MEASURE & COMPARE

Baker Hughes delivers Best-in-Class results

MICRO-WASH™ system unlocks productivity on two highly prolific deepwater wells, for incremental value of $1.7 million per day

Location: Rosa Field, Angola

Challenges:

- ✓ Wells and screens damaged and plugged by oil based mud filter cake.
- ✓ Initial production of 900 bbls on two wells that were expected to produce 25,000/ bopd.
- ✓ Operator already made a significant investment in drilling and well remediation without success.

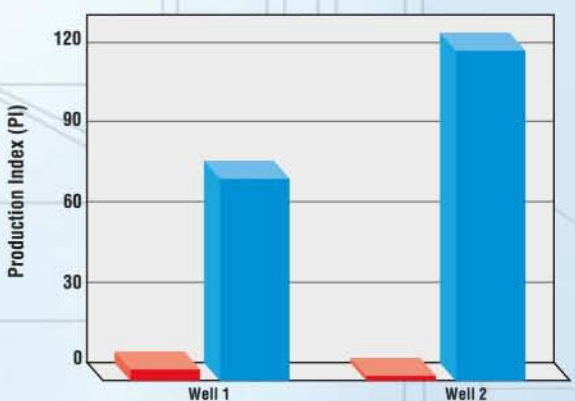
Solution:

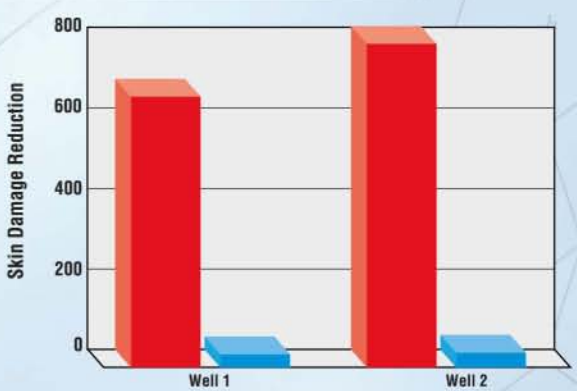
MICRO-WASH High Definition Remediation system

- ✓ MICRO-WASH system combines customized, proprietary technology with application expertise to remediate damaged reservoirs.
- ✓ Two open-hole volumes of MICRO-WASH system were applied with a coiled tubing unit across the sand screens and reservoir in each well.
- ✓ Following a 24-hour flow back period, a production log indicated that crude oil was flowing through 100% of the completion screens in both wells.

Results:

- ✓ The reservoir was effectively remediated and became a viable production asset.
- ✓ Delivered exceptional technical performance, removing severe damage and increasing production by more than 24,000/bopd.
- ✓ Reduced the skin damage in each well from 660 and 800 to 15 and 16 respectively.
- ✓ Increased the production index for each well from nearly zero to 75 and 130 respectively.
- ✓ Incremental value to the operator after MICRO-WASH system was $1.7M per day.





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MICRO WASH

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CONDENSATE EAST OF SUEZ: NGL and its Naphtha Impacts in Asia Pacific and Mideast Gulf

Condensate and the Light-End Products Squeeze

By Asia Pacific Energy Consulting

- **This is the "definitive" report on condensate in the fastest growing, critical regions of the world, Asia Pacific and the Mideast Gulf.**
- **The study provides a complete guide to optimizing value in future condensate production, utilization, and trade.**

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Condensate coming into its own

Condensate, one of the two groups defined as Natural Gas Liquids (NGLs), is finally coming of age in world trade, marketing, refining and petrochemicals. Condensate sales are moving from a niche marketing specialty to a mainstream segment of crude and products trade, and nowhere is this more evident than in the Mideast Gulf and Asia Pacific.

This report explains how the protean nature of condensate allows it to be used in a wide range of sectors: as a refinery slate component; in specialized distillation towers called condensate splitters; in direct feed to ethylene crackers; in gasoline blending and as a substitute for gas in turbine power generation. It can be defined as a base material, a blending component, a feedstock or a boiler feed.

See website for Table of Contents and sample tables, charts and graphs.

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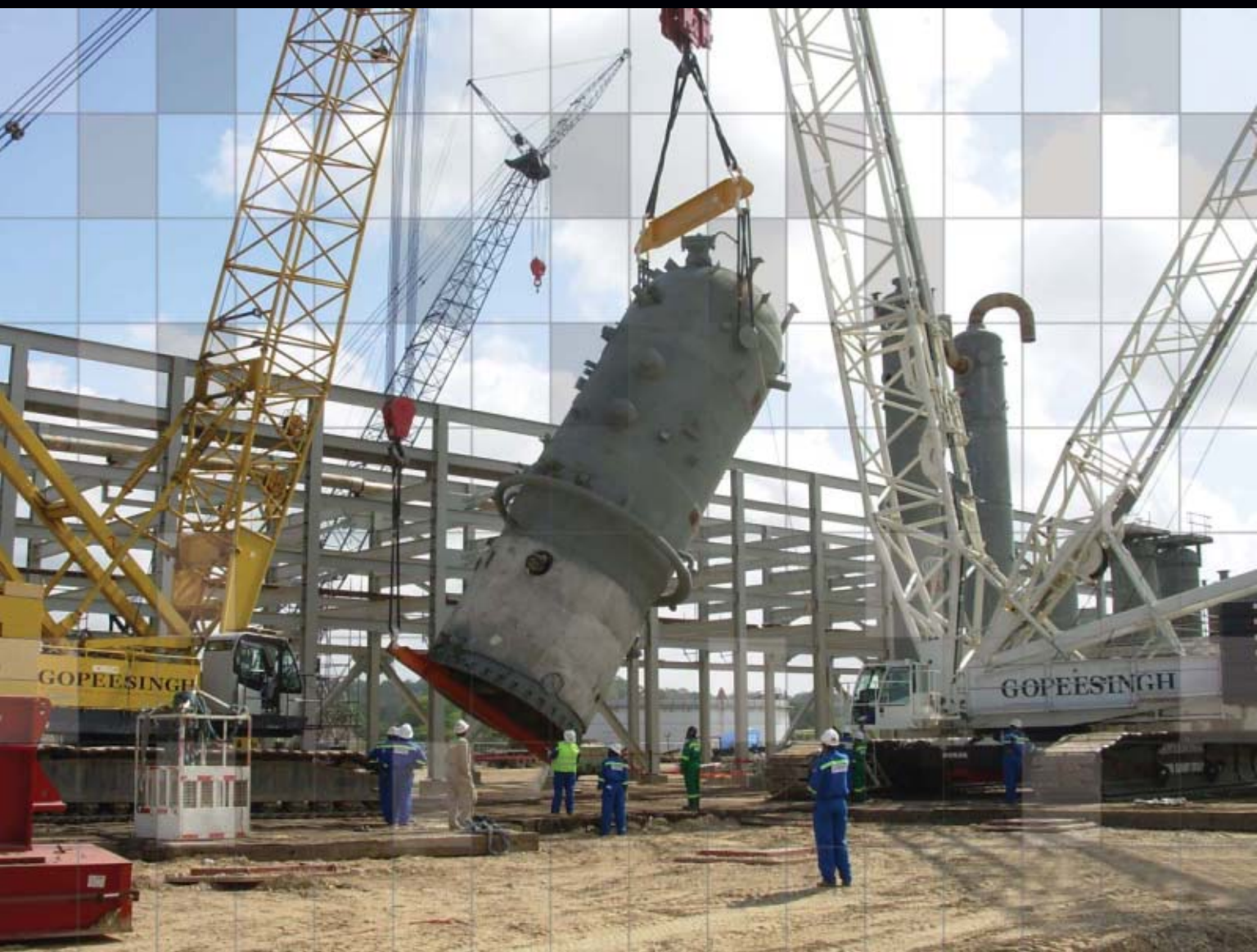

Gas-to-Liquids Update

BC's Muskwa shale shaping up as Barnett gas equivalent
1,200-hp submersible pump produces Jubarte well off Brazil
StatoilHydro Angola assays Mondo crude
Study addresses black powder's effects on meters

OIL&GAS JOURNAL®

Mar. 24, 2008
Volume 106.12

GAS-TO-LIQUIDS UPDATE

REGULAR FEATURES

COVER

The reactor is moved into place during construction of the World GTL plant in Trinidad and Tobago. World GTL Trinidad Ltd. is a joint venture of World GTL Inc. and Petroleum Co. of Trinidad & Tobago. The plant will be fully operational this year, producing 2,250 b/d of liquids and requiring about 21 MMcfd of gas feedstock. A special report updating the prospects for GTL and coal-to-liquids technology begins on p. 22. Photos courtesy of World GTL Trinidad and Sasol Chevron.

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Oil & Gas

Innovation: it's genetic

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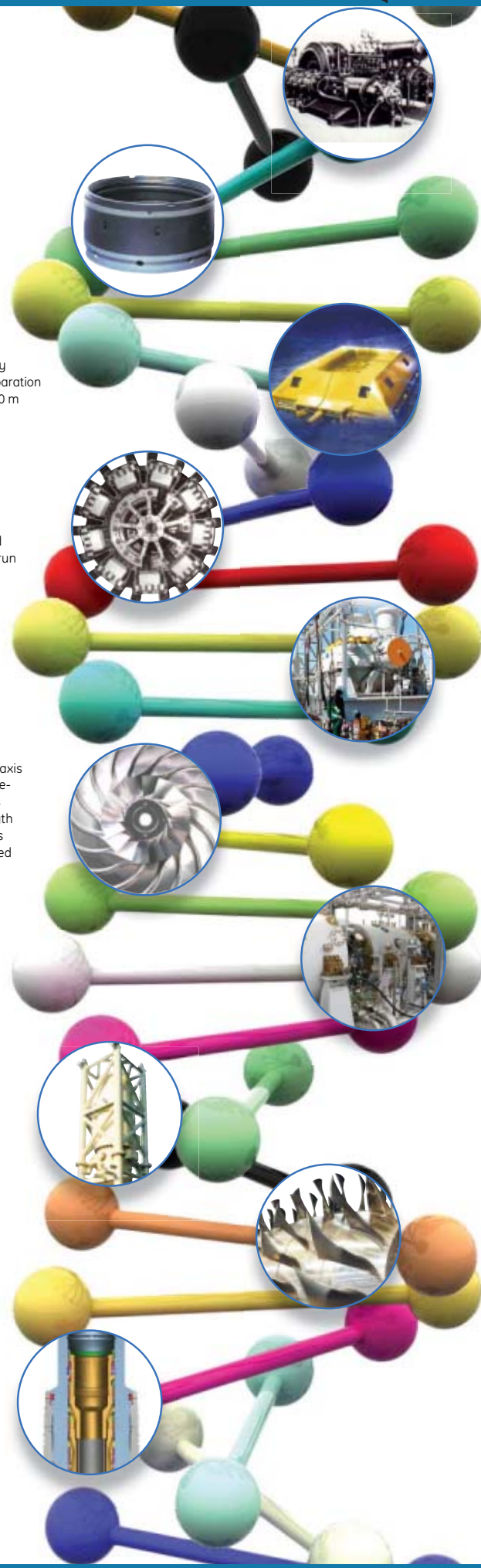
For more information, visit ***ge.com/oilandgas***

imagination at work



1900: reciprocating compressors for refrigeration cycles

1935: world's first metal-to-metal seals for oil well completion systems

1999: first commercially scaled pilot subsea separation system launched in 340 m water depth at Troll C

2004: UltraScan™ Duo, first pipeline inspection tool to detect and measure cracking and metal loss in a single run

2004: first FR9 LNG supertrain with largest capacity ever – 8 MTPY

2006: introduced five-axis milling, EDM and single-piece forged impellers with significant strength and stability advances over multi-piece welded fabrications

2006: BCL centrifugal compressors set 820 bar pressure record for sour gas re-injection

2006: first subsea compressor at 900 m below sea level

2007: Power Crystal technology for gas turbines to significantly extend parts life or increase power

2008: MS-800 FullBore subsea wellhead system for 20,000 psi and 350°F

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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Mar. 24, 2008

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General Interest — Quick Takes

EU member states' gas use falls 1.5% in 2007

Natural gas consumption in the 27 member states of the European Union fell 1.5% in 2007 compared with 2006 because of widespread mild weather early in the year.

In some countries high energy prices and increased efficiency also played a role, said Eurogas in Brussels. Natural gas consumption amounted to 505 billion cu m compared with 513 billion cu m in 2006.

By yearend 2007, the number of customers connected to the EU 27 gas grid increased 1% to 110.2 million, pulled along by the UK, Spain, and Italy, which made up for a negative trend in the other countries.

Indigenous production decreased 7% to 198 billion cu m with drops in major producing countries such as the UK, down 9.9%; Germany, down 8.3%; Denmark, down 11.4%; and Italy, down 11.5%. Eurogas said indigenous production provides the highest percentage of gas supplied in the EU 27, covering 38% of total net supplies in 2007.

The main external sources of gas are Russia with 23%, Norway with 18%, and Algeria 10%. It was increasing imports from Norway, which mainly compensated for the drop in indigenous production.

ETP settles gas market manipulation charges

Energy Transfer Partners LP of Dallas and three of its subsidiaries agreed to pay a $10 million fine to settle charges that they attempted to manipulate natural gas markets, the US Commodity Futures Trading Commission announced.

The federal commodities regulator charged the Dallas publicly traded energy partnership and subsidiaries Energy Transfer Co. of San Antonio and Houston, Houston Pipeline Co. of Houston, and ETC Marketing Ltd. of San Antonio and Houston in a Jul. 26, 2007, complaint.

The complaint alleged that from September to early December of 2005, ETP and its subsidiaries sold massive quantities of gas on the InterContinental Exchange to place downward pressure on prices at the Houston Ship Channel (HSC) delivery hub, according to CFTC.

It said the defendants then reported these transactions to McGraw Hill Co.'s Inside FERC Gas Market Reports in an effort to manipulate the HSC gas price index that the reporting service calculated and disseminated in its October and December 2005 issues. ETP and its units did this in an effort to benefit their financial swap positions which were tied to Inside FERC HSC gas index prices during that period, CFTC said.

The agency and ETP settled the charges in a consent order that imposed a permanent injunction against all defendants and ordered them to pay the fine while releasing ETP and its affiliates, directors, and employees from claims or assertions in the proceeding. The agreement, which contains no findings of fact or conclusions of law, was entered before US District Judge Ed Kinkeade of the Northern District of Texas on Mar. 17.

Indonesia looks to replace BP Migas chairman

Indonesia, seeking to replace Kardaya Warnika as chairman of the country's upstream oil and gas regulator BP Migas, will present three potential candidates for parliament to consider next month.

Energy and Mineral Resources Minister Purnomo Yusgiantoro, who Mar. 12 confirmed that Kardaya would be replaced before his tenure ended in 2010, identified the three candidates and said their names would be presented to parliament.

Purnomo said it was simply time to "refresh" the agency, declining to say if the replacement plan had come in response to complaints by lawmakers over Kardaya's performance in office.

Purnomo named the candidates as R. Priyono, currently director for upstream activities at the ministry; Evita H. Legowo, an assistant to the minister for human resources and technology; and Hadi Purnomo, director of a research and development center for oil and gas technology.

Reports said lawmakers have been demanding a replacement for Kardaya, saying his administration of BP Migas failed to increase the country's output of crude oil. The country's oil production has declined over the past 5 years, falling below 1 million b/d in 2007.

Kardaya, who has held his post since 2005, several times failed to appear before legislators, sending his deputy instead. Lawmaker Tjatur Sapto Edy said parliament is ready to test the candidates next month and hope to install the new chairman by the end of April. ✦

Exploration & Development — Quick Takes

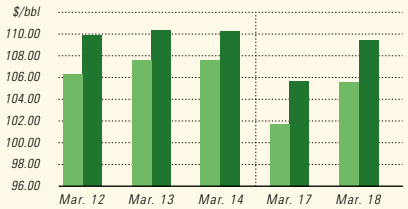
Hess reports on Pony well in deepwater gulf

Hess Corp. reported the results of its Pony No. 2 appraisal well on Green Canyon Block 468 in the deepwater Gulf of Mexico.

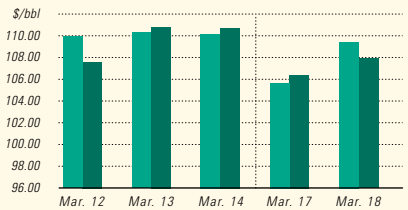
The appraisal well was drilled about 1.5 miles northwest of the discovery well and reached a measured depth of 32,900 ft. The Pony No. 2 well encountered the objective target sands in a downdip position in the water leg. Following wireline evaluation and pressure data collection of the Pony No. 2 well, the objective

Industry Scoreboard

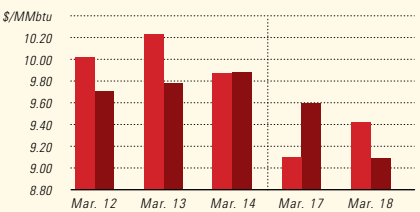
IPE BRENT / NYMEX LIGHT SWEET CRUDE



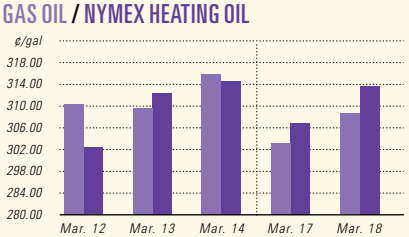
WTI CUSHING / BRENT SPOT



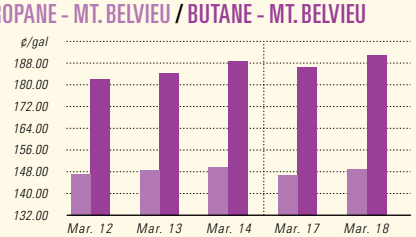
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



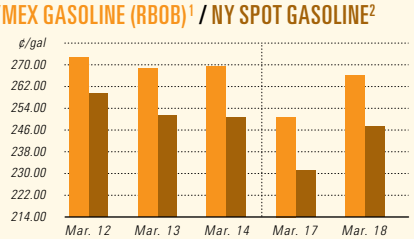
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



NYMEX GASOLINE (RBOB)[1] / NY SPOT GASOLINE[2]



[1]Reformulated gasoline blendstock for oxygen blending.
[2]Non-oxygenated regular unleaded.

US INDUSTRY SCOREBOARD — 3/24

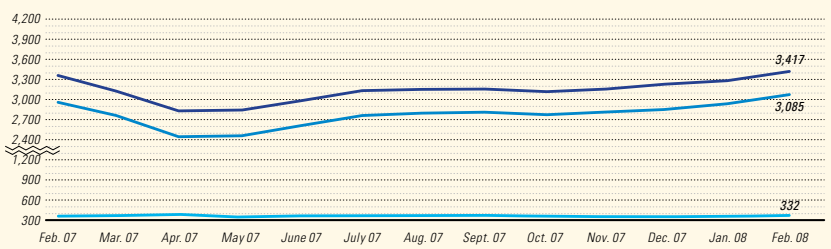
Latest week 3/7	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	9,093	9,056	0.4	9,063	9,028	0.4
Distillate	4,354	4,543	–4.2	4,277	4,399	–2.8
Jet fuel	1,612	1,618	–0.4	1,572	1,602	–1.8
Residual	655	905	–27.6	701	820	–14.4
Other products	4,832	4,990	–3.2	4,994	4,938	1.1
TOTAL DEMAND	20.546	21.112	–2.7	20.608	20,786	–0.9
Supply, 1,000 b/d						
Crude production	5,057	5,154	–1.9	5,039	5,174	–2.6
NGL production[2]	2,611	2,265	15.3	2,508	2,303	8.9
Crude imports	10,011	9,324	7.4	10,070	9,890	1.8
Product imports	3,393	3,211	5.7	3,433	3,373	1.8
Other supply[3]	857	965	–11.2	979	909	7.8
TOTAL SUPPLY	21,929	20,919	4.8	22,029	21,649	1.8
Refining, 1,000 b/d						
Crude runs to stills	14,795	13,611	8.7	14,795	14,757	0.3
Input to crude stills	14,967	14,890	0.5	14,967	15,123	–1.0
% utilization	85.8	85.3	—	85.8	86.6	—

Latest week 3/7	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	311,626	305,449	6,177	325,336	–13,710	–4.2
Motor gasoline	235,967	234,276	1,691	213,939	22,028	10.3
Distillate	116,400	117,625	–1,225	120,439	–4,039	–3.4
Jet fuel-kerosine	38,925	39,342	–417	39,770	–845	–2.1
Residual	36,564	36,508	56	35,169	1,395	4.0
Stock cover (days)[4]			Change, %		Change, %	
Crude	21.3	20.9	1.9	22.3	–4.5	
Motor gasoline	26.0	25.8	0.8	23.3	11.6	
Distillate	26.7	26.7	—	26.2	1.9	
Propane	17.5	18.4	–4.9	17.2	1.7	

Futures prices[5] 3/7			Change		Change	%
Light sweet crude, $/bbl	109.42	103.42	6.00	61.05	48.37	79.2
Natural gas, $/MMbtu	10.03	9.59	0.44	7.28	2.74	37.7

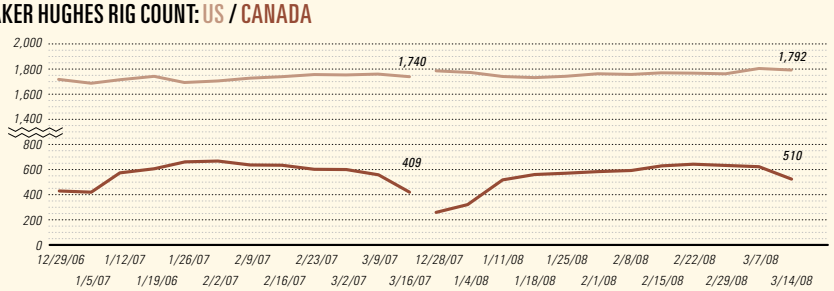
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

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



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

The Norwegian company Thermtech AS is the owner and supplier of a thermal treatment technology, the Thermomechanical Cutting Cleaner (TCC). The TCC is a world leading methodology for treatment of oily waste such as OBM drill cuttings. From its head office in Paradis outside Bergen, Thermtech delivers the friction based TCC to treatment companies all over the world. The technology is adopted by companies like TWMA, MI-SWACO, Halliburton and Scomi Oiltools, and serves all major oil & gas operators.

HELP US IN SETTING THE GLOBAL STANDARD

Thermtech needs to extend its highly motivated team with 5 to 7 internationally oriented team players who can help us both in establishing the TCC as the global standard for treatment of drill cuttings and in bringing the technology to new markets and new industries.

We are looking for people with a technical and/or commercial background to work mainly within the following areas:

- Procurement, spare parts management and logistics
- Compliance and quality management
- IP protection and management of research projects (Patent Engineer or similar)
- Mechanical engineering and project management
- Sales and marketing

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send your application to us by e-mail to gunn.hauge@thermtech.no.

www.thermtech.no

is to sidetrack the well to the oil leg updip, Hess said.

"Based on the results to date of the Pony No. 2 well, the estimated range of gross recoverable resource on the Hess-owned portion of the structure has been narrowed to 100-500 million bbl from the previous estimated 100-600 million bbl," the company said.

Hess owns a 100% working interest in Pony, and is evaluating a range of development options for the discovery.

Aminex has gas success near Songo Songo field

A wildcat well operated by Ndovu Resources Ltd. (Aminex) in a joint venture with Australian companies Key Petroleum Ltd. and Bounty Oil & Gas NL, both of Perth, has found natural gas about 2 km from producing Songo Songo gas field in Tanzania.

Key Petroleum, which has 20% interest, said the well, Kiliwani North-1, was drilled in the southern tip of Songo Songo Island and has intersected a 60-m gross gas column in the same Neocomian sand reservoirs producing at Songo Songo field.

Electric logs and formation pressure data have confirmed the presence of gas.

Kiliwani North-1 was drilled on the so-called Nyuni Block and will be completed as a future gas producer. Further drilling will be needed to confirm the size of the find.

The close proximity of Songo Songo to Dar Es Salaam gas pipeline bodes well for an early development. Key Petroleum said there is additional potential in Tertiary age reservoirs that may be the target of future wells.

Ndovu Resources holds 40%, RAK Gas Commission 25%, Key Petroleum 20%, East Africa Exploration Ltd. 10%, and Bounty 5%.

Total acquires interest in Alaskan blocks

Total SA will join Chevron Corp. in exploring the onshore White Hills blocks in Alaska by drilling three wells for the winter season. The White Hills blocks lie 40 km southwest of Prudhoe Bay field in Alaska's central North Slope.

Total has gained a 30% interest in the blocks and the partners plan to drill several exploration wells during next winter. Chevron will operate the blocks with a 70% interest.

The acreage covers 2,000 sq km. ✦

Drilling & Production — *Quick Takes*

TPAO producing gas from Ayazli field

Operator Turkish Petroleum Corp. (TPAO) has begun producing natural gas from Ayazli gas field in the Black Sea off Turkey, reported partner Stratic Energy Corp., Calgary.

Ayazli is the third gas field in which production has begun under Phase 1 of the South Akcakoca sub-basin development program. Production began last year from Akkaya and East Ayazli fields. Officials said initial flow rates from Ayazli support operator estimates that production from the field will average more than 10 MMscfd. Production from the two existing fields recently has been 17 MMscfd gross.

TPAO has started well intervention projects to add further perforations on the East Ayazli-2 well to increase production from that field.

TPAO has 51% interest in the permit area. Dallas-based Toreador Resources Corp. has 36.75%, and Stratic Energy has 12.25%.

UK Chancellor changes decommissioning tax rules

North Sea operators are welcoming tax changes by the UK Chancellor that aim to extend the life of marginal oil fields.

During his first budget, Alistair Darling reported he would reform petroleum revenue tax (PRT) and help operators cover the treatment of decommissioning costs of oil and gas installations in the UK North Sea.

Companies can delay decommissioning because of an extension of corporation tax loss carry-back to 2002, instead of 3 years as was previously the case. The government will also address inconsistencies regarding the application of PRT to decommissioning liabilities and the proposal to remove PRT nonpayers from future exposure to the tax.

Trade association Oil & Gas UK welcomed the measures but stressed that more fiscal changes were needed to attract investment in a competitive global environment.

Malcolm Webb, OGUK's chief executive, said the new changes will provide greater certainty and consistency. "However, this should only be regarded as the start of the process of simplifying and easing the tax burden on UK oil and gas production, and we look forward to the next stage of the government consultation producing further positive outcomes to that end."

Investment on the UK continental shelf fell by £1 billion in 2007. OGUK said it was necessary to change the 50-75% tax rate on new projects if the UK is to carry on producing hydrocarbons.

Mike Tholen, OGUK's economics director, added: "The future of the North Sea can only be properly secured by simplifying and reducing the overall tax burden to ensure [that] investment can be sustained in this mature and challenging province."

The government estimates that it will receive £9.9 billion in tax revenues from the North Sea in 2008-09, up from £7.7 billion this year. ✦

Processing — *Quick Takes*

P&G: World LPG supply, prices rising fast

Worldwide supply of LPG will expand particularly fast during the next 4-5 years, but record high prices have slowed demand in many developing markets, said Ken Otto of Houston-based consultancy Purvin & Gertz Inc. in opening remarks Mar. 18 to the firm's 21st Annual International LPG Seminar in The Woodlands, Tex.

Several events slowed the expansion of LPG supply in 2007, but

Purvin & Gertz expects the growth to pick up in 2008-09.

High LPG prices are reducing demand growth in residential and commercial sectors, especially in unsubsidized markets in developing economies, Otto said.

All of these factors will push more supplies into the petrochemical feedstock sector. A large expansion of petrochemical capacity is under way in the Middle East, which will increase fairly dramatically base-load demand for LPG. Global LPG supplies, however, will grow faster than base demand, which will increase the amount of LPG available for the feedstock market, Otto said.

Global LPG supply will increase by 43 million tonnes during 2007-12, increasing to about 272 million tonnes from 229 million tonnes, Otto said.

LPG production is growing in most regions of the world, the exception being North America. Because LPG production in North America will be fairly flat, Otto expects the Middle East to surpass North America in a few years to become the largest LPG producing region in the world. The Middle East will expand LPG production more than 45% during 2007-12.

Overall, Otto expects that LPG supply growth will average 3.5%/year through 2012. About 50% of this growth will come from nonassociated gas.

Repsol-YPF to build coker complex at Cartegena

Repsol-YPF SA has awarded a contract to Foster Wheeler Ltd. unit Foster Wheeler Iberia SAU, Madrid, for the detailed engineering, procurement services, and construction management of a new delayed coker complex at its refinery in Cartagena in southeastern Spain.

The coking complex consists of a 53,000 b/sd delayed coker unit, a gas concentration unit, and a 90,000 b/sd vacuum distillation unit. The coker will use Foster Wheeler's Sydec process technology.

The value of this contract was not disclosed. In 2007, Foster Wheeler Iberia was awarded a separate contract for the design and supply of the coker-fired heaters that are an integral part of the coker unit.

Total responds to Donges refinery bunker oil spill

Total SA is cleaning up bunker oil that spilled Mar. 17 from a pipe leak at the company's Donges refinery in the Loire Atlantique district. The accidental leak occurred during the loading of a vessel. About 300 tonnes of the heavy oil spilled onto the banks around the refinery and 100 tonnes into the Loire River.

In close liaison with authorities, Total mobilized 200 people to limit the impact of the spill, conduct cleaning operations, and coordinate with teams mobilized by the authorities, as bunker oil requires special handling precautions the group said.

Total has apologized to the riverside residents and the communities the spill affects and confirms its commitment to assume full costs of the cleanup.

BP, Irving join in Eider Rock refinery project

UK major BP PLC and Canadian refiner and marketer Irving Oil Ltd., St. John, NB, have signed a memorandum of understanding to work together on the next phase of engineering, design, and feasibility for the proposed 300,000 b/d Eider Rock refinery in St. John.

BP will contribute $40 million as its share for this stage of the study. The two companies also will consider forming a joint venture to build the refinery, should they decide to proceed.

Irving Oil conducted initial feasibility work and informal public consultation in 2006 on the proposed refinery, and has been engaged since January 2007 in permitting, public consultation, and engineering design for the facility.

The refinery would be situated close to Irving Oil's existing 300,000 b/d refinery and the existing Irving Canaport deepwater oil terminal, which receives cargoes of oil from very large crude carriers (VLCCs) and is 65 miles from the US border.

This next phase of engineering, design and feasibility work, combined with ongoing permitting and community engagement activities, represents more than $100 million of investment over the next 12-15 months, Irving Oil said.

A final investment decision is not expected before 2009. The refinery is expected to cost at least $7 billion. If permitting approval is received and an investment decision is made to proceed, site preparation would begin in 2010 with full-scale construction to begin in 2011. Start-up is expected in 2015.

Petrobras, Mitsui form Brazilian ethanol venture

Brazil's Petroleo Brasileiro SA (Petrobras) is forming a 50:50 joint venture with Mitsui & Co. Ltd. of Japan for investments in renewable energy.

The new joint venture, called Participacoes Nippo Brasileira em Complexos Bioenergeticos SA, will provide ethanol for the Japanese market, Petrobras said.

In February Petrobras said it would join with Mitsui and Brazilian builder Camargo Correa SA to form a JV to build the world's first ethanol-only pipeline.

The pipeline, with a capacity to transport 12 million cu m/year of ethanol, will ship the biofuel from sugarcane-growing areas in western Brazil to the Atlantic coast in Sao Paulo state.

Japanese refiners to push biofuels use by 2013

Fumiaki Watari, chairman of the Petroleum Association of Japan (PAJ), said Japanese refiners will aim to substitute biofuels for 500,000 kl/year of oil equivalent of fuels by the business year ending in March 2013.

The refiners' stated aim will more than double the initial target of a cut in refining of 210,000 kl/year by 2010, and it comes in response to government requests that the industry reduce carbon dioxide emissions.

Watari said the industry would use only ethyl tertiary butyl ether to blend with gasoline.

He said PAJ will accept the new target if the government helps it tackle problems such as ensuring adequate imports of bioethanol. He also said PAJ wanted to know who would be responsible for CO_2 emissions produced in transporting the fuel from overseas.

PAJ's announcement came as Mitsui & Co. Ltd and Brazil's state-owned Petroleo Brasileiro SA recently announced the formation of Participacoes Nippo Brasileira em Complexos Bioenergeticos SA, a 50-50 joint venture that will provide ethanol for the Japanese market.

Such changes also coincide with decisions by Japanese automakers to develop cars that use bioethanol fuel on the government

view that they can help reduce consumption of gasoline.

Nissan Motor Co. received government approval for a sport utility vehicle that can run on E10, which has 10% ethanol, while Toyota Motor Corp. received government approval for a vehicle that runs on a gasoline-bioethanol mix. ✦

Transportation — *Quick Takes*

GDF receives first LNG from Snohvit

The first shipment to France of LNG from Snohvit in Norway was delivered to Gaz de France's Montoir-de-Bretagne terminal in Brittany Mar. 12. The Provalys LNG carrier, especially fitted out to withstand the severe weather conditions in Norway's arctic waters, will unload 154,500 cu m of LNG, marking the opening of a new LNG supply route capable of providing 700 million cu m/year of gas for the European market.

Snohvit field licensees are StatoilHydro (operator) 33.5%, Petoro 30%, Total E&P Norway 18.4%, Gaz de France 12%, Hess 3.3%, and RWE Dea Norway 2.8%.

LNG accounted for 31.5% of Gaz de France's overall gas supplies in 2007. Deliveries from Snohvit will increase its supply flexibility. The group is already the largest LNG importer in Europe. It has been involved in the Snohvit project, in which it holds a 12% stake, from initial development planning. Commissioned in September 2007, the Hammerfest facility is the first liquefaction plant in Europe, said Gaz de France.

Norway currently is the group's main natural gas supplier, accounting for 21.5% of its overall supply portfolio. Gaz de France Norge is also involved in Norway's upstream and in 2006 was approved by the Norwegian authorities as operator for the production phase of Gjoa field, another natural gas development.

Woodside bids to supply LNG to Singapore

Woodside Petroleum Ltd. is competing for a multibillion-dollar contract to become Singapore's exclusive supplier of LNG, according to Woodside Chief Executive Officer Don Voelte.

Woodside is on a shortlist of five groups bidding for a contract to provide 3 million tonnes/year of LNG starting in 2012, Voelte said, adding that his company might partner with Singapore Power, if successful.

Singapore's Energy Market Authority, which expects to announce the successful bidder as early as next month, has not disclosed the names of the four other bidders. The winner will supply the country's planned LNG regasification facility.

Construction of the $1 billion terminal is expected to begin late this year or early in 2009 to enable the city-state to begin importing LNG by late 2011 or early 2012, according to S. Iswaran, Minister of State for Trade and Industry (OGJ Online, Feb. 2, 2008).

Williams, TransCanada propose gas pipeline

Williams Cos. Inc. and TransCanada Corp. are evaluating joint development of Sunstone Pipeline, a major transmission line that would transport natural gas supplies from the Rockies to the US West.

The proposed 618-mile, 42-in. Sunstone line would have a capacity of 1.2 bcfd. The line, proposed for service in 2011, would be built parallel to the existing Williams Northwest Pipeline system between the Opal Hub in Wyoming and Stanfield, Ore. Williams' Northwest system interconnects at Stanfield with TransCanada's Gas Transmission Northwest (GTN) pipeline system.

The project provides the option to deliver gas to markets served by the Northwest and GTN pipeline systems. Sunstone's open season commenced Mar. 17 and extends through Apr. 30. GTN will have an additional open season to offer existing capacity available on its pipeline system between Stanfield and GTN's terminus at Malin, Ore., near California's northern border.

Sunstone would provide broad access and enhance supply diversity to markets throughout the Pacific Northwest, northern Nevada and northern California. It would require construction of fewer miles of pipeline along existing utility corridors, including segments of Northwest's existing pipeline system and would provide favorable rates due to efficiencies from existing infrastructure and operations along the route, officials said. Moreover, Williams has recent construction experience along the pipeline corridor.

Keystone oil line construction to start in 2Q

A partnership of TransCanada Corp. and ConocoPhillips subsidiaries received a presidential permit from the US State Department to proceed with construction, maintenance, and operation of the proposed 2,148-mile Keystone oil pipeline. It will transport Canadian crude to US markets.

"We will begin construction in second-quarter 2008 to achieve an in-service date of fourth-quarter 2009," said Hal Kvisle, TransCanada president and chief executive officer.

Affiliates of TransCanada will construct and operate Keystone, which will be capable of delivering 590,000 b/d of crude from Hardisty, Alta., to US Midwestern markets at Wood River and Patoka, Ill., and to Cushing, Okla. Initial deliveries to Patoka are expected to begin in late 2009.

Keystone has secured firm long-term contracts of 495,000 b/d with an average duration of 18 years.

Taiwan mulls ending CPC's gas import monopoly

A number of wTaiwanese legislators have proposed a new Natural Gas Industry Act that could end state-owned CPC Corp.'s monopoly on gas importation. A draft of the act is expected to be completed and submitted to the Taiwan's Cabinet for approval before the end of April.

If enacted into law, the act would enable other companies to lease CPC's LNG terminals and pipelines. CPC owns Taiwan's only two LNG receiving terminals.

A prime candidate for leasing CPC's terminals is the Taiwan Power Co. (Taipower), which accounts for 60% of Taiwan's total LNG consumption. Taipower has petitioned the government to import LNG directly and will consider building its own terminal if permission is granted. ✦

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Letters

Enterprise drives exploration

The letter "Peak-oil context" by Michael Lynch (OGJ, Feb. 25, 2008, p. 12) correctly points out that large additional reserves continue to be added to the world's capacity, despite statements that the "elephants" have all been found (see, for example, the size of Tupi, p. 34 of the same edition). The figures should influence the market price of oil. The fact that they do not and the daily fluctuation of a few dollars along a rising trend point to market manipulation for which we all pay, and for which the industry will undoubtedly soon suffer, repeating history (yet again).

Peak oil understanding rests upon the presumption that current paradigms are correct and final. These act as a brake on knowledge development.

Fortunately, enterprise drives exploration to new frontiers, new surprises (Jack, Tupi, Indian gas, etc.), and new reserve additions.

An example of a paradigm that needs to fall is the 40-year-old idea that the Caribbean Plate came from the Pacific and therefore is oceanic. Many data show that the area shares geological history with the Gulf of Mexico and that continental crust is distributed around and within the plate.

Oil is seen in Puerto Rico, Hispaniola, Jamaica, Cuba, Belize, Guatemala, Honduras, Nicaragua, Costa Rica, and Panama. Prolific hydrocarbon provinces exist north and south in the Gulf of Mexico and along northern South America. The Caribbean is a surprise waiting to happen. Once understood it will point the way to analogues elsewhere in the world. Peak-oil history has a long way to go.

Keith H. James
Consultant geologist
Burgos, Spain

Calendar

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

OIL&GAS JOURNAL online

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

2008

MARCH

AAPG Prospect & Property Expo (APPEX), London, (918) 560-2679, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org. 24-26.

AAPG Pacific Section Meeting, Bakersfield, Calif., (918) 560-2679, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org. Mar. 29-Apr. 2.

NPRA International Petrochemical Conference, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. Mar. 30-Apr. 1.

SPE Middle East Petroleum Engineering Colloquium, Dubai, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. Mar. 30-Apr. 2.

PIRA Understanding Global Oil Markets Conference, Tokyo, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. Mar. 31-Apr. 1.

ERTC Sustainable Refining Conference, Brussels, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. Mar. 31–Apr. 2.

APRIL

SPE/ICoTA Coiled Tubing & Well Intervention Conference & Exhibition, The Woodlands, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 1-2.

ERTC Biofuels+ Conference, Brussels, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 2-4.

GIOGIE Georgian International Oil & Gas Conference & Showcase, Tbilisi, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 3-4.

Middle East Petroleum & Gas Conference, Doha, +65 6222 0230, +65 6222 0121 (fax), e-mail: mpgc@cconnection.org, website: www.cconnection.org. 6-8.

Australian Petroleum Production & Exploration Association (APPEA) Conference & Exhibition, Perth, +61 2 9553 1260, +61 2 9553 4830 (fax), e-mail: appea2008@saneevent.com.au, website: www.appea2008.com.au. 6-9

ACS National Meeting & Exposition, New Orleans, 1 (800) 227-5558, e-mail: natlmtgs@acs.org, website: www.acs.org. 6-10.

American Institute of Chemical Engineers (AIChE) Spring National Meeting, New Orleans, (212) 591-8100, (212) 591-8888 (fax), website: www.aiche.org. 6-10.

CIOGE China International Oil & Gas Conference, Beijing, + (44) 020 7596 5000, + (44) 020 7596 5111 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 7-8.

API Pipeline Conference & Cybernetics Symposium, Orlando, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 7-10.

EAGE Saint Petersburg International Conference & Exhibition, Saint Petersburg, +7 495 9308452, +7 495 9308452 (fax), e-mail: eage@eage.ru, website: www.eage.nl. 7-10.

IADC Well Control Europe Conference & Exhibition, Amsterdam, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 9-10.

ENTELEC Annual Conference & Expo, Houston, (888) 503-8700, website: www.entelec.org. 9-11.

North Caspian Regional Atyrau Oil & Gas Exhibition & Petroleum Technology Conference, Atyrau, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 9-11.

CERI World Oil Conference, Calgary, Alta., (403) 220-2380, (403) 289-2344 (fax), e-mail: jstaple@ceri.ca, website: www.ceri.ca. 13-15.

API Spring Refining & Equipment Standards Meeting, New Orleans, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 14-16.

API/NPRA Spring Operating Practices Symposium, New Orleans, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 15.

SPE Gas Technology Symposium, Calgary, Alta., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 15-17.

SPE International Health, Safety & Environment Conference, Nice, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 15-17.

Base Oils & Lubricants in Russia and the CIS Conference, Moscow, +44 207 067 1800, +44 207 430 0552 (fax), e-mail: e.polovinkina@theenergyexchange.co.uk, website: www.wraconferences.com/Overview.html. 16-17.

GPA Midcontinent Annual Meeting, Okla. City, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 17.

AAPG Annual Convention & Exhibition, San Antonio, 1 (888) 945 2274, ext. 617, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org/sanantonio. 20-23.

SPE Improved Oil Recovery Symposium, Tulsa, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 20-23.

ERTC Coking & Gasification Conference, Rome, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 21-23.

WestAsia Oil, Gas, Refining, & Petrochemicals Exhibition & Conference, Oman, +968 24790333, +968 24706276 (fax), e-mail: clemento@omanexpo.com, website: www.ogwaexpo.com. 21-23.

International Pump Users Symposium, Houston, (979) 845-7417, (979) 847-9500 (fax), website: http://turbolab.tamu.edu. 21-24.

SPE Progressing Cavity Pumps Conference, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 27-29.

MAY

IOGCC Midyear Meeting, Calgary, Alta., (405) 525-3556, (405) 525-3592 (fax), e-mail: iogcc@iogcc.state.ok.us, website: www.iogcc.state.ok.us. 4-6.

Calendar

PIRA Canadian Energy Conference, Calgary, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 5.

API International Oil Spill Conference, Savannah, Ga., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 5-8.

Offshore Technology Conference (OTC), Houston, (972) 952-9494, (972) 952-9435 (fax), e-mail: service@otcnet.org, website: www.otcnet.org. 5-8.

GPA Permian Basin Annual Meeting, Odessa, Tex., , (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 6.

PIRA Understanding Global Oil Markets Conference Calgary, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 6-7.

ERTC Asset Maximization Conference, Lisbon, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 12-14.

Oil and Gas Pipelines in the Middle East Conference, Abu Dhabi, +44 (0) 1242 529 090, e-mail: c.pallen@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk/mepipes8/mepipes8register.html. 12-14.

International School of Hydrocarbon Measurement, Oklahoma City, (405) 325-1217, (405) 325-1388 (fax), e-mail: lcrowley@ou.edu, website: www.ishm.info. 13-15.

Uzbekistan International Oil & Gas Exhibition & Conference, Tashkent, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 13-15.

NPRA National Safety Conference, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. 14-15.

IADC Drilling Onshore America Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 15.

SPE Digital Energy Conference, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: service@spe.org, website: www.spe.org. 20-21.

Mediterranean Offshore Conference & Exhibition (MOC), Alexandria, Egypt, + 39 0761 527976, + 39 0761 527945 (fax), e-mail: st@ies.co.it, website: www.moc2008.com. 20-22.

NPRA Reliability & Maintenance Conference & Exhibition, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. 20-23.

Society of Professional Well Log Analysts (SPWLA) Annual Symposium, Edinburgh, (713) 947-8727, (713) 947-7181 (fax), website: www.spwla.org. 25-28.

Middle East Refining and Petrochemicals Conference & Exhibition, Bahrain, +973 1755 0033. +973 1755 3288 (fax), e-mail: mep@oesallworld.com, website: www.allworldexhibitions.com. 26-28.

SPE International Oilfield Corrosion Conference, Aberdeen, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 27.

SPE International Oilfield Scale Conference, Aberdeen, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 28-29.

The CIS Oil and Gas Summit, Paris, +44 (0) 207 067 1800, +44 207 430 0552 (fax), e-mail: l.hannant@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk/summit8/summit8register.html. 28-30.

JUNE

ERTC Management Forum, Copenhagen, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 2-4.

Caspian Oil & Gas Exhibition & Conference, Baku, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 3-6.

Oklahoma Independent Petroleum Association (OIPA) Annual Meeting, Dallas, (405) 942-2334, (405) 942-4636 (fax), website: www.oipa.com. 6-10.

SPEE Society of Petroleum Evaluation Engineers Annual Meeting, Hot Springs, Va., (713) 651-1639, (713) 951-9659 (fax), e-mail: bkspee@aol.com, website: www.spee.org. 7-10

PIRA Scenario Planning Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 9.

Asian Geosciences Conference & Exhibition, Kuala Lumpur, +44 (0) 20 7862 2136. +44 (0) 20 7862 2119, e-mail: geoasia@oesallworld.com, website: www.geo-asia.com. 9-11.

Independent Liquid Terminals Association (ILTA) Annual Operating Conference & Trade Show, Houston, (202) 842-9200, (202) 326-8660 (fax), e-mail: info@ilta.org, website: www.ilta.org. 9-11.

SPE Tight Gas Completions Conference, San Antonio, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 9-11.

EAGE/SPE EUROPEC Conference & Exhibition, Rome, +31 30 6354055, +31 30 6343524 (fax), e-mail: eage@eage.org, website: www.eage.nl. 9-12.

ASME Turbo Expo, Berlin, (973) 882-1170, (973) 882-1717 (fax), e-mail: infocentral@asme.org, website: www.asme.org. 9-13.

PIRA London Energy Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 10.

Asian Oil, Gas & Petrochemical Engineering Exhibition, Kuala Lumpur, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: oga@oesallworld.com, website: www.allworldexhibitions.com. 10-12.

Global Petroleum Show, Calgary, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 10-12.

IADC World Drilling Conference & Exhibition, Berlin, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 11-12.

PIRA Understanding Global Oil Markets Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 11-12.

Asia's Subsea Conference & Exhibition, Kuala Lumpur, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: subsea@oesallworld.com, website: www.subseaasia.org. 11-13.

CIPC/SPE GTS Joint Conference, Calgary, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 16-19.

American Association of Professional Landmen (AAPL) Annual Meeting, Chicago, (817) 847-7700, (817) 847-7704(fax), e-mail: aapl@landman.org, website: www.landman.org. 18-21.

LNG North America Summit, Houston, (416) 214-3400, (416) 214-3403 (fax), website: www.lngevent.com. 19-20.

IPAA Midyear Meeting, Colorado Springs, Colo., (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 19-21.

PIRA Scenario Planning Conference, Houston, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 23.

API Tanker Conference, San Diego, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 23-24.

API Exploration & Production Standards on Oilfield Equipment & Materials Conference, Calgary, Alta., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 23-27.

PIRA Understanding Global Oil Markets Conference, Houston, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 24-25.

Russian Petroleum & Gas Congress, Moscow, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 24-26.

NEFTEGAZ Exhibition, Moscow, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 24-26.

PIRA's Globalization of Gas Study Conference, Houston, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 25.

PIRA Understanding Natural Gas Markets Conference, Houston, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 26-27.

World Petroleum Congress, Madrid, +34 91 745 3008, +34 91 563 8496 (fax), e-mail: info@19wpc.com, website: www.19wpc.com. June 29- July 3.

JULY

International Offshore & Polar Engineering Conference, Vancouver, (650) 254 2038, (650) 254 1871 (fax), e-mail: meetings@isope.org, website: www.isope.org. 6-11.

Annual Rocky Mountain Natural Gas Strategy Confer-

ence & Investment Forum, Denver, (303) 861-0362, (303) 861-0373 (fax), e-mail: conference@coga.org, website: www.coga.org. 9-11.

IADC Lifting & Mechanical Handling Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 15-16.

Oil Sands and Heavy Oil Technology Conference & Exhibition, Calgary, Alta., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilsandstechnologies.com. 15-17.

AUGUST

ACS National Meeting & Exposition, Philadelphia, 1 (800) 227-5558, e-mail: natlmtgs@acs.org, website: www.acs.org. 17-21.

IADC/SPE Asia Pacific Drilling Technology Conference, Jakarta, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 25-28.

Offshore Northern Seas Exhibition & Conference, Stavanger, +47 51 59 81 00, +47 51 55 10 15 (fax), e-mail: info@ons.no, website: www.ons.no. 26-29.

Summer NAPE Expo, Houston, (817) 306-7171, (817) 847-7703 (fax), e-mail: info@napeexpo.com, website: www.napeonline.com. 27-28.

SEPTEMBER

China Power, Oil & Gas Conference & Exhibition, Guangzhou, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.chinasenergyfuture.com. 2-4.

ECMOR XI-European Mathematics of Oil Recovery Conference, Bergen, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 8-11.

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

Rocky Mountain GPA Annual Meeting, Denver, (918) 493-3872, (918) 493-3875 (fax), email: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 10.

API Fall Refining & Equipment Standards Meeting, Los Angeles, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 15-17.

Rio Oil & Gas Conference & Expo, Rio de Janeiro, 55 21 2112 9078, 55 21 2220 1596 (fax), e-mail: riooil2008@ibp.org.br, website: www.riooilegas.com.br. 15-18.

API/NPRA Fall Operating Practices Symposium, Los Angeles, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 16.

GEO India South Asia's Geosciences Conference & Exhibition, New Delhi, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: geo@oesallworld.com, website: www.geo-india.com. 17-19.

SPE Annual Technical Conference & Exhibition, Denver, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 21-24.

ERTC Petrochemical Conference, Cannes, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. Sept. 29- Oct. 1.

International Pipeline Exposition, Calgary, Alta., 403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. Sept. 30-Oct. 2.

Unconventional Gas International Conference & Exhibition, Ft.Worth, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.unconventionalgas.net. Sept. 30-Oct. 2.

OCTOBER

NPRA Q&A Forum, Orlando, Fla., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 5-8.

GPA Houston Annual Meeting, Kingwood, Tex., (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessor.com. 7.

KIOGE Kazakhstan International Oil & Gas Exhibition & Conference, Almaty, + (44) 020 7596 5000, + (44) 020 7596 5111 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 7-10.

IADC Drilling West Africa Conference & Exhibition, Lisbon, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 8-9.

International Gas Union Research Conference, Paris, +31 50 521 30 78, +31 50 521 19 46 (fax), e-mail: igrc2008@gasunie.nl, website: www.igrc2008.com. 8-10.

ERTC Lubes and Additives Conference, Berlin, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 13-15.

Middle East Plant Maintenance Conference, Abu Dhabi, +44 207 067 1800, +44 207 430 0552 (fax), e-mail: d.michalski@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 13-15.

API Fall Petroleum Measurement Standards Meeting, Long Beach, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 13-17.

Central and Eastern European Refining & Petrochemicals Roundtable, Warsaw, +44 207 067 1800, +44 207 430 0552 (fax), e-mail: c.taylor@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 14-16.

ISA EXPO, Houston, (919) 549-8411, (919) 549-8288 (fax) website: www.isa.org. 14-16.

Oil & Gas Transportation in the CIS & Caspian Region Conference, Moscow, +44 (0) 207 067 1800, +44 207 430 0552 (fax), e-mail: j.golodnikova@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk/cispipes10register.html. 14-16.

PIRA New York Annual Conference, New York, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 16-17.

Petchem Arabia Conference, Abu Dhabi, +44 207 067 1800, +44 207 430 0552 (fax), e-mail: c.verma@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 20-22.

SPE Asia Pacific Oil & Gas Conference & Exhibition, Perth, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 20-22.

SPE International Thermal Operations & Heavy Oil Symposium, Calgary, Alta., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 20-23.

Calendar

Permian Basin International Oil Show, Odessa, Tex., (432) 367-1112, (432) 367-1113 (fax), e-mail: pbioilshow@pbioilshow.org, website: www.pbioilshow.org. 21-23.

AAPG International Conference & Exhibition, Cape Town, (918) 560-2679, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org. 26-29.

Biofuels Conference, Berlin, +44 207 067 1800, +44 207 430 0552 (fax), e-mail: c.taylor@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 28-30.

SPE Russian Oil & Gas Technical Conference & Exhibition, Moscow, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 28-30.

IADC Contracts & Risk Management Conference, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 29-30.

NOVEMBER

ASME International Mechanical Congress & Exposition, Boston, (973) 882-1170, (973) 882-1717 (fax), e-mail: infocentral@asme.org, website: www.asme.org. 2-6.

Abu Dhabi International Petroleum Exhibition & Conference (ADIPEC), Abu Dhabi, website: www.adipec.com. 3-6.

Deepwater Operations Conference & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepwateroperations.com. 4-6.

North African Oil and Gas Summit, Vienna, +44 (0) 207 067 1800, +44 207 430 0552 (fax), e-mail: c.brown@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk/nas3register.html. 4-6.

Mangystau International Oil & Gas Exhibition, Aktau, + (44) 020 7596 5000, + (44) 020 7596 5111 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 5-7.

IADC Annual Meeting, Paradise Valley, Ariz., (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 6-7.

SEG International Exposition and Annual Meeting, Las Vegas, (918) 497-5542, (918) 497-5558 (fax), e-mail: register@seg.org, website: www.seg.org. 9-14.

IPAA Annual Meeting, Houston, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 10-12.

Houston Energy Financial Forum, Houston, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.accessanalyst.net. 11-13.

American Institute of Chemical Engineers (AIChE) Annual Meeting, Philadelphia, (212) 591-8100, (212) 591-8888 (fax), website: www.aiche.org. 16-21.

ERTC Annual Meeting, Vienna, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 17-19.

IADC Well Control Middle East Conference & Exhibition, Muscat, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 24-25.

Annual European Autumn Gas Conference (EAGC), Cernobbio, Italy, +44 (0) 1737 855281, +44 (0) 1737 855482 (fax), e-mail: vanessahurrell@dmgworldmedia.com, website: www.theeagc.com. 25-26.

DECEMBER

Annual Refining & Petrochemicals in Russia and the CIS Countries Roundtable, Prague, +44 207 067 1800, +44 207 430 0552 (fax), e-mail: e.polovinkina@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 2-4.

Downstream Asia Refining & Petrochemicals Conference, Singapore, +44 (0) 207 067 1800, +44 207 430 0552 (fax), e-mail: a.ward@theenergyexchange.co.uk, website: www.wraconferences.com/FS1/dalregister.html. 3-4.

IADC Drilling Gulf of Mexico Conference & Exhibition, Galveston, Tex.,

(713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 3-4.

Deep Offshore Technology International Conference & Exhibition, Perth, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepoffshoretechnology.com. 3-5.

International Petroleum Technology Conference (IPTC), Kuala Lumpur, +971 (0)4 390 3540, +971 (0)4 366 4648 (fax), e-mail: iptc@iptcnet.org, website: www.iptcnet.org. 3-5.

PIRA Natural Gas Markets Conference, New York, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 8-9.

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

Seatrade Middle East Maritime Conference & Exhibition, Dubai, +44 1206 545121, +44 1206 545190 (fax), e-mail: events@seatrade-global.com, website: www.seatrade-middleeast.com. 14-16.

AAPG Annual Convention & Exhibition, San Antonio, 1 (888) 945 2274, ext. 617, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org/sanantonio. 20-23.

XSPE Improved Oil Recovery Symposium, Tulsa, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 20-23.

XSPE Progressing Cavity Pumps Conference, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 27-29.

2009

JANUARY

Oil & Gas Maintenance Technology Conference & Exhibition, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilandgasmaintenance.com. 19-21.

Pipeline Rehabilitation & Maintenance Conference & Exhibition, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.piipeline-rehab.com. 19-21.

SPE Hydraulic Fracturing Technology Conference, The Woodlands, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 19-21.

FEBRUARY

ASEG International Conference & Exhibition, Adelaide, +61 8 8352 7099, +61 8 8352 7088 (fax), e-mail: ASEG2009@sapro.com.au. 22-26.

MARCH

GPA Annual Convention, San Antonio, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 8-11.

Middle East Oil & Gas Show & Conference (MEOS), Manama, +973 17 550033, +973 17 553288 (fax), e-mail: aeminfo@batelco.com.bh, website: www.allworldexhibitions.com/oil. 15-18.

Asian Biofuels Roundtable, Kuala Lumpur, +44 (0) 207 067 1800, +44 207 430 0552 (fax), e-mail: a.ward@theenergyexchange.co.uk, website: www.wraconferences.com/FS1/AB1register.html. 24-25.

MAY

ACHEMA International Exhibition Congress, Frankfurt, +1 5 168690220, +1 5 168690325 (fax), e-mail: amorris77@optonline.net, website: http://achemaworldwide.dechema.de. 11-15.

JUNE

Oil and Gas Asia Exhibition (OGA), Kuala Lumpur, +60 (0) 3 4041 0311, +60 (0) 3 4043 7241 (fax), e-mail: oga@oesallworld.com, website: www.allworldexhibitions.com/oil. 10-12.

OCTOBER

International Oil & Gas Exploration, Production & Refining Exhibition, Jakarta, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: ogti@oesallworld.com, website: www.allworldexhibitions.com. 14-17.

STEPPING UP

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The second Oil Sands and Heavy Oil Technologies Conference & Exhibition is scheduled for July 15 – 17, 2008, at the Calgary TELUS Convention Centre in Alberta, Canada. Once again this conference will highlight new technology in the growing oil sands and heavy oil industry.

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Gas price logic

Marilyn Radler
Senior Editor-Economics

It's March. Gasoline demand is weak, and inventories of the fuel are comfortable with higher imports, but the price is close to $1/gal higher than it was this time last year.

It doesn't follow market logic, and few drivers enjoy paying more than $3/gal to fill up their auto's fuel tank.

An internet search for "gas price" returns 2.57 million results in just 0.23 sec. The first page of results shows sites that offer to find the cheapest gas in a given area. There's another site that will calculate how much gas a car might require to get from one city to another.

And then there's the Gas Price Watch Reporting Form from the US Department of Energy. This web page states: "The Department of Energy is very concerned about the impact of gasoline prices on American families. While we are working to address longer-term supply issues, we're also working to make sure American families are being treated fairly. If you believe there may be price-gouging, or price-fixing, please contact your local authorities and fill out the form below." Then follow the fields in which to report the offending station.

But again this year, as during price spikes in recent years, Congress wants to round up oil company executives for hearings on why fuel prices are so high.

The reasoning is repeated daily in the popular press. Gasoline prices follow the price of crude—a commodity that is currently in high demand worldwide. The dollar is weak, further boosting the price of commodities traded in the currency. Refinery problems sometimes cause supply disruptions. And so on.

Consider the movement of crude futures around the announcements of interest rate cuts by the Federal Reserve. If the market anticipates a rate cut, then traders bid up the price of crude because it would be a sign of further weakness in the US dollar more so than because it would be a boost to an economy that would require more oil products.

"Oil has become the 'new gold'—a financial asset in which investors seek refuge as inflation rises and the dollar weakens," said Daniel Yergin, chairman of Cambridge Energy Research Associates and executive vice-president of IHS. "The credit crisis has been fueling the flight to oil and other commodities, and that will last until the dollar strengthens or the recession becomes more pronounced," Yergin said.

Refining losses

Meanwhile, integrated oil companies aren't making much money from their refining and marketing operations. In fact, refining is what pulled down many firms' earnings in the fourth quarter of 2007. Independent refiners lost money not only for the quarter, but also for the entire year (see story, p. 31).

Refining margins sank during last year's final quarter, as feedstock costs soared to record highs. US refining margins posted sharp declines from their second-quarter 2007 peaks.

For example, the US Gulf Coast cash refining margin fell to average $8.11/bbl in the fourth quarter of last year vs. $19.68/bbl in the second quarter, according to Muse, Stancil & Co. Meanwhile, feedstock costs in the same region averaged $89.40/bbl in the fourth quarter, up from $71.64/bbl in the second quarter of last year.

Refinery utilization is lower, too. Last month, it averaged 85.6% in the US, according to the American Petroleum Institute. For all of 2007, utilization averaged 88.5%.

In its most recent Monthly Oil Market Report, the Organization of Petroleum Exporting Countries said the decline in refining margins over the last few months has negatively affected refining operations across the board, leading to early maintenance, especially in the Western Hemisphere.

Further, the report said the current conditions of the product markets (i.e., sluggish demand) and refining margins may encourage more discretionary cuts to utilization in the near future. ✦

Editorial

Attention to cost

Economic gloom fast engulfing the US economy contains at least one reason for hope. The new attention it forces onto cost might keep the country from rushing into peril over global warming.

Politically, sad as it is to say, the global-warming debate is over in the US. All candidates with any hope for winning the presidency support mandatory limits on emissions of greenhouse gases, whether or not the measures offer reasonable prospect for affecting global average temperature. All candidates, in other words, support the imposition of certain cost in pursuit of very uncertain benefit against the crucial metric of measured temperature. They all want the government to set limits on emissions of greenhouse gases, especially carbon dioxide. And they all dodge the core question: Can restriction of the relatively small amount of CO_2 subject to human control, which may well represent a minor influence over temperature, meaningfully alter observed warming?

Condescending dismissal

People who would be asked to sacrifice wealth to global-warming fear deserve a better answer to that question than anyone so far has offered. What they hear instead are mourning over the melting of glaciers, meaningless assertions about a consensus of scientists, and stilted hints of doom from a United Nations initiative riveted to climate models with demonstrably limited powers of prediction. Questions, in fact, encounter nothing more than condescending dismissal, such as that delivered by England's Prince Charles, who recently called skepticism about global warming alarm "sheer madness."

In the US, if presidential candidacy validly indicates popular mood, intellectual bigotry of that abysmal order has won the day. Come next January, no veto will await legislation enacted in a cost-blind panic. Even worse, the leading proposition of the moment is a bill that camouflages economic consequences behind a "cap-and-trade" smokescreen.

The US can't cut emissions of CO_2 without reducing the combustion of hydrocarbons, which means raising the cost of energy. There must never be any confusion about this. The only political issue that remains after the decision has been made to cut CO_2 emissions is the mechanism for the cost hike.

Politicians and business people favor the cap-and-trade mechanism—politicians because it hides the costs and business people because it creates opportunities to make money through the trading of emissions allowances. But cap-and-trade schemes in no way eliminate the costs, which ultimately must be borne by taxpayers and energy consumers.

The alternative is a tax on carbon. Because this option promises no trading opportunities, business people dislike it. Politicians spurn the tax, too, because it would make costs painfully clear to the people who must pay them. That reason alone is enough to make a carbon tax preferable.

Even in the cap-and-trade house of mirrors, though, costs can be analyzed. Two cost estimates recently emerged for the Climate Security Act sponsored by Sens. Joseph Lieberman (I-Conn.) and John Warner (R-Va.). One, by the National Association of Manufacturers and American Council for Capital Formation, said the bill, which would set a declining cap on US CO_2 emissions, would lower gross domestic product by $151-210 billion/year by 2020 and $631-669 billion/year by 2030. The reduction in average disposable household income would be $739-2,927/year in 2020 and $4,022-6,752/year by 2030.

Energy costs

The other estimate, by the Environmental Protection Agency, sees reductions in GDP of $238-983 billion in 2030 and $1.012-2.856 trillion in 2050. EPA notes that its analysis makes no attempt to account for economic benefits associated with emissions cuts. In both studies, forced emission cuts inevitably raise energy costs appreciably over projected baselines. Gasoline, for example, would be up 60-144% by 2030, according to the NAM-ACCF study. EPA puts the gasoline price increment attributable to the Lieberman-Warner bill in that year at 53¢/gal. A public antagonized by rising fuel prices should know what its government contemplates for it in this area.

Pampered royals to whom the word "cost" has no meaning can afford to ignore warnings like these. To everyone else, not heeding costs and not addressing doubts about the likely effectiveness of hasty warming remedies are truly what constitute madness. ✦

GTL, CTL finding roles in global energy supply

Iraj Isaac Rahmim
E-MetaVenture Inc.
Houston

Interest in Fischer-Tropsch (F-T) chemistry and associated technologies such as gas-to-liquids (GTL) and coal-to-liquids (CTL) continues to grow worldwide. Within the last few years one new world-scale unit came on line, three others are in construction, and many more are planned, while other approaches and synergies, such as biomass-to-liquids (BTL) and integrated coal gasification-combined cycle (IGCC), are under evaluation.

During this period, commercial products have been tested, certified, shipped, and used. However, concerns such as CTL's carbon dioxide (CO_2) manufacture have come to the center stage. Technology development and demonstration, economics of construction and operation, and regulatory directions in various jurisdictions continue to be in flux. This article

reviews recent GTL and CTL activities and discusses the likely directions and commercial impact of this technology.

Background

A general arrangement diagram of F-T-based processes is shown in Fig. 1.

Commercial F-T chemistry uses cobalt or iron-based catalysts in fixed, fluidized, or slurry-phase reactors to convert synthesis gas (syngas) to large-molecular-weight hydrocarbons, such as naphtha, diesel, lube, and wax range material.

The syngas stream, primarily carbon monoxide (CO) and H_2, can originate from different sources, such as natural gas methane partial-oxidation or steam reforming, coal or coke gasification, or the gasification of biomass (not yet commercially demonstrated). The source of the syngas affects F-T chemistry both in terms of potential impurities—such as sulfur and various metals from coal-derived syngas—that need removal and in terms of the syngas CO/H_2 composition.

Aside from the feed and its properties, F-T reactor product composition depends on factors that include reactor type and design and operating conditions such as temperature. One can modulate the mix to produce primarily waxes or diesel, for example. Most often, in low-temperature operation much waxy and lube-range material is produced, which is then mild-hydrocracked to high-quality diesel having near-zero sulfur and a cetane number of 70-75.

Many variations can be considered in terms of how the key elements are combined and which products are made. Fig. 2, for example, shows the use of coal or other higher-carbon sources as feedstock while potentially generating power, CO_2, or liquid hydrocarbons such as diesel, naphtha, lubes, and waxes. In addition, aside from hydrocracking the lubes-wax stream, the naphtha or light ends could be steam-cracked to syngas and recycled back to the F-T reactor to increase production of high quality diesel.

References 1-3 give more detail on the F-T chemistry and GTL-CTL processes, products, and qualities.

Drivers and issues

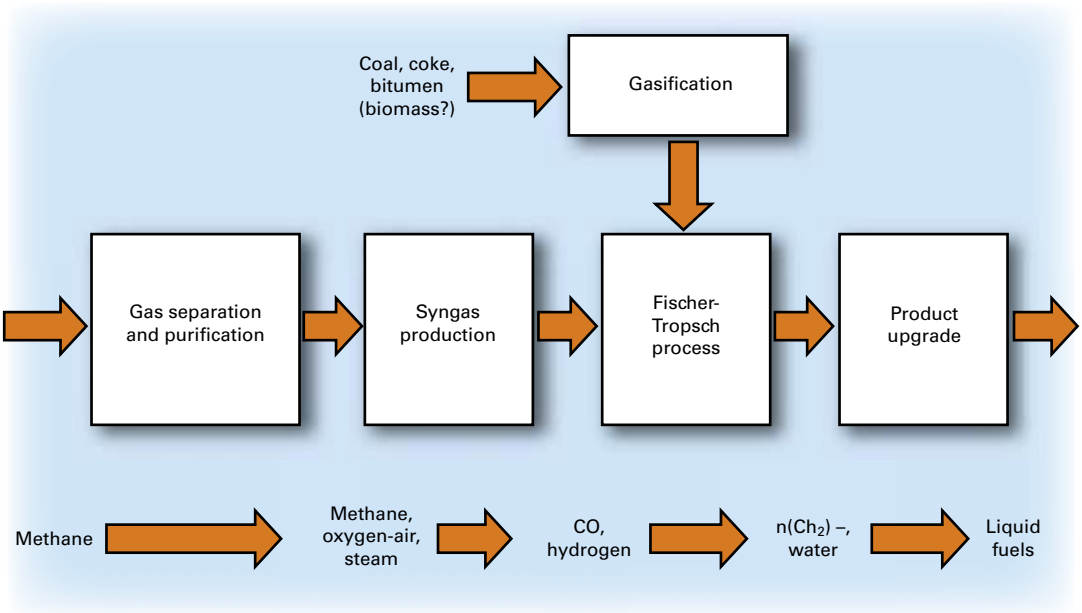
Many factors that originally aroused interest in GTL and associated processes during the past decade remain valid:

- A steady increase in global energy demand. F-T-based processes along with a number of other approaches are

being developed to meet this growing need, much of which is muscled by emerging economies. China has an annual 8-11% historical and projected growth in diesel requirement, and energy demand is projected to remain strong in India and Brazil. Barring major upsets, the industrial economies will develop at a low single-digit pace. Escalation of energy use to 2030 for Organization for Economic Cooperation and Development (OECD) and non-OECD countries is projected to average 0.8 and 2.9%/year respectively, with a global average of 1.8%/year.[4 5]

FISCHER-TROPSCH-BASED PROCESSES DIAGRAM

Fig. 1



- Large volumes of stranded gas in several global areas having little access to the market.[6 7 8] In addition to GTL, other options such as LNG and gas-to-chemicals (GTC) facilities are either operational or in various stages of progress.
- Tightening quality specifications such as those for sulfur in hydrocarbon products, particularly diesel and gasoline, in many jurisdictions. These requirements are being met largely through improved hydrocracking, hydrotreating, and other refining processes, although F-T-based synthetic products are excellent blendstocks due to their low sulfur and high cetane.
- The need to reduce gas flaring for economic, environmental, and legal reasons in countries such as Nigeria, which flares 2.5 bcfd.[9]

At the same time, certain factors have gained in importance during the past years:

- The increase in the market value of crude oil. An oil price that has crossed the psychological $100/bbl mark multiple times with little expectation of retreating to pre-2004 levels has improved the economics of many technologies, including CTL and GTL.[63 64]
- Worldwide resource security concerns, given the current global political climate. Of great interest in this arena are gas—only about 40% of the proved reserves are in the Middle East—and coal, of which the US has the largest reserves in the world.
- Concern about the possibility of global climate change and the potential impact of CO_2 release. This has led to the exploration of a number of approaches ranging from technology improvements for increased efficiency to CO_2 capture, compression, and sequestration (CCS).[10] Additionally, topics such as BTL conversion are seriously on the table, although many technological as well as economic and strategic issues remain to be resolved.[11]

GTL projects

A list of existing GTL-CTL plants and those under construction is shown in Fig. 3. There has been a flurry of activity in this area, the most important being the construction, start-up, and operation of the first GTL plant in 15 years.

General contractor Foster Wheeler began construction of the Sasol Chevron and Qatar Petroleum Oryx GTL facility in Ras Laffan, Qatar, in 2003 and completed it in mid-2006. It has a design capacity of 34,000 b/d and will use 300 MMscf of gas from North field. Slurry reactors start-up took about 6 months—2 months longer than expected—and

GLOBAL PRIMARY ENERGY RESERVES

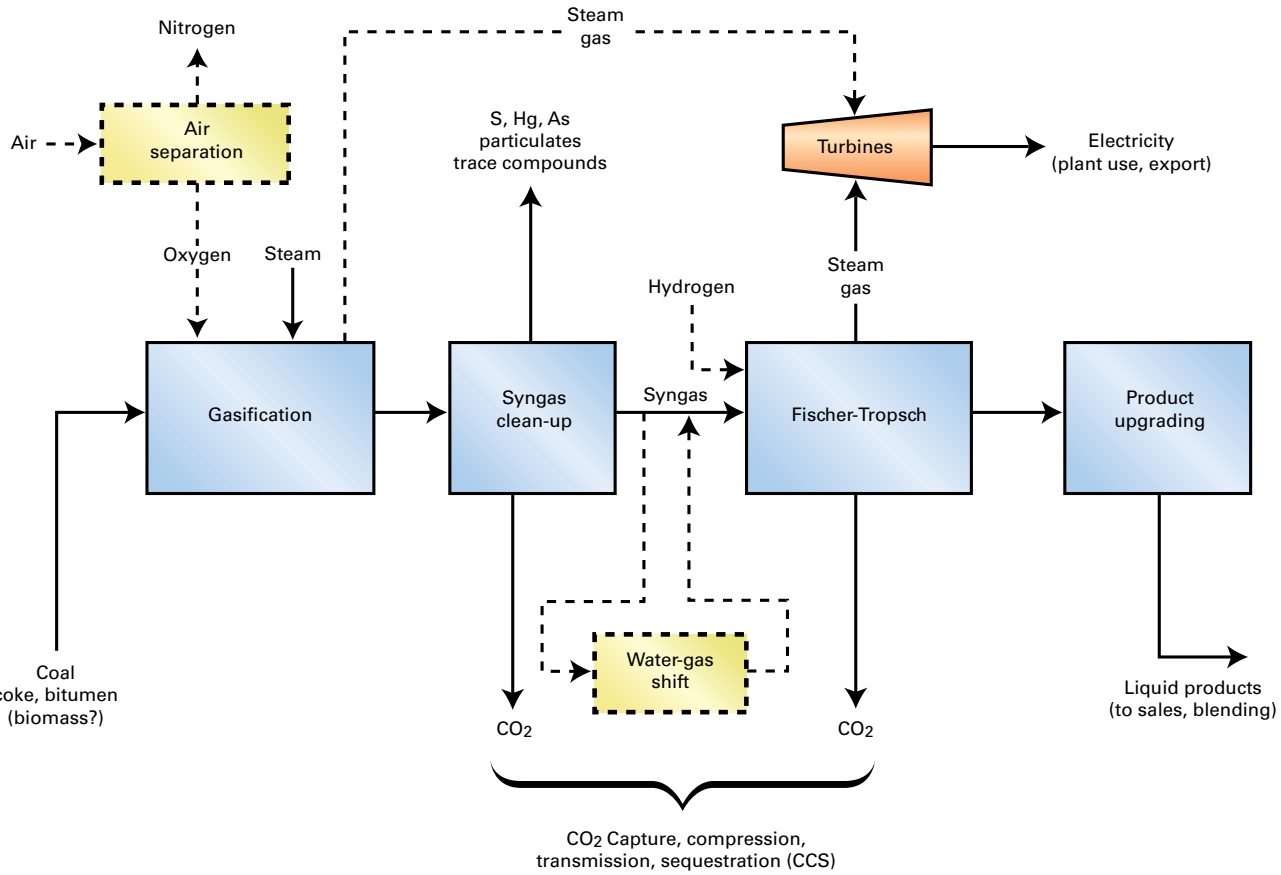
Table 1

Resource	Proved reserves	Energy, quadrillion btu	Million tons of oil equivalent	Years remaining at current production
Oil*	1,372 x 10^9 bbl 191 x 10^9 tons	7,600	191,000	41
Natural gas	6,405 tcf	6,600	165,000	63
Coal	479 X 10^9 tons	8,500	213,000	147

* Includes Canadian oil sands.
Source: BP Statistical Review of World Energy, 2007

BLOCK FLOW DIAGRAM OF A CTL PROCESS

Fig. 2



Gasification involves pyrolysis, combustion, and gasification chemistries:

$2C–H + 3/2\ O_2 \rightarrow 2CO + H_2O + Heat$

$C–H + H_2O \rightarrow CO + 1.5\ H_2$

Also, some water-gas shift: $CO + H_2O \leftrightarrows CO_2 + H_2$

F–T converts syngas to hydrocarbons:

$CO + ?H_2 \rightarrow –CH_2 – + CO_2 + H_2O + heat$

(long chain)

production began in earnest in December 2006.[12]

Sasol claimed the plant was completed within budget, originally stated at $950 million. The first product shipment from the plant was announced in May 2007.

The companies encountered a number of technical problems, including issues with the utility section and with catalyst-slurry separation, the latter resulting in the contamination of intermediate waxy streams with particulates and fines to some downstream units.[13]

Consequently, the plant has been operated at levels below 10,000 b/d during 2007-08 while solutions are devised.

OVERALL CTL BALANCE

Table 2

Total liquid product capacity	11,000 b/d[1]	50,000 b/d[2]
Coal (Illinois #6, bituminous), tons/day	4,891	24,533
Other feeds: air, water,...		
Diesel, b/d	7,500	27,819
Naphtha, b/d	3,509	22,173
Co_2, tons/d	6,035	32,481
Net Power, Mw	9.7	124.3
Other products: S, slag, fuel gas, ...		
Bbl liquid/Ton coal	2.25	2.04
Ton CO_2/Ton coal (carbon /carbon)	0.53	0.57
Ton CO_2/Ton coal	1.23	1.32
Overall thermal efficiency, % HHV	[3]51	[3]47

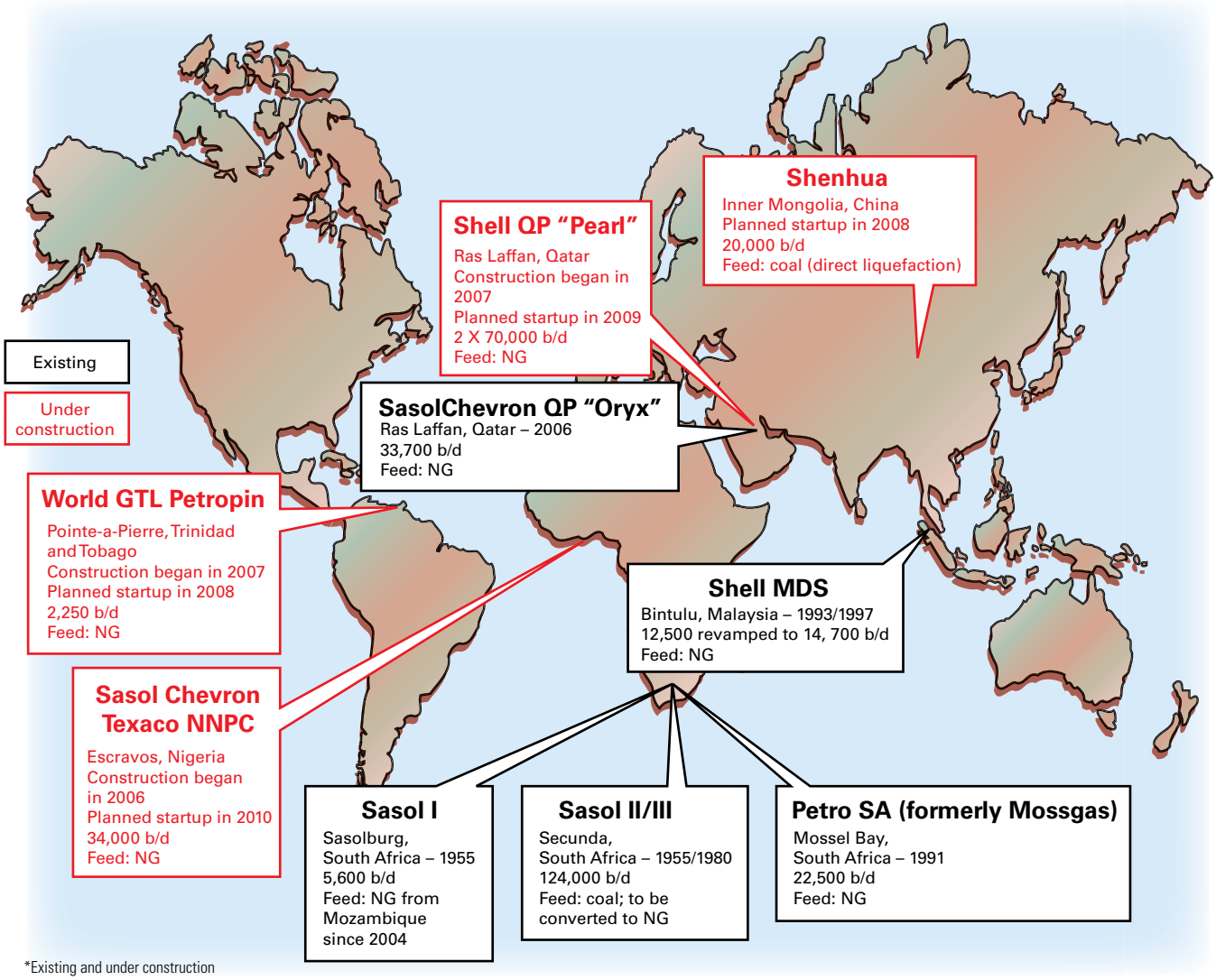
[1]NETL study for DOD/Air Force Apr. 9, 2007. [2]NETL/DOE study Aug. 24, 2007. [3]Not verified. Does not include all energy recovered in process.
Sources: NETL/DOD feasibility study, DOE/NETL feasibility study.

Sasol announced late in 2007 that the facility will begin operating at full capacity by July 2008.[14] It more recently said the facility is unlikely to reach full capacity for some time.

Construction of the other large GTL facility in Qatar—the 140,000 b/d Shell-Qatar Petroleum Pearl plant—continues apace, although with major cost overruns. Construction began in February 2007 on the plant, which will have two 70,000 b/d trains and fixed-bed reactors and is due to start up

COMMERCIAL GTL-CTL UNITS*

Fig. 3



*Existing and under construction

in 2009.[15] Projected construction cost, originally $6 billion in 2004, increased rapidly to $12-18 billion and then to $20 billion.[16 17 18] Factors causing the overruns include the large amount of engineering and construction activity globally, especially in the Middle East, with the rising price of crude and petroleum products.[19]

In part resulting from such cost escalations, a number of GTL projects in Qatar were cancelled or placed on hold until at least 2009.[16 20 21] Particularly noticeable is the cancellation of the Exxon-Mobil and QP Palm GTL plant having a planned capacity of 154,000 b/d, which leaves much of the burden of "proving" GTL's economic and technical feasibility in Qatar on the shoulder of Oryx. The other facilities put on hold include plants planned with Conoco-Phillips and Marathon-Petro-Canada as Qatar assesses North field reserves.

Another major project, the Escravos GTL plant in Nigeria, has a design capacity of 34,000 b/d and would use more than 300 MMcfd of gas and contain slurry-bed reactors. Chevron Nigeria Ltd. and Nigerian National Petroleum Co., however, say they expect the capacity to be expanded to 120,000 b/d within 10 years.[22] The engineering, procurement, and construction contract for this $3 billion project was awarded in 2005, and construction started in mid-2006.[23]

PARTIAL LIST OF US CTL PROJECTS

Table 3

Project lead	Project partners	Location	Feedstock	Status	Capacity, b/d	Cost, $ billion
American Clean Coal Fuels	None cited	Oakland, Ill.	Bituminous, biomass	Feasibility	25,000	—
Synfuels Inc.	GE, Haldor-Topsoe, NACC, ExxonMobil	Ascension Parish, La.	Lignite	Feasibility	—	5
DKRW Advanced Fuels	Rentech, GE	Medicine Bow, Wyo.	Bituminous	Design (2011)	15,000-20,000	1.4 (?)
DKRW Advanced Fuels	Rentech, GE, Bull Mountain Land Co.	Roundtop, Mont.	Sub-bituminous, lignite	Feasibility	22,000	1-5
AIDEA	ANTRL, CPC	Cook Inlet, Alas.	Sub-bituminous	Feasibility	80,000	5-8
Mingo County	Rentech	WV	Bituminous	Planning	25,000	2 (?)
WMPI	Sasol, Shell, DOE	Gilberton, Pa.	Anthracite culm	Design	5,000	0.612
Rentech/Peabody	N/A	Montana	Sub-bituminous, lignite	Feasibility	10,000-30,000	—
Rentech/Peabody	N/A	Illinois, SW Indiana, Kentucky	Bituminous	Feasibility	10,000-30,000	—
Rentech		Natchez, Miss.	Coal, petcoke, biomass	Planning	1,600 (Ph. I)	—
Baard Energy	AMEC Paragon	Wellsville, Ohio	Sub-bituminous, lignite	Feasibility	35,000	4

Despite some delays, first production is set for 2010.[24]

Also being constructed is the 2,250 b/d World GTL plant in Trinidad and Tobago (see cover). This facility, to use about 21 MMscfd of gas and contain two fixed-bed reactors, is a rather latecomer, with $100 million financing obtained in 2007.[25] World GTL is relocating mothballed equipment, such as a reactor from a Delaware methanol plant and a hydrocracker from Guatemala.[26] It has an aggressive construction plan, with start-up set for March or April.

Along with these, a large number of other projects are at various stages of study, planning, and design around the world, including plants in Australia, Egypt, Thailand, and Papua New Guinea, among others.

Product demonstrations

Although commercial GTL units in South Africa and Malaysia and CTL units in South Africa have been operating for decades, their products' utility and performance, including emission characteristics, were further demonstrated in several ways during the past few years.

A number of fleet tests of GTL diesel blends were or are being performed. For example, in 2007 Chevron and a northern California transit district initiated 6-month-long test evaluations involving 60 buses using GTL diesel and biodiesel.[27]

The US Air Force Synthetic Fuel Initiative, meanwhile, has successfully performed a number of tests using 50:50 blends of F-T and JP-8 jet fuels to certify all of its aircraft by 2011—and 50% synfuel use in the US by 2016.[28] These tests include flight testing of B-52s and subsequent certification of the F-T blend, ground testing of the engine that powers the C-17 and Boeing 757, and a transcontinental flight-test of the C-17 in October 2007.[29 30 31]

Last month Airbus A380 became the first commercial aircraft to complete a flight using GTL jet fuel blend. Parties to the flight test included Shell, Qatar Airways, and Rolls Royce, the engine manufacturer.

There have been flashy demonstrations. Ten Audis used in the 2007 World Economic Forum annual meeting at Davos, Switzerland, were run on Shell GTL fuel.[32 33] In April to June 2006, Sasol Chevron ran a 6,500-km "GTL challenge" where five cars, including one on pure GTL diesel, were raced from Sasolburg, South Africa, to Doha, Qatar.[34] In both 2006 and 2007 the entries using fuel formulated to include Shell Bintulu GTL diesel raced in and won the 24-hr Le Mans competition.[35]

Coal-to-liquids

Lately, CTL has gained a relatively high profile in the US—witness a 60 Minutes segment as well as multiple New York Times editorials and articles—as the country leads a small group of countries with substantial proved coal reserves, including Russia, China, India, and Australia (Fig.4).[36-39] Within the US, coal reserves are distributed in several states, including Montana and Wyoming in the West, Illinois and West Virginia in the Midwest and East, and Louisiana and Mississippi in the South. The quality of the coal varies in different US and global regions with respect to water, sulfur, and energy content, but based on current levels of usage—primarily in power generation—it is expected to last two to four times as long as world oil or gas reserves (Table 1).

In the US, many stakeholders are involved in improving the technology, evaluating implementation feasibility, and affecting policy. Parties include:

- Private industry, which includes coal companies such as Peabody; technology suppliers such as Chevron, ConocoPhillips, Sasol, Rentech, Syntroleum, and GE; and industry advocacy groups such as the National Coal

Council, American Coal Foundation, and Coal-to-Liquid Coalition.

- Environmental stakeholders having concerns regarding CO_2 generation and water usage. These include the Natural Resources Defense Council and Groundwork USA.
- Government entities, including the departments of Defense and Energy, which are active in technology evaluation and development; and state and federal governments and agencies involved in policy development and project funding.
- The general public having dual interests in the development of cost-effective and secure energy resources and good shepherding of the environment.

A number of recent technical and economic feasibility studies provide information on CTL and its prospects.[40 41] Table 2 provides overall mass balance from two works in which many design and strategic factors are examined.[42 43] Note especially the production of 1.3 tons of CO_2/ton of coal (0.65 tons/bbl of liquid product).

CTL projects

Currently, only one commercial CTL unit—in South Africa—is operating, with even this likely to be converted to GTL gas feed during the next few years (Fig. 3). However, CTL has a long commercial history, with multiple units operational for as long as 5 decades. Many projects are at various stages of progress globally, including the US (Table 3).

Although all of the US CTL projects are in the early stages, at least one project in China is under construction and slated for start-up this year. The Shenhua Inner Mongolia facility has a capacity of 20,000 b/d of liquid products using direct liquefaction technology as opposed to classical CTL routed through the manufacture of syngas. [4 44 45]

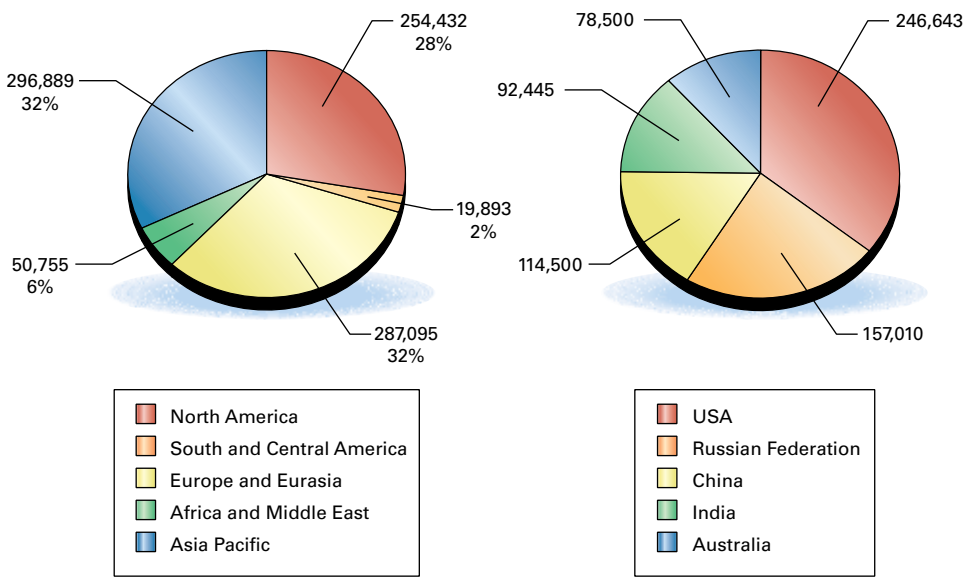
This technology historically has not been favored, as the chemistry is considered to be more difficult, requiring better controls for good operational reliability. In light of its large coal resources and growing energy demand, China has made a strong commitment to CTL, with several projects in the works and various entities stressing the importance of CTL to the country's energy policy.[46]

At the same time, the Chinese leaders have expressed concern for environmental quality issues and are particularly mindful of the large amounts of water required in CTL as many parts of the country are arid.[47 48] Given these issues and the high capital cost of CTL, there are reports that China might cancel some projects.[49]

Other non-US CTL undertakings at various stages of study, planning, and design include projects in Lu'an and Yankuang and joint ventures with Sasol and Shell in China and projects by Alon Resources PLC in Australia, Pertamina in Indonesia, Tata Group and Sasol in

PROVED WORLDWIDE COAL RESERVES, MILLION TONS

Fig. 4



Source: Energy Information Administration, US Department of Energy

GLOBAL CTL, GTL LIQUID FUELS PRODUCTION

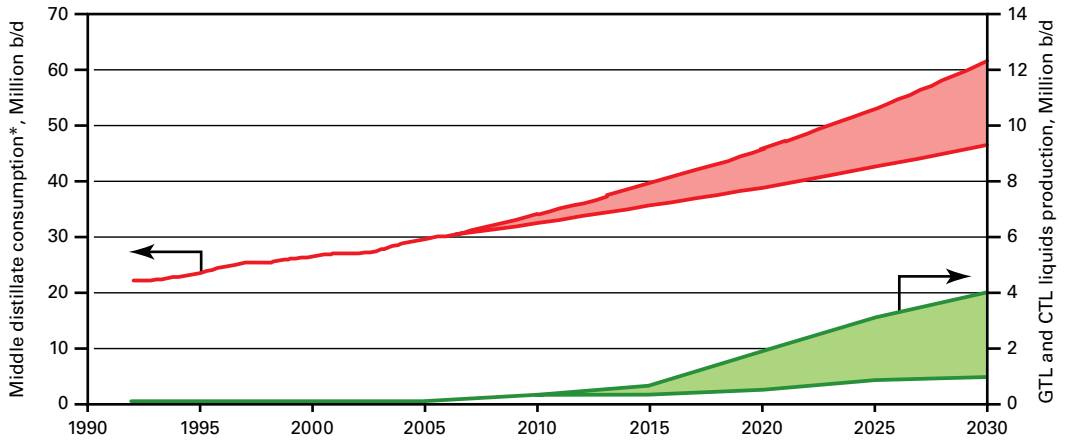
Table 4

	1992	2004	2005	2010	2015	2020	2025	2030
				1,000 b/d				
GTL liquid products								
High case	—	—	—	20	60	100	110	140
Low case	—	—	—	20	30	40	50	60
Reference case	—	—	—	20	50	90	100	120
CTL liquid products								
High case	100	100	100	300	600	1,800	3,000	3,900
Low case	100	100	100	300	300	500	800	900
Reference case	100	100	100	300	600	1,200	1,700	2,400

Source: Energy Information Administration, International Energy Outlook 2007

GLOBAL F-T LIQUID OUTPUT RANGE VS. MIDDLE DISTILLATE CONSUMPTION RANGE

Fig. 5



*Assumes 1.9-3%/year growth in middle distillate consumption.
Sources: Energy Information Administration, International Energy Outlook 2007, BP Statistical Review of World Energy, 2007

India, Sasol in South Africa, CIC Energy in Botswana, and L&M Group in New Zealand.

US policy action

A number of entities are involved in influencing, evaluating, and developing policy at the US state or federal levels and, over the years, various elements have been put in place:

- A 50¢/gal subsidy on F-T naphtha and diesel in the 2005 Federal Transportation Bill. This was extended to 2010 in the 2007 Farm Bill, although a requirement for recovery and sequestration of at least 50% of CO_2 was also included—and up to 75%, if technologically possible.
- Loan guarantees for gasification projects with less than 65% electricity output as mandated in the Energy Policy Act of 2005.
- A 20% investment tax credit applied to the first $650 million during the first year of operation, also included in the Energy Policy Act of 2005.
- Over $2.2 billion funding for CCS R&D, demonstration, and assessment in Title VII of the Energy Independence and Security Act (EISA) of 2007 that President George W. Bush signed into law last December. This includes provisions for at least seven large-scale CO_2 sequestration tests as well as carbon capture demonstrations.

In addition to these, there are numerous regulations and incentives related to plant emissions and fuel usage as well as regulations on fuel quality and specifications. In Europe, an emissions trading scheme is in place, while in the US voluntary emissions trading markets, such as the Chicago Climate Exchange, exist, and California and some northeastern states have their own initiatives in the works.[50 51]

Is a cap-and-trade regime coming? What about a carbon tax? Noting the great uncertainty and flux in the policy area, particularly as related to CO_2 emissions, many players, particularly in the US, are awaiting more visibility in this area before committing large resources to actual commercial CTL implementation.

TYPICAL CTL CAPITAL COST FOR NOMINAL 50,000 B/D UNIT

Table 5

Capital cost, $ million[1]		
Coal and slurry prep	425	67%
Gasification	1,150	
Air separation unit	425	
Syngas clean-up	850	
WGS + F.T	510	12%
Product upgrading	210	5%
Power generation	255	16%
Other	425	
TIC	4,250	
~$85,000/bbl installed capacity		

[1]Excludes CO_2 compression, transportation, sequestration costs.

GTL, CTL projections

Many studies and analyses during the first half of the decade projected 400,000-800,000 b/d of worldwide GTL liquid products for the medium term (2015-20).[1] However, the 2007 EIA projections suggest that much of the F-T liquid products might be the result of added CTL units rather than GTL.[4]

Evaluating cases ranging from projected low to high oil prices, they project global CTL liquid fuels of 0.9-3.9 million b/d by 2030 while, for GTL, they show a more modest production of 60,000-140,000 b/d (Table 4). In their scenarios, China will account for nearly 60% and Qatar 80% of the added global CTL and GTL capacity by 2030. Assuming growth of 1.8%/year in the global consumption of middle distillates, CTL and GTL would contribute modestly though meaningfully in meeting the expected demands— as much as 9% of the 2030 demand under the high GTL and CTL implementation scenario (Fig. 5).

The EIA's CTL projections for the US shown in Fig. 6 suggest that by 2030 as much as 6% (2007 projection) to 9% (2008 projection) of the US middle distillate demand can be met through CTL.[4 52] As expected, given the value of natural gas in the US, no GTL units, except demonstration units, are likely to be built in the US.

There are other projections for CTL and GTL growth. International Energy Agency expects 180,000 b/d of CTL in China by 2015 and 750,000 by 2030

while none in India during the same time period, a surprise given India's large reserves of coal.[5] These numbers are decidedly modest when compared with EIA's projections. Another analysis suggested a global GTL capacity of about 400,000 b/d during the next decade.[53]

Projections also vary quite a bit with respect to the US. Depending on government policy decisions, the Federal Task Force on Strategic Unconventional Fuels forecasts US CTL capacity ranging from 400,000 to 2.6 million b/d by 2035.[54] The National Coal Council similarly projects 2.6 million b/d of CTL liquids by 2025, while the Southern States Energy Board calls for a very aggressive growth of CTL to 5.6 million b/d by 2030.[56] More reasonably, a Baker and O'Brien study suggests 250,000 bbl of CTL middle distillates from four to six large-scale CTL plants by around 2020.[41]

It is likely that some of the projections, particularly for CTL, are too aggressive, as several elements could moderate the pace of CTL implementation:

- The fate of CO_2 and the CCS option will be slow to resolve because studies such as finding and certifying suitable geologic formations for sequestration will take years to give results. At the same time, policy actions in a democracy such as the US will be slow to develop and decidedly conservative in implementation.
- CTL units cost $70,000-100,000/bbl-capacity. This high capital cost will require multiple partners and several sources of financing as well as higher return potential, all of which result in slower analysis and approval for such projects (Table 5).

Overall, the global progress of CTL will likely be at the lower end of the EIA projections and may reach 0.5-1 million b/d of capacity by 2030.

On the other hand, GTL capacity might grow a bit faster than expected, as it has lower capital costs—assuming the cost escalation at Qatar's Pearl is an aberration—and fewer environmental concerns compared with CTL. As such, growth in the upper range of the EIA estimates—150,000-250,000 b/d—by 2030 seems reasonable.

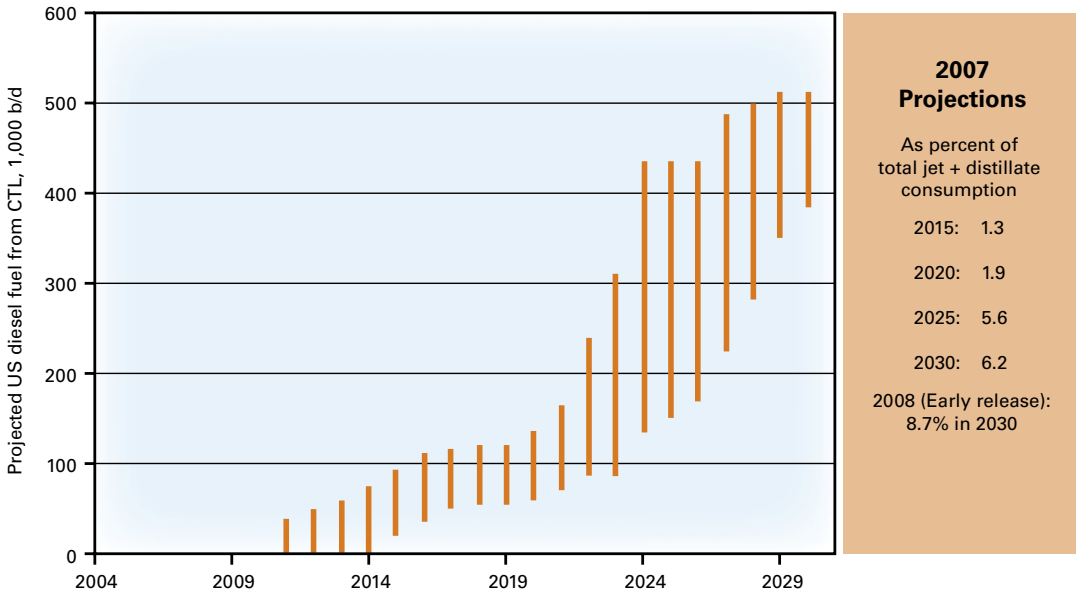
Potential impact

Given the understandably great variation on projections and the many assumptions involved, including potential policy action, few elements can be predicted with authority. However, the following are likely:

- A handful of projects are operational or are being built. Given the high capital cost for these technologies and other uncertainties, such as CO_2 regulation and cost, many parties will suspend or slow projects for the next few years until results of the existing projects from technical, economic, and strategic points of view become known.
- In light of the very large regional reserves of stranded gas and coal, demands by existing and new GTL, CTL, and related technologies such as GTC will not overly tax these reserves. At the same time, some additional coal mining will be needed, especially in the US.[57]
- The impact of GTL and CTL products such as diesel and naphtha on the markets will be generally modest in helping meet the increasing demand. At the same time, the products can have a major impact on meeting demand in certain regions. One analysis suggests that as much as 15% of

PROJECTED US CTL DIESEL

Fig. 6



Sources: Energy Information Administration, International Energy Outlook 2007, International Energy Outlook 2008 (Early release)

the near-to-medium-term European diesel deficit can be met by the commercial F-T units currently under construction.[53] F-T diesel will be an excellent blendstock in Europe although not fully valued for its low sulfur and high cetane, as the European refineries have implemented a large number of hydroprocessing units to satisfy sulfur restrictions. In Asia and other jurisdictions with evolving specifications, however, the F-T diesel could have additional value as it blends to help meet the new specifications.

- F-T naphtha, due to its paraffinicity and linearity, is best used as petrochemical feedstock. However, it can be processed in the refinery using isomerization (light-end) and reforming (heavy-end) units for improved octane, although these might need to be dedicated or run at different conditions.[65]
- F-T units will produce only a small amount of lubes and waxes, as these streams will be hydrocracked down to diesel and naphtha to avoid overwhelming the global lubes and wax markets—about 1 million and 100,000 b/d, respectively. The quality of the F-T lubes and waxes is high, and even the small amount added to the market will help retire the less efficient lube refineries, which generally produce lower viscosity index products.

CO_2 and CCS

About 28 billion tons of CO_2 was emitted globally into the atmosphere in 2005, the US share of which was about 6 billion tons.[4] About half of this came from large stationary sources, primarily coal-fired power plants, from which CO_2 is considered to be captureable (Table 6).

Given production of a typical 0.65 ton CO_2/bbl of liquid products, a 50,000 b/d CTL plant is expected to produce 11.3 million tons/year of CO_2 (Table 2). In light of CTL growth projections, simple calculations suggest that, without CO_2 CCS, US CTL units might emit as much as 175-230 million tons of CO_2 in 2030, equal to 1.3-1.7% of the 2005 global large stationary source emissions (Table 7). The implementation of CCS can reduce emissions by 80-90%, reducing the projected CTL emissions shown in Table 7 to 0.1-0.3% of that of the global large stationary sources.

There is disagreement about the efficacy of CCS. Some argue that, even with CCS, CTL diesel manufacture results in higher CO_2 compared with conventional diesel.[58] However, over the past few years, all major parties in the US and other industrial nations have agreed that CCS is critical to the acceptance and implementation of CTL, and therefore great effort is beginning to be expended in this area.

The elements of CCS—CO_2 capture, compression, transmission, sequestration—have been implemented commercially in many contexts over the decades. Currently there are more than 2,500 km of pipelines transporting more than 40 million tons/year of CO_2 in the US, as 30 million tons/year of CO_2 is injected for enhanced oil recovery. And about 1 million tons/year of CO_2 is injected from Sleipner gas field into a saline aquifer under the North Sea.[10]

Given the large volumes of CO_2 that would require sequestration from CTL, coal-fired power plants, and other sources, suitable geologic formations must be found and investigated for capacity, stability, and impact in tests that require several years. Many parties are at work on this in the US and internationally. Major US efforts include:

- The FutureGen Alliance, a nonprofit organization representing some of the world's largest coal and utility companies. It has a budget of $1.7 billion, 74% of which comes from the US government, excluding EISA 2007 funding. The alliance selected a test site at Matton, Ill., in December 2007, but the Department of Energy canceled funding for the project, making its current status uncertain.[59 60]
- Plains CO_2 Reduction Partnership, part of a $300 million program testing three regions in North America. In one, 1 million tons/year of compressed and

WORLDWIDE LARGE STATIONARY CO_2 SOURCES

Table 6

Process	No. of sources	Emissions, Million tons CO_2/year
Power	4,942	10,539
Cement production	1,175	932
Refineries	638	798
Iron and steel Industry	269	646
Petrochemicals industry	470	379
Oil and gas processing	Not available	50
Other fossil fuels	90	33
Bioethanol and bioenergy	303	91
Total	**7,887**	**13,466**

Source: Intergovernmental Panel on Climate Change Special Report, Cambridge University Press, 2005

US CTL CO_2 EMISSIONS PROJECTIONS

Table 7

Projected emissions from CTL, Million tons CO_2/year	Without CCS	With CCS
2015	10-41	1-8
2020	28-61	3-12
2030	175-230	17-46
2030 CTL emissions as % 2005 Global large stationary sources	1.3-1.7	0.1-0.3

Source: Energy Information Administration, International Energy Outlook 2007

liquefied CO_2 will be injected into a formation about 10,000 ft below North Dakota.[61]

These parties are joined by others outside the US, such as GreenGen in China, Coal21 in Australia, and the Asia Pacific Partnership.

Meaningful progress

The advancement of F-T-based technologies over the past few years have been measured but meaningful: one commercial unit is on stream, and three others are to start operating by the end of the decade; products have been tested and are used in commercial quantities; and technical problems have been confronted and are being resolved.

Yet important issues remain: capital cost, economics, and potential growth in the near term and the environmental impact of CO_2 emissions during CTL production in the long term.

Nevertheless, excitement exists in these areas fueled by higher global energy demand and rising crude prices. It is likely that, given all this, F-T-based technologies will continue to improve in commercial application and relevance, although they will remain a modest component of the overall search for clean, secure, and cost-effective transportation fuels.

Acknowledgment

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Producers' profits higher in fourth quarter, flat in 2007

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Laura Bell
Statistics Editor

The combined fourth-quarter 2007 (4Q07) earnings of a sample of US-based oil and gas producers and refiners increased from a year earlier. Many operators reported that production volumes climbed from a year earlier, but on the downstream side, refining margins were weak.

For all of 2007, the group posted a small decline in earnings, as high operating costs weighed on a majority of the companies' profits.

A group of service and supply firms reported a 98% increase in 4Q07 earnings compared with the fourth quarter of 2006, while revenues were up 19%. This sample, which includes drillers, suppliers, and engineering firms, reported a combined 69% surge in 2007 earnings compared with 2006 net income.

Meanwhile, a group of companies based in Canada reported a 61% earnings increase for the recent quarter compared with the final quarter of 2006. Some of these companies benefited from high oil prices and increased production volumes. Full-year earnings were little changed year-on-year for most of these firms.

Results

The collective 4Q07 earnings of a sample of 72 US-based oil and gas operators and refiners climbed 16.5% from the same 2006 period. Meanwhile, their revenues moved up a combined 32%.

Full-year results for this group of operators were not as good. These companies posted a combined 1.6% net loss for 2007, on revenues that were up 8% from 2006. While 10 of the companies posted a loss for the year, 15 recorded a net loss for 4Q07.

Higher oil price realizations and lower refining margins drove the quarterly results in opposite directions, and high operating costs continued to weigh on earnings.

Many of the independent oil and gas producers sampled recorded leaner profits in the recent quarter compared with the final 2006 quarter.

Although they both reported profits for 4Q07 and for 2007, large independent producers Anadarko Petroleum Corp. and Chesapeake Energy Corp. posted declines in earnings from a year earlier. Losses on derivatives weighed on Anadarko's net income, while exploration expenses moved lower for the quarter but climbed for the full-year.

Meanwhile, Chesapeake reported year-on-year production gains of 34% for the quarter and 23% for the entire year. But the company's earnings were affected by an unrealized after-tax mark-to-market loss of $180 million in 4Q07 and $257 million for the full year resulting from its oil, gas, and interest rate hedging programs.

Integrated firms

Most integrated companies reported

US OIL AND GAS FIRMS' FOURTH QUARTER 2007 REVENUES, EARNINGS

	Revenues		Net income		Revenues		Net income	
	4th quarter				Full year			
	2007	2006	2007	2006	2007	2006	2007	2006
	Million $							
Anadarko Petroleum Corp.	3,062.0	3,183.0	265.0	1,923.0	15,892.0	10,230.0	3,781.0	4,749.0
Apache Corp.	3,013.7	1,966.7	1,072.5	520.8	9,977.9	8,288.8	2,812.4	2,552.5
Apache Offshore Investment Partnership	2.1	1.9	1.3	1.1	7.8	10.4	4.8	7.1
Aspen Exploration Corp.[1]	1.4	1.1	0.2	0.3	2.7	2.1	0.3	0.6
Atlas America Inc.	366.3	201.4	(1.9)	14.4	1,207.6	749.3	35.3	45.8
ATP Oil & Gas Corp.	212.7	132.9	12.7	35.1	615.5	424.4	48.6	6.9
Aurora Oil & Gas Corp.	7.6	5.7	(0.7)	2.1	28.5	22.4	(4.4)	(1.9)
Basic Earth Science Systems Inc[2]	2.1	1.6	0.6	0.3	5.6	5.7	1.5	1.8
Berry Petroleum Co.	148.4	115.2	32.3	19.1	583.5	486.3	129.9	107.9
Bill Barrett Corp.	90.5	109.0	11.0	2.5	392.7	377.9	26.8	62.0
Brigham Exploration Co.	26.2	28.9	1.8	5.0	119.6	167.5	10.2	19.8
Cabot Oil & Gas Corp.	193.9	171.7	42.0	32.1	732.2	762.0	167.4	321.2
Cano Petroleum Inc.[1]	10.1	6.2	(0.7)	(0.4)	18.9	13.9	(1.0)	(0.8)
Carrizo Oil & Gas Inc.	40.0	24.2	5.6	4.3	126.5	83.9	15.5	18.2
Cheniere Energy Inc.	0.6	0.8	(52.6)	(93.3)	0.6	2.4	(181.8)	(145.9)
Chesapeake Energy Corp.	2,092.0	1,874.0	303.0	471.0	7,815.0	7,352.0	1,451.0	2,003.0
Chevron Corp.	61,410.0	47,746.0	4,875.0	3,772.0	220,904.0	210,118.0	18,688.0	17,138.0
Cimarex Energy Co.	438.5	295.6	130.0	58.7	1,431.2	1,267.1	346.5	345.7
CNX Gas Corp.	118.9	119.2	29.9	38.2	477.3	513.9	135.7	159.9
Comstock Resources Inc.	195.8	126.8	21.7	8.4	688.5	512.9	68.9	70.7
ConocoPhillips	52,685.0	41,519.0	4,371.0	3,197.0	194,495.0	188,523.0	11,891.0	15,550.0
Contango Oil & Gas Co.[1]	21.7	1.0	111.7	(2.3)	36.2	2.5	117.9	(2.6)
Credo Petroleum Corp.[3]	4.0	4.2	1.4	1.5	17.0	16.5	6.1	5.9
Cross Timbers Royalty Trust	5.2	7.2	5.2	7.2	20.2	25.8	19.8	25.4
Delta Petroleum Corp.	45.1	37.3	(30.0)	(10.5)	164.2	146.7	(149.3)	0.4
Denbury Resources Inc.	321.8	167.4	106.0	55.1	972.0	732.3	253.1	202.5
Devon Energy Corp.	3,197.0	2,418.0	1,316.0	582.0	11,362.0	9,767.0	3,606.0	2,846.0
Dorchester Minerals LP	18.3	15.6	12.4	10.0	65.4	74.9	43.0	50.2
El Paso Corp.	1,262.0	913.0	160.0	(166.0)	4,648.0	4,281.0	1,110.0	475.0
Encore Acquisition Co.	239.7	157.7	19.4	10.1	754.9	640.9	17.2	97.4
Energy Partners Ltd.	114.9	112.0	(73.4)	(52.5)	456.2	451.0	(80.0)	(50.4)
EOG Resources Inc.	1,250.8	931.4	361.2	242.6	4,190.8	3,912.5	1,089.9	1,299.9
Equitable Supply	131.4	125.8	75.3	68.5	501.7	488.6	263.5	269.2
Evolution Petroleum Corp.[1]	0.9	0.9	(0.8)	(0.4)	1.8	1.9	(1.4)	(0.9)
Exco Resources Inc.	145.5	211.4	(1.0)	(37.0)	0.9	0.6	0.1	0.1
ExxonMobil Corp.	111,965.0	86,858.0	11,660.0	10,250.0	404,552.0	377,635.0	40,610.0	39,500.0
Fidelity Exploration & Production Co.	88.1	61.3	43.5	38.4	288.1	251.2	142.5	145.7
Forest Oil Corp.	333.6	183.9	27.6	30.8	1,083.9	820.0	169.3	168.5
Frontier Oil Corp.	1,319.6	1,087.3	43.4	52.4	5,188.7	4,796.0	499.1	379.3
Gasco Energy Inc.	5.6	6.6	(2.8)	(1.8)	22.2	25.7	(104.4)	(55.8)
Helix Energy Solutions Group Inc.	500.2	395.8	121.3	163.4	1,767.4	1,366.9	320.5	347.4
Hess Corp.	9,456.0	7,155.0	510.0	359.0	31,924.0	28,718.0	1,832.0	1,920.0
HKN Inc.	6.3	6.5	0.5	0.3	24.3	30.3	3.2	(0.9)
Holly Corp.	1,444.8	940.9	49.8	47.7	4,806.8	4,033.0	334.1	266.6
Kinder Morgan CO2 Co. LP	222.4	183.7	144.7	115.3	824.1	736.5	252.8	295.3
Lucas Energy Inc.	0.9	0.4	0.2	0.2	1.9	1.0	0.3	0.4
Marathon Oil Corp.	18,185.0	13,807.0	668.0	1,079.0	65,207.0	65,449.0	3,956.0	5,234.0
Murphy Oil Corp.	5,608.6	3,346.5	206.1	88.4	18,439.1	14,307.4	766.5	644.7
Newfield Exploration Co.	398.0	427.0	313.0	82.0	1,783.0	1,673.0	450.0	591.0
Noble Energy Inc.	921.5	714.2	300.3	165.0	3,272.0	2,940.1	943.9	678.4
Occidental Petroleum Corp.	5,571.0	4,309.0	1,452.0	930.0	20,013.0	17,674.0	5,400.0	4,191.0
Parallel Petroleum Corp.	36.1	23.9	(8.3)	11.1	116.4	97.2	(4.7)	26.2
Penn Virginia Corp.	228.5	185.5	5.4	10.7	856.6	757.6	50.8	75.9
Petrohawk Energy Corp.	227.3	201.9	(0.1)	26.1	883.4	587.8	52.9	116.6
PetroQuest Energy Inc.	67.4	45.6	12.1	0.3	263.7	200.5	40.6	24.0
Pioneer Natural Resources Co.	530.9	389.8	204.7	27.7	1,833.3	1,500.9	372.7	739.7
Plains Exploration & Production Co.	493.6	207.6	80.0	383.6	1,279.2	1,024.0	158.8	597.5
Quest Resource Inc.	35.9	17.7	(24.6)	(41.3)	123.3	70.9	(30.4)	(48.5)
Questar Corp.	800.4	772.8	130.8	121.5	2,740.9	2,848.5	507.4	444.1
Quicksilver Resources Inc.	149.1	102.0	369.1	19.7	561.3	390.4	479.4	93.7
Range Resources Corp.	223.4	176.6	34.3	0.4	862.1	744.8	230.6	158.7
Rosetta Resources Inc.	111.1	72.6	17.4	13.2	365.2	276.3	57.2	44.6
San Juan Basin Royalty Trust	26.5	26.5	26.0	26.4	115.2	137.5	113.2	135.9
Southwestern Energy Co.	402.8	214.0	71.6	33.8	1,255.1	763.1	221.2	162.6
St. Mary Land & Exploration Co.	275.2	202.7	32.9	43.5	990.8	789.3	189.7	190.0
Stone Energy Corp.	201.6	179.2	64.9	(298.5)	765.4	691.5	181.4	(254.2)
Sunoco Inc.	13,162.0	9,036.0	(9.0)	123.0	44,728.0	38,715.0	891.0	979.0
Swift Energy Co.	196.4	144.6	(80.1)	35.3	654.1	550.8	21.3	161.6
Tesoro Petroleum Corp.	6,533.0	4,020.0	(40.0)	158.0	21,915.0	18,104.0	566.0	801.0
Ultra Petroleum	162.2	150.8	110.0	60.6	567.7	510.6	263.0	231.2
Unit Corp.	308.5	299.3	72.1	81.2	1,158.8	1,162.4	266.3	312.2
VAALCO Energy Inc.	37.0	15.9	2.0	5.3	125.0	98.3	19.1	40.3
Valero Energy Corp.	28,671.0	18,835.0	567.0	1,114.0	95,327.0	87,640.0	5,234.0	5,463.0
W&T Offshore Inc.	339.5	264.4	49.4	38.1	1,113.7	800.5	144.3	199.1
Warren Resources Inc.	20.2	9.6	4.0	0.3	61.6	36.1	11.4	6.4
Whiting Petroleum Corp.	251.1	171.9	45.8	28.0	818.7	778.8	130.6	156.4
Williams Cos. Inc.	571.5	418.6	185.3	134.6	2,093.0	1,488.0	731.0	530.0
XTO Energy Inc.	1,594.0	1,199.0	464.0	429.0	5,513.0	4,576.0	1,691.0	1,860.0
Totals	**342,558.9**	**259,600.5**	**31,107.6**	**26,705.5**	**1,224,999.0**	**1,136,253.6**	**113,889.2**	**115,782.2**

[1]2nd quarter. [2]3rd quarter. [3]4th quarter ending Oct. 31.

SERVICE-SUPPLY COMPANIES' FOURTH QUARTER 2007 REVENUES, EARNINGS

	Revenues — 4th quarter		Net income — 4th quarter		Revenues — Full year		Net income — Full year	
	2007	2006	2007	2006	2007	2006	2007	2006
	Million $							
Allis-Chalmers Energy Inc.	143.8	114.9	5.8	10.4	571.0	311.0	50.4	35.6
Baker Hughes Inc.	2,740.3	2,452.7	400.5	326.2	10,428.2	9,027.4	1,513.9	2,419.0
BJ Services Inc.[1]	1,285.5	1,184.3	172.2	207.1	NA	NA	NA	NA
Bronco Drilling Co. Inc.								
Cameron International Corp.	1,344.1	1,076.7	125.9	96.5	4,666.4	3,742.9	500.9	317.8
Diamond Offshore Drilling Inc.	666.7	578.2	164.9	221.4	2,567.7	2,052.3	846.5	706.8
Dril-Quip Inc.	118.3	132.8	24.5	32.2	340.8	443.0	32.6	86.9
Foster Wheeler Ltd.	1,465.5	1,193.3	78.1	63.1	5,107.2	3,495.0	393.4	262.0
GlobalSantaFe Corp.								
Grant Prideco	505.4	452.2	128.5	140.1	1,908.6	1,550.3	519.2	464.6
Grey Wolf Inc.	213.0	240.3	34.0	52.5	919.8	957.0	169.9	220.0
Gulfmark Offshore Inc.	91.5	69.0	12.7	30.6	309.2	252.2	99.0	89.7
Halliburton Co.	4,179.0	3,509.0	690.0	658.0	15,264.0	12,955.0	3,499.0	2,348.0
Horizon Offshore Inc.								
Hornbeck Offshore Services Inc.	101.1	65.3	25.8	16.6	339.0	274.6	94.8	75.7
Nabors Industries Ltd.	1,317.0	1,268.4	222.2	237.8	4,940.7	4,829.8	930.7	1,020.7
Noble Corp.	831.6	558.8	347.4	199.7	2,995.3	2,100.2	1,206.0	731.9
Oceaneering International Inc.	481.6	342.4	45.5	29.8	1,743.1	1,280.2	180.4	124.5
Parker Drilling Co.	180.8	146.3	34.6	37.2	654.6	586.4	104.1	81.0
Patterson-UTI Energy Inc.	521.0	638.7	85.1	156.3	2,116.5	2,552.5	438.6	673.3
Pioneer Drilling Co.[2]	105.4	113.3	14.8	24.0	316.3	315.8	39.6	67.0
Pride International Inc.	502.3	438.3	135.0	68.9	2,043.8	1,610.8	784.3	296.5
Rowan Cos. Inc.	623.6	410.9	138.5	62.4	2,115.9	1,538.8	483.8	318.2
RPC Inc.	186.2	160.3	34.7	47.3	690.2	596.6	142.0	177.8
Schlumberger Ltd.	6,248.0	5,350.0	5,177.0	1,131.0	23,276.5	19,230.5	5,176.5	3,710.0
Smith International Inc.	2,297.2	1,999.0	167.0	143.0	8,764.3	647.1	7,333.6	502.0
Transocean Inc.	2,077.0	1,186.0	1,056.0	621.0	6,377.0	3,882.0	3,131.0	1,385.0
Weatherford International Inc.	2,191.8	1,807.6	331.0	272.0	7,832.1	6,578.9	1,070.6	896.4
Totals	**30,417.7**	**25,488.7**	**9,651.7**	**4,885.1**	**106,288.2**	**80,810.3**	**28,740.8**	**17,010.4**

[1]1st quarter. [2]3rd quarter.

improved results from a year earlier. ExxonMobil Corp. posted record 4Q07 and annual results.

For the recent quarter, net income increased 14% to $11.66 billion. ExxonMobil reported its production increased nearly 1% from the fourth quarter of 2006. Excluding the expropriation of assets in Venezuela, divestments, effects of the Organization of Petroleum Exporting Countries' quota, and price and spend impacts on volumes, production was up nearly 3%.

For the year, ExxonMobil's upstream earnings were a record $26.5 billion, up $267 million from 2006 due to higher crude oil realizations and favorable sales mix effects, mostly offset by higher operating expenses, net unfavorable tax items, and lower natural gas realizations.

Marathon Oil Corp. reported reduced earnings for the quarter and for 2007. Net income slid 38% to $668 million for 4Q07. Annual earnings declined 24% to $4 billion while revenues for 2007 were up only slightly to $65.2 billion.

Marathon's downstream income was $4 million in 4Q07 and $2 billion for the year, compared to $533 million and $2.8 billion in the same periods of 2006, down in both periods mostly as a result of lower refining and wholesale marketing gross margins.

The refining and wholesale marketing gross margin per gallon was 4.8¢ in 4Q07, compared with 17.07¢ a year earlier, and 18.48¢ for 2007, compared with 22.88¢ for 2006.

"The fourth quarter of 2007 was a difficult quarter that included lower downstream margins driven primarily by rapidly rising crude prices; relatively flat upstream production due to delays in the Alvheim (Norway) project and unscheduled downtime for warranty repairs at our Equatorial Guinea LNG production facility, unscheduled downtime at our Athabasca oil sands project in Canada, and higher exploration costs," said Clarence P. Cazalot Jr., Marathon president and chief executive officer.

Refiners

Sunoco Inc., Tesoro Petroleum Corp., and Valero Energy Corp. posted mixed results for the quarter and the year.

While each of these refiners reported stronger revenues from the year-earlier periods, they each saw their net income drop. High crude prices and weak refining margins held earnings in check.

Valero reported 4Q07 income from continuing operations of $567 million, compared with $1.1 billion in the fourth quarter of 2006. Despite the decline, recent results were better than analyst expectations.

Analyst Eitan Bernstein with Friedman, Billings & Ramsey said that behind Valero's operating earnings were better-than-expected refining margins, which benefited from the company's use of lower-cost, lower-quality crude oils and other discounted feedstocks.

Valero said its complex refineries were able to take advantage of wide sour crude discounts during 4Q07, and it benefited from having a large, geographically diverse refining system, which provides relatively more earnings stability through exposure to multiple refining regions.

Canadian firms

Boosted by higher oil prices, a sample

CANADIAN OIL AND GAS FIRMS' FOURTH QUARTER 2007 REVENUES, EARNINGS

	Revenues — 4th quarter		Net income — 4th quarter		Revenues — Full year		Net income — Full year	
	2007	2006	2007	2006	2007	2006	2007	2006
	Million $ (Can.)							
Canadian Natural Resources Ltd.	3,200.0	2,826.0	798.0	313.0	12,543.0	11,643.0	2,608.0	2,524.0
Enbridge Inc.	3,198.5	2,785.7	250.4	172.9	11,919.4	10,644.5	707.1	622.3
EnCana Corp.	5,732.0	3,632.3	1,069.1	655.1	21,190.8	16,203.9	3,911.9	5,584.7
Husky Energy Inc.	4,760.0	3,084.0	1,074.0	542.0	15,518.0	12,664.0	3,214.0	2,726.0
Imperial Oil Ltd.	6,740.0	5,631.0	886.0	794.0	25,443.0	24,788.0	3,188.0	3,044.0
Nexen Inc.	1,846.0	1,281.0	194.0	77.0	6,604.0	5,386.0	1,086.0	601.0
Pennwest Energy Trust	538.6	447.3	127.0	122.9	2,008.0	1,645.7	175.5	665.6
Petro-Canada	5,434.0	4,550.0	522.0	384.0	21,250.0	18,669.0	2,733.0	1,740.0
Suncor Energy Inc.	4,958.0	3,787.0	963.0	358.0	17,933.0	15,829.0	2,832.0	2,971.0
Talisman Energy Inc.	2,085.0	1,840.0	656.0	598.0	7,919.0	7,646.0	2,078.0	2,005.0
TransCanada Corp.	2,189.0	2,091.0	377.0	269.0	8,828.0	7,520.0	1,223.0	1,079.0
Totals	**40,681.1**	**31,955.3**	**6,916.5**	**4,285.9**	**134,409.2**	**117,473.1**	**20,455.5**	**20,478.6**

of oil and gas producers, refiners, and transporters each recorded earnings increases for the recent quarter. Meanwhile, results for the year were lower for a few of the 11 companies in the group.

EnCana Corp. reported a 63% gain in net income for 4Q07 and a 30% decline in full-year 2007 earnings.

"With strong production growth and successful price hedges that delivered a $1 billion benefit to 2007 cash flow, our company's cash flow, operating earnings, and free cash flow all increased substantially in a year when our industry faced many challenges," said Randy Eresman, EnCana president and chief executive officer. "In 2007, production from our key natural gas resource plays grew 14%, while production from our integrated oil projects increased 25%. Our newly established refining business also delivered great results, achieving twice the cash flow we expected during its inaugural year," he said.

For the quarter and for 2007, Nexen Inc. posted large increases in net income due to strong oil and gas production from Buzzard field in the North Sea, robust commodity prices, and high cash operating margins. Net income in 4Q07 grew 152%, and for the year, the company's earnings climbed 81%.

Nexen reported that although average benchmark West Texas Intermediate prices for the year increased 9%, it grew its cash netbacks per barrel by 32%.

Suncor Energy Inc. said that the 169% jump in its 4Q07 earnings primarily reflects higher oil sands operating revenues, as stronger price realizations more than offset lower production in the quarter.

Suncor's earnings also benefited from a lower oil sands royalty expense. But earnings were tempered by lower refining and marketing earnings due to a planned outage at the company's Sarnia refinery that resulted in increased product purchases to meet customer commitments.

For the year, Suncor's net income declined almost 5% due to maintenance that reduced oil production and increased operating expenses, but higher oil prices partly offset these factors.

Service, supply firms

A sample of 25 oil service and supply companies recorded robust combined earnings increases for 4Q07, but a dozen companies in the group reported declines in net income from a year earlier. For the year, seven of the firms posted lower earnings from 2006. None of the companies in the sample posted a loss for either the quarter or the year.

For 4Q07, Rowan Cos. Inc. had record net income of $138.5 million compared with $62.4 million a year earlier. And 4Q07 revenues were a record $623.6 million, up from $410.9 million in the 2006 fourth quarter. Full-year results climbed as well on strong rig utilization and day rates.

Nabors Industries Ltd. announced net income of $222.2 million for 4Q07, compared with $237.8 million in the fourth quarter of 2006.

The quarter's results include the previously disclosed gain on the sale of a portion of the company's oil and gas holdings, a smaller loss in certain investments which losses the company believes are over, and during the quarter the Canadian statutory federal tax rate was reduced, resulting in a reduction in Canadian deferred taxes. Nabors' results also partially reflect the company's repurchase of 3.93 million shares during the fourth quarter at an average cost of $27.12/share. ✦

US Senate votes to extend OCS, oil shale moratoria

Nick Snow
Washington Editor

The US Senate voted Mar. 13 to extend moratoria on federal oil and gas leasing on most of the Outer Continental Shelf as well as on developing oil shale resources.

The actions came on a pair of amendments to the budget bill for fiscal year 2009. Both proposed establishing a deficit-neutral reserve fund to encourage consumers to buy more-efficient wood stoves and install smart electricity meters. Both supported carbon capture and storage from coal. But they differed in their treatment of OCS leasing expansion and oil shale resources in

Colorado, Utah, and Wyoming.

The first amendment, submitted by Sen. Bill Nelson (D-Fla.), deleted oil shale completely and limited OCS oil and gas development to areas not covered by congressional moratoria or presidential withdrawals. It passed by 56 to 43 votes.

Nelson proposed his amendment to head off one by Sen. LaMar Alexander (R-Tenn.), which was defeated by 51 to 47 votes despite Alexander's limiting new federal OCS leasing to tracts off Virginia. "That is the proverbial camel's nose under the tent and what we fight about each year: oil drilling off the coast," the Floridian said.

Alexander responded that Nelson's approach would strike provisions "which will tend to reduce the price of gasoline and reduce the price of natural gas and make us less dependent on people in other countries who are trying to kill us."

His oil shale provision would have overturned a moratorium enacted as part of the US Department of Interior's fiscal 2008 budget in December as part of the omnibus budget bill. This moratorium delays a program authorized under the 2005 Energy Policy Act.

Sen. Pete V. Domenici (R-NM), the Energy and Natural Resources Committee's ranking minority member, said the oil shale program delay was "somebody in one of those states putting a moratorium on in appropriations with nobody around." He said, "This senator wasn't there. If I were there, it would not have happened. We would not have had a bill."

But Sen. Ken Salazar (D-Colo.) said the Alexander amendment overturning the oil shale moratorium should be defeated. "We have a thoughtful way to move forward with that program. This is putting the horse ahead of the cart. This is the wrong way to go," Salazar said.

In a statement after the Senate recessed for the day, Salazar said the US Bureau of Land Management "is rushing toward a commercial lease sale and the potential environmental impacts

WATCHING GOVERNMENT

Nick Snow, Washington Editor

Colorado using the moratorium

Several coastal states have used the congressionally imposed federal leasing moratorium for about 30 years to keep oil and gas activity away from their shores. Colorado now seems willing to use it onshore.

Democrats in the state's congressional delegation inserted a provision into the fiscal 2008 budget reconciliation act in December which suspends federal oil shale leasing for a year. The US Senate voted to extend the delay through fiscal 2009.

Meanwhile, Assistant US Interior Sec. C. Stephen Allred told Colorado Gov. Bill Ritter Jr. that the Bureau of Land Management is incorporating concepts Ritter proposed in December into its management plan for the Roan Plateau on the state's Western Slope.

This includes placing 38,470 acres, or more than half the federal acreage on the plateau, off-limits to surface disturbance and scheduling development in phases to assure that no more than 1% of the remaining federal land's surface would be disturbed at any one time.

State would participate

"BLM will continue to work closely with the state of Colorado on implementing the plan. Also, we continue our offer to fund state employees to be colocated with our employees to provide implementation oversight," Allred said in a letter to the governor.

Ritter responded that he appreciated the consideration of his proposal. "However, I strongly disagree with and am disappointed in the department's decision not to pursue phased leasing and not to expand areas that would be off-limits," he said.

Ritter called his plan "a uniquely Colorado solution" which struck a good balance that would benefit the state's economy, communities, and energy industry while minimizing environmental impacts. "Our plan to pursue phased leasing received strong support from a broad spectrum of stakeholders," he said.

Rep. Mark Udall (D-Colo.) said it was clear BLM would have to reopen its record of decision for the Roan Plateau management plan when he and Rep. John Salazar (D-Colo.) asked the agency to consider Ritter's proposal in December.

'Just a charade'

"BLM's refusal to do so is deeply disappointing because it means a refusal to properly fulfill what the Bush administration should, but evidently does not, recognize as its obligation to the people of Colorado. The administration's decision leads me to question whether or not granting the additional time for comments was just a charade," he said.

Sen. Ken Salazar (D-Colo.), said, "I will do all I can to stop the federal government, and I will not let them turn Colorado's West Slope into a sacrificial zone for unimpeded oil and gas development. Their 'drill under every rock approach' will degrade the long-term economy and natural wonder of the Western Slope."

Ritter said the state would begin discussing legislative alternatives with its congressional delegation. Salazar and Udall separately said they are ready to act, raising the possibility of a second onshore leasing moratorium in Colorado. ✦

are unknown." He said, "Because of this uncertainty, we do not even know whether state and local government support a commercial lease sale."

Sen. Robert Menendez (D-NJ) opposed Alexander's proposal because of its OCS provision. "If we want to end our addiction and we care about prices, then don't do it by striking another vein, ultimately, of the same energy resource. We should do it by considering alternatives. This amendment does nothing about that but it does undermine the moratorium on the OCS," he said. ✦

Inquiry launched into DOJ plea agreement with BP

Nick Snow
Washington Editor

Two leading Democrats on the US House Energy and Commerce Committee announced an investigation into the US Department of Justice's Oct. 22 plea agreement with BP concerning the company's violations of federal Clean Air Act provisions.

"We have examined the plea agreement with respect to BP's admitted criminal conduct that led to the Mar. 23, 2005, explosion at its Texas City refinery, which killed 15 and injured more than 70 workers," Reps. John D. Dingell (D-Mich.), the committee's chairman, and Bart Stupak (D-Mich.), who chairs its Oversight and Investigations Subcommittee, said in a Mar. 12 letter to US Attorney General Michael B. Mukasey.

"We question whether DOJ has followed congressional intent by recommending this plea agreement since it does not appear to either protect the safety of workers and residents near this refinery or ensure that a proper signal is sent to BP's senior management whose budgeting decisions led to this tragedy," they continued.

Under the agreement, BP subsidiary BP Products North America agreed to plead guilty to a single count of violating the Clean Air Act, pay a $50 million criminal fine and serve 3 years of probation. The criminal fine was the largest ever assessed for a Clean Air Act violation, DOJ said in announcing the plea agreement on Oct. 25. It added that during the probation, the company will have to spend an additional estimated $265 million to complete facility-wide relief valve studies and renovations of its flare systems.

"We also have questions about whether DOJ has fulfilled its responsibilities to victims. In particular, we want to understand whether DOJ met its obligation to give victims a timely opportunity to confer before it negotiated a plea agreement, as required by the attorney general's guidelines," Dingell and Stupak said.

They asked Mukasey and DOJ to respond to five basic questions:

- Did decisions made by BP PLC., the parent company, aid and abet non-compliance by BP Products North America, which Dingell and Stupak described as "a fourth-tier subsidiary," at Texas City and, if so, did the executives have culpability, and should they have been held to account?
- By charging the subsidiary instead of the corporate parent, did DOJ consider the totality of BP's corporate misconduct when assessing "the history and characteristics of the defendant" as part of the criminal penalty process?
- Why didn't the plea agreement mandate future Clean Air Act compliance in addition to settlement agreement with the US Occupational Safety and Health Administration and the Texas Commission on Environmental Quality? Dingell and Stupak noted that on Jan. 14, a 32-year employee at the Texas City refinery was killed when a 500-pound steel lid was suddenly and violently blown from a vessel that was connected to an ultracracker which was being restarted, and that the US Chemical Safety Board is investigating the accident.
- Is a $50 million criminal fine an adequate deterrent to future noncompliance?
- Did DOJ evade the purposes and intent of the Crime Victims Rights Act and the attorney general's victims and witness assistance guidelines?

Dingell and Stupak asked Mukasey and DOJ to provide responses within 10 days. They want documents which DOJ and the US Environmental Protection Agency prepared concerning benefits to BP in not complying to federal regulations at the refinery and communications about efforts to notify victims before plea negotiations were completed. Also documents regarding possible consolidation of press announcements regarding this felony plea with a deferred prosecution plea of a BP propane price-fixing case and a misdemeanor plea stemming from North Sea crude oil pipeline leaks in 2006.

The committee does not expect any documents that were prepared for a grand jury, the lawmakers said. ✦

Worldwide oil, gas transactions, total value dips

Paula Dittrick
Senior Staff Writer

The total transaction value for worldwide upstream corporate and asset deals slipped to $154 billion in 2007 compared with $166 billion in 2006, consultants said in an annual report.

John S. Herold Inc. and Harrison Lovegrove & Co. Ltd. on Mar. 12 released highlights of their joint 2008

Global Upstream Mergers and Acquisitions Review, an analysis of more than 330 major upstream transactions announced during 2007.

The pricing for transactions declined during 2007 after having hit two consecutive records in 2005-06. John S. Herold is an IHS company, and Harrison Lovegrove belongs to Standard Chartered Bank.

"The industry has been facing rough seas" and those conditions are likely to be repeated in 2008, said Christine Juneau, John S. Herold chief operating officer, and Martin Lovegrove, Harrison Lovegrove vice-chairman, oil and gas, Standard Chartered Bank.

"Access to opportunities has continued to become more restricted and securing approval for project and deal go-aheads has lengthened," they said in a joint statement. "Ironically, the industry had better margins at $30[/bbl] oil than at the yearend 2007 price of $96/bbl."

Industry profit margins, as a percentage of revenue, have declined since 2005 based upon West Texas Intermediate future prices, according to statistics from the previously released John S. Herold and Harrison Lovegrove 2007 Global Upstream Performance Review.

The industry margin was 17% in 2005 compared with an estimated 2008 margin of 10%, the upstream performance review said.

Proved reserves values down

Worldwide weighted average pricing for proved reserves fell to $9.99/boe, down 22% from 2006. The average 2007 proved reserves value in the US and Canada was $16.57/boe, down 7%. Elsewhere, proved reserves prices were $5.05/boe, down 44%.

Reserves values in the former Soviet Union dampened global transaction values, the review said. Excluding FSU deals, worldwide weighted average and median proved reserves pricing held roughly flat with 2006 pricing.

For worldwide transactions involving proved plus probable reserves, the weighted average pricing declined 10% compared with 2006. But excluding FSU transactions, the global average for proved plus probable reserves pricing increased more than 20%.

The number of worldwide asset transactions surged 30% to 240 deals in 2007 compared with 2006. About 75% of the transactions involved properties in the US and Canada. Worldwide, asset transactions reached a total $89 billion in 2007.

Meanwhile, the 2007 worldwide total for transactions involving corporations dropped to $65 billion. It was the first year since 2004 that industry reported no individual corporate transactions greater than $10 billion.

A surge of transactions worth $5-$10 billion drove corporate transactions. The total for those transactions of $5-10 billion jumped to nearly $34 billion during 2007 from a total of $5 billion in 2006, the review showed.

Transactions involving state-owned or state-controlled oil and gas companies (NOCs) slipped from a record set in 2006 when NOCs accounted for one third of global upstream M&A spending (OGJ, Mar. 26, 2006, p. 30).

During 2007, NOCs accounted for $43 billion, or 29%, of total worldwide deal value during 2007. Total transaction value for NOCs outside of their home countries was $13 billion in 2007, the same level as 2006. ✦

NPRA: Valero looking to sell three refineries

David N. Nakamura
Refining/Petrochemical Editor

Valero Energy Corp. is conducting a "strategic alternative review" of three of its refineries in an effort to possibly sell them, according to Chief Executive Officer Bill Klesse.

Speaking Mar. 11 at the National Petrochemical & Refiners Association annual meeting in San Diego, Klesse said that given Valero's entire refining portfolio, it does not make sense to invest in every plant. "Some of our plants are clearly worth more to others and it is a real opportunity to some other companies. The Lima refinery [in Ohio], which we sold last year, was a good fit for Husky [Energy Inc.] (OGJ, May 14, 2007, Newsletter).

"Today, we are looking at strategic alternatives...at Aruba, Memphis, Tenn., and Krotz Springs, La. We've elected not to invest further in those refineries," Klesse said, adding, "We expect to complete this strategic alternative review by the end of the year."

Klesse said Valero would still be interested in acquisitions, but that the company does not necessarily need to make any. Valero is focusing its capital investment on its existing refineries.

"We have two very large projects that we've announced on the US Gulf Coast," he said. "Our capital spending this year should be somewhere between $4 and 4.5 billion. I would expect next year's to be in the $5 billion range."

Prices, taxes

Klesse also outlined Valero's positions on future gasoline trends in the US as well as tax issues.

He said gasoline demand may increase in the US this year, but probably will be flat and maybe even more likely decrease. "The high retail prices and the weak economy are having a very negative impact on demand," he said. "Our view is that crude oil prices are going to stay high. The world economy has shown that it can handle these high prices."

Regarding the renewable fuel standard, Klesse says an ethanol mandate, tax credit, and import duty are not all needed. "The ethanol program and other programs like it are just a huge

transfer of wealth from [the refining] industry to the Midwest farmer," he said. "Since we have a mandate, let's at least eliminate the excise tax credit on ethanol. This is pork-barrel legislation at its worst."

Klesse said the US gasoline supply will likely contain 10-15% ethanol in the next few years. He noted, however, that ethanol volumes above this level are "totally impractical, totally uneconomical, and just crazy."

Due to the RFS mandate and CAFE standards, Klesse believes that "to maintain the US gasoline producing capability, our industry may need our government to increase import duties on gasoline and blendstock to protect the [refining] industry and prevent the dumping of gasoline in the US market."

Klesse also said Valero "would support an increase in the federal excise tax on transportation fuels combined with the elimination of the ethanol tax credit, which is not needed because we have the mandate." He said, "This would generate significant funds [to improve road infrastructure and eliminate bottlenecks]." ✦

Gulf lease sales attract $3.7 billion in high bids

Two federal sales of offshore oil and natural gas leases in the eastern and central planning areas of the Gulf of Mexico have attracted a total of more than $3.7 billion in apparent high bids. Central Gulf Lease Sale 206 and Eastern Gulf Lease Sale 224, both conducted by the US Department of the Interior's Minerals Management Service, were held back-to-back Mar. 19 in New Orleans.

Central Lease Sale 206, held first, attracted $3,677,688,245 in apparent high bids, setting a record in US leasing history for high bids since area-wide leasing began in 1983, MMS reported. In Sale 206 the agency received 1,057 bids from 85 companies on 615 tracts.

For Eastern Lease Sale 224, held second, MMS received 58 bids from 6 companies on 36 tracts resulting in $64,713,213 in apparent high bids.

"Today's lease sales mark an important milestone in sharing substantially increased revenue from offshore oil and gas development with states willing to support it," said Interior Sec. Dirk Kempthorne. "Beginning with Lease Sale 224, Louisiana, Mississippi, Alabama, and Texas will receive a greater share in all these revenues, including bids, rental payments, and royalties," he said.

Sale details

Central Sale 206 offered 5,569 tracts comprising about 29.8 million acres in federal areas off Louisiana, Mississippi, and Alabama. The acreage lies 3-230 miles offshore in 3-3,400 m of water.

About 34% of the tracts receiving bids in this sale are in ultradeep water, more than 1,600 m. The deepest tract to receive a bid is Lloyd Ridge Block 286, which lies in 3,076 m of water. The highest bid received on a block was $105,600,789 submitted by Anadarko Exploration & Production Co. LP, Murphy Exploration & Production Co.-USA, and Samson Offshore Co. for Green Canyon Block 432.

Eastern Sale 224 encompasses 118 whole or partial unleased blocks covering 546,971 acres in the gulf's eastern planning area. The acreage is 125 miles and more offshore—south of the Florida panhandle and west of the Military Mission Line—in 810-3,113 m of water.

The sale is the first in which the revenue-sharing provisions of the Gulf of Mexico Energy Security Act of 2006 (GMESA 2006) will start immediately. The states of Alabama, Mississippi, Louisiana, and Texas will share in 37.5% of the high bids on whole and

RESULTS OF CENTRAL GULF OF MEXICO LEASE SALE 206

Top 10 companies based on total number of high bids submitted

Company	Total high bids	Sum of high bids, $
1. BP Exploration & Production Inc.	63	336,575,445
2. Chevron USA Inc.	49	240,987,863
3. BHP Billiton Petroleum (Deepwater) Inc.	42	95,652,498
4. Cobalt International Energy LP	36	389,056,079
5. Devon Energy Production Co. LP	35	94,795,020
6. Repsol E&P USA Inc.	32	95,477,260
7. Eni Petroleum US LLC	31	113,125,970
8. Hess Corp.	25	437,541,152
9. LLOG Exploration Offshore Inc.	25	104,854,780
10. Stone Energy Corp.	25	43,019,844

Companies submitting Top 10 single highest bids

Company	Block	Water depth, m	High bid amount, $
1. Anadarko E&P Co. LP* Murphy E&P Co.-USA Samson Offshore Co.	Green Canyon 432	800-<1,600	105,600,789
2. Marathon Oil Co.* Hess Corp.	Walker Ridge 226	>2,000	93,024,910
3. Cobalt International Energy LP	Green Canyon 858	1,600-2,000	85,418,889
4. Chevron USA Inc.	Green Canyon 945	1,600-2,000	81,063,073
5. Cobalt International Energy LP	Keathley Canyon 163	1,600-2,000	74,418,889
6. ConocoPhillips Co.	Keathley Canyon 654	>2,000	73,448,446
7. Marathon Oil Co.* Hess Corp	Walker Ridge 269	>2,000	73,424,910
8. Hess Corp	Keathley Canyon 469	1,600-2,000	71,489,800
9. Hess Corp	Garden Banks 829	800-1,600	71,489,800
10. Statoil Gulf of Mexico LLC	Green Canyon 480	800-1,600	68,525,300

*Denotes the submitter.
Source: US Minerals Management Service

partial blocks in the eastern planning area. These four gulf producing states also will share in 37.5% of all future revenues generated from the acreage leased today in the gulf's eastern planning area.

The enhanced revenue-sharing program was mandated by GMESA 2006, and no royalty relief will be issued with these leases.

With Central Sale 206, the royalty rate for blocks in all gulf water depths is increased to 18¾% from 16⅔%, MMS said.

In addition, 12.5% of revenues from today's lease sales will be deposited into the Land and Water Conservation Fund for use by states to enhance parklands and for other conservation projects.

Eastern Sale 224 is the only sale scheduled to be held in the eastern gulf under the current 5-Year Outer Continental Shelf oil and gas leasing program. The acreage included in this latest eastern sale was last available for lease in 1988.

Currently there are more than 7,000 leases in the gulf that account for 25% of the nation's domestically produced oil and 15% of the domestically produced natural gas.

Top bidders

The top five companies submitting the highest dollar amount of high bids for Central Sale 206 included Hess Corp., 25 bids, $437,541,152; Cobalt International Energy LP, 36 bids, $389,056,079; BP Exploration & Production Inc., 63 bids, $336,575,445; ConocoPhillips Co., 20 bids, $323,891,298; and Chevron USA Inc., 49 bids, $240,987,863.

The top five companies submitting the highest dollar amount of high bids for Sale 224 included BHP Billiton Petroleum (Deepwater) Inc., 27 bids, $47,858,420; Anadarko E&P, 7 bids, $12,754,728; Murphy Exploration & Production Co., 7 bids, $3,188,682; Eni Petroleum US LLC, 1 bid, $527,006; and Shell Offshore Inc., 1 bid, $384,377. ✦

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Switzerland irks US with gas deal

Switzerland is not a household word for most people in the oil and gas industry. After all, how much can be said about a country that produces no oil of its own and consumes just 278,000 b/d?

Well, much has recently been said about Switzerland's involvement in the petroleum industry. Consider US concerns about an agreement signed on Mar. 17 between Switzerland's Elektrizitaets-Gesellschaft Laufenburg and National Iranian Gas Export Co.

"We have conveyed to the Swiss that major new oil and gas deals with Iran send precisely the wrong message at a time when Iran continues to defy UN Security Council resolutions," the US embassy in Bern said in a statement.

The US embassy said it believes the deal "violates the spirit of the sanctions" imposed on Iran by the UN Security Council as part of an effort to try to force Iran to give up its program of uranium enrichment and cooperate further with the International Atomic Energy Agency.

No problem

But the Swiss see nothing wrong with the agreement. Joachim Conrad, member of EGL's executive management and head of EGL's gas division, said the agreement with NIGEC is a strategic milestone in the company's gas business.

"Natural gas from Iran is necessary to the opening of a fourth gas transportation corridor to Europe," Conrad said. "This corridor will ensure diversification and security of supply on the continent as Europe needs to tap into new gas sources in the immediate future, and EGL today made an important contribution to reaching this goal."

Swiss Foreign Minister Micheline Calmy-Rey, who attended the signing ceremony between EGL and NIGEC, agreed with that assessment, saying the agreement did not violate UN sanctions and served only to secure uninterrupted energy supplies for Switzerland.

Strategic interests

"We have a strategic interest to secure our gas supplies and diversify our gas suppliers," Calmy-Rey said. She said the agreement may even reduce Europe's dependency on energy supplies from Russia. "We are decreasing our dependence, and the dependence of Europe, on Russian gas."

The duration of EGL's natural gas procurement contract with NIGEC is 25 years. The contracted gas quantities will allow EGL to cover its 50% share of transportation capacity of the Trans Adriatic Pipeline (TAP), which it will build with Norway's StatoilHydro ASA (OGJ online, Feb. 14, 2008).

A first delivery of natural gas by NIGEC to EGL is planned for 2009, assuming that the necessary transport rights are in place by then. Larger gas volumes will follow in 2012, when the TAP project is expected to become operational, and gas deliveries from NIGEC will reach as much as 5.5 billion cu m/year in a second phase of the contract.

But the US won't give up, declaring in its statement that, "We are disappointed and will continue our discussions with the Swiss regarding the need to maintain pressure on Iran to meet its international obligations." ✦

BC's Muskwa shale shaping up as Barnett gas equivalent

Alan Petzet
Chief Editor-Exploration

An Upper Devonian shale gas play, emerging the past 2-3 years in remote northern Northeast British Columbia, has the potential to become one of North America's larger gas fields.

The play is for gas in the Muskwa shale in the Horn River basin 775 miles northwest of Calgary.

EOG Resources Inc., Houston, with 140,000 acres in the play, estimates 70 tcf of gas in place in the shale of which a net 6 tcf seems recoverable. Gas in place in the Muskwa on EOG lands averages 318 bcf/sq mile, 2.5 times that of the Barnett shale in Johnson County, Tex., in the Fort Worth basin south of Fort Worth.

EnCana Corp. and Apache Corp. hold a combined 400,000 acres in the play in a 50-50 area of mutual interest. Other independents have smaller leaseholds, and the total area under lease is estimated at 600,000-700,000 acres.

EOG said its land is in the richest gas-in-place portion of the play, where the Muskwa is half again as thick as its thickest Johnson County Barnett shale.

The play is sparsely drilled so far, so much so that Apache told analysts it is still determining whether it is commercial. If commercial, it would expose Apache to 3-6 tcf of net recovery.

EOG said it expects Muskwa to develop more slowly than the Barnett.

The company estimated that industry will have drilled a total of 17-21 horizontal wells in the play by the end of 2008. EnCana-Apache will drill nine horizontal wells and EOG two vertical and four to eight horizontal wells this year.

Formations compared

The Muskwa shale, which lies at about the same depth as the Barnett, is thicker and has higher pressure than the Barnett in the Northeast BC area south of Fort Liard, NWT, EOG said.

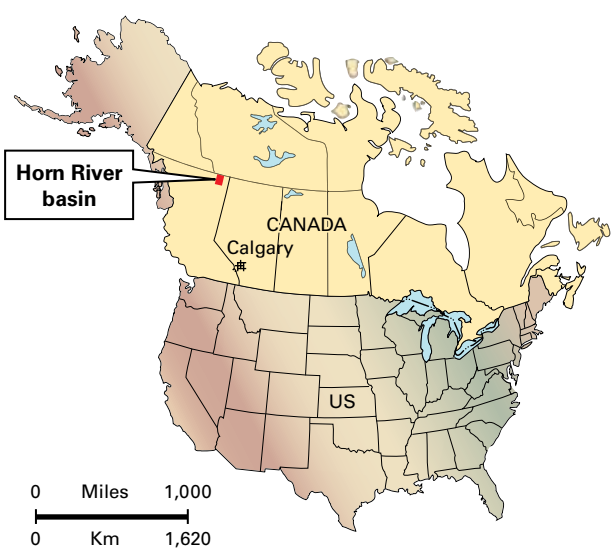
Muskwa is geologically less complex than the Barnett, with equivalent permeability of 230 nanodarcies, equivalent 4% gas-filled porosity, 2.8% vitrinite reflectance, better silica content at 65%, and no water.

The Muskwa has continuous gas thicknesses in the upper and lower parts of the formation, which will smooth completions. EOG has a large proprietary data base of core, log, and microseismic data from area wells that were drilled through the formation.

The Muskwa has limited faulting, and the carbonate that underlies it has no sinkholes, EOG added.

EOG's expectations in the Barnett grew from a 10-12% recovery factor in 2004 to as much as 20% by late 2005 to 30% maximum in early 2007 and

MUSKWA SHALE GAS PLAY



Source: EOG Resources Inc.

Shale rock properties

	Muskwa, Horn River basin, BC	Barnett, Johnson County, Tex.
Thickness, ft	530	355
Permeability, nd	230	250
Gas-filled porosity, %	4	4.5
Maturity, Ro	2.8	2.2
Silica content, %	65	55
Gas in place, bcf/sq mile	265	193

Source: EOG Resources Inc.

then to 50-55% in late 2007.

In the Muskwa, the company initially assumes 20-30% recovery. Using 20% recovery and viewing 60% of its acreage as prospective is how the company reached the initial estimate of 6 tcf recoverable. The calculation takes into account 12% carbon dioxide in the gas and 85% net revenue interest.

Wells would likely be on 40-acre spacing initially.

Early drilling

Two large gas pipelines flank the Muskwa play.

EOG plans to begin production in June 2008 from its first two wells through a 15-km gathering line to a 24 MMcfd conditioning plant and doesn't see important contributions of production until 2010-11.

Apache, which has referred to the shale as "Ootla," plans to experiment with different multistage fracs this year to enhance flow rates.

EOG's first vertical Muskwa well, in 2006, made 750 Mcfd after a two-stage frac.

Its first horizontal well in 2007 tested 5 MMcfd after a six-stage completion in 3,000 ft of mostly off-azimuth (to formation fractures) lateral. Reservoir simulation of that well indicated ultimate recovery of 4-6 bcf/well if the full length of the lateral had been on azimuth.

EOG's second horizontal well tested 4.2 MMcfd after a five-stage completion in a 1,700-ft lateral. Its third well made 3.5 MMcfd with a five-stage completion in a 1,600-ft lateral.

A 120 MMcfd gas processing plant at Fort Nelson, BC, has a 450 MMcfd capacity if existing trains are restarted, and even more capacity will be needed if the play turns out to be as large as the Barnett, EOG said.

Other considerations

EOG sees at least four reasons for caution in its expectations for Muskwa play progress.

It has few drilling results, although the company reported a one-third drilling time reduction on its second 2008 horizontal well.

The longest an existing well has been on production is 10 months.

Permits must be obtained from native corporations that own much of the basin's surface rights.

Assembling a technical staff to operate in the remote basin will be a challenge.

Overall, it estimated that the play's rate of return will not be quite that of the Barnett shale but will still be acceptable.

EOG floated early development well cost assumptions of $9.4 million/well plus $600,000 for leasehold and tie-in, but Apache indicated that much lower costs should be obtainable.

Other participants in the play include Nexen Inc., Devon Energy Canada, and Crew Energy Inc., Calgary. Storm Ventures International Inc. and Storm Exploration Inc. were pursuing acreage in late 2007, and the province is to offer more leases this month and next. ✦

New York to get Utica shale exploration

Gastem Inc., Montreal, took a farmout from Utica Energy LLC, private New York operator, to drill one horizontal and five vertical wells in New York state by Jan. 16, 2009.

Gastem will earn a 65% working interest in all 29,000 acres of leases held by Utica Energy and in other leases that may be obtained during the year.

Drilling is to start in the second quarter subject to permitting and other approvals. The companies declined to identify the location more precisely.

Gastem's program will target gas in the Upper Ordovician Utica shale formation, already the object of exploration on Gastem's Yamaska property west of Drummondville, Que., in the St. Lawrence lowlands.

Utica Energy drilled, completed, and ran frac jobs on two test wells on its acreage in mid-2007. Other intervals identified during logging, notably the Devonian Marcellus shale, will also be tested for gas potential. The acreage is near gas pipelines.

Gastem named Orville Cole president and chief executive officer of Gastem USA, a wholly owned subsidiary, which will administer the company's operations in the US. ✦

Cuba

Sherritt International Corp., Toronto, plans to drill one exploratory well and 11 development wells as part of its companywide $150 million budget for 2008.

Sherritt expects its 2008 gross working interest oil production in Cuba to be consistent with the 2007 average of 30,637 b/d, which was steady with 2006 output. The fourth quarter 2007 average was 31,453 b/d.

The company signed one production-sharing agreement for a contiguous block in Cuba in 2007 and in early 2008 was negotiating terms and conditions of an enhanced oil recovery concession and several exploration blocks.

India

Oilex Ltd., Sydney, will try to establish oil and gas production in abandoned Cambay gas field in Gujarat, India.

The company has spud the first of six appraisal and development wells to gather lithological and fluid data from Oligocene and Eocene formations.

Four of the wells will also test deeper targets at the base of the Eocene section and fractured Deccan basalts that are oil reservoirs on the Gujarat State Petroleum Corp.-operated Tarapur block to the north.

Oil & Natural Gas Corp. discovered Cambay in 1957 and developed it as a gas field that produced 52 bcf until shut-in. Best estimate of hydrocarbons in place in the OS II and EP IV sandstones only total 48 million stb of oil, 14 million stb of condensate, and 356 bcf of gas. Working interests are Oilex 45% and GSPC 55%.

Nicaragua

Norwood Resources Ltd., Vancouver, BC, drilled a stratigraphic test to 650 ft at Maderas Negras to assist with casing design for Maderas Negras-1, projected to at least 6,500 ft in the Sandino basin onshore Nicaragua.

The well logged oil shows at 75-650 ft and a weak gas show at 650 ft. The deeper well is to spud by the end of March.

A petrophysical interpretation by Schlumberger identified prospective intervals in the Paleocene Brito formation that were not previously identified or tested in the 2007 program, Norwood said.

The Maderas Negras-1 wellsite is 2.75 miles north and 3,000 ft updip of the San Bartolo well.

Nigeria

Addax Petroleum Corp., Calgary, successfully appraised the Kita Marine oil discovery off southeastern Nigeria, raising the possibility of the first development and production in the northeastern part of OML 123.

The KTM-6 well, 2 km southwest of the discovery well drilled in late 2005, cut 173 ft of gross oil column in four zones. The wells penetrated adjacent and separate fault blocks.

KTM-6's results included individual gross oil columns of 94 ft and 52 ft at depths between 5,350 and 6,300 ft subsea.

Flow tests were not run, but pressure and fluid sample data indicate medium gravity oil to be present, consistent with the 30° gravity Antan blend produced from OML123, the company said.

The discovery well cut 100 ft of gross oil column in three main zones and flow-tested 1,000 b/d of 28° gravity oil.

Kita Marine is in 10 m of water near the Cameroon marine border and 10 km northeast of the North Oron/Oron West producing facility.

Alberta

Trident Exploration Corp., Calgary, said its 2007 net production in western Canada averaged 98 MMcfd, 37% higher than in 2006.

Trident previously said 51% of its production is coalbed methane from the Mannville formation, 44% is CBM from the Horseshoe Canyon formation, and 5% comes from conventional reservoirs. Part of the Mannville output is from western Canada's first commercial Mannville CBM field.

Trident participated in the drilling of 157 new wells or horizontal legs in 2007 and connected 175 new wells or laterals to production.

The company has more than 770,000 net acres in Alberta and British Columbia and more than 537,600 net acres in the US. It is also involved in Montney shale gas exploration in Northeast British Columbia.

Compton Petroleum Corp., Calgary, said its first horizontal well in the Lower Cretaceous Basal Quartz sandstone formation in the deep basin south of Calgary is flow-testing at 6 MMcfd of gas. It is to be tied-in within 2 weeks.

The company performed multistage fracs in a 700-m lateral in the well in 9-17-17-29w4, is drilling a second Basal Quartz horizontal well, and has identified 15 follow-up locations.

One horizontal well could reduce the need for downspacing by replacing two to three vertical wells in the Hooker resource play, which has been developed mostly with one to two vertical wells per square mile, Compton said.

As presently delineated, the play extends over four townships where Compton is operator with an average 85% working interest. Eighty vertical wells are on production.

New Mexico

The Santa Fe County Commission in late February banned oil and gas drilling in central New Mexico's Galisteo basin for 1 year or more.

Tecton Energy LLC, private Houston operator, has leased 65,000 acres in this area of the Rio Grande rift and proposed to drill near the basin's only producing well, Black Oil Inc. Ferrill-1, completed in 1986.

The well initially pumped 86 b/d of 44° gravity oil from a small faulted slice of a Tocito sand stringer at 2,740 ft in a thrusted fault block in the Cretaceous section. TD is 3,696 ft.

The commission also plans to draft new oil and gas regulations by late 2008.

Texas

East

TXCO Resources Inc., San Antonio, paid $19.6 million to undisclosed sellers to boost its holding in Fort Trinidad field to 36,498 gross acres, or 20,526 net acres, from 18,000 gross acres, or 8,000 net acres.

The acquisition included 8.1 bcfe of proved reserves at yearend. The company is drilling a second well, plans to add a second rig in April, and just placed its first Cretaceous Glen Rose shoal gas well on production in the field, in Houston, Madison, and Leon counties.

Besides numerous Cretaceous pay zones, the field is prospective in the downdip Jurassic Bossier formation, the company said.

DEEPWATER ESP—1

Subsea, downhole 1,200-hp ESP produces Jubarte well off Brazil

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Based on a presentation to the Deep Offshore Technology International Conference & Exhibition, Houston, Feb. 12-14, 2008.

To produce the heavy oil from the JUB-6 well in the Jubarte field off Brazil, Petrobras decided to install the highest horsepower electric submersible pump (ESP) yet installed subsea. The system has a 1,200-hp motor and a pump capable of producing more than 22,000 b/d.

The well is part of Petrobras' Phase 1 plan for the field that includes four wells producing about 60,000 b/d to the P-34 floating production, storage, and offloading (FPSO) vessel.

Two wells are on gas lift, one has an ESP installation on the seabed, and the fourth, discussed in this article, has a downhole ESP.

New technologies

As new deepwater discoveries enter the production phase, operators require new technologies to economically bring this production to market.

Many traditional subsea production systems for water depths less than 1,000 ft and with moderate stepouts are not applicable for fields in deeper water and with longer stepouts. Also, heavier oil becomes a consideration. Consequently, service companies and operators are seeking cost-effective ways for producing these reserves during the life of the fields.

Operators have traditionally preferred gas lift in subsea applications with relatively short stepouts in subsea areas off Brazil.

But with high flow of heavy and viscous oil in a long stepout, gas lift becomes inefficient and ESPs provide the best artificial lift option.

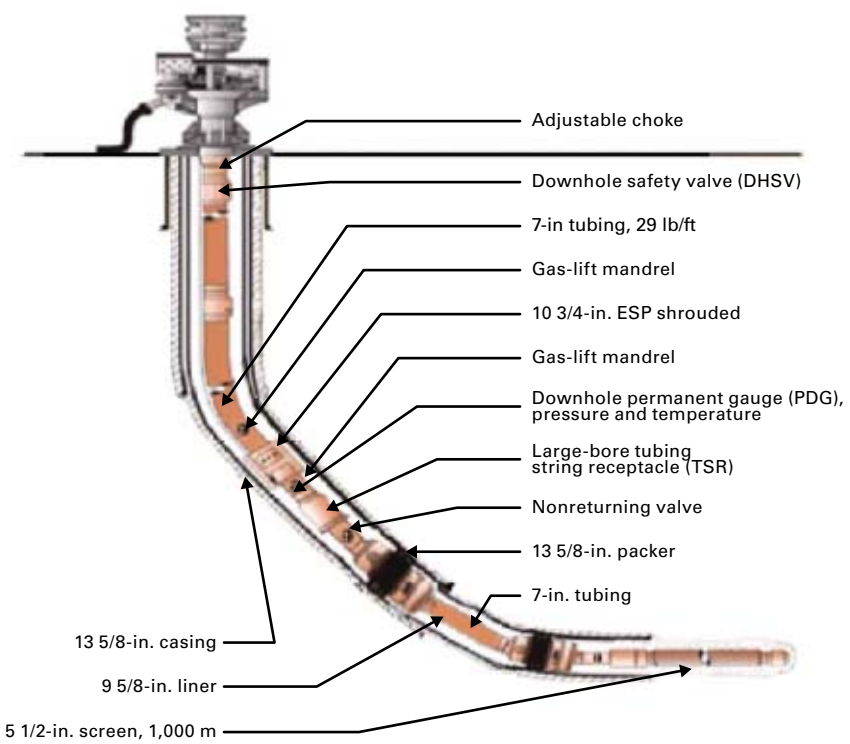
The ESP in JUB-6 started operating in April 2007, 17 months after its November 2005 installation.

Reliability is a main concern with ESPs and, therefore, the system has to be properly selected for the particular application.

This first article of a two-part series describes the selected ESP system for JUB-6. The conclusion will provide details on system testing and qualification.

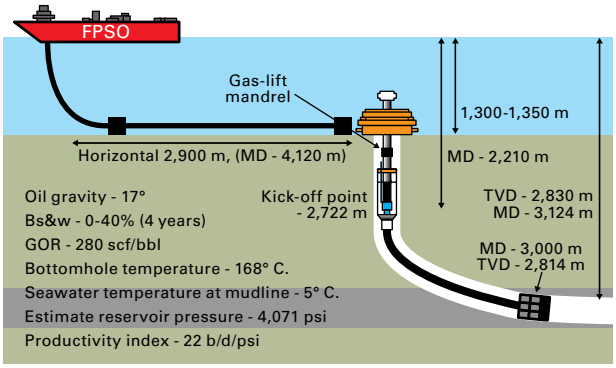
JUB-6 COMPLETION

Fig. 1



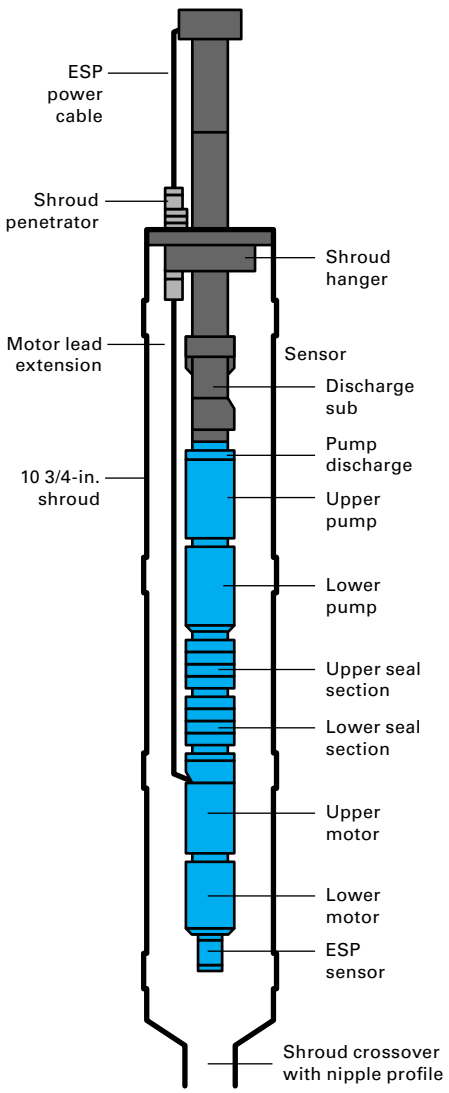
FIELD LAYOUT

Fig. 2



ESP CONFIGURATION

Fig. 3



Pump
- 675 series (6.75-in. OD).
- 58 stages HC-27000. Capable of producing up to around 4,500 cu m/day stock tank volume at 60 hz. High efficiency pump, 73%.
- Composed of upper and lower section (27 stages each). Intake incorporated to lower section.
- Compression pump.
- Tungsten carbide bearings in each stage.
- High-strength shaft rated at 1,250 hp @ 60 hz.
- Special coating (ARMOR I) to prevent scale deposition. All surface area is coated and cured to a soft, impact resistant finish. The coating designed to prevent buildup of scale as well as minimize abrasive wear.

Seal section
- 675 series (6.75-in. OD)
- Tandem seal section with 3 protection chambers each. Upper 2 chamber rubber bag and lower labyrinth in each seal section.
- High-strength shaft, rated to 1,462 hp at 60 hz.
- High-load thrust bearing, self leveling, tilting pad design, which compensates for misalignment. The pads are "Peek" coated for higher temperature and insulation. Loaded at a maximum of 65%, worst case.
- Tungsten carbide bearings in base and head to improve stabilization of the shaft.

Motor
- 725 series (7.25-in. OD)
- Tandem motor 600 hp, 2,080 v, 178 amp each, for a total of 1,200 hp, 4,160 v, 178 amp.

Power cable
- Model CELR AWG 1/0; 5 kv with double galvanized armor.
- Capillary line 3/8-in., 0.049-in. wall thickness for chemical injection.
- Lead cable to improve reliability in the event of gas lift backup production method.
- Rated for 450° F.
- Maximum estimated operating temperature 260° F.

Motor lead extension
- Model KLHT AWG 1; 5 kv, lead sheathed, Monel armor
- Rated for 450° F.
- Maximum estimated operating temperature 220° F.

Shroud penetrator
- RMS Penetrator Type 016/12/463; Model HE AWG 1
- Make up in shroud hanger; port 2 3/8-in. EUE
- Rated for 180 amp at 130° C. (266° F.)
- Maximum operating temperature 93° C. (200° F.)
- Working pressure 5,000 psi

Capsule
- Composed of 10 3/4-in. FJL 60.5 lb/ft casing joints
- Shroud hanger with ports for 2 3/8-in. penetrator and 3/8-in. cap line
- Capable to pressure test after assemble capsule body (before ESP assembly) running and standing valve to a nipple profile located on the shroud crossover
- Rated at 5,000 psi differential pressure

Downhole ESP

Jubarte field is in the north part of the Campos basin, about 80 km off Espirito Santo state.

The field, discovered in January 2001, had an extended well test for evaluating drilling, completion, artificial lift technology, and for verifying reserves.

The extended well test proved the economics of the field and Petrobras started Phase 1 development that includes four wells producing to the P-34 FPSO.

JUB-6 produces through 7-in. tubing, 26 lb/ft, ID 6.276 in (Fig. 1). The string is carbon steel except for the downhole safety valve (9% Cr) and the pup joint, crossover, and adjustable union above the safety value (13% Cr).

The well has a long horizontal, about 1,000 m, that creates a high productivity index and is openhole gravel packed for sand control.

The tubing string has gas lift mandrels for backup artificial lift if the ESP fails.

Water depth is about 1,400 m at Jubarte.

The well has 13⅝-in. casing to about 2,480 m. The kick-off point is at about 2,175 m from the surface.

The ESP, installed at 0° from vertical, is encapsulated in a 10¾-in. flush joint capsule. The well has 9⅝-in. liner from 2,480 m to 3,130 m. At this point, the well is already in the reservoir.

The 8½-in hole in the reservoir was drilled horizontally to about 1,000 m. The completion has a 7-in. gravel pack.

Above the gravel-pack packer, the well has a nonreturning valve (NRV). This valve prevents brine being injected into the reservoir during well-intervention work. The NRV is closed, isolating the reservoir, if the fluid weight above the NRV is greater than the reservoir pressure. The closed valve allows fluid to circulate through an orifice above the NRV with minimal or no loss of fluid to the reservoir. The orifice at the bottom of the string is in a gas lift mandrel.

The NRV is incorporated in the bottom string and is not pulled during intervention.

A tubing-string receptacle installed at about 2,385 m completes the lower string that has a gravel-pack assembly.

The pressure and temperature gauge sensor (PDG), manufactured by ProductionQuest, is set as close as possible to the reservoir for accurate reservoir

readings. A T-wire cable (11 x 11 mm) runs from the wellhead to the sensor. This line has an epoxy encapsulation for improving the line's resistance if something is hit downhole.

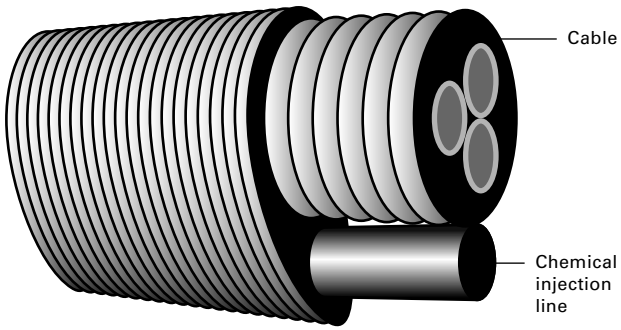
The encapsulated ESP is in a 10¾-in. flush-joint capsule at about 2,100 m from the surface. The T-wire cable to the PDG passes outside the capsule up to the mandrel. The installation required specially manufactured stamp clamp protectors for holding and preventing damage to the T-wire cable (feeding the PDG) through the capsule.

A gas-lift mandrel with a ⅜-in. orifice, just above the ESP capsule, provides lift gas in the event of ESP failure.

An adjustable union orients the cable to the hole of the wellhead hanger. Also, the excess cable slack is removed after connection of the subsea penetrator. This tool is capable of orienting 360° with a maximum misalignment of 30° and has a maximum stroke of 24 in.

Armored cable

Fig. 4



Fluid properties

Table 1

Oil gravity, °	17.19
GOR, cu m/cu m	45.97
Dead oil viscosity, cp	357 at 50° C. 1,411 at 30° C.
Incorporation water limit (water/oil emulsion), %	60
Wax appearance temperature, °C.	15.2
Asphaltene precipitation	Very steady (onset >2 ml)
Hydrate blockage tendency	Without tendency
Foam formation	Severe
Water density	1.1056
PH	5.8
Scale formation	Barium sulfate, strontium sulfate, and iron oxidant

	Test 1	Test 2
Barium (Ba^{2+}), mg/l.	46	124
Strontium (Sr^{2+}), mg/l.	411	330
Sulfate (SO_4^{2-}), mg/l.	51	20

Scale formation

The Jubarte field produces a 17 °API gravity crude with about a 258 scf/bbl GOR (Table 1).

When the ESP that operated for 1 year in the extended well test was dismantled, inspectors found scale in the pump stages. The scale contained 86% barium sulfate, 12% strontium sulfate, and 2% iron oxidant. Also, two water analyses at two different points confirmed the quantity of solids present in the water (Table 1).

Scale formation is a function of pressure and temperature changes. The consequences of forming scale in and around the ESP are:

- If scale forms around the motor, the scale acts like a layer inhibiting heat transfer from the motor to the well fluid, causing the motor to run hotter.
- Scale incrustation on the impellers degrades pump performance and increases the risk of locking.

The design must take into account scale precipitation to prevent pump damage. The system included two different solutions:

1. To further prevent scale deposition, the impellers and diffusers of the ESP have an Armor I coating. Armor I is a fluoropolymer coating that makes the nucleation and growth of scaling difficult and also aims to improve the physical properties of the pump stage material by reducing surface roughness and providing better pump performance. The fluoropolymer coating also protects pump parts against aggressive chemical agents and ambient factors.
2. To reduce the potential precipitation, the system will also include continuous injection of an antiscale chemical product through the umbilical and chemical injection manifold. The injection point is at the pump intake.

Chemical injection can prevent scale formation but this well also produces a foamy oil with emulsion problems. Because the completion has only one injection line, the well required the development of a new chemical product that simultaneously acts as a demulsifier, antifoamer, and scale inhibitor.

The chemistry must be compatible with the metallic and nonmetallic components of the string, umbilical, and ESP system. Testing is still continuing for checking its compatibility.

The metallic compatibility test is based on the calculated weight loss for each coupon, and is expressed in mils/year (mpy) corrosion rate.

The test involves subjecting coupons of different materials to the chemical attached under simulated wellbore pressures and temperatures. The metals tested are materials from the housing, shafts, stages, and spring of the mechanical seals.

The nonmetallic compatibility test verifies that the elastomers are compatible with the well fluids (liquid and gas). They prevent contamination and recirculation of the fluid through critical points in the ESP equipment. Well fluids can attack the elastomer and affect its mechanical properties. The resistance of an elastomer to certain conditions is measured by these parameters:

- Volume change refers to the volume that the elastomer changes after contact with the well fluid at certain temperatures. The more volume changes, the worse the compatibility with the fluid.
- Tensile, elongation, hardness, and physical dimension changes in elastomers determine the capacity of the elastomer to work with the well fluid.

One product tested passed the metallic but not the nonmetallic compatibility test. The metallic test was successful with a maximum corrosion rate of 4.7 mpy. The nonmetallic test, at a concentration of 50,000 ppm (the injection rate in the well was calculated at 200 ppm) did not succeed.

Physical barriers, or bags, are in the seal section made of elastomers. During the test, the elastomer of the bag had high swell and low physical property retention (tensile strength, elongation, and hardness). Its size increased about 140%, and it also lost tensile strength, which means that the chemical attacked the elastomer.

This would reduce the run time of the ESP. The test involved a higher concentration of chemical from the proposed injection concentration because there are areas downhole in which the chemical could accumulate.

The product tested is soluble in oil, and the test was performed in water. It was suspected that the results will differ just by changing the base from water to a mixture between oil and water. The test was repeated with 5,000 ppm in a mixture of water and oil, and the results were good.

The elastomer did not lose any tensile strength in a water-oil base. The conclusion was that the product is compatible with the elastomers in this application.

ESP design

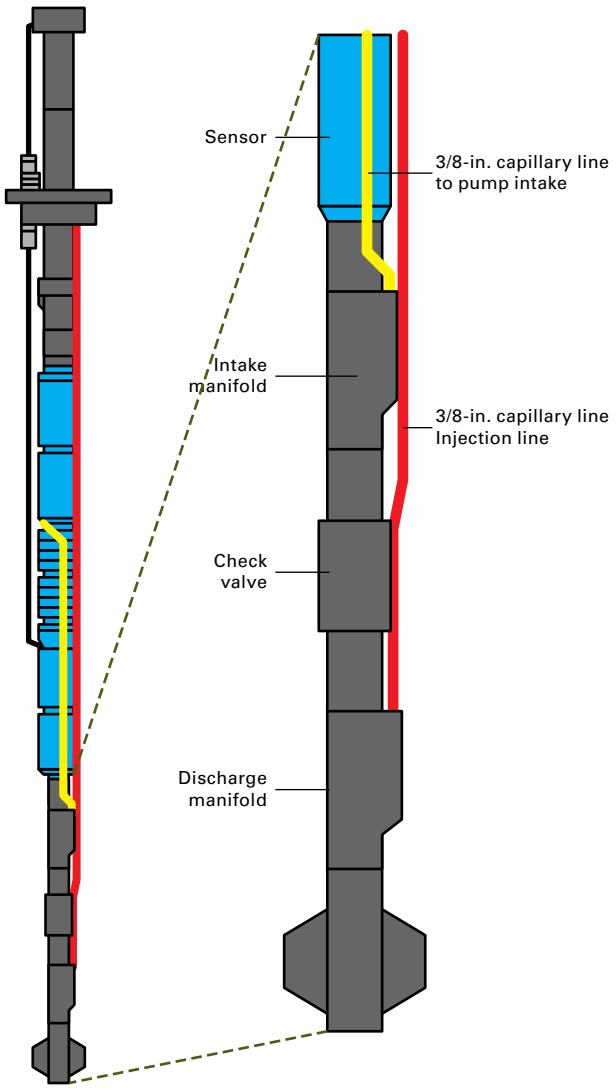
Fig. 2 provides general information on the ESP equipment.

Petrobras had requested a design for a 3,500-cu m/day production rate with other design specifications:

- Motor not to exceed 1,200 hp.
- Maximum 200-amp motor because of subsea penetrator limitations.
- ESP housed in a 10¾-in. capsule.
- Tubing string and ESP of carbon steel.
- Chemical injection to prevent scale formation, break emulsion, and foaming.
- Operate within the designed ESP operating range.
- Maximum 4,500-v motor. The selected motor was 4,160 v that can go up to 64.9 hz.
- A 62-hz maximum recommended operating frequency, as recommended by pump manufacturer.
- A 35-hz minimum starting frequency for no more than 30 min and a 40-hz minimum operating frequency. The compression pump has stages fixed to the shaft that have all downthrust forces that are transferred to the bearings in the seal section. The rpm is one parameter that forms the lubricating film between thrust runner and bearing. Lower speed leads to thinner lubricating film.
- ESP set in vertical position above the kickoff point.
- A discharge pressure below the maximum subsea flowline rating and an ESP burst-pressure housing below the subsea flowline rating.
- Variable-speed drive with filtered pulse width modulation power in the operation mode. It is not allowed to run the ESP without filtering, which could result in degradation of the motor and cable insulation due to poor quality of the wave signal.
- Carbon steel housing material.
- Addresses scale formation.

CHEMICAL INJECTION

Fig. 5



Design selected

Fig. 3 shows the main features of the selected pump and installation.

High-end technology motor construction improves motor reliability compared with standard construction. The extreme performance motor with Vanguard technology is a precision design manufactured to the highest industry standards.

The design features extreme high-load thrust bearings as well as an advanced hardened rotor-bearing system. The thrust bearings are a self-aligning design to compensate for any misalignment, and the rotor-bearing technology improves lubricity and vibration characteristics.

The high-strength shaft design incorporates proprietary materials to enhance run life in high-horsepower applications. High-temperature electrical connections provide a strong mechanical connection.

Like all Centrilift motors, the design features epoxy-encapsulated motor windings for enhanced stability and improved heat transfer.

The ESP sensor provides downhole communications with a discharge sub for discharge pressure reading capability. Principal readings are intake pressure and temperature, motor temperature, vibration, and discharge pressure.

Gas lift also can produce the well, but this is not recommended while the downhole ESP is in good condition. Gas lift can create problems with the ESP cable. Gas can enter the rubber insulation of the cable and during decompression, the increasing gas volume can rupture the insulation.

To minimize possible damage to the cable during gas-lift operations, the design includes a lead cable (Fig. 4). Lead is a physical barrier, preventing gas from getting into the insulation. The lead cable is AWG 1/0 dual armor and includes a capillary line for chemical injection.

Chemical injection

Fig. 5 shows the chemical injection for preventing scale formation, reducing foamy effects, and emulsions. The system injects the product directly at the pump intake to avoid as much as possible chemical contact with nonmetallic materials of the ESP (especially from the motor and seal section).

At the base of the ESP is a 2⅜-in. check valve. ✦

The authors

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Tools aid discovery of fatigue cracks

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A suite of examination techniques is used to discover fatigue cracks in drilling components. Fatigue is the most common cause of drillstem failure and can occur at stresses well below the normal operating stress in most drillstem components.

Several factors influence fatigue, a complex mechanism, including material properties, mud corrosiveness, drilling trajectory, rotary speed, loads, and several others. This complexity plus the lack of meaningful knowledge about the amount of prior fatigue damage, makes accurate, absolute fatigue life prediction practically impossible.[1-3]

In practice, there is no reliable method to quantify the total amount of fatigue damage a component may have accumulated. Rather, present inspection technology is limited to looking for fatigue cracks. Even when these inspections are performed properly, they can still occasionally fail to find small cracks.[3]

Most of the fatigue life of a drillstring component is used up by the time a crack has formed and grown large enough to be detected by inspection; therefore, a fatigue crack, once detected, is cause for immediate rejection of the component.

How quickly a fatigue crack will form and propagate to failure depends on many variables, here called drivers.[3] The four major drivers are:

1. Mean tensile stress. Higher mean stress shortens fatigue life.
2. Cyclic stress excursions about the mean stress. Larger stress excursions shorten fatigue life.
3. Corrosiveness of the mud system. More corrosive environments shorten fatigue life.
4. Fracture toughness of the material. Tougher materials (high KIC) will have a longer fatigue life and support a larger crack before final failure. Fracture toughness, rather than being a driver of fatigue damage, should be thought of as a retarder.

General view of the failed jar, as received by lab (Fig. 1).

Case study 1: drilling jar

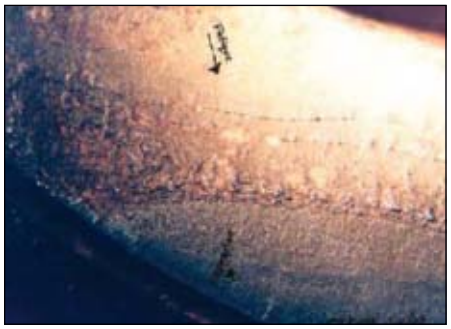
We examined the fatigue failure of a drilling jar. One section of a drilling string, the drilling jar, failed during drilling operations at 9,943-ft depth. A high torque value of 13,000 ft-lb, sudden loss of string weight (40,000 lb), and a drop in mud pressure (900 psi) were noted in geoservice logs at the time of failure.

Immediately after the jar rupture, the drillers requested fishing tools to retrieve the parted piece. They replaced the failed section and recommenced drilling.

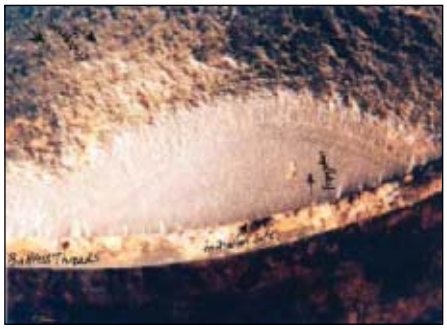
After the fishing operation, the operator reviewed all documents related to the drillstring and particularly the parted jar. They also reviewed pre-job inspection reports and found they were adequate according to the manufacturer's procedure, as documented in the company quality management system.

The company's inspection included full magnetic particle inspection (MPI) and visual thread inspection of the failed jar components and connections before they were put in service. Independent, third-party inspectors also inspected and certified the failed jar.

Based on this, the company decided to conduct independent investigations with samples from the failed jar, accompanied by the internal failure investigation report and geoservice logs.



Macroscopic view shows fatigue cracks initiated from external (threads) and internal (corrosion pits) jar surfaces (Fig. 2).



Macroscopic view reveals fatigue crack initiated from jar external surface (buttress threads). Counter fatigue cracks originating from jar internal surface are also visible (Fig. 3).

Macroscopic view shows two merged fatigue cracks resulting from high drilling torque (shear stress) during drilling operations (Fig. 4).

Investigation, results

The investigation included visual examination, macroscopic examination, X-ray analysis of the attached deposit on the failed piece, and mechanical assessment (hardness test) of the received jar sample.

Visual examination. The jar bottom sub was carefully cleaned using a special solution and then subjected to a visual check, which revealed:

- Failed jar sub showed pronounced brittle failure (i.e. fatigue cracks and overload) and little ductile tearing (Fig. 1).
- Small corrosion pits that developed under deposits are visible. The corrosion most likely occurred because oxygen was present (Fig. 1). Halides, such as chloride ions, can also accelerate localized corrosion.
- Sign of ratchet marks were visible on the parted jar. Fatigue cracks originating at the external (threads) and internal (corrosion pits) jar surface were visible.
- Extent of fatigue cracks or areas covered by the fatigue marks were small, isolated, and extensively distorted. The number of fatigue cracks, however, originating from the jar connector (external threads) was greater compared with those initiated from the internal surface (corrosion pits).
- Jar connectors or threads have acted as a potential site for initiation of fatigue cracks from the external surface while corrosion pits (oxygen corrosion) have acted as a stress raiser or potential initiation of fatigue cracks from the internal surface.
- About 50% of the fracture surface was flat, brittle fracture without any sign of marking or plastic deformation (Fig. 1). This type of fracture surface resulted from the overload or high torque exerted on the drilling string including the failed jar.
- All fatigue markings (ratchet markings) were visible on one side of the jar fracture surface. This may be because of drilling with high torque in a dogleg zone or a highly inclined borehole. This can be confirmed from the drilling data sheets or daily report.

Macroscopic examination. This confirmed all the findings of the visual examination. The failed jar showed a large, flat area with several isolated fatigue markings.

Figs. 2-5 show that a few initiated at the external thread connector and others initiated from small corrosion pits (internal surface). Mechanical curvature, dents, and corrosion pits can act as stress raisers where fatigue cracks may initiate. The initiation stage usually takes more time compared with the propagation stage. Propagation depends on operating conditions and mechanical properties of the materials.

The macroscopic examination confirmed that the fatigue cracks seem to have propagated during a short period of time due to cyclic loading and unusual drilling operations or conditions (inclination, bending, high stresses/torque, etc.). In addition, the fracture surface showed deformed (nonuniform) fatigue marks, rough fatigue markings, and opposite-propagated fatigue cracks (Figs. 2-5). This indicates that the string operated under high torque and stress levels and the fatigue propagation rate was quite fast.

Macroscopic examination also confirmed that about 50% of the jar fracture surface was flat and the rest was slightly inclined, resulting from overload failure. Small corrosion pits initiated at the jar internal surface were also evident.

Hardness. The Vickers hardness-testing machine (10 kg) was used to measure across the jar's cross-section. Hardness was up as specified.

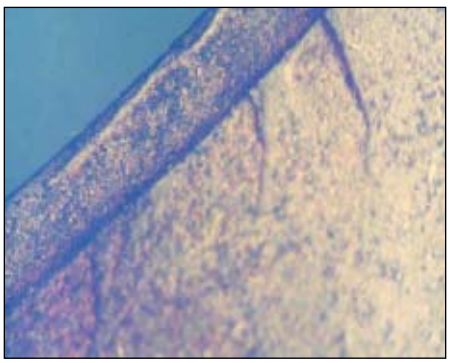
X-Ray diffraction. The compound found on the jar connector (buttress threads) was collected and subjected to X-ray diffraction. It was composed mainly of calcium carbonate (94% calcite), silica, and a little potassium chloride.

Failure mechanism, jar

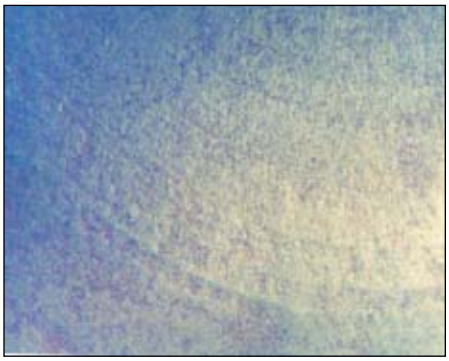
In the light of results of the fracture surface examination, chemical analysis, and hardness measurements, in addition to the reviewed geoservice log documents, we suggest the following jar failure mechanism:

1. The jar integrity was weakened by the development of several fatigue cracks at the jar threads connector as well as from localized corrosion pits. The exerted load also assisted the initia-

Macroscopic view shows two fatigue cracks initiated from external and internal jar surfaces. Highly deformed fatigue cracks are visible (Fig. 5).



Macroscopic photographs show the initiation sites of fatigue cracks from the stabilizer thread root. Damage encountering the threads is visible (Fig. 6).



Macroscopic photographs show the beach marking originating from the stabilizer thread root (Fig. 7).

tion. These cracks seem to propagate quite fast due to severe working conditions and operations, i.e., high string deflection, drilling in dogleg areas, high torque, high rotation, etc.

The inspection did not reveal the propagated minute cracks. It was difficult to confirm whether these cracks initiated before or after the last conducted inspection. This requires us to establish the crack propagation rate and some calculations.

2. Several propagated fatigue cracks reduced the jar total cross-sectional area; therefore, the failure is expected when high load or torque (remaining sound material can no longer carry the applied load) was exerted during the drilling operation. The jar failure mechanism depends on the toughness of the jar materials (KIC). It seems that torque exerted during drilling (14,000 lb) was high enough, and in presence of small isolated fatigue cracks, to lead these minute cracks to propagate quickly, resulting in overload and catastrophic rupture of the jar.

The nondestructive test techniques and procedures used, such as MPI, do not seem to detect small fatigue cracks in the jar threads. As previously mentioned, the observed fatigue marks (ratchet marks) extended over small and isolated areas on the jar fracture surface. In addition, some of the examined fatigue cracks showed a tiny initiation point or site, indicating that only small part of the crack will be apparent (external surface) and the rest will propagate through the jar's cross section.

Based on these findings, we suggested that the company change the inspection procedure and technique to avoid any misinterpretation during the inspection process.

Jar determination

We can summarize the lessons learned from the failed drilling jar:

1. The drilling jar failed catastrophically due to high torque during drilling operations. The fatigue cracks initiated at the jar threads and those initiated from corrosion pits reduced the load-bearing capability (reduced the cross-sectional area) and therefore assisted in the jar's premature failure.

2. Observed fatigue cracks seem to propagate over a short time. Rough fatigue marks were visible on the examined fracture surface, which indicates that high load or torque was applied to the drilling string.

3. Jar connectors (threads) on the external surface and corrosion pits on the internal surface acted as "stress raisers" where the fatigue cracks initiated.

4. Using MPI on the threaded components is sometimes insufficient to detect the fine fatigue cracks. The inspector should consult nondestructive testing experts regarding conducting additional testing techniques for thread inspections.

5. The proper torque needs to be applied when the joint is made up (make up torque).

6. Drillers need to be aware of the limits for applied torque, weight on bit, and rotation (rpm) while drilling in the dogleg zone and at high inclination to avoid buckling. Drilling outside of recommended limits endangers the integrity of the drilling tools and reduces markedly the working life.

Case study 2: drilling stabilizer

We received a sample from a failed 12 3/16-in. ID drilling string stabilizer. We were asked to conduct a detailed metallurgical investigation and to establish the main cause of string stabilizer failure. The failure report included stabilizer dimensions, material, stabilizer number, last inspection date, and the geoservices logging chart.

We conducted visual and microscopic examinations on the fracture surface of the failed part (extracted piece) after the pieces were cleaned with special chemicals and brushes.

Examination confirmed that the string stabilizer failed predominantly in a brittle manner. The fracture is partly planar and covers about 70% of the total fracture surface. The rest of the fracture was inclined 45°, which is a ductile rupture.

Shear leaps, twisting, and washout were all visible on the collar sample. Small washouts occurred due to high

drilling-fluid pressure leakage (pressure drop was reported in geoservice chart) followed by the complete failure (separation) of the stabilizer.

The flat fracture of the stabilizer was due to initiation of multiple fatigue cracks at the thread roots of the last four threads. These cracks extended or propagated throughout the stabilizer wall thickness during service wall thickness during services such as drilling at a high rotation rate, drilling through a dog-leg; high loading on the bit, buckling and vibration when drilling hard rock zones, etc.

The rate of crack growth or propagation depends on the material fracture toughness and applied load. The applied load, due to stressed threads, should be below the fatigue endurance limit for the stabilizer material.

Visual examination. We scrutinized the fracture surface and threads of the failed string stabilizer. The fracture surface was partly flat, typical of brittle failure, and partly inclined by 45°, typical of shear or ductile failure.

Washout was visible on the failed stabilizer. This may have occurred due to leaking high-pressure drilling fluid before failure. The geoservice chart, which reported a pressure drop of 150 psi before the final failure, confirmed this.

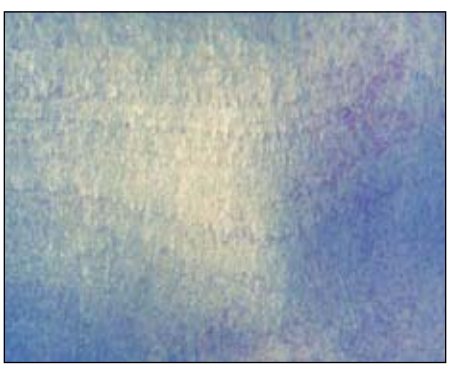
Over the flat area of the fracture surface, noncontinuous beach marks typical of fatigue failure originated from the thread root. These beach marks appear to have originated from multiple initiation sites at the thread root (8½-in. OD female box), where high residual stresses are attained. The beach marks were found across 70% of the total fracture surface of the failed stabilizer. The remaining 30% were inclined, however, typical of ductile failure.

In some areas, beach marks appeared rough, indicating that the stabilizer was subjected to high stresses (bending stresses and vibration) or to high load rate. Recent geoservice data just before failure show high applied torque (up to13,800 ft-lb), which exceeds the allowable or recommended value.

Shear lip, indicating the final fracture due to overload failure, was visible on various areas on the fracture surface, such as the external side (outer rim) of the stabilizer as well as the inclined surface. Shear lips over a thin area along the rim of the stabilizer confirms the difficulties in detecting the fatigue crack from the external surface even when a wet fluorescent magnetic particle was used.

Microscopic examination. We examined the failed part of the stabilizer in a low-magnification stereomicroscope. This confirmed that the stabilizer failed due to the initiation of multiple fatigue cracks at the thread root (Fig. 6).

Generally, thread roots attain maximum residual stresses, which are introduced during machining. The level of stresses depends on the thread morphology. The magnitude of residual stresses is high when the applied load or torque is above the allowable range.



Macroscopic photographs show clear beach marks, typical of fatigue failure (Fig. 8).

The applied load (dead load, load on drilling pit) and torque during drilling seem to be high in some cases. This was clear from the morphology of beach marks (fatigue crack steps, Figs. 7 and 8).

Shear leaps were evident on the outside of the external surface. The shape of the final fracture (shear lip) indicates that the stabilizer before failure was subjected to twisting (Fig. 8). This is imminent before complete failure where fatigue cracks have already propagated over a large area and only a small section is carrying the load.

Hardness. Measured hardness of the small specimens cut out of the received string stabilizer met the required specification.

Failure mechanism

Failure of the string stabilizer is mainly due to the fatigue failure that initiated from the most weak and stressed area of the stabilizer (threads of 8⅛-in. OD female box). The fatigue crack initiated during drilling operations, i.e., drilling in the dogleg area, string buckling, string bending, etc.

High load on pit, high torque, or service load (abnormal load) all initiate fatigue microcracks at the thread roots (a0). Initiated cracks grow during drilling operations until they reach a critical size (ac), at which catastrophic failure of the string stabilizer is imminent. Fatigue cracks in this case were mainly flat; others were inclined 45° as a result of overload.

Generally, development of a fatigue crack can be divided into two main steps:

1. Incubation and initiation of microscopic cracks. Detection of the flaw is impossible due the minute size of the crack.
2. Propagation of the microscopic crack until it reaches a critical size. In this case, detecting the crack is possible; however, the propagation duration is shorter than the initiation stage, particularly when the drillstring was abnormally used.

The company technical report stated that the last conducted inspection on the failed stabilizer was 1 month before failure occured. In addition, the company technician conducted an additional inspection on the failed stabilizer; no cracks were detected in the failed stabilizer.

A professional inspection of the drilling string is necessary, particularly on the threaded areas. Visual inspection of threads on the box side is difficult and alternative methods such as ultrasound, which is more reliable than MPI,

should be considered. A shear wave ultrasonic system can detect transverse fatigue cracks. An array of several transducers with sound beams overlapping can detect flaws.

Other versions of ultrasonic measurements can detect cracks in the threaded box connection. A 4° wedge allows compression-wave ultrasound with a frequency of about 10 milli-hz to enter the ends of a shouldered connection at a suitable angle for directing a beam along the thread roots.

Stabilizer determination

After examining the failed stabilizer, we conclude:

1. The string stabilizer failed due to the initiation of multiple fatigue cracks at the thread root. Cracks propagated during stabilizer operations (string-up/string-down), vibration, inclined drilling string (buckling/bending), etc., until they reached a critical size before final fracture.
2. High applied torque, load on bit, rotation, and the hole shape (dog leg) may have accelerated the stabilizer failure.
3. The last inspection, conducted 1 month before failure, did not detect the propagated fatigue crack. One can estimate the propagation stage of fatigue cracks using a scanning electron microscope and calculating the number of cycles from the present fatigue striations on the stabilizer fracture surface.
4. Fatigue cracks extended across 70% of the fracture surface. The remaining 30% failed by overload (shearing).
5. A sign of little washout due to drilling fluid leakage and twisting before final failure were visible on the string stabilizer sample.
6. The 150-psi pressure drop, as was reported in the geochart, is due to the first leakage (washout) or erosion through the stabilizer wall thickness. Complete separation or final fracture of the stabilizer then occurred.
7. Morphology of beach marks in some areas confirms that the applied load was high.
8. Some threads suffered from some galling, cuts, and dents, which were on the last threads.
9. The lack of a professional inspector or inspection techniques to detect the fatigue cracks led to the catastrophic failure of the string stabilizer (cost of drilling rig standby time).

General recommendations

Fatigue control and drillstring inspection are critical to maintaining drilling equipment.

As previously discussed, fully predicting and totally eliminating fatigue in drillstrings is probably not possible. Fatigue, however, can be controlled and it requires an understanding of:

1. The drivers that are steadily damaging the drillstring in small and irreversible steps.
2. Work to reduce or weaken the drivers using all practical means. By doing this, companies can reduce the rate of fatigue damage accumulated and the crack propagation rate. This lengthens time between failures.
3. The greater chance of finding cracked components via inspection rather than via downhole failure. Finally, the inspection must be performed properly to give the highest probability of finding cracks when they exist.
4. Controlling fatigue in the well planning and drilling phases entails three simple objectives:
   - Reduce the magnitudes of mean stress (torque) and stress excursions.
   - Monitor and reduce the corrosion rate in the mud system.
   - Inspect the components properly and at optimum intervals.

Inspecting the drilling string includes:

1. Reviewing the inspection procedure adopted by Weatherford and third-party inspection teams. A professional nondestructive testing consultant should perform this inspection.
2. Using other inspection methods such as eddy currents. Fatigue cracks can be fine and sometimes not easily detected using MPI. In addition, fatigue cracks sometimes initiate in the subsurface. ✦

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3. Vaisberg, O., Vincke, O., Perrin, G., Sarda, J.P., and Fay, J.B., "Fatigue of drillstring: state of the art," Oil and gas science and technology, Rev. IFP, Vol. 57 (2002), No. 1, pp. 7-37.

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StatoilHydro Angola assays Mondo crude

StatoilHydro Angola conducted an assay of the Mondo crude, which is part of the Kizomba C development that started production in January 2008, off Angola.

ExxonMobil Corp. unit Esso Exploration Angola Ltd., the field's operator, started oil production from the Kizomba C development on Block 15, about 90 miles off Angola (Fig. 1). Kizomba C, which is designed to develop 600 million bbl of oil from the Mondo, Saxi, and Batuque fields, lies in 2,400 ft of water (OGJ, Jan. 21, 2008, p. 8). The Kizomba C development has come on stream with Mondo field; Saxi and Batuque fields are expected to come on stream later in 2008.

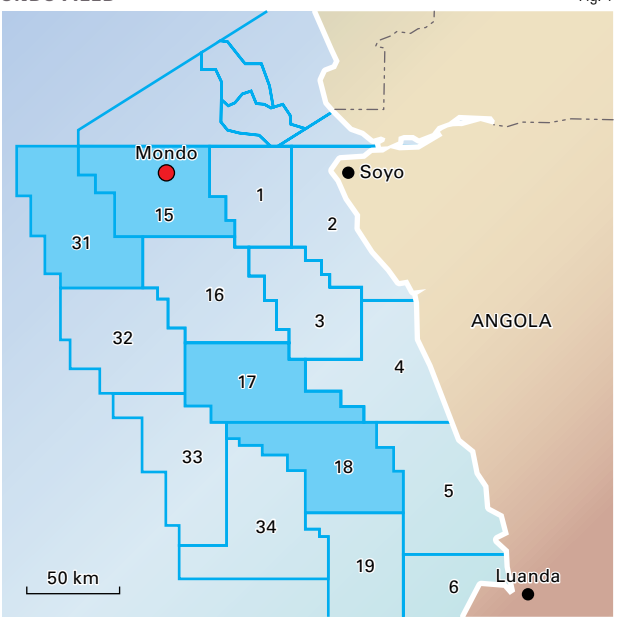
Mondo is expected to plateau at a peak production rate of 100,000 b/d. Plateau production from all three fields is expected to reach a total 200,000 b/d. Mondo is a medium gravity, moderate acidity, and sweet crude, according to BP Exploration (Angola) Ltd.

Esso Angola serves as operator of Block 15, holding 40% interest. Its other block partners are BP 26.67%, Eni Angola Exploration BV 20%, and StatoilHydro Angola 13.33%.

Fig. 2 shows a true boiling point (TBP) curve for the whole crude. These data are from StatoilHydro.

MONDO FIELD

Fig. 1



Source: BP PLC

Whole crude

Gravity, °API: 30.29
Specific gravity: 0.8746
Pour point, °F.: 1
Neutralization number (TAN), mg KOH/g: 0.773
Sulfur, wt %: 0.3873
Viscosity at 20° C., cst: 21.46
Viscosity at 40° C., cst: 10.44
Viscosity at 50° C., cst: 7.8
Viscosity at 100° C., cst: 2.81
Viscosity at 150° C., cst: 1.53
Mercaptan sulfur, ppm: 3.3
Nitrogen, ppm: 2,657.6
Conradson carbon residue, wt %: 5.3
Nickel, ppm: 24.6
Vanadium, ppm: 6.9
rvp, psi: 3.9
Heat of combustion (gross), btu/lb: 19,277
Heat of combustion (net), btu/lb: 18,084
Hydrogen sulfide, ppm: 0.3
Salt, lb/1,000 bbl: 35
Cetane index (D4737): 27

Butane, lighter

TBP cut point, °F.: ≤60
Yield, vol %: 1.8
Gravity, °API: 120.7
Specific gravity: 0.5611
Carbon, wt %: 82.45
Hydrogen, wt %: 17.55
Viscosity at 20° C., cst: 0.4
Viscosity at 40° C., cst: 0.34
Viscosity at 50° C., cst: 0.32
Viscosity at 100° C., cst: 0.24
Viscosity at 150° C., cst: 0.19
Heat of combustion (net), btu/lb: 19,265
Paraffins, vol %: 100
Naphthenes, vol %: 0
Cetane index (D4737): 144

Light naphtha

TBP cut point, °F.: 60-165
Yield, vol %: 5.26
Gravity, °API: 83.46
Specific gravity: 0.6583
Carbon, wt %: 83.82
Hydrogen, wt %: 16.18
Viscosity at 20° C., cst: 0.45
Viscosity at 40° C., cst: 0.38
Viscosity at 50° C., cst: 0.36
Viscosity at 100° C., cst: 0.26
Viscosity at 150° C., cst: 0.2
Heat of combustion (net), btu/lb:

18,870
Paraffins, vol %: 85
Naphthenes, vol %: 14.48
Cetane index (D4737): 49

Heavy naphtha

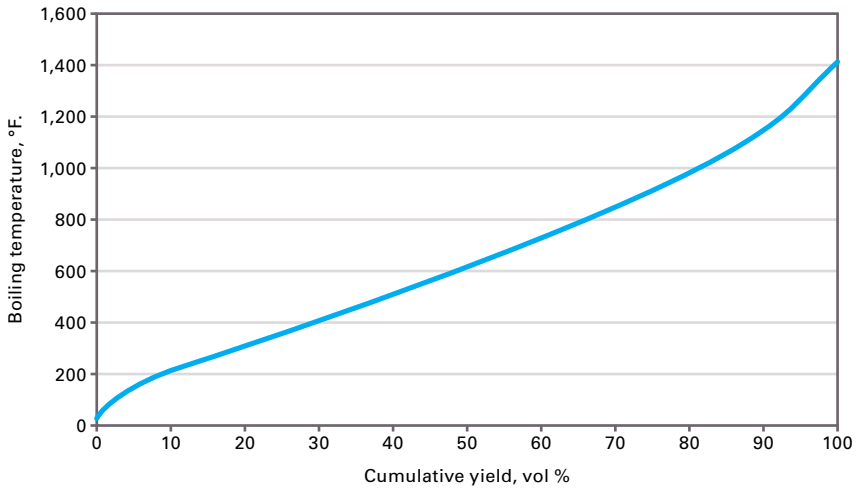
TBP cut point, °F.: 165-330
Yield, vol %: 14.74
Gravity, °API: 55.4
Specific gravity: 0.7571
Carbon, wt %: 85.6
Hydrogen, wt %: 14.4
Sulfur, wt %: 0.0056
Viscosity at 20° C., cst: 0.77
Viscosity at 40° C., cst: 0.63
Viscosity at 50° C., cst: 0.57
Viscosity at 100° C., cst: 0.39
Viscosity at 150° C., cst: 0.29
Mercaptan sulfur, ppm: 0.7
Heat of combustion (net), btu/lb: 18,624
Paraffins, vol %: 47.07
Naphthenes, vol %: 41.9
Aromatics, vol %: 10.39
Cetane index (D4737): 31

Kerosine

TBP cut point, °F.: 330-480
Yield, vol %: 13.95
Gravity, °API: 42.02
Specific gravity: 0.8155
Carbon, wt %: 86.17
Hydrogen, wt %: 13.78
Pour point, °F.: -81
Sulfur, wt %: 0.0391
Viscosity at 20° C., cst: 1.92
Viscosity at 40° C., cst: 1.39
Viscosity at 50° C., cst: 1.21
Viscosity at 100° C., cst: 0.72
Viscosity at 150° C., cst: 0.49
Mercaptan sulfur, ppm: 0.9
Nitrogen, ppm: 2.3
Heat of combustion (net), btu/lb: 18,551
Paraffins, vol %: 32.53
Naphthenes, vol %: 52.25
Aromatics, vol %: 14.2
Freeze point, °F.: -57.3
Smoke point, mm: 19.5
Naphthalenes, vol %: 4
Cetane index (D4737): 41
Cloud point, °F.: -68
Aniline point, °F.: 138.9

TBP DISTILLATION

Fig. 2



Diesel

TBP cut point, °F.: 480-650
Yield, vol %: 16.47
Gravity, °API: 32.1
Specific gravity: 0.8649
Carbon, wt %: 86.61
Hydrogen, wt %: 13.31
Pour point, °F.: –13
Neutralization number (TAN), mg KOH/g: 0.899
Sulfur, wt %: 0.2019
Viscosity at 20° C., cst: 8.21
Viscosity at 40° C., cst: 4.5
Viscosity at 50° C., cst: 3.53
Viscosity at 100° C., cst: 1.53
Viscosity at 150° C., cst: 0.91
Nitrogen, ppm: 109.1
Paraffins, vol %: 33.84
Naphthenes, vol %: 42.85
Freeze point, °F.: 12.4
Cetane index (D4737): 50
Cloud point, °F.: 2
Aniline point, °F.: 157.1

Vacuum gas oil

TBP cut point, °F.: 650-1,000
Yield, vol %: 27.17
Gravity, °API: 22.02
Specific gravity: 0.9217
Carbon, wt %: 86.88
Hydrogen, wt %: 12.5
Pour point, °F.: 76
Neutralization number (TAN), mg KOH/g: 0.669
Sulfur, wt %: 0.4584
Viscosity at 20° C., cst: 281.45
Viscosity at 40° C., cst: 74.78
Viscosity at 50° C., cst: 44.43
Viscosity at 100° C., cst: 7.81
Viscosity at 150° C., cst: 3
Nitrogen, ppm: 1,231.2
Conradson carbon residue, wt %: 0.36
Nickel, ppm: 0.1
Paraffins, vol %: 16.91
Naphthenes, vol %: 41.06
Cetane index (D4737): 50
Aniline point, °F.: 181.1

Vacuum residue

TBP cut point, °F.: 1,000+
Yield, vol %: 20.61
Gravity, °API: 7.1
Specific gravity: 1.0209
Pour point, °F.: 145
Neutralization number (TAN), mg KOH/g: 0.951
Sulfur, wt %: 0.8937
Viscosity at 20° C., cst: 1,600,070,334
Viscosity at 40° C., cst: 18,740,139.05
Viscosity at 50° C., cst: 3,169,757.61
Viscosity at 100° C., cst: 7,770.81
Viscosity at 150° C., cst: 303.97
Nitrogen, ppm: 9,065.8
Conradson carbon residue, wt %: 21.45
n-Heptane insolubles, wt %: 7.5
Nickel, ppm: 99.8
Vanadium, ppm: 26.9
Cetane index (D4737): 28 ✦

Study addresses black powder's effects on metering equipment

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DESFA SA
Athens

Preventing black powder contamination from damaging a gas pipeline's metering system requires regular dismantling and cleaning of its metering instruments, manifolds, impulse lines, and associated facilities. Determining which cleaning method to apply, however, requires gathering comprehensive information about the nature of the black powder problem. Only then can the operator determine which technique will provide the most efficient and cost-effective method of removing black powder from gas installations.

Based on presentation to the Pipeline Rehabilitation & Maintenance conference, Manama, Bahrain, Dec. 11-13, 2007.

Background

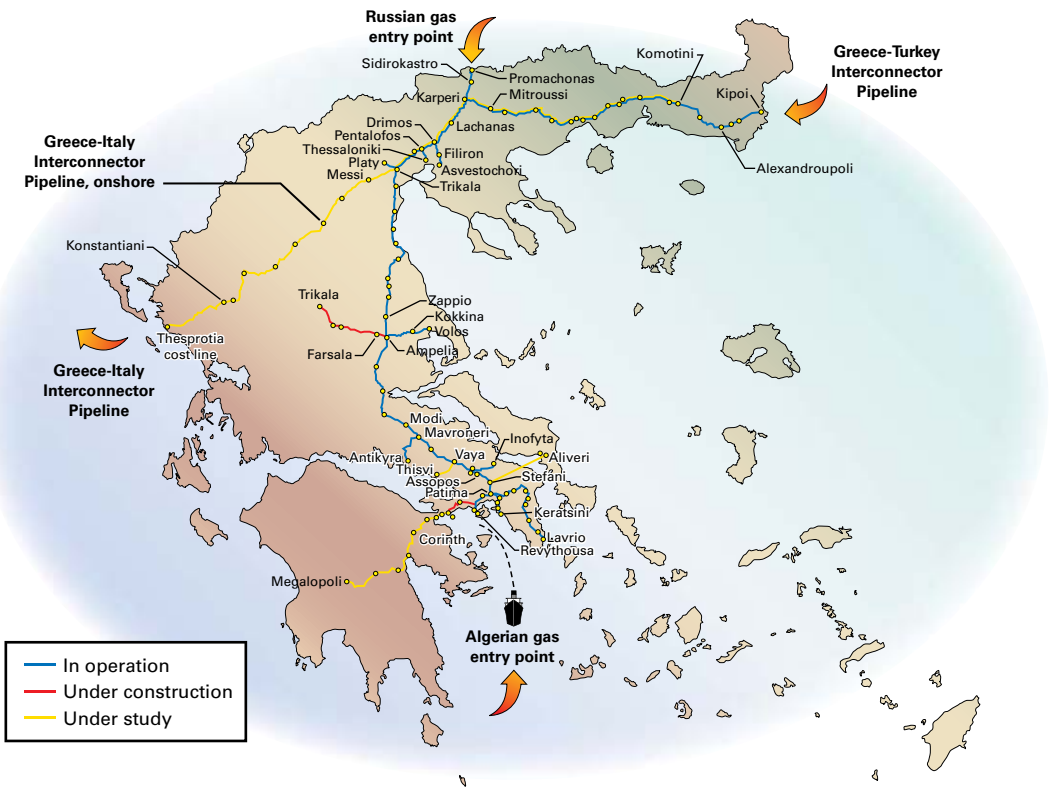
Solid contaminants—known as black powder—found in natural gas transmission and distribution systems are a cause of increasing concern in the global natural gas industry. Chemical or biological reactions with steel found in natural gas pipelines, gas wells, and associated facilities can create black powder. Operators can detect black powder in both dry and wet gas pipelines and in conjunction with other contaminants such as oil, grease, liquid hydrocarbons, and sand.[1]

Black powder influences the flow performance of gas pipelines and can also impair the function of valves and measurement systems, requiring the development of specific inspection and cleaning methods.[2]

The Hellenic Gas Transmission System Operator (DESFA) SA, founded in April 2007 as a wholly owned subsidiary of DEPA SA, operates, and is expanding, Greece's national gas transmission system (Fig. 1).

The Greek gas transmission system faced its first black-powder-induced operational problems in imported Russian natural gas a few years ago.[3] Pigging performed on the first 12 km of the Greek high-pressure gas network removed 1,000 kg of powder. Black powder contamination, however, continued to increase as gas off-takes grew. Powder gathering in gas piping and installations resulted in reduced flow efficiencies, clogged and collapsed filters, depositions on gas measurement

DESFA HIGH-PRESSURE GAS PIPELINE NETWORK Fig. 1



devices, clogging of instrumentation, and increased deterioration of valves due to erosion.

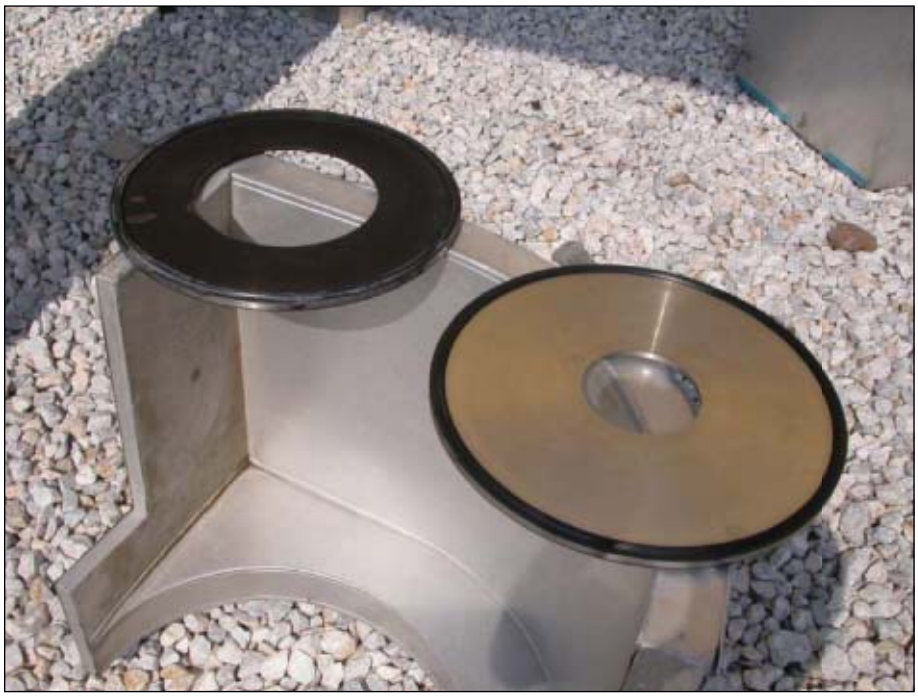
The greatest accumulation of black powder lay in the first segment of the network, immediately downstream of the Bulgarian-Greek border, but large flow migration of the powder was documented through the mainline to various downstream lateral lines and customer delivery points.

Filtering at the entrance of processing plants or networks is the most common method of fighting contaminants. Black powder particulates, however, can shear easily to submicron sizes and pass through gas separation devices and filters, making filter-based control difficult.

Two vertical cartridge filters at the inlet of the Sidirokastro border metering station served as the primary facilities to remove black powder from Greece's gas stream. These filters separated 100% of particles larger that 3 µm, and 99% of particles 0.5-3 µm. Black powder deposits continued to appear downstream, however, despite nearly continuous cleaning of these filters' cartridges. Other network gas filtration devices clogged regularly and had to be replaced. The extra maintenance load on the new transmission system increased greatly workman hours, creating higher costs.

The network operator installed two cyclone (centrifugal) filtration facilities with 99% separation efficiency for contaminants larger than 5 µm at the entry point for Russian natural gas to further protect the downstream system. Operation of these cyclone separators efficiently removed the black powder.

The operator also pigged the contaminated pipelines and purged specific sections. Black powder had heavily contaminated all vented gas. Literature provides an extensive description of both the harm caused by black powder in gas pipelines and the experience gained from cleaning operations.[3]



Black powder thoroughly coated the orifice plate shown on the left of this photograph. A clean orifice plate provides contrast (Fig. 2).

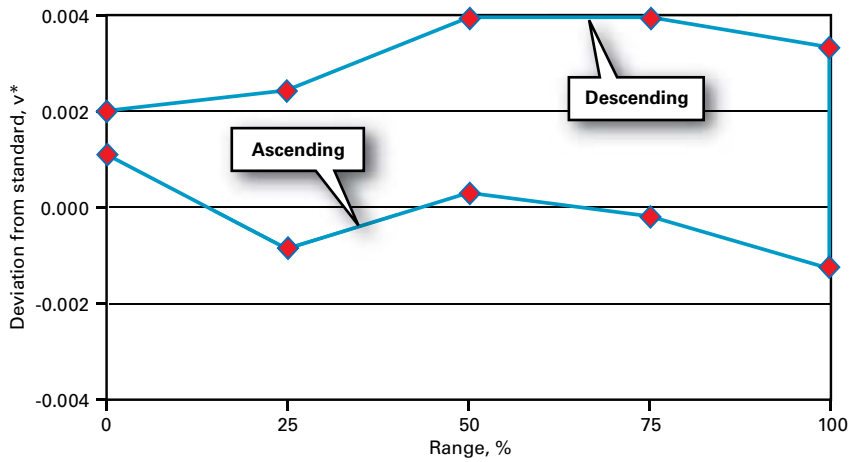
Despite these efforts, however, small particles continued to flow through filtration devices, agglomerating to larger sizes downstream. Traces of black powder appeared in metering lines, fiscal metering instruments, analysers, density meters, and control valves.

This article evaluates black powder's effect on gas metering equipment, giving guidelines for checking and cleaning instrumentation and presenting a laboratory analysis of the black powder itself.

Black powder from just one gas pressure transmitter lies on the floor beneath the transmitter assembly and metering instrumentation (Fig. 3).

CALIBRATION RESULTS, BLACK-POWDER CONTAMINATED TRANSMITTER

Fig. 4



*Accepted tolerance limit, ±0.004 v.

Black powder has almost completely blocked this pressure transmitter (Fig. 5).

Laboratory analysis

Samples taken from the debris of pigging operations or from filters' deposits provided material for analysis of the powder's chemical composition and particle-size distribution (OGJ, Mar. 12, 2007, p. 52). Black powder consists mainly of magnetite (iron oxide), a form of rust, and is highly magnetic. All other compounds found through laboratory analysis exist in common dirt. The powder contains practically no iron sulfide or other sulfur compounds.

The amorphous nature of the powder caused variance in particle-size analysis with both large particles and submicron flakes detected, though a dominant peak appeared at about 30 µm. Large particles stayed in filters and dropout vessels, while the smaller ones carried downstream and tended to agglomerate due to their magnetic properties (OGJ, Mar. 12, 2007, p. 52).

The black powder examined in this article consists of about 80% corrosion products, with the rest made up of typical soil minerals. Corrosion of upstream internal uncoated steel pipeline is the main mechanism of black powder formation,[4] with gas flow introducing it into the Greek system.

Installation contamination

Small particles flowed through filtration devices despite continuous operation of cyclone and cartridge filters, prompting an investigation as to whether black powder had entered fiscal metering instrumentation and associated installations. DESFA examined all instruments and installations at its Sidirokastro border metering station (BMS).

- *Orifice plates.* Pressure differential devices (orifice plates) measure the gas quantity at BMS. An investigation uncovered heavy black powder deposits on the upstream face of orifice plates. The left side of Fig. 2 shows an orifice plate covered by a thick layer of black powder. This layer consists of black powder together with oil or grease, which gives the mixture adhesive properties. The right side of Fig. 2 shows a clean plate. The operator removed the dirty orifice plate from a metering line after about 1 month of operation. Both the upstream and downstream faces of the removed orifice plate showed black powder deposits.
- *Metering lines.* Black powder contaminated the inner metering lines, potentially affecting their roughness. Contamination may decrease pipe roughness by filling the relatively rougher underground to a smoother surface. Altering inner pipe roughness upstream of the orifice plate affects the discharge coefficient, C_d (ISO 5167), increasing the uncertainty of gas measurement[5] by altering the shape of the flow profile. The unpredictable nature of this effect with time makes retroactive corrections difficult to apply.
- *Impulse lines, instrument manifolds.* Fig. 3 shows the arrangement of instruments on a metering line at BMS. Impulse lines feeding pressure transmitters at

rethinking
RECOVERY METHODS

UNCONVENTIONAL GAS™ INTERNATIONAL CONFERENCE & EXHIBITION

September 30 – October 2, 2008
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THE RETHINKING CONTINUES

By rethinking recovery methods, producers have brought to a hungry market gas from reservoirs once considered economically and technically impossible. Tight sands, shales, and coalbeds now represent large and growing sources of an essential form of clean energy.

But they're still unconventional. The reservoirs are complex. The costs of drilling into and completing wells in them are high and rising. They present unique environmental problems.

Producing gas from unconventional reservoirs profitably, safely, and in amounts demanded by the market requires continuous rethinking – the kind of thinking that shoves back limits on what's possible with gas supply.

Rethinking of recovery methods will continue Sept. 30 – Oct. 2, 2008, at the Unconventional Gas International Conference & Exhibition at the Hilton Fort Worth in Fort Worth, Texas. Planned by editors of Oil & Gas Journal and an advisory board of industry experts, the event will highlight innovation from unconventional gas plays around the world. It will be your chance to meet and learn from other professionals in the fastest-growing sector of the gas-producing industry.

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The photograph on the left shows parts of a ball valve from the feed line of an online densitometer heavily contaminated by black powder. The right photograph shows the inlet filter element of a similarly contaminated online densitometer (Fig. 6).

all metering lines contained black powder, as did the impulse lines' primary isolation valves. Two isolation valves required changing. Enough black powder accumulated in some of the three-valve and five-valve manifolds at the fiscal pressure transmitters to cause permanent damage.

A pellet launcher (left) removed black powder from gas metering impulse lines. The pellets used (right) turned black after just one pass through the impulse line (Fig. 7).

• *Influence on pressure measurements.* Regular monthly calibration performed to fiscal metering instruments verifies their performance. Black powder affected instrument performance. Fig. 4 shows calibration results for a representative differential pressure transmitter (Tag No. FT 20101C), with a calibration range of 0-500 millibar and a tolerance of ±0.0040 v. The instrument's output exhibits a large hysteresis (shift) between ascending and descending applied pressures. The hysteresis recorded at the top of the calibration range (500 mbar) is particularly high (0.0046 v). These calibration results fall within the marginally acceptable range, but a clean transmitter shows negligible hysteresis in the same test.

Such metering instruments are highly likely to deviate beyond acceptable tolerance when put back in operation. When this specific pressure transmitter returned to operation, for instance, it triggered a high differential pressure (DP) deviation alarm at the corresponding flow computer.

Operators dismantled and inspected the DP transmitter, finding the manifold and associated impulse lines heavily contaminated with black powder.

Fig. 5 shows this pressure transmitter as found during inspection. Black powder almost completely blocked both the transmitters' diaphragms.

• *Water dewpoint analyzer.* Contaminants clogged about 80% of the analyzer's inlet filter, moving into the pipe beyond the filter and appearing in the sample line just before the dew point sensor. The sensor's porous surface also likely allowed migration of the powder into it.

• *Gas chromatographs.* The operator detected traces of black powder at the inlet filters for sample lines of online gas chromatographs.

• *Specific gravity meters.* Black powder contaminated impulse lines, pressure reducers, and catch pots.

• *Online densitometers.* The left portion of Fig. 6 shows parts of a ball valve at the impulse line of an online densitometer. Black powder heavily contaminated the seats of this valve, filling the den-

sitometer's inlet pressure filters (Fig. 6, right). Black powder also contaminated the densitometer's low-pressure internal filters, passing on to its sensitive vibrating cylinders. The operator sent the instruments to the manufacturer's laboratories for maintenance. The manufacturer confirmed that the densitometers' sensors were contaminated with black powder.

Corrective actions

Preventing damage to metering instruments required inspection for black powder as part of monthly inspection and calibration of fiscal instruments. These inspections repeated the findings discussed in this article; a large amount of black powder existing in instruments of all metering lines, creating the danger that impulse lines would be plugged by contaminants.

BMS operators applied a regular cleaning program to avoid abnormal operation of the instruments and reduce possible errors in gas measurement, cleaning all transmitters similar to that shown in Fig. 5 by blowing compressed air and the transmitters' diaphragms with acetone solution.

Operators also began thoroughly cleaning all manifolds and impulse lines as part of the monthly calibration process, purging impulse lines with air and nitrogen. A special air tool also pushed pellets of cylindrical sponge into the tubes of impulse lines (Fig. 7). The white pellets turned black after just one pass through an impulse line.

The air driven pellet launcher can also remove contaminants from hoses, tubes, or pipes.

Acknowledgments

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Equipment/Software/Literature

New offshore crew supply vessel

A new offshore crew supply vessel designed for international operations combines the Cheetah CrewZer high speed Class DP2 catamaran and the nine passenger Frog capsule personnel transfer safety system.

The joint effort consists of Houma, La.-based Seacor Marine's catamaran and Aberdeen, Scotland-based Reflex Marine Ltd.'s personnel transfer equipment.

The 165 ft supply vessel is designed to carry 150 passengers at speeds of 36-42 knots. The high capacity personnel transfer safety system is specially developed for this vessel. The Frog capsule transfers personnel from the CrewZer to the drilling rig in a protected and safe environment, while achieving a high rate of crew transfers, the firms say.

The CrewZer design provides seats like business-class in an airplane—reclining, spacious, and comfortable, with wireless internet, satellite TV, and cinema.

Source: **Reflex Marine Ltd.,** D1 Balgownie Technology Centre, Aberdeen, AB22 8GW, UK.

Data sheet discusses underwater pig and test units

A subsea pigging unit (SPU) and subsea hydrostatic testing unit (SHU) are discussed in a new data sheet, yours free for the asking.

The SPU has the capability to filter and chemically treat flooding water while continuously regulating and monitoring the flooding and pigging operation autonomously and without the need for umbilicals or constant attendance by a support vessel.

The SHU allows hydrostatic testing operations to be completed entirely on the seabed, moving the risks posed by high pressure fluids to a location far removed from personnel.

Source: **Halliburton Co.,** Box 3, Houston, TX 77001.

Services/Suppliers

Honeywell International Inc.,

Gilsdorf

Morris Township, NJ, has appointed Norman Gilsdorf to vice-president and general manager for Honeywell Process Solutions operations in Europe, the Middle East, and Africa. Gilsdorf was formerly senior vice-president and general manager of UOP LLC's Process Technology and Equipment business unit. He replaces Paul Orzeske, who now leads the integration of Honeywell's acquisition of Hand Held Products. At UOP, a wholly owned subsidiary of Honeywell International, Gilsdorf most recently served as senior vice-president of UOP's licensing, equipment and systems, and engineering and services business, which serves the refining, petrochemical, and gas processing industries. Earlier, he was responsible for UOP's Catalysts, Adsorbents and Specialties business unit, and prior to that held various technical services, R&D, business development, and marketing and sales roles. Gilsdorf spent 5 years working for UOP in the UK in various roles, where he served as director of sales and services across Europe, Middle East, CIS, India, and Africa for the petrochemical industries. He also spent 7 years in Moscow as director of sales and services for the CIS region, where he and his team helped launch UOP into Russia in the1990s. He joined UOP in 1977. Gilsdorf holds a BS in chemical engineering from Purdue University and an MBA in international business and finance from Northwestern University.

Honeywell International is a $36 billion diversified technology and manufacturing leader, serving customers worldwide with aerospace products and services; control technologies for buildings, homes and industry; automotive products; turbochargers; and specialty materials. Honeywell Process Solutions is part of Honeywell's Automation and Control Solutions group, a global leader in providing product and service solutions that improve efficiency and profitability, support regulatory compliance, and maintain safe, comfortable environments in homes, buildings, and industry.

KBR,

Houston, has named Charles Schneider interim CFO to replace Cedric Burgher, who has resigned to pursue other opportunities, while the search for Burgher's successor is conducted. Schneider joined KBR in August 2006 and has served as the company's vice-president and treasurer.

KBR is a global engineering, construction, and services company supporting the energy, petrochemicals, government services, and civil infrastructure sectors. The company offers a wide range of services through its Downstream, Government and Infrastructure, Services, Technology, Upstream, and Ventures business segments.

Petris Technology Inc.,

Houston, has named John Archer product manager for PetrisWINDS Enterprise. He previously worked for BEA as a senior account systems engineer.

Petris offers vendor-neutral data management and exchange technologies to the energy industry.

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Supporting Organization: GEP

Imports of crude and products

	Districts 1-4		District 5		Total US		
	3-7 2008	2-29 2008	3-7 2008	2-29 2008	3-7 2008	2-29 2008	*3-9 2007
	1,000 b/d						
Total motor gasoline	710	745	35	55	745	800	910
Mo. gas. blending comp.	341	455	35	5	376	460	627
Distillate	123	186	10	—	133	186	322
Residual	264	257	—	45	264	302	391
Jet fuel-kerosine	258	87	—	—	258	87	372
Propane-propylene	164	121	23	9	187	130	160
Other	1,309	1,119	44	58	1,353	1,177	897
Total products	**3,169**	**2,970**	**147**	**172**	**3,316**	**3,142**	**3,679**
Total crude	**9,614**	**8,520**	**934**	**917**	**10,548**	**9,437**	**9,802**
Total imports	**12,783**	**11,490**	**1,081**	**1,089**	**13,864**	**12,579**	**13,481**

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

Purvin & Gertz LNG netbacks—Mar. 14, 2008

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	7.76	6.22	7.58	6.10	6.88	7.50
Everett	9.14	6.74	8.72	6.80	7.40	9.48
Isle of Grain	9.02	6.58	8.76	6.46	7.27	8.32
Lake Charles	7.22	5.05	6.95	5.24	5.56	7.93
Sodegaura	6.69	8.42	6.63	8.43	7.68	5.64
Zeebrugge	7.87	6.06	7.16	5.98	6.43	7.17

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

Crude and product stocks

District	Crude oil	Motor gasoline		Jet fuel, kerosine	Fuel oils		Propane-propylene
		Total	Blending comp.[1]		Distillate	Residual	
	1,000 bbl						
PADD 1	13,525	64,427	34,179	8,435	38,195	14,297	3,271
PADD 2	64,634	59,637	20,610	8,206	32,604	1,346	7,951
PADD 3	165,611	72,036	34,361	12,907	28,894	15,612	15,932
PADD 4	13,129	7,091	1,997	534	2,832	342	[1]962
PADD 5	54,727	32,776	26,140	8,843	13,875	4,967	—
Mar. 7, 2008	**311,626**	**235,967**	**117,287**	**38,925**	**116,400**	**36,564**	**28,116**
Feb. 29, 2008	**305,449**	**234,276**	**116,493**	**39,342**	**117,625**	**36,508**	**28,873**
Mar. 9, 2007[2]	**325,336**	**213,939**	**97,456**	**39,770**	**120,439**	**35,169**	**27,690**

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

Refinery report—Mar. 7, 2008

District	REFINERY OPERATIONS		REFINERY OUTPUT				
	Gross inputs	Crude oil inputs	Total motor gasoline	Jet fuel, kerosine	Fuel oils		Propane-propylene
					Distillate	Residual	
	1,000 b/d						
PADD 1	1,401	1,397	1,630	93	458	120	56
PADD 2	3,074	3,057	2,443	218	862	65	196
PADD 3	7,152	7,056	3,109	729	1,907	339	765
PADD 4	519	518	313	19	151	9	[1]148
PADD 5	2,672	2,594	1,535	420	513	174	—
Mar. 7, 2008	**14,818**	**14,622**	**9,030**	**1,479**	**3,891**	**707**	**1,165**
Feb. 29, 2008	**14,979**	**14,868**	**9,042**	**1,392**	**4,005**	**630**	**1,127**
Mar. 9, 2007[2]	**14,894**	**14,592**	**8,741**	**1,375**	**3,912**	**701**	**1,070**
	17,436 operable capacity		**85.0% utilization rate**				

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

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

OGJ crack spread

	*3-14-08	*3-16-07	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	116.78	76.58	40.21	52.5
Brent crude	108.91	60.75	48.16	79.3
Crack spread	7.87	15.83	–7.96	–50.3
FUTURES MARKET PRICES				
One month				
Product value	119.54	76.60	42.94	56.1
Light sweet crude	109.42	57.93	51.49	88.9
Crack spread	10.12	18.67	–8.55	–45.8
Six month				
Product value	116.73	76.22	40.51	53.1
Light sweet crude	104.23	63.56	40.67	64.0
Crack spread	12.50	12.67	–0.16	–1.3

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

OGJ GASOLINE PRICES

	Price ex tax 3-12-08	Pump price* 3-12-08	Pump price 3-14-07
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	287.6	327.3	251.4
Baltimore	275.2	317.1	249.7
Boston	270.8	312.7	247.0
Buffalo	274.7	334.8	265.4
Miami	290.1	340.4	266.9
Newark	265.8	298.7	240.7
New York	254.5	314.6	257.7
Norfolk	276.4	314.0	239.5
Philadelphia	269.9	320.6	264.6
Pittsburgh	268.1	318.8	253.6
Wash., DC	284.0	322.4	252.5
PAD I avg.	274.3	320.1	253.5
Chicago	297.0	347.9	276.6
Cleveland	265.3	311.7	247.5
Des Moines	275.1	315.5	242.7
Detroit	264.6	313.8	253.6
Indianapolis	273.8	318.8	250.7
Kansas City	275.3	311.3	241.9
Louisville	296.2	333.1	247.5
Memphis	275.4	315.2	239.6
Milwaukee	260.5	311.8	252.8
Minn.-St. Paul	267.3	307.7	250.6
Oklahoma City	275.8	311.2	240.7
Omaha	271.5	317.9	252.5
St. Louis	265.4	301.4	240.9
Tulsa	268.6	304.0	238.6
Wichita	259.7	303.1	243.0
PAD II avg.	272.8	315.0	248.0
Albuquerque	272.2	308.6	245.3
Birmingham	279.5	318.2	240.4
Dallas-Fort Worth	273.7	312.1	241.6
Houston	272.9	311.3	239.3
Little Rock	274.8	315.0	241.5
New Orleans	272.9	311.3	241.5
San Antonio	266.9	305.3	232.8
PAD III avg.	273.3	311.7	240.3
Cheyenne	268.3	300.7	227.5
Denver	274.6	315.0	241.5
Salt Lake City	271.0	313.9	230.0
PAD IV avg.	271.3	309.9	233.0
Los Angeles	287.1	345.6	305.4
Phoenix	264.0	301.4	257.4
Portland	297.1	340.4	281.5
San Diego	298.9	357.4	312.6
San Francisco	311.4	369.9	332.3
Seattle	297.1	349.5	281.7
PAD V avg.	292.6	344.0	295.1
Week's avg.	**276.0**	**319.6**	**253.8**
Feb. avg.	**259.5**	**303.1**	**228.0**
Jan. avg.	**260.9**	**304.5**	**225.3**
2008 to date	**262.6**	**306.4**	—
2007 to date	**187.4**	**231.0**	—

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

REFINED PRODUCT PRICES

	3-7-08 ¢/gal		3-7-08 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	256.00	New York Harbor	300.13
Gulf Coast	259.75	Gulf Coast	294.63
Los Angeles	275.75	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	246.73	ARA	305.14
Singapore	260.76	Singapore	290.95
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	254.25	New York Harbor	172.55
Gulf Coast	260.25	Gulf Coast	177.69
Los Angeles	279.75	Los Angeles	216.72
		ARA	190.85
		Singapore	184.59

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

BAKER HUGHES RIG COUNT

	3-14-08	3-16-07
Alabama	5	2
Alaska	10	10
Arkansas	37	45
California	34	30
Land	33	28
Offshore	1	2
Colorado	118	96
Florida	0	0
Illinois	0	0
Indiana	2	1
Kansas	11	15
Kentucky	11	10
Louisiana	143	192
N. Land	46	58
S. Inland waters	17	25
S. Land	29	41
Offshore	51	68
Maryland	0	0
Michigan	1	2
Mississippi	11	16
Montana	10	21
Nebraska	0	0
New Mexico	74	72
New York	6	8
North Dakota	59	30
Ohio	13	13
Oklahoma	203	185
Pennsylvania	19	15
South Dakota	2	1
Texas	881	825
Offshore	8	6
Inland waters	3	1
Dist. 1	26	28
Dist. 2	39	33
Dist. 3	56	56
Dist. 4	88	95
Dist. 5	191	158
Dist. 6	130	123
Dist. 7B	32	44
Dist. 7C	53	56
Dist. 8	120	104
Dist. 8A	26	28
Dist. 9	39	29
Dist. 10	70	64
Utah	42	39
West Virginia	24	29
Wyoming	66	74
Others—NV-4; TN-4; VA-3	11	9
Total US	**1,792**	**1,740**
Total Canada	**510**	**409**
Grand total	**2,302**	**2,149**
Oil rigs	343	282
Gas rigs	1,441	1,453
Total offshore	60	76
Total cum. avg. YTD	**1,765**	**1,732**

Rotary rigs from spudding in to total depth.
Definitions, see OGJ Sept. 18, 2006, p. 46.

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

SMITH RIG COUNT

Proposed depth, ft	Rig count	3-14-08 Percent footage*	Rig count	3-16-07 Percent footage*
0-2,500	76	2.6	69	4.3
2,501-5,000	105	54.2	109	60.5
5,001-7,500	197	21.8	227	22.0
7,501-10,000	441	2.9	427	3.2
10,001-12,500	423	4.4	421	3.5
12,501-15,000	308	0.3	271	0.3
15,001-17,500	97	—	106	1.8
17,501-20,000	81	—	77	—
20,001-over	38	—	32	—
Total	**1,766**	**7.6**	**1,739**	**8.6**
INLAND	31		44	
LAND	1,680		1,637	
OFFSHORE	55		58	

*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]3-14-08	[2]3-16-07
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	16	20
Alaska	705	749
California	655	665
Colorado	45	39
Florida	6	5
Illinois	27	26
Kansas	97	97
Louisiana	1,349	1,309
Michigan	15	16
Mississippi	50	59
Montana	93	93
New Mexico	165	162
North Dakota	115	115
Oklahoma	171	171
Texas	1,340	1,336
Utah	45	51
Wyoming	144	145
All others	64	70
Total	**5,102**	**5,128**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

	3-14-08 $/bbl*
Alaska-North Slope 32°	85.76
South Louisiana Sweet	113.50
California-Kern River 13°	97.60
Lost Hills 30°	106.05
Southwest Wyoming Sweet	101.83
East Texas Sweet	106.25
West Texas Sour 34°	99.25
West Texas Intermediate	106.75
Oklahoma Sweet	106.75
Texas Upper Gulf Coast	103.25
Michigan Sour	99.75
Kansas Common	105.75
North Dakota Sweet	100.25

*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

	3-7-08 $/bbl[1]
United Kingdom-Brent 38°	102.30
Russia-Urals 32°	97.61
Saudi Light 34°	98.62
Dubai Fateh 32°	94.83
Algeria Saharan 44°	102.58
Nigeria-Bonny Light 37°	103.70
Indonesia-Minas 34°	102.70
Venezuela-Tia Juana Light 31°	97.75
Mexico-Isthmus 33°	97.64
OPEC basket	99.69
Total OPEC[2]	98.17
Total non-OPEC[2]	97.82
Total world[2]	98.01
US imports[3]	95.15

[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]

	3-7-08	2-29-08	3-7-07	Change, %
	bcf			
Producing region	512	535	570	–10.2
Consuming region east	706	760	754	–6.4
Consuming region west	180	189	224	–19.6
Total US	**1,398**	**1,484**	**1,548**	**–9.7**
	Dec. 07	**Dec. 06**	**Change, %**	
Total US[2]	**2,879**	**3,070**	**–6.2**	

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

Statistics

World oil balance

	2007 3rd qtr.	2007 2nd qtr.	2007 1st qtr.	2006 4th qtr.	2006 3rd qtr.	2006 2nd qtr.
	Million b/d					
DEMAND						
OECD						
US & Territories	21.03	20.97	21.07	21.09	21.25	20.91
Canada	2.38	2.28	2.34	2.29	2.31	2.20
Mexico	1.98	2.07	2.05	2.00	1.96	1.98
Japan	4.67	4.61	5.39	5.29	4.75	4.72
South Korea	2.06	2.12	2.35	2.32	2.04	2.04
France	1.93	1.85	1.97	1.95	1.93	1.87
Italy	1.63	1.67	1.69	1.71	1.68	1.65
United Kingdom	1.75	1.78	1.80	1.81	1.78	1.82
Germany	2.56	2.40	2.39	2.71	2.75	2.59
Other OECD Europe	7.54	7.26	7.36	7.54	7.46	7.29
Australia & New Zealand	1.09	1.07	1.09	1.10	1.07	1.06
Total OECD	**48.62**	**48.08**	**49.50**	**49.81**	**48.98**	**48.13**
NON-OECD						
China	7.69	7.62	7.43	7.53	7.24	7.30
FSU	4.34	4.45	4.37	4.43	4.35	4.14
Non-OECD Europe	0.73	0.78	0.85	0.78	0.72	0.77
Other Asia	8.63	8.82	8.73	8.82	8.54	8.71
Other non-OECD	15.26	14.94	14.66	14.46	14.69	14.42
Total non-OECD	**36.65**	**36.61**	**36.04**	**36.02**	**35.54**	**35.34**
TOTAL DEMAND	**85.27**	**84.69**	**85.54**	**85.83**	**84.52**	**83.47**
SUPPLY						
OECD						
US	8.40	8.53	8.43	8.40	8.38	8.34
Canada	3.35	3.33	3.42	3.39	3.31	3.16
Mexico	3.46	3.61	3.59	3.52	3.71	3.79
North Sea	4.27	4.48	4.80	4.76	4.51	4.71
Other OECD	1.56	1.54	1.50	1.55	1.55	1.44
Total OECD	**21.04**	**21.49**	**21.74**	**21.62**	**21.46**	**21.44**
NON-OECD						
FSU	12.56	12.60	12.61	12.48	12.26	12.07
China	3.87	3.96	3.92	3.81	3.85	3.87
Other non-OECD	12.05	11.77	11.40	11.73	11.91	11.70
Total non-OECD, non-OPEC	**28.48**	**28.33**	**27.93**	**28.02**	**28.02**	**27.64**
OPEC*	**34.90**	**34.58**	**34.51**	**34.97**	**35.66**	**35.19**
TOTAL SUPPLY	**84.42**	**84.40**	**84.18**	**84.61**	**85.14**	**84.27**
Stock change	**–0.85**	**–0.29**	**–1.36**	**–1.22**	**0.62**	**0.80**

*Includes Angola.
Source: DOE International Petroleum Monthly
Data available in OGJ Online Research Center.

OECD total net oil imports

	Nov. 2007	Oct. 2007	Sept 2007	Nov. 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	–1,349	–1,191	–1,218	–1,441	92	–6.4
US	11,569	11,628	12,282	11,651	–82	–0.7
Mexico	–1,520	–1,217	–1,545	–1,761	241	–13.7
France	1,951	1,792	1,707	1,855	96	5.2
Germany	2,167	2,289	2,236	2,483	–316	–12.7
Italy	1,641	1,689	1,681	1,736	–95	–5.5
Netherlands	1,204	790	1,084	830	374	45.1
Spain	1,514	1,539	1,700	1,634	–120	–7.3
Other importers	4,148	4,252	4,174	4,127	21	0.5
Norway	–2,030	–2,165	–2,129	–2,459	429	–17.4
United Kingdom	168	84	251	330	–162	49.1
Total OECD Europe	**10,763**	**10,270**	**10,704**	**10,536**	**227**	**2.2**
Japan	5,101	4,825	4,503	5,169	–68	–1.3
South Korea	1,909	2,194	2,152	2,305	–396	–17.2
Other OECD	877	913	873	865	12	1.4
Total OECD	**27,350**	**27,422**	**27,751**	**27,324**	**26**	**0.1**

Source: DOE International Petroleum Monthly
Data available in OGJ Online Research Center.

OECD* total gross imports from OPEC

	Nov. 2007	Oct. 2007	Sept 2007	Nov. 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	410	429	538	459	–49	–10.7
US	5,941	5,606	6,250	5,703	238	4.2
Mexico	32	31	40	33	–1	–3.0
France	792	766	848	781	11	1.4
Germany	360	420	448	441	–81	–18.4
Italy	1,272	1,255	1,210	1,399	–127	–9.1
Netherlands	555	537	665	717	–162	–22.6
Spain	562	730	732	744	–182	–24.5
Other importers	1,310	1,296	1,266	1,326	–16	–1.2
United Kingdom	257	273	244	294	–37	–12.6
Total OECD Europe	**5,108**	**5,277**	**5,413**	**5,702**	**–594**	**–10.4**
Japan	4,419	4,326	3,927	4,511	–92	–2.0
South Korea	2,158	2,549	2,298	2,476	–318	–12.8
Other OECD	695	802	738	716	–21	–2.9
Total OECD	**18,763**	**19,020**	**19,204**	**19,600**	**–837**	**–4.3**

*Organization for Economic Cooperation and Development.
Source: DOE International Petroleum Monthly
Data available in OGJ Online Research Center.

US petroleum imports from source country

	Nov. 2007	Oct. 2007	Average YTD 2007	Average YTD 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	1,000 b/d					
Algeria	447	410	677	657	20	3.0
Angola	415	342	513	527	–14	–2.7
Kuwait	154	157	185	186	–1	–0.5
Nigeria	1,306	1,241	1,119	1,118	1	0.1
Saudi Arabia	1,620	1,400	1,471	1,461	10	0.7
Venezuela	1,381	1,388	1,359	1,433	–74	–5.2
Other OPEC	618	668	648	162	486	300.0
Total OPEC	**5,941**	**5,606**	**5,972**	**5,544**	**428**	**7.7**
Canada	2,431	2,411	2,432	2,343	89	3.8
Mexico	1,581	1,417	1,553	1,737	–184	–10.6
Norway	100	110	144	198	–54	–27.3
United Kingdom	210	287	282	279	3	1.1
Virgin Islands	414	357	342	327	15	4.6
Other non-OPEC	2,518	2,762	2,768	3,370	–602	–17.9
Total non-OPEC	**7,254**	**7,344**	**7,521**	**8,254**	**–733**	**–8.9**
TOTAL IMPORTS	**13,195**	**12,950**	**13,493**	**13,798**	**–305**	**–2.2**

Source: DOE Monthly Energy Review
Data available in OGJ Online Research Center.

Oil stocks in OECD countries*

	Nov. 2007	Oct. 2007	Sept. 2007	Nov. 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million bbl					
France	177	176	187	190	–13	–6.8
Germany	272	275	278	281	–9	–3.2
Italy	130	132	134	133	–3	–2.3
United Kingdom	98	103	99	106	–8	–7.5
Other OECD Europe	673	660	675	658	15	2.3
Total OECD Europe	**1,350**	**1,346**	**1,373**	**1,368**	**–18**	**–1.3**
Canada	197	201	195	181	16	8.8
US	1,686	1,707	1,719	1,745	–59	–3.4
Japan	622	629	630	650	–28	–4.3
South Korea	149	159	157	158	–9	–5.7
Other OECD	106	112	108	108	–2	–1.9
Total OECD	**4,110**	**4,154**	**4,182**	**4,210**	**–100**	**–2.4**

*End of period.
Source: DOE International Petroleum Monthly Report
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EPA, Congress share blame for high fuel prices

Congressional oil-price inquisitions target the wrong people. Government officials, not oil-company executives, should have to answer for zooming prices.

As Rep. Edward J. Markey (D-Mass.) on Mar. 12 announced a new grilling of oil executives, the Environmental Protection Agency was raising the costs of gasoline manufacture.

Markey has summoned chief executives

The Editor's Perspective

by Bob Tippee, Editor

of the five largest major oil companies to an Apr. 1 hearing of the House Select Committee on Energy Independence and Global Warming, which he chairs. He'll try to make them look responsible for painful gasoline prices.

EPA, meanwhile, has toughened federal air-quality standards for ozone in a move that will squeeze fuel consumers far more than anything oil executives can do.

By lowering the 8-hr ozone standard to 0.075 ppm from 0.08 ppm, EPA will push new areas of the US into noncompliance.

This will happen as new mandates for renewable fuels, enacted by Congress last December, take effect. Those mandates aggravate ozone pollution. Biodiesel increases emissions of nitrogen oxides. Ethanol puts volatile organic compounds into the air. In sunlight, those compounds form ozone.

So EPA is raising an ozone standard that Congress, by lifting renewable-fuel standards, is making increasingly difficult to achieve.

The problem will be most severe when summertime volatility limits take effect for gasoline. Areas newly out of compliance with air-quality standards because of the new ozone standard will lower gasoline volatility limits or require reformulated gasoline, which doesn't qualify for volatility waivers available to conventional fuel.

To accommodate growing volumes of high-volatility ethanol, refiners will have to reject growing volumes of light gasoline components. This will lower supply as demand rises at the start of driving season, further lifting the costs of making gasoline and raising prices at retail.

EPA says new scientific evidence about health effects forced it to toughen the ozone standard. That evidence is controversial. And continuing improvement in ozone pollution under the existing standard casts doubt on the need to act and wisdom of doing so while gasoline prices are high.

EPA can't worry about gasoline prices, though. It can't by law-a law written by blame-dodgers like Markey.

(Online Mar. 14, 2008; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Measuring 'extreme' oil prices

For seven sessions Mar. 5-13, the front-month crude contract consecutively set record high prices on the New York Mercantile Exchange as the US dollar fell to record lows vs. the euro and a 12-year low against the Japanese yen.

Crude climbed to an intraday high of $111/bbl Mar. 13 prior to a record $110.33/bbl closing as the weak dollar prompted investors and speculators to put their money into commodities like oil and gold, which for the first time hit $1,000/oz.

Adam Sieminski, chief energy economist for Deutsche Bank in New York, and Michael Lewis, the bank's head of global commodities research in London, issued a report Mar. 14 outlining several measures to examine how far oil prices would need to rise to represent extreme levels of valuation. "Although oil demand side fundamentals are deteriorating, we expect the oil price will be captivated by a collapsing US dollar, a relationship we hold with deep suspicion. A further 4% decline in the US dollar index would imply oil prices hitting $120/bbl," Sieminski said.

Although crude is at an all-time high in nominal terms, oil prices would have to hit $118/bbl to exceed earlier records in real terms "deflated by US consumer prices," Sieminski said.

Relative to per capita income, crude would have to reach $134/bbl to bring the purchasing power of "an average G7 consumer" from the group of seven industrialized nations—Canada, France, Germany, Italy, Japan, UK, and US—to 1981 levels. "In 1970, back in the days of cheap oil and prior to the 1973 and 1979 oil crises, oil prices were trading at around $3.50/bbl. At the same time the average G7 per capita income was around $3,400 and consequently sufficient to buy just over 1,000 bbl of oil each year," the report said. "Following the two surges in oil prices, purchasing power of an average G7 consumer deteriorated rapidly such that by 1981 an average G7 consumer was only able to buy 318 bbl of oil."

In this decade, the purchasing power of an average G7 consumer has deteriorated as oil prices climbed faster than incomes. "However, the oil price would need to average $134/bbl in 2008 to reduce the purchasing power of an average G7 consumer such that he or she would be able to buy just 318 bbl, or a similar level of purchasing power as prevailed in 1981. As a result, on this measure oil prices are not yet at extreme levels," the report concluded.

"West Texas Intermediate prices would have to rise to $150/bbl for oil as a percent of global gross domestic product to hit the all-time high that prevailed in 1980," the report said. "Crude prices would need to hit $145/bbl to raise energy expenditures as a percent of US disposable income to early 1980s levels."

Ethanol outlook

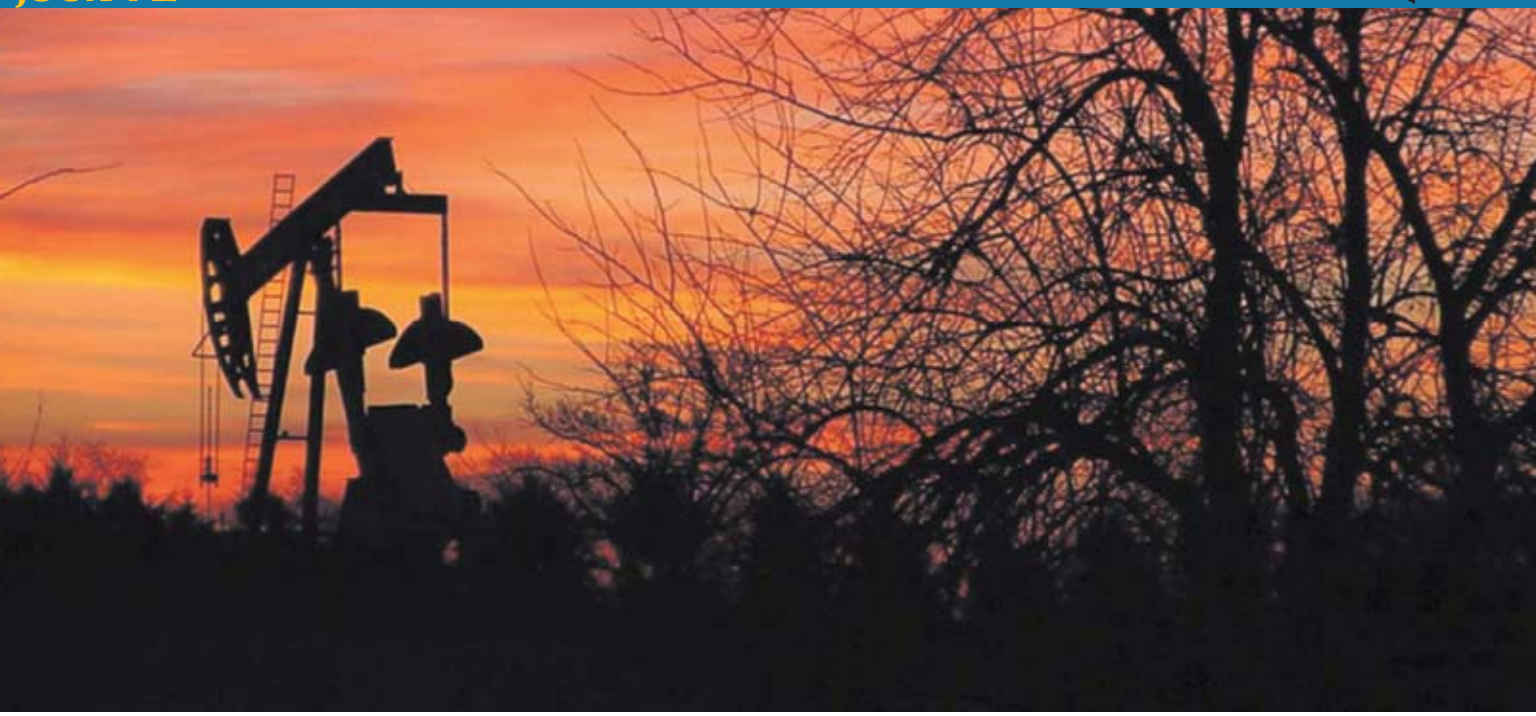
In a separate report, Sieminski said, "We believe population growth, rising incomes, and increased ethanol production will lead to a doubling in grains demand by 2050." But the major benefactor of that market will be Brazil and probably would require further encroachment on its rain forests. Brazil, Sieminski said, "is the only country in the world that combines 20% of the world's unused arable land, weather patterns which allow two annual harvests, political stability, and close proximity to US markets."

A broad-based market rally has boosted the nominal prices for soft grains—corn, wheat, rice, and soybeans—to record high levels. "However, in real terms prices are still significantly below the highs reached in the early 1970s," Sieminski said.

He said, "The US government has made a key strategic decision to increase the relevance of ethanol in its energy matrix over the next decade. We forecast that global soft grain demand for ethanol production should reach approximately 350 million tonnes by 2010 and 675 million tonnes by 2030. These figures are based on our calculations that US ethanol consumption will reach 13 billion gal by 2010 and 24 billion gal by 2030." Sieminski added, "We estimate that 26% of total growth in soft grains consumption between 2005 and 2050 will be driven by ethanol."

Sieminski said, "We believe that there is plenty of unused arable land available for agricultural purposes. We find that the world has approximately 4 billion hectares of potential arable land, of which 1.6 billion hectares was being used in 2005. If we factor in the increase in global soft grain demand coupled with stable crop yields going forward—an aggressive assumption as yields are likely to continue to rise—the amount of available arable land could decrease to just 600 million hectares by 2050."

(Online Mar. 17, 2008; author's e-mail: samf@ogjonline.com)



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- ✓ Initial production of 900 bbls on two wells that were expected to produce 25,000/ bopd.
- ✓ Operator already made a significant investment in drilling and well remediation without success.

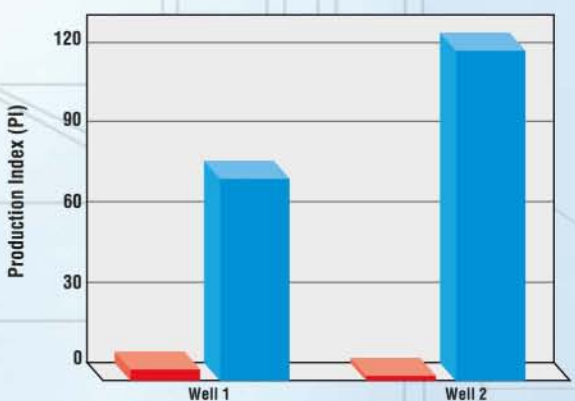
Solution:

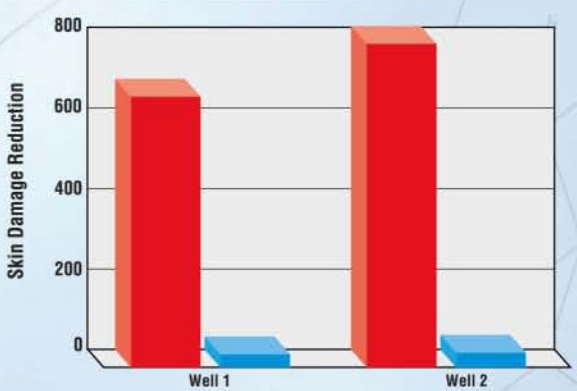
MICRO-WASH High Definition Remediation system

- ✓ MICRO-WASH system combines customized, proprietary technology with application expertise to remediate damaged reservoirs.
- ✓ Two open-hole volumes of MICRO-WASH system were applied with a coiled tubing unit across the sand screens and reservoir in each well.
- ✓ Following a 24-hour flow back period, a production log indicated that crude oil was flowing through 100% of the completion screens in both wells.

Results:

- ✓ The reservoir was effectively remediated and became a viable production asset.
- ✓ Delivered exceptional technical performance, removing severe damage and increasing production by more than 24,000/bopd.
- ✓ Reduced the skin damage in each well from 660 and 800 to 15 and 16 respectively.
- ✓ Increased the production index for each well from nearly zero to 75 and 130 respectively.
- ✓ Incremental value to the operator after MICRO-WASH system was $1.7M per day.





For customized solutions for your reservoir applications, contact Baker Hughes Drilling Fluids.

MICRO WASH

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