 million b/d in 2007 from 1.1 million b/d in 2006. IEA said non-OPEC supply, including biofuels, should average 53 million b/d next year, with countries from the former Soviet Union and Africa accounting for 60% of the growth and the Americas for 30%. "New oil fields and an assumed rebound after severe 2005-06 outages underpin the increase in 2007. The North Sea and OECD Pacific also [should] see a temporary respite in 2007 from recent declines," it said (OGJ Online, July 12, 2006).

IEA forecasts a 1.2 million b/d (1.4%) increase in crude consumption globally during 2006 and a 1.6 million b/d (1.9%) increase in 2007.

Analysts at the Houston office of Raymond James & Associates Inc. said, "IEA believes that Asian, South American, and Saudi Arabian producers may help fill suspended supply from the US. However, the agency has also raised its 2006 Chinese oil demand growth forecast from 6.1% to 6.5%." (OGJ Online, Aug. 11, 2006).

Energy prices

In the future, oil prices are likely to be driven by a shortage of crude oil production capacity instead of refined products—"exactly the mirror image of the situation today," said Lim. "Additional refining capacity is limited in the short term, but much more is coming before the end of the decade. China will add 2.3 million b/d of refining capacity between now and 2010, while India will add more than 1.3 million b/d of refining capacity by 2010" Lim said. "In addition, the Middle East is expected to add around 3 million b/d of capacity by 2012, and another 1.2 million b/d is expected to be added in the US. There is a potential refining surplus looming by 2010-12, and this surplus will have a worldwide impact," he said.

The global market has been growing strongly with incremental demand close to 1.5 million b/d since 1995. Demand projections by IEA, OPEC, and the US Energy Information Administration average about 1.5 million b/d in annual growth for the next 5 years. "The Asia Pacific has been the engine for this growth. Demand growth in China and India is likely to stay strong," FACTS reported.

China, the "key driver" of demand growth, accounted for 73.1% of Asia's 1.07 million b/d incremental demand

in 2004. "This solid growth can be traced to China's robust economic performance, with 10.1% real GDP growth and the corresponding growth in petroleum use in almost every sector of the economy," FACTS reported.

India's energy demand growth is likely to stay strong, with expanding demand in its agricultural sector after growing strongly in the past 2 years. Japan's demand is declining, with its nuclear power issue "somewhat resolved." Although Japan's economic situation improved recently, its mature economy and soon-to-be-shrinking population are not promising prospects for long-term growth of oil demand, FACTS said.

South Korea has recovered somewhat from the brief recession of early 2003 and is expected to grow at a moderate rate as a maturing economy. "Overall, Asia Pacific is expected to have an incremental demand of around 700,000 b/d for 2006," Lim said.

With oil prices holding at relatively high levels in a prolonged increasing trend, observers now seem to be more receptive to Colin Campbell's theory of peak oil, which holds that "oil production is going to be flat or even decline in the near future," said FACTS. "We believe that the issue is not so much that the oil is not there in the coming decades, but that it will be more difficult to deliver the oil to the market," its analysts said.

Key factors contributing to high prices are persistently strong, though moderating, demand and the perception of tighter supply and rising costs in the future. Unexpected strong demand for petroleum products led to a sudden reduction in spare refining capacity worldwide that drove up product prices, bringing with them increases in crude prices, said FACTS analysts. "Petroleum prices have so far been product-led and demand-driven, but there is now the underlying fundamental concern with the industry's lack of resources or problem of adding new production capacity," Lim said.

That has been exacerbated by the "alleged speculative factor caused by hedge funds that inflate the prices further above what the fundamentals would indicate," he said. "The bullish sentiment of the energy market has led to a rise in activities by hedge funds in the futures markets."

Lim said, "The price of crude may rise steadily from 2007 onwards due to the tightness of supply. As such, we believe that in the longer run, oil prices in real terms have to increase to a level which curbs the demand growth." He said real prices would have to rise "by at least 50-100% on the back of moderate economic growth before demand is curbed, resulting in lower demand due to more efficiency and new technologies that will reduce dependency on oil."

The key to the future oil market is US policy on domestic tax and auto standards, said FACTS analysts. "Current prices have moderated demand in a big way in emerging markets but not in the US. Only higher prices can stop or cut US demand, and new policies will need to be enacted. There is no political will or courage in the US to embark on such a task, so only prices can force a demand adjustment," Lim said. "The rest of the world, particularly the developing world, will suffer until the US is forced to change course."

"Only higher prices can stop or cut US demand; new policies will need to be enacted. There is no political will or courage in the US to embark on such a task, so only prices can force a demand adjustment."

Crude prices are likely to stay strong—above $50/bbl in the near term, Lim said.

Crude supplies

World oil production may be insufficient to meet future demand, Lim said. FACTS sees non-OPEC supply growth slowing, averaging 500,000 b/d in 2007-10 and likely plateauing by 2015. Global production should peak in 2015-20 at 100 million b/d, as a result of resource and policy constraints.

Most non-OPEC countries are not expected to have significant output increases in the next few years, except for Russia, where high taxes on extraction and exports and growing state control have increased uncertainty for investment. There seems to be a government decision to not allow an output growth much above 10 million b/d to ensure long-term sustainable production, Lim reported.

"A similar policy is also seen in Mexico, with little or no growth in output expected."

With non-OPEC production averaging 500,000 b/d in 2007-10 and OPEC's decline rate of 1.2 million b/d annually, OPEC would have to add more than 10 million b/d of new production by 2010. Lim questions whether it can handle that increase.

Overall, OPEC faces a natural decline of some 1.2 million b/d annually, roughly one-fourth in Iran and Saudi Arabia each, FACTS reported. Indonesia and Venezuela's production capacities have declined significantly over the past 5 years.

"Adding capacity is very difficult, as much new capacity is needed just to stay in the same place. The production is also subject to [political] uncertainties," the study concluded. And the delivery of oil to markets remains a continuing challenge.

Refining capacity

Refining capacity has remained tight because of low investment in those facilities over the past decade, particularly in upgrading capacity to refine heavy crudes into lighter products. "The situation has worsened as many countries move towards lower-sulfur specifications, making the need for sophisticated

capacities and light-sweet crudes even more dramatic," Lim said.

The switch from methyl tertiary butyl ether (MTBE) to ethanol as an oxygenate blend in reformulated gasoline in the US due to environmental issues added more strain on the sector, keeping product prices high.

"Additional refining capacity is limited in the short term, but much more is coming before the end of the decade. The bulk of the expansions will be in China and India, with some potential large-scale expansions in South Korea," said Lim. FACTS projects that Asian refining capacity will increase by more than 4.3 million b/d by the end of 2010. China is expected to add 2.3 million b/d of refining capacity, while India will add more than 1.3 million b/d of refining capacity in that same period. The Middle East also is expected to add around 3 million b/d of capacity by 2012. Another 1.2 million b/d of new capacity is scheduled in the US.

The potential refining surplus expected by 2010-12... will have a worldwide impact.

Most of China's refining addition is driven by domestic demand, but capacity additions in India and the Middle East pose a threat to future refining margins.

The potential refining surplus expected by 2010-12 will not only be critical in Asia but will also have a worldwide impact, Lim reported. ✦

Gazprom to develop Shtokman alone, pipe gas to Europe

Judy Clark
Senior Associate Editor

Nina Rach
Drilling Editor

In a surprise move, Russia's OAO Gazprom announced on Oct. 9 that it will develop giant Shtokman (Shtokmanovskoye) natural gas-condensate field in the Barents Sea without foreign partners and will pipe the gas to Europe rather than convert it to LNG for North American markets as had been planned.

In a television broadcast followed by a written statement, Gazprom Chief Executive Alexei Miller cited a number of factors for the decisions.

"The foreign companies were unable to provide the capital required," he said. "Foreign companies could not offer us assets that corresponded in size and quality with the reserves of the Shtokman field." Miller added that foreign companies would be considered "only as contractors" for the project.

The announcement stunned international companies vying for a 49% interest in the project. Many of them have been working in the field with Gazprom under short-term contracts for more than 15 years (OGJ, Sept. 4, 2006, p. 70).

Norsk Hydro Pres. Morten Ruud had said earlier that Gazprom would probably select several companies from the group of companies bidding. "Even for Gazprom, the Shtokman development requires such huge investment there is need for several partners," he said. Development of the field is expected to cost $10-20 billion.

Miller earlier this year said Gazprom would set up a consortium with two or three of the five short-listed companies biding on the project: Total SA, ConocoPhillips, Chevron Corp., Statoil ASA, and Norsk Hydro Oil & Energy. The Norwegian companies had been considered front-runners because of their experience in the Barents Sea. Hydro participated with Gazprom in drilling the fourth Shtokman appraisal well and is providing the rig for the seventh well, and Statoil is developing fields in the western Barents Sea.

Russian Energy and Industry Minister Viktor Khristenko in mid-July said the foreign partners could be announced in October.

"Today's announcement by Gazprom was not expected," Statoil said in a statement. "We are confident that Statoil is a good partner for Russia in realizing the Barents Sea potential. Statoil is still committed to a long-term presence in Russia and will continue to pursue business opportunities there."

Politics at play?

Energy analysts venture that politics influenced the decision to shut out foreign companies. Russia's President Vladimir Putin wants to retain as much control as possible over Russia's energy resources and revenues to give the country a new source of wealth and power.

Russia used its leverage last winter when it cut off gas to Ukraine—and consequently to parts of Europe—in a successful attempt to double the price of gas to Ukraine (OGJ, Mar. 20, 2006, p. 57). The incident followed a similar crisis in 2004 between Russia and Belarus. This month Gazprom threatened to cut gas exports to Bosnia unless Bosnia begins to pay a $105 million debt amassed over 1992-95 (OGJ, Sept. 4, 2006, Newsletter).

The Kremlin also takes issue with what it considers interference by the US in Russia's attempt to join the World Trade Organization. US President George W. Bush publicly chastised Putin for what Bush termed backsliding on human rights and democracy issues, an encounter that generated a hot response from Putin and a cooling of relations between the countries.

In addition, Putin is said to be exasperated by Washington's warm relationship with Russia's ex-Soviet neighbor

WATCHING GOVERNMENT

Nick Snow, Washington Correspondent

Those elusive pass-throughs

Oil and gas prices have fallen more quickly than autumn leaves in the past few weeks, which has helped improve the US economic outlook.

While the US Energy Information Administration forecasts higher heating fuel prices for the coming winter months, it also anticipates prices will be lower than in the comparable 2004-05 period. Winter heating demand could raise the cost of West Texas Intermediate crude to $67/bbl by January from an average $63.80/bbl during September, EIA said.

That would still be less than this past summer's peak price—enough, some economists and policymakers say, to ease concerns about inflation. Oil prices apparently haven't ignited inflation yet, and it's reasonable to wonder why. The standard explanation is that the US economy is more diverse and relies less on cheap energy than it did in the 1970s and '80s, when businesses passed through higher energy costs as increased prices for goods and services.

Obvious increases

But it's not completely immune. Higher fuel costs in 2006 led to higher prices for airline tickets, refuse collection, and other energy-intensive services, noted Donald L. Kohn, vice-chairman of the Federal Reserve Board. Such services represent a small part of the core consumer price index, and the small acceleration of prices in other nonshelter sectors, "while consistent with a small pass-through of energy costs, could be attributed to nonenergy factors," he said at New York University on Oct. 4.

Kohn said energy price pass-throughs were much more evident before 1980, when US monetary policy not only accommodated them but also allowed second-round effects to become embedded in more persistent inflation increases.

"Since the early 1980s, the pass-through to core prices has been limited or nonexistent, at least in part because households and firms have expected the Federal Reserve to counter any lasting inflationary impulse that they might produce," he said.

Reduced reactions

Oil price movements were more persistent before 1980 than they were after—until recently. "Households and firms probably expected deviations of energy prices from long-run averages to be largely reversed and saw less reason to try to adjust wages and prices in response to what they viewed as transitory changes in energy costs," Kohn suggested. He said there probably have been some pass-throughs recently as wage and price decision-makers began to believe higher energy costs would not be reversed soon. "But the magnitude of the effect has been small—perhaps on the order of a half percentage point or less since the end of 2003," he said. Kohn said consumer energy prices flattened during August and probably will register a big decline when the US Bureau of Labor Statistics releases its next consumer price index on Oct. 18. Such a decrease will not erase the past few years' increases, he went on, but it could reduce consumers' fears that continued energy price increases will set off higher long-run inflation. ✦

Georgia, which is seeking membership in the North Atlantic Treaty Organization. Russia has imposed sanctions on Georgia for alleged spying.

That background, along with the recent curtailing of Royal Dutch Shell PLC's work on Sakhalin II for "environmental infringements," also leaves analysts wondering about the role of politics in Gazprom's decision to deliver gas to Europe via pipeline rather than as LNG to North America.

Europe to receive gas

Miller, however, said that Europe, Gazprom's traditional export customer, was the company's first priority. It has been providing gas to Europe for more than 30 years, and European gas demand is expected to grow about 2%/year, according to the International Energy Agency.

In 2005 Gazprom sold 156.1 billion cu m of gas in Europe, more than a quarter of European gas supply, Miller said in the company's 2005 annual report. That is about 2.9 billion cu m more than it provided in 2004. With European production declining, members of the European Union will import as much as 75% of their natural gas in 2015, compared with 57% in 2005, IEA said.

Russia has the gas. The Russian part of the Barents Sea is estimated to contain about 22 billion boe (OGJ, June 13, 2005, p. 45). Shtokman, one of the largest gas fields in the world, lies 555 km east of Murmansk in 350 m of water (see map, OGJ, Sept. 4, 2006, p. 70). In January, the Russian Federation Nature Ministry's State Commission for Mineral Reserves estimated Shtokman reserves at 3.7 trillion cu m of natural gas and more than 31 million tonnes of condensate. The hydrocarbons are in four main reservoirs at depths of 1,900-2,300 m.

Gazprom expects to begin production from Shtokman in 2010. The gas initially will be piped from the field to the Russian coast and then under the Baltic Sea from Russia to Germany through the proposed 1,200 km Nord

Stream pipeline, formerly called the North European Gas Pipeline. Nord Stream, based in Zug, Switzerland, is a consortium of Gazprom, with 51% interest, and subsidiaries of Germany's BASF AG and E.ON AG, 24.5% each.

Construction began Dec. 9 on the 917 km, 56-in. onshore portion at Babayevo, Russia, 800 km east of St. Petersburg, Gazprom said (OGJ, Dec. 19, 2005, Newsletter). It will connect existing pipelines from Siberian gas fields to the planned Nord Stream transmission line. The onshore system will include seven compressor stations delivering an operating pressure of 100 bar.

Original plans also called for an LNG liquefaction plant near St. Petersburg.

Wingas and E.ON Ruhrgas will build two onshore connections totaling 850 km from Geifswald to the south and west of Germany. From Germany the gas can be transported to Denmark, the Netherlands, Belgium, the UK, and France, with a possible new pipeline spur to Sweden.

Intec Engineering has completed work preliminary to front-end engineering and design on the subsea line, which will be 48-in. in diameter with a 6-in. concrete coating for a total of 60-in. diameter. It will have an operating pressure of 210 bar. Pipeline operations are scheduled to begin in 2010 with an initial capacity of 27.5 billion cu m/year. Capacity could be doubled with a parallel second line to be built in Phase 2 (OGJ Online, Sept. 21, 2005). The subsea line will need no compression stations in the Baltic, Nord Stream said.

Total capital expenditure for the offshore part of the project, if both pipelines are built, would exceed €4 billion to be financed 100% by Gazprom.

The Nord Stream project received the European Commission's Trans European Network (TEN-E) designation in 2000 as a priority energy project contributing to ensuring safe and reliable supplies for Europe. ✦

Cavaney: Industry needs to reconcile good with bad

Nick Snow
Washington Correspondent

The oil and gas industry faces a huge paradox as executives from its biggest companies gather in Washington, DC, for the American Petroleum Institute's 2006 annual meeting Oct. 15-16.

On one hand, the business itself is in excellent shape. Profit margins are good not only in exploration and production, but also, for a change, in refining and marketing. Efficient operations and dedicated employees kept disruptions from Hurricanes Katrina and Rita last year from being worse, and the recovery since has been impressive.

On the other hand, the industry has a bad public image. The Gallup Poll listed energy as No. 4 in its Top 10 2006 election issues on Sept. 21. "The oil and gas industry receives the most negative ratings of 25 US business and industry sectors rated in 2006. This suggests that government efforts aimed at controlling and regulating the oil industry will be met with high levels of public approval," it said in an article posted on its web site.

Industry leaders are very much aware of this paradox, API Pres. Red Cavaney says. In fact, they have been trying to address it for some time, he told OGJ in an interview before the trade association's meeting. Until fairly recently, natural resources industries traditionally did not consider external communications a top priority but concentrated on operating their businesses, he explained. That approach seemed to work when there were three commercial television networks and more daily newspapers.

The growth of cable television, to a point where viewers could select from hundreds of channels, and the arrival of the internet changed all that. API and its member companies had been trying to improve their external communications for 3-4 years when Katrina and Rita slammed into the Gulf Coast late last summer. The effort intensified following the hurricanes, Cavaney said.

Don't expect kudos

The industry "did a Herculean job of keeping supplies going despite a horrendous loss of production and refining capacity," he said. It didn't expect kudos. But it also didn't anticipate being widely portrayed as a group of opportunistic price manipulators exploiting a natural disaster to fatten their profits.

That was when API and its members concluded that politicians and the public may not fully understand how the business works, Cavaney said. "We had to become more vocal. Our friends were telling us they couldn't go on being the only voices," he said.

Cavaney emphasized that what API and its members are undertaking is an educational advocacy effort, not an image campaign. "At our coming annual meeting, we'll ask the board and membership for reaffirmation that the industry needs to carry forward over several years to try and get a more balanced perspective in developing national policies," he said.

"It's an incredible dichotomy," Cavaney observed. "From an operations standpoint, companies are at the top of their game. From a public policy standpoint, the industry is in a severe downdraft. Mistrust on a broad scale allows people to believe the worst. This has to be a long-term effort."

He expects API members to support continued aggressive educational advocacy. "The industry leadership has clearly recognized that it can't sustain strong operating and financial performances if public policy is working against it," Cavaney said.

Antioil sentiment intensified following President George W. Bush's "oil ad-

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Japan exploring methane hydrate

In a bid to move Japan toward energy self-sufficiency, the country's Ministry of Economy, Trade, and Industry is promoting technologies to provide new fuel sources, among them methane hydrate.

Described by some observers as a sherbet-like substance, methane hydrate is a mixture of methane trapped in frozen water. Some reports say the energy generated by each cubic meter of hydrate is equal to that released by up to 180 cu m of natural gas.

Word of the new resource emerged last February when a research team from the University of Tokyo and the Japan Agency for Marine-Earth Science and Technology (JAMSTEC) announced that it had successfully tapped a cache of methane hydrate lying relatively close to the seabed 30 km north of Joetsu, Niigata Prefecture.

Near the seabed

The new cache was said to be the first discovered in Asia lying relatively close to the seabed, making it fairly easy to extract, unlike most known deposits, which exist hundreds of meters below the ocean floor.

JAMSTEC identified the methane hydrate deposit off the coast of Joetsu at ocean depths of 800-1,000 m and successfully extracted samples from the site by inserting a 10 cm-diameter tube just 6-12 m into the ocean floor. Seabeds around Japan are now thought to contain 7 trillion cu m of methane hydrate, equal to 100 years of natural gas consumption in Japan at the current rate of use. It will thus come as no surprise to learn that the Japanese government hopes to extract and use its of subsea methane hydrate to reduce its dependence on crude oil, a dependence made all the more uncertain by future price rises due to supply-demand conditions and geopolitical risks.

Tests in Canada

Indeed, starting about December, METI, and Japan Oil, Gas & Metals National Corp. plan to conduct methane production tests in northwestern Canada with the Canadian government. If the experiments go well, the Japanese interests may begin trial extractions of methane hydrate from the Pacific Ocean floor by fiscal 2009.

The Japanese government, which aims to begin commercialized extraction of methane hydrate in fiscal 2017, believes that commercial methane hydrate harvesting can become a reality if low-cost, high volume production methods are developed.

It is not alone in that belief.

China plans to spend $100 million over the next decade on studying natural gas hydrates, and trial exploration of methane hydrate is expected to become viable between 2010 and 2015. According to one report, China so far has discovered enormous deposits of gas hydrates in offshore areas; those spotted in the northern part of the South China Sea are expected to amount to half the country's onshore oil resources.

But the National Development and Reform Commission said that further technological breakthroughs were necessary before the fuel would be commercially developed. Doubtlessly, the Chinese will be keeping a very close eye on developments in Japan. ✦

diction" reference in his 2006 State of the Union address. Cavaney said it was a catalyst for groups and individuals opposing the use of oil to aggressively promote alternatives as ways to achieve energy independence.

'A fool's errand'

"As a long-term goal, it might be worthwhile. But looking at what the US economy faces over the next few decades, the idea is a fool's errand. None of the current technology will accomplish this," Cavaney said.

He said control of the US House of Representatives, and possibly the Senate, could move to the Democrats, and their energy strategies may rely more on mandates than the marketplace.

"We've seen this movie before. After the oil embargo in the 1970s, government tried to develop several programs. It did a pretty good job on energy efficiency standards initially but just about everything else, from price controls to the windfall profit tax, failed," he said.

At that time, he said, there was enough spare productive capacity that the industry could continue to supply consumers. "Now, there's such a passionate search for the successor to oil and gas that we're concerned that policymakers could direct efforts toward perceived solutions. But what if they fall short of their goals and the oil industry has been so marginalized that it can't step up to fill the void? Our national economy would be at a serious disadvantage," Cavaney said.

He said he would like to see national energy policymakers emphasize energy security, instead of independence, by first, recognizing the value of conservation and efficiency, particularly with growing demand overseas from emerging economies; second, increasing and diversifying supply sources, both domestically and globally; and third, increasing government's support of technology research and development.

Cavaney said the industry has been doing its part to foster research and development. Of the $135 billion of US expenditures for emergency energy

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technology from 2000 through 2005, he said the oil and gas industry spent 73% of the total, government spent another 4%, and the remainder came from other businesses, academia, and special foundations.

"If we are marginalized with burdensome taxes, we'll lose our capacity to reinvest," he warned.

National oil companies

Cavaney also pointed out that the worldwide oil industry has changed in the last 30 years as national oil companies have become dominant, reaching a point where they own 79% of the total reserves. "If US policy formulas for energy marginalize publicly held oil companies and make them noncompetitive, who does that leave to supply consumers?" he asked. Cavaney said that for every example of successful government-driven energy efforts, such as automotive fuel efficiency and the removal of lead as a gasoline antiknock compound, there are several more failures.

"Most economists agree that command-and-control schemes don't work as well as a free market. Many say that while there is no totally free market in oil and gas, it still is preferable to mandates," he said.

API's president observed that while free and transparent energy markets are preferable, "at the end of the day, energy is driven by government policies—from where you can drill or build facilities to the composition of fuels. There has to be a constructive partnership between industry and government." ✦

GAO recommends spending limits for SPR fill

Nick Snow
Washington Correspondent

The US Department of Energy could have saved about $590 million from late 2001 through 2005 if it had used a steady dollar value of crude oil over time to assure that more purchases were made for the Strategic Petroleum Reserve when prices were low, the Government Accountability Office says.

Using this approach, DOE would buy crude for the reserve using a preset target based on expenditures instead of volume. This could take advantage of market fluctuations because a preset dollar amount would buy more oil when prices fell and less when they climbed, GAO concluded in a report it released Oct. 3.

"Simulations we performed of this approach under various potential oil market conditions, including scenarios of rising and falling prices and periods of larger and smaller price volatility, showed that this approach would likely save money in the future as well," it indicated.

DOE currently buys crude for the SPR at a steady pace, which was adopted soon after Congress voted to establish the reserve and begin filling it. The approach places greater emphasis on economic and strategic security than price.

Some of the experts from the oil industry and academia who were assembled by the congressional watchdog also suggested that DOE let producers delay deliveries to the SPR when supplies were tight by providing additional crude for the reserve later.

GAO said that the experts questioned some past presidential decisions about when to use the reserve but generally supported providing broad discretion in reaching those decisions.

The report also concluded that a larger SPR would be needed to maintain the current level of protection if domestic oil demand increases as expected. It cited US Energy Information Administration projections of about 12% higher demand for oil products by 2015 and 24% more demand by 2025 compared with 2005's average.

Under those projections, GAO said, DOE estimates that the US would drop below its stock-building obligations to the International Energy Agency by 2025. Another study prepared in 2005 found that the benefits of expanding the reserve to 1.5 billion bbl outweighed the cost over a range of conditions, GAO said.

Factors could change

Factors that influence the SPR's ideal size could change, it added. "For example, although projections show increasing oil demand in the United States and [the] world, the level of oil demand depends on many factors, including rates of economic growth, the price of oil, future policy choices related to increasing conservation and availability of alternative energy sources, and technology changes," GAO said.

"As the world oil market changes, periodic reassessments of the appropriate size of the SPR could be helpful as part of the nation's long-term energy security planning," it said.

GAO also recommended that DOE buy heavier crudes to make oil stored in the strategic reserve more closely matched to what US refineries process under normal supply conditions. It said 3.5 million bbl, about 40% of the 8.3 million b/d of non-Canadian oil imported into the US in 2004, was heavy oil. "Refineries that process heavy oil may have difficult operating at capacity if their supply of heavy oil is disrupted," it said.

A December 2005 DOE report identified 74 refineries connected to the SPR that receive non-Canadian oil imports. The report found that the types of oil currently stored in the reserve would not be fully compatible with 36 of those refineries, or slightly less than 50%, GAO said.

If these refineries had to use SPR oil, US refining throughput would decrease

by 750,000 b/d, or about 5%, with substantial drops in distillate production from refineries processing heavy oil, according to DOE estimations.

GAO said DOE's 2005 report recommended having about 10% heavy oil in the reserve to keep the supply compatible with the current refining lineup. But a larger amount might be better, GAO said, because heavy oil is less costly and refiners who process it say they would not be able to maintain normal gasoline production levels if they used only SPR oil.

DOE's responses

Responding to the report, DOE said it agreed with most of the recommendations but noted that the SPR's history "is replete with changes in priorities that led to either acceleration or deceleration of the fill program."

DOE said that in accordance with both federal law and good management, it always favors minimizing oil acquisition costs but cannot always delay or defer purchases for this reason.

For instance, during 2002-04 several domestic producers that send oil into the SPR under the Department of Interior's royalty-in-kind program were willing to defer deliveries because of spot and future market prices. DOE said that its fossil energy office was focused on security concerns at that point and did not generally agree to deferrals.

"In the current market, futures prices are generally higher than spot prices and consequently companies are not eager to defer deliveries, and there is no opportunity for the department to significantly reduce acquisition costs," it added.

DOE also questioned GAO's estimate of $590 million in potential savings from 2001 through 2005 using dollar-cost averaging because all oil acquired for the reserve during this period was under DOI's royalty-in-kind program and involved no cash purchases.

Although DOE said it agrees that some SPR oil should be heavier than what is currently stored, it does not want to set a specific goal or replace any of the current inventories. Instead, as the reserve expands it would prefer including a third quality stream in addition to the sweet and sour streams it already has because that would be more economical and efficient.

GAO's review aimed to answer three questions:

- Based on experience, what factors do experts believe should be considered in filling and using the strategic reserve?
- To what extent can the SPR protect the US economy from damage during oil supply disruptions?
- Under what circumstances would a larger SPR be warranted? ✦

Congressional panel hears of produced water potential

Nick Snow
Washington Correspondent

Water produced with oil and gas can help relieve pressure on surface-water resources, witnesses told a US House Resources subcommittee hearing Sept. 26.

The three witnesses spoke in support of HR 5110, which Rep. Mark Udall (D-Colo.) introduced on Apr. 10.

The bill would direct the interior secretary to identify obstacles to using more produced water. It also would authorize $5 million for three pilot plants in Colorado, California, and Arizona or Nevada to demonstrate ways in which produced water can be made suitable for other uses.

"Developing beneficial uses for produced water could reduce costs of oil and gas development while also easing demand for water by alleviating drought conditions in Colorado and the West and providing water for agriculture, industry, and other uses," Udall said at the hearing of the water and power subcommittee.

Witnesses agreed that more produced water could be used aboveground, but obstacles loom. They include the oil and gas industry's unfamiliarity with water marketing, produced water supply duration uncertainties, the relatively poor quality of produced water and need for extensive treatment, and Clean Water Act limits on the discharge of produced water to surface water in western states, according to David R. Stewart, a professional water engineer based in Fort Collins, Colo.

Other obstacles include fluctuating oil and gas prices and the resulting fluctuation of interest in water-recycling investments, identifying and minimizing risks of public exposure to produced water, and a wide difference between the desired pace of development by the water-recycling industry once the decision is made to proceed and the lower rate at which public water systems are built, he said in written testimony.

Stewart also noted that the oil and gas industry's focus of capital and talent on its core business and the relatively low value of water compared with oil and gas pose problems.

Potential benefits

Stewart said surface use of produced water can cut or eliminate costs associated with disposal and treatment and lower environmental risks. It also can improve the efficiency of thermal oil recovery, reduce the potential for reservoir damage from water reinjection and recirculation, and lower oil-field energy use.

The practice would boost water supplies in the US West and ease pressure on surface water resources, Stewart said.

David Templet, environment, health, and safety manager at Devon Energy Corp., Oklahoma City, said US onshore oil and gas operations generated about 18 billion bbl of produced water in 1995. Some of the water already irrigates land and waters livestock, he said.

He testified on behalf of the Domestic Petroleum Council, the Independent Petroleum Association of America, the US Oil & Gas Association, and the Colorado and New Mexico oil and gas associations.

Powder River potential

US produced water with the lowest concentration of total dissolved solids (less than 10,000 ppm) is found in the West, where water is a critical resource, he continued. "Energy operations in the Powder River basin in North-Central Wyoming produced approximately 1.4 million bbl of relatively good-quality water per day. A large volume of this water could be used for agricultural, ranching, and other purposes," he said in written testimony.

Templet suggested that wider use of produced water could benefit oil and gas producers and water consumers but added that water-treatment costs and inconsistent water-quality regulations among states make this difficult.

He said Section 3 of HR 5110 recognizes the need to identify these legal and regulatory problems. "The research conducted in response to this legislation needs to evaluate existing regulatory barriers for beneficial use, particularly with surface discharge under the Environmental Protection Agency's National Pollutant Discharge Elimination System onshore permit programs," he said.

"Additionally, a number of the issues preventing or posing obstacles to the surface discharge of produced water are firmly within the arena of state agencies, current rule-making, and lawsuits," he continued.

Kevin Bliss, the Washington representative of the Interstate Oil & Gas Compact Commission, confirmed that states are the principal regulators of water produced in association with oil and gas and have more experience than any other entity.

"Research performed by the IOGCC and its member states documents the presence of produced water whose quality is compatible with irrigation," he said in written testimony. "Water of this quality dominates some oil and gas basins and is in the minority in others. Some of this water is useable in its native state. There are instances where some can be used for irrigation with minor changes to the way ranchers and farmers manage their crops. Treatment prior to field application benefits other sources." An impediment to aboveground use of is its changing availability as oil and gas production changes, Bliss said. The bill would help connect producers, water-treatment companies, and irrigators, he added.

Two projects

Stewart cited two produced-water projects under way or nearly complete.

The first, near Wellington, Colo., will

treat and sell produced water to increase the town's supply by up to 300%. A second, at San Ardo oil field near Monterey, Calif., could make 100,000 b/d of water available for agriculture, groundwater recharge for salt barrier intrusion, and environmental reclamation in addition to the 50,000 b/d the producer uses for steam injection.

Stewart also cited water produced with coalbed methane in the West. "This is a difficult water to dispose of due to its mineral content. Technologies have been developed to treat this water, but its beneficial use has not been researched or developed. Its potential uses include municipal augmentation of a new water resource, industrial and agricultural interests, and environmental enhancement through the creation of wetlands and in-stream flows," he said.

He said two federal agencies could help find ways to use produced water aboveground. The Bureau of Reclamation has experience removing salt from brackish water and has access to end users, while the US Geological Survey understands how produced water can be used and what water-quality technologies are necessary.

"In addition, there will be a need to prove to the energy industry that these technologies are feasible and will assist in the development of new energy resources," Stewart said.

Templet told the subcommittee, "Water treatment must compete with the lower-cost option of deep-well injection. While this is the most environmentally sound disposal method, it forgoes the opportunity to use millions of gallons of water as a resource."

Critical cost

Managing produced water can be critical to production economics. Templet pointed out. "Research that provides concise and comprehensive information on produced water and ways in which it can be managed can help operators, regulators, landowners and other stakeholders to be better informed and support management options that can lower production costs and protect, and even enhance, the environment," he said.

Bliss said the IOGCC expects by the end of 2006 to complete a national study with ALL Consulting LLC of Tulsa of managing produced water from conventional and unconventional onshore oil and gas exploration and production operations. The Department of Energy's National Energy Research Laboratory funded the study, which has identified uses for produced water that include agricultural irrigation, power generation, aquifer storage and recovery, enhanced oil recovery, surface discharge, and water for wildlife.

Bliss said the final handbook for the project is due by the end of October, and a produced-water analysis tool will be finished by the end of the year. ✦

Drilling confirms radar-mapped atmospheric seepage anomalies

Thomas C. Bailey
James M. Grubb
Premier E&P LLC
Houston

This article will discuss three types of atmospheric seepage anomaly (ASA).

Pickett's Ridge is an Eocene Yegua (8,500 ft) ASA that demonstrates that atmospheric seepage anomalies disappear with production, reflecting the response to a changing subsurface accumulation.

Sand Ridge is an Eocene Wilcox formation ASA at a depth of 12,000 ft. It is an example of a deeper trap that was recognized and differentiated from an overlying, existing Yegua field using the ASA.

Jones, the third ASA, at about 7,600 ft, was mapped as one seepage anomaly but reflects two adjacent gas sands. The locations of these three ASAs are shown on Fig. 1 along with the three ASAs presented in a previous article (OGJ, July 31, 2000, p. 75).

Introduction

The authors formed Premier E&P in 1992 to resolve the question: Can oil and gas fields be quickly, cheaply, and accurately identified in the subsurface by mapping seepage in the atmosphere?

The first author and Merrill Skolnik in 1996 published a two-part article[1,2] on radar mapping of atmospheric seepage to locate hydrocarbon accumulations in the subsurface.

In 1997 Skolnik and Bailey coauthored a paper presented at the Southern Methodist University Fifth Unconventional Methods Conference[3] on the same topic. In 2000, a third article[4] discussed the successful drilling of three ASAs in Wharton County, Tex.

In 1992 Premier E&P funded a seepage survey over the northern half of Wharton County. Premier found seepage clouds (ASAs) present in the atmosphere directly above most Yegua and Wilcox fields in Wharton County. The company also found numerous anomalies with no wells drilled to the Yegua or Wilcox.

Premier resurveyed the same area in 1998 and again in 2004. Premier found no new anomalies in the two resurveys, indicating that the features are fixed.

These ASAs had several characteristics:

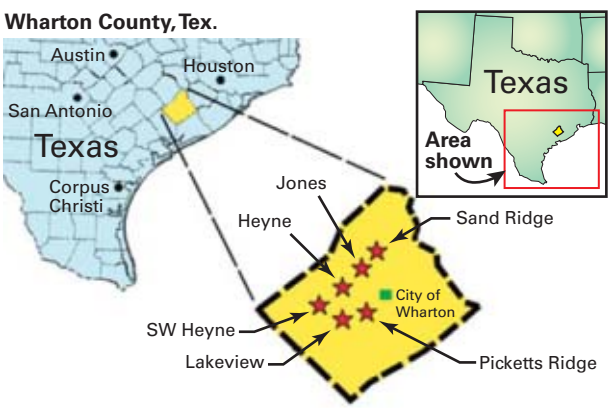
1. They were a definitive size and shape.
2. They appeared as the same size and shape after each survey except after they had been produced, and they then shrank in size or disappeared.
3. Those over recently developed fields conformed to field boundaries.
4. They were oriented parallel to the structural trends of the area.

The publishing of articles in the last 10 years validating vertical movement of gas molecules to the surface has confirmed Premier's conclusions about the validity of atmospheric seepage mapping to locate subsurface hydrocarbon accumulations.

Depth to the trapped hydrocarbons is determined in a number of ways but primarily by the shape and size of the seepage anomaly with respect to subsur-

ATMOSPHERIC SEEPAGE ANOMALY LOCATIONS

Fig. 1



face traps when mapped on 3D seismic surveys.

Production effects

Premier's 1992 survey identified Picketts Ridge, a 200-acre ASA named after the Yegua field that was present on the far southwest end of the ASA (Fig. 2).

This ASA was an elongate anomaly with the Energy Development No. 1 Barr, producing 1.2 MMcfd of gas and 23 b/d of oil (completed in 1991) located in the southwest corner of the anomaly. It appeared to Premier that an offset opportunity could be drilled in the northeast part of the anomaly.

In attempting to lease the offset acreage, Premier found that a company was already preparing to drill to the northeast about a half mile. The Landers No. 1 was located on 2D seismic data to test the crest of a Yegua structure (Fig. 2). This structural test was located just outside the ASA.

The well cut three Yegua sands but was plugged and abandoned as the sands were tight and wet. In 1996, after 5 years, the No. 1 Barr well went off production.

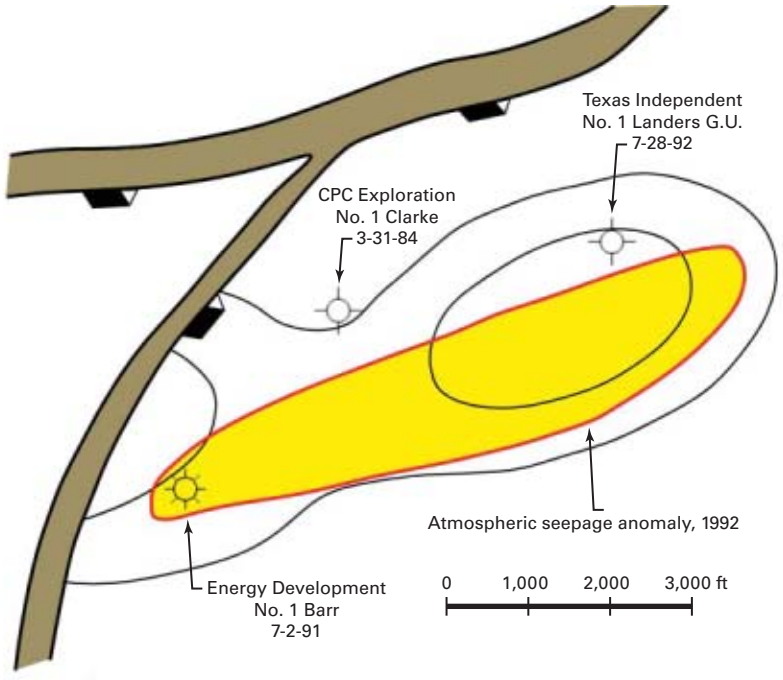
Premier resurveyed the Picketts Ridge Prospect in 1998 to determine what effect the depleted No. 1 Barr had had on the ASA. That survey found that the ASA was now absent around the Barr well but was still present to the northeast covering 160 acres (Fig. 3).

Premier interpreted this to mean that hydrocarbons were still trapped and that the No. 1 Barr did not drain the entire accumulation. This makes sense considering the Barr well produced only 0.315 bcf but the original ASA covered 200 acres.

In 2003, Patterson Petroleum drilled this remnant ASA 500 ft south of the Landers dry hole and made a completion in the Lower EY Yegua sand at a rate of 1.5 MMcfd and 325 b/d of oil. Patterson's well confirmed Premier's interpretation of hydrocarbons still trapped as reflected by the remnant ASA. This discovery well, despite its proxim-

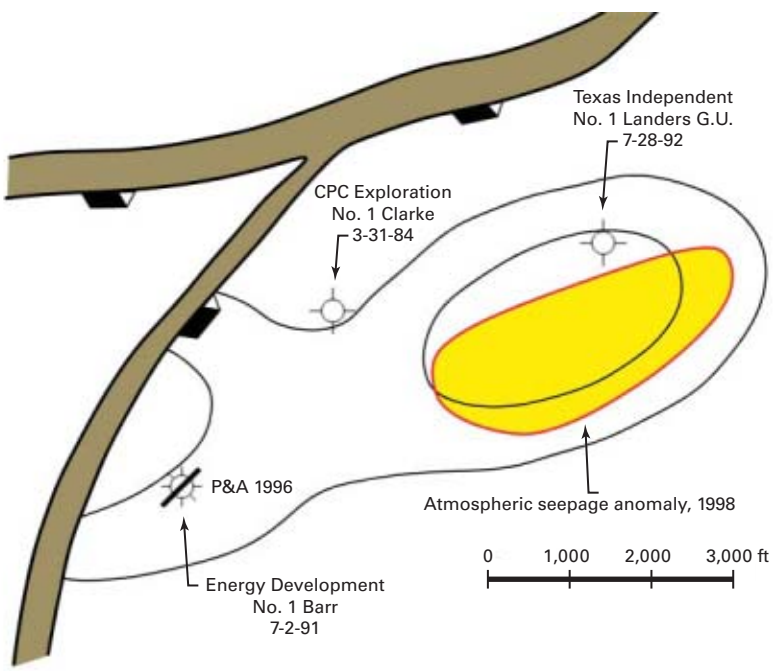
PICKETTS RIDGE ASA AND TOP YEGUA STRUCTURE, 1992

Fig. 2



PICKETTS RIDGE ASA AND TOP YEGUA STRUCTURE, 1998

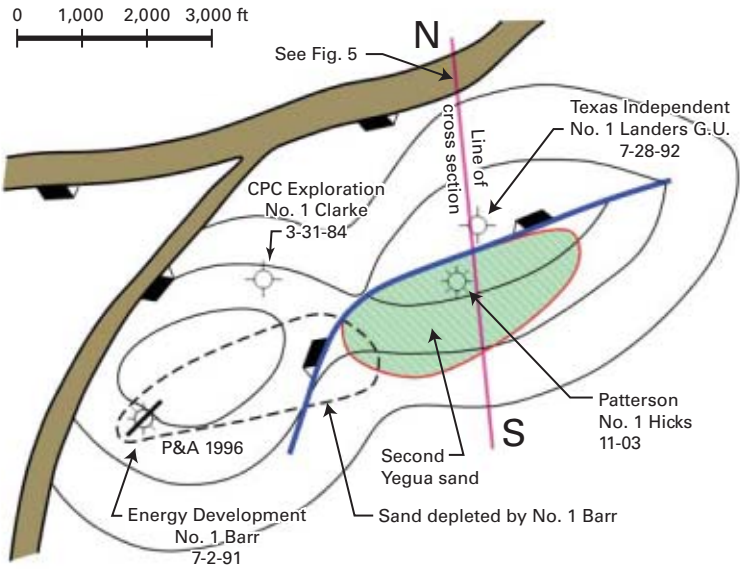
Fig. 3



Note: No. 1 Barr no longer producing

PREMIER E&P'S INTERPRETATION OF PICKETTS RIDGE, 2006

Fig. 4



Note: No. 1 Barr no longer producing

ity to the No. 1 Landers, had a much thicker and more productive sand package (Fig. 4).

It was now apparent that the ASA at Picketts Ridge was actually composed of three sands and two trap styles (Fig. 5). After the No. 1 Barr depleted the two shallower Yegua sands, the bottom sand became apparent in the 1998 seepage survey.

Several things can be gleaned from the drilling of the Picketts Ridge prospect. The presence of the ASA on the flank of what had been mapped as a Yegua structure was an indication that this was not purely a structural-high trap. Another component that was overlooked was the antithetic faults that were controlling the hydrocarbon trap.

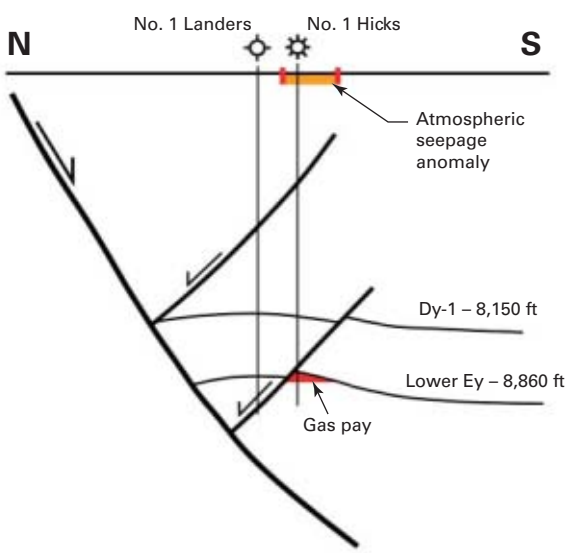
Multiple vertical traps

In the 1992 survey, Premier identified a 1,200-acre ASA that enclosed the Egypt/Bonus SE Yegua field (Fig. 6).

The obvious conclusion would have been that the ASA was associated with the Yegua production, but a clue something was amiss is that the productive area of the 9-year-old Yegua field was much smaller than the ASA.

CROSS SECTION FROM LANDERS TO HICKS, PICKETTS RIDGE

Fig. 5



Egypt/Bonus SE Yegua field had been discovered in 1983 and had an original pressure around 3,100 psi. At the time of the survey in 1992, the field pressure was down to about 600 psi, and the field had produced in excess of 12 bcf and 30,000 bbl of oil.

In the authors' experience, as fields produce and the pressures decline, the seepage that reaches the atmosphere is greatly reduced and may disappear. This decline in atmospheric seepage usually occurs in the first 3 years of production. By the time of the 1992 seepage survey, this field was 9 years old and the pressures had dropped by 75% but the atmospheric seepage signature was strong and covered a larger area than the Yegua wells (Fig. 6).

Based on Premier's experience with the Picketts Ridge anomaly, the Sand Ridge ASA should have been weak, almost absent, or broken into individual undrained areas if the Yegua accumulation was responsible for the ASA (Fig. 6).

Premier suspected a deeper productive zone was generating the strong ASA. This interpretation was confirmed in 1999 when the National Onshore No. 1 Schweinle was completed as a Wilcox discovery in the ASA at the location shown on Fig. 7. The well flowed at a rate of 10 MMcfd and 325 b/d of oil with a bottomhole pressure around 7,500 psi.

This well is now one of more than 25 wells that makes up Bonus Southwest Wilcox field, which fills the ASA unlike the Yegua production. Fig. 8 is a sketch from a seismic line trending NW-SE across the Sand Ridge ASA. This cross-section shows the anticlinal trap at the Yegua level and the fault closure trap at the Wilcox level. This stacking of reservoirs in the Yegua and Wilcox is characteristic of Wharton County fields.

Sand traps juxtaposed

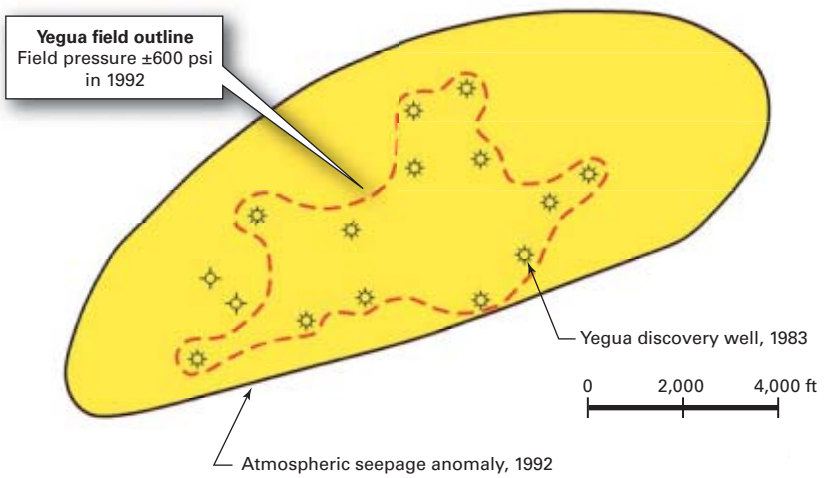
The Jones ASA mapped in 1992 covered 600 acres and was an isolated anomaly that was not on trend with other Wilcox or Yegua production (Fig. 9). It was an oval anomaly that was enigmatic without seismic to map the subsurface.

In 2004 Dynamic Energy drilled two wells in the Jones ASA. The wells were completed at two different depths in Yegua sands and had rates of 784 Mcfd and 6 b/d of condensate and 1.8 MMcfd and 46 b/d of condensate. The ASA appeared to indicate one trap but was reported to be two separate AVOs in the Yegua, which seems to be corroborated by the depths of the different perforated intervals (Fig. 9).

The ASA shape from well locations probably reflects two hydrocarbon traps that parallel the regional grain and are stratigraphic in nature. Contrast this with the Picketts Ridge ASA, where the traps are in line (Fig. 2).

SAND RIDGE ASA AND EGYPT/BONUS SE YEGUA FIELD, 1992

Fig. 6



The ASA survey identifies anomalies and places the explorationist in the immediate area of subsurface accumulation(s) but requires the interpretation of seismic data to define the trap(s) and their depth(s).

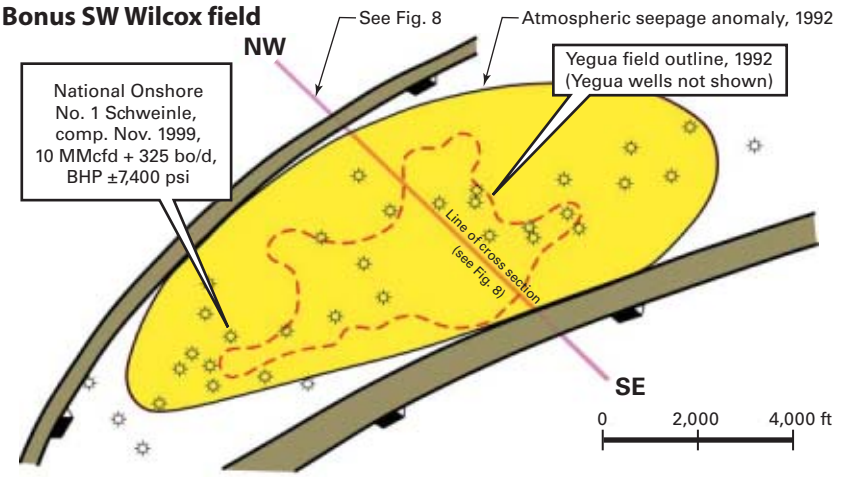
Track record

The airborne seepage surveys conducted by Premier in 1992 identified 21 significant ASAs in Wharton County.

Since the 1992 survey, seven of these have been drilled and are discoveries in

SAND RIDGE 1992 ASA AND WILCOX WELLS 2006

Fig. 7



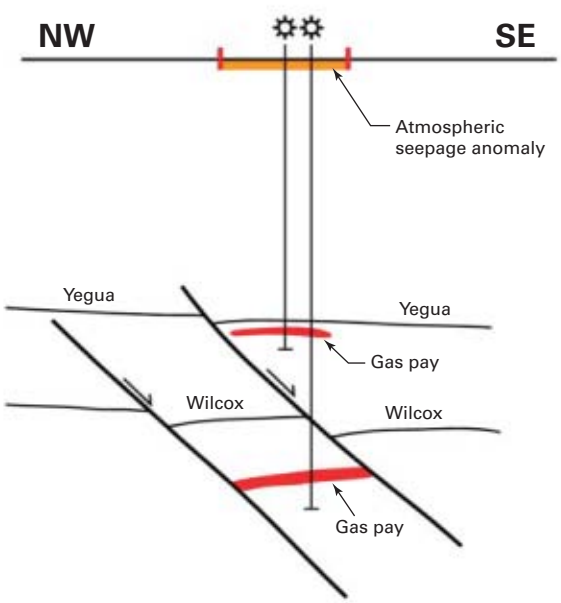
the Yegua or Wilcox sand section. We believe this confirms that ASAs reflect vertical seepage of gas from subsurface hydrocarbon traps to the surface and then to the atmosphere. This atmospheric seepage information defines the size, shape, and geological orientation of hydrocarbon accumulations and saves time and improves success rates.

Premier's airborne seepage work in Wharton County confirmed our postulation that an exploration program that begins with an atmospheric seepage survey can cut costs and immediately begin delineating drillable prospects when followed up with a solid geological and geophysical evaluation.

An airborne survey can assess 30,000 to 45,000 acres/day. As the Gulf Coast trend is now covered with extensive 3D surveys for sale, ASA mapping can be used to focus an explorationist on the specific areas to purchase 3D seismic data for prospect mapping.

SKETCH OF SEISMIC LINE ACROSS SAND RIDGE

Fig. 8



Plans

Premier continues to purchase seismic data to develop anomalies defined from the 1992 survey.

One current prospect will test a deeper structure under a Yegua, Nod mex field. The strong anomaly over a depleted Nod mex field indicates the high probability of a deeper trap.

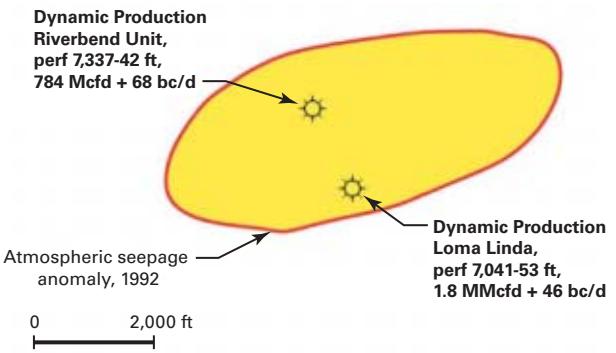
The other ASA to be drilled later this year is a 2,200-acre Wilcox trap. It was one of several ASAs larger than 2,000 acres Premier initially identified with the 1992 seepage survey. Other Wilcox ASAs in the immediate area have proven productive, and the similarity of this anomaly to them and Wilcox structure supports this as a Wilcox trap. A 3D survey was purchased and an up-to-the-coast fault develops a trap in the top 200 ft of the Wilcox, forming a three-way closure.

Acknowledgments

This exploration tool would have been dismissed for lack of science if not for two individuals, Dr. Merrill I. Skolnik, superintendent emeritus of the Radar Division of the Naval Research Laboratory, and Dr. Owen M. Phillips, Decker Professor Emeritus and Research Professor at John Hopkins University. Premier thanks Skolnik for having shared his knowledge and vast experience with radar and for coauthoring two papers with Bailey. Premier is indebted to Owen, a pioneer in geophysical fluid mechanics, which includes atmosphere turbulence, for his explanation of the radar returns. He provided the atmospheric model that explained the radar returns seen over hydrocarbon accumulations. ✦

JONES ASA AND YEGUA WELLS

Fig. 9



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James M. Grubb (jgrubb@premierE-P.com) started with Chevron and has worked for large independents such as Aminoil, Louisiana Land & Exploration, L.B. Simmons, and J.M. Huber Corp. With 34 years' experience in the Texas Gulf Coast, he has spent the last ten years mapping and understanding how seepage anomalies relate to subsurface geology and hydrocarbon traps in Wharton, Jackson, and Fort Bend counties. His geological expertise is Wilcox and Yegua stratigraphy and structure. (www.premierE-P.com)

Argentina

Gold Point Energy Corp., Vancouver, BC, took farmouts from APCO Argentina Inc., Tulsa, Okla., and Antrim Energy Inc., Calgary, on the Capricorn License (Yacimiento Norte 1/B Block) in northern Argentina.

GP Energy committed to pay 50% of a $1 million, 60 sq km 3D seismic program (completed in August 2006) and 50% of a $2 million, 2,300-m exploration well to earn a 25% working interest in the Martinez del Tineo Oeste Prospect.

The prospect, on the Cretaceous

Yacoraite oil trend, covers 54 sq km of the 4,008 sq km Capricorn License. The well is to be drilled in the first half of 2007.

After the prospect is drilled, GP Energy will have the option to earn a 25% interest in the entire block by funding 50% of the acquisition of as much as 300 sq km of 3D seismic data and 50% of the cost of two more exploration wells.

The farmout allows Antrim to focus on its Tierra del Fuego region.

Indonesia

A subsidiary of China's CNPC (Hong Kong) Ltd. completed the acquisition from Continental Energy Corp., Dallas, of 70% of Continental Energy's shareholding in its Continental-GeoPetro (Bengara-II) Ltd. subsidiary and the Bengara-II production sharing contract.

Continental Energy retained 18% of the 900,000-acre PSC in East Kalimantan.

To earn its 70% stake, CNPC will pay an $18.7 million earning obligation into an account jointly controlled by Continental. The money will fund exploratory drilling on the block.

CNPC will lend Continental development funds and carry Continental's development costs, if any, in the amount of $41.3 million above the earning obligation. CNPC will pay Continental a $3 million cash bonus contingent on the first commercial oil or gas discovery in the PSC.

The PSC is in the Tarakan basin, where 15 fields with 349 wells have produced more than 310 million bbl of oil and 97 bcf of gas.

Italy

A joint venture has approved the drilling of the Monte Grosso-2 exploration well on the Serra San Bernardo exploration permit in the southern Apennines and is negotiating with Eni SPA for a land rig.

Intergas Piu SRL, a subsidiary of Mediterranean Oil & Gas PLC, London, will operate the well and holds 20% interest in the permit. The other joint venture partners include Eni and Total.

The location is just north of Monte Alpi oil field, one of continental Europe's largest oil fields, producing 95,000 b/d. Eni operates Monte Alpi. The location is north of Tempa Rossa field, recently cleared for development by Total.

The well is to be drilled to 6,900 m in the third quarter of 2007 seeking oil in Mesozoic carbonates.

Russia

The LLC NK Recher-Komi joint venture reported a modest oil discovery on the North Irael block in the Pechora basin in Russia's Komi region.

The No. 61 exploration well recovered 59.3 bbl of clean oil and drilling mud and recorded virgin pressures of 182.5 atm on a drillstem test in the Devonian interval at 1,625 m subsea, 15 m high to prognosis, said Arawak Energy Corp., Anguilla, British West Indies. Arawak and Lundin Petroleum AB, Stockholm, each holds 50% interest in Recher-Komi.

Open hole logs indicated 5 m of net pay. The well was being cased for completion.

The block is producing 1,600 b/d of oil from five of the six wells that had been drilled prior to the June 2006 acquisition of Recher-Komi by Arawak's 50% owned subsidiary, RF Energy Investments Ltd. The block averaged 400 b/d at the time of acquisition.

Arawak looks toward a full 3D seismic survey of the block.

Newfoundland

Vulcan Minerals Inc., St. John's, Newf., plans to drill two land wells in the Bay St. George basin in western Newfoundland in October and November.

Flat Bay-5 is a downdip test of the Flat Bay oil accumulation, where the company expects to encounter improved reservoir character based on seismic and geological interpretation. It is 2 km east of the shallow Flat Bay-1 discovery well, which encountered 34° gravity, low sulfur oil.

Flat Bay-5 is projected to TD 900 m to evaluate the Ship Cove limestone and Fischells Brook conglomerate of Mississippian age.

North Dakota

Missouri Basin Well Service Inc., Belfield, ND, is moving in a rig to reenter the State 16-1H well in McKenzie County and drill two horizontal legs in Rival, the uppermost member of the Mission Canyon formation of the Mississippian Madison Group.

Rival had produced oil through the vertical wellbore since the initial completion earlier this year.

Basic Earth Science Systems Inc., Denver, said the reentry effort is to take 20 days and cost $350,000 to its 20% working interest. The well is on Basic's Banks prospect in the Williston basin.

Wyoming

Two wells are under way in Sublette County that target overpressured gas in multiple formations, including Cretaceous Hilliard shale, in the northern Green River basin.

Gasco Energy Corp., Denver, and Hunt Petroleum Corp., Dallas, plan to drill the Cottonwood Ranch 24-21, in 21-32n-111w, to 16,500 ft to test gas potential in the Lance, Mesaverde, Ericson, Rock Springs, and Hilliard shale formations. Gasco is operator with 25% working interest in the well, estimated to cost $8 million to drill and complete.

Gasco Energy, with 100% interest, is drilling toward projected TD of 14,400 ft at the Billy Canyon 2-11, in 11-31n-112w. It is to evaluate Lance, Mesaverde, Rock Springs, and Hilliard. It is eight miles north of 67 Draw field, recently spaced for production from the Mesaverde Group, including the Rock Springs and Ericson formations, and Baxter shale, equivalent to the Hilliard shale.

DRILLING MARKET FOCUS

New jack ups will soon hit the water

Nina M. Rach
Drilling Editor

Without accounting for likely attrition of older units, the world's supply of jack ups will expand more than 16% by 2009, adding 61 jack ups now under construction, in addition to 3 delivered earlier this year.

Nearly two-thirds (39) are being built in Southeast Asia, chiefly at Keppel FELS, Jurong Shipyard Pte. Ltd., and PPL Shipyard Pte. Ltd. in Singapore. Twelve jack ups are being built on the US Gulf coast, about 20% of the total. Yards in China and United Arab Emirates are each building 4 rigs, a yard in Indonesia is building 2, and India and Russia are each building 1 (Table 1).

Most of these newbuilds will come to market in 2007 (21 rigs) and 2008 (27 rigs).

Analysts have been concerned that an increasing number of rigs built on spec, without firm contracts, might flood the market and drive down day rates. However, given the robust demand for modern, efficient units, it is unlikely that there will be any softening of contract pricing in 2007-08. Many of the contractors have announced contracts over the last 6 months, while the jack ups are still in early stages of construction.

Some of the rigs are being sold by speculators to drilling contractors, such as A.P. Moeller-Maersk's recent $420-million purchase of two Baker Marine Pacific Class jack ups under construction at the Jurong shipyard for Petrojack ASA.

Matt Simmons, chairman of Simmons & Co. International, told attendees at the Canadian Offshore Resources Exhibition & Conference in Halifax on Oct. 4 that the international offshore rig fleet is too small, too old, and insufficient to drill the existing portfolio and meet future needs. He stressed continuing attrition of older units and a dearth of arctic-class rigs, and noted that two jack ups will be leaving the Canadian Maritimes in the next 6 months.

It seems likely that the newbuilds will have only a small impact on the market and that will probably not appear until first or second-quarter 2008, in the middle of the surge.

Lately, many jack ups have been moving to the Middle East for contracts. Rigzone reports that about 18% of the worldwide jack up fleet is working in the Persian Gulf (73 rigs) and about 3% (11 rigs) is working in the Red Sea.

Saudi Aramco announced in early July that it had 101 rigs working, a new record, including 16 jack ups. By

Rowan's third Tarzan-class 225C jack up, the Hank Boswell, was christened at Sabine Pass, Tex., in late September (Fig. 1; photo by Charlie Wharton, Rowan Cos. Inc.).

JACK-UP RIGS UNDER CONSTRUCTION, 2006-09

Table 1

Rig name	Owner	Design	Shipyard, country	Delivery date	Cost, $ million
				2006 (4)	
Gulf 004	Gulf Drilling International	KFELS Mod V B	Keppel FELS (KFELS), Singapore	September	153
Hank Boswell	Rowan Cos. Inc.	LeTourneau Tarzan class	LeTourneau, USA	October	153
Deep Driller 003	DDI Holding AS	KFELS Mod V Super B Class	KFELS, Singapore	December	153
WilCraft	Awilco	KFELS Mod V B	KFELS, Singapore	December	153
				2007 (21)	
Soehanah	Apexindo	Baker Marine Pacific Class 375	PPL Shipyard Pte Ltd., Singapore	January	134
PV Drilling 001	PetroVietnam	KFELS Mod V B	KFELS, Singapore	March	144
Petrojack 001	A.P. Møller	Baker Marine Pacific Class 375	Jurong Shipyard Pte Ltd., Singapore	March	175
ENSCO 108	ENSCO International Inc.	KFELS Mod V B Bigfoot	KFELS, Singapore	March	134
Offshore Courageous	Scorpion Offshore	Letourneau Super 116	Keppel AmFELS, USA	April	160
WilSuperior	Awilco	Baker Marine Pacific Class 375	PPL Shipyard, Singapore	May	134
Panuco	Perforadora Central	Letourneau Super 116E	LeTourneau, USA	May	131
Deep Driller 004	DDI Holding AS	Baker Marine Pacific Class 375	PPL Shipyard, Singapore	June	144
Deep Driller 005	DDI Holding AS	KFELS Mod V Super B Class	KFELS, Singapore	June	140
West Prospero	SeaDrill Invest II	KFELS Mod V B	KFELS, Singapore	June	163
Arcticheskaya	Gazprom	CDB Corrall 6500/10-30	Zvezdochka Shipyard, Russia	July	130
Noble Roger Lewis	Noble Corp.	Friede & Goldman (F&G) JU-2000E	Dalian Shipbuilding Industry Co., China	August	129
West Atlas	Stella	KFELS Mod V B	KFELS, Singapore	September	147
JP Bussell	Rowan	LeTourneau Tarzan class	Signal International, USA	October	126
Offshore Defender	Scorpion Offshore	LeTourneau Super 116	Keppel AmFELS, USA	October	120
West Triton	Caleb	Baker Marine Pacific Class 375	PPL Shipyard, Singapore	October	133
Maersk JU Tbn001	A.P. Møller	Marine Structure Consultants (MSC) CJ50-X100MC	KFELS, Singapore	November	145
Thule Energy	Thule Drilling	F&G Super M2	QGM, UAE	November	140
Wilforce	Awilco	Baker Marine Pacific Class 375	PPL Shipyard, Singapore	December	140
COSL 942	China Oilfield Services Ltd.	F&G JU-2000E	Dalian Shipbuilding, China	December	150
Gulf 005	Gulf Drilling International	KFELS Mod V B	KFELS, Singapore	December	150
				2008 (27)	
Petrojack 002	Petrojack	Baker Marine Pacific Class 375	Jurong Shipyard, Singapore	January	171
Ocean Scepter	Diamond Offshore Drilling Inc.	KFELS Mod V Super B Class	Keppel AmFELS, USA	February	117
Ocean Shield	Diamond Offshore	KFELS Mod V Super B Class	KFELS, Singapore	February	100
Noble Hans Deul	Noble	F&G JU-2000E	Dalian Shipbuilding, China	February	182
Hakuryu 010	Japan Drilling	Baker Marine Pacific Class 375	PPL Shipyard, Singapore	February	-
Thule Force	Thule Drilling	F&G Super M2	QGM, UAE	March	90
Offshore Resolute	Scorpion Offshore	LeTourneau Super 116	Keppel AmFELS, USA	March	130
WilBoss	Awilco	KFELS Mod V B	KFELS, Singapore	April	180
Maersk JU TBN2	A.P. Møller	MSC CJ50-X100MC	KFELS, Singapore	May	130
Aban JU TBN1	Aban Offshore	Baker Marine Pacific Class 375	PPL Shipyard, Singapore	June	184
Wilseeker	Awilco	Baker Marine Pacific Class 375	PPL Shipyard, Singapore	June	180
Mosvold JU TBN1	Mosvold Drilling Ltd.	F&G Super M2	Maritime Industrial Services (MIS), UAE	June	143
Rowan JU TBN1	Rowan	LeTourneau Class 240-C	LeTourneau, USA	June	143
West Ariel	SeaDrill Ltd	KFELS Mod V B	KFELS, Singapore	June	153
Offshore Vigilant	Scorpion Offshore	LeTourneau Super 116	Keppel AmFELS, USA	June	156
Petrojack 003	A.P. Møller	Baker Marine Pacific Class 375	Jurong Shipyard, Singapore	July	190
Deep Driller 006	DDI Holding AS	KFELS Mod V Super B Class	KFELS, Singapore	August	133
Deep Driller 007	DDI Holding	Baker Marine Pacific Class 375	PPL Shipyard, Singapore	September	140
Standard JU TBN1	Standard Drilling	MSC CJ-46-X100D	Labroy Shipbuilding and Engineering, Indonesia	September	110
Atwood Aurora	Atwood	LeTourneau Super 116E	Keppel AmFELS, USA	September	100
Mosvold JU T2	Mosvold Drilling	F&G Super M2	MIS, UAE	October	125
Maersk JU TBN3	A.P. Møller	MSC CJ50-X100MC	KFELS, Singapore	November	165
Great Eastern JU TBN 2	Great Eastern	—	Bharati Shipyard, India	November	165
Offshore Intrepid	Scorpion Offshore	LeTourneau Super 116	Keppel AmFELS, USA	November	148
Jindal JU Tbn1	Discovery Hydrocarbons	KFELS Mod V B	KFELS, Singapore	December	156
Petrojack 004	JackInvest I Pte	Baker Marine Pacific Class 375	Jurong Shipyard, Singapore	December	143
Jindal JU Tbn2	Jindal Pipes	KFELS Mod V B	KFELS, Singapore	December	144
				2009 (8)	
Rowan JU Tbn2	Rowan	LeTourneau Class 240-C	LeTourneau, USA	February	148
Deep Driller 008	DDI Holding AS	KFELS Mod V Super B Class	KFELS, Singapore	March	121
Mercator JU Tbn1	Mercator Lines	KFELS Mod V B	KFELS, Singapore	March	132
Noble Scott Marks	Noble	F&G JU-2000E	Dalian Shipbuilding, China	March	146
Standard JU Tbn2	Standard Drilling	MSC CJ-46-X100D	Labroy Shipbuilding and Engineering, Indonesia	April	146
Maersk JU Tbn004	A.P. Møller	MSC CJ50-X100MC	KFELS, Singapore	May	129
Wilstrike	Awilco	KFELS Mod V B	KFELS, Singapore	May	126
Great Eastern JU Tbn 1	Great Eastern	KFELS Mod V B	KFELS, Singapore	October	126
				Total funds committed, $7.344 billion	

Source: ODS-Petrodata

the end of the year, Fahad A. Al-Moosa, vice-president of drilling and workover said, "We expect to have 121 rigs in the field."

Designs

Independent leg cantilever (ILC) rigs comprise about 74% of the jack up fleet, followed by independent leg slot (ILS) with about 7%, and mat cantilever (MC) and mat slot (MS) rigs, which together comprise about 18% of the fleet (mostly found in the Gulf of Mexico).

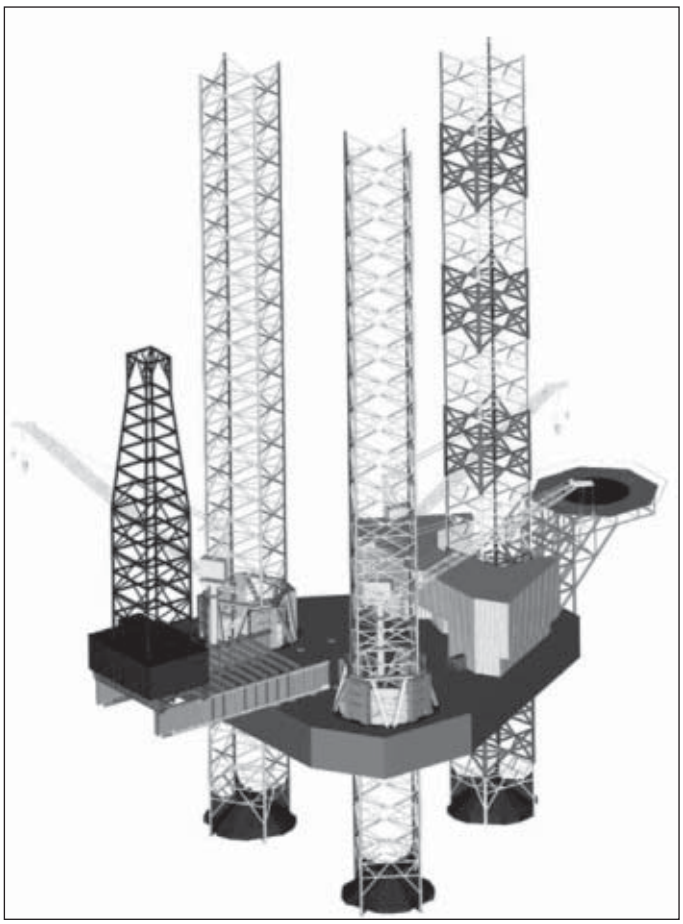
The Keppel FELS Modified V B and Super B-Class jack ups are the most popular designs, accounting for nearly one third of the current newbuilds (20).

Baker Marine's Pacific Class 375 is also among the most popular designs chosen by drilling contractors and operators, with 13 under construction.

Several LeTourneau designs are being built on the Gulf Coast at Keppel AmFELS in Texas and LeTourneau's yard in Mississippi. Six of the Super 116 and 116E designs, two 240C, and two Tarzan Class jack ups are under way.

Houston-based Friede & Goldman have four JU-2000E jack ups and four Super M2 jack ups under construction in China and the UAE.

Drillers ordered six jack ups following two designs by Marine Structure Consultants BV: the CJ50 (four rigs for Maersk under construction at KFELS in Singapore) and CJ46 (two rigs for Standard Drilling ASA at Labroy's new yard in Indonesia).



Rowan is building two jack-up drilling rigs at its facility in Vicksburg, Miss., using the new LeTourneau 240C design, to be delivered in mid-2008 and early 2009, at $165 million each (Fig. 2; image from Rowan Cos. Inc.).

SCORE

Utilization of jack ups remains high, driving day rates and profitability to rosy levels for fleet owners.

GlobalSantaFe Corp.'s worldwide SCORE, or Summary of Current Offshore Rig Economics, increased 3.6% to 128.1 in August 2006 from the previous month's SCORE of 123.6. The SCORE for jack ups increased 5.8% month-to-month, nearly three times the improvement for semisubmersibles (2.1%). The jack up SCORE has increased 47.4% in the past year, and 98.6% in the past 5 years.

Regionally, Southeast Asia and the Gulf of Mexico led demand for offshore rigs; the SCOREs were up 7% and 6.1% respectively, month-to-month, reflecting increasing profitability in those markets.

Average rates for jack ups working in August were just under $90,000/day. About half of the jack up fleet is contracted through 2007, at rates averaging $132,000/day.

USA, Rowan

Rowan Cos. Inc. and LeTourneau Inc. Marine Group are building four jack ups in Vicksburg, Miss., and Sabine Pass, Tex., including two Tarzan-class 225C rigs and two new LeTourneau 240C rigs.

Tarzan rigs can drill to 35,000 ft. The first two, Scooter Yeargain and Bob Keller, were completed in 2004 and 2005. The Scooter Yeargain began working at $80,000/day, but the Bob Keller received an advance, single-well contract of $95,000/day.

The third Tarzan rig, Hank Boswell, was christened in Sabine Pass, Tex., on Sept. 23.

The fourth Tarzan rig, JP Bussell, will be delivered in 2007.

Rowan announced it would build two rigs in the new 240C design in December 2005, at $165 million each. The new rigs are designed for high-pressure, high-temperature (HPHT) drilling, and with legs up to 535-ft long, they will be able to work in water as deep as 400 ft.

Compared to the 116C, Rowan said the 240C has more deck space, greater drilling capacity (2 million lb hookload), further cantilever reach (as much as 85 ft), and more accommodation space (for 120 personnel). The 116C has been the "workhorse" jack up for the offshore drilling industry for 25 years, and now there are several robust designs on the market to replace it.

Keppel Corp.'s Keppel AmFELS yard in Brownsville, Tex., is building:

- Five LeTourneau Super 116 jack ups for Scorpion Offshore Ltd., to be delivered in 2007 (Offshore Courageous, Offshore Defender) and 2008 (Offshore Resolute, Offshore Vigilant, Offshore Intrepid).
- A KFELS modified V Super B Class jack up for Diamond Offshore Drilling Inc., the Ocean Scepter, to be delivered in February 2008, for $117 million.
- A Super 116E jack up for Atwood Oceanic, the Atwood Aurora, to be delivered in September 2008, for $100 million.

Singapore

There are 23 jack ups currently under construction at Keppel FELS Ltd.

yard; 9 at SembCorp Marine's PPL Shipyard Pte. Ltd.; and 4 at Jurong Shipyard Pte. Ltd. in Singapore (Table 1).

Keppel FELS is building KFELS modified V B, V Super B Class, V B Bigfoot, and MSC CJ-50 design jack ups.

Customers include Qatar's Gulf Drilling International Ltd., DDI Holding AS, Awilco Offshore ASA, PetroVietNam, ENSCO Inc., SeaDrill Invest, Stella Shipping International Inc., A.P. Moeller-Maersk, Diamond OffshoreDrilling Inc., SeaDrill Ltd., Discovery Hydrocarbons Pvt. Ltd. (a subsidiary of Jindal Group), Jindal Pipes Ltd., Mercator Lines Ltd., and India's Great Eastern Shipping Co. Ltd. Group.

PPL Shipyard is building Baker Marine Pacific Class 375 jack ups, and customers include: PT Apexindo Pratama Duta, Awilco Offshore, DDI Holding, Caleb Maritime SA (a subsidiary of SeaDrill Ltd.), Japan Drilling Co. Ltd., and Aban Offshore.

Jurong Shipyard is also building Baker Marine 375 jack ups, for A.P. Moeller, Petrojack, and JackInvest 1 Pte.

In July A.P. Moeller-Maersk announced it bought two jack ups under construction for Petrojack at Jurong Shipyard in Singapore. The PetroJack I and PetroJack III Baker Pacific Class 375 rigs sold for $420 million. The rigs cost Petrojack about $238 million; so the sale netted them a cool $182 million, a 76% profit margin.

Indonesia

Labroy Offshore Ltd., a subsidiary of Labroy Marine Pte Ltd., has developed a new 40-hectare rig construction yard at Batam, Indonesia, south of Singapore. In March, Tan Boy Tee, chairman and managing director of Labroy, said the yard has the capacity to accommodate construction of "a minimum of six jack ups." Labroy has received orders to build its first four jack ups (www.labroy.com.sg).

In March, the company announced it would build two jack up drilling rigs for Norway's Standard Drilling ASA for S$475 million ($292 million). The contract covers platform and leg construction, and proprietary hardware components, such as the skidding, fixation, and jacking systems.

The MSC CJ-46-X 100D design jack ups will be capable of drilling to a total depth of 30,000 ft in water to 350 ft deep. The rigs will be delivered to Standard Drilling in fourth-quarter 2008 and second-quarter 2009.

In June, Labroy announced that it has an $18-million contract for two more jack up platforms from a Dutch company. Labroy will build the platforms, but the customer will supply the jacking system, legs, machinery, and equipment. These two jack ups are scheduled for delivery in 2007.

Tan said, "We are confident of more orders from the jack up segment."

China

Noble Corp. has three new jack ups under construction by China Shipbuilding at the Dalian shipyard in China. All three are Friede & Goldman JU-2000E design and capable of working in water as deep as 400 ft and drilling to 30,000 ft. Derricks, drawworks (4,600 hp), mud pumps (three 2,200 hp), and rotary tables (49.5 in.) are all from National Oilwell.

These new heavy-duty, harsh-environment (HDHE) jack ups will be delivered in 2007 (Noble Roger Lewis), 2008 (Nobel Hans Deul), and 2009 (Noble Scott Marks).

The Noble Scott Marks has a construction cost of about $190 million. Under a 2-year contract with Aberdeen-based Venture Production PLC announced June 27, the rig will be available for Venture's 2009-11 drilling campaign in the southern and central North Sea.

Mike Wagstaff, chief executive of Venture Production, said the contract "will bring the first dedicated newly built drilling rig into the UKCS for many years" and indicates the company's "significant long-term commitment to the North Sea."

China Oilfield Services Ltd. also has a JU-2000 jack up under construction at the Dalian New Shipyard. The COSL 942 jack up will be delivered in 2008.

Persian Gulf

Four jack up drilling rigs are under construction at two new yards in the emirate of Sharjah, UAE. All four are based on the Friede & Goldman (F&G) Super M2 rig design. The Super M2 is an updated version of F&G's L 780 Mod II jack up rig, of which there are more than 30 operating worldwide.

The Super M2 has a modular hull with wrap-around living quarters, enhanced leg design, and an extended-reach cantilever. It is designed to work in 300 ft water depth, drilling down to 30,000 ft.

Matthew Hemker is the F&G project manager.[1]

The rigs are being built for Thule Drilling ASA and for Mosvold Drilling Ltd.

Thule's rigs (Thule Energy and Thule Force) are being built at the QGM Group LLC's rig construction yard in the Hamriyah Free Zone, UAE, to be delivered in 2007 and 2008.

Mosvold's rigs are being built at Maritime Industrial Services Co. Ltd. Inc. (MIS) yard and will both be delivered in 2008. They will feature 3,000-hp drawworks and three 2,200-hp mud pumps.

The American Bureau of Shipping announced in July that it would class all four of the rigs. Viro Valian, ABS project manager for the Mosvold drilling rigs being built at MIS, told OGJ that work began on the rigs in August 2006.

ABS said that it had about 76% market share of the worldwide drilling rig fleet.[1]

New yards

New yard capacity is opening up in Indonesia, China, and South Africa, and may be a future possibility for Venezuela.

In addition to Labroy Offshore's new capacity at Batam, Keppel is planning to build a fabrication yard on the southeast coast of Bintan Island, Indonesia. It will operate under the name Bintan

Offshore Fabricators Pte. Ltd.[2]

A subsidiary of Germany's MAN Group, Ferrostaal, is planning to build a rig fabrication yard at Saldanha Bay and a rig repair facility in Cape Town. Ferrostaal Chairman Matthias Mitscherlich announced the plans at the Oil Africa 2006 conference in Cape Town in March. The company will spend R200 million (about $27 million) on both yards.[3]

Aveng's Grinaker-LTA Ltd., South Africa's largest construction company, will be the main rig builder and South African engineering giant DCD-Dorbyl (Pty.) Ltd. will work at both facilities, which should be complete by first-half 2007.

In addition to the new yards in Indonesia, South Africa, and China, new yards may be under construction soon in Venezuela, according to a June 12 BNAmericas story. Armando Valladares, director of PDV Marina Transport, a subsidiary of Venezuela's PdVSA, said that the country could either expand Venezuela's state-owned shipyard, Dianca, or create a new shipyard with China or Iran.

Top operators

Based on jack up expenditures 2001-05, the top 10 operators are Chevron Corp., Total SA, Petróleos Mexicanos (Pemex), India's Oil and Natural Gas Corp., ExxonMobil Corp., BP PLC, Royal Dutch/Shell, Maersk Olie og Gas AS, Apache Corp., and Belgium's Petrobel NV. These 10 companies spent $8.7 billion on jack up rig expenses over the 5-year period, compared to $10.7 billion spent by all other operators. ✦

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Best practices limit fluid effects on CRA tubulars

Proper procedures in the design of clear brine completion fluids combined with proper handling of the fluids can mitigate annular environmentally assisted cracking (AEAC) in wells completed with corrosion-resistant alloys (CRAs), according to TETRA Technologies Inc.

TETRA says that it and JFE Steel Corp. spent more than 3 years researching corrosive factors associated with AEAC.

Based on this research, the company has written software programs and guidelines for selecting the fluid and determining the best practices for ensuring proper quality controls during transportation and handling of the completion fluids from the plant to the wellbore.

AEAC research program

The companies conducted more than 3,700 tests simulating actual conditions found in a well. The tests examined various combinations of highly stressed CRAs with numerous clear-brine-fluid blends in a broad range of fluid densities and temperatures (100-400° F.).

The testing program also looked at the effect of corrosion inhibitor packages and common contaminants such as those that might leak through faulty connections or packers or be introduced by careless transportation or handling practices.

From this data, TETRA developed a software program called MatchWell Fluid Compatibility Selector to assist operators in choosing the safest and most cost effective fluids for the specific metallurgy in a well.

Field contamination

To minimize potential for AEAC events, TETRA says it is equally important to retain the requisite chemical parameters of the clear brine fluid from the time it leaves the manufacturing facility until the fluid enters the well.

Its research improved the understanding of the relationship between contaminating substances in the fluid and AEAC events. The testing showed many opportunities for contamination and chemical compromise that could cause the fluid to deviate from the original specifications set by the operator (Fig. 1).

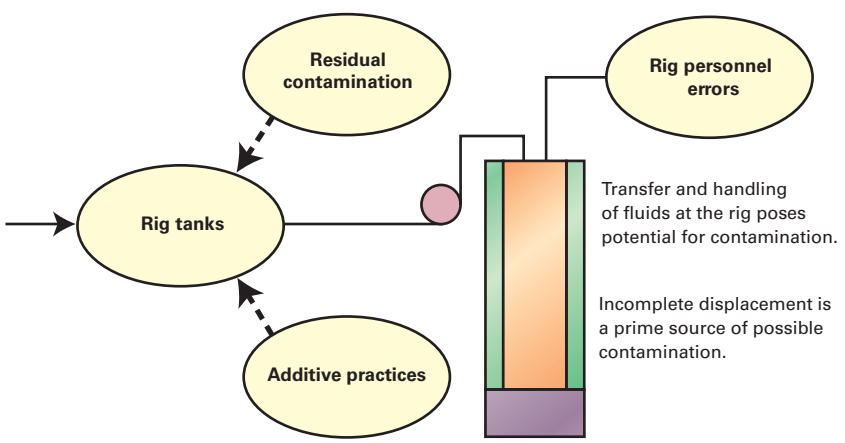
In fact, Tetra says that field contamination could contribute as much to AEAC failures as selecting a fluid that is incompatible with the tubing.

Transportation, handling

Quality control during transportation and throughout the handling of the fluid in the field is important, and TETRA says the practices that transporters, resellers, and end-users follow often are inconsistent and can compromise the fluid chemistry. The company's testing showed that even small amounts of contaminants can

FLUID HANDLING

Fig. 1



Source: TETRA Technologies Inc.

Upstream Projects

Import Projects

Storage Projects

Transportation

How Strong is Your Natural Gas Value Chain?

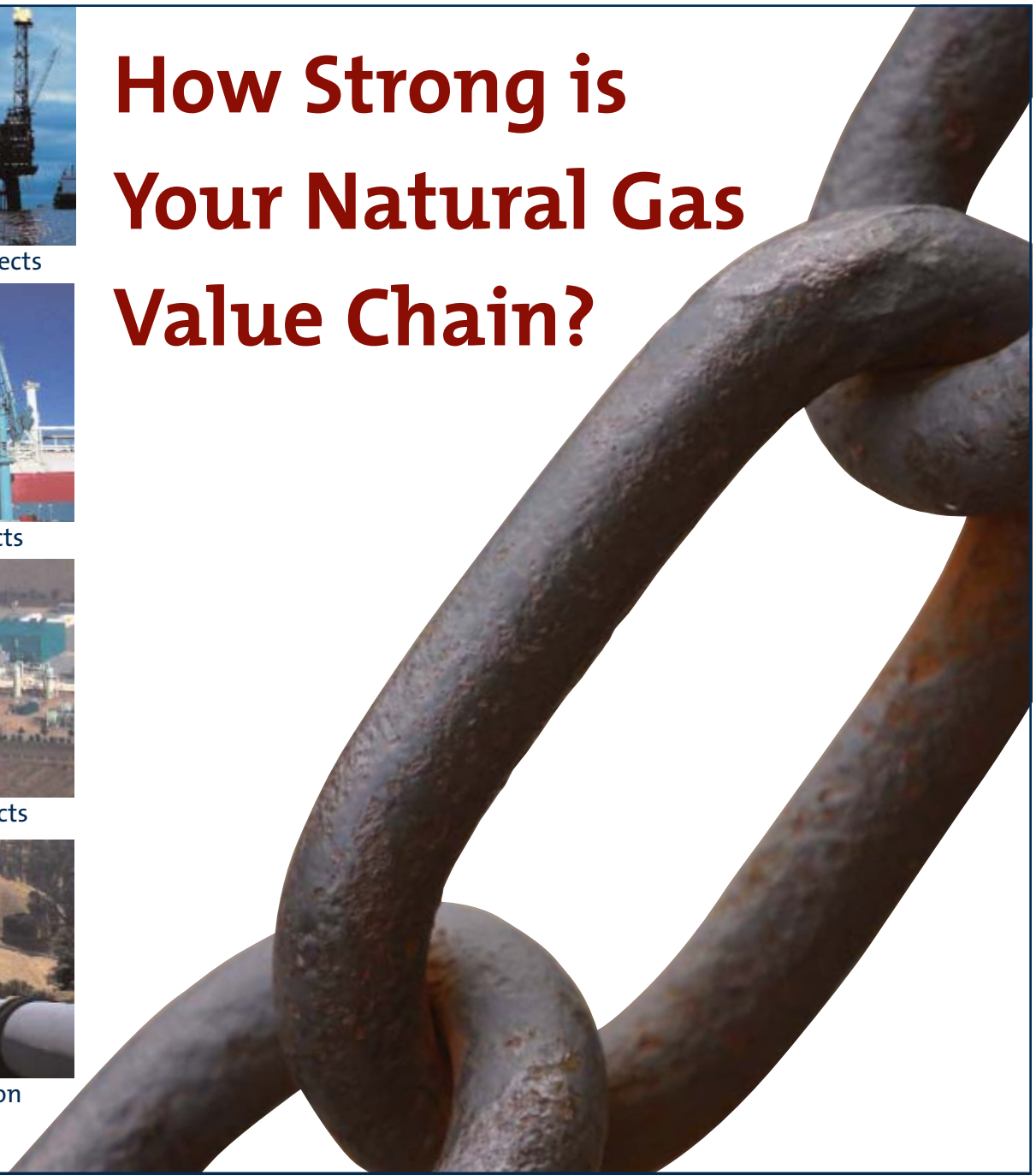


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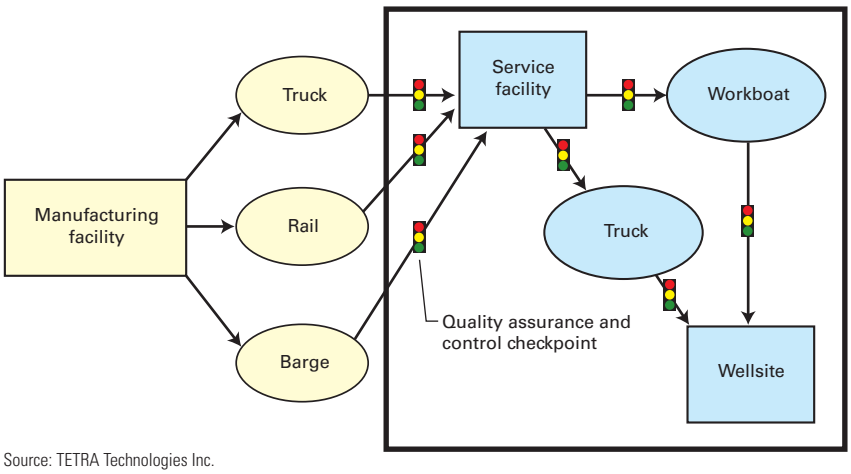
Fig. 2



Source: TETRA Technologies Inc.

contribute to initiating AEAC.

For this reason, TETRA developed a set of best practice guidelines and procedures to help fluid suppliers, transporting contractors, and operators to ensure proper quality control of the fluids. It says maintaining active quality assurance and control throughout the transportation cycle ensures that fluids pumped into a well will have the same specifications as ordered or designed.

The company determined that the chemical effectiveness of the fluid can be compromised when fluids are conveyed in lines or placed in trucks, workboats, or rig tanks that previously held a fluid incompatible with the metallurgy used in the well completion.

TETRA, therefore, designed a best practices program that provides specific guidelines and procedures for inspecting and cleaning trucks, tanks, lines, and vessels to ascertain that the chemical integrity of the clear brine fluids has been maintained.

For example, because the use of thiocyanate-containing corrosion inhibitors is common in fluids used in non-CRA applications, the company says it is reasonable to assume that any vessel or storage tank may be exposed routinely to a reclaimed fluid containing the thiocyanate ion or other contaminants. As a consequence, small but significant amounts of residual thiocyanate or related sulfur compounds can be inadvertently introduced into a clear brine fluid.

These contaminants can be damaging even for wells with lower pressures and temperatures than would normally be associated with high pressure, high-temperature (HPHT) applications, the company says.

It adds that thiocyanate and other contaminants pose a potential risk to tubing failure, but such contamination is avoidable through proper inspection and cleaning when necessary.

TETRA's procedures specify maximum limits of allowable thiocyanate and sulfur and other potentially contaminating substances, below which the properties and the performance of the fluid will not be compromised for the intended CRA application.

Its new best-practices program ensures that chemical integrity of the fluid is maintained throughout the transportation cycle, TETRA says.

TETRA has developed a method for sampling the fluid prior to each transfer for quality-assurance analysis (Fig. 2).

It will file the results of these analyses to provide a quality-control trail, documenting the proper maintenance of the fluid during each step of the fluid's trip from the plant to the well.

Fluid at the well

Tetra says improper handling of the fluid at the well is equally important as handling during the transportation cycle. It, therefore, includes in its best-practices program a guide for rig personnel that covers proper procedures to receive, store, and handle all fluids so as to minimize AEAC.

The procedures address inspection and cleaning of rig tanks and lines and involve additional sampling and analysis by TETRA technicians to attest to the chemical integrity of the clear brine fluid.

The program can alert rig personnel to the potential for contamination through otherwise normal rig procedures and preclude other potential problems.

For example, Tetra says a common practice of some operating and drilling companies is to use corrosion inhibitors in brine fluids as a means of protecting storage tanks from corrosion. In some cases, the practice results in contaminating the fluids and possibly causing stress corrosion cracking in the well.

The program also provides safe procedures to deal with an incomplete drilling mud displacement, which Tetra says is a common occurrence in many well completions.

It warns that the effects of an incomplete displacement can be particularly pernicious in wells drilled with oil-based mud.

TETRA says that with the muds having entrained additives, residual mud in the hole becomes a potential source of sulfur that can contribute to sulfide stress cracking, a form of AEAC.

Final steps

TETRA's program also recommends taking a final sample from the well annulus before putting it on production.

If this fluid is found to be contaminated by materials such as thiocyanate, iron, or other detrimental substances, the operator can take remedial steps to restore the fluid to a proper chemical balance to minimize potential future AEAC problems during production. ✦

PROCESS CONTROL—Conclusion

Ethylene plant uses best practices to improve controller performance

David Shook
Matrikon Inc.
Edmonton

Nova Chemicals Corp. used a holistic, best-practices approach to help sustain and improve the performance of control system assets at its Joffre, Alta., ethylene plant.

This article, the second of two, will discuss a case study that describes the maintenance of a multivariable predictive control (MPC) controller, quickly identifying problems in the MPC itself, and in the regulatory control and instrumentation layers.

The first part (OGJ, Oct. 9, 2006, p. 52) discussed MPC systems, causes of poor performance, and the best-practices approach.

NOVA Chemicals case study

NOVA Chemicals Corp. operates three ethylene plants and two polyethylene plants at Joffre, Alta. This case study describes a DMCplus controller that was commissioned at this plant.

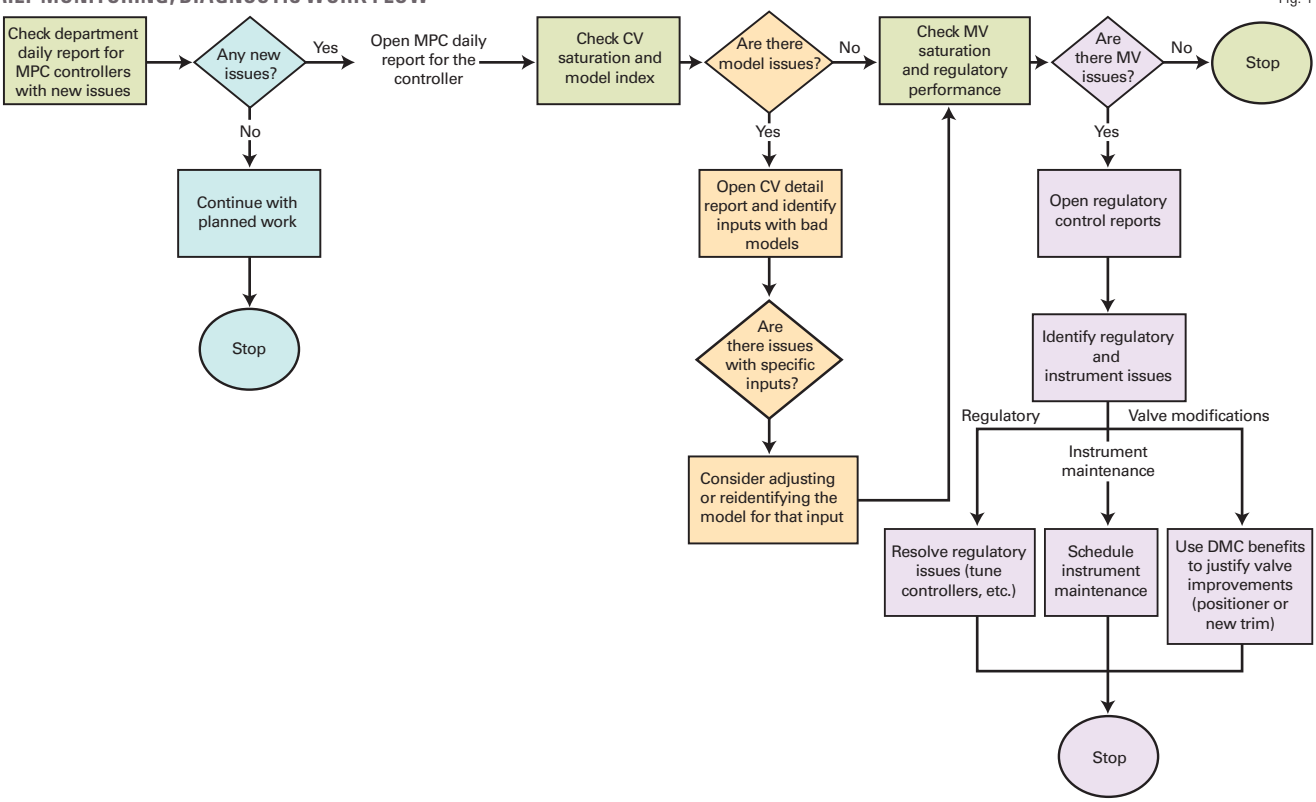
The process separates two feed streams into three components—a light hydrocarbon and two considerably heavier hydrocarbons. The middle component is removed in a side draw, which is then further purified in a side column. The application covers the feed drum, where the two feed streams are mixed, the main column, and the side column.

Software solution

Nova installed a control asset-management solution that provides a methodology and performance monitoring that aim to improve performance while simultaneously lowering the long-term cost of sustaining the performance of control assets in the whole organization.

DAILY MONITORING, DIAGNOSTIC WORK FLOW

Fig. 1



The solution, ProcessDoctor Online, monitors applications and reports on performance and diagnostic measures. More importantly, it integrates with plant maintenance business processes, providing all interested parties with information needed for specific job functions in the applications' maintenance work processes.

It contains these best-practice functions:

- Benefit documentation.
- A holistic control asset-monitoring and reporting platform.
- Targeted information.
- Flexible deployment.
- Compatibility with multiple controller technologies.

It allows plants with MPC applications to document their benefits and automatically report the benefits to senior managers. It provides continuous monitoring of MPC and regulatory controls and instrumentation, can be deployed on site, at corporate headquarters, or deployed as a service, and is compatible with several different commercial MPC packages.

It also supports several monitoring and diagnostic work flows. Monthly reviews by managers, daily or weekly monitoring by engineers, and long-term assessments by engineers to find subtle patterns of behavior are all supported. This article will discuss the daily monitoring and diagnostic work flow shown in Fig. 1.

The work flow is intended to facilitate the standard investigations that engineers must perform in order to maintain MPC applications. It focuses on the most common maintenance problems with MPC controllers, and integrates the investigation of MPC, regulatory control and instrumentation.

Nova application

Fig. 2 shows an excerpt of the monthly report for this controller. It has only been in service occasionally and when active its performance has been weak. The service factor has only been 100% for 2 days, and on 5 other days it was only turned on for about a third of the day, probably during the day shift while engineers were present.

The controller relative performance index (RPI) is a composite index that compares the speed of the controller to its original design performance. When the RPI is 1, then the controller is performing as designed. If the RPI is less than 1, then the controller is slow.

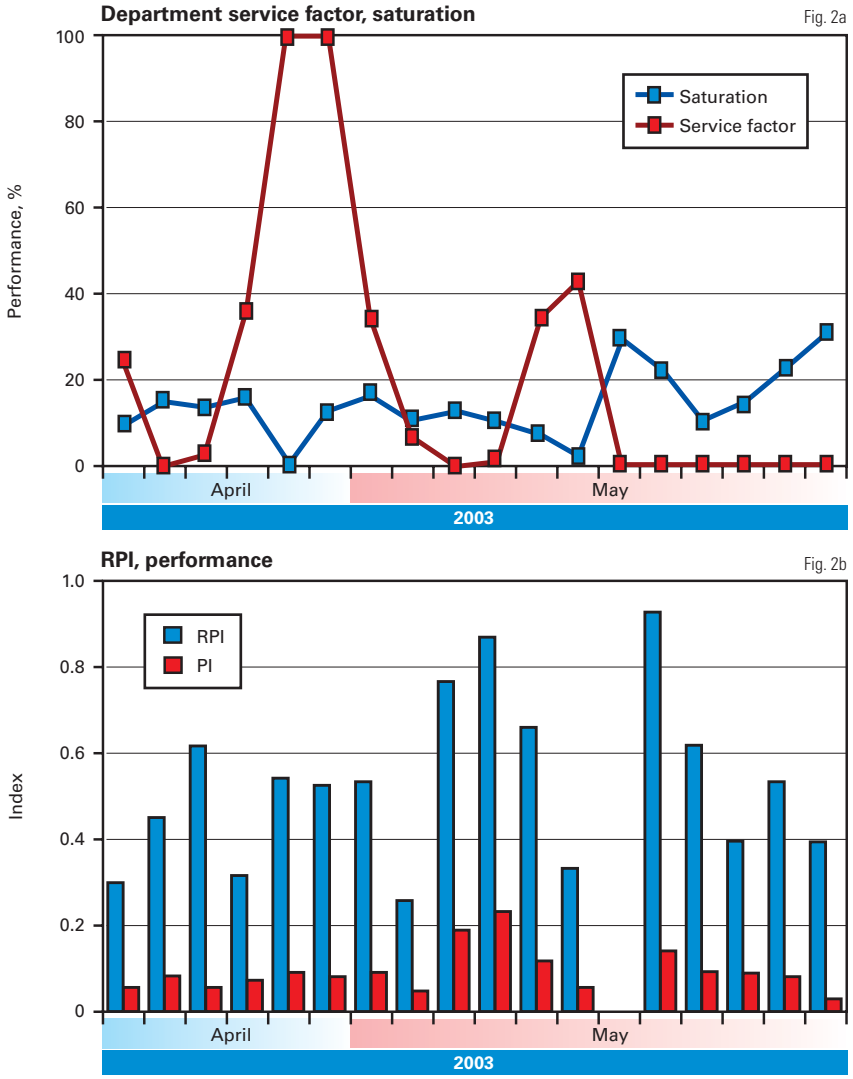
RPI is described in detail in Shah et al.[1] and Huang and Shah[2] and applications of RPI to industrial controllers are described in Gao, et al.[3]

This controller is quite slow; RPI varies somewhat from day to day but averages 0.5 when the controller is in service. Clearly there are some issues with this controller.

Table 1 shows another excerpt from the department summary. It shows the monthly average values for the specific controller. Saturation, at 14%, is an insignificant issue for the controller as a whole, although it may be an issue for

Monthly summary

Fig. 2



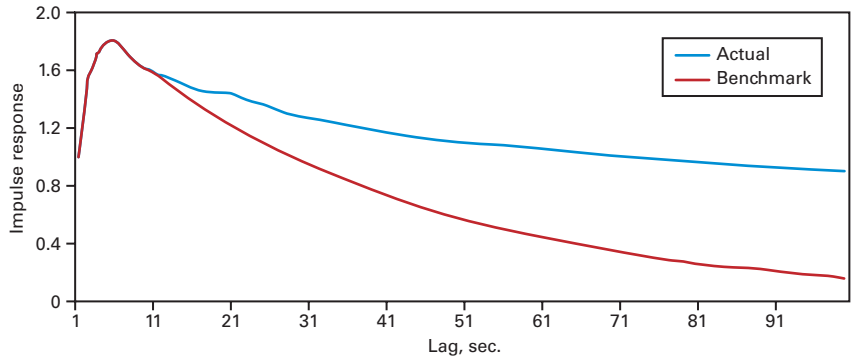
Controller average results

Table 1

Controller	SMDMC
Performance index	0.9
RPI	0.50
Saturation, %	14.19
Model index	0.59
Optimization, %	0.00
Service factor, %	21.01
Cost	0.00
Weight	1.00

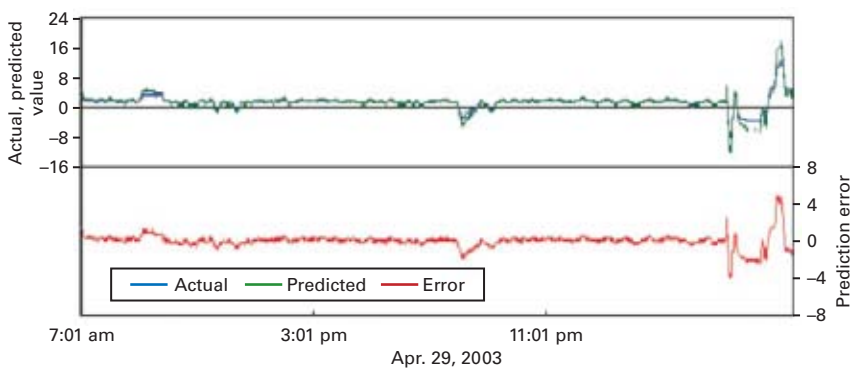
IMPULSE RESPONSE

Fig. 3



CV MODEL ANALYSIS

Fig. 4



CV DETAILS FOR DMC ANALYSIS

Table 2

Tag name	Service factor	PI	Constraint violation, %	Average	Standard deviation	Model index
SMAFEZ111.PV	—	0.56	52.99	1.17	0.28	0.86
SMTC169.PV	100	0.45	52.29	–1.27	10.68	0.95
SMTC045.PV	100	0.52	38.19	–2.25	2.20	0.92
SMAFCZ111.PV	—	0.02	30.56	1.02	0.01	0.99
SMTC080F.PV	100	0.31	15.56	1.79	0.47	0.82
RBASMY367.PV	—	0.11	9.10	–2.21	1.09	0.86
SMLC125.PV	100	0.66	6.18	14.26	15.52	0.90
SMPC183.OP	100	0.02	5.90	13.28	15.57	1.00
SMTDC044.PV	100	0.22	5.76	1.37	1.72	0.48
SMFC101.OP	100	0.22	3.75	–8.47	6.04	0.80
SMTD080F.PV	—	0.11	2.22	1.19	0.52	–0.97
SMFC058.PV	100	0.30	0.28	1.83	6.41	0.91
STPC112.CV	—	0.54	0.21	4.87	3.32	0.92
SMFC082.OP	100	0.43	—	0.50	2.35	0.91
SMLC047A.PV	100	0.28	—	–0.26	2.29	0.98
SMPD169.PV	100	0.08	—	19.00	—	1.00
SMRIL2F.PV	—	—	—	10.00	—	—
SMTC036.OP	100	0.21	—	–2.03	7.66	0.97
SMTC044.OP	100	0.36	—	2.34	6.83	0.93
SMTYC169.OP	100	0.15	—	3.48	5.22	0.91

individual controlled variables (CVs) or manipulated variables (MVs).

The model index shows some problems. Model index is a measure of the accuracy of the models in the DMC controller. Values close to 1 indicate good models and values below 0.5 indicate significant problems with the models. The average model index of 0.59 for this controller indicates that there are some models with significant problems.

Daily analysis

Fig. 3 shows the impulse response graph for the last day the DMC controller was active. It shows that the controller is slow relative to the desired, or benchmark, performance. Disturbances, models, poor regulatory control, or constraint issues may cause this.

Low values for CV constraint violation (14.47%) and MV saturation (12.53%) indicate that the controller is not significantly affected by the active constraint set, but the model index of 0.62 indicates some problems with the models. The next step is to review the CV details in the same report (Table 2) to investigate the low model index.

Details for the CVs show that most of the models are excellent, except for three CVs: SMTDC044, SMTD080F, and SMRIL2F. Of these, two have been disabled (service factor is equal to 0). The third, SMTDC044, must be investigated.

The detail report for SMTDC044.PV shows that the prediction error does rise and fall with the value of the CV itself. This is particularly clear at the very end of the data set. Analysis of the contributions to prediction error shows that a feed-forward variable, SMTI042.PV, is most likely causing the prediction error. The model between SMTI042.PV and SMTDC044.PV is the most likely cause for the poor predictions (Fig. 4).

Further analysis of the average model index during the month indicates that models are excellent, with a few exceptions. SMTD080F and SMTDC044 have consistently poor predictions, and SMTC080F is marginal, with an average model index of 0.66.

For all of these CVs, the manipulated variable SMFCRFLX.SP is usually among the MVs that correlate well with prediction error. While there are other MVs that correlate with the prediction error, SMFCRFLX, the column reflux, is likely to be a dominant variable. The models corresponding to this MV are therefore suspicious and should be investigated to see if they need to be reestimated.

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MV analysis

Although there are a few bad models, the main problem with this controller is not prediction. Most of the models are excellent. Analysis of the MVs does illustrate a problem (Table 3).

MV DETAILS FOR DMC ANALYSIS Table 3

Tag name	Service factor	RPI	Saturation, %	Average	Standard deviation
SMTC044.SP	100	—	0.07	0.29	0.66
SMFC047.SP	100	0.52	—	0.19	0.55
SMFCRFLX.SP	100	—	—	2.81	5.85
SMLC047A.OP	100	0.38	—	1.20	2.30
SMPC169.SP	100	0.51	—	3.49	3.12
SMPC183.SP	—	0.18	—	–8.18	9.55
SMRCSTRP.SP	100	—	—	0.33	0.09
SMTC036.SP	100	1.72	—	–1.25	0.51
SMTCC080.SP	100	0.41	—	4.57	1.01

The MV analysis shows that the regulatory control is at fault. Of the controllers analyzed that were in service that particular day, only one, SMTC036, has an acceptable RPI value at 0.72. All of the other regulatory controllers show poor performance. Again, RPI should be close to 1. Values less than 0.5 may indicate problems with regulatory control.

Analysis of SMFC047, the column feed flow controller, shows problems with a sticking valve, as can be seen in a regulatory control report excerpt. The RPI is 0.5, and the valve stiction of 0.31 indicates that the controller output must change by 0.31% before the valve begins to move.

The actual settling time of the controller is 7 min, even though the desired settling time is 1.5 min. In other words, it takes this controller 7 min to remove the effects of disturbances. This is extremely slow.

The valve is sticking 0.3%, which is not a large amount, but is responsible for almost 30% of the control error. For this particular controller, there may be a tuning issue, but the dominant issue is the sticking valve.

The recommendation is that a positioner be added to the valve. The positioner will improve the performance of this flow controller and, therefore, the DMCplus application. The cost of the positioner can be justified by the benefits of the DMCplus controller.

Case study conclusions

This controller still has significant issues with the models corresponding to the column reflux and SMTDC044.PV, and some regulatory control and instrumentation issues. There are currently no significant constraint issues.

The best-practice integration of MPC, regulatory control, and instrumentation analysis in a single system supports the actual monitoring, diagnostic, and troubleshooting process followed by engineers responsible for commissioning and maintaining the application.

Acknowledgment

We acknowledge the support and cooperation of Nova Chemicals Corp. for participating in the case study and permitting the publication of their data. ✦

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Field use supports move to suspension-based DRA

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Suspension-based drag-reducing agents (DRAs) have proven to be an alternative to gel-based technology for ConocoPhillips Pipeline Co.'s US crude pipelines. This article examines data from one of Conoco's pipelines in addressing the relative advantages of suspension-based (vs. gel-based) DRA technology.

When added to pipelines or conduits, DRAs typically perform one of two major tasks:

- Reduction of energy consumption where the same target throughput is accomplished with less pumping power.
- Increased throughput of the fluid in the pipeline by use of the same pumping power that was used before addition of the DRA.

Fig. 1 illustrates the effect of treating a continuous, single-phase fluid in a conduit. The pressure drop of a fluid in laminar flow increases linearly as flow rate increases, but in turbulent flow, a more significant increase in pressure drop appears as flow rate increases.

Adding a DRA, however, can minimize the pressure drop of the same fluid in a conduit at a given flow rate, allowing it to be pumped with less energy.

Drag reduction

In a pipeline, a fluid moves in one of two types of flow: laminar or turbulent. Laminar flow exists with no deviation in velocity in the direction of flow, and turbulent flow exists with local deviations in velocity relative to the bulk flow of the fluid.

Crosscurrents and eddies cause the velocity deviation in turbulent flow. This causes the fluid molecules to move randomly, wasting a significant portion of the applied energy used to move the fluid.[1]

Four major factors govern the flow regime of a fluid in a pipeline: pipe diameter, fluid density, fluid viscosity, and the average velocity of the fluid. The transition from laminar to turbulent flow is governed by the dimensionless group called the Reynolds number (N_{Re}). The following equation calculates the Reynolds number:

$$N_{Re} = DV\rho/\mu$$

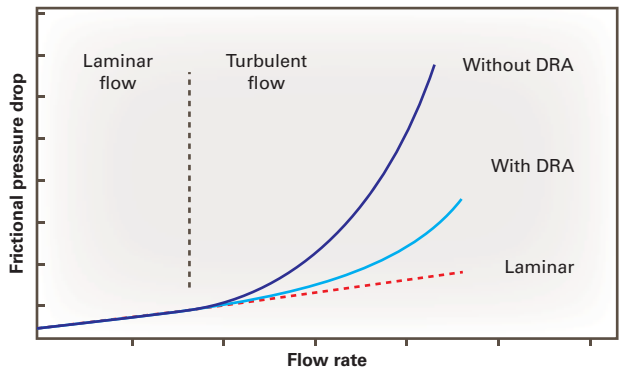
where: D = pipe diameter; V = average velocity of the fluid; ρ = density of the fluid; and μ = viscosity of the fluid.

DRAs are only useful if a fluid is in turbulent flow. A turbulent state typically corresponds to Reynolds numbers greater than 4000. The greater the Reynolds number, the higher the levels of potential drag-reduction performance.

The Reynolds number is directly proportional to diameter, velocity, and density, but indirectly proportional to fluid viscosity.

CONTINUOUS, SINGLE-PHASE FLUID

Fig. 1



DRA EFFICIENCY

Fig. 2

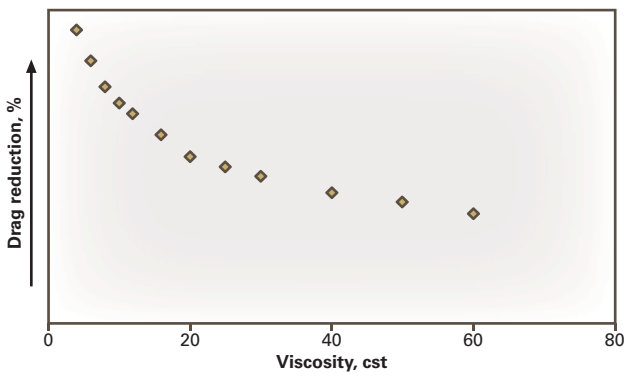
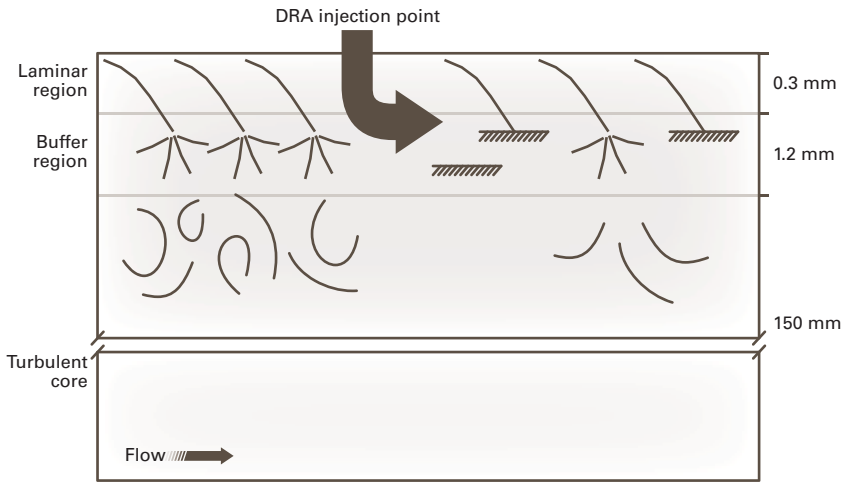


Fig. 2 illustrates the effect of fluid viscosity on drag-reduction performance. Percent DR (drag-reduction performance) decreases as fluid viscosity increases. Low-viscosity fluids have a much higher potential for drag reduction than highly viscous fluids, due to the asymptotic relation between drag performance and viscosity.

Fig. 3, not drawn to scale, shows a cross section of the near-wall region of a pipeline in turbulent flow. The three flow regions shown are the laminar region, the buffer region, and the turbulent core. The turbulent core accounts for the majority of the pipe's area, and it is here that eddy currents and random motions of turbulent flow occur. Nearest to the pipeline wall is the laminar region where the fluid moves laterally. The region between the laminar region and turbulent core is the buffer region.

CROSS-SECTION, 12-IN. PIPELINE

Fig. 3



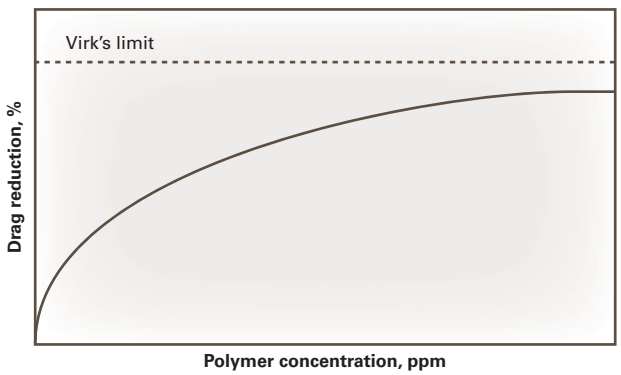
Portions of fluid in the laminar region can streak into the buffer region, creating vortices and oscillation. Ultimately the streak becomes unstable, creating turbulent flow. Injecting DRA allows ultra-high molecular weight polymers to absorb the energy of the streaks associated with turbulent flow, rendering a more stable flow where the applied energy necessary to move the fluid is not wasted.

The concentration of polymer in the pipeline affects its ability to disrupt turbulent bursts from cross-currents and eddies, but ultimately, an upper boundary for DRA performance in a pipeline exists with respect to polymer concentration.

Fig. 4 illustrates the concentration dependence of drag-reducer performance. The overall efficiency (the slope of the curve) of the drag reducer decreases as polymer concentration increases. Drag-reduction performance also approaches a limit near the theoretical limit of the pipeline, commonly referred to as Virk's limit.[2,3]

DRA PERFORMANCE

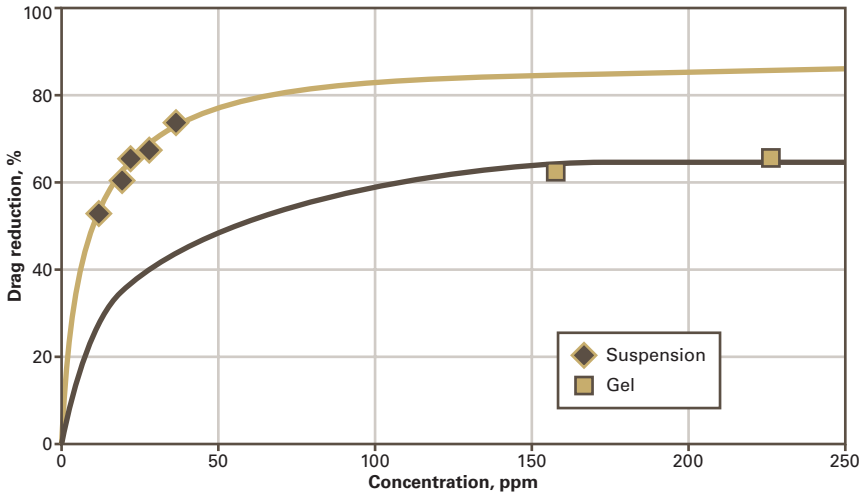
Fig. 4



Virk's limit ultimately suggests a ceiling value for drag-reduction performance for a given additive in a pipeline. Once the limit for the pipeline is reached, additional DRA does not effectively redirect the remaining energy produced by turbulent flow.

WICHITA FALLS, TEX.-TO-BRAY, OKLA., 12-IN. CRUDE LINE

Fig. 5



Polymer composition

Other factors governing drag-reduction performance in a pipeline include polymer molecular weight and its solubility in the flowing fluid. Dissolution of the active polymer into a continuous medium, not the coating of the pipeline wall, achieves drag reduction. Given this, certain molecular and physical properties are desirable for DRA polymers. For example, the monomer units used in the production of the polymer must promote polymer-solvent interaction and minimize polymer-polymer interaction, allowing for the rapid dissolution in the continuous medium necessary in achieving DRA performance.

The polymer composition also must be shear-stable to avoid becoming part of the pipeline's turbulent flow.

Polymer molecular weight (MW) also plays a large role in governing the final performance of a DRA. Once the polymer is dissolved, drag-reduction performance in the pipeline is proportional to MW. Various methods suggest that the MW of effective DRA polymers is in excess of 10 million, but measurable drag reduction can be observed at 1-5 million.

Gel technology

The active ingredient in flow-improver products meeting these criteria is ultrahigh-molecular-weight poly alpha olefins. The composition of these polymers ranges between, but is not limited to, homopolymers and copolymers consisting of C4-C14 olefins. Combining the olefin monomer with a petroleum distillate achieves synthesis.[1] A catalyst used at temperatures ranging from 20-50° F. facilitates polymerization. The final product is a viscous gel, containing 4-10 wt % active polymer.

Suspension technology

Preparing suspension-based DRAs follows a significantly different pattern than preparing gel-based DRAs. The initial manufacturing synthesizes the poly alpha olefins via a bulk polymerization technique, introducing a monomer and catalyst mixture into a reactor with polymerization occurring at 45-85° F. The resulting product is a solid polymer.

A separate production step pulverizes the polymer into a powder, which is then suspended in a nonsolvent liquid medium. The final product consists of an aqueous or nonaqueous based suspension, containing 20-30 wt % active polymer.

Suspension vs. gel

Using a suspension-based product instead of a gel product affords many advantages. Suspension products include higher percentages of active polymers than do gel products. The use of bulk polymerization also allows the synthesis of a higher-performance polymer.

Fig. 5 illustrates performance data obtained from the Wichita Falls, Tex.-to-Bray, Okla., segment of the Wichita Falls to Oklahoma City 12-in. crude oil pipeline operated by ConocoPhillips Pipe Line Co. Lower concentrations of the suspension product (LP 100 Flow Improver) afford higher performance (% DR) than the gel product (CDR 203).

Concentration levels of 19 ppm and 22 ppm (vol) of the suspension product result in percent DR levels of 61 and 66, respectively, whereas concentration levels of 158 ppm and 227 ppm (vol) are required for similar percent DR levels for the gel product. The theoretical maximum percent DR for this pipeline is much higher for a suspension-based product than for the gel product.

Bulk polymerization produces higher molecular weight polymer than solution-polymerized polymer; a very important factor for pipelines with a polymer-loading limitation such as refined gasoline and diesel products pipelines. The injection of a bulk-polymerized suspension product allows increased throughput at the same concentration levels.

Suspension products are also easier to handle than gel products. For example, as gel is injected into a pipeline, proper dissolution requires that it form a stable strand, necessitating specialized injection nozzles that can reduce the number and limit the location of injection sites.

On the other hand, once injected, suspension products do not need to form a strand, allowing them to be injected through any available pipeline port. Such flexibility increases the versatility of a suspension product by allowing it to be injected both upstream and downstream of the mainline pump.

The viscosity of the gel-based DRA is approximately 100,000 cp and the viscosity of suspension product is approximately 300 cp. The high viscosity of the gel product requires the use

of a pressurized delivery vessel, while suspension products can be stored in nonpressurized product totes and fed via gravity systems. ✦

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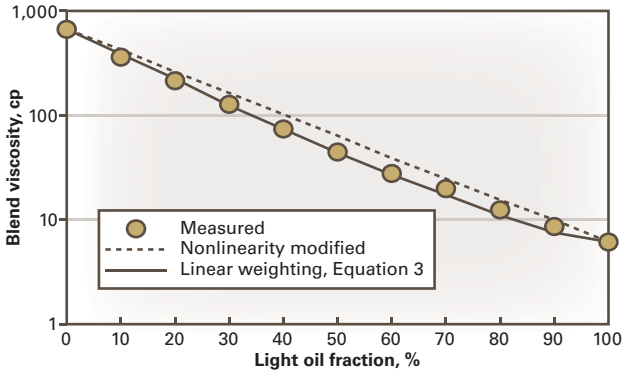
NONLINEARITY MODIFICATION

Fig. 1



Study evaluates viscosity prediction of crude blends

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Jinjun Zhang
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Qiang Zhang
China University of Petroleum
Beijing

Transporting crude oil blends via pipeline requires careful estimation of their viscosities.

Crude transportation often requires that different crude oils be blended and transported through the same pipeline. Intentionally diluting heavy crudes by adding less viscous oil also increases the efficiency of pipelining heavy oils. Solvents injected into the reservoir for well cleaning, stimulation, fracturing and, less frequently, miscible displacement may also remain in the crude during shipment.

A mixture's viscosity as a function of composition is extremely complex.[1] Theoretical considerations have offered little help in explaining these complexities. Attempts such as McAllister's to derive a generalized expression for viscosities of all mixtures resulted in equations with many undetermined constants.[2,3] No method allows a reliable prior prediction of these constants. These methods, therefore, are purely descriptive.

The predictive methods for viscosity of liquid mixtures include semitheoretical and empirical models. Most semitheoretical models for petroleum fractions, which have a theoretical framework but parameters determined from experimental data, are based on either the corresponding-states approach or the modified Chapman-Enskog theory. Monnery and Mehrotra have reviewed such semitheoretical models.[4,5]

This article reviews the empirical viscosity models for crude oil blends, and the validity and accuracy of 14 models suited for practical engineering, using 1,577 sets of viscosity data from 22 groups of crude oil blends (Table 1).

MODEL EVALUATION CRUDE-OIL BLENDS

Table 1

Group	Number of components	Component sources
1-6	2	Northwest China
7	3	Northwest China
8	4	Northwest China
9	5	Northwest China
10	6	Northwest China
11	7	Northwest China
12	8	Northwest China
13	9	Northwest China
14	2	East China
15	2	Northwest China
16	2	Northwest China
17-20	2	East China and Middle East*
21-22	3	East China and Middle East*

*Data compiled for current study.

Mathematic models

A wide variety of liquid-mixture viscosity prediction formulas use the simple-mixing-rule equation based on calculations of the weighted average of the component viscosities (Equation 1, see accompanying box). This approach is very straightforward and requires no experimental viscosity determination of crude oil blends.

The complex nature of crude oils, however, renders such formulas ineffective and has led to numerous efforts to develop viscosity models capable of adequately predicting the viscosity of crude oil blends. Most simple viscosity-mixing formulas do not involve any viscous interaction term and can be expressed by Equation 2.

Literature suggests many forms of the viscosity function, $f(\mu)$.[6-10] Choosing $f(\mu) = \lg\mu$ transforms Equation 2 into the Arrhenius model (Equation 3).[6]

Viscosity function $f(\mu)$ may also serve as the cube root equation of viscosity, as in the Kendall-Monroe model (Equation 4),[7] the reciprocal viscosity[6,8] (Equation 5), double-log term[9] (Equation 6), and the more complex Cragoe model (Equation 7).[10]

The viscosity functions, however, often do not obey the linear weighting rule described in Equations 3-7, necessitating further modifications to nonlinearity. Fig. 1 illustrates this deviation for

EQUATIONS

$$\mu_m = \sum_{i=1}^{n} x_i \mu_i \quad (1)$$

where μ denotes viscosity, x may be the volume, or mass (weight), or mole fraction of components; the subscript m means the mixture, and the subscript i means the ith component in the mixture.

$$f(\mu_m) = \sum_{i=1}^{n} x_i f(\mu_i) \quad (2)$$

$$\lg\mu_m = \sum_{i=1}^{n} x_i \cdot \lg\mu_i \quad (\text{lg is short for 'logarithm'}) \quad (3)$$

$$\mu_m^{1/3} = \sum_{i=1}^{n} x_i \cdot \mu_i^{1/3} \quad (4)$$

$$\mu_m^{-1} = \sum_{i=1}^{n} x_i \cdot \mu_i^{-1} \quad (5)$$

$$\lg\lg\mu_m = \sum_{i=1}^{n} x_i \cdot \lg\lg\mu_i \quad (6)$$

$$\begin{cases} \mu_m = 5 \times 10^{-4} \exp(1{,}000\ln 20/F_m) \\ \text{where } F_m = \sum_{i=1}^{n} x_i \cdot F_i \\ \text{and} \quad F_i = (1{,}000\ln 20)/[1n\mu_i - \ln(5 \times 10^{-4})] \end{cases} \quad (7)$$

$$\ln\mu_m = \left(\frac{\alpha V_1}{\alpha V_1 + V_2}\right)\ln\mu_1 + \left(1 - \frac{\alpha V_1}{\alpha V_1 + V_2}\right)\ln\mu_2 \quad (8)$$

where V is the volume fraction of component oil and α is an empirical constant having values between 0 and 1; the subscript 1represents the heavy oil, while subscript 2 means the solvent.

$$\alpha = \frac{17.04(\rho_1 - \rho_2)^{0.5237}\rho_1^{3.2745}\rho_2^{1.6316}}{\ln(\mu_1/\mu_2)} \quad (9)$$

where ρ is the density.

$$\alpha = 0.35242695 \times x_S^{-0.71154} \quad (10)$$

where x_S is the mole fraction of solvent in the mixture.

$$\ln\mu_m = x_1 \ln\mu_1 + x_2 \ln\mu_2 + 2x_1x_2G \quad (11)$$

where G is an empirical parameter.

$$\ln\mu_m = \sum_{i=1}^{n} x_i \cdot \ln\mu_i \pm (\ln\mu)^E \quad (12)$$

where the excess function $(\ln\mu)^E$ was defined as Eq. 13 for ternary component mixtures.

$$(\ln\mu)^E = a_{12}x_1x_2 + a_{13}x_1x_3 + a_{23}x_2x_3 + a_{123}x_1x_2x_3 \quad (13)$$

$$\ln\nu_m = \sum_{i=1}^{n} W_i \ln\nu - 4.976 \times 10^{-3} W_1W_2(\Delta\text{API})^2 \quad (14)$$

where ν is the kinematic viscosity; W is the weight fraction; ΔAPI is the difference between API gravities of two components.

$$\lg(\mu_m + 0.7) = \sum_{i=1}^{n}[x_i(M_i/\overline{M})^{0.5}]\lg(\mu_i + 0.7) \quad (15)$$

where x is the mole fraction; M is the molar mass, and $\overline{M}$ is the mean molar mass of bitumen, so the term $x_i(M_i/\overline{M})^{0.5}$ is actually the geometric mean of mass and mole fractions.

$$f(\mu_m) = \sum_{i=1}^{n} x_i f(\mu_i) + 2\sum_{j=1}^{n-1}\sum_{k=j+1}^{n} x_jx_kC_{jk} \quad (16)$$

where C_{jk} (with $C_{ij} = C_{kk} = 0$ and $C_{jk} \equiv C_{kj}$) is a binary interaction parameter.

$$\lg(\mu_m + 0.8) = \sum_{i=1}^{n}[x_i(M_i/\overline{M})^{0.5}]\lg(\mu_i + 0.8) + 2\sum_{j=1}^{n-1}\sum_{k=j+1}^{n} x_jx_k(M_jM_k/\overline{M}^2)^{0.5}C_{jk} \quad (17)$$

$$C_{jk} = 2[2f(\mu_{jk}) - f(\mu_j) - f(\mu_k)] \quad (18)$$

where μ_{jk} is the viscosity of the binary crude oil mixture with equal fraction (1:1) of the jth and kth components.

$$\lg\mu_m = \sum_{i=1}^{n} x_i \cdot \lg\mu_i + \sum_{j=1}^{n-1}\sum_{k=j+1}^{n} C_{jk} \cdot x_j \cdot x_k \quad (19)$$

$$\lg\lg\mu_m = \sum_{i=1}^{n} x_i \cdot \lg\lg\mu_i + \sum_{j=1}^{n-1}\sum_{k=j+1}^{n} C_{jk} \cdot x_j \cdot x_k \quad (20)$$

$$\begin{cases} \mu_m = 5 \times 10^{-4} \exp(1{,}000\ln 20/F_m) \\ \text{where } F_m = \sum_{i=1}^{n} x_i \cdot F_i + \sum_{j=1}^{n-1}\sum_{k=j+1}^{n} C_{jk} \cdot x_j \cdot x_k \\ \text{and} \quad F_i = (1{,}000\ln 20)/[1n\mu_i - \ln(5 \times 10^{-4})] \end{cases} \quad (21)$$

$$B_{jk} = [\log(100x_j)/\log(100x_k)]^{\text{sgn}(C_{jk})} \quad (\mu_k < \mu_j) \quad (22)$$

where B_{jk} is fraction modification parameter.

$$\lg\mu_m = \sum_{i=1}^{n} x_i \cdot \lg\mu_i + \sum_{j=1}^{n-1}\sum_{k=j+1}^{n} C_{jk} \cdot B_{jk} \cdot x_j \cdot x_k \quad (23)$$

$$\lg\mu_m = \sum_{i=1}^{n} x_i \cdot \lg\mu_i + \sum_{j=1}^{n-1}\sum_{k=j+1}^{n} C_{jk} \cdot \frac{1}{B_{jk}} \cdot x_j \cdot x_k \quad (24)$$

$$\lg\lg\mu_m = \sum_{i=1}^{n} x_i \cdot \lg\lg\mu_i + \sum_{j=1}^{n-1}\sum_{k=j+1}^{n} C_{jk} \cdot B_{jk} \cdot x_j \cdot x_k \quad (25)$$

$$\lg\lg\mu_m = \sum_{i=1}^{n} x_i \cdot \lg\lg\mu_i + \sum_{j=1}^{n-1}\sum_{k=j+1}^{n} C_{jk} \cdot \frac{1}{B_{jk}} \cdot x_j \cdot x_k \quad (26)$$

$$\begin{cases} \mu_m = 5 \times 10^{-4} \exp(1{,}000\ln 20/F_m) \\ \text{where } F_m = \sum_{i=1}^{n} x_i \cdot F_i + \sum_{j=1}^{n-1}\sum_{k=j+1}^{n} C_{jk} \cdot B_{jk} \cdot x_j \cdot x_k \\ \text{and} \quad F_i = (1{,}000\ln 20)/[1n\mu_i - \ln(5 \times 10^{-4})] \end{cases} \quad (27)$$

$$\begin{cases} \mu_m = 5 \times 10^{-4} \exp(1{,}000\ln 20/F_m) \\ \text{where } F_m = \sum_{i=1}^{n} x_i \cdot F_i + \sum_{j=1}^{n-1}\sum_{k=j+1}^{n} C_{jk} \cdot \frac{1}{B_{jk}} \cdot x_j \cdot x_k \\ \text{and} \quad F_i = (1{,}000\ln 20)/[1n\mu_i - \ln(5 \times 10^{-4})] \end{cases} \quad (28)$$

$$VD = [(\mu_c - \mu_o)/\mu_o] \times 100\% \quad (29)$$

where VD denotes viscosity deviation; μ_c is the viscosity calculated from the models, and μ_o is the observed viscosity in the experiments.

$$AAD = \frac{1}{n}\sum_{i=1}^{n}|VD_i| \quad (30)$$

where AAD denotes absolute average deviation; n is the number of data sets.

$$MAX = \max_{i=1}^{n}|VD_i| \quad (31)$$

where MAX denotes maximum deviation.

$$Y_{ij} = \frac{\text{Max}_{j=1,2,\ldots,m} X_{ij} - X_{ij}}{\text{Max}_{j=1,2,\ldots,m} X_{ij} - \text{Min}_{j=1,2,\ldots,m} X_{ij}} \quad (1 = 1, 2, \ldots, k) \quad (32)$$

where Y is index matrix; X_{ij} is the element of the matrix of original indexes, with the subscript i denoting the ith model, and subscript j denoting the jth index; m is the total number of indexes, and k is the total number of models.

$$E = Y \times \omega^T \quad (33)$$

where E is evaluation matrix; ω^T the matrix of weight for each of the four indexes.

the Arrhenius model.

Based on the Arrhenius model, Lederer developed a correlation (Equation 8) for predicting the viscosities of heavy petroleum oil with light petroleum solvent mixtures.[11] For the limiting value of $\alpha = 1$, the logarithm of the mixture viscosity equals the volumetric fraction of heavy oil times the logarithm of the heavy oil viscosity, plus the volumetric fraction of the solvent times the logarithm of the solvent viscosity.

These volumetric fractions are unbiased. But for a value of α lower than 1, the volumetric fraction is biased toward the solvent, and the limiting value of 0 provides a mixture viscosity identical to the solvent viscosity.

Rhames and Nelson examined this equation for mixtures with low viscosity ratios, defined as (μ_1/μ_2), and found this functional expression provided an excellent fit for their data.[6] Shu used the same functional expression for mixtures of high-viscosity ratios typical of bitumen and solvent fractions, and correlated the parameter with characteristic properties of the individual mixture components, including the viscosity ratio and the densities of solvent and oil

Polyguard RD-6™ Pipeline Coating System

Got Pipeline Responsibilities ? ?

If you have pipeline responsibilities, it is important that you know about cathodic shielding.

Can you define *"shielding"*?

Why the need to know?

"Materials and construction practices that create electrical shielding should not be used on the pipeline."

NACE Standard RPO169-2002, *Control of External Corrosion on Underground or Submerged Metallic Piping Systems*

The NACE standard (page 3) defines shielding:

"Shielding: Preventing or diverting the cathodic protection current from its intended path."

Coatings with solid film backing are proven to shield. That is why shrink sleeves and solid film backed tapes have lost favor with pipeline operators in North America. High resistivity of film backings "hides" corrosion activity from cathodic protection currents.

First, the Pipeline Research Council reported(1) that both corrosion and SCC were; *"..enhanced by cathodic shielding at the disbonded areas.."* by solid polyethylene film backed tapes. In the mid 1990's, Canada's National Energy Board concluded that solid film back tapes contributed to an outbreak of SCC failures because of shielding.

Although usage of solid film back tapes and shrink sleeves has declined in North America, both are still broadly specified elsewhere in the world.

FBE and Polyguard RD-6 are "*fail / safe"* coatings. This means that they have been proven to allow passage of protective currents to reach disbonded areas with corrosion potential. Once there, the current raises the pH of the water to 9 or more, a level which significantly reduces corrosion.

POLYGUARD RD-6 COATING HAS BEEN USED OVER 18 YEARS ON THOUSANDS OF PROJECTS. TO OUR KNOWLEDGE, NEITHER EXTERNAL CORROSION NOR SCC HAS BEEN A PROBLEM UNDER RD-6. WHY? BECAUSE RD-6 IS "FAIL/SAFE".

We don't have space here to show you the evidence, but we invite you to our website to review both external and internal testing. Or, call us at 214.515.5000.

(1) *A Review of Gas Industry Pipeline Coating Practices, July 1988, Corrosion Supervisory Committee, Pipeline Research Committee, Catalog L51586, Technical Toolboxes, Inc, Houston, TX 77098*

Web Site:www.polyguardproducts.com/failsafecoating3.htm
PH: 214-515-5000

Polyguard

Polyguard Products' has been certified to these quality systems requirements:
- American Natl. Standards Institute
- Dutch Council for Certification
- Deutscher Akkreditierungs Rat

(Equation 9).[12]

Barrufet et al. used their experimental viscosity data to calibrate the Lederer model (Equation 8) and fitted the parameter α to the power-law expression shown in Equation 10.[13] Predicting the viscosity of the mixture with Equations 8 and 10 requires knowing the density, molecular weight, and viscosity of each component.

Grunberg and Nissan also proposed a modification of the Arrhenius equation to predict the viscosity of liquid binary mixtures (Equation 11), but there was no method published for predicting this parameter.[14,15]

Irving considered this the best descriptive of a binary liquid mixture.[8]

A change in volume or in the force field surrounding molecules generally causes nonideal behavior. Association generally increases as dissociation reduces viscosity from the values it would normally assume.

This is not, however, always the case with liquids. The nonideality of viscosity due to mixing creates a more complicated phenomenon, and there is no general law that explains why, or the manner in which it happens, particularly for mixtures of complex liquids, such as crude oils, which are termed undefined mixtures. Al-Besharah et al. assumed that any divergence from ideality (either positive or negative) could be expressed by an excess function, leading to a modified Arrhenius equation, including an excess function (Equation 12).[16]

Solving a set of four simultaneous equations and using experimental mixture data provides the four parameters of Equation 13.

Since the nonideal viscosity behavior increased with an increase in the difference between the densities of component crude oils, Al-Besharah correlated G in Equation 10 with $(\Delta API)^2$ and proposed a new viscosity correlation (Equation 14; OGJ, Feb. 20, 1989, p. 35).

Mehrota et al. proposed and validated a viscosity-mixing rule based on the Arrhenius model for Cold Lake bitumen and its five fractions (Equation 15).[17]

A mixture consisting of $n > 2$ components allows generalized expression of Equation 11 (Equation 16).

To improve the viscosity prediction, Mehrota developed a revised form of Equations 15 and 16 and derived a new mixing formula for the blends of toluene and bitumen-bitumen fractions (Equation 17).[18]

The deviation between the calculated viscosities of binary crude oil blends (Equation 2) and measured viscosities reached a maximum when the components had a 1:1 ratio. Accordingly, Li proposed that C_{jk} in Equation 16 be determined by Equation 18.[19]

Calculating the viscosities of crude oil blends by Equation 16 and 18 therefore requires the viscosities of every binary component blend.

$f(\mu) = \lg\mu$ allows Equation 16 to be rewritten as Equation 19.

Similarly, substituting the double-log viscosity function, or Cragoe model, in Equation 16 yields the models shown in Equations 20 and 21.[20,21]

In addition to introducing the binary interaction parameter, C_{jk}, to improve the accuracy of the viscosity models, this substitution introduced a fraction modification parameter, B_{jk}, defined by Equation 22.[19,21]

Equations 23-28 list the resulting representative modified models.

The preceding review shows that only the viscosities of each component were necessary for Equations 3-7, but the viscosities of every binary component blend with equal fraction were also needed for Equations 19-21 and 23-28.

It also, however, demonstrated that the parameters either obtained from physical properties or experiments should be inputs to the other models. Equations 3-7, 19-21, and 23-28, therefore, are most practical for engineering use.

Viscosity data

This article used

CRUDE BLEND VISCOSITY DATA

Table 2

Number of components	Flow behavior classification	Number of blends	Number of data sets
2	Newtonian	12	311
	Non-Newtonian	10	336
	Total*	13	647
3	Newtonian	3	339
	Non-Newtonian	2	559
	Total*	3	898
>3	Newtonian	6	32
Overall	Newtonian	21	682
	Non-Newtonian	12	895
	Total*	22	1,577

*Some blends exhibited Newtonian behavior at high temperatures but became a non-Newtonian fluid as temperature decreased.

DEVIATION PROFILES

Table 3

Equation	Newtonian viscosity AAD[1]	Newtonian viscosity D1[2]	Newtonian viscosity D2	Newtonian viscosity D3	Non-Newtonian viscosity AAD	Non-Newtonian viscosity D1	Non-Newtonian viscosity D2	Non-Newtonian viscosity D3	Overall AAD	Overall D1	Overall D2	Overall D3
	%				%				%			
3	39.9	31.5	23.4	45.1	83.0	12.2	11.7	76.1	64.4	20.7	17.2	62.1
4	121.2	14.3	11.5	74.2	150.2	11.3	10.6	78.1	137.7	13.0	11.5	75.5
5	34.1	6.8	8.2	85.0	44.3	9.9	14.0	76.1	39.9	9.1	11.4	79.5
6	21.2	20.3	38.2	41.5	41.1	15.7	18.4	65.9	32.5	18.0	26.3	55.7
7	20.0	45.5	33.7	20.8	52.7	13.5	17.2	69.3	38.5	27.2	23.9	48.9
19	8.0	64.9	20.9	14.2	20.3	33.4	18.7	47.9	15.1	46.7	19.6	33.7
20	7.7	63.4	22.2	14.4	19.3	39.0	19.2	41.8	14.4	49.2	20.5	30.3
21	7.2	67.2	20.0	12.8	19.1	39.5	17.8	42.7	14.1	51.2	18.7	30.1
23	10.2	53.5	28.0	18.5	22.5	32.4	24.4	43.2	17.3	41.3	25.9	32.8
24	7.0	65.7	21.4	12.9	20.5	35.7	21.2	43.1	14.8	48.3	21.3	30.4
25	7.6	63.8	22.8	13.4	19.6	36.8	20.1	43.1	14.6	48.2	21.2	30.6
26	9.5	55.7	25.4	18.9	21.1	33.4	21.5	45.1	16.2	42.8	23.1	34.1
27	7.7	64.0	22.5	13.5	19.9	35.9	21.3	42.8	14.8	47.7	21.8	30.5
28	7.2	65.4	20.9	13.7	20.9	35.5	19.2	45.3	15.1	48.1	19.9	32.0

[1]Absolute average deviation. [2]D1, the proportion of viscosity deviation falling into the range 0-6%; D2, the proportion of viscosity deviation falling into the range of 6-15%; and D3, the proportion of viscosity deviation falling into the range 15%-∞.

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Evaluation results

Table 4

Equation	X: DP1[1]	X: DP2[2]	X: AAD[3]	X: |MAX|[4]	% Y: DP1	Y: DP2	Y: AAD	Y: |MAX|	Evaluation 1: E_1[5]	Evaluation 1: Ranking	Evaluation 2: E_2[6]	Evaluation 2: Ranking
3	79.3	62.1	64.4	672.7	0.2755	0.3522	0.5930	0.8023	0.4782	12	0.4706	12
4	87.0	75.5	137.7	1,921.8	0.0926	0.0810	0.0000	0.0000	0.0428	14	0.0440	14
5	90.9	79.5	39.9	364.9	0.0000	0.0000	0.7913	1.0000	0.4165	13	0.4165	13
6	82.0	55.7	32.5	404.2	0.2114	0.4818	0.8511	0.9748	0.6247	11	0.5977	11
7	72.8	48.9	38.5	440.0	0.4299	0.6194	0.8026	0.9518	0.6880	10	0.6691	10
19	53.3	33.7	15.1	427.9	0.8931	0.9271	0.9919	0.9595	0.9495	7	0.9461	7
20	50.7	30.3	14.4	429.7	0.9549	0.9960	0.9976	0.9584	0.9846	2	0.9805	2
21	48.8	30.1	14.1	429.0	1.0000	1.0000	1.0000	0.9588	0.9959	1	0.9959	1
23	58.7	32.8	17.3	432.9	0.7649	0.9453	0.9741	0.9563	0.9219	9	0.9038	9
24	51.7	30.4	14.8	422.3	0.9311	0.9939	0.9943	0.9631	0.9785	3	0.9722	3
25	51.8	30.6	14.6	435.2	0.9287	0.9899	0.9960	0.9549	0.9766	4	0.9705	4
26	57.2	34.1	16.2	423.9	0.8005	0.9190	0.9830	0.9621	0.9252	8	0.9134	8
27	52.3	30.5	14.8	434.3	0.9169	0.9919	0.9943	0.9554	0.9742	5	0.9667	5
28	51.9	32.0	15.1	423.3	0.9264	0.9615	0.9919	0.9625	0.9668	6	0.9632	6

[1]Proportion of the deviations greater than 6%. [2]Proportion of the deviations greater than 15%. [3]Absolute average deviation. [4]Maximum deviation. [5]Evaluation group weights: $\omega_{DP1} = 0.2$, $\omega_{DP2} = 0.3$, $\omega_{AAD} = 0.4$, $\omega_{MAX} = 0.1$. [6]Evaluation group weights: $\omega_{DP1} = 0.3$, $\omega_{DP2} = 0.2$, $\omega_{AAD} = 0.4$, $\omega_{MAX} = 0.1$.

both literature and in-house sources to compile 1,577 sets of viscosity data from 22 groups of crude oil blends, ranging from binary to nonary. One group of blends might have contained the same components as another group, but the fractions of each component were different.

Table 1 lists the sources and the number of the components of the crude oil blends. The components included paraffin-based crude oils, asphaltic-based heavy crude oils, and light crude oils. The crude oil blends included Newtonian fluids and non-Newtonian fluids.

Table 2 shows the viscosity data of the crude oil blends.

Model evaluation

Four indexes described the deviation of the predicted viscosity from the measured viscosity: viscosity deviation (VD, Equation 29), absolute average deviation (AAD, Equation 30), maximum deviation (MAX, Equation 31), and profile of deviation (DP).

DP consists of three groups: D1 is the proportion of viscosity deviation falling into the range 0-6%; D2 is the proportion of viscosity deviation falling into the range of 6-15%; and D3 is the proportion of viscosity deviation falling into the range 15%-∞.

The consideration that, according to the precision of the viscosity measurement (dependent on viscometer and the procedures employed), reproducibility is 6% for Newtonian crude oils and 15% for non-Newtonian crude oils provides the basis for these groupings.

Table 3 shows both the AADs and deviation profiles of the 14 models with reference to Newtonian viscosity and non-Newtonian apparent viscosity and the overall data without distinguishing between Newtonian and non-Newtonian flow behavior.

The models provide more accurate predictions for Newtonian crude oil blends than for non-Newtonian crude oil blends. The average AAD of the 14 models for Newtonian blends is 22.0%, while the average AAD for the non-Newtonian blends is 39.6%.

The nonlinearity modification with the binary interaction parameter and the fraction modification parameter greatly improves the accuracy of viscosity prediction. For the Newtonian blends, the average AAD of the first five models without nonlinearity modification is 47.3%, but the average AAD of the 9 nonlinearly modified models (Equations 19-21 and 23-28) is only 8.0%; very good given that the measured viscosity has a 6% margin of error. Similarly, for non-Newtonian blends, the average AAD of the first five models is 74.3%, but the average AAD of the 9 nonlinearly modified models is only 20.4%.

Combining indexes

Comprehensive evaluation of these models requires combining the AAD, MAX, and DP indexes. Newtonian blends used a DP value of the deviations greater than 6%. Non-Newtonian blends took the DP value as the proportion of deviations greater than 15%. Overall data points, including both Newtonian and non-Newtonian viscosities, used two values of DP:

- DP1 denoting the proportion of the deviations greater than 6%.
- DP2 denoting the proportion of the deviations greater than 15%.

Calculation of the comprehensive evaluation values converted the original values of these indexes with Equation 32.

This conversion places the values of the elements of the new index matrix, Y, in a range of [0, 1].

Multiplying the index matrix Y with the matrix of weight for each of the four indexes, ω^T, evaluates the models (Equation 33).

The value of the evaluation matrix, E, from larger to smaller comprehensively ranks the models.

The weight of each index influences the evaluation results. This article used two groups of weight: Evaluation 1: $\omega_{DP1} = 0.2$, $\omega_{DP2} = 0.3$, $\omega_{AAD} = 0.4$, $\omega_{MAX} = 0.1$; and Evaluation 2: $\omega_{DP1} = 0.3$, $\omega_{DP2} = 0.2$, $\omega_{AAD} = 0.4$, $\omega_{MAX} = 0.1$.

Table 4 shows the evaluation results. The two sets of weights resulted in the same ranking of the models. Equation 21 ranks first, with Equations 20, 24, 25, 27, and 28 quite close.

Acknowledgment

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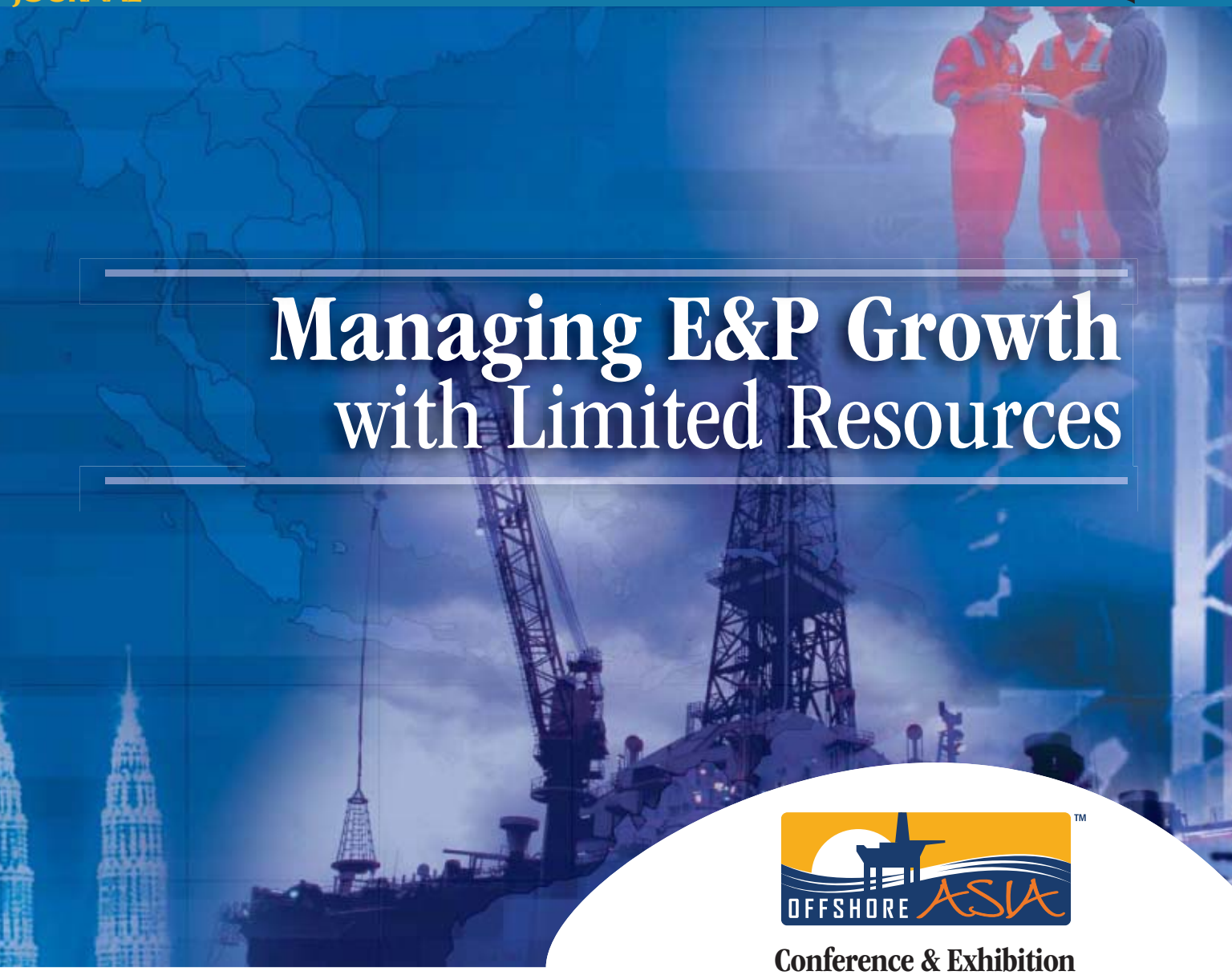

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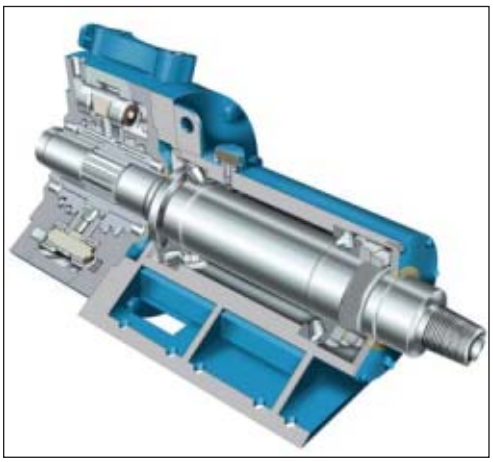

Baker Hughes Inc.

Houston, has appointed Frank M. Davis as president of Baker Hughes Russia Inc., William P. Faubel as vice-president of enterprise marketing for Baker Hughes oilfield operations, Paul S. Butero as president of Baker Atlas, and Gary G. Rich as president of Hughes Christensen.

Davis joined Hughes Tool Co. in 1976, and has held a variety of positions in Baker Hughes, including management positions in the Middle East and Asia Pacific.

Faubel has a BS degree in mechanical engineering from Southern Methodist University, and joined Hughes Tool Co. as a field engineer in 1977. He has served as president of Baker Atlas since November 2005.

Butero, who earned a BS degree from the University of Colorado, has been with Baker Hughes for 25 years in a number of operations roles in the US and Eastern Hemisphere.

Rich joined Inteq as a senior financial analyst in 1987, and has held a number of marketing and operations positions with the company since that time. He received his BS degree in accounting from Brigham Young University and MS degree in science & technology commercialization from the University of Texas.

Baker Hughes Inc. is a leading provider of drilling, formation evaluation, completion, and production products and services for the worldwide oil and gas industry.

Clark-Reliance Corp.

Strongsville, Ohio, has named Richard A. Solon as president and CEO. Solon has held senior management positions with various manufacturing companies, most recently serving as president and CEO of Trans-Industries Inc.

Clark-Reliance Corp. is a multi-divisional corporation serving the petrochemical, refining, and power generating industries. Its three operating groups are: instrument and controls group, filtration group, and filtration elements group.

Verano Inc.

Mansfield, Mass., has announced the acquisition of the Managed Security Services Div. of e-DMZ Security LLC. As a result of the acquisition, Verano is launching Industrial Defender Co-Managed Security, the market's only co-managed security service for the real-time SCADA and control environment.

e-DMZ Security Managed Services provides co-managed firewall and intrusion detection services for high-risk financial services, pharmaceutical, and industrial networks.

Verano Inc., a SCADA security company, supplies services to customers in power generation, utilities, energy, transportation, chemicals, and process manufacturing industries.

Global Industries Ltd.

Carlyss, La., has named B.K. Chin as chief executive officer and member of the board of directors. He succeeds William J. Dore, founder of Global Industries and CEO since 1973. Dore has elected to retire from active management.

Chin has more than 25 years of experience managing engineering and marine construction projects in the energy services industry, most recently serving as president and COO of Air Liquide USA. He also spent a number of years with Halliburton subsidiary Brown & Root. He holds a BS degree in mechanical engineering from the University of Singapore.

Global Industries Ltd. provides pipeline construction, platform installation and removal, diving services, and other marine support to the oil and gas industry in the Gulf of Mexico, West Africa, Asia Pacific, the Mediterranean, Middle East, India, South American, and Mexico's Bay of Campeche.

Sola Communications LLC

Lafayette, La., has announced plans to merge with PetroCom, a New Orleans-based provider of telecommunications and network solutions with over 20 years of experience in the offshore industry.

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Middle East region, which holds 2/3rds of the world's oil reserves, is working towards meeting the rising global demands for oil by investing billions on oil exploration, production, processing, maintenance and infrastructure development. According to industry estimates, about $50 billion will be invested in the region over the coming decade in the energy sector. Abu Dhabi plans to create an oil and gas industrial services complex offering foreign investors 100 per cent ownership in Specialized Economic Zones, making it another global energy hub.

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- To discuss key issues that will set the pace for the evolution of the Oil and Gas industry in the days ahead.

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Baltimore	182.8	224.7	267.4
Boston	191.2	233.1	285.5
Buffalo	172.3	240.2	286.9
Miami	187.4	237.9	282.4
Newark	200.5	233.4	293.6
New York	179.6	247.5	285.5
Norfolk	179.1	217.1	279.1
Philadelphia	187.9	238.6	292.1
Pittsburgh	185.4	236.1	277.3
Wash., DC	203.8	242.2	295.5
PAD I avg.	185.8	233.4	282.4
Chicago	192.3	247.4	290.5
Cleveland	167.4	213.8	278.1
Des Moines	162.7	202.8	264.2
Detroit	171.9	224.8	264.9
Indianapolis	165.8	214.8	271.9
Kansas City	174.8	210.8	259.9
Louisville	170.9	207.8	268.8
Memphis	182.3	222.1	276.9
Milwaukee	181.5	232.8	285.8
Minn.-St. Paul	180.4	220.8	259.8
Oklahoma City	173.4	208.8	263.6
Omaha	175.0	220.4	283.1
St. Louis	182.2	218.2	276.9
Tulsa	170.7	206.1	260.9
Wichita	170.4	213.8	270.2
PAD II avg.	174.8	217.7	271.7
Albuquerque	189.5	225.9	277.8
Birmingham	173.3	212.0	281.7
Dallas-Fort Worth	168.6	207.0	277.7
Houston	172.6	211.0	283.3
Little Rock	174.8	215.0	274.5
New Orleans	190.6	229.0	NA
San Antonio	186.3	224.7	282.4
PAD III avg.	179.4	217.8	279.6
Cheyenne	215.3	247.7	279.6
Denver	214.5	254.9	286.1
Salt Lake City	218.4	261.3	281.5
PAD IV avg.	216.1	254.6	282.4
Los Angeles	201.3	261.9	297.2
Phoenix	204.0	241.4	297.6
Portland	218.5	261.8	273.8
San Diego	205.3	265.9	308.5
San Francisco	216.4	277.0	302.2
Seattle	222.4	271.8	284.6
PAD V avg.	211.3	263.3	294.0
Week's avg.	**186.6**	**231.0**	**273.1**
Sept. avg.	**208.9**	**253.3**	**282.5**
Aug. avg.	**252.4**	**296.7**	**250.2**
2006 to date	**221.2**	**264.8**	—
2005 to date	**179.0**	**221.0**	—

*Includes state and federal motor fuel taxes and state sales tax. Local governments may impose additional taxes.
Source: Oil & Gas Journal.
Data available in Oil & Gas Journal Energy Database.

REFINED PRODUCT PRICES

	9-29-06 ¢/gal		9-29-06 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	152.13	New York Harbor	169.00
Gulf Coast	158.15	Gulf Coast	170.90
Los Angeles	169.25	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	144.47	ARA	177.85
Singapore	156.43	Singapore	173.10
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	158.38	New York Harbor	90.79
Gulf Coast	155.90	Gulf Coast	89.88
Los Angeles	177.00	Los Angeles	114.39
		ARA	96.47
		Singapore	107.19

Source: DOE Weekly Petroleum Status Report.
Data available in Oil & Gas Journal Energy Database.

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Alaska	7	10
Arkansas	26	14
California	35	25
Land	31	21
Offshore	4	4
Colorado	93	86
Florida	0	2
Illinois	0	0
Indiana	0	0
Kansas	8	7
Kentucky	10	7
Louisiana	191	174
N. Land	58	52
S. Inland waters	20	19
S. Land	43	33
Offshore	70	70
Maryland	1	0
Michigan	1	2
Mississippi	13	8
Montana	17	25
Nebraska	0	0
New Mexico	91	96
New York	6	5
North Dakota	37	24
Ohio	9	9
Oklahoma	186	156
Pennsylvania	15	13
South Dakota	1	4
Texas	791	663
Offshore	13	11
Inland waters	2	1
Dist. 1	22	13
Dist. 2	26	41
Dist. 3	52	97
Dist. 4	97	68
Dist. 5	137	74
Dist. 6	115	101
Dist. 7B	47	19
Dist. 7C	41	39
Dist. 8	94	75
Dist. 8A	28	23
Dist. 9	43	35
Dist. 10	74	66
Utah	42	26
West Virginia	25	26
Wyoming	108	87
Others—HI-1, ID-1, NV-1,OR-1, TN-1, VA-1, WA-1	7	6
Total US	**1,724**	**1,481**
Total Canada	**449**	**477**
Grand total	**2,173**	**1,958**
Oil rigs	310	209
Gas rigs	1,422	1,264
Total offshore	95	86
Total cum. avg. YTD	**1,628**	**1,355**

Rotary rigs from spudding in to total depth.
Definitions, see OGJ Sept. 22, 1997, p. 46.

Source: Baker Hughes Inc.
Data available in Oil & Gas Journal Energy Database.

SMITH RIG COUNT

Proposed depth, ft	10-6-06 Rig count	10-6-06 Percent footage*	10-7-05 Rig count	10-7-05 Percent footage*
0-2,500	50	—	26	3.8
2,501-5,000	84	45.2	64	35.9
5,001-7,500	229	18.7	149	22.1
7,501-10,000	398	4.0	327	4.8
10,001-12,500	420	1.9	323	1.8
12,501-15,000	274	0.3	293	—
15,001-17,500	109	—	110	—
17,501-20,000	73	—	50	—
20,001-over	34	—	18	—
Total	**1,671**	**6.3**	**1,360**	**5.8**
INLAND	39		35	
LAND	1,565		1,277	
OFFSHORE	67		48	

*Rigs employed under footage contracts.
Definitions, see OGJ Sept. 22, 1997, p. 46.

Source: Smith International Inc.
Data available in Oil & Gas Journal Energy Database.

OGJ PRODUCTION REPORT

	[1]10-6-06	[2]10-7-05
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	17	21
Alaska	753	827
California	674	696
Colorado	58	53
Florida	7	6
Illinois	28	30
Kansas	91	92
Louisiana	1,328	540
Michigan	14	17
Mississippi	50	42
Montana	92	95
New Mexico	160	160
North Dakota	102	100
Oklahoma	169	170
Texas	1,346	1,158
Utah	44	46
Wyoming	140	143
All others	68	76
Total	**5,141**	**4,272**

[1]OGJ estimate. [2]Revised.

Source: Oil & Gas Journal.
Data available in Oil & Gas Journal Energy Database.

US CRUDE PRICES

$/bbl*	10-6-05
Alaska-North Slope 27°	66.06
South Louisiana Sweet	55.50
California-Kern River 13°	48.00
Lost Hills 30°	55.40
Wyoming Sweet	60.01
East Texas Sweet	58.34
West Texas Sour 34°	47.75
West Texas Intermediate	56.50
Oklahoma Sweet	56.50
Texas Upper Gulf Coast	53.25
Michigan Sour	49.50
Kansas Common	55.50
North Dakota Sweet	47.00

*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 Oil & Gas Journal Energy Database.

WORLD CRUDE PRICES

$/bbl[1]	9-29-06
United Kingdom-Brent 38°	58.72
Russia-Urals 32°	55.40
Saudi Light 34°	55.23
Dubai Fateh 32°	56.28
Algeria Saharan 44°	60.27
Nigeria-Bonny Light 37°	60.73
Indonesia-Minas 34°	60.15
Venezuela-Tia Juana Light 31°	54.56
Mexico-Isthmus 33°	54.45
OPEC basket	57.38
Total OPEC[2]	56.07
Total non-OPEC[2]	54.16
Total world[2]	54.93
US imports[3]	53.26

[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 Oil & Gas Journal Energy Database.

US NATURAL GAS STORAGE[1]

	9-29-06	9-22-06	Change
	Bcf		
Producing region	965	942	23
Consuming region east	1,914	1,874	40
Consuming region west	448	438	10
Total US	**3,327**	**3,254**	**73**
	July 06	**July 05**	**Change, %**
Total US[2]	**2,779**	**2,450**	**13.4**

[1]Working gas. [2]At end of period.
Note: Current data not available.
Source: Energy Information Administration
Data available in Oil & Gas Journal Energy Database

Statistics

International rig count

Region	Sept. 2006 Land	Sept. 2006 Off.	Sept. 2006 Total	Sept. 05 Total
WESTERN HEMISPHERE				
Argentina	83	—	83	75
Bolivia	3	—	3	1
Brazil	13	19	32	27
Canada	441	5	446	497
Chile	1	—	1	—
Colombia	26	—	26	17
Ecuador	11	—	11	11
Mexico	59	23	82	106
Peru	4	—	4	3
Trinidad	4	3	7	2
United States	1,647	92	1,739	1,452
Venezuela	62	19	81	63
Other	2	—	2	—
Subtotal	**2,356**	**161**	**2,517**	**2,256**
ASIA-PACIFIC				
Australia	9	9	18	16
Brunei	1	3	4	3
China-offshore	—	18	18	16
India	53	32	85	83
Indonesia	31	17	48	57
Japan	2	—	2	4
Malaysia	—	11	11	14
Myanmar	8	—	8	10
New Zealand	3	—	3	7
Papua New Guinea	2	1	3	2
Philippines	1	—	1	2
Taiwan	—	—	—	—
Thailand	2	7	9	7
Vietnam	—	10	10	10
Other	4	—	4	4
Subtotal	**116**	**108**	**224**	**235**
AFRICA				
Algeria	29	—	29	23
Angola	—	4	4	3
Congo	1	—	1	2
Gabon	1	1	2	3
Kenya	—	—	—	—
Libya	10	—	10	8
Nigeria	1	11	12	10
South Africa	—	—	—	—
Tunisia	2	1	3	—
Other	3	—	3	3
Subtotal	**47**	**17**	**64**	**52**
MIDDLE EAST				
Abu Dhabi	9	5	14	14
Dubai	—	2	2	3
Egypt	32	5	37	26
Iran	—	—	—	38
Iraq	—	—	—	—
Jordan	1	—	1	1
Kuwait	14	—	14	12
Oman	40	—	40	33
Pakistan	19	—	19	11
Qatar	3	8	11	13
Saudi Arabia	67	7	74	38
Sudan	—	—	—	17
Syria	23	—	23	24
Yemen	16	—	16	14
Other	2	—	2	2
Subtotal	**226**	**27**	**253**	**246**
EUROPE				
Croatia	1	—	1	3
Denmark	—	4	4	2
France	1	—	1	1
Germany	5	—	5	3
Hungary	3	—	3	1
Italy	5	2	7	4
Netherlands	—	5	5	4
Norway	—	12	12	16
Poland	1	—	1	1
Romania	2	—	2	3
Turkey	4	—	4	5
UK	1	25	26	20
Other	5	—	5	4
Subtotal	**28**	**48**	**76**	**67**
Total	**2,773**	**361**	**3,134**	**2,856**

Definitions, see OGJ Sept. 18, 2006, p. 42
Source: Baker Hughes Inc.
Data available in Oil & Gas Journal Energy Database.

Oil import freight costs*

Source	Discharge	Cargo	Cargo size, 1,000 bbl	Freight (Spot rate) worldscale	$/bbl
Caribbean	New York	Dist.	200	247	1.78
Caribbean	Houston	Resid.	380	146	1.17
Caribbean	Houston	Resid.	500	159	1.27
N. Europe	New York	Dist.	200	240	2.74
N. Europe	Houston	Crude	400	170	2.89
W. Africa	Houston	Crude	910	138	2.54
Persian Gulf	Houston	Crude	1,900	101	3.41
W. Africa	N. Europe	Crude	910	138	1.89
Persian Gulf	N. Europe	Crude	1,900	103	2.55
Persian Gulf	Japan	Crude	1,750	114	2.32

*September 2006 average.
Source: Drewry Shipping Consultants Ltd. Data available in Oil & Gas Journal Energy Database.

US LNG imports

Country	July 2006	June 2006	July 2005	Change from a year ago, %
	MMcf			
Algeria	3,028	2,808	6,028	–49.8
Brunei	—	—	—	—
Malaysia	—	—	—	—
Nigeria	6,129	5,998	—	—
Oman	—	—	—	—
Qatar	—	—	—	—
Trinidad and Tobago	33,390	38,568	41,187	–18.9
Others	15,003	14,331	5,926	153.2
Total	**57,550**	**61,705**	**53,141**	**8.3**

Source: US Energy Information Administration
Data available in Oil & Gas Journal Energy Database.

Baker oil tools workover rig count*

Region	Sept. 2006	Sept. 2005	Change, %
Gulf Coast	312	251	24.3
Midcontinent	261	253	3.2
Northeastern	85	81	4.9
Rocky Mountains	237	210	12.9
Southeastern	204	179	14.0
West Texas	337	282	19.5
Western	134	137	–2.2
Total US	**1,570**	**1,393**	**12.7**
Canada	576	709	–18.8
Total N. America	**2,146**	**2,102**	**2.1**

*Wells over 1,500 ft deep and tubing out of the wellbore. Excludes rigs on rod jobs. Definitions, see OGJ Sept. 18, 2006, p. 42. Source: Baker Hughes Inc. Data available in Oil & Gas Journal Energy Database.

Propane prices

	Aug. 2006	Sept. 2006	Aug. 2005	Sept. 2005
	¢/gal			
Mont Belvieu	113.77	101.18	94.08	113.05
Conway	112.09	97.58	96.22	112.25
Northwest Europe	107.54	104.76	82.27	97.28

Source: EIA Weekly Petroleum Status Report
Data available in Oil & Gas Journal Database.

Muse, Stancil & Co. refining margins

	US Gulf Coast	US East Coast	US Mid-west	US West Coast	North-west Europe	South-east Asia
	$/bbl					
September 2006						
Product revenues	72.46	67.89	71.79	75.67	69.56	66.27
Feedstock costs	–62.44	–63.66	–57.48	–57.80	–61.55	–63.18
Gross margin	10.02	4.23	14.31	17.77	8.01	3.09
Fixed costs	–2.02	–2.34	–2.27	–2.65	–2.27	–1.77
Variable costs	–1.98	–1.36	–1.77	–3.13	–2.13	–0.75
Cash operating margin	**6.02**	**0.53**	**10.27**	**11.99**	**3.61**	**0.57**
August 2006	13.61	7.20	21.84	19.33	5.57	–0.47
YTD avg.	13.89	16.02	7.39	25.92	6.43	1.31
2005 avg.	12.53	6.98	12.31	20.55	5.51	1.52
2004 avg.	6.16	3.70	6.64	11.76	5.08	1.83
2003 avg.	2.92	2.22	4.84	5.43	2.35	–0.31

Source: Muse, Stancil & Co. See OGJ, Jan. 15, 2001, p. 46.
Data available in Oil & Gas Journal Energy Database.
NOTE: The refining models that comprise the basis for the Muse refining margins have been updated to reflect changing crude slates, product specifications, and market pricing. All current and historical margin series have been revised.

Muse, Stancil & Co. gasoline marketing margins

August 2006	Chicago*	Houston	Los Angeles	New York
	¢/gal			
Retail price	321.87	288.92	321.63	316.33
Taxes	58.29	38.40	61.12	52.09
Wholesale price	242.39	221.75	241.34	233.21
Spot price	226.20	208.06	227.63	209.92
Retail margin	21.45	28.77	19.17	31.03
Wholesale margin	16.19	13.69	13.71	23.29
Gross marketing margin	**37.64**	**42.46**	**32.88**	**54.32**
July 2006	15.72	18.92	8.76	23.07
YTD avg.	13.78	18.99	10.32	27.99
2005 avg.	19.77	16.26	17.32	27.13
2004 avg.	22.49	17.49	20.53	30.38
2003 avg.	22.69	19.10	28.58	31.42

*The wholesale price shown for Chicago is the RFG price utilized for the wholesale margin. The Chicago retail margin includes a weighted average of RFG and conventional wholesale purchases.
Source: Muse, Stancil & Co. See OGJ, Oct. 15, 2001, p. 46.
Data available in Oil & Gas Journal Energy Database.
Note: Effective April 2003, Los Angeles margins include ethanol blending.

Muse, Stancil & Co. ethylene margins

	Ethane	Propane	Naphtha
	¢/lb ethylene		
September 2006			
Product revenues	60.16	96.69	113.10
Feedstock costs	–26.45	–57.41	–83.01
Gross margin	33.71	39.28	30.09
Fixed costs	–5.38	–6.36	–7.19
Variable costs	–4.90	–5.78	–7.75
Cash operating margin	**23.43**	**27.14**	**15.15**
August 2006	15.16	18.13	4.05
YTD avg.	20.17	23.38	1.23
2005 avg.	14.43	20.68	1.28
2004 avg.	9.00	12.03	0.51
2003 avg.	8.33	11.36	3.72

Source: Muse, Stancil & Co. See OGJ, Sept. 16, 2002, p. 46.
Data available in Oil & Gas Journal Energy Database.

Muse, Stancil & Co. US gas processing margins

Setpember 2006	Gulf Coast	Mid-continent
	$/Mcf	
Gross revenue		
Gas	4.73	3.95
Liquids	1.03	2.80
Gas purchase cost	5.27	5.30
Operating costs	0.07	0.15
Cash operating margin	**0.43**	**1.30**
August 2006	0.35	1.16
YTD avg.	0.28	1.06
2005 avg.	–0.06	0.25
2004 avg.	0.07	0.33
2003 avg.	–0.08	–0.06
Breakeven producer payment, % of liquids	56%	52%

Source: Muse, Stancil & Co. See OGJ, May 21, 2001, p. 54.
Data available in Oil & Gas Journal Energy Database.

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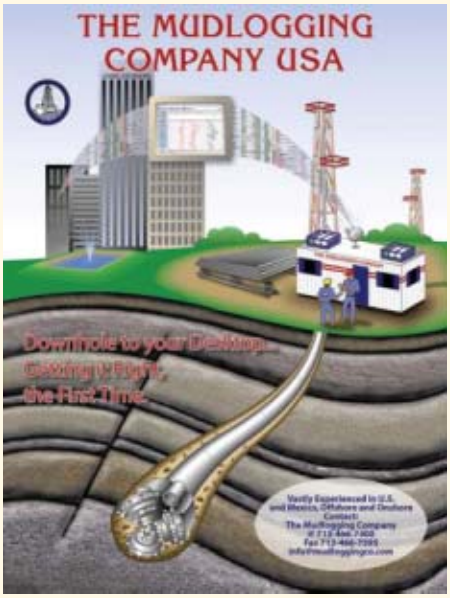

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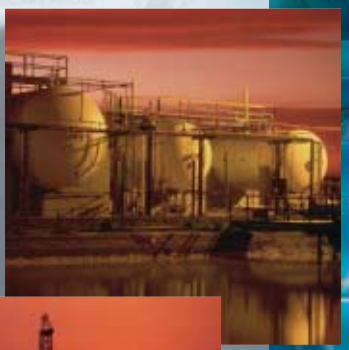

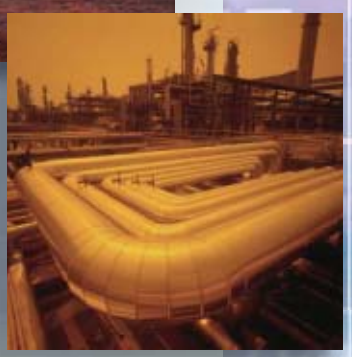

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Who said crude wouldn't drop below $60/bbl?

Here's an assignment for anyone who has at any time this year declared that the price of crude oil would never again fall below $60/bbl.

Find a legal pad and a pencil, and write this sentence 500 times: Oil prices can't rise forever.

If the statement still seems questionable, write it 500 times again.

The price of West Texas Intermediate crude fell below $60/bbl last week after reaching $75/bbl at times in July and August.

Suddenly, instead of asking how high the crude price might go, people are wondering about the bottom.

Does a 20% price drop in 2 months' time constitute a collapse? If not, it's certainly the grad-school version of what economists refer to as "a correction."

Whatever you call it, the price drop should surprise no one.

A coincidence of extraordinary influences elevated crude prices earlier this year: low levels of idle production capacity, failure of production outside the Organization of Petroleum Countries to come on stream as expected, unusual strains in key product markets, geopolitical pressures, hurricane fears.

Several of those pressures have eased. And demand has relaxed seasonally in the US and other important markets. Prices are dropping. What else can they do?

So where's the floor? The answer to that question depends on two forces.

One of them is demand, which has wobbled under the weight of high prices but still has structural support from economic development in Asia and India and developed-world prosperity. The other critical force is the unpredictable price that elicits real production cuts, as opposed to talk about the subject, from OPEC's most important producers. That price will be the level at which revenues from unadjusted production become too low to sustain national budgets.

So there is a floor, and it's probably higher than the floor level of the last price collapse—or correction, as the case may be. Maybe it's much higher.

But for anyone who risked money on the proposition that the crude price would never again fall below $60/bbl, the difference between a floor of $40/bbl and one of, say, $30/bbl might now not matter very much.

(Online Oct. 6, 2006; author's e-mail: bobt@ogjonline.com)

The Editor's Perspective

by Bob Tippee, Editor

Market Journal

by Paula Dittrick, Senior Staff Writer

Crude prices dip below $59/bbl

The November contract for benchmark US light, sweet crudes fell $2.35 to $58.68/bbl Oct. 3, the lowest front-month closing on the New York Mercantile Exchange since Feb. 16. But oil prices rallied upon reports that oil exporters informally agreed to cut production.

The Oct. 5 Financial Times reported that the Organization of Petroleum Exporting Countries informally plans to cut production by at least 1 million b/d, or at least 4%.

An OPEC spokesman said most member nations support a voluntary reduction, and that the change could be ratified during the cartel's scheduled Dec. 14 meeting in Abuja, Nigeria. "OPEC is going to defend a price floor for its oil of $50-55/bbl," FT reported an OPEC spokesman as saying.

But OPEC's president denied reports of an informal agreement. Edmund Daukoru, Nigerian oil minister and OPEC president, told the Wall Street Journal, "We are toying with the idea of an emergency meeting. We will have to agree on how much, how soon, and how we distribute it among the member countries." Daukoru said cartel members would not agree to a formal cut in production quotas until after OPEC had met. The production quota for OPEC, excluding Iraq, is 28 million b/d.

OPEC produced 27.7 million b/d in August, the US Energy Information Administration said. Iraq produced 2.2 million b/d in August but was not part of the quota.

Until the FT report, the markets appeared unconcerned about oil supply. Earlier in the week, traders showed little reaction to announcements that Nigeria cut oil production by 120,000 b/d and Venezuela by 50,000 b/d, effective Oct. 1.

The voluntary reductions in Nigeria and Venezuela's production represented less than 1% of OPEC supply, and oil prices continued to decline despite those production cuts. Venezuela President Hugo Chavez suggested an "appropriate" oil price would be $50-60/bbl.

Analysts in the Houston office of Raymond James & Associates Inc. said front-month crude oil futures plunged more than 20% in just over 2 months. They cited an all-time closing high of $77.03 on July 14.

In both dollars and percentages, the overall fall of crude prices since July 14 marked the steepest sustained decline since late 2004 when oil fell to levels around $40/bbl from $55/bbl, RJA analysts said. "Recognizing that oil in [the fourth quarter] is likely to average below our $68/bbl forecast, we lowered it [on Sept. 25] to $62, but we again reaffirm our confidence in our $70 forecast for 2007," RJA said.

Barclays Capital Inc. analyst Paul Horsnell foresses a "drawn-out stabilization" of oil markets. "We suggest that the best template for current circumstances is the experience of 2001-02," Horsnell said. And [we] see the path as being determined by five main aspects: perceptions on the US economy, the global economy, non-OPEC supply, OPEC policy, and Iran."

Natural gas

Natural gas prices on Oct. 5 marked a 5-week high, gaining 30.3¢ to close at $6.298/MMbtu on the NYMEX.

EIA reported a 73 bcf gas storage injection for the week ended Sept. 29 compared with a 77 bcf injection for the previous week, a 44 bcf injection last year, and the 5-year average injection of 68 bcf.

The year-over-year storage surplus rose to 398 bcf, and the 5-year average storage surplus increased to 366 bcf. Supplies are now at 3.3 tcf vs. 2.9 tcf last year.

Ronald J. Barone, UBS Securities LLC managing director, expects that EIA will report a 70-80 bcf injection into storage for the week ended Oct. 6. "Given current weather forecasts and year-earlier injection comparisons, we expect the year-over-year surplus will be in the 400-425 bcf range by the middle of October."

The EIA weekly inventory report showed an increase in US fuel stockpiles, which was what traders had expected. On Oct. 4, EIA reported commercial US crude inventories rose by 3.3 million bbl to 328.1 million bbl during the week ended Sept. 29.

Gasoline stocks increased by 1.2 million bbl to 215.1 million bbl during the same period. Distillate fuel inventories rose by 200,000 bbl to 151.5 million bbl.

Imports of crude into the US averaged 10.5 million b/d, down 570,000 b/d from the previous week. During the last 4 weeks, crude oil imports have averaged 10.7 million b/d. Input of crude into US refineries declined by 573,000 b/d to 15.3 million b/d, with refineries operating at 89.9% of capacity.

Gasoline production dropped, averaging 8.9 million b/d while distillate fuel production fell slightly, averaging nearly 4.2 million b/d.

(Online Oct. 9, 2006; author's e-mail: paulad@ogjonline.com)

The world consumes two barrels of oil for every barrel discovered.

So is this something you should be worried about?

The fact is, the world has been finding less oil than it's been using for twenty years now. Not only has demand been soaring, but the oil we've been finding is coming from places that are tough to reach. At the same time, more of this newly discovered oil is of the type that requires a greater investment to refine. And because demand for this precious resource will grow, according to some, by over 40% by 2025, fueling the world's growing economic prosperity will take a lot more energy from every possible source.

The energy industry needs to get more from existing fields while continuing to search for new reserves. Automakers must continue to improve fuel efficiency and perfect hybrid vehicles. Technological improvements are needed so that wind, solar and hydrogen can be more viable parts of the energy equation. Governments need to create energy policies that promote economically and environmentally sound development. Consumers must demand, and be willing to pay for, some of these solutions, while practicing conservation efforts of their own.

Inaction is not an option. But if everyone works together, we can balance this equation. We're taking some of the steps needed to get started, but we need your help to get the rest of the way.

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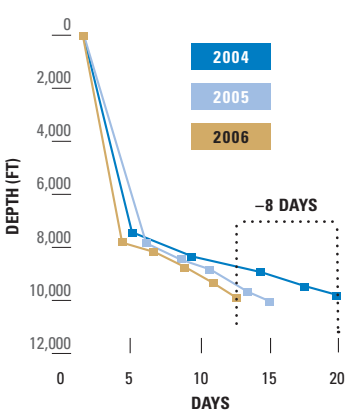

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