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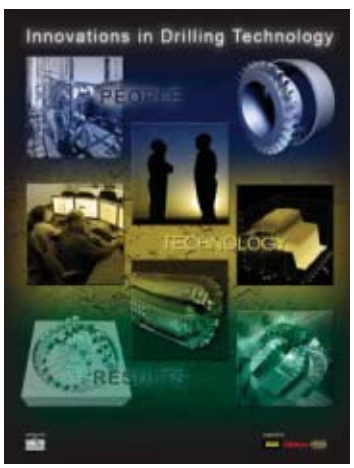

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Process Plant Maintenance & Turnaround

India steers new course toward energy reform
Weather's role important in marine E&D operations
Russian field tests yield cements for arctic wells
DNV certifies pipe for LNG projects

OIL&GAS JOURNAL®

May 21, 2007
Volume 105.19

PROCESS PLANT MAINTENANCE & TURNAROUND

REGULAR FEATURES

COVER

Maintenance workers from ThyssenKrupp Xervon GMBH lift and install a vessel at ExxonMobil Corp.'s 326,000-b/cd refinery, Fawley, UK, during an October 2006 shutdown. Optimizing unit turnarounds and avoiding unplanned delays allows plant owners to maximize profitability and ensure product supplies. The first article in this week's special report, Process Plant Maintenance & Turnaround, starting on page 48, discusses a study of actual turnarounds and variables that lead to on-schedule and safe projects. The second article, page 55, discusses problems and solutions in cooling water systems. Photos from ThyssenKrupp Xervon.

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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General Interest — Quick Takes

Bodman to Europe: rethink Russia's line proposal

US Sec. of Energy Samuel Bodman has criticized Russia's plans to construct a new pipeline from Turkmenistan to Europe, saying that Europe needs diversity of suppliers.

Speaking at a press conference during a meeting of the International Energy Agency in Paris, Bodman said the pipeline, which would pass through Kazakhstan and along the Caspian coast into Russia towards Europe, would "fly in the face of what is needed, which is diversity of supply." He added, "The Europeans should take due note of this and adjust their response accordingly."

On May 12, the presidents of Russia, Turkmenistan, and Kazakhstan struck a preliminary deal to restore the existing Caspian shore gas pipeline and build a new pipeline along the Caspian Coast which would circumvent Uzbekistan (see related story, p. 10). The nations met at a summit in the Turkmen Caspian port of Turkmenbashi.

According to Russian President Vladimir Putin, the upgraded and new infrastructure is expected to boost capacity by 20 billion cu m/year by 2012. However, the deal has prompted fears among European, US, and Chinese circles of losing control over future potential Central Asian gas supplies to Russia. The agreement also increases Russia's leverage with the European Union as the EU continues to seek out other suppliers and reduce its reliance on Russian gas following strains in their relationship.

For Russia the deal signifies a major triumph over the rival 8 billion cu m/year Nabucco project, which would bring Central Asian gas across the Caspian to Europe. However, Turkmenistan President Gurbanguly Berdymukhammedov has not ruled out supplying Turkmen gas to Nabucco.

Russia, Turkmenistan, and Kazakhstan hope to sign final agreements by September for their projects and expect work to start in first half 2008. One of the key outstanding commercial issues is whether Turkmenistan can demand more money from Russia for Turkmen gas which Russia imports to meet its European export obligations and sells for a higher price.

Oman, Iran sign oil, gas cooperation agreement

Oman and Iran have signed a memorandum of understanding to jointly develop oil and gas fields, for Iran to export gas to Oman, and to establish joint petrochemical projects.

Iran and Oman also will establish a joint company to carry out oil projects, according to the MOU. The nations hope to implement their agreement within the next 4 months.

Oman's Commerce and Industry Minister Maqbool bin Ali bin Sultan and visiting Iranian Petroleum Minister Vaziri Hamaneh signed the agreement May 15 in Oman.

Iran is expected to export 1 billion cu m/day of gas to Oman either by pipeline or as LNG, according to local Omani and Iranian reports.

Mahmoud Zirakchian Zadeh, managing director of Iranian Offshore Oil Co., was quoted as saying, "Specifying the price of export gas to Oman needs to be further scrutinized." He said the two countries have also agreed to develop Hengam gas field, which is shared between the two Persian Gulf states.

Domestic Petroleum Council changes name

The Domestic Petroleum Council, a trade association representing large US independent producers, has been renamed American Exploration & Production Council.

Duane Radtke, the group's chairman and also president and chief executive officer of Dominion Exploration & Production Inc., said the new name reflects activities of the 24 members. At its creation in 1975, the council represented midsized companies of any type, including refiners. Radtke said it has included only E&P companies for many years.

In addition, he said, many members have operations outside the US.

The group has adopted the abbreviation AXPC. William F. Whitsitt remains president.

IOGCC, EPA sign environmental agreement

The Interstate Oil & Gas Compact Commission and the US Environmental Protection Agency signed a memorandum of understanding to outline the two groups' environmental regulatory oversight of oil and natural gas exploration and production activities.

The MOU was signed May 7 at the start of IOGCC's midyear issues summit in Point Clear, Ala. It replaces and renews the MOU signed in December 2002 and renewed in March 2005. This agreement's timeframe has been extended to 3 years from the previous 2-year expiration.

The MOU's purpose is "to improve regulatory cooperation among the states and EPA in a manner that promotes protection of the environment in a cost-effective manner, minimizes duplication, increases efficiencies, enables the exchange of information and expertise, and increases communication," it said.

Some of the objectives outlined in the agreement include renewing a joint taskforce that will:

- Improve communication between EPA and the states.
- Foster environmental protection based on each group's missions, responsibilities, and authorities.
- Form subgroups to address concurrent jurisdiction between EPA and the states.

"In some instances the states and EPA have concurrent jurisdiction relating to a host of oil and gas regulatory efforts," the MOU said. "In other instances, the states and EPA have independent authorities that may be complementary when effectively coordinated." ✦

Industry Scoreboard

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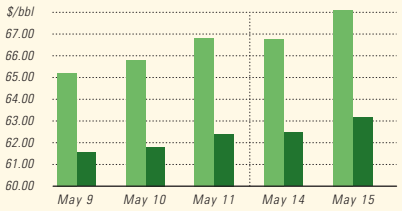
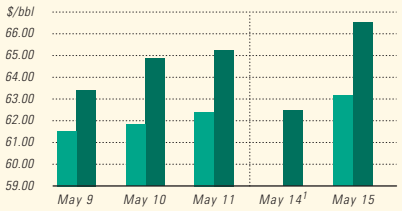
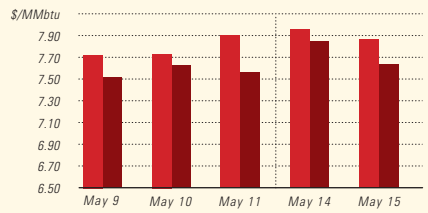


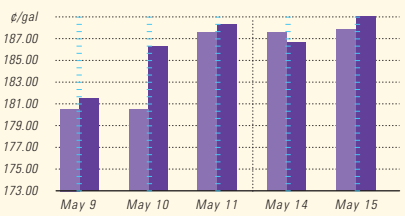
WTI CUSHING / BRENT SPOT



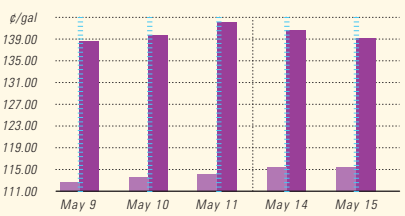
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



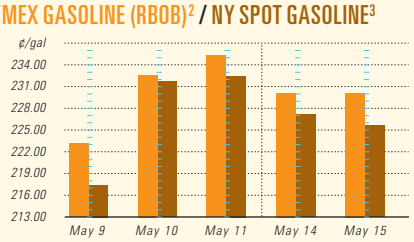
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



[1]Not available
[2]Reformulated gasoline blendstock for oxygen blending

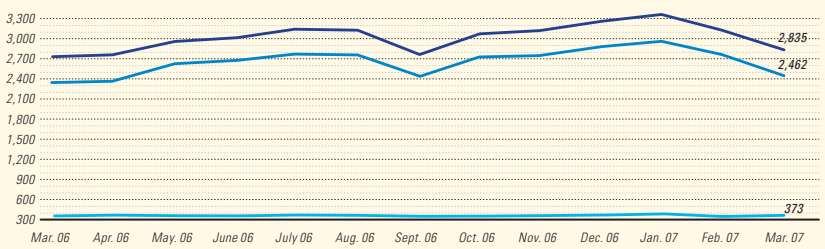
US INDUSTRY SCOREBOARD — 5/21

Latest week 5/11	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	9,059	9,208	–1.6	9,108	9,029	0.9
Distillate	4,168	4,066	2.5	4,374	4,218	3.7
Jet fuel	1,562	1,645	–5.1	1,609	1,585	1.6
Residual	806	650	24.0	758	749	1.2
Other products	4,887	4,724	3.4	4,971	4,772	4.2
TOTAL DEMAND	20,481	20,292	0.9	20,821	20,363	2.3
Supply, 1,000 b/d						
Crude production	5,134	5,080	1.1	5,249	5,056	3.8
NGL production[2]	2,327	2,345	–0.8	2,405	2,168	10.9
Crude imports	10,251	9,966	2.9	9,786	9,890	–1.1
Product imports	3,482	3,704	–6.0	3,216	3,573	–10.0
Other supply[3]	1,123	1,037	8.3	966	1,102	–12.3
TOTAL SUPPLY	22,317	22,132	0.8	21,622	21,788	–0.8
Refining, 1,000 b/d						
Crude runs to stills	14,856	15,165	–2.0	14,680	14,890	–1.4
Input to crude stills	15,266	15,528	–1.7	15,114	15,231	–0.8
% utilization	88.1	89.3	—	87.2	87.7	—

Latest week 5/11	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	349,935	344,778	5,157	343,795	6,140	1.8
Motor gasoline	201,448	199,230	2,218	205,493	–4,045	–2.0
Distillate	120,376	119,052	1,324	116,133	4,243	3.7
Jet fuel	39,518	39,685	–167	40,286	–768	–1.9
Residual	38,747	38,779	–32	42,185	–3,438	–8.1
Stock cover (days)[4] **5/4**			**Change, %**		**Change, %**	
Crude	22.4	22.1	1.4	23.1	–3.0	
Motor gasoline	20.9	20.8	0.5	22.4	–6.7	
Distillate	27.8	27.1	2.6	28.2	–1.4	
Propane	27.1	27.1	—	35.1	–22.8	
Futures prices[5] **5/11**			**Change**		**Change**	**Change, %**
Light sweet crude, $/bbl	62.00	63.30	–1.30	71.59	–9.59	–13.4
Natural gas, $/MMbtu	7.75	7.84	–0.09	6.62	1.13	17.1

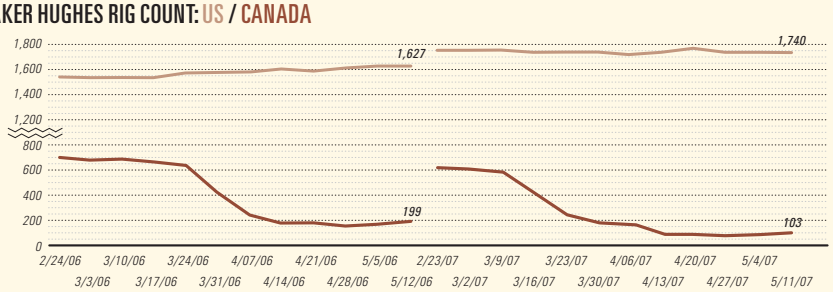
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

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



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

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Exploration & Development — *Quick Takes*

Petrobras finds gas with Espirito Santo basin well

Petroleo Brasileiro SA (Petrobras) has reached 130-m thick gas-saturated sandstone reservoirs at 3,378 m with its 6-ESS-168 well in Camarupim offshore field in the Espirito Santo basin.

The well, which was drilled in the Espirito Santo Sea in the BM-ES-5 exploratory concession, is being drilled nearly 37 km off Espirito Santo in 763 m of water.

Petrobras, with a 65% stake, operates the block in partnership with El Paso Corp., which holds the remaining 35%.

These preliminary results confirm that Camarupim field extends to the north; commercial viability of the field was declared in late 2006 (OGJ Online, Dec. 29, 2006). The field was discovered with the 4-ESS-164A well, which detected 112 m of gas-containing reservoirs.

Talisman unit hits pay with three wells in Alaska

Talisman Energy Inc. subsidiary FEX LP has completed a three-well drilling program in the northwest planning area of the National Petroleum Reserve-Alaska.

The well sites, about 60 miles southeast of Barrow, were drilled using Doyon-Akita Arctic Wolf and Nabors Industries Ltd. 14E drilling rigs.

All three wells—Aklaqyaaq-1, Amaguq-2, and Aklaq-6—encountered hydrocarbon-bearing sandstones in several formations, based on log analysis and strong gas and oil shows, including oil staining and free oil in the drilling mud in one of the wells.

One well was plugged and abandoned and the other two were suspended.

The abandoned well is believed to be "subcommercial given current infrastructure," Talisman said, adding that recently acquired high-fold seismic will assist in analyzing this well.

The two suspended wells encountered more than 225 ft of net hydrocarbon-bearing sandstones. Plans are to evaluate these wells during the next drilling season when longer-term test equipment is mobilized to the field area.

The initial estimate of contingent resources present in these formations is 300-400 million bbl net to Talisman. Additionally, there is significant follow-up potential on many similar structures on Talisman's acreage if commercial productivity is proved, the company said.

FEX holds 60-80% working interest in all the wells and Petro-Canada (Alaska) Inc. holds the remaining interests.

India's KG D6 block has 18th discovery

Reliance Industries Ltd., Mumbai, reported the 18th hydrocarbon discovery on the D6 block in the Krishna-Godavari basin off India.

KG-D6-R1 cut two Mio-Pliocene zones confirmed as gas-bearing from logs and modular dynamic testing. Designated Dhirubhai-34, it opens new areas in deeper stratigraphic levels on the block.

The well, drilled to TD 4,860 m, is in 2,010 m of water and is the deepest-water well on the block. Block interest holders are Reliance 90% and Niko Resources Inc., Calgary, 10%.

Esso Australia farms into Bonaparte Gulf permit

Esso Australia has farmed into Bonaparte Gulf permit WA-318-P off northern Australia. The permit is wholly owned by Drillsearch Energy Ltd. of Sydney.

The permit contains the prospective ready-to-drill Marina prospect, a four-way dip closed anticline about 40 km west of Eni SPA's Blacktip gas-condensate field, now under development.

Esso has agreed to pay 85% of the costs of drilling Marina-1 in exchange for a 65% working interest and operatorship of the permit. Drillsearch will pay 15% of the well costs and retain 35% interest in the permit.

The Premium Wilcraft jack up rig has been contracted to drill the well in September.

The permit contains a strong lead called Balzac to the northeast of Marina that is a salt-related feature similar to the nearby Santos Ltd.-held Tern and Petrel gas fields to the east.

A 3D survey of 100 sq km will be run over the prospect to firm up a drilling prospect.

The ExxonMobil farm-in marks the company's first return to northern Australian waters after pulling out of the Timor Sea in the late 1980s.

Hydro, Anadarko to develop Peregrino oil field

Hydro ASA and Anadarko Petroleum Corp. have received permission from the Agencia Nacional do Petroleo for plans to develop Peregrino oil field, which lies in 100 m of water about 85 km off Brazil.

Under a $2.5 billion investment plan, the field will be developed with a floating production, storage, and offloading vessel, two drilling platforms, 30 production wells, and seven water-injection wells. The partners are drilling a delineation well in the southwest extension of the field and expect to produce 100,000 b/d of oil by 2010 (OGJ Online, Apr. 2, 2007).

Maersk Contractors will lease and operate the FPSO, and Kiewit Offshore Services Ltd. will supply the drilling platforms. An agreement also has been reached with Subsea 7 for the engineering, procurement, construction, and installation of the pipelines connecting the platforms to the ship, Hydro said.

Hydro said this will be its first Brazilian project.

Hydro and Anadarko each hold a 50% share in the project. Hydro is the operator during the project planning phase, and Anadarko will assume operatorship during the project execution and operation ✦

Drilling & Production — *Quick Takes*

Al-Naimi: Saudi Arabia to increase gas production

Saudi Arabia's Oil Minister Ali bin Ibrahim Al-Naimi said his country plans to increase its natural gas production in order to meet demand growth from domestic industries.

"We are planning to add in the next 10 years 100 tcf to our current reserves of gas," Al-Naimi said in Riyadh at a conference on Saudi economic development. He said the gas expansion would be an integral part of the country's National Project to Develop Industrial Areas.

"Our future gas production and development plans will meet current and future need for gas in the kingdom...now we are entering a new period of developing petrochemical industries and gas exploitation which will have a big impact on the economy," Al-Naimi said.

Domestic gas sales are expected to rise by 40% through 2012 from the current level of around 7 bcfd, Al-Naimi said, adding that demand growth would come from industries producing such commodities as cars, construction materials, household appliances, and metals.

To produce the additional gas, Al-Naimi said his country plans to drill 186 gas exploration wells and 332 gas development wells by 2012—the same year that production of gas will start at the offshore Karan gas field which, he said, is expected to support domestic gas sales of 770 MMcfd.

Chevron to start production from Thai gulf block

A group of companies led by Chevron Offshore (Thailand) Ltd. will start oil production from Block G4/43 in the northern Gulf of Thailand by yearend. The block is 125 miles south of Bangkok.

Production of an initial 6,000-8,000 b/d of oil will come from Lanta field, one of the two oil and gas-bearing structures found in the 9,686-sq-km tract, which lies in less than 250 ft of water off Prachuab Khiri Khan province.

The Lanta No. 1 exploration well and the Lanta No. 2 appraisal well were drilled 3 years ago (OGJ Online, July 22, 2004). Since the concession was awarded in July 2003, six exploration wells have been drilled in the Lanta and Similan structures.

The group is preparing to drill a development well as part of the Lanta development plan, which was approved by the Thai Energy Ministry, according to Thailand's PTT Exploration & Production PLC, a partner.

PTTEP has exercised its right to raise its stake in Block G4/43 to 21.375% from 15% following the declaration of commerciality of Lanta. As a result, Chevron's share in the block was reduced to 51% from 60%, Mitsui Oil Exploration Co.'s holding drops to 21.25% from 25%, and Bangkok-based Palang Sophon Two Ltd. holds the remaining 6.375%.

Talks continue for Cepu block output start date

ExxonMobil Corp. and Indonesia's state-owned PT Pertamina are involved in discussions with government authorities aimed at resolving their differences and advancing the start of oil production from Indonesia's Cepu block.

Peter J. Coleman, president and general manager of ExxonMobil Oil Indonesia Inc., said the two firms are seeking a way to meet the government's request to begin oil production at the block by yearend 2008, about 2 years ahead of schedule.

Coleman said the two sides are in discussions with BPMigas, the country's upstream oil and gas regulatory agency, as well as Lemigas, the government's oil and gas research and development center, in order to meet the government's target.

Indonesia wants to increase the country's oil production by 30% to 1.3 million b/d by 2009 from the current 1 million b/d. To meet that goal, the government has urged the Cepu partners to speed up operations.

Coleman, who said he understands the aim of boosting production, also suggested that the government should assess if earlier production is economically viable given the technical and social problems now facing the two companies.

In January, ExxonMobil officially advised Indonesia of its desire for a 10-month delay for oil production from Cepu in Central Java from its initial target of first quarter 2009 (OGJ Online, Jan. 30, 2007).

Indonesian officials had said earlier that month that Cepu block in the border area of Central and East Java would start producing oil in first-quarter 2009, one quarter later than originally scheduled (OGJ Online, Jan 4, 2007). ✦

Processing — *Quick Takes*

ExxonMobil to pay for California air violations

ExxonMobil Corp. agreed to pay $250,000 in penalties to the South Coast Air Quality Management District (AQMD) for excess emissions on Mar. 22 from its 130,000 b/d Torrance, Calif., refinery, AQMD confirmed May 10.

AQMD is the air pollution control agency for Orange County, Calif., and the urban portions of Los Angeles, Riverside, and San Bernardino counties.

A failure in a sulfur-recovery unit prompted shutdowns of other refining equipment and the release of nitrogen oxides, carbon dioxide, and other substances, ExxonMobil said.

Also related to the Mar. 22 incident, ExxonMobil agreed to spend up to $2 million for a supplemental environmental project to cut CO_2 emissions, volatile organic compounds, and other pollutants from the Torrance refinery, AQMD said.

The major agreed to pay an additional $150,000 penalty for 23 notices of violations issued by AQMD that were unrelated to the Mar. 22 incident.

Fatal blaze shuts ExxonMobil unit off Singapore

ExxonMobil Corp. has shut down a crude distillation unit af-

ter two workers were killed and two others injured in a fire at its 309,000 b/d Pulau Ayer Chawan off the southwestern coast of Singapore.

ExxonMobil said the fire has been extinguished, and the Singapore Civil Defense Force was investigating the cause of the blaze. Meanwhile, ExxonMobil said the 115,000 b/d unit would not resume production "until it is safe to do so."

A company spokesperson couldn't provide an estimate on how long the unit would be out of action, but said the refinery's second 185,000 b/d unit continues to operate.

Industry observers said the decision to restart the damaged unit will likely be left to Singapore's Ministry of Manpower, which undertakes its own investigation when there are fatalities involved.

They also said any extended closure, required by authorities investigating the deaths, would affect the gasoline market, as regional supplies are tight.

Total Canada plans bitumen upgrader

Total E&P Canada Ltd. plans to begin detailed engineering in 2008 for a bitumen upgrader to be installed near Edmonton. Cost of the project was not divulged.

The company filed a public disclosure document May 7 with Alberta regulators. After all approvals are in hand, the upgrader will be constructed in two phases: Phase I is designed to produce 130,000 b/d of light, sweet synthetic crude that could come on stream as early as 2013-14, and Phase II would increase total bitumen processing capacity to over 200,000 b/d.

"Constructing the project in two separate phases will allow Total to match upgrading capacity with upstream bitumen production," said Michel Borrell, president of Total E&P Canada. "Early in the next decade the proposed Joslyn North mine project should be up and running in the Athabasca oil sands area." The Joslyn North mine project, currently under review by regulators, is expected to produce 100,000 b/d of bitumen. Future development could increase production to about 200,000 b/d.

Total E&P Canada Ltd. is operator of the Joslyn lease 65 km northwest of Fort McMurray in the Athabasca oil sands region. Joslyn, in which Total has an 84% stake, is expected to produce 2 billion bbl of bitumen over 30 years. Steam-assisted gravity drainage (SAGD) commercial production on the site began in fourth-quarter 2006 and will plateau at 10,000 b/d by 2008.

Total E&P Canada also has a 50% stake, in partnership with ConocoPhillips, in the 544 sq km Surmont project 60 km southeast of Fort McMurray. SAGD commercial production is expected to begin this year, with plateau reaching 27,000 b/d of bitumen. Initial evaluations set the development potential of the site upwards of 200,000 ✦

Transportation — *Quick Takes*

Kazakhstan, Russia join in oil pipeline projects

Kazakhstan's president Nursultan Nazarbayev said his country will join with Russia in two pipeline projects aimed at nearly doubling the amount of oil shipped westward from the Central Asian nation to international markets.

"I discussed in detail with President [Vladimir] Putin the question of increasing the capacity of the Caspian Pipeline Consortium from 23 million [tonnes/year] to 40 million tonnes/year," said Nazarbayev, referring to the existing 1,500-km pipeline that extends from Kazakhstan's Tengiz oil field to Russia's Black Sea port of Novorossiysk.

"The extra 17 million tonnes[/year] may go to Burgas-Alexandroupolis pipeline," Nazarbayez said, referring to a planned 280-km route backed and shared by Russia (51%), Greece (24.5%), and Bulgaria (24.5%) that will carry crude from Bulgaria's Black Sea port of Burgas to the Greek port of Alexandroupolis on the Aegean.

An agreement on the Burgas-Alexandroupolis line was signed by the three partner countries in Athens on Mar. 15, and the Russian government approved a draft law on May 10 that would govern the agreement to be sent to the Russian parliament for ratification. The line will initially carry 35 million tonnes/year, rising eventually to 50 million tonnes/year.

Under the agreement signed in Athens, Russia's 51% stake will be owned by a consortium comprised of OAO Transneft 33.4%, along with Rosneft 33.3%, and GazpromNeft 33.3%. Transneft also will hold the operating rights of the line, which will receive oil at Burgas carried by tankers from the Russian ports of Novorossiysk and Tuapse as well as from the Ukrainian ports of Odessa and Pyvdenny, both outlets for Russian oil.

The Burgas-Alexandroupolis line has been touted as an alternative to ships traversing the busy Bosporus Straits, something that Turkey has expressed concern over for years.

In April, however, Turkish authorities launched construction of a rival 700-km oil pipeline linking its Black Sea port of Samsun to its Mediterranean port of Ceyhan in the south. As with the Burgas-Alexandropolis line, the new Turkish project is being touted as a new energy route and one that bypasses the busy Bosporus.

Kinder Morgan to expand Texas pipeline

Kinder Morgan Energy Partners LP plans to build a $72 million natural gas pipeline to bring supplies from East Texas to Houston and Beaumont.

The proposed 58-mile, 24-in. pipeline will have multiple interconnections and will link the Kinder Morgan Tejas system in Houston County to the Kinder Morgan Texas system in Polk County near Goodrich, Tex.

The line will have an initial capacity of 225 MMcfd using existing horsepower and will be expandable to 400 MMcfd with additional horsepower.

Firm transportation for most of the initial capacity has been secured via a long-term binding agreement with CenterPoint Energy Services Inc.

Texas Intrastate Pipeline Group Pres. Tom Martin said the amount of drilling occurring along KMP's system in East Texas, including initial testing of the deep Bossier play in Houston and surrounding counties, were primary factors in deciding to add the pipeline, which will more than double capacity on Kinder Morgan's Tejas intrastate pipeline system. ✦

Calendar

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

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When gasoline prices rise

Laura Bell
Statistics Editor

When people find out that my job entails tracking US gasoline prices, they often ask, "Why are prices so high?" and "Are they going to continue to rise?" Many accept the explanations, but they still like to criticize oil companies for the high prices. This topic is much like talking about the weather; people just like to converse and voice their opinions. As much as they detest the high prices, consumers continue to dip into their pocketbooks and continue with their normal driving habits.

How high will gasoline prices have to go before consumers modify their driving habits? Recent reports on gasoline consumption indicated that as prices have risen, demand has not slowed down.

According to the US Energy Information, 4-week average demand data reported weekly for motor gasoline rose after Feb. 2 but started a slow descent in the middle of April, when gasoline prices, according to Oil & Gas Journal's weekly gasoline price survey, hovered around $2.78/gal.

In the latest data available, EIA's 4-week average for motor gasoline consumption for the week ending May 11 was up slightly at 9.293 million b/d. OGJ's average gasoline price for regular unleaded for May 9 jumped 9¢ from a week earlier to $3.05/gal. Despite the continued rise in price in gasoline, motorists are not slowing down.

Vehicle changes

High gasoline prices have affected not only consumers' pockets but also the US automobile industry.

In 1990, the industry introduced what would soon become one of the hottest vehicles on the market, the sports utility vehicle (SUV). Many baby boomers, who typically start purchasing trends, found that the SUV met their needs beyond what the family van or sedan once did. While sales were slow in the beginning, the SUV's popularity soared. In 2000, SUV sales in the US exceeded 3 million units. Adding to popularity of the vehicles were favorable financing options and rising disposable incomes. Families wanted something that could meet several needs, whether it was to tow boats or camping trailers, chauffer children to soccer games, or simply provide the luxuries of size and comfort. Gasoline prices were not a worry to most consumers who could afford and drive SUVs.

According to Ford Motor Co. sales analyst George Pipas, the auto industry began to see a slowdown in 2003, when SUV sales dropped by 4% due in part to the expanding market for sales of crossover utility vehicles (CUVs). In 2005, SUV sales declined by 13% as rising fuel costs drove more and more people to prefer fuel-efficient vehicles. The trend favored CUVs, which typically get slightly better gasoline mileage. In 2006, CUV sales amounted to 2.4 million units, topping SUV sales by 300,000 units.

The National Automobile Dealers Association's chief economist, Paul Taylor, in a speech earlier this year, said he expects the CUV market to "remain a key source of continued growth, rising by another 8% in 2007." He also said, "Sales of new cars and light trucks in 2007 will roughly equal the 2006 sales mark of 16.5 million."

Changing habits

Americans love and enjoy the independence provided by personal vehicles, which they are far from ready to abandon. Most of them are making room in their budgets to continue driving the way they want and need.

If gasoline prices continue to rise, however, many can be expected to begin to carpool, use alternative transportation, or manage schedules to cut time spent driving. The question mentioned earlier about how high gasoline prices go will be determined largely by adjustments such as these.

Small changes in many personal routines, coupled with big changes already evident in vehicle preference, can make a dramatic difference in retail gasoline prices. ✦

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Editorial

Arguing over cosmetics

US President George W. Bush doesn't know how much gasoline Americans should use. US senators and congressional representatives have no supernatural insight that the president lacks on this subject and thus don't know how much gasoline Americans should use, either. Yet Bush has advanced his plan for cutting US gasoline use by 20% in 10 years, and lawmakers are debating tactics rather than the merits of national consumption targets.

To be sure, the president's goal, announced in his state-of-the-union address in January, is vacuous. What makes 20% below some random baseline a reasonable objective?

Unpredictable mixture

The appropriate level of gasoline use 10 years from now will reflect an unpredictable mixture of influences including, but not limited to, economic activity, personal incomes, vehicle purchases between now and then, the cost of transportation not fueled by gasoline, end-use costs of alternative motor fuels, and the price of gasoline itself, which will depend on its own tangle of variables, including the price of crude oil. The president and his energy advisors have no valid way to forecast these complexities well enough to judge future consumption of gasoline. They have just picked a number and called it—by gosh—a national goal. That they can have done nothing more sophisticated than this raises a question: Which came first, the 20% target or the "20-in-10" slogan they've given their program?

In service to this mush, Bush issued an executive order calling on several federal agencies to cooperate on the implementation of mandates he announced when he set the gasoline-use goal. One of them would push the mandate for domestically produced renewable and other alternative motor fuels to 35 billion gal/year by 2017. Another would toughen corporate average fuel economy standards for cars and light trucks. In a clear indication of the priority this project is to receive, the agencies have until the end of Bush's term in office to work out details.

To Democrats in control of Congress, of course, the program doesn't do enough. Senate Energy and Natural Resources Committee Chairman Jeff Bingaman (D-NM) exposed the dark core of current energy policy-making when he responded to Bush's executive order by saying, "The absence of any standards in today's announcement is a reason why Americans will be looking to Congress for stronger leadership on energy policy." The prevailing assumption in Washington, DC, must be that Americans want their government to tell them how much and what forms of energy to use.

Can this be so? Do Americans really want to surrender economic choice to arbitrary consumption targets? Do Americans want to spend more than they should on motor fuels whose lone supposed advantage is that they contain no petroleum? Is their misdirected anger at oil companies so intense that they're willing to sacrifice freedom and wealth?

The problem, as Bush's initiative and the responses it has provoked make clear, is that legitimate policy options are not now under consideration in the US capital. No one with any national attention is acknowledging the historically clear need to leave fuel choice, price, and consumption levels to the market. Instead, they're arguing over cosmetics.

In the current environment, national leaders ignore market explanations for gasoline price movements in favor of repeatedly discredited allegations of unfair manipulation. In this environment, lawmakers waste public money on energy sources that might never be economic on their own. In this environment, loose talk about taxes and regulation poisons the climate for investment in energy infrastructure. In this environment, politicians appeal to energy security while refusing to allow oil and gas leasing of promising federal land.

National mistakes

This is the type of environment that breeds national mistakes on energy. It develops when leaders become arrogant enough to think that politics, with its compromises and tradeoffs, makes better energy choices than markets do. This has never been the case before. It's not the case now.

But when energy leadership starts with the metaphorically challenged assertion that the country has an "addiction" to a commodity preferred by the market, anything can happen—little of it good. ✦

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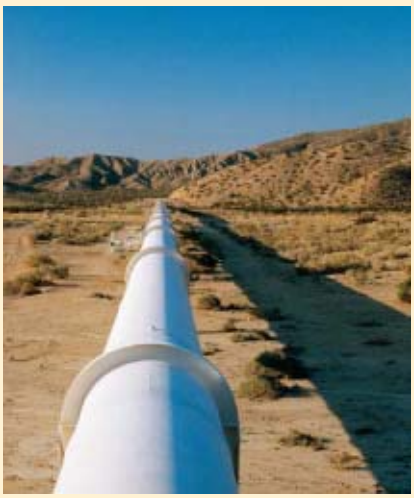

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THE OIL MARKET'S HARD CHARGERS—2

India steers new course toward energy reform

Gawdat Bahgat
Indiana University of Pennsylvania
Indiana, Pa.

India is the world's second most populous country (after China). Its population is projected to increase to 1.46 billion by 2030 from 1.09 billion in 2006. This expansion means an increasing number of energy consumers.

India's energy outlook is further complicated by its robust economic growth. After years of pursuing economic policies based on import substitution and state ownership of key industries, India's government has embarked on a series of economic reforms since the mid-1990s. This economic liberalization includes a relaxation of restrictions on foreign ownership in some sectors and privatization of some industrial enterprises. These reform policies are considered the main drivers for the nation's economic growth.

India is projected to maintain its impressive economic growth in the foreseeable future. During 2003-30, the world economy is expected to grow by 3.1%/year, while India's economy's growth rate will be 5.8%. Without reliable and affordable energy, India will not be able to sustain high economic growth. Its fast-growing economy and rapidly increasing population raise serious concern about the nation's energy security.

Indigenous production has failed to keep pace with rising demand, and the already large gap between energy production and consumption is growing larger. Because this skyrocketing energy demand has been increasingly met by imports, India is growing more dependent on and vulnerable to foreign energy supplies.

Energy mix

India currently is the world's fifth largest energy consumer—after the US, China, Japan, and Russia. Like other major energy consumers, India seeks to diversify its energy mix. The nation's energy sector is largely dominated by coal, followed by oil, and to a lesser extent natural gas. New Delhi plans to reduce its dependence on fossil fuels by expanding its reliance on nuclear power.

India holds the world's fourth largest proved coal reserves (after the US, Russia, and China) and is the world's third largest coal producer and consumer (after the US and China). Coal satisfies more than half of India's energy demand, particularly in the electric power generation sector. Coal production is controlled almost entirely by the government.

Oil accounts for about one third of India's energy consumption. Most of the oil and its products are consumed in the transportation, commercial, industrial, and domestic sectors. India holds limited proved oil reserves, with only 0.5% of the world's total. The country accounts for only about 0.9% of total world production but about 3% of worldwide consumption. India consequently imports 70% of its oil supply. Given stagnant production and a high depletion rate, India is expected to continue importing an incrementally large proportion of its oil supply.

The search for oil in India started in the 1860s when the country was under British occupation. Upon independence, the government realized the importance of oil in consolidating its political and economic development. In the mid-1950s the government set up the Oil and Natural Gas Directorate to develop natural resources. Later, the directorate was elevated into a commission with additional powers. These institutional initiatives underscore the government's intention to maintain a dominant role in the oil industry. The intentions became clearer in 1959, when Oil India Ltd. (OIL) was created, with substantial government ownership and control.

In the following decade, the government tried unsuccessfully to attract private investment to oil exploration and development. But private companies hesitated to participate in India's oil industry for two reasons: the low recovery rates and uncertain political climate.

In line with the state-led economic strategy, India in the mid-1970s nationalized the few private and foreign

About this series

China and India have charged into the oil market with consumption growth well above global average rates and with keen interest in securing supply. This article examines India's energy needs and its approaches to meeting them. The author profiled China in the first part of this two-part series (OGJ, Apr. 23, 2007, p. 20).

oil companies operating in the country. In addition, the Administered Pricing Mechanism (APM) was introduced to set the price of petroleum products. These steps ensured a dominant government role in the oil industry and eliminated private and foreign competition. As a result, the oil sector suffered from inefficiency, and production levels became stagnant. In response, the New Delhi government decided to change course and adopted a new measure known as the New Exploration Licensing Policy (NELP) in order to again attract foreign investment.

Most of India's oil reserves are located in the Mumbai High, Upper Assam, Cambay, Krishna-Godavari, and Cauvery basins. The offshore Mumbai High field is by far India's largest producing field. Production from these reservoirs has proven insufficient to meet the country's skyrocketing demand. The nation's oil consumption is projected to rise at a rate of 2.4%/year by 2030 to 4.5 million b/d from 2.3 million b/d in 2003. Meanwhile, production will rise to 1.4 million b/d from 800,000 b/d during the same time.

Natural gas

Like oil, India holds limited proved gas reserves—only about 0.6% of the world's total—but the balance between gas production and consumption is a little better than that of oil. India's share of world gas production is 1.1%, while its share of world consumption is 1.3%.

India is a relative newcomer to the use of gas. However, in the last few years, gas has become the fastest growing source of energy in the country. Its share of the nation's energy consumption rose to about 7% in the mid-2000s from 2.5% in the 1980s. By 2030, this share is projected to rise to more than 10%. The surge in gas consumption is due to its being a less polluting fuel than coal or oil.

In order to meet growing demand for gas, the government has invested substantial resources in exploration and development. Since the early 2000s several important new discoveries have been announced. These include a discovery in the Krishna-Godavari basin off Andhra Pradesh along India's southeast coast, another one off Orissa, and a third one off Gujarat. However, India will grow more dependent on imported gas.

New Delhi has considered two options for importing gas: LNG and pipelines. The nation's first major gas import deal was effected in January 2004 with the start of deliveries to the Dahej terminal from Qatar's Rasgas LNG plant. India's Foreign Investment Promotion Board actually approved 12 prospective LNG import terminal projects in the mid-1990s, but this plan was considered unrealistic because the combined capacity would have exceeded the most optimistic demand projections. Consequently, the government froze approvals of new LNG terminals in 2001. By 2009-10, Gas Authority of India Ltd. (GAIL), the main gas operator, expects LNG imports to supply about 38% of consumption, up from 22% in 2005.[1]

Proximity to several major gas producers adds financial and strategic incentives to the pipeline option. All pipeline options rely on difficult negotiations with neighboring countries. Four pipeline schemes have been under consideration for several years that would deliver gas from Bangladesh, Myanmar, Iran, and Turkmenistan.

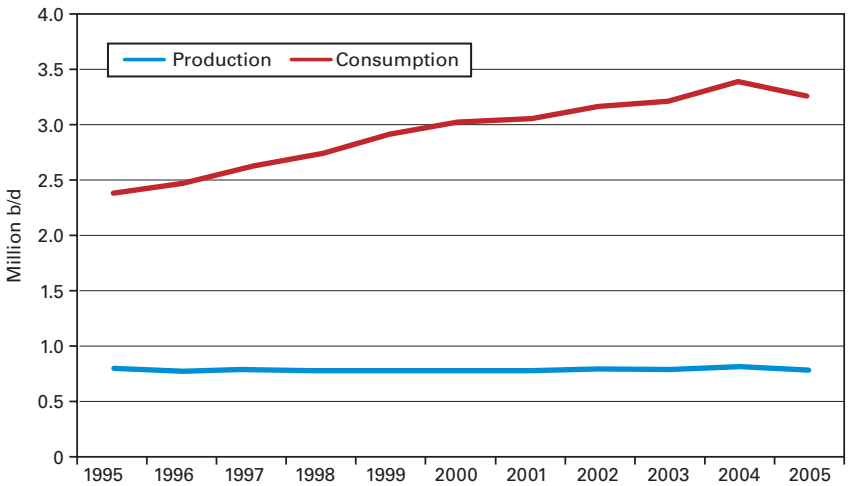
Nuclear power

Nuclear energy is seen as critical to fostering India's economic growth because of the environmental, geological, financial, and geostrategic limitations on the development and importation of fossil fuels. Nuclear-energy generation, however, has fallen woefully short of projections made in the 1970s, when it was thought that 10% of the nation's electric power would be nuclear by 2000. In 2002, nuclear power constituted only about 2% of the electricity generated in India, far less than in many other nations.[2]

India's nuclear power industry received a boost from the US in the mid-2000s, however. In July 2005 Washington and New Delhi reached an agreement under which India agreed to take several steps to demonstrate its commitment to being a responsible nuclear power and supporter of nonproliferation goals. In exchange, the US agreed to permit exports of nuclear equipment and technology to India.

In December 2006 President George W. Bush signed into law a bill called the US-India Peaceful Atomic Energy Cooperation Act. Under the law, India will allow inspections of its 14 civilian nuclear plants in exchange for fuel and nuclear technology from the US. Eight military plants in India will be

INDIA'S OIL CONSUMPTION VS. PRODUCTION



off-limits to inspection, though. The bill was passed overwhelmingly by the US House and Senate.

Opponents of the law warn that it could be a huge mistake that will only accelerate the proliferation of nuclear weapons and foment a dangerous nuclear arms race in Asia. Proponents of the law, however, argue that with a population of more than a billion people, India has massive and growing energy needs, and civilian nuclear technology would help it to modernize.

Despite these promising prospects for India's nuclear energy, the implementation of nuclear cooperation with the US will take many years. For the foreseeable future, coal, oil, and gas will continue to dominate India's energy.

Fractured energy strategy

India's efforts to address the dilemma of energy security are further complicated by what can be described as "institutional fragmentation." Despite long traditions of central planning and a state-led economy, there is no central authority in charge of drawing and implementing a long-term energy strategy. Many governmental institutions and private companies with competing interests vie for influence in shaping the nation's energy policy. The long list includes governmental entities such as the Ministry of Petroleum and Natural Gas, the Ministry of Coal, the Ministry of Nonconventional Energy Sources, and the Department of Atomic Energy.

In addition, the state owns several major oil and gas companies such as Oil & Natural Gas Corp. (ONGC), OIL, GAIL, Indian Oil Corp. Ltd., Bharat Petroleum Corp. Ltd., and Hindustan Petroleum Corp. Ltd.

The Indian government and national companies are not the only players in the nation's energy sector. Increasingly, private and foreign companies have made their presence felt. Essar Oil Ltd., Reliance Industries Ltd., Videocon Industries, British Gas Group, British Petroleum, and Royal Dutch Shell carry out major exploration and development. Despite this fragmentation among public and private entities, the government still holds decisive influence in making and implementing the energy policy.

"India's population is projected to increase to 1.46 billion by 2030."

For the last several decades the Indian government has tried to enhance the nation's energy security and reduce its vulnerability to supply disruption. A major step in this direction is the multidimensional deregulation of the oil and gas industry. In the early 1990s the government determined that fixed prices had deprived oil companies of the financial resources needed for exploration and development.

In response, oil and products prices were raised gradually, domestic prices were linked to international prices, and eventually companies were allowed to set their own prices. These developments have transformed the overall pricing structure away from a subsidized-controlled regime to a more market-based, competitive one.

These steps to reform the pricing system were accompanied by several cuts in taxes and duties on some petroleum products. The government also has encouraged research in fuel substitution, particularly biofuels such as biodiesel and ethanol. Like other major energy consumers, India is seeking to reduce energy losses and improve conservation and efficiency.

"By 2009-10, Gas Authority of India...expects LNG imports to supply about 38% of [India's] consumption."

Another major shift in India's energy policy was the introduction of NELP in 1997. The policy seeks to attract private and foreign investors by proposing attractive fiscal and contractual terms. According to NELP, all companies would compete on an equal footing to obtain exploration licenses from the government and would have equal access to high-quality seismic data. NELP promises a stable fiscal regime and guarantees companies the right to market their oil and petroleum products.[3]

The efforts to attract foreign investment have achieved modest success. Direct foreign investment in the 2000s is higher than that of the 1990s but much lower than in China and other competitors. The underlying reason behind multinationals' hesitation to invest in India's energy sector is that the probability of striking hydrocarbons in India is perceived as being extremely low. India will continue its heavy dependence on imported oil and gas, particularly from the Middle East.

Oil diplomacy

Heavy dependence on foreign supplies suggests a growing preoccupation with energy that is certain to shape India's foreign policy for years. The goal is to ensure continued access to outside suppliers. Indian officials describe this energy-driven foreign policy as "enlightened self-interest." The efforts to enhance the nation's energy security have prompted New Delhi to seek cooperation and partnerships with major oil and gas producers.

In addition, Indian oil companies have sought to acquire stakes in oil and gas blocks overseas. Indian oil companies, with governmental encouragement and approval, have won exploration and development rights in several foreign countries since the mid-1990s. The list includes Russia, Vietnam, Myanmar, Sudan, Qatar, Syria, Iran, Iraq, Australia, Cuba, and Egypt. India's quest for equity overseas faces strong competition from the other Asian giant—China.

New Delhi's drive to cooperate with other nations has expanded to other neighbors. India has called for the creation of a so-called Asian Oil Commu-

nity to promote dialogue between the energy producing nations of Azerbaijan, Kazakhstan, Russia, Turkmenistan, and Uzbekistan and energy consuming nations of China, India, Japan, and South Korea. Given Russia's massive hydrocarbon resources, India has expressed strong interest in investing in and working with Russian companies. India's ONGC, for example, owns a 20% stake in Russia's Sakhalin-1 project.

Like other energy consuming nations, India tries to diversify the sources of its oil and gas supplies. However, the bulk of India's imported oil comes from the Persian Gulf. The top five oil exporters to India are Saudi Arabia, Nigeria, Kuwait, Iran, and Iraq. This close cooperation between the two sides reflects long-standing historical, cultural, and strategic ties.

Two recent highly-publicized developments have demonstrated these close ties between India and energy producers in the Persian Gulf. In January 2006 King Abdullah visited India on his first trip outside the Middle East since becoming the Saudi ruler in August 2005. This was also the first visit by a Saudi king to India since 1955. The kingdom does not want to be too dependent on exporting its oil to a few Western markets and seeks to diversify its oil export destinations. Accordingly, the bulk of Saudi oil is shipped to China and India under its so-called "Look-East Policy."

The other important event was the convening of a meeting in New Delhi in January 2005 of major Asian energy consumers (China, India, Japan, Malaysia, and South Korea) and major Persian Gulf producers (Iran, Kuwait, Oman, Qatar, Saudi Arabia, and the UAE) The goal was to foster energy partnership between the two sides and address mutual concerns about security of supply and demand. A second meeting was held in Riyadh on May 2, 2007.

The way ahead

For the next several years four projections can be made regarding India's energy sector. First, the fundamental shift in India's overall economy and its energy industry away from central planning to a more competitive and market-based system is likely to continue. India's membership in the World Trade Organization since January 1995 reflects and reinforces this trend.

Second, booming economic growth in India and other Asian economies has turned Asia into the center of gravity for energy consumption. The fact that India and its Asian neighbors lack sufficient indigenous energy resources means that they will grow more dependent on foreign supplies.

Third, the International Energy Agency projects that non-OPEC production will be flat in the coming few years. Most of the incremental demand for oil will be met by OPEC members, particularly those in the Persian Gulf.

Fourth, India and other Asian countries need long-term energy supply security.

On the other hand, Persian Gulf producers need to secure markets for their oil and gas. This emerging "interdependence" between the two sides would serve their mutual interests and would contribute to the overall stability of global energy markets. ✦

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Refiners pull back on plans for capacity additions, EIA chief says

Nick Snow
Washington Correspondent

US refiners apparently have scaled back plans for additional capacity from levels of a year ago, the head of the US Energy Information Administration told a Senate committee on May 15.

Unexpectedly higher costs for the additions and uncertainty created by growing discussions of alternative energy sources are the primary reasons, EIA Administrator Guy Caruso told the US Senate Energy and Natural Resources Committee.

Caruso said a member of his staff noticed the difference after informally surveying refiners at the National Petrochemical & Refiners Association's 2006 and 2007 annual meetings.

The staff member, senior analyst Joanne Shore, told reporters following the hearing that EIA also monitors refiners' financial results and their statements to financial analysts. "We saw some projects pulled back or delayed due to sharp increases in costs and uncertainties due to alternative fuels," she said.

Shore said one of the biggest reductions in plans to add capacity came from Valero Energy Corp., the nation's largest independent refiner and marketer. "It had very aggressive plans in 2006," Shore said.

Via phone from Valero's headquarters in San Antonio, spokesman Bill Day said higher costs and a shortage of labor have made the company delay some projects. But it just completed one that expanded capacity at its Port Arthur, Tex., refinery to 325,000 b/d, and it is tentatively considering another that would cost $1 billion to raise capacity there to 400,000 b/d, he told OGJ.

'Starving investment'

Caruso's comment led committee member Ron Wyden (D-Ore.) to observe, "We've seen starving investment and record profits in refining the past few years."

A second witness, Paul Sankey, said, "Even with all the uncertainty, there's still tremendous investment, particularly in capacity to upgrade and process heavier crudes." Sankey is managing director of Deutsche Bank AG's oil equity research team in New York.

Their comments and testimony came as the committee held its annual hearing on the summer oil and gasoline outlook. But it came as many members of the 110th Congress expressed concern over recent gasoline price increases.

In his opening statement, Chairman Jeff Bingaman (D-NM) said he called the hearing because gasoline prices have reached historic highs. "Yesterday, the [EIA] posted the highest-ever price for gasoline, at a nationwide average of $3.10/gal. This is the third summer in a row that we are having this discussion about why prices are at record levels," he said.

Chief minority member Pete V. Domenici said while rising gasoline prices frequently bring heightened scrutiny and accusations of manipulation, the main culprit is increased global demand coupled with reduced supplies. "Unfortunately, this particular hearing has become as predictable as the cherry blossoms here in Washington. We may not know exactly when, but you can bet that in the late spring, this committee will hold a hearing to talk about gas prices," he said.

"I don't think there's a free market here at all," said committee member Byron L. Dorgan (D-ND). "You've got [the Organization of Petroleum Exporting Countries] trying to restrict production. You've got major oil companies, which are stronger through mergers. And you have refining, where ownership is highly concentrated."

Robert Menendez (D-NJ), another committee member, said, "This is the third year in a row that consumers are facing prices above $3/gal, yet there's been no event like a hurricane or a major refinery outage to cause it."

Lingering outages

But Caruso said US gasoline production was affected more than usual by refinery outages this spring, which extended past the first quarter into May. That, combined with low imports and seasonally rising gasoline demand, made inventories drop sharply to 193 million bbl by the end of April, more than 14 million bbl less than a year earlier and 12 million bbl less than the lower end of the typical range for this time of year, he told the committee.

"During April, EIA estimated that refinery outages may have reduced gasoline production by 150,000 b/d over average outages for that period. Refinery throughputs have just begun to show the seasonal increase typical at this time and are expected to increase over the next several months, which should ease pressure on gasoline prices," Caruso said in his written statement.

EIA expects average US prices for regular grade gasoline to grow from $2.24/gal in January to $3.01/gal in May. This could ease slightly during the summer before returning to May's level as Labor Day approaches, the EIA administrator said. The price through the summer driving season is a projected $2.95/gal, 11¢ higher than the comparable 2006 period's average, he added.

Sankey added that two of the nation's five largest refineries—both owned by BP PLC—are running at 50% of their usual capacity for safety reasons. The plants in Texas City, Tex., and Whiting, Ind., are producing 400,000 b/d less than usual, with the remainder "operating suboptimally, running rate light, sweet crude when they should be using more abundant heavy, sour grades," he said in his written testimony.

The Deutsche Bank analyst also said years of reduced refining investment have led to a lack of qualified engineering procurement and construction staff. "One vital issue here is that the tightness of US refining capacity at this time is not because companies are unwilling to invest in more capacity, it is that they are unable to. There is competition from nonrefining investment to exacerbate the problem, notably in Canadian heavy oil sands," he said.

Kevin J. Lindemer, executive managing director of Global Insight in Lexington, Mass., told the committee that a smooth transition from current low inventories and extended maintenance to full production in the next several weeks could bring gasoline prices down to a nationwide average of $2.75/gal by the end of the summer.

"However, the system remains extremely vulnerable to disruptions and events. The risk of higher prices at the retail level comes from refining operations and the global crude market. Further events that increase supply concerns materially could drive average gasoline prices to the $3.25 range by the end of summer," he said.

Minimum inventories

Geoff Sundstrom, public affairs director for AAA, said the motorist organization believes Congress and

the administration of President George W. Bush should explore measures that would require refiners to maintain a minimum level of gasoline and other product inventories.

"Such a system exists in Europe and was able to provide critical gasoline to the US during production shortfalls that occurred following the 2005 hurricanes. Should similar or worse disasters occur in the future, our ability to immediately move gasoline to areas that need it will again be critical," he said.

When Bingaman asked if refiners could be required to report planned outages to the federal government, Caruso said it would be difficult to manage. "Even in planned outages, they may find the problem is more extensive than they anticipated. So even if they did report, I don't know if we'd have enough information to say whether they should proceed or wait," the EIA administrator said.

Sankey also was skeptical of calls by some federal lawmakers to give the Federal Trade Commission authority to investigate oil product price manipulation allegations. "We believe there have been enough investigations by Republicans and Democrats to show that there's no price-gouging taking place nationwide. There may be some rogues doing it regionally. But the fact is that refiners are making so much money legitimately that they don't need to do it," he said.

"There's also great concern that all these gasoline investigations which are being proposed will lead to regulations which would make new investments uneconomic," Sankey added.

When Wyden and some other committee members asked why more investments haven't been made in refining with profits so high the past few years, the Deutsche Bank analyst said that the past 3 years of strong earnings followed about 3 decades of miserable results.

"If you look at how the stock market values refiners, they are still among the cheapest investments at about 5 times earnings. It's obvious that investors believe economically attractive refining conditions aren't permanent," Sankey said. ✦

Oil costs, demand push gas prices up, House panel told

Nick Snow
Washington Correspondent

High crude costs remain the single biggest force behind rising gasoline prices, said John C. Felmy, American Petroleum Institute chief economist, on May 9. But the current increase also reflects record US demand for gasoline during the first quarter, he told a US House special committee.

"In addition, the annual switchover to 'summer blend' required by [the US Environmental Protection Agency] has occurred and this warm-weather gasoline is more expensive to produce," Felmy told the House Select Committee on Energy Independence and Global Warming. "The switchover requires a large supply drawdown to meet regulations."

His testimony came a day after the Senate Commerce, Science, and Transportation Committee added an amendment that would make gasoline price gouging a federal crime to a bill aimed at improving automotive fuel efficiency requirements (OGJ Online, May 9, 2007). Two separate House subcommittee chairmen also have announced in the past week that they would hold hearings to investigate rising gasoline prices.

Felmy said the US Department of Energy forecasts continued strong gasoline demand through the summer driving season. "Moreover, nearly half of US gasoline is blended with ethanol, so as demand has gone up, ethanol prices and the cost of ethanol-blended gasoline have risen as well," he said.

There also is less gasoline available to import as European refineries undergo spring maintenance, he added. A 17-day strike in March by French port workers also led some European refiners to reduce production, he said.

Crude stocks grow

US oil producers and refiners are responding to consumers' price concerns, Felmy said. "Crude oil inventories have been building and, as of today, are 8.9% above the 5-year average for this time of year. Year-to-date gasoline production is 8.85 million b/d, the highest ever," he said.

"Thanks to the industry's major investments in state-of-the-art refining technology, our companies are squeezing out more gasoline and diesel fuel from a barrel of crude oil this year compared to past years. Looking ahead, we expect to bring the equivalent of eight new refineries into operation by 2011," Felmy continued.

While rising gasoline prices are a burden to consumers, they cannot be isolated from the overall US energy situation, he said. "The solution to the energy challenges we face is to increase and diversify sources of supply, including alternatives; reduce demand and expand infrastructure," he told the committee.

"We have plentiful oil and gas resources remaining to be discovered in the US—enough oil to power more than 60 million cars and heat more than 25 million homes for 60 years, and enough natural gas to heat an additional 60 million homes for 160 years. Only government policies stand in the way of increasing access to these resources, facilitating refining capacity and pipeline expansions, and increasing energy security," Felmy said.

Four other witnesses—Sylvia Estes, president of Pipeline and Industrial Group in Virginia Beach, Va.; Michael Mitternight, owner of Factory Service Agency in Metairie, La.; Terry Thomas, chief executive of Community Bus Services in Youngstown, Ohio; and Donn Teske, president of the Kansas Farmers Union in McPherson, Kan.—testified about the impacts of higher gasoline prices on their businesses. ✦

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Bush orders action on CAFE, motor fuel alternatives

Nick Snow
Washington Correspondent

US President George W. Bush ordered federal agencies to implement proposals to increase motor fuel efficiency and develop motor fuel alternatives more quickly.

The May 14 executive order uses the plan to cut US gasoline consumption by 20% in 10 years, which Bush announced in his 2007 State of the Union address on Jan. 23, as a starting point. It directs the Environmental Protection Agency and the Departments of Energy, Agriculture, and Transportation to coordinate efforts and complete their work by the end of 2008.

"I've also asked them to listen to public input; to carefully consider safety, science, and available technologies; and evaluate the benefits and costs before they put forth the new regulations," Bush said.

The proposals separately mandate that the amount of renewable and other alternative motor fuels produced domestically reach 35 billion gal/year by 2017 and that corporate average fuel efficiency standards be increased for cars and light trucks.

Bush noted that the US Supreme Court ruled last month that EPA must take action under the Clean Air Act to regulate greenhouse-gas emissions from motor vehicles. "The steps I announced today are not a substitute for effective legislation, so members of my cabinet, as they begin the process toward new regulations, will work with the White House to work with Congress to pass the 20-in-10 bill," he said.

Congressional reactions

Several members of Congress reacted immediately to the president's announcement. Senate Energy and Natural Resources Committee Chairman Jeff Bingaman (D-NM) said the order essentially mandates federal agencies to work together but lacks specifics. "The absence of any standards in today's announcement is a reason why Americans will be looking to Congress for stronger leadership on energy policy," he said.

Pete V. Domenici (R-NM), the committee's chief minority member, said Congress should work with the administration to reach the goals Bush listed but added that the country also "must continue to engage China, India, and other developing nations to reduce carbon emissions." He said, "Only a truly global effort with shared sacrifices will have a meaningful impact on improving the world's climate."

Rep. John E. Peterson (R-Pa.) said while he agreed with Bush that federal funds need to be directed to developing alternative fuels and increase motor vehicles' mileage per gallon, "this administration continues to disregard the fact that if 85% of our Outer Continental Shelf remains off-limits for natural gas exploration due to presidential and congressional moratoria, we will undoubtedly become a second-grade nation."

The American Petroleum Institute also issued a statement following Bush's announcement, noting that it was pleased that the administration "has decided to undertake a full rulemaking and comment approach that recognizes the technological challenges and significant infrastructure hurdles that must be resolved to significantly increase renewable and alternative fuels in the nation's fuel mix."

API said Bush's plan calls for an increase in the use of motor fuel alternatives to 35 billion gal/year by 2017. Ethanol has a role, but it will be limited until significant technology breakthroughs permit ethanol's economic production of biomass, API said, adding, "The timing of such breakthroughs is highly speculative." ✦

Deloitte: Gas supply question makes Europe edgy

Nick Snow
Washington Correspondent

European countries are increasingly apprehensive about Russia's attempts to control natural gas supplies and transmission, noted speakers at the 2007 Deloitte Energy Conference on May 14.

"Most of the nations in Europe get it. They're concerned about the possibility of a natural gas cutoff by Russia. They recognize the potential impact of all those pipelines flowing east from Kazakhstan and other Caspian producers," said Richard G. Lugar (R-Ind.), ranking member on the US Senate Foreign Relations Committee, following his keynote address.

He told conference participants that the North Atlantic Treaty Organization's members face security questions about gas that are as severe as the political situations that led to NATO's initial formation following World War II. "The attack may not come with guns or warships, but with the more expedient approach of simply turning off the natural gas tap," Lugar said.

Nader Sultan, senior partner in the F&N Consultancy and director of the Oxford Energy Seminar in the UK, also suggested that Russia's influence over Europe's future natural gas supplies will increase.

"It's interesting that it's trying to go downstream and increasingly control transmission. But it's also important that while major [LNG] exporters in the [Persian] gulf and Middle East aren't going to increase production much in the next 5 years, Russia will," he said.

An energy minister of one former Soviet republic observed recently that

energy has become Russia's major weapon, one that's more powerful because there's no way to retaliate, Sultan said.

'No longer cheap'

Bruno Lescouer, senior executive vice-president of Elétricité de France SA, said that Europe's demand for electricity is expected to increase 50%, and the share of gas used in its generation is forecast to more than double by 2030, raising the continent's dependence on imported energy to 70%.

"Gas is no longer the cheap technology it was in the 1990s. Prices have recently tripled, and supplies are limited and in faraway countries," he said, adding that the situation has generated renewed interest in nuclear power across Europe.

"There is no easy way out. It will take years to find other supplies," observed Sead Vilogorac, senior economic affairs officer in the United Nations Economic Commission for Europe's sustainable energy division, during a luncheon conversation with reporters.

Lugar noted that in the past 2 years, Ukraine and Belarus each confronted gas supply threats from Russia that Russian officials said were simply market matters.

"Some NATO members said the organization was not designed to handle something like this when I raised the point at a recent summit. But there are no major new storage and transmission facilities in Europe. There was talk of Kazakhstan putting a pipeline beneath the Caspian Sea, but when the announcement came this past weekend, it went another direction and into Russia," the US lawmaker said.

"So there's a lot of whispering taking place in many governments on an issue that could fray the NATO alliance," he added.

Vilogorac said he was not particularly surprised that Russia and Kazakhstan reached that gas pipeline agreement. "There's a long history—decades—of cooperation between the two countries so it was easier to develop," he said.

WATCHING GOVERNMENT

Nick Snow, Washington Correspondent

The benefits of initiative

Kenneth Irving, chief executive of Irving Oil Ltd. in St. John, NB, has a recommendation for his refining competitors in the US: Don't resist the push for action on global warming. Embrace it instead—but carefully.

He and the company his grandfather started in the 1920s have benefited from promptly investing to produce fuels that respond to environmental concerns, such as low-sulfur gasoline and diesel fuel.

"We don't see a sudden and complete withdrawal of petroleum products from the energy equation. We do see a gradual reduction in their share of overall North American demand," he said at the Deloitte 2007 Energy Conference May 14 in Washington, DC.

This raises a question of whether future processing investments will be confined to areas where demand is growing. "It's possible that future product suppliers will have to meet more stringent emissions requirements in North America while leaving a bigger carbon footprint abroad," Irving said.

He still has questions about nonpetroleum motor fuel alternatives, however. "The biggest one is whether all the new plant investments that are being encouraged are moving ahead before their life cycles have been determined," he said.

Series of firsts

Irving Oil has benefited from moving quickly. When it built its refinery in 1960, it was in a unique line formation on 780 acres that allowed for expansions in 1971, 1974, and 2000. The current crude capacity is 250,000 b/cd. Irving was the first Canadian refiner to produce high-octane gasoline without lead additives. It offered low-sulfur gasoline 5 years before requirements for the fuel took effect. It was the first Canadian refinery to produce ultralow-sulfur gasoline and diesel fuel.

One result, said Irving, was that Irving Oil supplied CARB-formula gasoline to California as many refineries there were still reconfiguring operations.

It also began seeking permits for an LNG terminal in the late 1990s, which its CEO said puts it ahead of many competitors. And it has several thousand acres of industrially zoned land next to one of North America's few true deepwater ports so it can build a second refinery.

No NIMBY here

The company emphasizes local public involvement as it grows, Irving said. "There's strong local concern about environmental impacts. There's also a surprising amount of interest in where a project fits globally. People in New Brunswick seem to think they'll have more influence if a project is close to where they live. It's the opposite of the 'not-in-my-backyard' attitude you hear about."

He suggested that refiners adopt new definitions of what constitutes reliable supplies. "Petroleum still constitutes 50% of all energy consumed, so our industry shouldn't be let off the hook in considering ways to better meet future demand," he said.

As for dealing with greenhouse gas emissions, said Irving, "Why wait for regulations? If we can do it, why not get on with it?" ✦

In the meantime, said Sultan, countries and governments are watching with interest as Qatar follows an LNG export model that could be replicated elsewhere. Instead of awarding each of its five projects to the highest bidder, it reached an agreement with a different large multinational firm for each, and is trying to develop strategic alliances along the value chain, he said.

Joseph A. Stanislaw, an independent senior advisor for energy and resources at Deloitte & Touche LLP, said it was in the interest of producers such as Qatar to gain access to more of the value chain so they can assure that the gas they produce continues to reach markets. ✦

IEA members seek energy security, sustainability

Doris Leblond
OGJ Correspondent

Ministers of the International Energy Agency's member countries, having confronted growing energy challenges since their last meeting in 2005, gathered in Paris May 14-15 to identify methods of achieving energy security and sustainability, which are "absolutely paramount," said IEA Executive Director Claude Mandil.

At a press conference that concluded the meeting, Mandil said, "Both must be taken care of simultaneously."

Members also called upon the organization to deepen its global reach. "Actions within our own borders will never be enough to achieve a truly sustainable energy future," said the ministers, who welcomed IEA's reinforced work with major non-IEA energy consumers and producers as "essential partners in achieving a secure and sustainable energy future and combating energy poverty."

The ministers want IEA to promote across the globe what it advocates for its own members—the development of efficiency goals and action plans that identify sustainable, least-costly policies for combating energy-related climate change.

That will require development and deployment of new technologies, among them carbon sequestration capture and storage to promote clean coal and the encouragement of research and development to reduce the costs of advanced biofuels, solar power, hydrogen fuel cells, and electric vehicles. Energy technology collaboration with major emerging economies must be enhanced, they said, both bilaterally and through IEA's technology network.

However, several leaders denounced the environmentally unfriendly way some biofuels were being produced in a number of countries. Each particular way of producing ethanol must be assessed to determine if it is good for the environment, they said. Brazil's method using sugar cane was considered the most environmentally friendly because less fuel is used. An IEA delegation will head to Brazil shortly to study its technology.

IEA is anticipating that second-generation biofuels will be ready in a few years, not decades, said Mandil.

Russia and OECD

Concerning relations with Russia—a possible candidate for the Organization for Economic Cooperation and Development's membership enlargement policy—IEA indicated that its rules were not the same as those of its OECD parent organization, and membership in one did not mean membership in the other.

Nonetheless, Mandil said the main driver of relations between IEA and Russia was one of mutual benefit. Such bilateral relations have been in effect over the past 15 years and were renewed a fortnight ago with a fresh memorandum of understanding signed, meaning that "our relations are existing and alive," he said.

This does not mean, added Mandil, that they were totally without dissent. "But on a number of topics we listen to each other."

Gas cartel?

Concerning the recurring topic of the formation of a gas cartel much like OPEC's being formed, Norway's Minister Odd Roger Enoksen, who chaired the Ministerial meeting, and Australia's Deputy Secretary Resources, Energy, and Industry, John Ryan, pointed out that they were major gas exporters—Australia by next year would be the third ranking LNG exporter worldwide—and did not see a gas OPEC emerging. "But open dialogue would be welcomed as for oil markets," they agreed.

In any case, unlike oil, gas can more easily be replaced by other fuels, pointed out Mandil, so a gas OPEC would not be a threat for the world energy market. He also revealed that at the close of the recent Doha meeting of gas exporters, there resulted a working group on transparency of the market, chaired by the Russians. Mandil asked if IEA could be part of that group, and he received a positive answer.

IEA expressed concern about a shortfall of oil and gas investment as outlined in the organization's recent publication "2007 Natural Gas Market Review."

"In the medium term," said Mandil, "we see increased capacity from investment projects, starting now. But this does not give us room for complacency."

The ministers' final press release cautioned: "Markets need more transparent, stable, and predictable regulatory frameworks to boost investment as well as better data for timely investment. All countries must accept the responsibility for creating such conditions." ✦

China's crude production rising slower than demand

China reached production of 3.6 million b/d of oil, 50 billion cu m of natural gas, and 5.8 million b/d of refining capacity by 2005, Facts Global Energy Group (FGE) reported in a May research paper. The group includes Fesharaki Associates Consulting & Technical Services Inc. (FACTS) of Honolulu.

China's 2000 crude oil output was 3.24 million b/d, and its natural gas output that year was 27.7 billion cu m. Refining capacity was 4.2 million b/d for 2000.

The FGE paper reviewed China's petroleum and gas production during the nation's 10th 5-year plan. During the 10th 5-year plan, China's added proved oil reserves increased to 34.8 billion bbl compared with 26.7 billion bbl for the 9th 5-year plan. The Asian giant's proved gas reserves increased to 2.5 trillion cu m by 2005 compared with 1.2 trillion cu m in 2000.

During 2000-05, China's oil consumption grew much faster than its oil production. Exports for oil decreased because of domestic oil demand growth.

China's crude oil imports increased to 2.54 million b/d in 2005 compared with 1.4 million b/d in 2000. Meanwhile, China's crude oil exports decreased to 161,300 b/d in 2005 compared with 205,600 in 2000.

The Middle East has been the largest source for China's import, with the nation receiving more than 50% of its total imports from that region. During the last 5 years, China began to diversify its import sources for crude oil. The share of imports from Africa increased to 30.3% from 22.7%. China's share of imports from Europe increased to 11.5% from 5.6%.

Refined products

China's production of refined products also grew. Its output of gasoline

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

China's Sudan work criticized

Critics are eyeing Chinese oil and gas exploration activity around the world, not least in Sudan where, it is claimed, Beijing is ruthlessly exploiting the government's economic vulnerabilities.

That's what London-based Al-Sharq al-Awsat newspaper suggested last week, explaining that Beijing is "taking advantage of the large deficit in the Sudanese government's budget and its need for weapons."

The paper said Beijing now buys oil from Khartoum "for peanuts" at a mere $13/bbl, adding that this grade of crude—all from Sudan's southern oil fields—fetches "many times" that price on the international market.

It said China buys two thirds of Sudan's production of crude oil, but "Khartoum has spent lavishly on the police apparatus, and this has led to a large deficit in its budget."

Hard to credit

Given the price of oil on the market these days, we find this story hard to credit. After all, Khartoum is in a seller's market and unlikely to be cash-strapped. If anything, Sudan is doing well out of the oil market, and that is the real cause for concern in some circles.

Sudan's success, in fact, is the reason why other knives are out for the Chinese. The other knives are largely in the hands of activists who are targeting large investors in publicly listed companies with interests in Sudan—especially oil interests.

For months, an activist coalition, formed to pressure Khartoum to end alleged genocide in Darfur, has been pushing investment funds managers to divest from PetroChina in particular because of its parent company's oil business in Sudan.

China National Petroleum Corp., PetroChina's state-owned parent company and the country's largest oil and gas enterprise, owns 40%—the largest single share—of the Greater Nile Petroleum Operating Co. (GNPOC), which has a hand in much of Sudan's oil industry.

A little help...

With a little help from GNPOC, Sudan's oil industry is moving along smartly, too. According to the US Energy Information Administration, Sudan's oil production has risen steadily since July 1999 when GNPOC completed construction of an export pipeline that carries oil from fields in central Sudan to the Port of Sudan on the Red Sea.

In 2006, Sudan's crude oil production averaged 414,000 b/d, up 14% from the 363,000 b/d produced in 2005. Still more is expected, with the government saying the country will produce 1 million b/d of oil by yearend 2008.

Given that outlook, one can understand why the activists are targeting PetroChina, apparently with success.

Under pressure from activists, Fidelity, the world's largest mutual funds company, recently announced it had sold 91% of its American Depository Receipts in PetroChina in this year's first quarter.

Fidelity did not say why it had sold the shares, but its action will likely embolden activist efforts to increase the pressure on other large foreign investors in the Sudanese oil industry—among them, the Chinese. ✦

increased to 1.26 million b/d in 2005 from 960,200 b/d in 2000. Its kerosene production increased to 214,000 b/d in 2005 compared with 188,300 b/d in 2000, FGE said.

Diesel output was 2.3 million b/d in 2005 compared with 1.4 million b/d in 2000. Its fuel oil production was 415,100 b/d in 2005 compared with 376,000 b/d in 2000.

China's exports of refined products continued to increase as well. The nation was a net exporter of gasoline and diesel, and a net importer of kerosine and fuel oil.

The refining sector accounted for 95.9% of total crude oil use. The transportation sector (including storage and postal services) accounted for about 50% of total consumption and was the largest consumer of refined products.

The industrial sector was the second largest consumer of refined products in China. Both the industrial and power-generation sectors were China's main consumers of fuel oil, FGE said. ✦

Bolivia decrees foreigners may not export products

Peter Howard Wertheim
OGJ Correspondent

Bolivia's President Evo Morales has issued a decree that forbids Brazil's state-owned Petroleo Brasileiro SA (Petrobras) and other foreign companies from exporting certain oil products.

Henceforth only Bolivia's state-owned Yacimientos Petroliferos Fiscales Bolivianos (YPFB) will be able to export oil products.

As a result of the Morales decree, Petrobras offered to sell Bolivia 100% of its two refineries that Bolivia nationalized last year along with hydrocarbons resources (OGJ Online, May 2, 2006).

Before Morales' decree Petrobras was negotiating the sale of 70% of its refineries to Bolivia and expected to retain 30%.

Bolivia had 2 days to respond to the May 7 sale offer, said Petrobras Pres. José Gabrielli, warning that Petrobras would seek international arbitration if an agreement couldn't be reached. He said it was "practically impossible" that Petrobras would make new investments in Bolivia.

Brazil's Foreign Ministry released a statement saying the decree could eventually have a "negative impact" on cooperation between the two nations.

Petrobras wanted a fair price for the refineries it owns and operates: the Guillermo Elder Bell in Santos Cruz and the Gualberto Villarroel in Cochabamba. The two refineries together process 40,000 b/d of oil and handle 90% of Bolivia's oil and gas for domestic consumption (OGJ Online May 2, 2007).

Bolivia Vice-President Alvaro Garcia Linera also skewered the drawn-out price negotiations between Bolivia and Brazil, saying in a radio broadcast that Bolivia would pay only $60 million for the refineries, while Petrobras wanted $200 million. It received $112 million (see story, p. 34).

Bolivian government sources have threatened to confiscate the refineries, which Petrobras bought in 1999 for $102 million and in which it has since invested another $100 million.

Brazil's Energy Minister Silas Rondeau confirmed that Petrobras could have sought arbitration if it and Bolivia could not reach a deal. He suggested that a company such as Venezuelan state-run oil firm Petroleos de Venezuela (PDVSA), working with narrower profit margins, could take over operation of the refineries.

Petrobras, the biggest investor in Bolivian gas, purchases 70% of Bolivia's natural gas output, importing some 25 million cu m of gas/day through the 3,150 km Bolivia-Brazil gas pipeline.

YPFB will run Bolivia's oil and gas pipelines and domestic sales and exports, said company Pres. Guillermo Aruquipa. The 44 new contracts signed recently by a dozen oil companies, including Petrobras, Repsol YPF SA, and British Gas, will yield $2 billion in 2007 said Arequipa.

Bolivia's Hydrocarbon Chamber said investment in Bolivia's oil and gas industry fell to $120 million last year from $650 million in 2002. The chamber represents 100 companies operating in Bolivia.

Bolivians not helped

One year after nationalizing its oil and gas sector, Bolivia has not yet placed a single boliviano (Bolivia's currency) into the people's pockets, say economic analysts.

"The resources from higher taxes and royalties are not reaching the majority of the population, which is very poor, despite the fact that from the macroeconomic point of view Bolivia is in a good situation," said economist Gonzalo Chavez, head of the economics and development department of Bolivia's Catholic university.

Bolivia said that with the revision of natural gas contracts, the country received $1.6 billion last year. Revenues from gas royalties and taxes before the nationalization were $600 million.

After the 2006 nationalization, Bolivia renegotiated contracts, signed on May 2, with foreign oil and natural gas firms operating within the country. The new contracts award the government an average of 82% revenues for natural gas and oil operations in Bolivia over the next 20-30 years.

Bolivia classifies these firms as "service providers" to YPFB. Petrobras describes the contractual arrangements differently, saying it is a "production partner" with YPFB. This divergence in the way the contracts are publicly portrayed has not become an open argument between the two, but it suggests the possibility of conflicting interpretations in later disputes.

Government statistics show that in 2006 Bolivia went through an external shock. For the first time in 5 years, ex-

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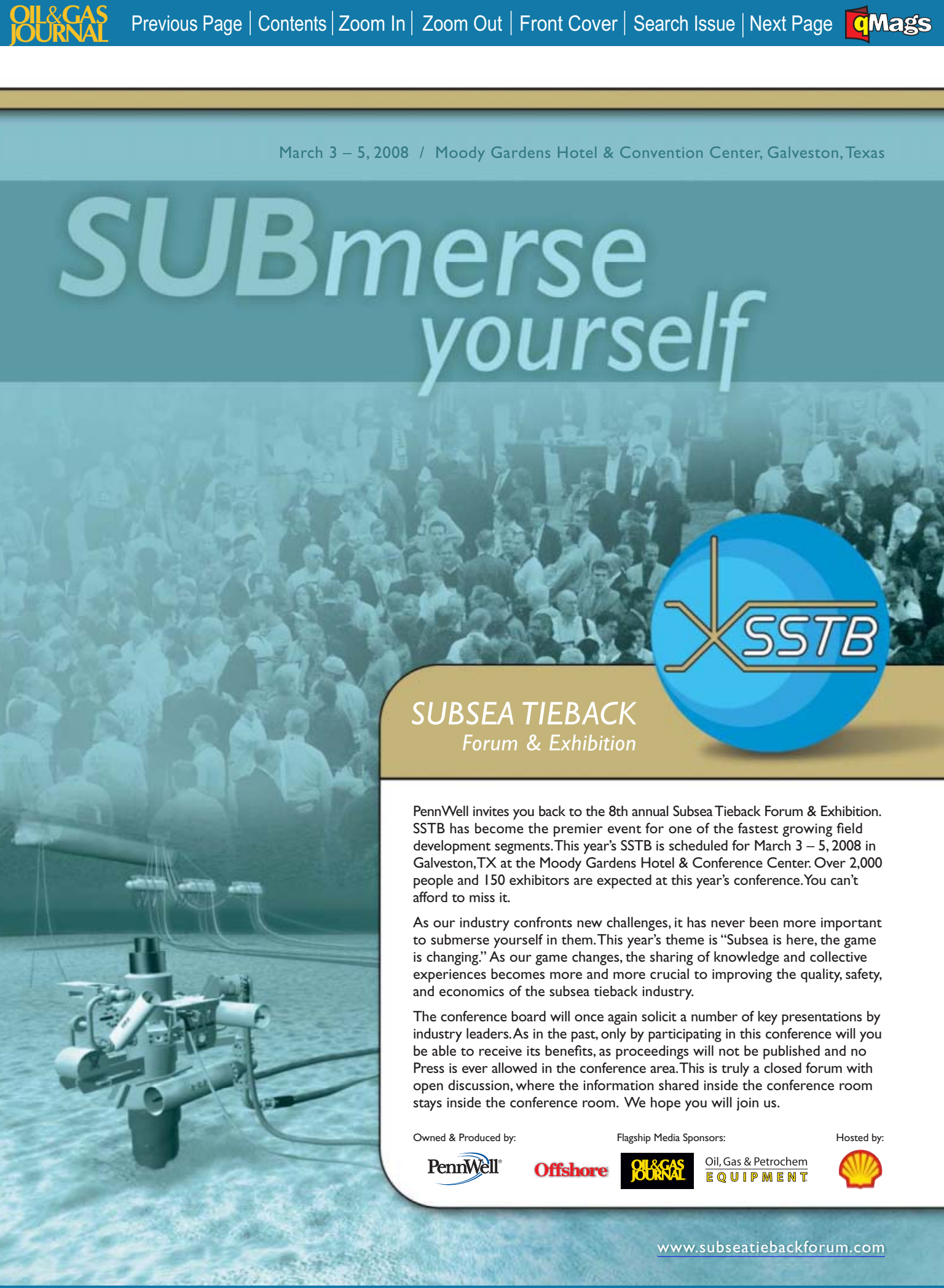

SUBSEA TIEBACK
Forum & Exhibition

SSTB

PennWell invites you back to the 8th annual Subsea Tieback Forum & Exhibition. SSTB has become the premier event for one of the fastest growing field development segments. This year's SSTB is scheduled for March 3 – 5, 2008 in Galveston, TX at the Moody Gardens Hotel & Conference Center. Over 2,000 people and 150 exhibitors are expected at this year's conference. You can't afford to miss it.

As our industry confronts new challenges, it has never been more important to submerse yourself in them. This year's theme is "Subsea is here, the game is changing." As our game changes, the sharing of knowledge and collective experiences becomes more and more crucial to improving the quality, safety, and economics of the subsea tieback industry.

The conference board will once again solicit a number of key presentations by industry leaders. As in the past, only by participating in this conference will you be able to receive its benefits, as proceedings will not be published and no Press is ever allowed in the conference area. This is truly a closed forum with open discussion, where the information shared inside the conference room stays inside the conference room. We hope you will join us.

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Bolivia to pay $112 million to buy back Petrobras refineries

After days of tense negotiations between Brazil's state-owned Petroleo Brasileiro SA (Petrobras) and the Bolivian government, Bolivia's President Evo Morales announced that his country had reached a deal to purchase the country's two refineries from Petrobras.

Bolivia will pay $112 million to buy back the two refineries, which together provide 90% of Bolivia's domestic products needs.

On May 6 Bolivia issued a decree that forbade Petrobras and other foreign companies from exporting certain oil products (see story, p. 32). Petrobras reacted strongly giving Bolivia 48 hr to buy all of the refineries.

Brazil's Mines and Energy Minister said Petrobras might accept payment in two installments or in natural gas.

Brazil currently buys about 25 million cu m/day of gas from the Andean country, representing about half of Brazil's gas consumption, and more than two thirds of Bolivia's gas output. Petrobras also has heavy exploration and production investments in Bolivia's oil and gas sectors.

Bolivia had initially offered only $60 million for the refineries, while Petrobras had started as high as $200 million as compensation for the original price as well as investments since then to modernize the plants. Bolivian government sources have threatened to confiscate the refineries, which Petrobras bought in 1999 for $102 million and in which it has since invested another $100 million.

When Petrobras gave its purchase ultimatum, it said if an agreement was not reached, Petrobras would seek international arbitration.

"An agreement is always better than [going] to court," said Brazilian energy specialist Marco Tavares of the consulting company Gas Energy. "And what is the guarantee that Bolivia would abide by a judicial decision? Bolivia has a track record since the 2006 nationalization of the oil and gas sectors of breaching contracts," Tavares added.

Marco Aurelio Garcia, a top aide to Brazilian President Luiz Inácio Lula da Silva, told BBC there will be a period of transition in handing over the refineries to Bolivia's state-owned Yacimientos Petroliferos Fiscales Bolivianos (YPFB). During the transition period Petrobras will work with YPFB personnel, especially in implementing safety criteria.

"Brazil depends on gas from Bolivia, but Bolivia is completely dependent on the Brazilian market since Petrobras is Bolivia's largest company," concluded Garcia.

ports that previously had not surpassed $1.8 billion jumped to $4.2 billion. Inflation dropped and the country's international reserves tripled, which led Bolivia to not renew its bridge loan with the International Monetary Fund.

Nevertheless Bolivia continues to be the poorest country in Latin America, and the hydrocarbons nationalization has yielded more political rhetoric than improvement to the lives of average citizens, say economic analysts. ✦

Canada to regulate greenhouse-gas, other air emissions

The Canadian government has issued a proposed framework for regulation of air emissions that it says contains "the toughest action on greenhouse gases ever proposed by a Canadian government."

The framework envisions regulations that for the first time in Canada set "mandatory and enforceable reduction targets" for emissions not only of greenhouse gases but also of specified air pollutants from major industrial sources.

The oil and gas industry is one of seven categories to which the industrial regulations apply. Others are electricity generation via combustion; forest products; smelting and metals refining; iron and steel; some mining; and cement, lime, and chemicals.

For greenhouse gases, the framework sets a 2010 implementation date for reduction targets for emission intensity, defined as greenhouse-gas emissions per unit of production. For air pollutants—nitrogen oxides, sulfur oxides, volatile organic compounds, and particulate matter—the framework sets fixed emission caps taking effect as soon as possible between 2012 and 2015.

All emission cuts are measured against 2006 baselines.

In addition to regulating industrial emissions, the framework calls for:

- A mandatory vehicle fuel-efficiency standard taking effect in the 2011 model year.
- A phaseout of incandescent light bulbs in common uses after 2012.
- New energy-performance standards for consumer and commercial products.
- Development of "a comprehensive regulatory agenda to improve indoor air quality."

Greenhouse gases

For greenhouse gases from existing facilities, the government seeks 6%/year improvement during 2007-10 in emissions intensity and 2%/year improvement for 10 years after 2010. New facilities—those beginning operations in 2004 or after—will have a 3-year grace period for greenhouse-gas emission targets. After the grace period, targets will be based on a "cleaner fuel standard," and the facilities will have to achieve 2%/year emissions improvements.

Production-related, noncombustion emissions that can't be cut with existing technology are exempt from the early, 6%/year targets.

The framework uses carbon dioxide equivalency, based on global warming potential, to report emissions of the various greenhouse gases.

Companies can meet their obligations under the proposed greenhouse-gas regulations by cutting their own emissions, contributing to a technology fund, trading emission-reduction credits, receiving credit for actions taken during 1992-2006, and participating in other North American emissions trading systems that might develop.

Air pollution cuts

For air pollutants, the framework sets national targets for cuts against 2006 levels, within which goals for specific industries will be set.

Fixed emission caps for pollutants from specific industries also will be set. The government used benzene from gas production and processing and refining as an example.

The national goals set volumetric caps for each pollutant that are to take effect as early as possible between 2012 and 2015. Against 2006 emission levels, these caps represent cuts of about 40% for nitrogen oxides, 55% for sulfur oxides, 45% for volatile organic compounds, and 20% for particulate matter.

A Canadian cap-and-trade emissions trading system will be available for sulfur oxides and nitrogen oxides only. ✦

US states seize opportunities to maximize oil, gas production

Steven Poruban
Senior Editor

US oil and gas-producing states must continue to work together to explore for and develop oil and gas resources and maximize production with a high sense of environmental awareness if they are to meet the nation's ever-increasing energy requirements.

This was one of the main messages voiced by members of the Interstate Oil & Gas Compact Commission May 7 at the start of its midyear issues summit in Point Clear, Ala.

Speakers at IOGCC's first general session agreed that maximizing US oil and gas production in an environmentally sound way should not, and don't have to be mutually exclusive goals.

North Dakota Gov. John Hoeven, current IOGCC chairman, said the US must seize opportunities now to increase oil and gas production. "It's going to take all of these sources of energy, and more" to fuel the US in the future, he said.

Hoeven also stressed the need for optimism in looking at the current state of US oil and gas production—seeing the glass as half-full, rather than half-empty. The US still produces about 40% of its oil domestically, he said, and it produces about 85% of its natural gas. He said the largest exporter of crude into the US remains Canada and the other 15% of natural gas comes from "friendly" sources.

Maximizing efficiency

Michael Ming, president of Research Partnership to Secure Energy for America (RPSEA), said increasingly advanced technologies will be required to raise oil and gas production in the US. He emphasized the importance of the role that US states play in the nation's energy future. "The states hold a lot of cards right now," he said.

RPSEA is a nonprofit corporation composed of members of industry, government, academia, and national laboratories. Its mission is to provide a role in ensuring research, development, and deployment of safe and environmentally sensitive technology that can effectively deliver hydrocarbons from US resources.

Ming said at the consumption end of the oil supply chain, US states must continue to invest in research and development to find ways to maximize energy efficiency. In most cases, Ming said, energy use in the US is about 45% efficient. In the transportation sector alone, he said, energy efficiency is about 17%.

"The potential is high to increase the end-use efficiency of our supplies," Ming said, adding that efficiency leverages all forms of supply—renewable resources as well as conventional ones.

Ming said the US uses about 20 million b/d of oil and 22 tcf/year of gas. Of this, the US wastes up to two-thirds with energy inefficiency. Also, the US imports about two thirds of its oil.

Currently, the energy resource base of the US is in a state of transition, Ming explained. Resources that may be easy to find are increasingly difficult to produce, citing the Barnett shale play and production from the ultradeep water as examples.

Independents' role

Speaking on the challenges of the 110th US Congress and its decisions' effect on US independent producers was Michael Linn, president of the Independent Petroleum Association of America and chairman, president, and chief executive of Linn Energy LLC, Houston. Linn noted that while addressing global climate change through mitigating emissions of carbon dioxide was "admirable," the solution would need to come from a worldwide perspective. Developing countries such as China and India should have to be as involved in the solution as the US.

Linn said development of alternative forms of energy is also vital and suggests using natural gas as a primary "buffer" source of energy while developing these other sources.

Linn also stressed that Congress should not pass any more legislation that would hurt US independent producers and their search for oil and gas. ✦

OFFSHORE ENERGY LOSS—3

Weather's role important in marine E&D operations

Mark J. Kaiser
Allan G. Pulsipher
Louisiana State University
Baton Rouge

The third and final part of this series examines the impact of weather on offshore losses.

Weather plays a major role in human activities offshore, and extreme weather in particular is one of the significant perils encountered. Storms and hurricanes regularly challenge and endanger the offshore energy industry, exposing their insurers, owners, and investors to significant capital loss.

A statistical assessment of weather damage and loss, broken out by region, time, and loss category is presented for the time horizon 1970-2004 based on the Willis Energy Loss database. We begin with a summary review of the 2005 hurricane season.

2005 gulf hurricanes

The 2005 hurricane season in the Gulf of Mexico was the worst in the history of offshore production and the most destructive and costliest natural disaster in the history of the US.

Hurricanes Katrina and Rita destroyed 136 structures, representing 1.7% of gulf oil production and 0.9% of natural gas output. Another 53 platforms suffered significant damage. Five rigs were destroyed, and 19 rigs sustained significant damage.[7 10 11]

Out of a total of $15 billion of energy losses, about $2 billion is applicable to the downstream sector (Table 1). Two-thirds of the loss estimates are due to physical damage, followed by business interruption (18%) and operators extra expense (14%).

Onshore losses as a whole were significantly smaller than the offshore sector. For Katrina, losses are estimated at $2.53 billion onshore, $6.63 billion offshore. Rita losses are estimated at $915 million onshore, $4.98 billion offshore.

Weather losses by region

Next, consider the number of weather incidents, annual claims, total weather loss, and average weather loss by world region (Table 2).

North America has the greatest total loss due to weather events and the largest percentage of total incidents, followed by Europe and the Far East.

North America also has the largest number of loss claims per year. In North America, the overall indexed loss from 1974 to 2004 totaled nearly $4 billion, or on average, $131 million/year. The average loss per claim in North America was $17.3 million.

Europe and the Far East realized insured losses of $828 million and

HURRICANES KATRINA AND RITA ENERGY LOSS[1] ESTIMATES

Table 1

Hurricane	Sector	Physical damage[2]	Operators' extra expense	Business interruption, million $	Total, billion $
		Billion $			
Katrina	Upstream ex rigs	4.137	1.228	831.7	6.197
	Rigs	0.474		58.3	0.532
	Downstream	1.791		628.5	2.420
	Total	**6.402**	**1.228**	**1,518.5**	**9.148**
Rita	Upstream ex rigs	2.763	0.870	853.3	4.486
	Rigs	0.498		50.0	0.548
	Downstream	0.482		364.6	0.846
	Total	**3.742**	**0.870**	**1,267.8**	**5.880**

[1]Loss estimates are for the energy industry as a whole and are not necessarily insured amounts. [2]For loss claims where no business interruption or operators extra expense split is available, the loss claim is included in the physical damage entry.

Source: Willis Energy Markets Review 2006

NUMBER OF WEATHER* INCIDENTS, TOTAL LOSS, AND AVERAGE LOSS BY REGION THROUGH 2004

Table 2

Region	Incidents	Annual claims	Percent total incidents	Total loss	Average loss
				Million $	
Africa	15	1	6	170	11.3
Australasia	8	2	10	85	10.7
Europe	70	3	7	828	11.8
Far East	52	2	15	743	14.3
Middle East	13	1	10	88	6.8
North America	227	8	23	3,927	17.3
South America	14	1	11	58	4.2
Total	**339**			**5,903**	**14.7**

*Weather events defined as heavy weather, ice/snow/freeze, and windstorms.

$743 million, and in total, North America, Europe, and the Far East sustain over 93% of the total weather losses in the world. The average cost per insured event ranged from $4.2 million (South America) to $17.3 million (North America). The world average for insured weather-related loss was $14.7 million.

Distribution of weather-related* insurance losses through 2004

Table 3

Range, million $	Africa	Australasia	Europe	Far East	Middle East	North America	South America	Total, million $
1-2.5	6	4	21	23	2	76	9	224
2.5-5	2	2	17	12	8	42	3	308
5-10	4	0	17	3	2	46	2	513
10-15	2	0	2	1	1	15	0	246
15-20	0	0	10	5	0	7	0	362
20-30	0	2	0	3	0	17	0	538
30-40	0	0	2	2	0	6	0	344
40-50	0	0	0	1	0	5	0	251
50-60	0	0	0	1	0	1	0	104
60-70	0	0	0	0	0	1	0	65
70-80	1	0	0	0	0	1	0	151
80-90	0	0	0	0	0	1	0	80
90-100	0	0	0	0	0	4	0	378
100+	0	0	1	1	0	5	0	2,316
Total	**15**	**8**	**70**	**52**	**13**	**227**	**14**	

*Weather events defined as heavy weather, ice/snow/freeze, and windstorms.

The average weather loss in the Gulf of Mexico exceeded the average world weather loss, indicating the high weather risk from operating in the region. In other regions of the world such as the Middle East and South America, weather loss is significantly less than the average loss. In Europe and Africa, weather loss is comparable to the average loss.

Weather loss distribution

The distribution of weather-related insurance losses by region is another consideration (Table 3). For most offshore regions, the data depicts a high frequency/low severity trend.

Although the vast majority of events are smaller than $20 million, these events only contribute about one-fourth of the total indexed loss.

One-fourth of the total losses are low frequency/high severity occurrences ($100+ million) that characterize catastrophic events.

Seasonal weather impact

Weather events may have a seasonal component, such as in the occurrence of tropical cyclones in the Gulf of Mexico and South China Sea or severe storms that occur throughout the year as in the North Sea.

Seventy-five percent of all North American events occur in August-October and comprise over two-thirds of the total indexed loss (Table 4). North Sea events occur throughout the year except for a brief summer lull.

Losses by category

In North America, offshore losses from platforms and rigs accounted for nearly 92% of the total indexed loss recorded and resulted in the average loss per claim of $17.3 million (Table 5).

In Europe, platforms, rigs, and floating storage units accounted for 84% of the total weather-related losses (Table 6). Floating storage units sustained the greatest average loss ($60.9 million), but the low frequency does not provide a reliable estimate for expected loss. Platform and rig losses are comparable.

In the Far East, rigs and vessels sustain the majority of the weather losses (80%), with an average loss of $28.4 million for rigs and $15.8 million for vessels (Table 7).

World totals and averages

The world total losses and total weather loss is depicted in Table 8, along with average loss and average weather loss, per category. Weather losses comprise about 17.4% total insured losses, and on average, yield somewhat larger losses relative to other events.

Acknowledgment

Andrew Jackson, Willis Global Markets (www.willis.com), provided comments and critique of this study. ✦

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Seasonal impact of weather events through 2004

Table 4

Region	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
Africa	3	1	1	2	1	3	0	2	0	1	0	1	15
Australasia	0	0	1	5	0	1	1	0	0	0	0	0	8
Europe	15	5	5	5	0	1	0	5	3	6	8	17	70
Far East	7	1	2	1	4	8	4	5	6	5	7	2	52
Middle East	3	1	0	1	0	0	0	0	2	0	3	3	13
North America	17	4	5	10	2	3	6	36	73	62	4	5	227
South America	2	0	1	2	0	2	2	0	3	0	1	1	14
Total	**47**	**13**	**15**	**26**	**7**	**18**	**13**	**48**	**88**	**74**	**23**	**29**	**401**
Total loss, million $	457	229	161	314	57	233	74	1,056	1,669	988	197	474	
Average loss, million $	9.7	17.6	10.8	12.1	7.3	12.9	5.7	22.0	19.0	13.4	8.6	16.3	

WEATHER LOSSES BY LOSS CATEGORY—NORTH AMERICA, 1974-2004

Table 5

Loss category	Frequency, %	Total loss, Million $	Avg. loss, Million $
Pipeline	7	70	4.2
Platform	54	2,493	20.3
Rig	26	1,116	19.2
SBM*	1	1	1.5
Vessel	7	148	9.2
Well	5	98	8.2
All	**100**	**3,927**	**17.3**

*Single-point buoy mooring.

WEATHER LOSS BY CATEGORY—FAR EAST, 1974-2004

Table 7

Loss category*	Frequency, %	Total loss, Million $	Avg. loss, Million $
FPSO	2	11	11.2
Pipeline	21	45	4.1
Platform	15	55	6.9
Rig	33	483	28.4
SBM	8	11	2.6
SC	2	3	2.9
Vessel	13	111	15.8
Well	6	24	8.1
All	**100**	**743**	**14.3**

*FPSO = floating production, storage, and offloading vessel; FSU = floating storage unit; SBM = single-point buoy mooring; SC = subsea completion.

WEATHER LOSS BY CATEGORY—EUROPE, 1974-2004

Table 6

Loss category*	Frequency, %	Total loss, Million $	Avg. loss, Million $
FPSO	4	19	6.5
FSU	4	183	60.9
Pipeline	7	22	4.5
Platform	28	229	11.4
Rig	34	285	11.9
SBM	8	44	7.4
SC	3	11	5.7
Vessel	8	30	5.0
Well	1	4	3.6
All	**100**	**829**	**11.7**

*FPSO = floating production, storage, and offloading vessel; FSU = floating storage unit; SBM = single-point buoy mooring; SC = subsea completion.

WORLD TOTAL AND AVERAGE WEATHER LOSSES BY LOSS CATEGORY THROUGH 2004

Table 8

Loss category*	Total weather loss, Million $	Total loss, Million $	Average weather loss, Million $	Average loss, Million $
FPSO	30	1,126	7.6	11.3
FSU	194	270	32.3	14.2
Pipeline	214	3,864	4.9	6.1
Platform	2,821	13,350	17.6	16.3
Rig	2,015	7,092	17.4	15.1
SBM	60	521	4.3	6.5
SC	14	796	4.8	4.9
Vessel	427	1,221	11.5	9.4
Well	126	5,694	7.9	9.9
Total	**5,903**	**33,949**	**14.7**	**11.3**

*FPSO = floating production, storage, and offloading vessel; FSU = floating storage unit; SBM = single-point buoy mooring; SC = subsea completion.

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Algeria

Gulf Keystone Petroleum Ltd., London, established a stabilized oil flow at HEK-3, a 2004 Sonatrach oil and gas discovery on Djebel Bottena Block 129 in the Southeast Constantine basin.

Sonatrach's initial tests achieved a flow after acid treatment of 184 bbl of oil in 4 hr from a Coniacian limestone.

On re-entry by Gulf Keystone, the same interval at 2,439-46 m after acid-frac stabilized at 1,040 b/d of 31° gravity oil on a $^{32}/_{64}$-in. choke. The well then made 3,500 bbl of oil in 4.5 days with a gas-oil ratio of 93 scf/bbl.

Gulf Keystone will consider installing a pump and is analyzing early development based on what appears to be a commercial production rate. Gulf Keystone has 75% interest and operates Block 129. Sonatrach has 25%.

Djebel Onk oil field is on the block but excluded. The block also contains the Djebel Foua gas discovery.

Chile

The government gave final approval to contracts with March Resources Corp., Calgary, to operate two oil and gas prospective blocks in the nonproducing Tamarugal basin.

March plans to begin work immediately on the Pica North and South blocks totaling 2.5 million acres where it plans to spud the first well in September 2007.

California Oil & Gas Corp., Calgary, has an agreement to explore the blocks jointly with March Resources.

Iran

National Iranian Oil Co. reported two giant oil discoveries in Iran but gave few details, press reports said.

One of the discoveries is named Paranj. The other, name not disclosed, is north of Abadan near Ab Teymour oil field.

Libya

A group led by Repsol YPF SA has begun appraising two light oil discoveries on Block NC 200 in the Murzuk basin 1,000 km south of Tripoli.

The E1 well tested 589 b/d of oil, and G1 flowed 334 b/d from undisclosed formations. They are the first commercial discoveries on the contract area, less than 100 km west-southwest of giant El Sharara oil field on Block NC 186. El Sharara, producing 200,000 b/d of oil, is one of seven discoveries on Block 186. Repsol operates Block 200 with 21% interest. Libya National Oil Corp. has 65%, and OMV AG has 14%. OMV produces 31,500 b/d of oil in Libya.

Russia

Matra Petroleum PLC, Chertsey, UK, let a contract to OOO Orenburg Drilling Co. to drill a well on the Sokolovskaya prospect on the northern part of the 158-sq-km Arkhangelovskoe exploration license. Projected to 3,900 m at a cost of $4.5 million, the well is to spud in late July 2007. The location is 35 km north of supergiant Orenburg gas field.

The prospect is a well-defined four-way dip structure defined by recent seismic. The well targets four Devonian reservoirs and Carboniferous and Permian reservoirs known to be productive on nearby licenses.

Prince Edward Island

Corridor Resources Inc., Halifax, NS, has an option to fund and drill an exploratory well to 2,800 m on 176,000-acre EL 02-03 on eastern Prince Edward Island under a farmout agreement with PetroWorth Resources Inc., Calgary.

The companies will exchange proprietary seismic data on PetroWorth's EL 02-03 license on PEI and Corridor's Rosevale and Elgin properties in New Brunswick. Corridor also has the option to take a farmout on EL 02-03.

Under the farmout, Corridor must decide by Aug. 12 whether to drill the well and spud by Feb. 1, 2008. If it drills, Corridor will have the option to drill two more exploratory wells by Oct. 1, 2008, to be funded 50-50. Corridor would earn a 50% working interest in the license and wells by drilling three wells. The agreement also gives Corridor the option to fund, drill, and complete two wells on four other PetroWorth PEI licenses totaling 250,000 acres to earn a 50% working interest in those licenses.

Illinois

Noble Energy Inc., Houston, plans to drill 16 wells to Devonian New Albany shale in the Illinois basin in the rest of 2007 and increase the capacity of its production facilities there.

The company plans to employ a second rig starting in June. It has drilled six wells since August 2006. Production began in March 2007, and the wells are still cleaning up but early results are encouraging, the company said in early May.

The game plan is to build strong returns at $1.2 million/well by drilling to 2,500 ft vertically and then 2,000-4,000 ft horizontally. The goal is to obtain producing rates of at least 800 Mcfd-1 MMcfd/well. Noble Energy has acquired more than 60,000 acres in the play since late 2005.

Louisiana

Universal Energy Corp., Orlando, Fla., plans to participate with Yuma Exploration & Production Co., Houston, in drilling the Lake Campo 3D seismic prospect in the Middle Miocene Trend in Plaquemines Parish.

The prospect has 10 Miocene-age sand objectives to proposed TD of 10,500 ft. Drilling is to start within 60 days.

Oklahoma

Bankers Petroleum Ltd., Calgary, is exploring the Devonian Woodford shale in southern and southeastern Oklahoma.

The company is drilling Greenway 35-1H, a horizontal offset to the Nickel Hill 1-26 discovery well in Carter County at which the initial potential was 470 Mcfd of gas. A second horizontal Woodford shale well is to be drilled 10 miles away in Johnston County.

Bankers and a partner are acquiring 115 sq miles of 3D seismic surveys in Carter and Johnston counties.

Bankers also plans to drill a horizontal Woodford shale test by the end of the third quarter in Hughes County. Its Lake Holdenville 35-1 well was disappointing, but a frac may not have effectively stimulated the shale, the company said. A 2.5-mile offshoot, however, had an initial production rate of 330 Mcfd after stimulation.

Washington

Torrent Energy Corp., Portland, Ore., spudded the first of three planned exploratory wells at its Vader Ryderwood coalbed methane project in the Chehalis basin of southwestern Washington 25 miles northeast of Mist gas field in Columbia County, Ore.

Torrent holds acreage in Lewis, Cowlitz, and Skamania counties, Wash.

The company intends to establish a large CBM resource in relatively shallow coals and investigate sandstone reservoirs similar to those that produce in Mist field. The first well, Cascadia Energy Corp. State 3-36-13-3, is projected to 3,000 ft. Individual coals will be cored and gas content determined from desorption tests. The companies are permitting wells in the adjoining Cedar Creek project area.

Russian field tests yield cements for arctic wells

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Field tests of arctic cements in the Bovanenkovo gas-condensate field on the Yamal peninsula in northern Russia will benefit an upcoming drilling program.

Oil and gas fields of Russia are being developed in the harsh climatic and geological conditions of the extreme north and Arctic seas shelf.

The complicated geological conditions include permafrost, intrapermafrost water, upper gas flowing horizons (100-150 m), and soft rocks with low-fracture gradients (0.0150-0.0160 MPa/m).

Low temperatures can cause certain energetic and kinetic deviations during the hydration of hardening cement in contrast to hydration at normal temperatures. Decreasing temperature retards hydration of clinker minerals. When passing below 0° C., hydration is sharply retarded and cement lattice structure cannot properly form due to propping action of ice.

At the same time, for exothermic reactions, characterized by intensive heat release, lowering the temperature increases formation of a number of compounds. This mechanism was the basis to design materials hardening at temperatures below freezing, including those based on hemihydrate gypsum[1] and a mixture of periclase, MgO, with monopotassic phosphate, KH_2PO_4 (OGJ, May 16, 2005, pp. 48-52; OGJ, May 9, 2005, pp. 53-55).

The aim of this work was to produce a water resistant, cement-gypsum mixture with no free water.

Arctic cement synthesis

Hydration of α-hemihydrate gypsum is an exothermic process. A change in temperature of gypsum test corresponds to a certain amount of hemihydrate gypsum reacting with water (Equation 1 in the equation box).

The constant reaction rate of α-hemihydrate dissolution (K_1) and process of double hydrate gypsum (K_2) crystallization was determined by the Condo equation (Equation 2).

According to test results, $K_1 = 0.25$ and $K_2 = 0.05$. These data indicate that crystallization is a limiting stage of the hardening process. Correspondingly, by adding different chemicals to the cementing agent, one can regulate the hydration and hardening processes. For this purpose, sodium chloride (a freezing point depressant) and softeners (water-cement ratio depressants) are of the most interest.

Equations 3 and 4 show the reactions for hemihydrate sulfate interaction. The reactions repeat until the initial hemi-

Equations

$$C\acute{s}H_{0.5} + 1.5H = C\acute{s}H_2 + Q \quad (1)$$

Condo equation:

$$(1-\sqrt{1-\alpha})^n = K \cdot \tau \quad (2)$$

Hemihydrate sulfate reaction:

$$2C\acute{s}H_{0.5} + 4NaCl + H \rightarrow Na_2SO_4 + 2CaCl_2 + 2H \quad (3)$$

$$Na_2SO_4 + CaCl_2 + H \rightarrow C\acute{s}H_2 + 2NaCl \quad (4)$$

$$CA(CA_2C_{12}A_7) + H \rightarrow CAH_{10} \quad (5)$$

Ettringite reaction:

$$CAH_{10} + C\acute{s}H_{0.5} + H \rightarrow C_3AC\acute{s}_3H_{32} \quad (6)$$

$$C_4(A,F)_3C\acute{s} + H \rightarrow C_3(A,F)C\acute{s}_3H_{32} \quad (7)$$

$$C_3AC\acute{c}H_{12} + C\acute{s}H_{0.5} + H \rightarrow C_3AC\acute{s}_3H_{32} + C\acute{c} \quad (8)$$

$$C_3A + 3C\acute{s}H_{0.5} + 29.5H \rightarrow C_3A \cdot C\acute{s}_3H_{31} \quad (9)$$

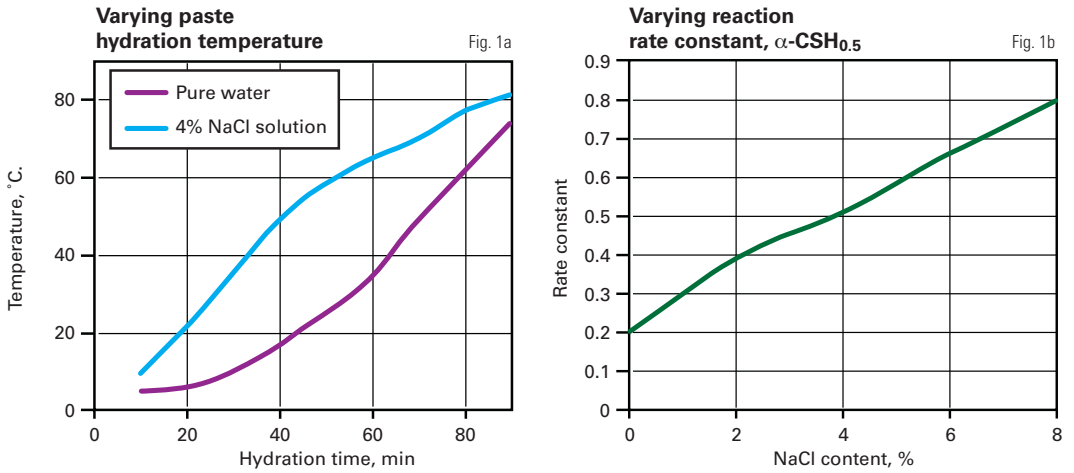
$$C_4AF + C\acute{s}H_{0.5} + 118/6H \rightarrow 1/3C_3AC\acute{s}_3H_{32} + 2/3C_4AH_{13} + 1/12CFH_{13} + 11/6H \quad (10)$$

Nomenclature

A	=	Al_2O_3
C	=	CaO
C_3A	=	$3CaO \bullet Al_2O_3$
CA	=	calcium aluminate
Cć	=	$CaCO_3$
Cś	=	$CS = CaSO_4 \bullet 2H_2O$
H	=	H_2O
K	=	constant of reaction rate
n	=	index characterizing the process mechanism
S	=	SO_3
τ	=	rate of material transformation

HEMIHYDRATE HYDRATION PROCESS

Fig. 1



hydrate is consumed.

Comparing temperature curves of the hemihydrate hydration process in water and in sodium chloride solutions at different concentrations demonstrates the accelerating action of sodium chloride on the formation process of α-$CSH_{0.5}$ (Fig. 1a). The constant of the reaction rate of hemihydrate dissolution in a water solution of sodium chloride (K_1) is four times higher than hemihydrate hydration in water (Fig.1b).

The formation of sodium sulfate during the exchange reaction enhances solution saturation and gypsum crystallization. Many companies use these properties of gypsum when preparing gypsum-cement mixtures to cement arctic wells.[1] According to physical-chemical analysis data, gypsum hemihydrate amounts to 50-60 mass %.[4] Useful properties of gypsum cements are:

- Setting and hardening ability at temperatures to –9° C.
- Independent setting times vs. temperature (+20° C. to –5° C.).

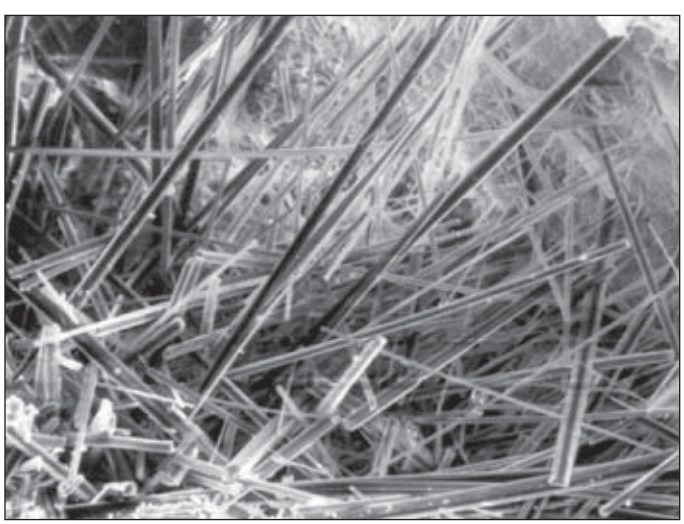
These mixtures, however, increase free water up to 5% and have a low water-resistance coefficient (Kw <0.8) owing to gypsum matrix dissolution in water-saturated beds. The mass of the cement samples in water may decrease as much as 50% in 1 year.

In order to eliminate these disadvantages, we propose three ways to replace part of the gypsum with components in whose presence hydrosilicate phases (C-S-H) and ettringite expanded phase ($C_3AC\acute{s}_3H_{32}$) will predominantly form. These network-forming elements of water-resistant cement stone are thermodynamically stable at lower temperatures.

The first way involves adding alumina cement to the gypsum cement mixture (Equations 5 and 6).

The second way involves adding ground sulfated clinker—$C_4(A,F)C3\acute{s}$—to a gypsum cement mixture (Equation 7).

The third way to improve the quality of the mixture is to replace part of the gypsum hemihydrate with nonhygroscopic calcium hydrocarboaluminate (a coproduct of integrated nepheline processing into alumina) and first-class coproducts (Equation 8).



This SEM photomicrograph shows the needle prisms of ettringite in mass of hydrosilicates (Fig. 2).

Experiment

Cement for the arctic wells was prepared using the first procedure by mixing ground Portland cement clinker, aluminous slag, and gypsum hemihydrate. To optimize the compositions, we investigated the structural formation of mixtures with a minimal water/cement (W/C) factor to provide an adequate period for pumping mud into the hole annular space. We decreased the W/C factor by adding plasticizing agents (S-3, LSTM, HG), which are also grinding intensifiers.

Calculation of the required amount of gypsum hemihydrate was performed based on Equations 9 and 10.

As the calculation indicates, it is sufficient to add 20-25 mass % of gypsum hemihydrate to Portland cement in order to achieve the purpose. As a whole, the hemihydrate in the mixture was 2-2.5 times less than that in the known gypsum cement mixtures.

We prepared the samples using a standardized procedure and subsequently tested

them for free-water content. Next, the samples were placed in a climate cell at 0° C. and –7° C. for 1, 2, 7, and 28 days. After the hardening time, the samples were tested for bending strength and water resistance. The water resistance coefficient was determined using the ratio between compressive strength of the samples hardening in an aqueous medium and the compressive strength of the samples hardening under air-dried conditions at 0° C. ±2° C. After a set time, hydration stopped and the samples were examined using physical-chemical analysis.

Results of X-ray phase analysis of the specimens' normal hardening (at 20° C.) showed that over time, the intensity of lines, characteristic of clinker materials and hemihydrate, decreases after only 1 day of hardening. The X-ray pictures clearly show lines belonging to ettringite (d = 9.8; 5.65; 3.92Å), the intensity of which increases with hydration time. SEM photomicrographs show the needle prisms of ettringite in a mass of hydrosilicates (Fig. 2).

By the third day, the intensity of the ettringite lines stabilizes, with the simultaneous appearance of diffraction lines of double-hydrate gypsum (d = 7.56; 4.27; 3.06Å). The intensity of the double-hydrate gypsum increases by Day 7 and changes insignificantly after that.

The X-ray picture shows distinct lines of calcium hydroxide (d = 4.92; 2.11Å). Specimens hardening at temperatures below freezing have distinct lines of the same formations. The intensity of the diffraction maximums of ettringite changes insignificantly in comparison with their intensity specimens hardened at temperatures above freezing. The maximum value of the calcium hydroxide diffraction line (d = 4.90Å) decreases somewhat, compared with its intensity under normal hardening conditions.

At lower temperatures, lime has higher solubility; in the presence of both lime and hemihydrate (the hydration of which gives significant amount of heat), ettringite quickly forms.

INFLUENCE COMPOSITION, HARDENING TEMPERATURE ON CEMENT BONDING STRENGTH Table 1

Mixture composition, mass %			Cement bending strength, MPa			
Portland cement + gypsum	Aluminous cement	Temperature, °C.	1 day	2 days	7 days	28 days
100	—	20	1.0	2.7	4.8	5.8
90	10	20	1.2	2.9	5.2	6.0
80	20	20	1.4	3.2	5.6	6.3
70	30	20	1.2	2.8	4.9	5.7
100	—	–7	0.5	1.0	2.7	4.0
90	10	–7	1.0	1.3	3.0	4.8
80	20	–7	1.2	2.0	3.8	5.7
70	30	–7	1.2	1.8	3.6	5.2

Diffraction maximum values (d = 7.1; 3.64; 3.24Å) characteristic of calcium hydrosilicate are also fixed on X-ray pictures of the specimens.

When sodium chloride comprises 2-8 mass % of the mixture, it accelerates the hydration process. Derivatography shows the results of the specimens' mass loss in the study. The amount of bound water during the hydration process is 25% at 20° C.; 25.7% at 0° C., and 26% at –7° C. Water adsorption by the multimolecular layer explains the increased amount of bound water at lower temperatures.[3]

Among the hydration products, is a composition characteristic of Portland cement; calcium hydrochloraluminate ($C_3A \cdot 3CaCl_2 \cdot 30H$) is observed with d = 7.9Å and endoeffect in the temperature interval 350-400° C. The cement bending strength increases during the hardening time (Table 1). The amount of free water in all cases is zero, and the water resistance factor ranges from 0.97 to 1.0.

Field tests

Commercial batches of arctic cement ("Arctcement") were used at the Bovanenkovo gas-condensate field on the Yamal peninsula in 1996-97 for cementing 426-mm diameter conductors at a depth of 150 m, and 324-mm diameter conductors at a depth of 450 m. Cementing was carried out by raising cement to the wellhead. According to acoustic cement-bond logging, the quality of cementing was good.

Results

Replacing part of the hemihydrate gypsum in the gypsum-cement mixture by aluminate cement with a complex additive (a plasticizing agent such as sodium chloride) results in cement that meets the requirements for cementing arctic wells:

- The ability to set in the casing string-borehole annulus at temperatures below freezing without having to heat liquid for mixing cement and displacing fluid.[4]
- No free water, which prevents casing string collapse in case of fluid backfreezing.
- Enhanced water resistance and, as a result, enhanced durability of cement insulation in a geologically complex well section.

Future

After a 10-year drilling hiatus, Gazprom is about to begin a 2-3-year development drilling program on the Yamal peninsula (Bovanenkovo gas-condensate field). The company intends to drill more than 150 wells and will use arctic cements in the well construction, including 324-mm and 245-mm diameter conductors. The field testing described in this article helped delineate cements most suitable for the extremely difficult conditions on the peninsula. ✦

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Gas injection enhances recovery from polymer flood pilot

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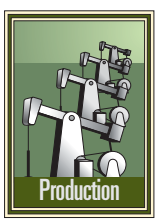


A field pilot showed that gas polymer, two-phase flooding could increase oil recovery from a low and intermediate permeable reservoir.

The combination of natural gas and polymer injection recovered about 10% more oil than with polymer injection alone after optimizing such parameters as the preflushing slug volume, polymer molecular weight, and injection rate.

Because it has high mobility, natural gas can enter low permeability zones into which polymer cannot.

Other benefits seen from the test was a decrease in water cut in some oil-producing wells and the need to inject less polymer because natural gas replaced some polymer.

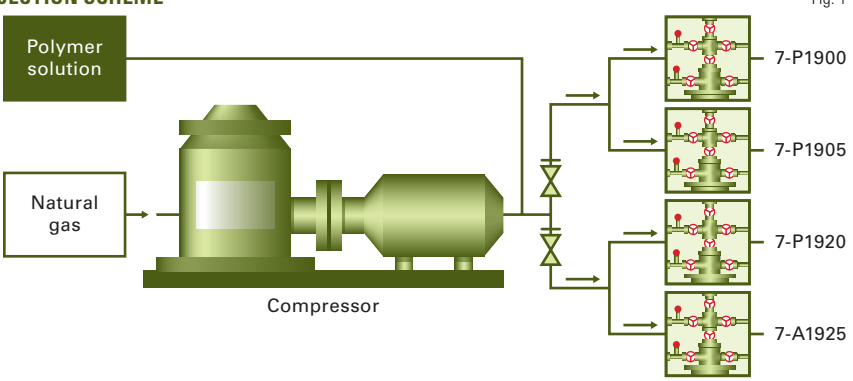
Fig. 1 shows the injection scheme in the pilot.

Polymer flooding

Polymer flooding began in 1996 at Lamadian oil field. The field is a part of the Daqing complex of oil fields in Heilongjiang province of northern China.[1-5]

INJECTION SCHEME

Fig. 1



Polymer injection at Lamadian has had good results, increasing oil recovery and helping to maintain production rates. But because of reservoir heterogeneity, however, the field still has some oil-bearing layers with low oil recovery.

To improve the effect of polymer injection in low and intermediate permeability layers, a pilot test injected natural gas, more than 95% methane, along with polymer in the west area of northern Lamadian oil field.

Feasibility studies

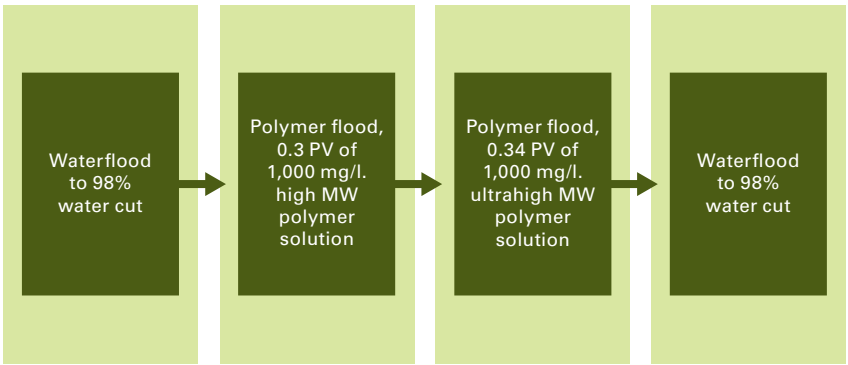
Prior to the field pilot, laboratory tests verified the feasibility of injecting both natural gas and polymer. The tests included two plans: the first with polymer and the second with gas and polymer.

Plan 1 (Fig. 2) had the following injection steps:

- Water until reaching a 98% water cut.
- A 0.3 pore volume (PV) of 1,000 mg/l. high molecular weight (MW) polymer solution.
- A 0.34 PV of 1,000 mg/l. ultra-high MW polymer solution.
- Water until reaching again a 98% water cut.

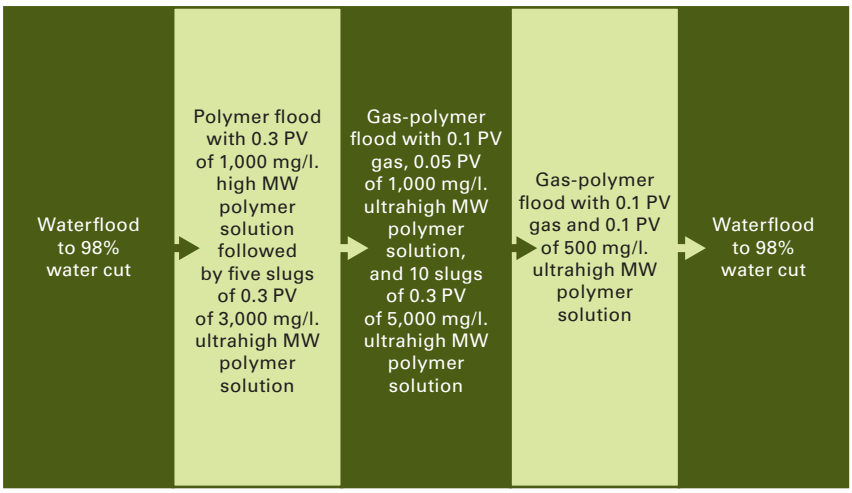
PLAN 1

Fig. 2



PLAN 2

Fig. 3



Injection steps in Plan 2 (Fig. 3) included:

- Water until a 98% water cut.
- A 0.3 PV of 1,000 mg/l. high-MW polymer solution.
- Five slugs of 0.03 PV of 3,000 mg/l. ultrahigh MW polymer solution.
- A 0.1 PV of natural gas.
- A 0.05 PV of 1,000 mg/l. ultra-high MW polymer solution.
- 10 slugs of 0.03 PV of 5,000 mg/l. ultrahigh MW polymer solution.
- A 0.1 PV of natural gas.
- A 0.1 PV of 500 mg/l. ultrahigh MW polymer solution.
- Water until reaching again a 98% water cut.

Plan 1 had a 56.88% recovery efficiency compared with 68.15% for Plan 2.

This result shows that with the same amount of polymer, gas polymer two-phase flooding improves recovery efficiency by 11.27% compared to polymer flooding.

Optimizing injection

Three experiments optimized the injection. All the tests used the same 640 PV and mg/l. of polymer.

One test showed that a higher gas-liquid ratio improves displacement. The test noted a 12.88% enhanced recovery for polymer flooding compared with waterflooding. Gas polymer two-phase flooding with a 0.4:1 gas-liquid ratio enhances oil recovery a further 18.54%. But with a 1:1 gas-liquid, gas polymer two-phase flooding ratio improves oil recovery by 22.21%.

Another test showed that increasing injection rate improves oil recovery for gas polymer two-phase flooding. With the same polymer amount and gas-liquid ratio, gas-polymer flooding with a normal injection rate increased recovery 12.1%. Gas-polymer flooding at a higher injection rate and constant pressure increased recovery by 13.59% compared with polymer flooding.

A third test showed that adding a slug of high-concentration polymer solution just before gas-polymer alternating injection and using intermediate-MW polymer for gas-polymer flooding further improves recovery.

The conclusion for the tests was that the best injection strategy was:

- Water to a 98% water cut.
- A 0.3 PV of 1,000 mg/l. high-MW polymer solution.
- Five slugs of 0.03 PV of 3,000 mg/l. ultrahigh MW polymer solution.
- A 0.1 PV natural gas.
- A 0.05 PV of 1,000 mg/l. intermediate-MW polymer solution.
- 10 slugs of 0.03 PV of 5,000 mg/l ultrahigh MW polymer solution.
- A 0.1 PV of natural gas.
- A 0.1 PV of 500 mg/l. intermediate-MW polymer solution.
- Water to again reach a 98% water cut.

This plan can enhance oil recovery by 13.36% compared with polymer flooding.

These laboratory studies show that gas polymer two-phase flooding with parameters optimized enhanced oil recovery by more than 10% compared with polymer flooding.

Field application

The 90-acre pilot is near the No. 4-2 polymer injection station at Lamadian oil field. The injection targets the PI1-2 oil-bearing zone that has an average 50-ft gross and 47-ft effective thickness. The sand has an 8.22 million bbl pore volume and originally contained 5.66 million bbl of oil in place.

The pilot has a line-drive well pattern and an injector-producer spacing of 780 ft. It includes 13 wells of which 4 are injectors and 9 are producers.

The central well is on 22-acre spacing and the sand in the well is 39-ft thick. The sand in this area has a 1.81 million bbl pore volume and originally held 1.25 million bbl of oil.

The injection strategy included low salinity (less than 500 ppm) water and salt-resistant polymer with a MW of 25 million. Injection rate was 0.12 PV/year and gas-liquid ratio was 1:1.

The injection sequence consisted of 10 days of gas followed by 10 days of polymer solution in each of two stages.

Injected first was a 0.01 PV high-concentration preflushing slug of polymer solution. Then a slug of gas-polymer was injected, alternating gas injection and 1,000 mg/l. polymer solution.

From February 2001, 1,000 mg/l. polymer flooding was initiated in the pilot area.

Gas polymer two-phase flooding started on May 19, 2005. By the end of September 2005, well 7-P1900 and well 7-A1925 had completed four turns of gas-polymer injection, well 7-P1905 and well 7-P1920 had completed five turns of gas-polymer injection.

Total gas injected in these four wells was 106.4 MMscf of natural gas (0.81 MMcf at reservoir conditions), which is 0.018 of the pore volume at formation conditions.

Total polymer solution injected in these four wells was 223,000 bbl, which is 0.027 of pore volume at formation conditions.

Gas-liquid ratio for the completed injection was 0.67:1.

Evaluation results

The current liquid production from the nine producers is 6,409 b/d of which 739 b/d is oil production. The water cut is 89.9% and the polymer concentration in the produced liquid is 438 mg/l. Bottomhole pressure is 980 psi.

Compared with production when the wells had the highest water cut, liquid production has increased by 75 b/d, oil production has increased by 66 b/d, and water cut has decreased by 0.8%.

Well 7-P191 had seen the best results with Wells 7-P1928 and 7-P1988 also having good results.

Liquid production from Well 7-P191 is now 1,150 b/d, oil production is 219 b/d, and the water cut is 83.0%. Compared with the production before, liquid production has stayed the same, oil production has increased by 117 b/d, and the water cut has decreased by 9.1%.

Field tests show that injection pressure in all injectors is higher when gas injection first started. After tubing pressure and annular pressure equalized, the gas injection became stable and injection pressure decreased by 290-435 psi.

Tracers added to the injected gas in Well 7-1900 were noted in the produced fluids 8 days after being added. This throughput time is much faster than for polymer solution and indicates that gas has a faster displacing speed and greater transport ability then polymer in the low permeability reservoirs.

One economic benefit of using gas has been to reduce the amount of polymer needed. To date, the flood has uses about 20.4 tonnes less polymer.

Acknowledgment

This work described in this article was supported by the National Natural Science Foundation of China under Grant No. 50634020. ✦

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Study measures effect of leading indicators on plant turnarounds

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Many factors with varying degrees of controllability affect the outcomes of refinery and petrochemical plant turnarounds. Based on quantitative data collected from recent refinery turnarounds, this article examines and presents these factors, the "leading indicators" of turnaround performance, and quantifies their effect on turnaround outcomes.

This article introduces turnaround risk and readiness indices and their relationship to turnaround outcomes, and the concept of a standardized turnaround scope index. Finally, benchmarks of best turnaround practices are shared.

Turnaround data

Turnaround data indicate that turnaround safety, cost, schedule, and operability problems are not random.

Rather, these problems are predictable months before a particular turnaround. Leading indicators such as turnaround characteristics and the level of definition and planning have a quantifiable effect on turnaround outcomes. There are varying degrees, however, to which these leading indicators can be controlled.

This article examines these controllable and uncontrollable factors and their effect on turnaround outcomes with a specific focus on turnaround cost predictability and competitiveness.

Although the turnaround organization does not have control over many turnaround characteristics such as qualified labor availability, material condition of the plant, equipment congestion, etc., the examination and understanding of these characteristics enable the quantification of their effect on turnaround outcomes. They therefore provide a gauge of the likelihood of meeting turnaround targets.

Just as importantly, effective risk management practices could lessen the effect of these characteristics on turnaround outcomes; therefore, lessen the negative impact that a protracted or costly turnaround may have on the manufacturing business.

Scope definition and planning practices are not only within the control of the turnaround organization, but are also leading indicators of turnaround success. The best turnaround systems effectively use a gated and phased approach to turnaround definition, planning, and execution. The best turnaround performers achieve integration and organizational alignment around their objectives, scope, plans, and execution strategies by effectively using their gated and phased turnaround work process and its alignment with their project development process.

Industry dataset

This study is based on an industry dataset of recent (past 4 years) turnarounds in the industry. The dataset contains more than 400 refining and

Based on a presentation to the 2007 National Petrochemical & Refiners Association Annual Meeting, Mar. 18-20, 2007, San Antonio.

chemical turnarounds. A subset (135 units) of the refining portion of the dataset contains detailed turnaround scope data.

Fig. 1 provides a breakdown of the turnaround database.

Turnaround complexity

The data indicate that there are three characteristics that have the most influence on turnaround predictability:

- The size of the turnaround measured in direct field labor hours.
- The amount of capital work required.
- The turnaround interval.

The first and the second factors measure the turnaround's size and difficulty, and the third factor is perhaps a proxy for the degree to which the material condition of the unit is known, as well as the experience of the team with the unit.

We developed a "turnaround complexity" factor that combines these three factors together, and is a single indicator of turnaround predictability.

Fig. 2 shows the significance of turnaround complexity (high, medium, and low).

Turnaround outcomes

In addition to the indications offered by turnaround complexity, two larger categories of leading indicators work together to increase turnaround predictability (Fig. 3):

- Inherent plant and turnaround characteristics that pose significant challenges and difficulties that the turnaround team cannot control.
- Level of scope definition, planning, preparation, and readiness to execute the turnaround, all of which are well within the control of the turnaround team.

Uncontrollable leading indicators

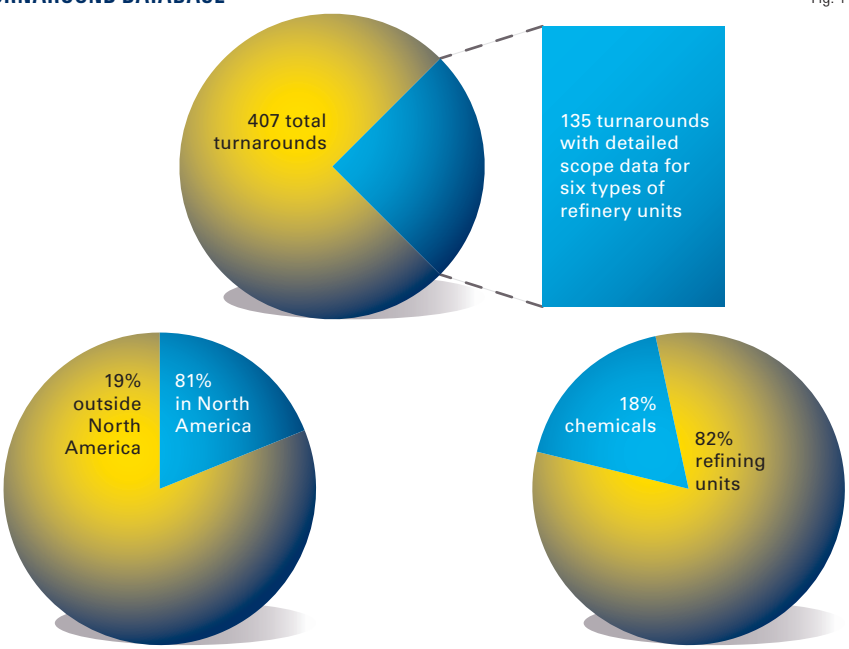
There are more than 20 characteristics that influence turnaround safety, schedule, cost, and operability outcomes. These are just a few examples:

- Turnaround complexity.
- Availability of skilled labor.
- Amount of piping work.
- Amount of instrumentation and electric work.
- Changes to decontamination method and procedures.
- Equipment congestion.

The level of control that the turnaround organization has over these characteristics is very limited. For example, the outcomes of turnarounds with highly dense work areas are less

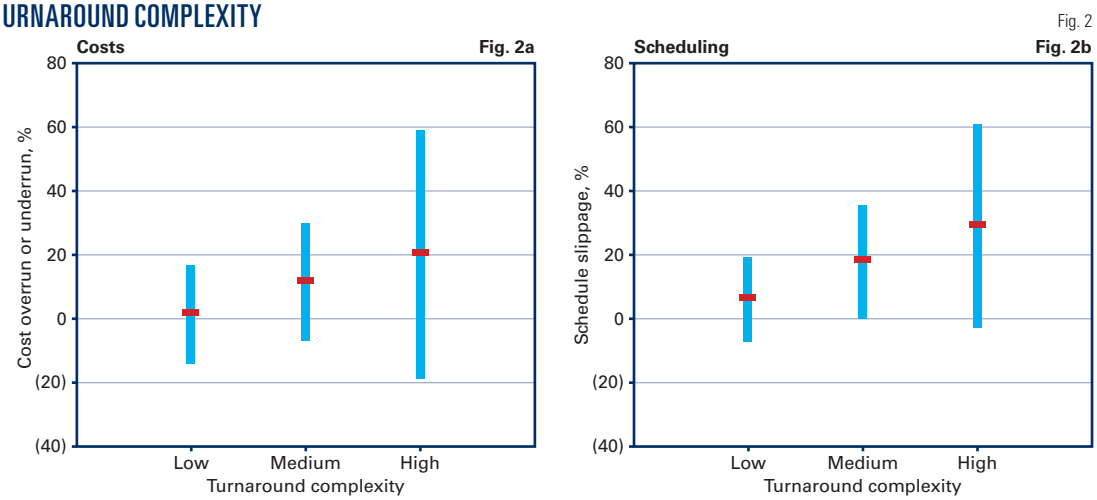
Turnaround database

Fig. 1



Turnaround complexity

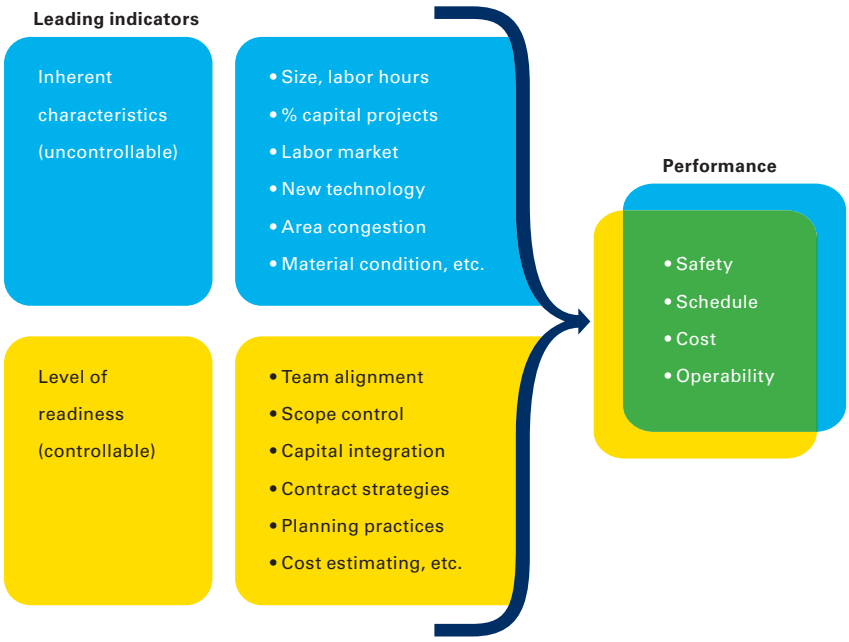
Fig. 2



Note: High-complexity turnarounds are unpredictable

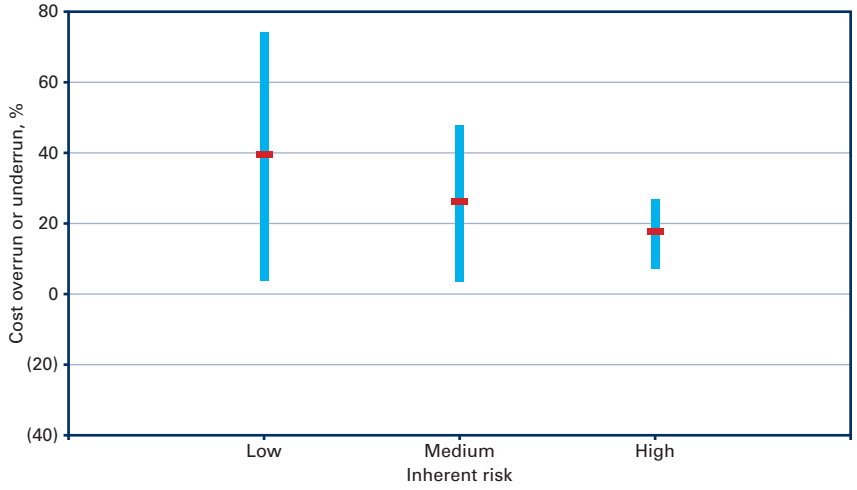
TURNAROUND PREDICTABILITY

Fig. 3



VARIANCE IN INHERENT RISKS

Fig. 4



desirable than those performed on less-congested units.

Turnaround organizations have no control over the plot plan or the equipment layout within the various operating units and, therefore, unit congestion is a given. Nevertheless, it has an impact on turnaround outcomes.

Fig. 4 shows the cost outcomes of a subset of turnarounds in our database. It shows that those with high inherent risks overrun their cost estimate by an average of 33%, while those with medium and low risks overrun by an average of 19% and 9%, respectively.

Although turnaround complexity is a significant factor in the risk calculation, the reference here to "high," "average," and "low" risks are different than the complexity categorization. The risk calculation accounts for more than 20 inherent factors, and complexity only reflects the most dominant three. For brevity, Fig. 4 shows only the cost variability; however, these inherent risks have a similar gradual impact (different percentages) on schedule outcomes.

Controllable leading indicators

Although each turnaround is characterized by a set of inherent, or uncontrollable, factors that affect its outcome, the turnaround team regularly deals with a myriad of factors that are controllable; and actually have a more profound impact on turnaround predictability.

At a high level, these are: team alignment, scope definition and control, comprehensive planning, schedule integration, and level of preparedness; collectively called "readiness."

Turnaround readiness

We developed a turnaround readiness pyramid tool to measure the level of readiness of a turnaround of any complexity at any point in time during the definition phase (i.e., the tool adjusts for three levels of turnaround complexities and for the time phases before the turnaround). This tool involves each turnaround team member independently evaluating the teams' status in the 21 components of the turnaround preparation process.

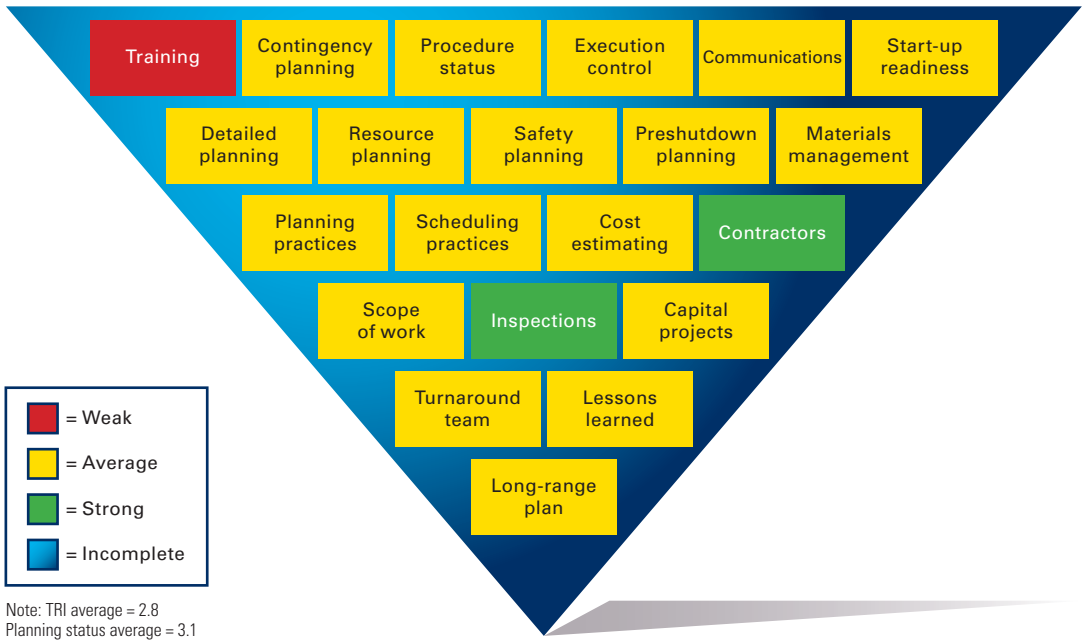
Results are collectively input into statistical algorithms and the status of each of the 21 elements is displayed as red, yellow, or green. Additionally, it calculates the level of alignment around the status of each of the 21 elements.

Fig. 5 shows turnaround readiness for an average industry turnaround of medium complexity in 2005. This shows the red, yellow and green status for each of the 21 elements. A similar tool details the team alignment for each of the 21 elements. The status and alignment tools are then used by the turnaround team to identify the more critical gaps, and ultimately prioritize resources.

Team alignment is often a more influential factor of turnaround outcomes than is status, especially for high-complexity turnarounds. The most significant misalignment is usually within the

TURNAROUND READINESS PYRAMID

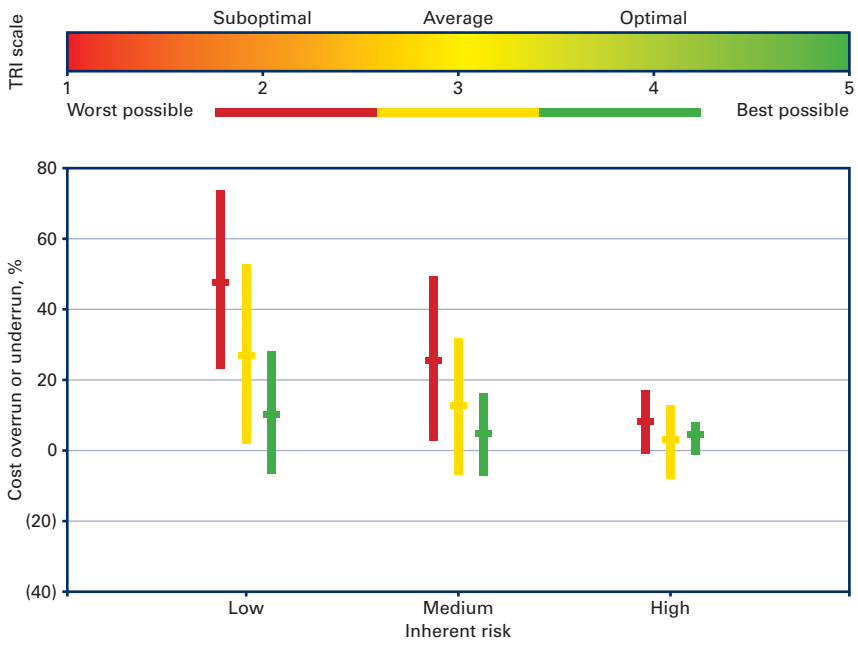
Fig. 5



Note: TRI average = 2.8
Planning status average = 3.1

READINESS, COST PREDICTABILITY

Fig. 6



capital projects component.

For turnarounds with a high percentage of capital work, the engineering representatives consistently rate the status of this element as close to best practical ("engineering packages have been reviewed and are being produced in a timely fashion"); while the turnaround team members consistently rate it as having significant gaps from best practices ("engineering packages are behind schedule"). Misalignment indicates an opportunity for improved communications, and possibly more.

TRI

The turnaround readiness index (TRI) results when the status and alignment tools are combined. TRI is used to indicate the ultimate level of readiness of a turnaround at any point in time in the preparation phase.

TRI ranges between 1 (poorest) and 5 (strongest), with the optimal range between 3.8-4.0. The best turnarounds are not only well-planned, but the team is also well aligned. This is especially true for high-complexity turnarounds.

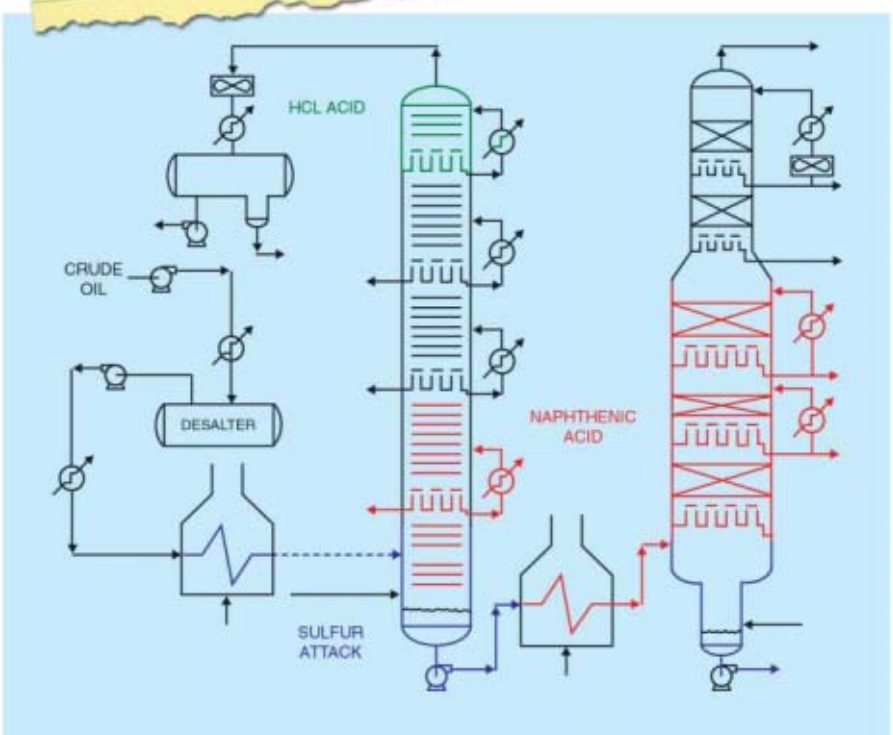
Fig. 6 breaks down Fig. 4 data into three levels of readiness: poor, average, and strong (shown as red, yellow, and green, respectively). The chart shows that readiness improvement correlates not only to reduced variability, but also to lower average cost overruns. TRI is an extremely reliable indicator of cost predictability and, similarly, schedule variation and average performance.

'Semicontrollable' factor

Inherent factors and readiness provide a very good indication of turnaround outcomes. Although both of these factors affect turnaround competitiveness, there is one additional and much more significant factor behind turnaround competitiveness—the amount of work scope. A scope index for each type of unit is required to be able to compare the amount of work scope for turnarounds on like units.

Fig. 7 shows the total picture of how inherent characteristics, turnaround readiness and the amount of scope can work together to deliver turnarounds that are predictable and competitive.

Process Notes



Opportunity Knocks

A group of interesting articles* deals with opportunity crudes, a mixed breed that includes very heavy, sour and high total acid number types as well as those with unexceptional naphthenic acid content but which do have significant concentrations of aliphatic acids or possess the ability to generate them during processing. They all sell at substantial discounts that give refiners who can process them the opportunity to reap higher profits. Hence their name.

Note that phrase "who can process them". It's not easy. Opportunity crudes can cause severe problems in the desalter, crude heat trains, fired heaters, atmospheric and vacuum towers and downstream process units all the way to waste water treatment facilities. Every piece of equipment can be at risk. Yet some of these crudes, such as Grane have a very flat TBP curve in the vacuum gas oil boiling range. High vacuum gas oil yield is the opportunity for those with a properly designed deepcut vacuum unit.

More important than any chemical treatment program is the flexibility that must be built into the basic process design. It must have the necessary resilience to accommodate varying crude characteristics. Proper metallurgy is critical but selection must depend as much on metal availability and cost as on specifics of corrosion resistance. Desalters have to handle not just brine and sediment but surface active molecules that tend to form stable emulsions. Wash water systems must be able to deal with different salt chemistries. Fractionation sections must concentrate refractory sulfur species without downgrading valuable distillates. Vacuum unit fired heaters must be specially designed to minimize coking.

No combination of measures can eliminate all these problems but put together in a rational and coherent process design they can extend refinery runs from months to years providing refiners with the opportunity to profit rather than suffer from the vagaries of the uncertain and skittish crude market.

**Hydrocarbon Engineering*, August 2006, pages 22-34.

For a more detailed discussion of some factors important in processing opportunity crudes, ask for Technical Papers 213 and 220.

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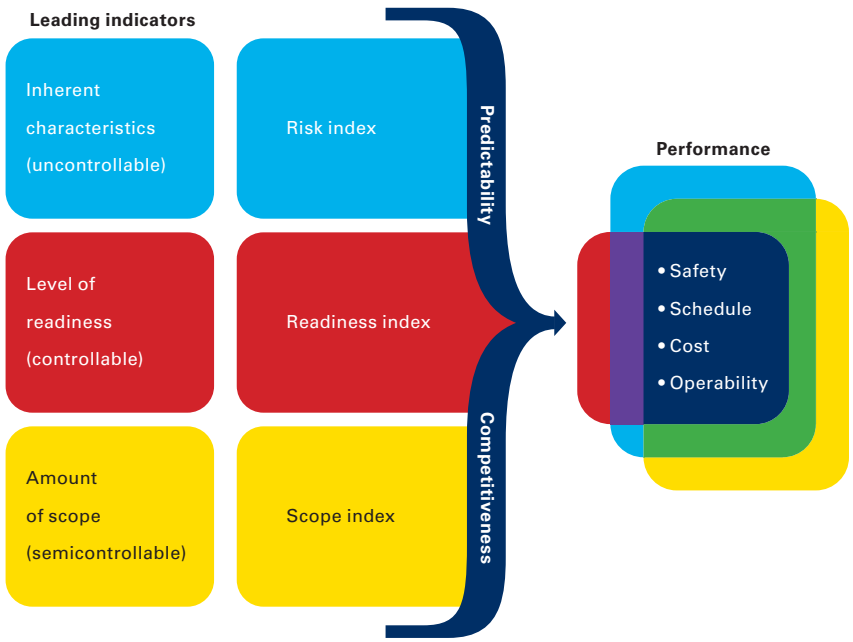
TURNAROUND PREDICTABILITY, COMPETITIVENESS

Fig. 7



When these fundamentals are complimented with the right benchmarks, competitive targets can be set and ultimately achieved.

Scope comparisons should be done on an "apples-to-apples" basis. In the past 2 years, we have extended our database to include detailed planned and actual scope data on six types of refinery units. Our scope database currently numbers 135 units; and there is always room for more data and benchmark participants.

Turnaround competitiveness

Not all turnaround disasters can be avoided. Through strong team integration, thorough scope definition, risk identification and mitigation, robust planning and scheduling practices, and diagnostics and monitoring tools, risks can be significantly minimized. As a result, the best turnaround teams plan and execute the right turnaround right by following their phased and gated turnaround work process.

This means starting with strategic decisions that lead to well-defined tactical planning, which, ultimately, ends up as a series of comprehensive integrated execution plans. Identifying, defining and freezing scope; completing planning early; managing risks; achieving team alignment and all along measuring readiness relative to world-class performers are the fundamental building blocks to achieve turnaround competitiveness and overall success. ✦

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Close monitoring, quick action reduce CW system problems

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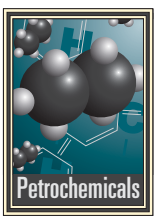


Stress variations in any cooling-water system bring about changes in the potential for scale, corrosion, and fouling. The ability to monitor the changing potential for these operational problems, detect upsets, and take appropriate, corrective action becomes increasingly important as the systems are pushed harder to reduce total cost of operation.

Over the past 2 years, new methods for managing open industrial cooling-water systems based on the actual stresses placed upon them have been developed and evaluated. This article discusses three applications in which variation in system stress presented the potential for scale, corrosion, and microbial fouling. Operational data will show how these stresses were managed with a comprehensive treatment, monitoring, and control strategy.

Process water

Continuous, reliable, efficient, and safe processing of clean sales gas is the primary goal of any gas processor. Cooling systems play an important role in that process, providing cooling for gas sweetening, compression, and fractionation units. Often located in areas where foulants become entrained in the cooling water, gas processing plants strive to minimize operating costs and prevent operational problems under high stress conditions.

Process water is used to heat or cool a process. Often, evaporative cooling—a process that involves recirculating the water through a cooling tower and using evaporation to cool it—provides most of the heat rejection. Obviously, as water evaporates from the process, it must be replaced. That makeup water often comes from publicly owned treatment works or a well.

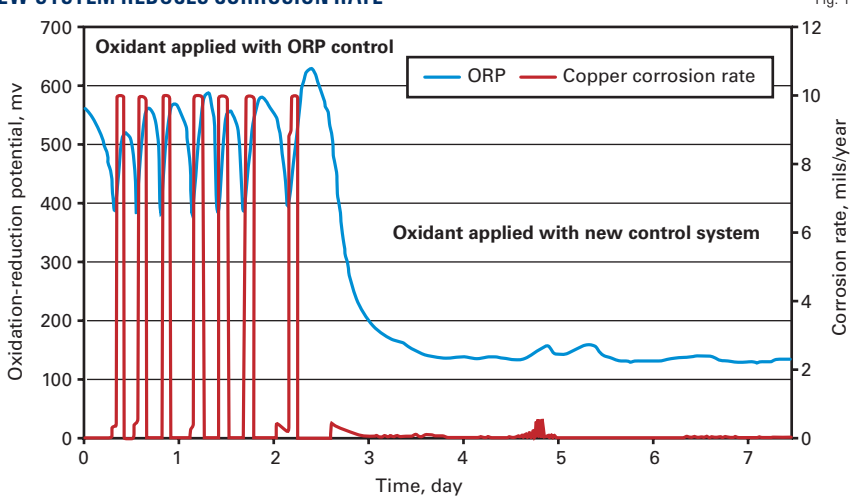
The quality of makeup water sources varies. Some are more naturally scale-forming than others; some are more corrosive than others. Treating water with problematic but relatively unchanging chemical compositions—pH, conductivity, hardness, phosphate, chloride concentration, etc.—is straightforward. The water chemistry is analyzed and a treatment program put in place to prevent operational problems.

In many parts of the world, however, municipal water supplies are being severely strained as demand upon them increases. Users cannot assume they will have access in future to the same quality or quantity of water they received in the past. Their water infrastructure is aging. Their demand for water is increasing. Water-quality requirements are higher today than ever.

The end result for industrial users: higher water costs, more calls from government and concerned citizens for responsible use of natural resources and

NEW SYSTEM REDUCES CORROSION RATE

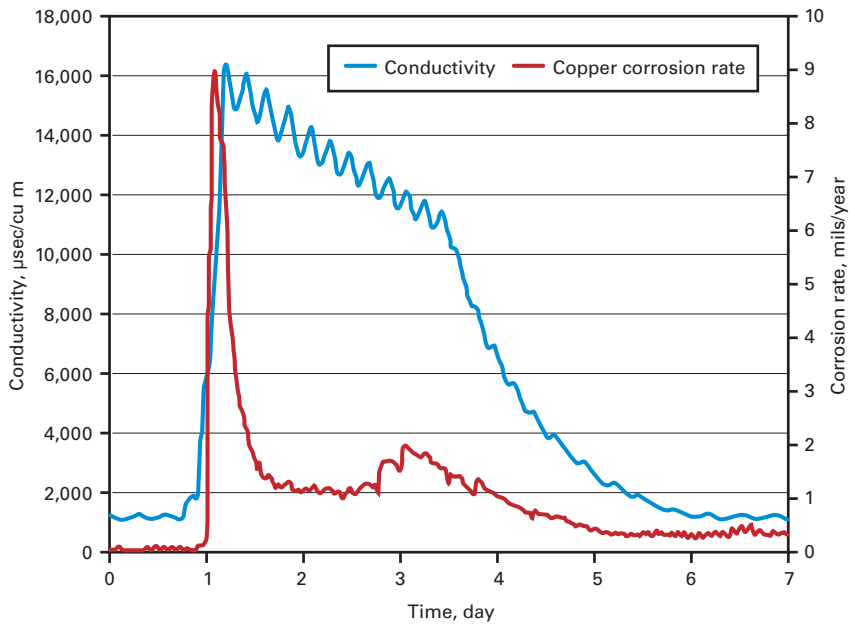
Fig. 1



Based on a presentation to the 86th GPA Convention, Mar. 11-14, 2007, San Antonio.

CONDUCTIVITY RISE SIGNALS INCREASED CORROSION RATE

Fig. 2



a quest for viable alternatives.

Alternative sources of makeup water exist: tertiary treated wastewater, water cascaded through other industrial processes, or water from brackish sources unacceptable for other uses. Although these sources are inexpensive and offer an environmentally friendly alternative to municipal sources, they are also highly variable.

It is not uncommon for the chemical composition of these waters to vary from scale forming to corrosive over relatively short periods of time. Microbial populations can vary over time as well. Contamination with all manner of compounds, many of which can cause serious damage to the cooling system, can occur without warning in response to causes beyond the control of the end users.

Defining system stress

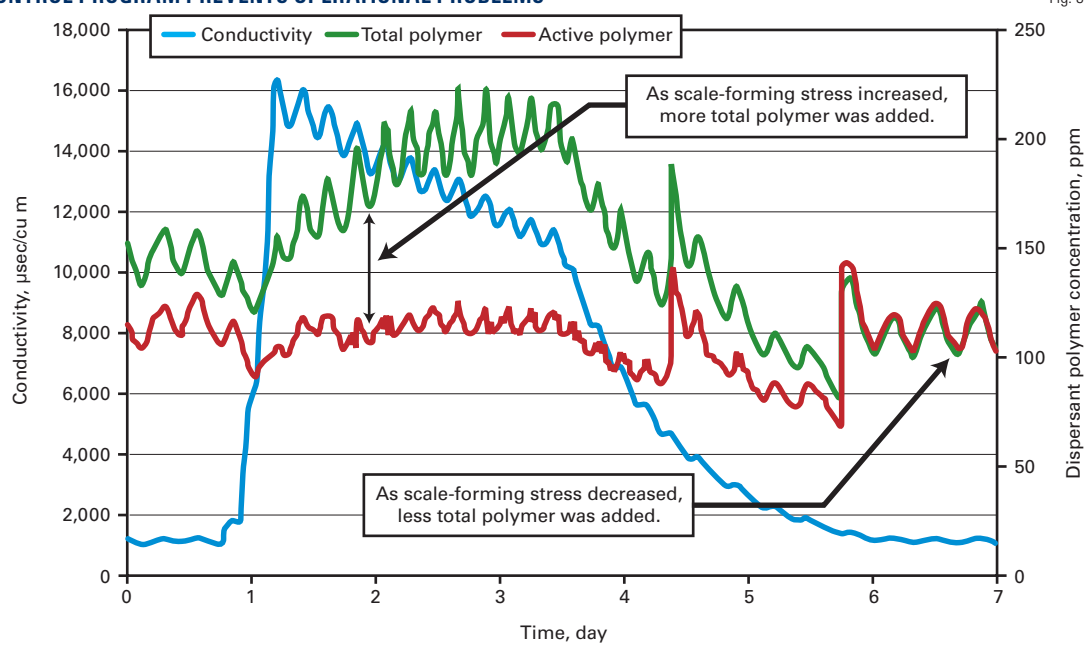
For this discussion, system stress refers to any mechanical, operational, or chemical aspect of system operation that could result in an operational problem: mineral scale, corrosion, or microbial fouling.

Here are some examples of stresses placed on cooling systems:

- *Variable makeup water phosphate concentration.* When concentrations exceed solubility limits, calcium phosphate scaling occurs and heat-exchanger efficiency decreases.
- *Variable cooling water pH.* The pH varies in response to changes beyond the control of the system operators. When the pH drops, corrosion occurs, reducing equipment life.
- *Variation in microbial activity.* Introduction of nutrients from process streams or changes in makeup water source change the biological loading on a cooling system. Without timely addition of a biocide, microbial fouling occurs and system performance degrades rapidly.
- *Operational constraints.* Cost-reduction efforts have decreased the number of operators available for routine cooling-system testing and monitoring. The time between detection of a problem and proper corrective action is long

CONTROL PROGRAM PREVENTS OPERATIONAL PROBLEMS

Fig. 3



enough to allow scale, corrosion, or fouling to occur.

• *Operational realities.* The need to take equipment off-line for periods of time influences effective biocide application, allowing biopopulations to grow.

Effective response to system stress requires constant monitoring of system parameters that reveal changing conditions. When upsets are detected, an appropriate, timely response is required to prevent a problem. Finally, information about the upset and the corrective action taken must be communicated to system users to allow them to take further corrective action, identify the root cause of the problem, or make operational changes to prevent its recurrence.

Case No. 1

A natural gas processor using cooling water to cool natural gas experienced mild-steel corrosion in several copper and steel shell-and-tube exchangers. This case study demonstrates how a comprehensive chemical treatment, monitoring, and control system can more effectively manage microbial populations by reacting to actual changes in microbial activity.

Much of the existing automation equipment was outdated and poorly maintained. This plant used conventional methods of control. It used, for example, an LMI pump for acid control of pH and conductivity as a control for blowdown. And it fed chemical continuously with another LMI pump.

In addition, no one at this plant was dedicated to cooling-system maintenance and operation.

Bacteria contamination was not uncommon. Sulfate-reducing bacteria created corrosion on the mild-steel heat exchangers. As a result, plant maintenance staff routinely repaired the exchangers. Inspection of the exchangers often revealed black slime. The high pH in the recirculating water made it corrosive to copper. Chemical dosage control was almost nonexistent.

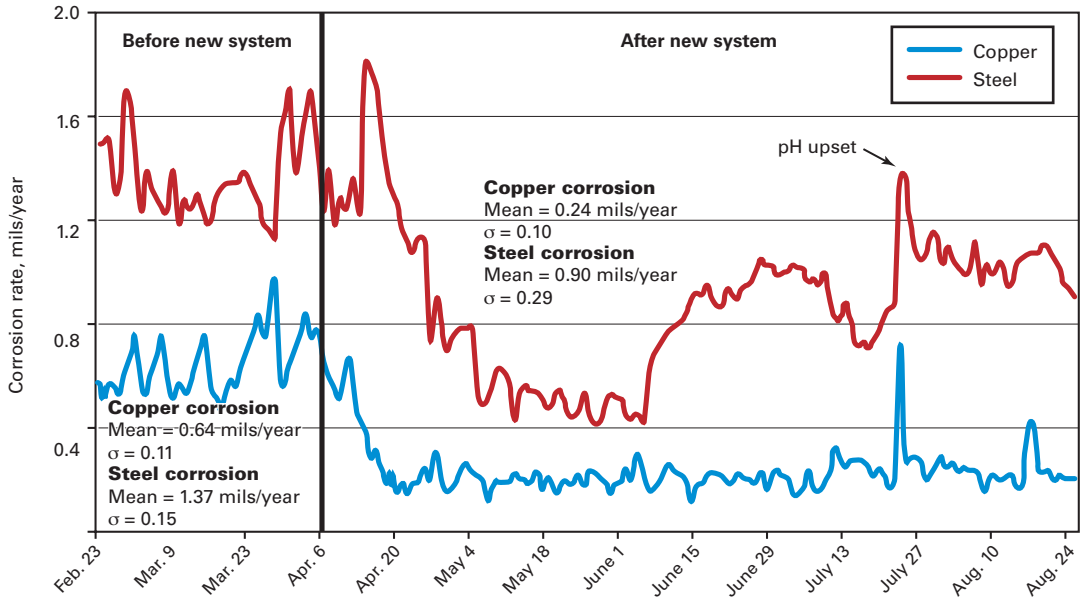
When corrosion caused a heat exchanger failure, hydrocarbon got into the cooling water, which presented a safety issue. The cause of the problem at this plant was microbiologically induced corrosion (MIC).

Without proper treatment, bacteria form corrosive biofilms that support 99% of the bacteria in a cooling system. Most microbial monitoring systems commonly in use, such as dip slides or plate counts, measure only planktonic bacteria, those living in the bulk water, which account for the remaining 1%. Low planktonic counts often leave users with a false sense of security because they do not reveal the presence of the sessile population.

The operator adopted a novel control system to address the cause: introduction into the recirculating water of a fluorescent "bioreporter." The biore-

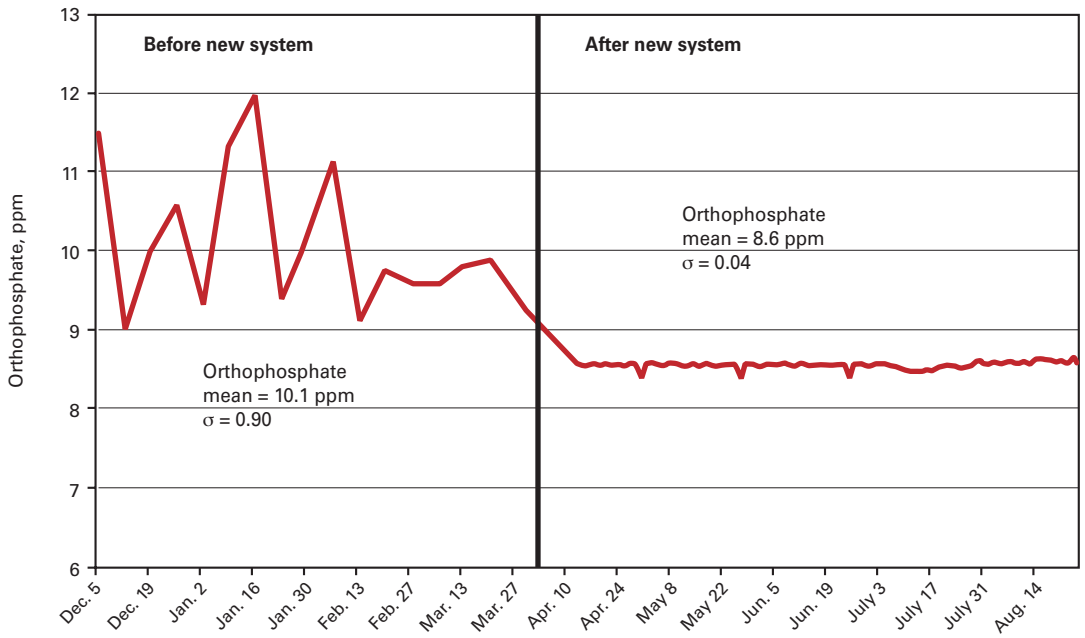
NEW PROGRAM REDUCES CORROSION

Fig. 4



EFFECTS OF INHIBITOR, BETTER CONTROL

Fig. 5



porter reacts with an enzyme, dehydrogenase, produced by all respiring organisms, planktonic or sessile. The reaction changes the bioreporter's fluorescent signature.

By measuring with a modular fluorometer both species and the rates at which they changed, the control system monitored changes in the amount of actual microbial activity, adjusting biocide application as necessary to keep activity under control.

After 4 months of operation, the operator opened the exchangers for a planned maintenance shutdown, finding no microbial deposits. Since, both steel and copper corrosion rates have been below industry norms. In 2 years after adoption of the control system, no failures have occurred in any of the exchangers.

As an additional benefit, the comprehensive data-gathering capability of the control system highlighted a correlation between oxidant application and copper corrosion rates. Controlling oxidant application in response to changes in microbial activity rather than oxidation-reduction potential (ORP) reduced copper corrosion rates (Fig. 1).

Case No. 2

Effective response to upset conditions requires fast detection of the problem and prompt correction. At a petrochemical plant, calcium chloride brine contaminated the cooling system. The implication was a heightened potential for calcium carbonate scale formation and corrosion. Calcium carbonate is a tenacious, highly insulating deposit. Once formed, it can generally be removed only through acid cleaning or other expensive, time-consuming processes.

This case demonstrates how a com-

prehensive chemical treatment, monitoring, and control system can detect an upset and correct it before system integrity is compromised.

The plant's cooling system was well designed. A comprehensive treatment, monitoring, and control system tracked key system parameters and was designed to take appropriate corrective action should an upset be detected.

Scale formation robs the cooling system of efficiency and can cause equipment failure. In this case, the calcium chloride brine leak increased the conductivity and chloride concentration of the recirculating water. Both of these effects increased the demand for dispersant polymer as the potential for calcium carbonate formation increased.

The chemical treatment, monitoring, and control system in place detected these chemical changes and applied more dispersant polymer to prevent deposition.

Dilution of the recirculating water through increased blowdown was another appropriate—but time-consuming—response. When plant personnel detected the upset, they increased the blowdown to reduce the calcium chloride concentration.

The combination of automatic corrective action by the control system and fast action by operators prevented a serious operational problem. In addition to the increased potential for scale formation, elevated chlorides increased corrosion potential. In this case, copper corrosion rates increased (Fig. 2). As blowdown reduced the chloride concentration, copper corrosion rates decreased.

The chemical treatment, monitoring, and control system in place at this facility prevented an operational problem by responding to upset conditions with an appropriate, automatic, corrective action (Fig. 3).

System operators minimized potential damage by diluting the recirculating water. The latter action could have been taken more quickly had the system alerted operators via page, email, or text message. Additional communications capability has been added to do just that.

Case No. 3

In this final case study, improved efficiency in critical heat exchangers improved control of calcium phosphate scale.

Conditions

Retubing and replacement of exchangers coupled with unnecessary downtime translated into a higher total cost of operation for this chemical

plant that produces vinyl products—chlorine, caustic soda, vinyl chloride monomer, and phosphorus trichloride. Conducted with Nalco sales engineers, a review of the mechanical, chemical, and operational aspects of system operation revealed some opportunities for improvement.

This case demonstrates how a comprehensive chemical treatment, monitoring, and control system can compensate for water chemistry variation, prevent operational problems and minimize operating costs.

High temperatures (>140° F.; 60° C.) and low flow rates (0.6 fps; 0.5 m/sec) contributed to $Ca_3(PO_4)_2$ scaling. The mechanical changes needed to address the high temperatures and low flows directly were not practical; operational and chemical solutions were therefore needed to address the mechanical problems.

The left photograph shows $Ca_3(PO_4)_2$ deposits before implementation of the new monitoring and control system. After adoption, the coupons (right photograph) show no deposition. Both sets of coupons were exposed for 4 months (Fig. 6).

Mineral scales such as calcium phosphate are poor thermal conductors. When critical heat exchangers foul with mineral scales, product quality, operational costs, or production rates suffer. Mineral scales restrict flow through tube bundles, reducing heat-transfer efficiency and making temperature control more difficult.

An online fluorometer controlled application of a polyphosphate-based corrosion inhibition program. A very accurate method, fluorescence-based control ensured the target dose of inhibitor was always present in the recirculating water. Good corrosion inhibition had been achieved historically.

Polyphosphate inhibited corrosion at the cathode; orthophosphate inhibited corrosion at the anode. The program worked well when proper concentrations of both species were maintained. Results suffered when the balance was upset, either through high temperatures, low flows, variations in the amount of orthophosphate present in the makeup water, or other uncontrollable factors. In the presence of too much orthophosphate, $Ca_3(PO_4)_2$ scale formed. When orthophosphate concentrations were too low, corrosion occurred.

Loss of heat-transfer efficiency through $Ca_3(PO_4)_2$ scaling represented a greater concern than corrosion. As a result, the operator maintained cooling-water pH at 6.8 to reduce potential for scale formation. The mineral solubility models employed to make this decision were based on discreet chemical conditions, essentially snapshots.

Without the ability to model the variability in the system, control decisions were based on worst-case scaling conditions. When orthophosphate concentrations dropped, no risk of scale formation existed, but corrosion rates increased. A more dynamic modeling tool was needed to understand the stresses placed on this system more completely.

The facility also maintained relatively high halogen concentrations that contributed to higher copper corrosion rates and degradation of the copper corrosion inhibitor. High halogen concentrations degraded tolyltriazole, the copper corrosion inhibitor in use. The result was high copper corrosion rates.

Copper deposition also contributed to corrosion of mild-steel heat exchangers. High chlorine residuals were necessary to comply with country-specific legionella control regulations. The facility had used both shock dosing and continuous chlorination at times.

Approach

To address these problems, the operator adopted a program that consisted of new chemical treatment combined with a monitoring and control system. This program continuously measured key parameters related to system stress, detecting upset conditions and taking appropriate, automatic corrective action. It then communicated with users, documenting what occurred, when, and what action was taken.

Uncontrolled reversion of the polyphosphate to orthophosphate was a key contributor to $Ca_3(PO_4)_2$ scale formation. The new program addressed the issue both chemically and through improved control.

Phosphino succinic oligomer (PSO) is a corrosion inhibitor that does not revert to orthophosphate as do traditional polyphosphates. By eliminating the orthophosphate contributed through reversion, the control automation could adjust system operation based on only one source of phosphate variation: the changing concentrations in the makeup

water. Eliminating one source of variability made both scale and corrosion control more successful (Fig. 4).

The monitoring and control technology used in this system combines fluorescence-based monitoring of an inert fluorescent material with an innovative chemical "tag" incorporated into the dispersant polymer backbone. The chemical "tag" responds to stress just as the polymer does. By continuously comparing the inert signal and the "tag" and the rates at which they change, the system can adjust blowdown and chemical feed to prevent scale formation. During periods of high scale-forming stress, more dispersant polymer was applied.

As the stress abated, less was applied, preventing $Ca_3(PO_4)_2$ scale formation and minimizing operational costs. Combining such innovative chemistries as PSO and "tagged" polymers with advanced control techniques provided this facility good return on investment.

Benzotriazole, a much more halogen-resistant azole, replaced tolyltriazole as the copper corrosion inhibitor and eliminated copper deposition through better copper corrosion inhibition.

In addition to the changes to the chemical program and control strategies, the cooling water pH was increased to 7.2. Computer modeling predicted good results—low corrosion rates and reduced potential for scale formation—at that pH when coupled with PSO and better control. This reduced acid feed and made the water chemistry less corrosive.

Results

The combination of a more reversion-resistant corrosion inhibitor and better control translated into lower corrosion rates and better scale control at this facility. Fig. 5 shows the reduction in overall orthophosphate concentrations and variability. Visual inspections of heat exchangers and corrosion coupons verified the improvement (Fig. 6).

Since the DPD chlorine analyzer was already installed, its signal output was combined with the other data collected by the new control system. The trend of free chlorine measured by the analyzer correlates well with the ORP measurement taken by the controller.

Plant engineers estimate the annual total cost of operation reduction at their facility to be $168,000, including $52,000 in heat exchanger cleaning, retubing, and repair costs.

Acknowledgment

The author thanks colleague Andrea Marek for her contributions in preparation and presentation of this article. ✦

The author

Daniel M. Cicero is a senior product manager in Nalco's Product Lifecycle Management Group. He has been with Nalco for more than 15 years in a variety of sales, marketing, new-product development, and product-line management roles. He is currently brand manager for Nalco's 3D TRASAR technology.

DNV certifies pipe for LNG projects

Det Norske Veritas in early May issued a "Certificate of Fitness for Service" for use in LNG projects to Houston-based ITP InTerPipe's triple-wall insulated pipe-in-pipe technology.

ITP started developing and qualifying the technology in 1998. Development complied with the DNV technology qualification process as defined in DNV RP-A203, Qualification Procedures for New Technology.

Four major oil companies joined ITP in a joint industry project in 2003 with the objective of qualifying ITP's pipe design for subsea transportation of LNG. The JIP successfully obtained "Approval in Principle" from the American Bureau of Shipping and "Statement of Feasibility" from Det Norske Veritas for the LNG pipe design for subsea service in 2004.

ITP completed the frontend engineering design study necessary to gain DNV's certification of fitness in 2006.

The DNV certificate of fitness for service affirms that, at the time of assessment, the new technology is considered fit for service. Certification means that failure modes identified through the process outlined in the DNV offshore service specification, DNV OSS-401, have been properly addressed, and that supporting evidence substantiates that the technology fulfils all stated functional requirements and meets the stated reliability target.

Makeup, capabilities

The 2003 JIP fabricated and tested a full-scale, triple wall section (Fig. 1) consisting of:

- A 24-in., 36% Ni steel inner pipe with 40-mm thick insulation.
- A 30-in. carbon steel intermediate pipe.
- A 34-in. carbon steel outer pipe.

As applied in the LNG pipeline configuration, the Izoflex insulation provides an overall U-value of 0.131 w/sq m-°C.

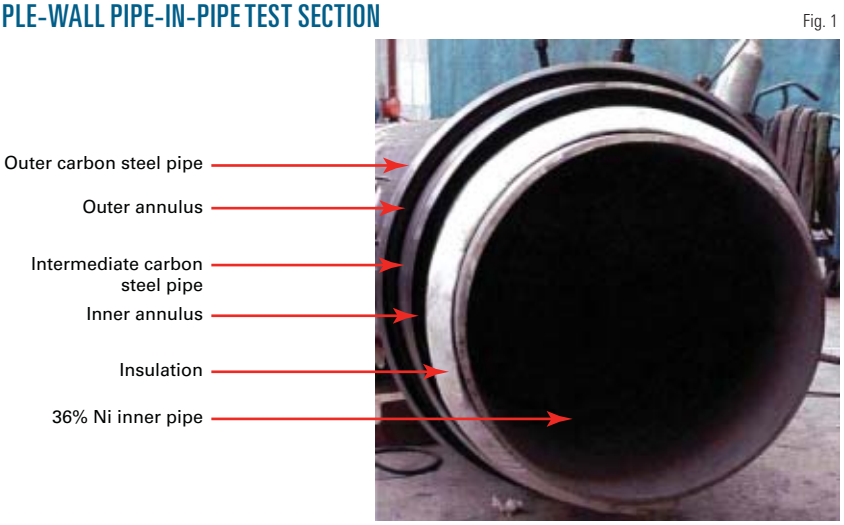
The 18-m test section consisted of a 12-m straight section and a 5D bend, for a total 18-m length. The test section included two full-scale end bulkheads and an inline bulkhead at the base of the bend. The straight section included one 36% nickel steel girth weld. The bend demonstrated the ability to manufacture bends through an induction bending process.

The test program consisted of the following:

- A hydrostatic pressure test at 30 barg and ambient temperature.
- Five thermal cycles from ambient temperature to –196° C. (–320° F.) and 1 barg, including shock cooling of the inner pipe with liquid nitrogen.
- Four boil-off tests at –160° C. (–256° F.) and 17 barg, across a range of inner annulus pressure conditions (OGJ, Nov. 14, 2005, p. 57).

TRIPLE-WALL PIPE-IN-PIPE TEST SECTION

Fig. 1



Potential use

One receiving terminal has selected the ITP LNG pipe as its base case design and several other projects are considering the technology for both import and export of LNG, accord-

ing to DNV.

Transporting LNG through subsea or buried pipelines can:

- Eliminate the trestle typically used in such instances.
- Increase security, as the pipeline is buried and thus not visible.
- Increase siting options by allowing loading or offloading further offshore and placement of tanks further inland.
- Decrease environmental and aesthetic consequences.
- Decrease or eliminate the need for dredging.

Fig. 2 provides a basic illustration of how use of this design would yield these benefits.

PlusPetrol SA, Buenos Aires, selected a similar ITP pipe-in-pipe technology in 2002 for use as the onshore and subsea propane and butane loading lines of its Camisea LPG export terminal.

Fig. 3 shows the LPG berth for Camisea at Pisco, Peru. The conventional trestle originally proposed for this project fell victim to local objections. These objections were based on the high visibility of such lines and concern that a trestle would interfere with fishing boat routes. The trestle was also subject to a risk of collision over the anticipated 35-year project life and was higher in cost than the subsea option.

In the end, two 20-in. by 24-in. pipe-in-pipe lines were used to transport propane and butane at temperatures as cold as –49° F. from the Pisco fractionation plant to the offshore berth; 1 km buried onshore and 3 km buried offshore.

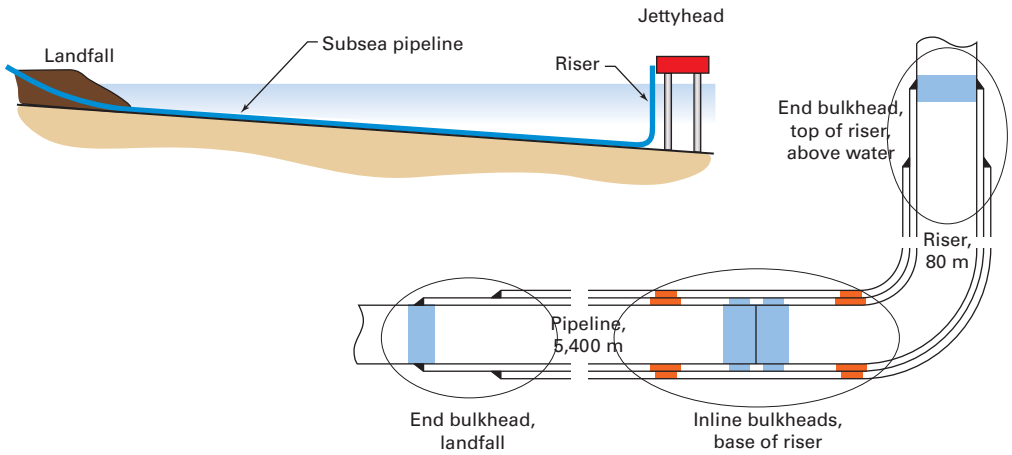
The pipelines became operational in September 2004 when the first load of butane was shipped. Field measurements of the thermal performance of the pipe-in-pipe loading system in operation confirmed that designed thermal performance had been achieved.

While the system is designed to circulate product continuously through the cryogenic lines to keep them cold, the system's thermal performance resulted in such a low boil-off rate that the LPG pipelines can be shut-in between shipments for longer than a week and still maintain operating temperatures (OGJ, Nov. 14, 2005, p. 57).

The Camisea LPG pipelines demonstrate all components of ITP's LNG pipeline design, construction, and installation except the 36% nickel steel pipe. ✦

TRIPLE-WALL PIPE-IN-PIPE APPLICATION

Fig. 2



The Camisea LPG berth offshore Pisco, Peru, uses buried subsea lines and is therefore missing both surface trestles and the need for repeated dredging (Fig. 3).

Pipelay, construction vessel design takes shipshape turn

Christopher E. Smith
Pipeline Editor

Designs for future heavy-lift pipelay vessels and deepwater construction vessels are taking on increasingly shipshape characteristics, as contractors seek to increase their operational flexibility through faster vessels.

Larsen & Toubro Ltd., Mumbai, together with SapuraCrest Petroleum Bhd, Selangor, Malaysia, in early May ordered a new-generation S2500 heavy-lift pipelay vessel designed by Sea of Solutions, part of Offshore Ship Designers Group, the Netherlands.

The $138 million vessel will enter service in 2009. ASL Marine, Singapore, will build it.

Sea of Solutions customized its Seabarge 3000 design in creating the S2500. The more shipshape hull with bulbous bow increases transit speed and generates additional space for the mooring system without affecting dynamic positioning layout.

The S2500 has a 10-point mooring system and can be upgraded to DP.

The design incorporates a center firing line with six single-joint welding stations to optimize pipelaying operations. The vessel is also equipped with a 3,000-ton single post crane.

Another company pursuing a more shipshaped design in its next vessel is Heerema Marine Contractors, which announced in November 2006 that it was investing $1 billion in a new Class III dynamic position system deepwater construction vessel of its own design.

The new vessel will be 220 m long, 88 m wide, and 44 m deep. It will have a maximum speed of 20 knots; up to four times the speed of Heerema's current deepwater construction vessels, according to the company.

The vessel will include facilities for 550 people, upgradeable to 750 people. Payload is 25,000 tonnes and power generation capacity will be of 75 Mw.

The vessel will have dual crane capacity of 15,000 tonnes. Its J-Lay tower and deepwater lowering equipment will allow it to install pipelines and structures in water 200-3,500 m deep, with a maximum 32-in. pipeline OD. Tension capacity of 2,000 tonnes doubles that of Heerema's DCV Balder.

Heerema expects the vessel to enter service in 2010.

Arctic, Asia-Pacific

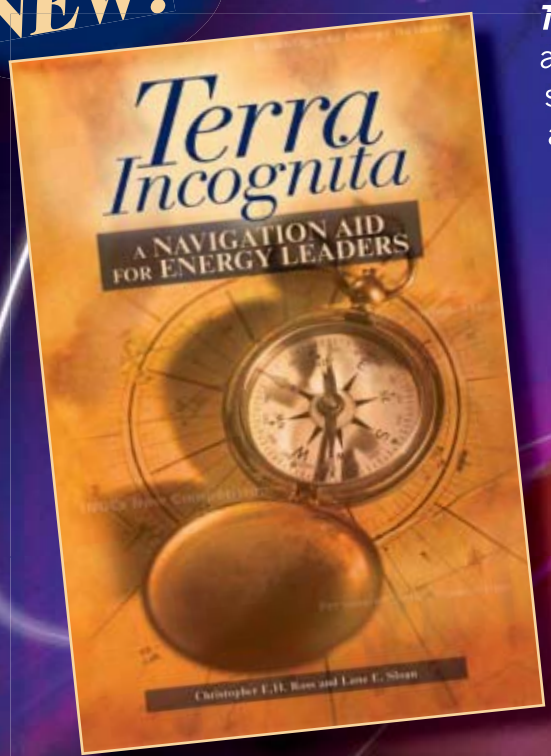
The new vessel's design and speed will allow it to undertake offshore construction in the Arctic. Heerema is locating the cranes, J-Lay tower, and other installation equipment on the vessel in a manner designed to minimize the effects of the Arctic environment. The hull and thrusters are also being designed to withstand arctic conditions, according to Heerema.

Heerema has targeted both the Barents Sea and Beaufort Sea as areas of future growth. Heerema also expects that the new vessel's speed will increase the company's ability to pursue business in the Asia-Pacific region, by either simply reaching the area more quickly following completion of work elsewhere or allowing it to station one of its current vessels in that region instead of the Atlantic Basin.

Heerema intends to order key long-lead components, such as the cranes and J-Lay Tower this summer and is in talks with potential suppliers. ✦

Charting a New Course for Energy Leaders

NEW!



Terra Incognita: A Navigation Aid for Energy Leaders addresses the forthcoming transition in energy supplies, identifies strategic leadership challenges ahead, and summarizes lessons learned from interviews with more than 20 energy company leaders.

In the first book ever written specifically for energy industry leaders, authors Chris Ross and Lane Sloan present:

- The understanding that recent trends are not sustainable, and that enduring energy companies must respond to new technological and social demands and opportunities
- Insights from corporate successes that have demonstrated sustainable and profitable growth since 2001
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- A profile of the energy leader of the future

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This picture shows a number of the corals relocated by CSA in their new environment (Fig. 1).

CSA tagged relocated corals relative to global positioning system-referenced stakes to facilitate monitoring activities (Fig. 2).

Qatar conducts reef restoration along three pipeline corridors

Qatar Gas contracted CSA International, Inc. to conduct a coral reef restoration project, designed as mitigation for three pipeline corridors off Ras Laffan Industrial City, Qatar.

The project consisted of collecting, transporting, and relocating 4,500 living hard corals from the proposed pipeline corridors crossing living coral reefs (Fig. 1). A team of CSA scientific divers, operating under a dive plan approved by RLIC and Qatar Petroleum, removed the corals.

The species, coral colony size, growth form, and health of the corals guided selection for removal. CSA caged the removed corals in metal baskets and transported them 40 km to Fasht al Hurabi, the relocation site approved by Qatar's supreme council for the environment and natural reserves.

A large vessel transported the removed corals in specially constructed tanks with circulating seawater. CSA attached, tagged, and mapped the corals relative to global positioning system-referenced stakes to facilitate monitoring activities (Fig. 2).

The project was CSA's 30th for 21 clients in Qatar since 1994.

CSA has completed a total of 36 artificial reef mitigation projects since 1985, including design, site planning and selection, engineering, procurement, transportation, construction, installation, and monitoring.

CSA recently opened new offices in Doha, Qatar, and Port of Spain, Trinidad, to provide environmental and socioeconomic management, impact assessment, mitigation, and monitoring services to oil and gas companies and other industries. ✦

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Manama, Kingdom of Bahrain
9–13 December 2007




This year's inaugural **Oil & Gas Maintenance Technology (OGMT)** conference and exhibition will take place alongside the 9th annual **Pipeline Rehabilitation & Maintenance** exhibition. Both events will bring together maintenance experts from the energy capitals of the Middle East and around the world. Technical sessions and equipment exhibitions will provide an opportunity to discuss the latest techniques and solutions related to inspection and maintenance issues in the industry.

The events will focus on all critical areas of the oil and gas industry—from E&P to transportation to refining and processing. An exhibition demonstrating the latest tools and technologies for the industry will complement the three-day technical conference.

CALL FOR ABSTRACTS
DEADLINE 14 MAY 2007

Opportunities now exist to submit paper abstracts for consideration, with actual case study presentations being of particular interest. Please forward your title and 150 – 200 word abstract and list all the authors. Full contact information for the primary contact author (company affiliation, telephone, fax number and email address) must be provided. For further information visit the event website.

www.oilandgasmaintenance.com

www.pipeline-rehab.com

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Service searches web-based energy intelligence

MetaCarta GeoIntel for Petroleum, an online geographic search service, provides a way to geographically search and discover web-based energy-related intelligence.

Public information on the web is manually searched daily by managers and geoscientists to aid in retrieval of pertinent information for new area reconnaissance, competitive analysis, environmental concerns, and areas of political unrest.

The service is a vertical geographic search engine that searches 3,500+ web sites and 9,000,000 web pages containing information that is specific to the energy industry. The content is continually being reviewed by a "content curator" for relevancy.

Two GeoIntel for Petroleum packages are available: For current MetaCarta GTS geOdrive users, the subscription-based service easily integrates into GTS geOdrive to extend their search beyond the firewall to access these industry specific web sites. Results from the GeoIntel for Petroleum search are aggregated with the results from their existing internal systems and presented in the same context.

Source: **MetaCarta Inc.**, 350 Massachusette Ave., Cambridge, MA 02139.

Protective wrap for downhole tubing

Ricewrap, a protective wrap of glass reinforced epoxy (GRE) material externally applied and bonded to steel pipe, is featured in new literature offered free upon request.

The wrap is recommended for external corrosion protection on downhole tubing typically used between injection mandrels and-or packers in multiple zones.

Nominal thickness of the externally applied GRE is 0.100 in. with a working envelope between –20° F. to +250° F.

Source: **Duoline Technologies LP,** 9019 N. County Road West, Odessa, TX 79764.

Bolt designed for corrosion-resistant uses

The new TuffCor bolt is engineered to provide lower maintenance and extended life in severe environmental conditions such as offshore and coastal onshore locations.

The company developed its new bolt category using salt fog tests conducted by independent laboratories. In these tests, TuffCor bolts lasted 5,000 hr without corroding, but standard bolts corroded after just 1,000 hr, the firm says. Although test times cannot be converted directly to field life, the tests showed a dramatic advance in corrosion resistance, the firm noted.

Because it promises to resist corrosion significantly better than conventional coated bolts, the TuffCor bolt looks better, eliminates rust bleed, and reduces breakout torque, the firm points out. It is also safer, since torch cutting isn't necessary.

Source: **Dan-Loc Bolt & Gasket**, 725 N. Drennan, Houston, TX 77003-1320.

Services/Suppliers

Wärtsilä Corp.

Helsinki, Finland, has announced the opening of an office in Hanoi, and a new service workshop in Ho Chi Minh City, Vietnam. Both facilities will support development of the region's offshore oil and natural gas industry. The company has 15 employees in Vietnam, eight of whom are engineers carrying out repairs in the new workshop as well as onboard ships or at other operating sites.

Wärtsilä Corp. is a leading provider of ship machinery, propulsion, and maneuvering solutions. The company supplies engines and generating sets, reduction gears, propulsion equipment, control systems, and sealing solutions for all types of vessels and offshore applications, as well as supplying maintenance and reconditioning services for those products.

J-W Wireline Co.

Addison, Tex., has announced expansion into the Permian Basin with the opening of an office in Monahans, Tex. Mike Gibson, with over 20 years of wireline experience in the area, serves as district manager for the office.

The company is scheduled to open additional district offices this year in Yuma, Colo.; Van Buren, Ark.; and Godley, Tex.

J-W Wireline Co., a subsidiary of J-W Operating Co., is one of the largest independent cased-hole wireline companies in the US. The company specializes in deep high pressure perforating, multiple zone completions, comprehensive cased-hole logging, and pipe recovery in the US mid-continent, and Rocky Mountain regions.

Ambar Lone Star Fluid Services

Lafayette, La., has completed a new distribution and operations complex in Tyler, Tex., serving customers in the Ark-La-Tex region, and replacing its Kilgore, Tex. facility.

Ambar Lone Star provides drilling and completion fluids designed to meet demanding well conditions, including a water base mud and synthetic fluid for deepwater environments. The company is a subsidiary of Patterson-UTI Energy Inc., one of the largest onshore contract drillers in North America.

Platt Sparks & Associates Consulting Petroleum Engineers Inc.

Austin, Tex., has announced that Atia Rahman has joined the firm. She will provide expertise on a broad range of reservoir engineering and regulatory projects.

Rahman, who holds a BS degree in chemical engineering from Bangladesh University of Engineering & Technology, and an MS degree in petroleum engineering from the University of Texas, previously was an engineering specialist with the Railroad Commission of Texas.

In another announcement, Platt Sparks has made John F. Miller III and Carter N. Davis partners in the firm. Miller joined Platt Sparks in 2001, and Davis has been with the firm since 1995.

Platt Sparks & Associates, founded in 1980, has offices in Austin and Midland, Tex.

API IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4		District 5		Total US		
	5-11 2007	[1]5-4 2007	5-11 2007	[1]5-4 2007	5-11 2007	[1]5-4 2007	5-12 2006
	1,000 b/d						
Total motor gasoline	455	479	21	7	476	486	626
Mo. gas. blending comp.	788	692	96	122	884	814	913
Distillate[2]	216	261	58	102	274	363	477
Residual	273	350	43	34	316	384	558
Jet fuel-kerosine	8	144	179	194	187	338	166
LPG	304	230	4	6	308	236	262
Unfinished oils	474	545	12	5	486	550	667
Other	865	382	58	70	923	452	239
Total products	**3,283**	**3,083**	**471**	**540**	**3,854**	**3,623**	**3,908**
Canadian crude	1,259	1,462	288	103	1,547	1,565	2,255
Other foreign	7,499	7,868	876	1,305	8,375	9,173	8,513
Total crude	**8,758**	**9,330**	**1,164**	**1,408**	**9,922**	**10,738**	**10,768**
Total imports	**12,141**	**12,413**	**1,635**	**1,948**	**13,776**	**14,361**	**14,676**

[1]Revised. [2]Includes No. 4 fuel oil.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

PURVIN & GERTZ LNG NETBACKS—MAY 11, 2007

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMBtu					
Barcelona	6.94	4.83	6.02	4.74	5.39	6.00
Everett	6.42	4.39	6.05	4.49	4.95	6.71
Isle of Grain	2.52	0.65	1.97	0.55	1.17	2.04
Lake Charles	5.34	3.41	5.09	3.60	3.89	5.93
Sodegaura	4.47	6.48	4.67	6.20	5.58	3.98
Zeebrugge	5.62	3.62	5.05	3.53	4.19	5.07

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

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

OGJ CRACK SPREAD

	*5-11-07	*5-12-06	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	87.47	86.75	0.72	0.8
Brent crude	64.27	70.60	–6.33	–9.0
Crack spread	23.20	16.15	7.05	43.6
FUTURES MARKET PRICES				
One month				
Product value	87.86	87.64	0.22	0.2
Light sweet crude	61.89	71.59	–9.70	–13.5
Crack spread	25.97	16.05	9.91	61.8
Six month				
Product value	79.67	84.78	–5.11	–6.0
Light sweet crude	66.92	75.42	–8.50	–11.3
Crack spread	12.75	9.36	3.39	36.2

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

API CRUDE AND PRODUCT STOCKS

	Crude oil	Motor gasoline		Jet fuel Kerosine	Fuel oils		Unfinished oils
		Total	Blending comp.[1]		Distillate	Residual	
	1,000 bbl						
PAD I	15,189	52,026	24,454	9,365	42,882	15,106	6,997
PAD II	75,247	47,577	16,173	7,368	28,412	1,182	13,996
PAD III	189,697	66,179	27,185	13,279	33,226	16,531	46,749
PAD IV	13,538	5,632	1,737	516	3,255	302	2,864
PAD V	[1]56,264	30,034	20,508	8,990	12,601	5,626	23,483
May 11, 2007	**[1]349,935**	**201,448**	**90,057**	**39,518**	**120,376**	**38,747**	**94,089**
May 4, 2007[3]	**344,778**	**199,230**	**89,747**	**39,685**	**119,052**	**38,779**	**95,534**
May 12, 2006	**343,795**	**205,493**	**89,938**	**40,286**	**116,133**	**42,185**	**93,016**

[1]Included in total motor gasoline. [2]Includes 6.500 million bbl of Alaskan crude in transit by water. [3]Revised.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

API REFINERY REPORT—MAY 11, 2007

District	REFINERY OPERATIONS					REFINERY OUTPUT			
	Total refinery input	Crude runs	Input to crude stills	Operable capacity	Percent operated	Total motor gasoline	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual
	1,000 b/d					1,000 b/d			
East Coast	3,367	1,419	1,421	1,618	87.8	1,792	125	498	145
App. Dist. 1	82	82	82	95	86.3	77	0	19	1
Dist. 1 total	**3,449**	**1,501**	**1,503**	**1,713**	**87.7**	**1,869**	**125**	**517**	**146**
Ind., Ill., Ky.	2,075	1,997	1,999	2,355	84.9	1,245	104	565	43
Minn., Wis., Dak.	395	387	389	442	88.0	346	29	126	13
Okla., Kan., Mo.	812	642	659	786	83.8	540	18	247	5
Dist. 2 total	**3,282**	**3,026**	**3,047**	**3,583**	**85.0**	**2,131**	**151**	**938**	**61**
Inland Texas	905	616	630	647	97.4	400	45	194	7
Texas Gulf Coast	3,939	3,233	3,342	4,031	82.9	1,394	338	880	141
La. Gulf Coast	3,414	3,269	3,271	3,264	100.2	1,246	360	809	109
N. La. and Ark.	219	180	186	215	86.5	65	7	46	6
New Mexico	157	106	106	113	93.8	111	3	37	1
Dist. 3 total	**8,634**	**7,404**	**7,535**	**8,270**	**91.1**	**3,216**	**753**	**1,966**	**264**
Dist. 4 total	**651**	**497**	**508**	**596**	**85.2**	**142**	**24**	**143**	**15**
Dist. 5 total	**2,731**	**2,525**	**2,728**	**3,173**	**86.0**	**1,523**	**395**	**581**	**148**
May 11, 2007	**18,747**	**14,953**	**15,321**	**17,335**	**88.4**	**8,881**	**1,448**	**4,145**	**634**
May 4, 2007*	**18,857**	**14,823**	**15,227**	**17,335**	**87.8**	**9,094**	**1,393**	**4,241**	**689**
May 12, 2006	**16,780**	**15,093**	**15,408**	**17,115**	**90.0**	**8,387**	**1,363**	**3,818**	**624**

*Revised.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

OGJ GASOLINE PRICES

	Price ex tax 5-9-07	Pump price* 5-9-07	Pump price 5-10-06
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	260.2	299.9	290.5
Baltimore	260.8	302.7	297.1
Boston	252.1	294.0	290.9
Buffalo	247.3	307.4	300.8
Miami	265.4	315.7	304.2
Newark	250.6	283.4	288.2
New York	243.6	303.7	302.9
Norfolk	253.0	290.6	292.6
Philadelphia	253.9	304.6	304.5
Pittsburgh	242.9	293.6	290.4
Wash., DC	269.5	307.9	309.6
PAD I avg.	254.5	300.3	297.4
Chicago	289.0	339.9	314.1
Cleveland	253.5	299.9	279.6
Des Moines	256.2	296.6	265.8
Detroit	256.1	305.3	281.8
Indianapolis	261.9	306.9	276.0
Kansas City	256.6	292.6	262.8
Louisville	268.0	304.9	280.5
Memphis	247.1	286.9	277.5
Milwaukee	265.6	316.9	290.8
Minn.-St. Paul	257.9	298.3	273.4
Oklahoma City	257.5	292.9	263.2
Omaha	255.5	301.9	278.6
St. Louis	258.2	294.2	267.3
Tulsa	257.8	293.2	264.4
Wichita	252.2	295.6	265.2
PAD II avg.	259.5	301.7	276.1
Albuquerque	266.8	303.2	285.4
Birmingham	250.9	289.6	278.0
Dallas-Fort Worth	255.1	293.5	295.3
Houston	252.2	290.6	290.1
Little Rock	248.4	288.6	273.4
New Orleans	248.8	287.2	281.5
San Antonio	239.8	278.2	272.8
PAD III avg.	251.7	290.1	282.3
Cheyenne	255.7	288.1	257.1
Denver	266.3	306.7	273.5
Salt Lake City	257.2	300.1	276.7
PAD IV avg.	259.7	298.3	269.1
Los Angeles	285.5	344.0	333.5
Phoenix	269.2	306.6	306.6
Portland	285.0	328.3	300.3
San Diego	294.4	352.9	340.3
San Francisco	310.8	369.3	338.5
Seattle	282.8	335.2	317.1
PAD V avg.	288.0	339.4	322.7
Week's avg.	**261.0**	**304.6**	**288.9**
Apr. avg.	**234.7**	**278.3**	**270.5**
Mar. avg.	**210.4**	**254.0**	**235.4**
2007 to date	**207.3**	**250.9**	—
2006 to date	**203.0**	**245.6**	—

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

REFINED PRODUCT PRICES

	5-4-07 ¢/gal		5-4-07 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	216.33	New York Harbor	183.45
Gulf Coast	218.20	Gulf Coast	182.85
Los Angeles	265.45	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	216.28	ARA	185.05
Singapore	208.57	Singapore	191.67
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	226.95	New York Harbor	122.33
Gulf Coast	229.45	Gulf Coast	124.40
Los Angeles	273.45	Los Angeles	141.34
		ARA	115.90
		Singapore	129.94

Source: DOE Weekly Petroleum Status Report.
Data available in OGJ Online Research Center.

BAKER HUGHES RIG COUNT

	5-11-07	5-12-06
Alabama	4	5
Alaska	8	8
Arkansas	44	22
California	33	33
Land	32	27
Offshore	1	6
Colorado	109	88
Florida	0	0
Illinois	0	0
Indiana	2	0
Kansas	14	7
Kentucky	8	5
Louisiana	184	191
N. Land	61	58
S. Inland waters	27	19
S. Land	32	34
Offshore	64	80
Maryland	0	0
Michigan	1	2
Mississippi	14	8
Montana	20	22
Nebraska	0	0
New Mexico	78	100
New York	5	6
North Dakota	33	26
Ohio	12	6
Oklahoma	182	178
Pennsylvania	14	14
South Dakota	2	1
Texas	819	740
Offshore	12	14
Inland waters	1	5
Dist. 1	21	21
Dist. 2	25	26
Dist. 3	57	69
Dist. 4	91	83
Dist. 5	171	134
Dist. 6	117	102
Dist. 7B	38	41
Dist. 7C	57	37
Dist. 8	114	83
Dist. 8A	24	25
Dist. 9	33	30
Dist. 10	58	70
Utah	43	40
West Virginia	33	24
Wyoming	70	99
Others—NV-2; TN-3; VA-3	8	2
Total US	**1,740**	**1,627**
Total Canada	**103**	**199**
Grand total	**1,843**	**1,826**
Oil rigs	282	259
Gas rigs	1,456	1,367
Total offshore	77	100
Total cum. avg. YTD	**1,738**	**1,548**

Rotary rigs from spudding in to total depth.
Definitions, see OGJ Sept. 18, 2006, p. 42.

Source: Baker Hughes Inc.
Data available in OGJ Online Research Center.

SMITH RIG COUNT

Proposed depth, ft	5-11-07 Rig count	5-11-07 Percent footage*	5-12-06 Rig count	5-12-06 Percent footage*
0-2,500	54	9.2	61	1.6
2,501-5,000	112	49.1	92	47.8
5,001-7,500	227	17.6	216	16.6
7,501-10,000	404	2.7	363	2.7
10,001-12,500	434	3.9	374	2.9
12,501-15,000	268	0.7	270	0.3
15,001-17,500	103	0.9	108	0.9
17,501-20,000	78	—	78	—
20,001-over	38	—	23	—
Total	**1,718**	**7.6**	**1,585**	**6.5**
INLAND	40		45	
LAND	1,613		1,468	
OFFSHORE	65		72	

*Rigs employed under footage contracts.
Definitions, see OGJ, Sept. 18, 2006, p. 42.

Source: Smith International Inc.
Data available in OGJ Online Research Center.

OGJ PRODUCTION REPORT

	[1]5-11-07	[2]5-12-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	19	21
Alaska	774	801
California	662	687
Colorado	51	63
Florida	7	7
Illinois	30	28
Kansas	96	99
Louisiana	1,355	1,222
Michigan	14	16
Mississippi	49	48
Montana	92	96
New Mexico	163	162
North Dakota	106	107
Oklahoma	167	172
Texas	1,319	1,308
Utah	45	49
Wyoming	142	137
All others	61	67
Total	**5,152**	**5,090**

[1]OGJ estimate. [2]Revised.

Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

US CRUDE PRICES

$/bbl*	5-11-07
Alaska-North Slope 27°	50.90
South Louisiana Sweet	65.50
California-Kern River 13°	52.35
Lost Hills 30°	60.15
Southwest Wyoming Sweet	58.12
East Texas Sweet	59.56
West Texas Sour 34°	52.15
West Texas Intermediate	59.00
Oklahoma Sweet	59.00
Texas Upper Gulf Coast	55.75
Michigan Sour	52.00
Kansas Common	58.00
North Dakota Sweet	53.25

*Current major refiner's posted prices except North Slope lags 2 months. 40° gravity crude unless differing gravity is shown.

Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

WORLD CRUDE PRICES

$/bbl[1]	5-4-07
United Kingdom-Brent 38°	66.92
Russia-Urals 32°	63.17
Saudi Light 34°	63.47
Dubai Fateh 32°	64.32
Algeria Saharan 44°	69.57
Nigeria-Bonny Light 37°	69.79
Indonesia-Minas 34°	69.00
Venezuela-Tia Juana Light 31°	60.10
Mexico-Isthmus 33°	59.99
OPEC basket	65.18
Total OPEC[2]	64.42
Total non-OPEC[2]	62.18
Total world[2]	63.40
US imports[3]	59.76

[1]Estimated contract prices. [2]Average price (FOB) weighted by estimated export volume. [3]Average price (FOB) weighted by estimated import volume.

Source: DOE Weekly Petroleum Status Report.
Data available in OGJ Online Research Center.

US NATURAL GAS STORAGE[1]

	5-4-07	4-27-07	Change
	Bcf		
Producing region	695	672	23
Consuming region east	777	716	61
Consuming region west	275	263	12
Total US	**1,747**	**1,651**	**96**
	Feb. 07	**Feb. 06**	**Change, %**
Total US[2]	**1,649**	**1,886**	**–12.6**

[1]Working gas. [2]At end of period.
Source: Energy Information Administration.
Data available in OGJ Online Research Center.

Statistics

International rig count

Region	Apr. 2007 Land	Apr. 2007 Off.	Apr. 2007 Total	Apr. 06 Total
WESTERN HEMISPHERE				
Argentina	86	—	86	79
Bolivia	3	—	3	3
Brazil	16	20	36	32
Canada	96	4	101	198
Chile	1	—	1	1
Colombia	35	—	35	24
Ecuador	9	—	9	12
Mexico	58	27	85	85
Peru	7	—	7	4
Trinidad	5	1	6	4
United States	1,675	75	1,750	1,597
Venezuela	61	18	79	82
Other	2	—	2	1
Subtotal	**2,055**	**145**	**2,200**	**2,122**
ASIA-PACIFIC				
Australia	10	13	23	19
Brunei	1	3	4	4
China-offshore	—	17	17	16
India	53	30	83	79
Indonesia	31	20	51	45
Japan	3	1	4	2
Malaysia	—	18	18	15
Myanmar	7	2	9	10
New Zealand	3	2	5	6
Papua New Guinea	2	—	2	3
Philippines	—	—	—	2
Taiwan	—	—	—	—
Thailand	3	10	13	11
Vietnam	—	8	8	8
Other	1	2	3	2
Subtotal	**114**	**126**	**240**	**222**
AFRICA				
Algeria	25	—	25	24
Angola	3	2	5	5
Congo	2	1	3	3
Gabon	2	—	2	2
Kenya	—	—	—	—
Libya	11	—	11	9
Nigeria	2	5	7	8
South Africa	—	—	—	1
Tunisia	2	1	3	2
Other	2	2	4	2
Subtotal	**49**	**11**	**60**	**56**
MIDDLE EAST				
Abu Dhabi	9	4	13	14
Dubai	1	—	1	2
Egypt	26	12	38	31
Iran	—	—	—	—
Iraq	—	—	—	—
Jordan	1	—	1	1
Kuwait	11	—	11	13
Oman	47	—	47	38
Pakistan	18	—	18	16
Qatar	2	8	10	10
Saudi Arabia	69	4	73	60
Sudan	—	—	—	—
Syria	21	—	21	22
Yemen	14	—	14	17
Other	1	—	1	2
Subtotal	**220**	**28**	**248**	**226**
EUROPE				
Croatia	1	—	1	3
Denmark	—	4	4	4
France	—	—	—	1
Germany	5	—	5	3
Hungary	2	—	2	4
Italy	2	1	3	2
Netherlands	2	2	4	6
Norway	—	23	23	21
Poland	2	—	2	2
Romania	2	—	2	2
Turkey	5	—	5	4
UK	—	32	32	25
Other	3	1	4	4
Subtotal	**24**	**63**	**87**	**81**
Total	**2,462**	**373**	**2,835**	**2,707**

Definitions, see OGJ Sept. 18, 2006, p. 42
Source: Baker Hughes Inc.
Data available in OGJ Online Research Center.

Oil import freight costs*

Source	Discharge	Cargo	Cargo size, 1,000 bbl	Freight (Spot rate) worldscale	$/bbl
Caribbean	New York	Dist.	200	235	1.98
Caribbean	Houston	Resid.	380	182	1.70
Caribbean	Houston	Resid.	500	146	1.37
N. Europe	New York	Dist.	200	391	5.23
N. Europe	Houston	Crude	400	186	3.65
W. Africa	Houston	Crude	910	118	2.55
Persian Gulf	Houston	Crude	1,900	52	2.11
W. Africa	N. Europe	Crude	910	133	2.14
Persian Gulf	N. Europe	Crude	1,900	48	1.42
Persian Gulf	Japan	Crude	1,750	53	1.26

*April 2007 average.
Source: Drewry Shipping Consultants Ltd. Data available in OGJ Online Research Center.

US LNG imports

Country	Feb. 2007	Jan. 2007	Feb. 2006	Change from a year ago, %
	MMcf			
Algeria	—	2,521	2,802	–100.0
Brunei	—	—	—	—
Malaysia	—	—	—	—
Nigeria	5,773	5,325	3,053	88.1
Oman	—	—	—	—
Qatar	—	—	—	—
Trinidad and Tobago	32,581	36,792	27,620	18.0
Others	5,777	8,803	5,262	9.8
Total	**44,101**	**53,441**	**38,737**	**13.8**

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

Baker oil tools workover rig count*

Region	Apr. 2007	Apr. 2006	Change, %
Gulf Coast	268	304	–11.8
Midcontinent	264	257	2.7
Northeastern	78	89	–12.4
Rocky Mountains	204	242	–15.7
Southeastern	186	210	–11.4
West Texas	329	331	–0.6
Western	145	136	6.6
Total US	**1,474**	**1,569**	**–6.1**
Canada	271	318	–14.8
Total N. America	**1,745**	**1,887**	**–7.5**

*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 OGJ Online Research Center.

Propane prices

	Mar. 2007	Apr. 2007	Mar. 2006	Apr. 2006
	¢/gal			
Mont Belvieu	103.71	110.83	92.60	101.61
Conway	100.47	107.93	90.38	101.55
Northwest Europe	100.54	103.47	104.76	102.01

Source: EIA Weekly Petroleum Status Report
Data available in OGJ Online Research Center.

Muse, Stancil & Co. refining margins

	US Gulf Coast	US East Coast	US Mid-west	US West Coast	North-west Europe	South-east Asia
	$/bbl					
April 2007						
Product revenues	94.09	82.97	91.84	97.14	78.58	75.28
Feedstock costs	–69.52	–68.82	–62.76	–58.93	–66.97	–69.62
Gross margin	24.57	14.15	29.08	38.21	11.61	5.66
Fixed costs	–2.04	–2.36	–2.30	–2.68	–2.30	–1.79
Variable costs	–2.15	–1.47	–1.92	–3.55	–2.42	–0.84
Cash operating margin	**20.38**	**10.32**	**24.86**	**31.98**	**6.89**	**3.03**
March 2007	14.97	8.59	17.26	29.76	5.85	2.04
YTD avg.	13.16	6.31	15.89	26.88	5.99	2.60
2006 avg.	12.49	6.01	15.00	23.72	5.88	1.06
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

Source: Muse, Stancil & Co. See OGJ, Jan. 15, 2001, p. 46.
Data available in OGJ Online Research Center.
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

March 2007	Chicago*	Houston	Los Angeles	New York
	¢/gal			
Retail price	256.81	241.12	307.86	266.08
Taxes	53.84	38.40	60.11	49.86
Wholesale price	197.24	200.21	242.93	209.42
Spot price	184.94	195.01	240.43	197.64
Retail margin	5.81	2.51	4.82	6.80
Wholesale margin	12.30	5.20	2.50	11.78
Gross marketing margin	**18.11**	**7.71**	**7.32**	**18.58**
February 2007	17.61	6.90	0.69	17.38
YTD avg.	23.58	15.04	12.29	27.04
2006 avg.	19.74	20.34	18.03	27.90
2005 avg.	19.77	16.26	20.39	27.13
2004 avg.	22.49	17.49	23.61	30.38

*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 OGJ Online Research Center.
Note: Effective April 2003, Los Angeles margins include ethanol blending.

Muse, Stancil & Co. ethylene margins

	Ethane	Propane	Naphtha
	¢/lb ethylene		
April 2007			
Product revenues	50.79	89.49	109.21
Feedstock costs	–28.22	–62.74	–117.30
Gross margin	22.57	26.75	–8.09
Fixed costs	–5.38	–6.36	–7.19
Variable costs	–5.55	–6.56	–8.84
Cash operating margin	**11.64**	**13.83**	**–24.12**
March 2007	13.93	14.72	–12.48
YTD avg.	13.83	15.20	–9.60
2006 avg.	19.55	22.53	1.77
2005 avg.	14.43	20.68	1.28
2004 avg.	9.00	12.03	0.51

Source: Muse, Stancil & Co. See OGJ, Sept. 16, 2002, p. 46.
Data available in OGJ Online Research Center.

Muse, Stancil & Co. US gas processing margins

April 2007	Gulf Coast	Mid-continent
	$/Mcf	
Gross revenue		
Gas	7.25	6.01
Liquids	1.15	3.16
Gas purchase cost	8.07	8.06
Operating costs	0.07	0.15
Cash operating margin	**0.26**	**0.96**
March 2007	0.23	0.91
YTD avg.	0.18	0.68
2006 avg.	0.26	0.97
2005 avg.	–0.06	0.25
2004 avg.	0.07	0.33
Breakeven producer payment % of liquids	74%	68%

Source: Muse, Stancil & Co. See OGJ, May 21, 2001, p. 54.
Data available in OGJ Online Research Center.

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EMPLOYMENT

The Petroleum Institute

Abu Dhabi, United Arab Emirates

Petroleum Engineering Program

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PROFESSOR AND PROGRAM DIRECTOR

The Petroleum Institute is seeking applications and nominations for the position of Professor and Program Director of the Petroleum Engineering Program. Candidates should have an earned doctorate in petroleum engineering or a closely related field, strong leadership credentials, a demonstrated profile of progressively increasing responsibility and achievement in an academic or industrial setting, and a commitment to petroleum engineering education.

The Petroleum Engineering Program is building strength in the areas of drilling engineering and rock mechanics, production engineering, and reservoir engineering, all with emphasis on carbonate reservoirs. The Program Director for Petroleum Engineering reports directly to the Chief Academic Officer and is responsible for all academic and administrative functions relating to the operation of the program, including the following activities:

- Faculty recruitment
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- Program assessment and development
- Curriculum and laboratory development
- Program staff management, recruiting, and evaluation
- Program strategic planning
- Program budgeting
- Interaction with petroleum industry and its activities in Abu Dhabi and the region

* We prefer to fill this position by Fall 2007 or as soon thereafter as feasible

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The Petroleum Institute is seeking applications for faculty positions in the Petroleum Engineering program. Applicants should possess an earned PhD degree in Petroleum Engineering or a closely related field. Outstanding records or potential in teaching, research and service relevant to the mission of the Petroleum Engineering program at the Institute are critical. Areas of specialization are open; experience with carbonate reservoirs will be a plus, as will industrial experience. Appointments at all levels (Assistant Professor, Associate Professor, and Professor) are available. For truly exceptional candidates, appointment as Distinguished Institute Professor or externally sponsored Chaired Professor is possible.

Program faculty report to the Program Director who has overall responsibility for leadership of the Petroleum Engineering program. Faculty will teach undergraduate and graduate courses, develop an active research program, and engage in departmental and institutional service. They will have outstanding opportunities to interact with national and international Petroleum Institute stakeholders for development of research and service (consulting, continuing education) programs. Involvement in professional society activities is encouraged and supported.

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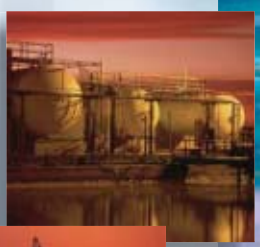

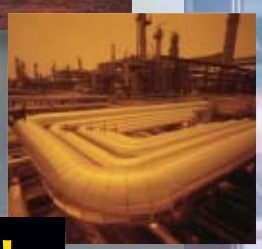

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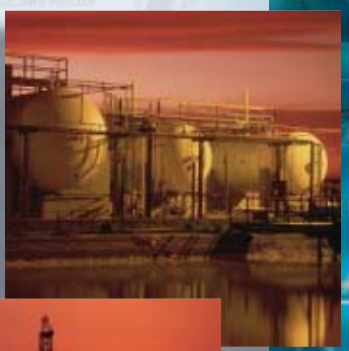

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Cellulose will strain ethanol's political unity

The US ethanol craze will become a political battle under current presuppositions.

The high-minded rationale for burning food for energy is that the tactic inaugurates a grand transition. (The low-minded and more accurate rationale is that burning food for energy lets politicians keep grain growers and distillers rich and happy.)

In the grand transition envisioned by the high-minded rationale, ethanol made from

The Editor's Perspective

by Bob Tippee, Editor

pricey grain establishes a market position into which ethanol made from cheap cellulose someday will move. For now, cellulose costs too much to process.

While grain ethanol's transitional market position depends on generous tax credits and market mandates, even greater favors await ethanol from cellulose.

In these early years of the grand ethanol transition, things are splendid for corn growers and mostly so for distillers. Disadvantageous combinations of corn and ethanol prices occasionally make members of the latter group sweat. Still, construction of ethanol plants remains active, and the federal mandate for ethanol in vehicle fuel grows each year and almost surely will be expanded by a bedazzled Congress.

Best yet for ethanol interests, nobody in Washington, DC, seems concerned about how much all this affects the Treasury and the costs of food and fuel.

So what happens if, say 5 years from now, researchers perfect the enzyme that makes cellulosic ethanol economic?

At that point, the political unity that turned ethanol into vehicle fuel fractures under the strains of ethanol-on-ethanol competition. Corn growers have to weigh the value of stover as an ethanol feedstock against the costs of market loss and replacement soil nutrients. Plant operators must consider retrofitting, rebuilding, or closing.

Here's the big one: If the cellulose dream comes true, corn will lose value.

By the time cellulose makes sense as a feedstock for fuel ethanol, consumers who don't grow grain for a living will welcome cheaper corn. Maybe politicians will have come to their senses by then and be ready to let it happen.

Also by then, however, corn growers and distillers who see no profit in the transition to cellulosic ethanol will have plenty of money for a political fight.

(Online May 14, 2007; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Sufficient supply or possible shortage?

Energy prices fluctuated sharply in early May because of differing assessments of sufficient supplies or possible shortages of crude and petroleum products.

On May 8, the June contract for benchmark US light, sweet crudes popped up 79¢ to $62.26/bbl on the New York Mercantile Exchange—ending a 6-day losing streak, the longest so far this year—when three major pipelines in Nigeria were shut in after rebel attacks. The next day, however, the June crude contract dropped 71¢, following an Energy Information Administration report that commercial US inventories of crude had jumped 5.6 million bbl to 341.2 million bbl, near the upper end of the average range, in the week ended May 4. That jump was larger than expected by Wall Street analysts and marked the first increase in US crude inventories in 13 weeks. Nonetheless, gasoline inventories remained at the lowest level for that time of year in 16 years.

The June contact regained 26¢ to $61.81/bbl May 10 as market worries about possible fuel shortages in the approaching driving season pushed up prices for reformulated blendstock for oxygenate blending (RBOB) lifting other commodities with it. The June RBOB contract continued to rally, escalating by 9.52¢ to $2.33/gal on NYMEX.

June crude futures continued climbing to $62.37/bbl May 11 as the International Energy Agency in Paris called for the Organization of Petroleum Exporting Countries to increase crude production to prevent possible fuel shortages this summer. IEA officials are looking to OPEC to meet a 1.6 million b/d jump in world demand for petroleum products this June, since crude production from non-OPEC producers has been much lower than IEA's earlier overly optimistic forecasts. Fears of supply shortages were fanned by thinning gasoline inventories in the face of growing demand in the US and other major consumer countries.

IEA officials recently reported the sharpest first-quarter draw of petroleum products in 11 years, down to 2.6 billion bbl at the end of March among member states of the Organization for Economic Cooperation and Development. However, many OPEC officials have said they see no need to boost their oil production when the real problem is the lack of capacity to refine the current supply of crude.

Imports of crude into the US increased by 727,000 b/d to 11 million bbl during the week ended May 4, but the input of crude into US refineries increased only 74,000 b/d to 15.3 million b/d, with units operating at 89% of capacity as a result of recent accidents and the seasonal turnaround (OGJ Online, May 9, 2007).

Import data

OECD data for February started to show the effects of OPEC's production cuts, with imports of crude from the 12 affected producer countries down by 1.3 million b/d from a year ago. "OPEC's compliance to its production cuts has been better than expected, but its impact has been somehow softened by a warm winter making for a lesser Asian pull. The real test on the visibility of the OPEC crude cuts will start in coming weeks as Asia moves out of its refinery maintenance period while the Atlantic Basin refinery runs should continue to increase," said analysts at Petromatrix GMBH, Zug, Switzerland. "While Saudi Arabia is almost exactly at its cut mark, Iran, Venezuela, and Libya are still trailing," they said.

OECD Europe did not suffer as much, since it received higher volumes of Iran and Iraq crude, offsetting the reduced Saudi Arabian, Nigerian, and Algeria imports, the analysts said. "For a globally unchanged level, Algeria continues the trend seen in 2006 of diverting its export away from Europe and into the US," analysts said.

Petromatrix analysts said, "Compared to a year ago, European exports of gasoline have increased in January-February, mainly to Mexico as higher demand in Latin America has reduced regional exports to Central America. European gasoline exports have also increased to Africa (South Africa, Nigeria) and the Mediterranean (Tunisia, Lebanon, the former Yugoslavia) making for less barrels available to the US and Canada." With European transportation fuel demand continuing to move away from gasoline to diesel, combined with a rebound in naphtha demand, analysts said, "The European refinery yield on gasoline also is lower vs. previous years. The US relies on Europe for the marginal supply of gasoline, but Europe is producing relatively less and shipping more of it to other destinations."

In other news, Andrea, the first named tropical storm of the 2007 hurricane season, was downgraded May 10 to a subtropical depression about 100 miles east-southeast of Jacksonville, Fla., and dissipated without posing any real threat to oil and gas facilities.

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