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OGJ200/100

NE Kansas well tests possibilities in Precambrian rocks
Triangle, Kerogen drilling Fayetteville shale gas
Acid-gas injection in New Mexico relieves SRU duty
Increased US ethanol output requires dedicated pipelines

OIL&GAS JOURNAL®

Sept. 17, 2007
Volume 105. 35

OGJ200/100

Regular Features

Cover

The OGJ200 list of companies has grown following years of consolidation. Despite a handful of mergers during 2006, the group now contains 144 US-based firms, up from 138 a year ago. Capital spending growth surged, as the group's combined earnings climbed 16% last year. This special report also includes the OGJ100, our annual look at the leading oil and gas companies based outside the US. The OGJ100 survey reveals improved financial results and decreased oil production among these 100 firms.

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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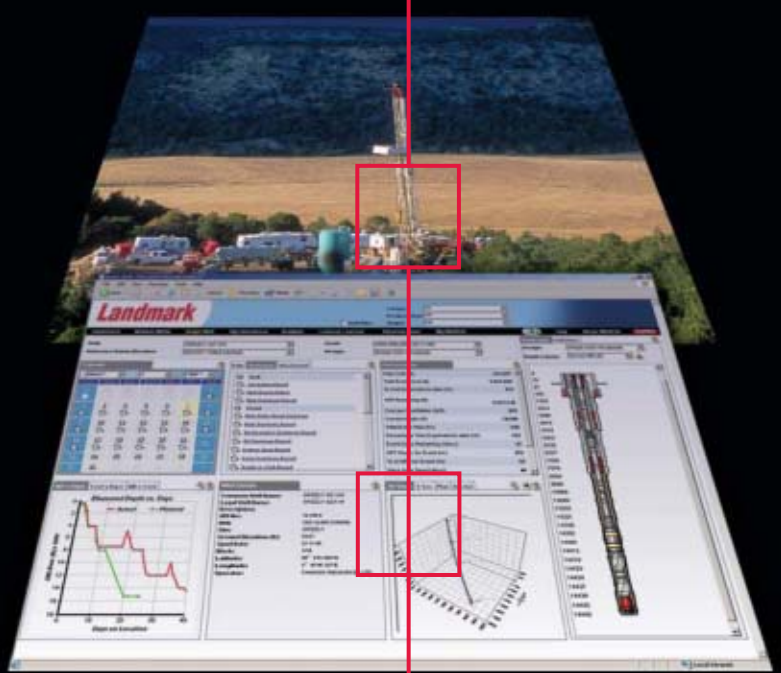

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Sept. 17, 2007

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General Interest — Quick Takes

Venezuela state oil firms to pay 'back taxes'

Venezuela's tax authority Seniat has received or been promised payments from two state-dominated joint venture firms after imposing large back-tax bills on recently nationalized heavy oil development projects in the country's Orinoco belt.

In a statement, Seniat said Ameriven paid some $400 million in back taxes from September 2001-December 2004, while Petrozuata agreed to pay $172 million for 1996-2006. The statement also said Cerro Negro was billed for $46 million in back taxes from 2001-04.

Petrozuata, now known as Petro Anzoategui, is 100% owned by state-run Petroleos de Venezuela (PDVSA), which also owns 70% of Ameriven, renamed Petro Piar in July. PDVSA controls 83.4% of Cerro Negro, now known as Petro Monagas.

The announcement, which comes after the state's recent takeover of majority control of Venezuela's energy projects, likely will be interpreted as a setback for ConocoPhillips and ExxonMobil Corp., which have been seeking compensation for the loss of their operations in the country.

When PDVSA started its takeovers, several international oil companies—among them BP PLC, Chevron Corp., Statoil ASA, and Total SA—came to terms over their continued minority involvement in the projects.

ConocoPhillips and ExxonMobil, however, failed to agree to handover terms that would have granted PDVSA at least a 60% stake in their projects. Failing any agreement, PDVSA appropriated ConocoPhillips's 30% share and ExxonMobil's 42%.

Nuke plant shutdown strains Asian markets

The July shutdown of Tokyo Electric Power Co.'s Kashiwazaki-Kariwa nuclear power plant will strain Asian LNG and oil markets.

Tomoko Hosoe, senior consultant at Facts Global Energy, Honolulu, said Tokyo Electric will have to buy 1.3 million tonnes more LNG than it planned in its current fiscal year and 87,900 b/d more fuel oil and crude for direct burning because of the shutdown.

The plant has been idle since June 26 because of an earthquake (OGJ, Aug. 6, 2007, p. 76).

Tokyo Electric now expects to need 18.8 million tonnes of LNG in fiscal 2007, compared with actual consumption of 16.8 million tonnes in 2006. It will need 180,900 b/d of fuel oil and crude vs. 69,600 b/d last year.

In a report, Hosoe described how Tokyo Electric's increased fuel requirements will affect Asian markets.

"An additional 2-3 million tonnes of LNG, which need to be secured from the spot market in 2007-08 in a very tight LNG market, is a serious problem," she said.

Tokyo Electric's increased oil demand, she added, will have "a dramatic impact" on prices of low-sulfur heavy fuel oil, low-sulfur waxy residue, and low-sulfur crude.

The 8.2 Gw Kashiwazaki-Kariwa plant is expected to remain closed through at least next March and might require at least a further year to return to full operation.

Firm applies for nuclear plant in Alberta

A privately held Canadian power generator has taken the first step toward construction of a nuclear power plant in the heart of Alberta's oil sands region.

Energy Alberta Corp., Calgary, filed an application for a license to prepare a site on private land adjacent to Lac Cardinal, 30 km west of Peace River.

The application is for as many as two, twin-unit Canadian deuterium uranium (CANDU) reactors. The first unit ultimately would have capacity of a net 2.2 Gw of electricity. Energy Alberta envisions a start-up date in early 2017.

Canada has seven commercial nuclear power plants, none of them in Alberta. They are in Ontario, New Brunswick, and Quebec.

Nuclear power has been examined as a way to meet the large energy needs of oil sands production, which now rely heavily on natural gas, while lowering the air emissions associated with hydrocarbon combustion.

But the nuclear option has strong environmental resistance.

Energy Alberta said its application to the Canadian Nuclear Safety Commission represents "the first of many steps in getting licenses to build the plant."

Nigeria to launch national energy council

Nigeria is to establish a new National Council on Energy in the next few weeks to discover ways to develop sufficient electric power capacity in the country over the next decade, according to Nigeria President Umaru Yar'Adua.

The council will invite experts in electric power and natural gas to propose ideas on the future development of the power sector. Yar'Adua has promised to declare a national emergency in the power sector to focus attention on it after the council is inaugurated.

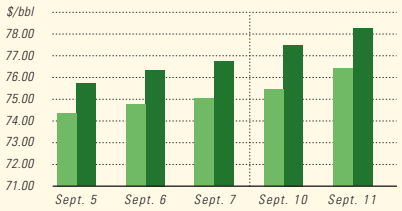
Nigeria needs adequate electric power generation to transform it into a modern economy and electricity networks are vital infrastructure, Yar'Adua said during a 3-day retreat for ministers, special advisers, and permanent secretaries in Abuja.

The council also will look at stabilizing the Niger Delta to get Nigeria back on track in oil and gas production. Militants from the Niger Delta have damaged infrastructure to pressure the federal government into granting them greater allocations of oil and gas revenues and development of their areas.

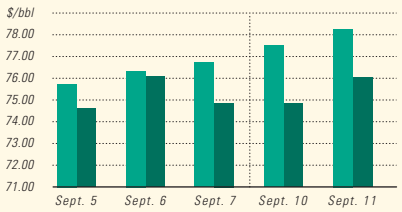
Nigeria's Vice-President Goodluck Jonathan has been in talks

Industry Scoreboard

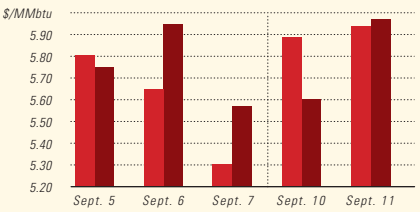
IPE BRENT / NYMEX LIGHT SWEET CRUDE



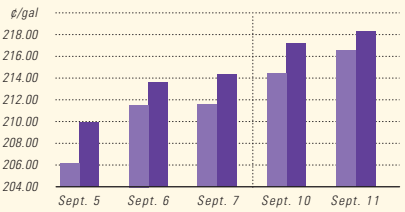
WTI CUSHING / BRENT SPOT



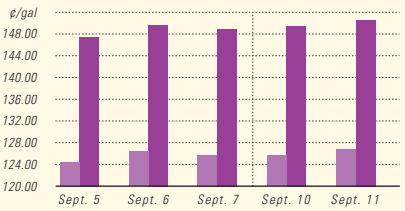
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



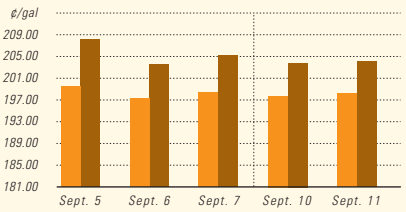
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



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

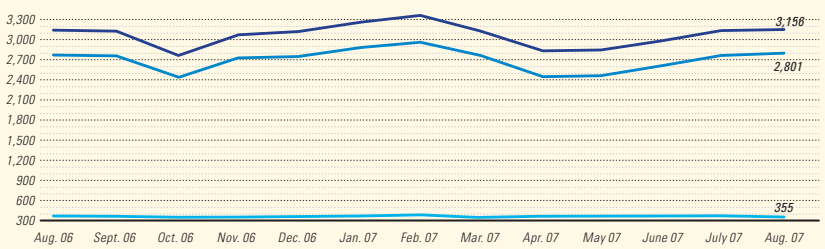
US INDUSTRY SCOREBOARD — 9/17

Latest week 8/31	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	9,643	9,585	0.5	9,321	9,222	1.1
Distillate	4,215	4,215	—	4,232	4,151	2.0
Jet fuel	1,656	1,618	2.3	1,626	1,618	0.5
Residual	796	756	5.3	767	720	6.5
Other products	4,981	5,148	–3.2	4,860	4,859	—
TOTAL DEMAND	21,282	21,322	–0.2	20,806	20,568	1.2
Supply, 1,000 b/d						
Crude production	5,123	5,155	–0.6	5,179	5,103	1.5
NGL production[2]	2,428	2,201	10.3	2,366	2,187	8.2
Crude imports	10,187	10,537	–3.3	10,063	10,102	–0.4
Product imports	3,324	4,075	–18.4	3,532	3,636	–2.9
Other supply[3]	1,023	1,251	–18.2	995	1,141	–12.8
TOTAL SUPPLY	22,085	23,219	–4.9	22,135	22,169	–0.2
Refining, 1,000 b/d						
Crude runs to stills	15,720	16,320	–3.7	15,268	15,221	0.3
Input to crude stills	15,956	16,215	–1.6	15,520	15,577	–0.4
% utilization	91.5	93.2	—	89.0	89.6	—

Latest week 8/31	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	329,660	333,632	–3,972	332,840	–3,180	–1.0
Motor gasoline	191,083	192,564	–1,481	206,162	–15,079	–7.3
Distillate	132,170	129,914	2,256	136,845	–4,675	–3.4
Jet fuel-kerosine	41,186	42,153	–967	41,608	–422	–1.0
Residual	36,375	38,599	–2,224	41,464	–5,089	–12.3
Stock cover (days)[4]			Change, %		Change, %	
Crude	21.0	21.3	–1.4	21.2	–0.9	
Motor gasoline	19.8	20.0	–1.0	21.5	–7.9	
Distillate	31.4	31.0	1.3	33.6	–6.5	
Propane	55.4	52.7	5.1	60.9	–9.0	
Futures prices[5] 9/7			Change		Change	Change, %
Light sweet crude, $/bbl	75.95	72.87	3.08	69.80	6.15	8.8
Natural gas, $/MMbtu	5.65	5.51	0.14	6.30	–0.66	–10.4

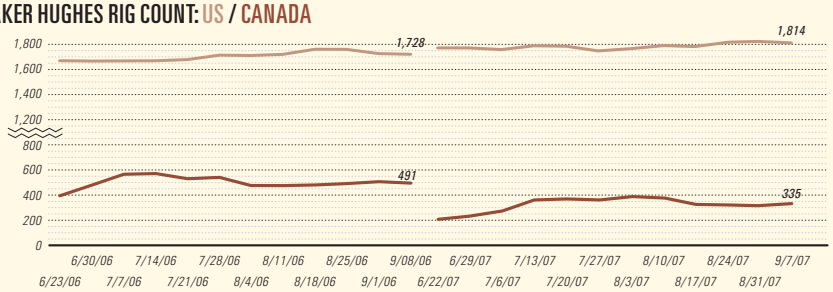
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average 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

with leaders of militant groups from the Niger Delta and Yar'Adua has said the federal government will begin to implement the Niger Delta master plan drawn up by Niger Delta Development Commission in partnership with the states in the region. ✦

Exploration & Development — *Quick Takes*

Wyoming Baxter shale gas flows without frac

Questar Corp., Salt Lake City, said it still has much to learn about the Cretaceous Baxter shale in the Vermillion subbasin in southwestern Wyoming after it began gas sales from a second horizontal well without treatment.

The Trail 14D-10H well in Sweetwater County, averaged 7 MMcfd of gas on 12/64-in. to 20/64-in. chokes in the first 24 hr with 7,100 psig initial flowing wellhead pressure. The well flowed from a 2,900-ft lateral in Middle Baxter after encountering multiple indications of natural fractures.

Questar set 4½-in. liner across the horizontal interval, perforated 850 ft of interval, and opened the well to sales. TD is 14,500 ft. Bottomhole location is in 9-13n-100w with surface location in Sec. 10.

The well, which produced at rates up to 9.1 MMcfd in the first 4 days on line, was making 2.7 MMcfd on a 12/64-in. choke on Sept. 4 with 3,300 psig flowing wellhead pressure. Questar's working interest is 100%.

The early results are encouraging, said Charles Stanley, president and chief executive officer of Questar E&P.

"We mapped, targeted, and drilled into multiple natural fractures. We perforated less than one third of the 2,900-foot horizontal section, and we produced gas at good initial rates without fracture stimulation," he said. "We believe natural fractures are the key to this play, and we think that the best way to tap the natural fracture network is with horizontal wells, but we still have much to learn about how to drill and complete these Baxter shale wells to optimize rate and recovery.

"We intend to produce the naturally completed 850-ft interval for a few weeks before making a decision to either fracture-stimulate the currently perforated section, or simply perforate the remaining 2,000 ft of lateral section."

Questar's first horizontal well in the play, Trail 13-15J, flowed 65 MMcf of gas in its first 11 days on production (OGJ Online, Feb. 27, 2007).

Iraq Taq Taq well tested at high oil rates

The fourth appraisal-development well in Taq Taq field in northern Iraq's Kurdistan area flowed 48° gravity oil at a combined rate of 37,560 b/d from three reservoirs, said Addax Petroleum Corp., Calgary.

The TT-7 well made 10,240 b/d from a 232-m barefoot interval in Shiranish, 10,250 b/d from a 111-m interval in Kometan, and 17,070 b/d from a 53-m interval in Qamchuqa, said Taq Taq Operating Co., a joint venture of Addax and Genel Enerji AS of Turkey. The flows were on 128/64-in., 7/64-in., and 128/64-in. chokes, respectively.

TT-7 is 2.9 km southeast of TT-4, which was on the crest of the structure. TD is 2,187 m. The companies are drilling the fifth and sixth wells in the program and have started shooting 290 sq km of 3D seismic over the field.

This is the highest rate of any Taq Taq well to date and will contribute to the Kurdistan regional government's goal of producing 1 million b/d of oil within 5 years, said Ashti Hawrami, minister of natural resources.

Addax said recent constructive efforts of the Kurdistan region and Iraq could result in a legal framework that will enable the corporation to begin full field development in 2008.

Gas-condensate find tested west of Shetland

Total SA gauged a gas-condensate discovery on Block 205/5a 100 km northwest of Sullom Voe west of the Shetland Islands.

The Tormore discovery well flowed 32 MMcfd of gas with 75 bbl of condensate per million cubic feet. TD is 3,936 m. The well is in 610 m of water 15 km southwest of the Total-operated Laggan discovery, successfully appraised in 2004 (see map, OGJ, Aug. 20, 2007, p. 38).

Total plans to evaluate the discovery's reserves in coming months.

Total operates Tormore with 47.5% interest. Partners are Eni UK Ltd. 22.5%, DONG E&P (UK) Ltd. 20%, and Chevron North Sea Ltd. 10%.

The Total group's proved and probable reserves in the UK exceeded 1 billion bbl of oil equivalent at the end of 2006. Total UK E&P's equity production on the UK Continental Shelf is 280,000 boe/d.

Imperial has two discoveries at Tomsk, Siberia

Imperial Energy Corp. reported two discoveries on its interests at Tomsk in Western Siberia.

Imperial said its North Chertalinskoye 403 exploration well identified potentially large oil deposits.

"The reservoirs are in the Bajenov, Jurassic, and Tyumen sections, with net oil pay in aggregate estimated at 68 m identified through logs and cores," Imperial said. The firm expects to flow-test the Tyumen section "by fraccing later this month, with the other sections to be tested during the winter period."

Imperial also said its Nyulginskoye-2 exploration well, which was spud in July, has identified "promising intervals of oil" in the Cretaceous and Tyumen sections.

"Net oil pay is estimated in aggregate to be 7 m through logs and cores," Imperial said. This well also is expected to be flow-tested later this month.

Meanwhile, Imperial said, its Tamratskoye-3 exploration well that was spud Aug. 27 is deeper than 1,000 m of its targeted depth of 3,000 m, while the Buranovskoye-2 exploration well on Block 74 was spud on Aug. 30 and is at 800 m of a targeted depth of 3,000 m.

The British firm said it expects to spud its South Maiskoye 395 exploration well on Block 70 later this month. ✦

Drilling & Production — *Quick Takes*

Production starts from North Sea's Blane field

Talisman Energy (UK) Ltd. has begun production from Blane oil field, which straddles the UK and Norwegian sectors of the North Sea.

Blane is about 160 miles east of Aberdeen on UKCS Block 30/3a and NCS Block N1/2. The field has been unitized at 82% and 18% respectively across the median line.

Production from two horizontal development wells drilled in 2006 is expected to peak at 17,000 b/d of oil equivalent.

The Blane development wells in the UK sector are tied back by pipeline to the Ula platform in the Norwegian sector.

Oil will be transported via the Ula Tambar system and Norpipe pipeline network to Teeside, UK.

Talisman said an injection well will be drilled in the fourth quarter.

Blane field was discovered in 1989 by well N1/2-1, which encountered oil in Paleocene Upper Forties sandstone. The structure was appraised via the 30/3a-1 well in the UK sector (OGJ Online, July 6, 2005).

Talisman Energy operates Blane field and holds a 43% interest. Partners include Eni UK Ltd. 13.9%, Eni ULX Ltd. 4.1%, Nippon Oil Corp. subsidiary MOC Exploration (UK) Ltd. 14%, Bow Valley Petroleum (UK) Ltd. 12.5%, and Roc Oil (GB) Ltd. 12.5%.

Whiting begins CO_2 flood at North Ward Estes

Whiting Petroleum Corp., Denver, has begun a field-wide carbon dioxide flood project in its North Ward Estes field covering 58,000 net acres in Ward and Winkler counties in Texas.

This represents the initial phase of a five-phase development project being carried out in the field through 2012 at an estimated cost of $639 million. The project's Phase 5, which would begin in 2013, has not been finalized, a company spokesman told OGJ.

The company began injecting 1 MMcfd of CO_2 in North Ward Estes field in May. Its current rate of injection is about 16 MMcfd.

By first quarter 2008, the company expects the injection rate to reach 100 MMcfd of CO_2.

Whiting has increased the field's injection wells to 440 from 180 and its producing wells to 935 from 580. These additions are the result of more drilling and converting inactive wells to producers, the spokesman said.

The field currently produces a net 5,300 b/d of oil. Peak production of 13,000 b/d of oil is expected in 2014. The field holds about 127 million boe in proved reserves as of Dec. 12, 2006.

Whiting acquired the field in 2005 from Celero Energy LP, Midland, for $459 million (OGJ Online, Oct. 7, 2005).

Aker completes Blind Faith semisubmersible hull

Aker Kvaerner ASA has completed the Froya deep-draft semisubmersible (DDS) hull for Chevron Corp.'s Blind Faith platform, which will use steel catenary risers for more-efficient exploration in ultradeepwater Gulf of Mexico.

The semisub is in a gulf integration yard to be outfitted with topsides. Once complete, the Blind Faith platform will be installed on Mississippi Canyon Block 650, about 162 miles southeast of New Orleans, in 6,500 ft of water.

The platform will produce 45,000-60,000 b/d of oil and 45-150 million cu m/day of gas from the high-temperature, high-pressure field that will start producing in first-quarter 2008. Initial production will be through three wells at rates of 30,000 b/d of oil and 30 MMcfd of gas (OGJ, Oct. 17, 2005, Newsletter).

Aker Kvaerner's DDS concept will enable the Blind Faith platform to reduce Chevron's operating costs, as operators will not have to continually change the flexible risers, and the platform will not move as much in the water, compared with others.

Chevron, with partner Anadarko Petroleum Corp., awarded the original engineering, procurement, and construction contract to Aker Kvaerner in October 2005.

GSF orders newbuild ultradeepwater rig

GlobalSantaFe Corp. is adding to its deepwater drilling fleet and has signed a turnkey contract with Hyundai Heavy Industries Ltd. for a newbuild ultradeepwater drillship.

The vessel, to be built in Ulsan, South Korea, at an estimated cost of $740 million, is scheduled for delivery in September 2010.

It is a next-generation drillship that combines the best features of GSF's drillships and semisubmersibles in a single unit, said GSF Pres. and Chief Executive Jon Marshall.

The vessel is an enhanced version of company's GSF C.R. Luigs and GSF Jack Ryan drillships, which entered service in 2000. Like those rigs, it will be capable of drilling in as much as 10,000 ft of water and upgradeable to 12,000 ft.

Also, the rig will feature advanced dynamic-positioning capabilities, triple activity load paths, a derrick rated for 4 million lb, dual liquid-storage systems, larger quarters, and an efficient deck design that provides more space than previous-generation drillships. ✦

Processing — *Quick Takes*

ExxonMobil plans Singapore steam cracker

ExxonMobil Chemical Co. plans to build a second world-scale steam cracker complex at its existing site in Jurong, Singapore (OGJ Online, Nov. 29, 1999).

The multibillion plant will be fully integrated with the company's 605,000 b/cd refinery and chemical plant, providing feedstock, operating, and investment synergies. The initial chemical plant began operating in 2001.

The new plant, expected to start up in early 2011, will include a 1 million tonne/year ethylene steam cracker, two 650,000 tpy polyethylene units, a 450,000 tpy polypropylene unit, a 300,000 tpy specialty elastomers unit, an aromatics extraction unit to produce 340,000 tpy of benzene, and an oxo-alcohol expansion of

125,000 tpy. A 220-Mw electric power cogeneration unit also will be built.

ExxonMobil Asia Pacific Pte. Ltd. has awarded the design, engineering, procurement, and construction contract for the steam cracker recovery unit to Shaw Group.

Mitsui Engineering & Shipbuilding and Heurtey Petrochem Group have been selected as EPC contractors for the steam cracker furnaces. Mitsui also received EPC contracts for the polypropylene and specialty elastomers units.

Mitsubishi Heavy Industries has been awarded the EPC for the two polyethylene units.

SP Chemicals plans petrochemical complex in Vietnam

SP Chemicals Ltd., Singapore, has signed a tentative agreement with Vietnam to build a $5 billion petrochemical complex at Phu Yen, about 560 km northeast of Ho Chi Minh City.

SP plans to submit its proposal to Vietnam's prime minister next year, according to Vo Dinh Tien, an official with central Phu Yen province's planning and investment department.

If the prime minister approves the project, construction would begin in 2009 on 1,300 ha, Tien said. The aim of the project is to supply domestic as well as export markets.

SP is expected initially to invest $1.5 billion to build several petrochemical facilities in that area from 2009-14. SP then will invest $3.5 billion to enlarge the complex.

A refinery and a port that can accommodate ships as large as 250,000 dwt also will be built as part of the project, Tien said. The completed complex is expected to attract further investment of $6 billion from foreign and domestic companies, he said.

Total to build desulfurization unit at German refinery

Total SA will invest $163.6 million to construct a 1 million tonne/year desulfurization unit at its Leuna refinery in Germany by fall 2009. Total will supply the domestic market with ultralow-sulfur heating oil.

Leuna, which Total described as one of the most efficient refineries in Europe, has a capacity of 227,000 b/cd and is able to process sour crude without producing heavy fuel oil.

Total said the project is part of its strategy to upgrade its refining base. It follows the commissioning of a distillate hydrocracker at the 140,600 b/d Normandy refinery in late 2006, the construction of a desulfurization unit and steam methane reformer at the 221,280 b/d Lindsey Oil refinery in the UK, and desulfurization capacity extensions carried out or under way at the Flandres, Provence, and 115,600 b/d Feyzin refineries in France.

Petrobras awards expansion of Cubatao refinery

Brazil's state-owned oil company Petroleo Brasileiro SA (Petrobras) has awarded a contract to Swedish construction group Skanska AB and its Brazilian partner Engevix Engenharia for an $84 million expansion of a refinery in Brazil, reported Skanska.

The contract covers construction of a sulfur recuperation unit and a residual gas treatment unit at the 162,800 b/d Presidente Bernardes refinery in Cubatao.

Skanska's share of the project comprises detailed engineering, procurement, construction and assembly, commissioning, and start-up assistance, and is valued at $55 million.

The project is to start immediately and is scheduled to be completed in 29 months, Skanska said. ✦

Transportation — *Quick Takes*

Konys-Kumkol oil pipeline opens in Kazakhstan

KuatAmlonMunai, a Chinese-Kazakh joint venture, has commissioned a 73-km crude oil pipeline from Konys field in Kazakhstan to Kumkol. It will deliver as much as 2,000 cu m/day of oil from Konys field to the Atasu-Alashankou export pipeline.

Built at a cost of 1.7 billion tenge, the Konys-Kumkol pipeline and pumping station will upgrade oil transportation in southern Kazakhstan, which earlier relied on deliveries by tanker truck from Konys to Kyzylorda and then by rail to eastern Kazakhstan.

KuatAmlonMunai, a 50:50 joint venture of China National Petroleum Corp. Ltd. and Kuat Holding Co., plans to produce 721,300 tonnes of oil this year, up more than 50% from the 417,500 tonnes produced in 2006. Officials said the new pipeline will speed deliveries of oil to China and will greatly reduce transport costs.

Gazprom seeks Japan Bank funding for Sakhalin-2

Russia's OAO Gazprom, said to be faced with financial constraints over the Sakhalin-2 LNG energy project, has resumed negotiations with the Japan Bank for International Cooperation (JBIC) to secure needed funding.

The European Bank for Reconstruction and Development, which had been central to Sakhalin-2's initially planned lending syndicate, withdrew in August due to concerns over Gazprom's efforts, perceived as illegitimate, to gain control of the development.

In April Gazprom acquired a 50%-plus-one share in the Sakhalin Energy Investment Co. for $7.45 billion under an agreement with SEIC shareholders (OGJ Online, Apr. 24, 2007).

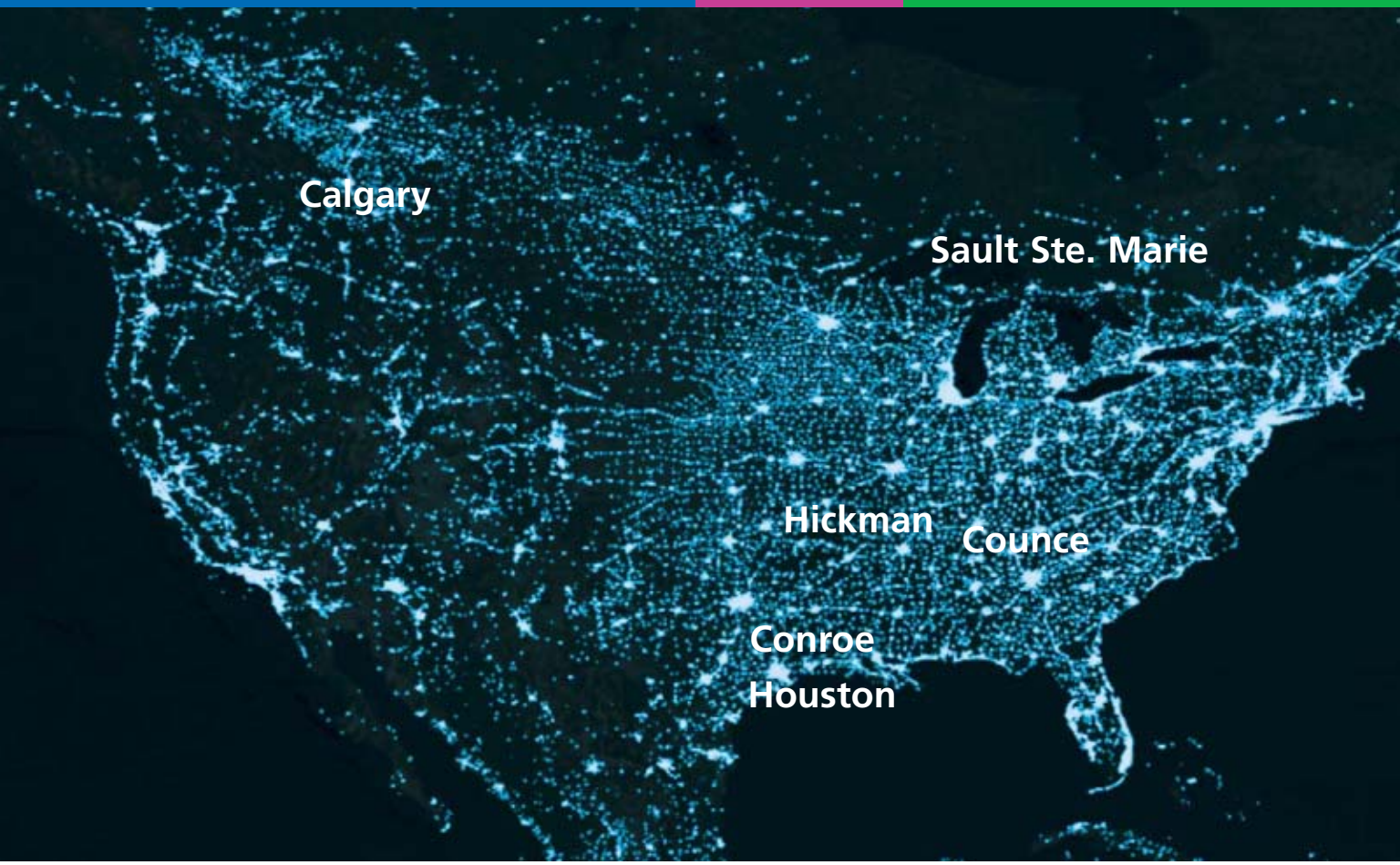
SEIC stakeholders—Royal Dutch Shell PLC, Mitsui & Co., and Mitsubishi Corp.—were forced to sell their majority stake to Gazprom following Russia's halting construction on the project for alleged environmental infractions.

Absent EBRD, Gazprom is seeking new backers to meet the project's 2-trillion-yen cost. Gazprom Deputy Chairman Alexander Medvedev said his firm and the three minority partners have reached a memorandum of understanding for JBIC financing.

Medvedev also said JBIC would consider financing other oil and gas development projects in such areas as East Siberia, a region of key concern to Japan.

Russia has long insisted that development of hydrocarbon resources in East Siberia would be essential to the development of the East Siberia Pacific Ocean oil pipeline that Japan has long sought.

In February, Russian Minister of Industry and Energy Viktor Khristenko made clear that his country would like Japanese investment in the development of East Siberian crude and gas reserves as part of the ESPO pipeline project (OGJ Online, Feb. 26, 2007). ✦



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Letters

Ethics questions

I incorporate a lot of ethics discussion in the finance classes I teach. In particular, the last assignment my finance graduate students have before completing the masters program is a lengthy paper that focuses on governance at a public company of their choosing.

So I found the column, "Ethics survey", of interest (OGJ, Aug. 27, 2007, p. 17. Unfortunately, it raises more questions for me than it answers.

First, I have no idea what standards Ethisphere (the organization that conducted the survey) actually has. The closest I can come from the column is that the standards are (per Step 7) influenced heavily by "nearly two dozen nongovernmental organizations and socially responsible investment firms." This criterion is weak and subjective, especially since we do not know the biases of the sampled group.

Let me use Wal-Mart to illustrate the problem with this standard. Most new stores the company opens have far more job applicants than positions available. Evidently, potential employees do not find the company's employment practices exploitative.

Nonetheless, Wal-Mart is berated routinely as exploitative by various "nongovernmental organizations." Are these groups among those in the Ethisphere sample? Arguably, these organizations have an axe to grind: unionizing the stores. In any event, the organizations' views amount to saying that people who want to work at Wal-Mart under the company's current policies would be better off unemployed.

My point isn't to defend or promote Wal-Mart. Rather, it's to argue that "nongovernmental organizations and socially responsible investment firms" have their own agendas; why should I (or anyone else) accept them unquestioningly as arbiters of my ethical views?

Let me address three other points in Ethisphere's "Eight steps": Steps 1 (litigation), 6 (governance), and 8 (programs and systems).

Step 1: Why should litigation be indicative of anything but the "deep pockets" of the party being sued? Filing

lawsuits is essentially free in the US, which does not normally require the loser to pay legal and court costs. Litigation in countries such as the UK, which has a "loser pays" rule, might be more indicative of substantive issues.

Step 6: I have little idea what constitutes "governance" in this context. In terms of the rest of your column, I infer that that governance has to do with established written policies and procedures. If one believes that written policies establish the presumption of ethical behavior, however, I suggest that one read the constitutions of, say, Russia and China and compare the text with reports of actual actions. Closer to home, Fortune held Enron up as a model of corporate governance in, I believe, 2000, based on its explicit policies (including board membership).

Finally, Step 8 is out of this world. In essence, if a company chooses not to respond to Ethisphere, Ethisphere won't consider it as highly ethical. Who is Ethisphere to insist on cooperation? And, if Ethisphere is entitled to insist on a response, how about the next hundred organizations that call? Who pays the costs of responding substantively to everybody who might come calling?

R. L. Promboin, PhD
Collegiate Professor
University of Maryland University College
Vienna, Va.

Calendar

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

OIL&GAS JOURNAL online

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

2007

SEPTEMBER

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

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

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

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

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

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

Rice Engineering & Construction Forum, Houston, (713) 552-1236, ext. 3, (713) 572-3089 (fax), e-mail: riceglobalforum@theassociationnetwork.com, website: www.forum.rise.edu. 25.

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

Annual Engineering & Construction Contracting

Calendar

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

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

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

OCTOBER

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

xGPA Houston Annual Meeting, Kingwood, Tex., (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 16.

Global E&P Technology Summit, Barcelona, +44 (0) 20 7202 7511, e-mail: anne.shildrake@wtgevents.com, website: www.eptsummit.com. 16-17.

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

PIRA New York Annual Conference, New York, 212-686-6808, 212-686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 18-19.

SPE/IADC Middle East Drilling and Technology Conference, Cairo, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 22-24.

World Energy & Chemical Exhibition and Conference, Kuwait City, +32 2 474 8264, +32 2 474 8397 (fax), e-mail: d.boon@bruexpo.be, website: www.wecec-kuwait.com. 22-25.

Annual Natural Gas STAR Implementation Workshop, Houston, (781) 674-7374, e-mail: meetings@erg.com, website: www.epa.gov/gasstar. 23-24.

Louisiana Gulf Coast Oil Exposition (LAGCOE), Lafayette, (337) 235-4055, (337) 237-1030 (fax), website: www.lagcoe.com. 23-25.

Pipeline Simulation Interest Group Annual Meeting, Calgary, Alta, (713) 420-5938, (713) 420-5957 (fax), e-mail: info@psig.org, website: www.psig.org. 24-26.

GSA Annual Meeting, Denver, (303) 357-1000, (303) 357-1070 (fax), e-mail: gsaservice@geosociety.org, website: www.geosociety.org. 28-31.

TAML Multilateral Knowledge-Sharing Conference, Reims, +44 (0) 1483 598000, e-mail: info@taml.net, website: www.taml.net. 29.

Expandable Technology Forum, Reims, +44 (0) 1483 598000, e-mail: info@expandableforum.com, website: www.expandableforum.com. 30-31.

Asia Pacific Oil and Gas Conference and Exhibition, Jakarta, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. Oct. 30-Nov. 1.

Chem Show, New York City, (203) 221-9232, ext. 14, (203) 221-9260 (fax), e-mail: mstevens@iecshows.com, website: www.chemshow.com. Oct. 30-Nov. 1.

Methane to Markets Partnership Expo, Beijing, (202) 343-9683, e-mail: asg@methanetomarkets.org, website: www.methanetomarkets.org/expo. Oct. 30-Nov. 1.

NOVEMBER

IADC Annual Meeting, Galveston, Tex., (713) 292-1945, (713) 292-1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 1-2.

Deepwater Operations Conference & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepwateroperations.com. 6-8.

IPAA Annual Meeting, San Antonio, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org/meetings. 7-9.

Regional Mangystau Oil & Gas Exhibition & Conference, Aktau, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 7-9.

GPA North Texas Annual Meeting, Dallas, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 8.

GPA North Texas Annual Meeting, Dallas, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 8.

SPE Annual Technical Conference and Exhibition, Anaheim, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 11-14.

World Energy Congress, Rome, +39 06 8091051, +39 06 80910533 (fax), e-mail: info@micromegas.it, website: www.micromegas.it. 11-15.

API/NPRA Fall Operating Practices Symposium, San Antonio, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 13.

Houston Energy Financial Forum, Houston, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.accessanalyst.net. 13-15.

Turkemenistan International Oil & Gas Conference, Ashgabat, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 14-15.

✦Annual Unconventional Gas Conference, Calgary, Alta., (866) 851-3517, e-mail: conference@emc2events.com, website: www.csugconference.ca. 14-16.

Australian Society of Exploration Geophysicists International Geophysical Conference & Exhibition, Perth, (08) 9427 0838, (08) 9427 0839 (fax), e-mail: secretary@aseg.org.au, website: www.aseg.org.au. 18-22.

ERTC Annual Meeting, Barcelona, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 19-21.

Asia Pacific Natural Gas Vehicle Conference & Exhibition, Bangkok, +66 0 2617 1475, +66 0 2271 3223 (fax), e-mail: angva@besallworld.com,

website: www.angvaevents.com. 27-29.

IADC International Well Control Conference & Exhibition, Singapore, (713) 292-1945, (713) 292-1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 28-29.

DECEMBER

International Oil and Gas Industry Exhibition & Conference, Suntec, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: osea@oesallworld.com, website: www.allworldexhibitions.com. 2-5.

Middle East Nondestructive Testing Conference & Exhibition, Bahrain, +973 17 729819, +973 17 729819 (fax), e-mail: bseng@batelco.com.bh, website: www.mohandis.org. 2-5.

International Petroleum Technology Conference, Dubai, +971 4 390 3540, +971 4 366 4648 (fax), e-mail: iptc@iptcnet.org, website: www.iptcnet.org. 4-6.

IADC Drilling Gulf of Mexico Conference & Exhibition, Galveston, Tex., (713) 292-1945, (713) 292-1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 5-6.

Oil & Gas Maintenance & Technology Conference & Exhibition, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilandgasmaintenance.com. 9-13.

Pipeline Rehabilitation & Maintenance Conference & Exhibition, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilandgasmaintenance.com. 9-13.

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.

2008

JANUARY

Middle East Petrotech Conference and Exhibition, Bahrain, +60 3 4041 0311, +60 3 4043 7241 (fax), e-mail: mep@oesallworld.com, website: www.allworldexhibitions.com/oil. 14-16.

World Future Energy Summit, Abu Dhabi, +971 2 444 6011, +971 2 444 3987 (fax), website: www.wfes08.com. 21-23.

API Exploration & Production Winter Standards Meeting, Ft. Worth, Tex., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 21-25.

API/AGA Oil & Gas Pipeline Welding Practices Meeting, Ft. Worth, Tex., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 23-25.

International Forum Process Analytical Technology (IFPAC), Baltimore, (847) 543-6800, (847) 548-1811 (fax), e-mail: info@ifpacnet.org, website: www.ifpac.com. 27-30.

SPE/IADC Managed Pressure Drilling & Underbalanced Operations Conference & Exhibition, Abu Dhabi, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 28-29.

Offshore West Africa Conference & Exhibition, Abuja, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.offshorewestafrica.com. 29-31.

*Petroleum Exploration Society of Great Britain Geophysical Seminar, London, +44 (0)20 7408 2000, +44 (0)20 7408 2050 (fax), e-mail: pesgb@pesgb.org.co.uk, website: www.pesgb.org.uk. 30-31.

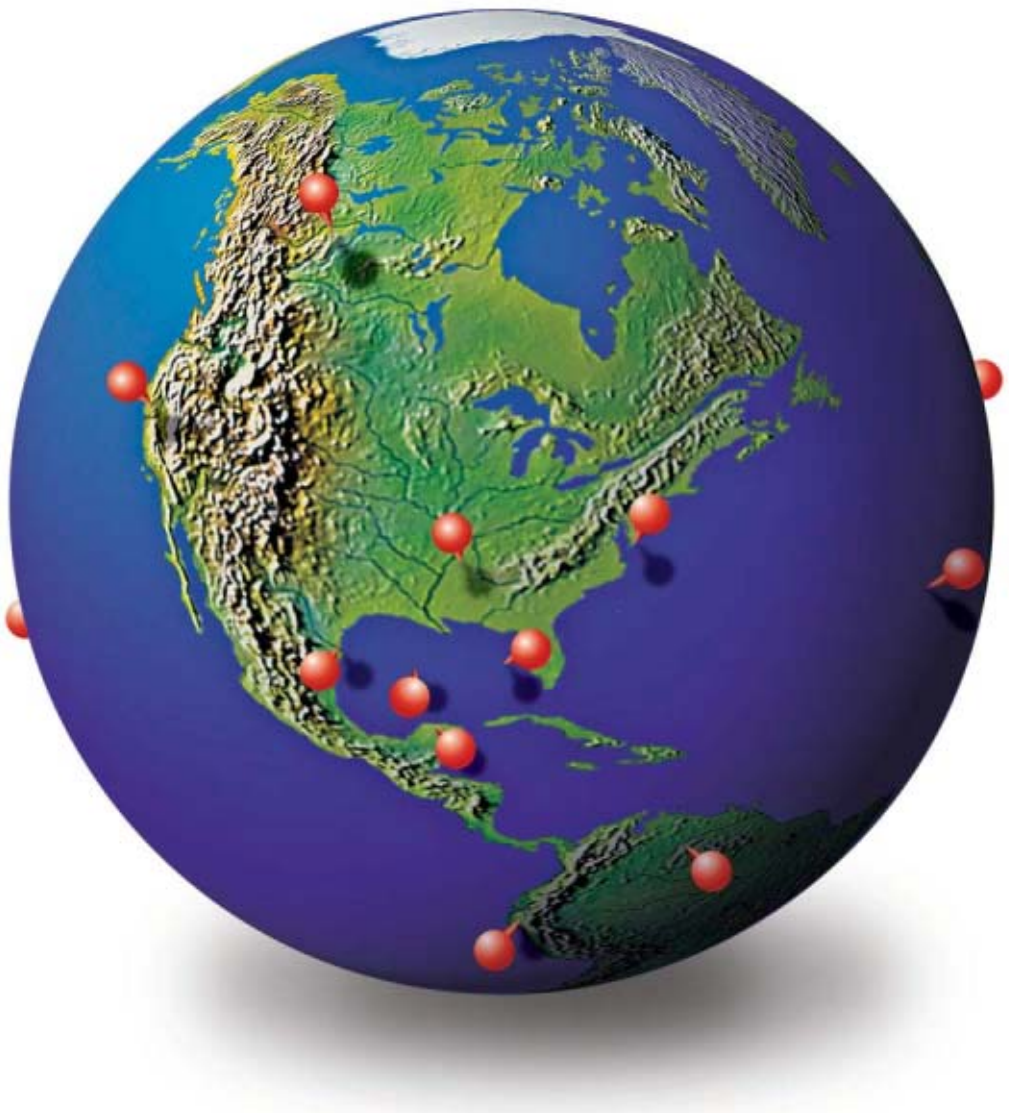
SIHGAZ International Hydrocarbon and Gas Fair, Hassi Messaoud, Algeria, website: www.sihgaz2008.com. Jan. 30-Feb. 3.

FEBRUARY

Middle East Corrosion Conference, Bahrain, + 973 17 729819, + 973 17 7299819 (fax), e-mail: bseng@batelco.com.bh, website: www.mohandis.org. 3-6.

IADC Health, Safety, Environment & Training Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 5-6.

SPE Heavy Oil Challenge: Completion Design and Production Management Forum, Sharm El Sheikh, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 9-13.



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OGJ200 popular, repopulating

Laura Bell
Statistics Editor

This week's issue includes Oil & Gas Journal's popular OGJ200 report. The report is a mainstay for many industry analysts, company executives, and financial traders, who use the information to determine how companies are faring in comparison with their competitors. OGJ200 ranks oil and gas firms in 14 financial and operational categories.

OGJ200 lists oil and gas companies whose headquarters are in the US and are publicly traded. In addition, each company must have crude oil or natural gas reserves and production located in the US in order to be included in the rankings. The compilation of data is a comprehensive snapshot of annual results.

History of OGJ200

As most longtime OGJ subscribers know, the OGJ200 originally was named the OGJ400. It was first published on Oct. 17, 1983, at a time when oil and gas companies were plentiful but financial results were dismal. Companies were hit hard by declining domestic and worldwide demand for oil and gas. Energy prices were depressed. Companies dependent on production for revenue suffered greatly.

That listing of 400 industry firms differs greatly from the current report. Some of the top 20 corporations listed in 1983 have since merged or otherwise been consolidated with other entities. Examples are Standard Oil of California, Atlantic Richfield, Gulf Oil, Tenneco, and Panhandle Eastern.

The report shrank in 1991 to become the OGJ300. Consolidation, acquisitions, mergers, and liquidation contributed to the slide of the number of operating companies. That trend continued throughout the 1990s. The list fell below 300 in 1995 to 281. Continued decline led to a change in the report name to the OGJ200 in 1996. Even though the list was shrinking, total assets for the group remained steady. Financial performance was strong as the US and worldwide demand experienced growth and energy prices rose.

In 1998, energy prices plunged, hurting the financial performance of the OGJ200 companies. Of the 200 companies in the 1999 report, almost two-thirds posted net losses for 1998. Group net income was down 89% from the year before. Only three companies qualified to be listed in the top 20 fastest grower's list, criteria for which include stockholder's equity and earnings growth. This is the only time in the history of the report that this has occurred.

After 2001, the number of companies that qualify for listing in the OGJ200 fell below 200. It reached a low of 138 in 2006. This year's report however, adds 12 companies to the group. Read about the group's 2006 financial and operating results starting on p. 20.

Data collection

Data for this mammoth report come from companies' 10-K reports filed with the US Securities and Exchange Commission. Additional data items come from companies' annual reports.

Every company must file a 10-K report with the SEC by deadlines that depend on the reported value of its public float, its stock shares available for trading. For instance, a corporation is deemed a "large accelerated filer" if it has more than $700 million of public float; it must file with the SEC within 75 days for fiscal years ending before Dec. 15, 2006, and 60 days for fiscal years ending on or after Dec. 15, 2006. An "accelerated" firm, with $75 million to $699 million of public float has 75 days, and a "small accelerated" firm has 90 days.

Smaller businesses can file an optional form for annual results or a transitional report called a 10-KSB; this form contains all data items that OGJ needs for inclusion to the OGJ200 listing.

OGJ starts collecting the data as soon as the information is available and continues to collect it up to our deadline. Occasionally, firms must file amendments to restate their financial results. In those cases, OGJ gathers and edits the data before going to print.

As a supplement to this report, quarterly financial results for the same group of companies are compiled and published in OGJ's sister magazine, Oil & Gas Financial Journal. Only financial data are available quarterly for this group. They're ranked in the same categories as the annual OGJ200. The August 2007 edition of OGFJ posts results for the quarter ending Mar. 31, 2007. ✦

Editorial

Ozone and ethanol

Before it tightens standards for ozone pollution, perhaps unnecessarily, the US government should fix programs that make current standards difficult to meet.

The Environmental Protection Agency proposes to lower the 8-hr primary ozone standard to 70-75 ppb from the current level, set in 1997, of 80 ppb. The primary standard is designed to protect human health. The agency further proposes to tighten its secondary standard, which is designed to protect "welfare," such as vegetation and crops.

Damage to health

In a fact sheet, EPA says "new scientific evidence" indicates that damage to health can occur after exposure to ozone at levels below the current standards, "particularly in those with respiratory illnesses." Ozone can reduce lung function. Exposure to it has been associated with indicators of health problems such as increases in susceptibility to respiratory infections, use of medicine by asthmatics, doctor and emergency-room visits, and hospital admissions. "Ozone exposure also may contribute to premature death in people with heart and lung disease," EPA says. The new scientific evidence also suggests that repeated exposure to low levels of ozone damages vegetation, trees, and crops.

If nothing were being done to reduce ozone pollution, those would be compelling reasons to act. But the US has been fighting ozone pollution for decades under the Clean Air Act. Nationwide, the effort has produced impressive results. During 1980-2006, air quality by the 8-hr ozone standard improved by 21%, according to EPA. The improvement during 1990-2006 was 9%. Emissions of ozone precursors also have fallen: of nitrogen oxides (NOx) by 33% in 1980-2006 and by 28% in 1990-2006 and of volatile organic compounds (VOCs) by 51% since 1980 and by 37% since 1990.

The main ozone problem now is nonattainment of the federal standards in urban areas with heavy vehicle traffic and plentiful sunlight. In most such areas, ozone pollution is diminishing, but attainment remains elusive, especially where vehicle traffic is growing.

Lowering the ozone limit would drag areas now barely meeting the standard into noncompliance, forcing motorists and businesses to incur new costs for emissions control. This might yield some health gains in whichever of such areas managed themselves back into compliance.

In the really troublesome ozone areas, however, the large cities that can't meet current standards, lower ozone limits would just push goals further out of reach and wouldn't affect health at all. In fact, the National Petrochemical and Refiners Association argues that scientific ambiguity raises doubt that compliance with toughened ozone standards would improve health anywhere. NPRA further notes that compliance through measures now at hand may not be possible in many areas.

EPA makes this new ozone move while another federal program renders current targets increasingly difficult for chronic problem areas to hit. The Renewable Fuel Standard (RFS) of the Energy Policy Act of 2005 is boosting emissions of ozone precursors with growing mandates for sales of ethanol in vehicle fuel. When it issued RFS regulations last April, EPA estimated that raising ethanol use would lift NOx emissions in areas not previously using large amounts of ethanol by 6-7% during 2004-12 and VOC emissions by 4-5%.

The ozone and RFS programs work against each other. In one program, EPA feels compelled by statute to lower the ozone threshold because new science, according to its interpretation, shows health to come under threat at exposure levels below the current standard. In the other, the agency administers the forced sale of a heavily subsidized fuel additive that aggravates ozone formation in some of the worst nonattainment areas.

Tough question

EPA didn't create this conflict. Congress did by passing laws without considering all the consequences, such as rising food costs and the potential health hazards of a fuel whose core appeal is that it makes corn growers and distillers rich. Congress can resolve the mess by injecting flexibility into the Clean Air Act and by repealing the ethanol mandate, the costs of which are only beginning to be obvious.

Early in an election season, EPA's initiative should force attention to a tough question: What's more important to lawmakers, farm-state votes or human health? ✦

OGJ200 expands as 2006 earnings, spending surge

Marilyn Radler
Senior Editor, Economics

Laura Bell
Statistics Editor

The OGJ200 group of companies posted a 16% gain in earnings for 2006, as capital expenditures surged and production and reserves increased. The number of companies qualifying for the group climbed for the first time since 1999, when the list was limited to the largest 200 firms.

OGJ began publishing its list of US-based, publicly traded oil and gas producing firms in 1983 as the OGJ400. This year's compilation contains 144 companies, up from last year's all-time low of 138.

Collectively, the current group of companies posted $110 billion in earnings during 2006. At $117 billion, the companies' capital and exploration expenditures were up sharply from a year earlier, and their combined revenues increased 5%.

List changes

Eleven companies appear in the OGJ200 for the first time this year, and another firm, Atlas America Inc., returns to the list.

Atlas America ranks No. 71 by assets and was previously included in the results of Resource America Inc., which last appeared in the report 2 years ago. In June 2005, Resource America spun off its oil and gas operations to Atlas America, with which Resource America formerly consolidated.

Six firms from the previous edition of the OGJ200 no longer appear in the compilation because of mergers and acquisitions (OGJ, Sept. 4, 2006, p. 20). They are Burlington Resources Inc., KCS Energy Inc., Kerr-McGee Corp., Natural Gas Systems Inc., Remington Oil & Gas Corp., and Western Gas Resources.

Altex Industries Inc., which last year ranked No. 134, is no longer listed. This Breckenridge, Colo., company sold its oil and gas assets last year.

Unavailable as of press time, the 2006 results of three of the companies that qualified for the compilation are not detailed in this report and are excluded from the group totals. These companies are Capco Energy Inc., Empiric Energy Inc., and Petrol Industries Inc.

KEY CHANGES FROM 2006 OGJ200

Table 1

How company appeared on last year's list	Why change?	How company appears on this year's list
Amerada Hess Corp.	Changed name to	Hess Corp.
Burlington Resources Inc.	Acquired by	ConocoPhillips
Cadence Resources Corp.	Changed name to	Aurora Oil & Gas Corp.
KCS Energy Inc.	Merged with	Petrohawk Energy Corp.
Kerr-McGee Corp.	Merged with	Anadarko Petroleum Corp.
Natural Gas Systems Inc.	Merged with and into	Evolution Petroleum Corp.
Remington Oil & Gas Corp.	Acquired by	Helix Energy Solutions Group Inc.
Western Gas Resources	Merged with	Anadarko Petroleum Corp.

The following company sold its US producing properties, liquidated, or became private since the last survey:
Altex Industries Inc.

TOP 20 IN TOTAL REVENUE

Table 2

Rank	Company	Total revenue, $1,000
1	ExxonMobil Corp.	377,635,000
2	Chevron Corp.	210,118,000
3	ConocoPhillips	188,523,000
4	Marathon Oil Corp.	65,449,000
5	Hess Corp.	28,720,000
6	Occidental Petroleum Corp.	18,160,000
7	Murphy Oil Corp.	14,307,387
8	Devon Energy Corp.	10,758,000
9	Anadarko Petroleum Corp.	10,187,000
10	Apache Corp.	8,288,779
11	Chesapeake Energy Corp.	7,351,058
12	XTO Energy Inc.	4,576,000
13	El Paso Corp.	4,281,000
14	EOG Resources Inc.	3,904,415
15	Dominion Exploration & Production	3,257,000
16	Noble Energy Inc.	2,940,082
17	Questar Corp.	2,848,500
18	Pogo Producing Co.	1,745,000
19	Newfield Exploration Co.	1,673,000
20	Pioneer Natural Resources Co.	1,632,881
	Total	**966,355,102**

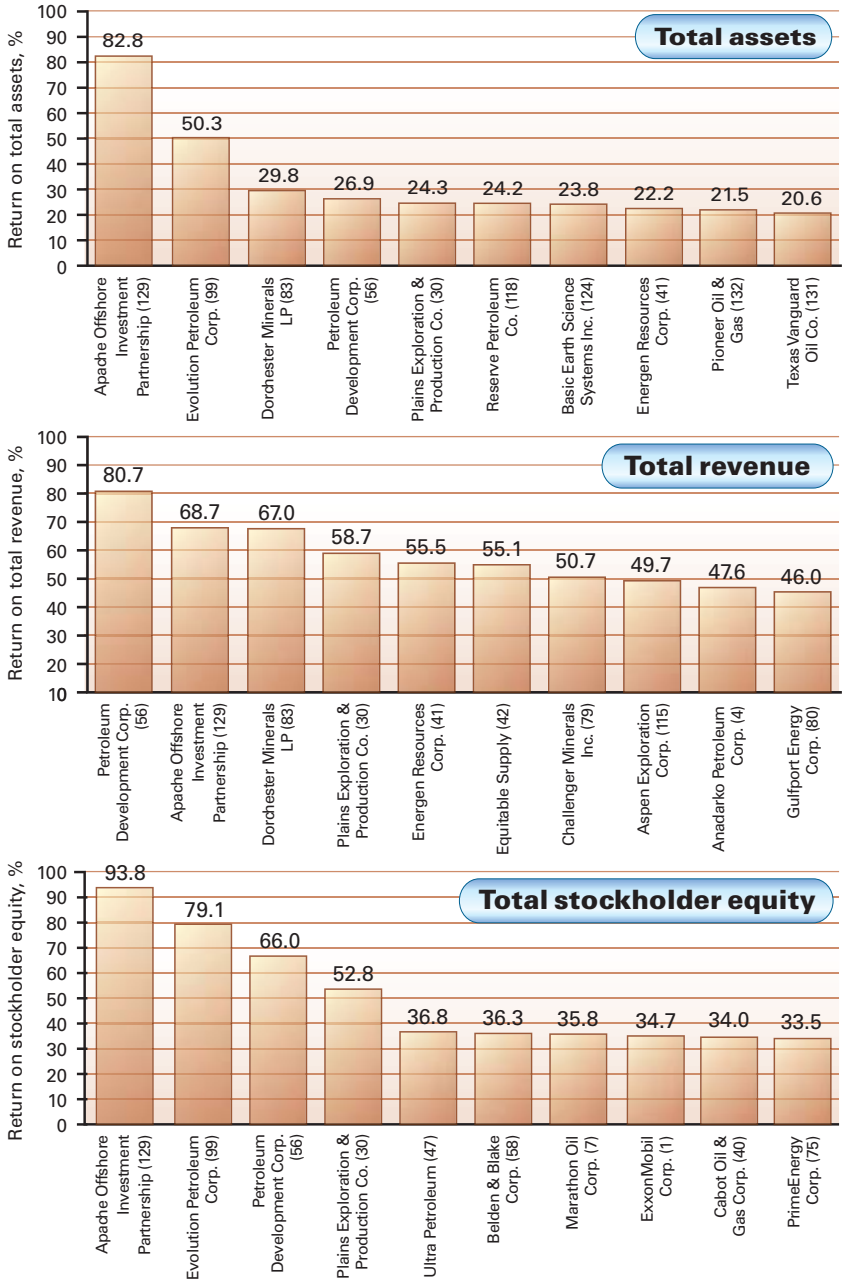
TOP 20 IN ASSETS—MARKET CAPITALIZATION[1]

Table 3

Rank	Company	Market capitalization, $1,000
1	ExxonMobil Corp.	439,013,270
2	ConocoPhillips	121,627,230
3	Chevron Corp.	159,159,967
4	Anadarko Petroleum Corp.	20,323,840
5	Devon Energy Corp.	29,785,465
6	Occidental Petroleum Corp.	41,013,202
7	Marathon Oil Corp.	32,168,807
8	El Paso Corp.	10,651,962
9	Chesapeake Energy Corp.	13,288,451
10	Apache Corp.	21,997,346
11	Hess Corp.	15,615,440
12	Dominion Exploration & Production[2]	29,260,160
13	XTO Energy Inc.	17,293,419
14	Noble Energy Inc.	8,451,508
15	EOG Resources Inc.	15,221,253
16	Williams Cos. Inc.[2]	15,596,252
17	Murphy Oil Corp.	9,538,046
18	Pioneer Natural Resources Co.	4,822,453
19	Pogo Producing Co.	2,830,293
20	Newfield Exploration Co.	5,935,990
	Total	**1,013,594,355**

[1]As of Dec. 31, 2006. [2]Based on parent company data.

TOP COMPANIES IN RETURN ON...*



*Includes subsidiary companies, whose accounting methods vary and who may be helped by contributions from parent companies. Excludes companies whose results were inflated by identifiable extraordinary gains. Excludes royalty trusts. Excludes companies that get only a small portion of their revenue from oil and gas. Numbers in parentheses indicate rank by total assets.

Market drivers

The OGJ200 companies benefited from higher oil prices last year than during 2005, but natural gas prices declined, and earnings were tempered by rising operating costs.

Worldwide economic growth and ensuing growth in oil demand combined with little spare production capacity and refinery glitches to put a floor under oil prices last year. The futures and wellhead prices of crude peaked in July amid tight refining conditions and strong product demand in the US.

At $66.31/bbl, the average closing futures price for crude oil on the New York Mercantile Exchange in 2006 was 17% higher than during the prior year.

Meanwhile, gas futures prices were down 21%, averaging $7.03/MMbtu for 2006. Gas prices peaked during the fourth quarter of 2005, following Gulf of Mexico production declines in the wake of a damaging hurricane season. From the start of 2006, gas prices weakened from those highs.

The OGJ200 firms with refining operations on the US West Coast and in the Midwest enjoyed higher cash refin-

20 FASTEST-GROWING COMPANIES[1]

Table 4

Rank by total assets	Company	Stockholders' equity 2006 $1,000	Stockholders' equity 2005 $1,000	Change, %	Net income 2006 $1,000	Net income 2005 $1,000	Change, %	Long-term debt 2006 $1,000	Long-term debt 2005 $1,000
23	Helix Energy Solutions Group Inc.	1,525,948	629,300	142.5	347,394	152,568	127.7	1,454,469	440,703
78	GMX Resources Inc.	131,481	61,225	114.8	8,975	7,156	25.4	41,569	1,410
82	Arena Resources Inc.	120,044	58,729	104.4	23,268	9,461	145.9	0	0
123	Blue Dolphin Energy Co.	9,572	4,788	99.9	913	541	68.8	0	0
27	W&T Offshore Inc.	1,042,917	543,383	91.9	199,104	189,023	5.3	413,617	40,000
56	Petroleum Development Corp.	360,144	188,265	91.3	237,772	97,390	144.1	117,000	24,000
9	Chesapeake Energy Corp.	11,251,471	6,174,323	82.2	2,003,323	948,302	111.3	7,375,548	5,489,742
26	Range Resources Corp.	1,256,161	696,923	80.2	158,702	111,011	43.0	0	0
58	Belden & Blake Corp.	143,703	89,399	60.7	52,199	17,243	202.7	0	0
40	Cabot Oil & Gas Corp.	945,198	600,211	57.5	321,175	148,445	116.4	220,000	320,000
2	ConocoPhillips	82,646,000	52,731,000	56.7	15,550,000	13,529,000	14.9	23,091,000	10,758,000
115	Aspen Exploration Corp.[2]	10,101	6,676	51.3	2,970	1,487	99.7	0	0
32	Denbury Resources Inc.	1,106,059	733,662	50.8	202,457	166,471	21.6	507,786	373,591
36	Quicksilver Resources Inc.	575,666	383,615	50.1	93,719	87,434	7.2	919,117	506,039
124	Basic Earth Science Systems Inc.[3]	8,560	5,736	49.2	2,815	1,845	52.6	445,000	0
80	Gulfport Energy Corp.	123,809	84,327	46.8	27,808	10,895	155.2	36,856	9,842
92	American Oil & Gas Inc.	62,088	42,331	46.7	1,211	1,082	11.9	0	0
21	Questar Corp.	2,205,500	1,549,800	42.3	444,100	325,681	36.4	1,022,400	983,200
13	XTO Energy Inc.	5,865,000	4,209,000	39.3	1,860,000	1,152,000	61.5	3,451,000	3,109,000
38	Unit Corp.	1,158,036	836,962	38.4	312,177	212,442	46.9	174,300	145,000

[1]Companies were selected on the basis of growth in stockholder's equity. Only companies with positive net income for both 2005 and 2006 were considered. Companies were not considered if they had a decline in net income for 2006, were subsidiaries of another company, or became public within the last year. [2]Fiscal yearend June 30. [3]Fiscal yearend Mar. 31.

TOP 20 IN NET INCOME AND STOCKHOLDERS' EQUITY

Table 5

Rank	Company	Net income, $1,000
1	ExxonMobil Corp.	39,500,000
2	Chevron Corp.	17,138,000
3	ConocoPhillips	15,550,000
4	Marathon Oil Corp.	5,234,000
5	Anadarko Petroleum Corp.	4,854,000
6	Occidental Petroleum Corp.	4,182,000
7	Devon Energy Corp.	2,846,000
8	Apache Corp.	2,552,451
9	Chesapeake Energy Corp.	2,003,323
10	Hess Corp.	1,916,000
11	XTO Energy Inc.	1,860,000
12	EOG Resources Inc.	1,259,576
13	Pioneer Natural Resources Co.	739,731
14	Dominion Exploration & Production	680,000
15	Noble Energy Inc.	678,428
16	Murphy Oil Corp.	638,279
17	Plains Exploration & Production Co.	597,528
18	Newfield Exploration Co.	591,000
19	Williams Cos. Inc.	529,700
20	El Paso Corp.	475,000
	Total	**103,825,016**

Rank	Company	Stockholders' equity, $1,000
1	ExxonMobil Corp.	113,844,000
2	ConocoPhillips	82,646,000
3	Chevron Corp.	68,935,000
4	Occidental Petroleum Corp.	19,184,000
5	Devon Energy Corp.	17,442,000
6	Anadarko Petroleum Corp.	14,913,000
7	Marathon Oil Corp.	14,607,000
8	Apache Corp.	13,191,053
9	Chesapeake Energy Corp.	11,251,471
10	Hess Corp.	8,111,000
11	XTO Energy Inc.	5,865,000
12	EOG Resources Inc.	5,599,671
13	El Paso Corp.	4,186,000
14	Noble Energy Inc.	4,113,817
15	Murphy Oil Corp.	4,052,676
16	Newfield Exploration Co.	3,062,000
17	Pioneer Natural Resources Co.	2,984,671
18	Cimarex Energy Co.	2,976,143
19	Pogo Producing Co.	2,567,400
20	Questar Corp.	2,205,500
	Total	**401,737,402**

ing margins last year than during 2005, according to Muse, Stancil & Co. Strong demand in these markets limited product supply and buoyed prices, especially during April-August of 2006.

Although they were strong in the second quarter of 2006, average margins for US Gulf Coast and East Coast refiners dipped last year from their full-year 2005 averages.

Exploration and production operating costs climbed as greater upstream activity increased demand for the inputs necessary to produce oil and gas. Companies paid more for labor, supplies, and services as a result.

Annual results

In addition to improved financial results, the OGJ200 companies reported a collective increase in worldwide oil and gas production and reserves during 2006.

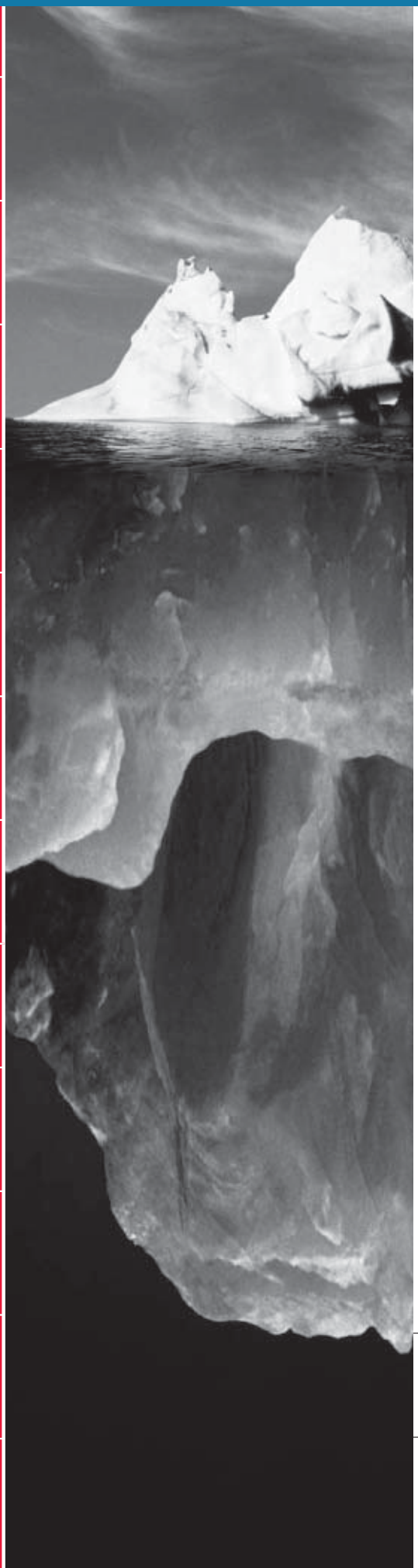
Last year, growth in the OGJ200 companies' spending and drilling programs surpassed 2005 growth rates. The group's capital spending last year increased 40%.

The 2006 capital spending surge resulted in a 27% increase in the number of US wells that the group drilled. The OGJ200 companies drilled 21,394 net wells in the US last year.

In 2005, the group's spending climbed 34%, and the number of US net wells that these companies drilled increased 24%.

The OGJ200 details each company's liquids and gas production and reserves worldwide and breaks out the results for the US. The group reported collective gains in nearly all categories for 2006. Results for natural gas were stronger than for oil.

The group's liquids production last year climbed 6% worldwide, but in the US liquids output was up just 1.8% from a year earlier. The group's liquids reserves increased 2% worldwide last



TOP 20 IN SPENDING AND US NET WELLS DRILLED

Table 6

Rank	Company	Capital, exploratory spending, $1,000
1	ExxonMobil Corp.	19,855,000
2	ConocoPhillips	15,596,000
3	Chevron Corp.	13,813,000
4	Devon Energy Corp.	7,551,000
5	Anadarko Petroleum Corp.	4,569,000
6	Apache Corp.	3,891,639
7	Hess Corp.	3,844,000
8	Chesapeake Energy Corp.	3,779,233
9	Marathon Oil Corp.	3,433,000
10	Occidental Petroleum Corp.	3,005,000
11	EOG Resources Inc.	2,819,230
12	El Paso Corp.	2,164,000
13	Dominion Exploration & Production	2,079,000
14	XTO Energy Inc.	2,047,000
15	Newfield Exploration Co.	1,693,000
16	Pioneer Natural Resources Co.	1,403,879
17	Williams Cos. Inc.	1,400,000
18	Noble Energy Inc.	1,357,039
19	Murphy Oil Corp.	1,191,670
20	Cimarex Energy Co.	1,030,791
	Total	**96,522,481**

Rank	Company	US net wells drilled
1	Chesapeake Energy Corp.	1,449.2
2	Dominion Exploration & Production	1,081.0
3	Chevron Corp.	986.0
4	Williams Cos. Inc.	954.0
5	XTO Energy Inc.	912.8
6	Anadarko Petroleum Corp.	873.8
7	Devon Energy Corp.	815.6
8	EOG Resources Inc.	762.0
9	ConocoPhillips	730.0
10	Range Resources Corp.	703.8
11	Noble Energy Inc.	687.4
12	Quest Resource Inc.	621.0
13	Occidental Petroleum Corp.	589.6
14	ExxonMobil Corp.	572.0
15	Newfield Exploration Co.	497.5
16	Equitable Supply	456.0
17	El Paso Corp.	433.0
18	Quicksilver Resources Inc.	382.4
19	Berry Petroleum Co.	365.0
20	Cimarex Energy Co.	346.2
	Total	**14,218.3**

TOP 20 IN LIQUIDS RESERVES

Table 7

Rank	Company	US liquids reserves, million bbl
1	ExxonMobil Corp.	1,884.0
2	Chevron Corp.	1,751.0
3	ConocoPhillips	1,679.0
4	Occidental Petroleum Corp.	1,678.0
5	Anadarko Petroleum Corp.	925.0
6	Apache Corp.	495.3
7	Pioneer Natural Resources Co.	406.7
8	Devon Energy Corp.	403.0
9	Plains Exploration & Production Co.	333.2
10	XTO Energy Inc.	267.4
11	Dominion Exploration & Production	216.8
12	Whiting Petroleum Corp.	195.0
13	Marathon Oil Corp.	172.0
14	Noble Energy Inc.	170.1
15	Encore Acquisition Co.	153.4
16	Hess Corp.	138.0
17	Kinder Morgan CO2 Co. LP	134.3
18	Denbury Resources Inc.	126.2
19	Berry Petroleum Co.	112.5
20	Forest Oil Corp.	107.2
	Total	**11,348.3**

Rank	Company	Worldwide liquids reserves, million bbl
1	ExxonMobil Corp.	8,194.0
2	Chevron Corp.	7,806.0
3	ConocoPhillips	6,696.0
4	Occidental Petroleum Corp.	2,264.0
5	Anadarko Petroleum Corp.	1,264.0
6	Apache Corp.	1,061.0
7	Devon Energy Corp.	983.0
8	Hess Corp.	832.0
9	Pioneer Natural Resources Co.	417.0
10	Plains Exploration & Production Co.	333.2
11	Noble Energy Inc.	296.1
12	XTO Energy Inc.	267.4
13	Dominion Exploration & Production	232.3
14	Whiting Petroleum Corp.	195.0
15	Murphy Oil Corp.	173.8
16	Pogo Producing Co.	163.3
17	Encore Acquisition Co.	153.4
18	Kinder Morgan CO2 Co. LP	134.3
19	Denbury Resources Inc.	126.2
20	EOG Resources Inc.	117.8
	Total	**31,709.8**

year, but US liquids reserves declined 0.4%.

The OGJ200 firms reported a 10% gain in worldwide natural gas production and a 7% increase in US gas production for 2006. And while the group's combined gas reserves in the US climbed 11% last year, the total was up 23% worldwide.

Financial performance

Growth in not only earnings but also stockholders' equity and total assets during 2006 outpaced revenue growth for the OGJ200 companies.

The group reported a 20% surge in yearend assets, totaling $942.4 billion at the end of 2006. Combined stockholders' equity climbed 21% to $431 billion.

Revenues increased to $993.5 billion last year on higher oil and gas production, but lower gas prices held growth in check. In 2005, this group of companies reported $942.7 billion in revenues.

In spite of higher operating costs, earnings climbed at a rate three times that of revenues. The OGJ200 firms posted collective earnings of $110 billion last year, up from $94.5 billion in 2005.

Thirty-eight of the companies in the current OGJ200 group reported net losses for 2006, though, while 37 members of this group posted losses for 2005. There are 44 firms in the group that recorded net income in excess of $100 million for 2006, while two companies' losses were greater than that amount.

Fast growers

Ranked at No. 23 by assets, Helix Energy Solutions Group Inc. is the fastest growing OGJ200 company based on 2006 results.

With a 143% gain in stockholders' equity, Houston-based Helix Energy Solutions Group posted a 128% increase in earnings from a year earlier. During 2006, the company acquired Remington Oil & Gas Corp. and divested 27% of its offshore contracting business, Cal

TOP 20 IN LIQUIDS PRODUCTION

Table 8

Rank	Company	US liquids production, million bbl
1	Chevron Corp.	169.0
2	ConocoPhillips	162.0
3	ExxonMobil Corp.	116.0
4	Occidental Petroleum Corp.	98.0
5	Anadarko Petroleum Corp.	54.0
6	Devon Energy Corp.	38.0
7	Marathon Oil Corp.	28.0
8	Apache Corp.	27.3
9	XTO Energy Inc.	20.8
10	Plains Exploration & Production Co.	19.0
11	Hess Corp.	17.0
12	Noble Energy Inc.	16.7
13	Kinder Morgan CO2 Co. LP	15.6
14	Pioneer Natural Resources Co.	14.1
15	EOG Resources Inc.	10.7
16	Dominion Exploration & Production	9.8
17	Denbury Resources Inc.	8.4
18	Pogo Producing Co.	8.1
19	Newfield Exploration Co.	7.8
20	Murphy Oil Corp.	7.7
	Total	**847.9**

Rank	Company	Worldwide liquids production, million bbl
1	ExxonMobil Corp.	832.0
2	Chevron Corp.	632.0
3	ConocoPhillips	534.0
4	Occidental Petroleum Corp.	142.0
5	Hess Corp.	94.0
6	Apache Corp.	86.2
7	Anadarko Petroleum Corp.	86.0
8	Marathon Oil Corp.	86.0
9	Devon Energy Corp.	78.0
10	Murphy Oil Corp.	27.7
11	Noble Energy Inc.	27.3
12	Dominion Exploration & Production	24.9
13	XTO Energy Inc.	20.8
14	Plains Exploration & Production Co.	19.0
15	Pioneer Natural Resources Co.	17.8
16	Kinder Morgan CO2 Co. LP	15.6
17	EOG Resources Inc.	13.7
18	Pogo Producing Co.	13.5
19	Newfield Exploration Co.	9.0
20	Denbury Resources Inc.	8.4
	Total	**2,768.0**

TOP 20 IN GAS PRODUCTION

Table 9

Rank	Company	US gas production, bcf
1	ConocoPhillips	900.0
2	ExxonMobil Corp.	706.0
3	Chevron Corp.	661.0
4	Devon Energy Corp.	566.0
5	Anadarko Petroleum Corp.	558.0
6	XTO Energy Inc.	433.0
7	Chesapeake Energy Corp.	322.0
8	EOG Resources Inc.	303.8
9	Dominion Exploration & Production	302.0
10	Williams Cos. Inc.	277.0
11	Apache Corp.	243.4
12	Occidental Petroleum Corp.	217.0
13	El Paso Corp.	213.0
14	Marathon Oil Corp.	194.0
15	Newfield Exploration Co.	189.6
16	Noble Energy Inc.	164.8
17	Pioneer Natural Resources Co.	134.4
18	Questar Corp.	113.9
19	Houston Exploration Co.	82.5
20	Equitable Supply	80.7
	Total	**6,662.3**

Rank	Company	Worldwide gas production, bcf
1	ExxonMobil Corp.	2,771.0
2	ConocoPhillips	2,070.0
3	Chevron Corp.	1,809.0
4	Devon Energy Corp.	815.0
5	Anadarko Petroleum Corp.	644.0
6	Apache Corp.	580.0
7	EOG Resources Inc.	493.7
8	XTO Energy Inc.	433.0
9	Chesapeake Energy Corp.	322.0
10	Dominion Exploration & Production	318.0
11	Marathon Oil Corp.	290.0
12	Williams Cos. Inc.	277.0
13	Occidental Petroleum Corp.	272.0
14	Hess Corp.	239.0
15	Noble Energy Inc.	227.3
16	El Paso Corp.	220.0
17	Newfield Exploration Co.	189.6
18	Pioneer Natural Resources Co.	166.8
19	Questar Corp.	113.9
20	Pogo Producing Co.	102.0
	Total	**12,353.3**

Dive, in a public offering.

The 20 fastest-growing companies are ranked by growth in stockholders' equity. For a firm to qualify for the list of fast growers, it must have recorded positive net income for both 2006 and 2005, and it must have recorded an increase in earnings from 2005. Limited partnerships, newly public companies, and subsidiaries are excluded from this list.

No. 78 by assets, GMX Resources Inc. is the second-fastest grower. The company, based in Oklahoma City, posted a 25% increase in earnings as its stockholders' equity climbed 115%.

Arena Resources Inc. is third on the list of fast growers and is ranked at No. 82 by assets. Arena Resources was the fifth-fastest grower in the previous edition of the OGJ200.

Other companies on the fast-growers list for at least the second consecutive year are Chesapeake Energy Corp., Aspen Exploration Corp., Basic Earth Science Systems Inc., Gulfport Energy Corp., and XTO Energy Inc.

Top 20 firms

Many of the 20 companies leading the current OGJ200 assets ranking were also in the top 20 of the previous edition of this annual report.

Removal of Burlington Resources and Kerr-McGee from this year's list made way for No. 19 Pogo Producing Co. and No. 20 Newfield Exploration Co., which previously were ranked 21 and 22 respectively.

Anadarko Petroleum Corp. moved to No. 4 from No. 8 a year ago. During 2006, Anadarko acquired Kerr-McGee and Western Gas Resources.

The top 20 firms' annual results grew almost as much as those of the entire group. The top 20 companies' combined earnings were $103.7 billion last year, up from $89.6 billion in 2005.

These 20 companies' total revenues last year were $965 billion, and their capital spending during 2006 grew 38% to $96.4 billion.

The total assets of the top 20 firms climbed 19% to $853.2 billion and

TOP 20 IN GAS RESERVES

Table 10

Rank	Company	US gas reserves, bcf
1	ConocoPhillips	12,441.0
2	ExxonMobil Corp.	12,049.0
3	Anadarko Petroleum Corp.	10,486.0
4	XTO Energy Inc.	6,944.2
5	Devon Energy Corp.	6,355.0
6	Dominion Exploration & Production	4,961.0
7	Chesapeake Energy Corp.	4,374.0
8	Chevron Corp.	4,028.0
9	Williams Cos. Inc.	3,701.0
10	EOG Resources Inc.	3,470.9
11	Apache Corp.	2,695.4
12	Pioneer Natural Resources Co.	2,686.0
13	Equitable Supply	2,487.5
14	Occidental Petroleum Corp.	2,442.0
15	Ultra Petroleum	2,258.1
16	El Paso Corp.	1,864.0
17	Noble Energy Inc.	1,739.2
18	Newfield Exploration Co.	1,535.0
19	Questar Corp.	1,461.2
20	Range Resources Corp.	1,436.0
	Total	**89,414.4**

Rank	Company	Worldwide gas reserves, bcf
1	ExxonMobil Corp.	32,480.0
2	ConocoPhillips	26,835.0
3	Chevron Corp.	22,884.0
4	Anadarko Petroleum Corp.	10,486.0
5	Devon Energy Corp.	8,356.0
6	Apache Corp.	7,512.9
7	XTO Energy Inc.	6,944.2
8	EOG Resources Inc.	6,094.9
9	Dominion Exploration & Production	5,136.0
10	Chesapeake Energy Corp.	4,374.0
11	Occidental Petroleum Corp.	3,810.0
12	Williams Cos. Inc.	3,701.0
13	Marathon Oil Corp.	3,510.0
14	Noble Energy Inc.	3,230.8
15	Pioneer Natural Resources Co.	2,927.8
16	Equitable Supply	2,487.5
17	Hess Corp.	2,466.0
18	Ultra Petroleum	2,258.1
19	El Paso Corp.	1,920.0
20	Newfield Exploration Co.	1,586.2
	Total	**159,000.5**

account for almost 91% of the total group's assets.

The market capitalization of the top 20 firms as of Dec. 31, 2006, was $1 trillion. In the previous OGJ200, the top 20 firms had a combined market cap of $853 billion as of yearend 2005.

Earnings, spending leaders

The OGJ200 ranks the companies not only by assets but also by revenues, earnings, capital spending, and other gauges. ExxonMobil Corp. tops most of these lists.

The top four companies as ranked by 2006 revenues are ExxonMobil, Chevron, ConocoPhillips, and Marathon Oil Corp.

Up 24% from a year earlier, Hess Corp. reported 2006 revenue of $28.7 billion. This puts Hess at No. 5 in terms of revenue. Ranked by assets, Hess is No. 11.

And ranked at No. 17 by assets, Murphy Oil Corp. reported the seventh-highest revenue for 2006: $14.3 billion, up from $11.9 billion in 2005.

With $39.5 billion in annual earnings, ExxonMobil tops the rankings by 2006 net income. Chevron, ConocoPhillips, Marathon, and Anadarko round out the top five firms by earnings.

Ranked No. 30 by assets, Plains Exploration & Production Co. is No. 17 ranked by 2006 earnings. Plains reported net income of $598 million, compared to a net loss of $214 million for 2005.

Plains reported that its net income for 2006 includes a gain on the sale of oil and gas properties, losses on mark-to-market accounting for derivatives contracts, a charge for extinguishment of debt, and other items. Sales volumes for the year were down 5% from 2005 as a result of the company's third-quarter 2006 producing property sale.

Ranked by capital and exploratory expenditures, Apache Corp. is sixth, with $3.9 billion in 2006 spending. Apache is ranked at No. 10 by assets.

Chesapeake Energy is the leading OGJ200 company in terms of net wells drilled in the US during 2006. Chesapeake's count of US net wells drilled is 1,449.2, followed by Dominion Exploration & Production with 1,081 wells. Chevron is third on this list with 986 US net wells drilled last year.

Reserves, production

While ExxonMobil is the highest ranking company in terms of worldwide liquids production, Chevron leads the OGJ200 firms in US liquids production during 2006. ConocoPhillips is second as ranked by US liquids production, and ExxonMobil is third.

But ExxonMobil leads the OGJ200 group in both US liquids reserves and worldwide liquids reserves. On each of these lists, ExxonMobil is followed by Chevron, ConocoPhillips, Occidental Petroleum Corp., Anadarko, and Apache.

With 900 bcf produced last year, ConocoPhillips is the leading OGJ200 company in terms of US gas production. ExxonMobil is second on this list with 706 bcf and is first as ranked by worldwide gas production for 2006.

ExxonMobil produced 2.77 tcf of gas worldwide last year, followed by ConocoPhillips with 2.07 tcf, and Chevron with 1.8 tcf. Devon Energy Corp. is fourth as ranked by worldwide gas production, with 815 bcf produced last year.

At the end of 2006, ConocoPhillips was the leading OGJ200 company in US gas reserves, with 12.44 tcf. And ExxonMobil held the largest gas reserves worldwide, totaling 32.48 tcf. ✦

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OGJ200

Rank by total assets 2006	Rank by total assets 2005	Company	Total assets $1,000	Total revenue Rank	Total revenue $1,000	Net income Rank	Net income $1,000	Stockholder equity Rank	Stockholder equity $1,000	Capital & expl. spending Rank	Capital & expl. spending $1,000
1	1	**ExxonMobil Corp.**	219,015,000	1	377,635,000	1	39,500,000	1	113,844,000	1	19,855,000
2	3	**ConocoPhillips**	164,781,000	3	188,523,000	3	15,550,000	2	82,646,000	2	15,596,000
3	2	**Chevron Corp.**	132,628,000	2	210,118,000	2	17,138,000	3	68,935,000	3	13,813,000
4	8	**Anadarko Petroleum Corp.**	58,844,000	9	10,187,000	5	4,854,000	6	14,913,000	5	4,569,000
5	5	**Devon Energy Corp.**	35,063,000	8	10,758,000	7	2,846,000	5	17,442,000	4	7,551,000
6	7	**Occidental Petroleum Corp.**	32,355,000	6	18,160,000	6	4,182,000	4	19,184,000	10	3,005,000
7	6	**Marathon Oil Corp.**	30,831,000	4	65,449,000	4	5,234,000	7	14,607,000	9	3,433,000
8	4	**El Paso Corp.**	27,261,000	13	[1] 4,281,000	20	475,000	13	4,186,000	12	2,164,000
9	12	**Chesapeake Energy Corp.**	24,417,167	11	7,351,058	9	2,003,323	9	11,251,471	8	3,779,233
10	9	**Apache Corp.**	24,308,175	10	8,288,779	8	2,552,451	8	13,191,053	6	3,891,639
11	11	**Hess Corp.**	22,404,000	5	28,720,000	10	1,916,000	10	8,111,000	7	3,844,000
12	13	**Dominion Exploration & Production[2]**	13,200,000	15	3,257,000	14	680,000	—	NA	13	2,079,000
13	15	**XTO Energy Inc.**	12,885,000	12	4,576,000	11	1,860,000	11	5,865,000	14	2,047,000
14	16	**Noble Energy Inc.**	9,588,625	16	2,940,082	15	678,428	14	4,113,817	18	1,357,039
15	18	**EOG Resources Inc.**	9,402,160	14	[3] 3,904,415	12	1,259,576	12	5,599,671	11	2,819,230
16	17	**Williams Cos. Inc.[4]**	7,850,900	21	1,487,600	19	[1] 529,700	—	NA	17	1,400,000
17	20	**Murphy Oil Corp.**	7,445,727	7	14,307,387	16	638,279	15	4,052,676	19	1,191,670
18	19	**Pioneer Natural Resources Co.**	7,355,399	20	1,632,881	13	739,731	17	2,984,671	16	1,403,879
19	21	**Pogo Producing Co.**	6,971,100	18	1,745,000	21	446,200	19	2,567,400	21	930,400
20	22	**Newfield Exploration Co.**	6,635,000	19	1,673,000	18	591,000	16	3,062,000	15	1,693,000
21	23	**Questar Corp.**	5,064,700	17	2,848,500	22	444,100	20	2,205,500	22	916,100
22	24	**Cimarex Energy Co.**	4,829,750	23	1,267,144	25	345,719	18	2,976,143	20	1,030,791
23	58	**Helix Energy Solutions Group Inc.**	4,290,187	22	[3] 1,366,924	24	347,394	22	1,525,948	36	469,091
24	38	**Petrohawk Energy Corp.**	4,279,656	41	[1] 587,762	43	116,563	21	1,928,344	42	395,479
25	25	**Forest Oil Corp.**	3,189,072	26	819,992	35	168,502	24	1,434,006	23	894,448
26	30	**Range Resources Corp.**	3,187,674	29	779,728	39	158,702	25	1,256,161	35	502,944
27	45	**W&T Offshore Inc.**	2,609,685	27	800,466	33	199,104	30	1,042,917	29	588,978
28	39	**Cheniere Energy Inc.**	2,604,488	84	51,458	140	(145,853)	61	143,247	109	3,138
29	28	**Whiting Petroleum Corp.**	2,585,403	30	778,827	40	156,364	26	1,186,670	38	464,407
30	26	**Plains Exploration & Production Co.**	2,463,228	25	1,018,503	17	597,528	28	1,130,683	26	634,330
31	31	**Southwestern Energy Co.**	2,379,069	31	[1] 763,112	36	162,636	23	1,434,643	24	850,910
32	35	**Denbury Resources Inc.**	2,139,837	35	731,536	32	202,457	29	1,106,059	33	507,327
33	29	**Stone Energy Corp.**	2,128,471	37	696,174	141	(254,222)	39	711,640	25	657,878
34	33	**Encore Acquisition Co.**	2,006,900	38	640,862	46	92,398	35	816,865	44	340,582
35	40	**St. Mary Land & Exploration Co.**	1,899,097	28	789,277	34	190,015	38	743,374	39	455,056
36	42	**Quicksilver Resources Inc.**	1,882,912	49	390,362	45	93,719	42	575,666	28	597,490
37	46	**Comstock Resources Inc.**	1,878,125	55	262,854	55	46,867	40	682,563	32	529,225
38	37	**Unit Corp.**	1,874,096	24	1,162,385	27	312,177	27	1,158,036	41	423,428
39	—	**Kinder Morgan CO_2 Co. LP**	1,838,223	34	736,524	28	295,231	—	NA	47	302,032
40	36	**Cabot Oil & Gas Corp.**	1,834,491	32	[1] 761,988	26	321,175	32	945,198	37	467,430
41	34	**Energen Resources Corp.[8]**	1,822,216	36	[1] 730,542	23	[1] 405,149	—	NA	51	259,678
42	32	**Equitable Supply**	1,794,485	44	488,571	29	[1] 269,164	—	NA	45	336,748
43	27	**Houston Exploration Co.**	1,771,726	42	545,092	49	67,783	31	964,604	27	614,228
44	41	**Penn Virginia Corp.**	1,633,149	33	753,929	48	75,909	45	382,425	48	269,773
45	44	**Swift Energy Co.**	1,585,682	39	615,441	37	161,565	36	797,917	31	557,492
46	51	**ATP Oil & Gas Corp.**	1,447,058	48	424,353	77	6,877	79	35,918	30	577,012
47	50	**Ultra Petroleum**	1,257,769	40	594,611	31	231,195	41	629,005	34	503,882
48	—	**Rosetta Resources Inc.**	1,219,405	53	276,266	56	44,608	34	822,289	55	236,579
49	43	**Seneca Resources Corp.[9, 10]**	1,209,969	51	355,562	67	20,971	—	NA	57	208,303
50	56	**Berry Petroleum Co.**	1,198,997	45	486,338	44	107,943	44	427,700	49	265,110
51	49	**Bill Barrett Corp.**	1,187,401	50	377,856	51	62,011	37	756,397	40	438,476
52	48	**Fidelity Exploration & Production Co.[11]**	1,173,797	46	[1] 483,952	41	145,657	—	NA	46	328,979
53	—	**CNX Gas Corp.**	1,155,001	43	513,859	38	159,867	33	880,215	66	154,243
54	47	**Energy Partners Ltd.**	1,003,845	47	450,978	136	(50,400)	46	372,270	43	341,936
55	54	**Delta Petroleum Corp.**	929,344	60	176,649	102	435	43	428,233	56	218,761
56	61	**Petroleum Development Corp.**	884,287	52	294,553	30	237,772	47	360,144	67	146,180
57	57	**Clayton Williams Energy Inc.**	795,433	54	265,998	71	17,799	59	144,980	52	254,840
58	52	**Belden & Blake Corp.**	777,023	61	159,090	53	52,199	60	143,703	82	37,577
59	60	**Callon Petroleum Co.**	625,527	58	198,748	57	40,560	50	281,363	63	167,979
60	62	**DTE Gas & Oil Co.[12]**	611,000	67	[1] 99,000	73	9,000	—	NA	60	186,000
61	67	**Peoples Energy Production[10, 13]**	532,742	64	126,750	58	[1] 31,097	—	NA	54	238,169
62	66	**Brigham Exploration Co.**	522,587	66	107,504	68	19,788	51	266,015	62	171,597
63	63	**PetroQuest Energy Inc.**	518,290	57	200,544	65	23,986	54	189,711	61	175,529
64	65	**Carrizo Oil & Gas Inc.**	494,795	72	83,914	70	18,248	52	213,187	58	201,773
65	71	**Goodrich Petroleum Corp.**	479,264	65	116,154	91	1,639	53	205,133	50	261,435
66	59	**Meridian Resource Corp.**	467,895	59	190,957	139	(73,884)	48	320,797	69	129,803

Worldwide 2006 liquids — production — Rank	Mill bbl	Worldwide 2006 natural gas — production — Rank	Bcf	Worldwide 2006 liquids — reserves — Rank	Mill bbl	Worldwide 2006 natural gas — reserves — Rank	Bcf	US 2006 liquids — production — Rank	Mill bbl	US 2006 natural gas — production — Rank	Bcf	US 2006 liquids — reserves — Rank	Mill bbl	US 2006 natural gas — reserves — Rank	Bcf	US 2006 net wells — drilled — Rank	Wells
1	832.0	1	2,771.0	1	8,194.0	1	32,480.0	3	116.0	2	706.0	1	1,884.0	2	12,049.0	14	572.0
3	534.0	2	2,070.0	3	6,696.0	2	26,835.0	2	162.0	1	900.0	3	1,679.0	1	12,441.0	9	730.0
2	632.0	3	1,809.0	2	7,806.0	3	22,884.0	1	169.0	3	661.0	2	1,751.0	8	4,028.0	3	986.0
7	86.00	5	644.0	5	1,264.0	4	10,486.0	5	54.00	5	558.0	5	925.0	3	10,486.0	6	873.8
9	78.00	4	815.0	7	983.0	5	8,356.0	6	38.00	4	566.0	8	403.0	5	6,355.0	7	815.6
4	142.0	13	272.0	4	2,264.0	11	3,810.0	4	98.00	12	217.0	4	1,678.0	14	2,442.0	13	589.6
8	86.00	11	290.0	28	67.00	13	3,510.0	7	28.00	14	194.0	13	172.0	24	1,069.0	30	237.0
23	7.686	16	220.0	24	82.54	19	1,920.0	21	7.439	13	213.0	34	50.69	16	1,864.0	17	433.0
26	6.764	9	322.0	23	87.96	10	4,374.0	26	6.764	7	322.0	24	87.96	7	4,374.0	1	1,449.2
6	86.25	6	580.0	6	1,061.0	6	7,512.9	8	27.31	11	243.4	6	495.3	11	2,695.4	26	287.3
5	94.00	14	239.0	8	832.0	17	2,466.0	11	17.00	35	43.00	16	138.0	48	236.0	71	29.00
12	24.95	10	318.0	13	232.3	9	5,136.0	16	9.752	9	302.0	11	216.8	6	4,961.0	2	1,081.0
13	20.80	8	433.0	12	267.4	7	6,944.2	9	20.80	6	433.0	10	267.4	4	6,944.2	5	912.8
11	27.34	15	227.3	11	296.1	14	3,230.8	12	16.72	16	164.8	14	170.1	17	1,739.2	11	687.4
17	13.65	7	493.7	20	117.8	8	6,094.9	15	10.68	8	303.8	22	96.62	10	3,470.9	8	762.0
—	NA	12	[5]277.0	—	NA	12	[5]3,701.0	—	NA	10	[5]277.0	—	NA	9	[5]3,701.0	4	954.0
10	27.70	42	28.50	15	173.8	34	531.4	20	7.700	47	20.70	35	44.00	63	148.6	45	112.6
15	17.82	18	166.8	9	417.0	15	2,927.8	14	14.09	17	134.4	7	406.7	12	2,686.0	28	254.0
18	13.48	20	102.0	16	163.3	25	1,233.0	18	8.107	24	73.55	21	98.72	27	914.7	70	30.50
19	9.000	17	189.6	65	5.300	20	1,586.2	19	7.800	15	189.6	23	92.80	18	1,535.0	15	497.5
36	2.600	19	113.9	44	28.40	21	1,461.2	36	2.600	18	113.9	45	28.40	19	1,461.2	34	196.3
75	0.269	96	[6]0.868	29	59.80	27	[6]1,090.4	73	0.269	95	[6]0.868	28	59.80	23	[6]1,090.4	20	346.2
33	3.400	43	27.95	37	36.34	45	318.0	32	3.400	41	27.95	37	36.34	42	294.4	80	13.20
42	1.555	52	20.22	42	29.23	49	261.9	41	1.555	49	20.22	43	29.23	46	261.9	41	137.0
21	8.026	26	73.02	21	112.9	29	778.0	25	6.887	31	48.67	20	107.2	31	580.1	39	146.0
30	4.252	25	75.27	34	53.71	22	1,436.0	30	4.252	23	75.27	33	53.71	20	1,436.0	10	703.8
27	6.456	30	60.45	31	55.66	38	401.2	27	6.456	28	60.45	30	55.66	36	401.2	73	26.30
124	0.003	111	0.318	126	0.024	117	1.736	123	0.003	111	0.318	125	0.024	116	1.736	98	[7]4.000
59	0.670	74	4.009	14	195.0	44	318.9	58	0.670	74	4.009	12	195.0	40	318.9	22	322.1
14	18.98	51	20.63	10	333.2	67	110.9	10	18.98	48	20.63	9	333.2	67	110.9	33	217.6
56	0.698	27	68.13	57	7.898	28	978.9	55	0.698	25	68.13	57	7.898	25	978.9	36	184.5
20	8.372	39	30.32	19	126.2	47	288.8	17	8.372	38	30.32	18	126.2	43	288.8	49	98.00
29	5.593	36	43.51	36	41.36	41	342.8	29	5.593	34	43.51	36	41.36	39	342.8	65	35.74
24	7.335	46	23.46	17	153.4	46	306.8	22	7.335	43	23.46	15	153.4	41	306.8	47	102.0
28	6.057	31	56.45	27	74.20	35	482.5	28	6.057	29	56.45	26	74.20	33	482.5	32	236.0
47	1.333	33	53.27	32	54.32	24	1,241.7	46	1.328	37	35.03	31	54.30	26	933.3	18	382.4
38	2.304	32	53.45	40	32.41	31	657.0	38	2.304	30	53.45	41	32.41	29	657.0	48	100.9
44	1.453	35	44.17	53	11.58	37	406.4	43	1.453	33	44.15	54	11.58	35	406.3	50	89.93
16	15.63	104	0.461	18	134.3	133	0.291	13	15.63	104	0.461	17	134.3	132	0.291	62	37.00
45	1.415	23	79.72	56	7.973	23	1,368.3	44	1.415	21	79.72	56	7.973	21	1,368.3	24	301.6
31	3.645	28	62.82	26	74.89	26	1,096.4	31	3.645	26	62.82	25	74.89	22	1,096.4	35	194.8
86	0.112	22	80.70	84	1.635	16	2,487.5	84	0.112	20	80.70	83	1.635	13	2,487.5	16	456.0
49	0.938	21	82.53	69	4.615	30	671.6	48	0.938	19	82.53	68	4.615	28	671.6	27	279.4
70	0.382	41	28.97	67	4.910	36	457.2	68	0.382	40	28.97	66	4.910	34	457.2	25	293.1
22	7.903	47	22.79	25	82.12	43	324.1	24	7.181	57	13.60	27	73.47	45	269.7	56	53.10
34	3.273	38	31.22	35	51.28	42	329.2	34	3.250	50	19.20	40	33.73	61	157.0	94	5.000
39	2.198	24	78.40	47	21.83	18	2,258.1	60	0.594	22	78.40	49	17.84	15	2,258.1	55	58.23
62	0.576	40	30.00	75	2.930	39	390.0	61	0.576	39	30.00	74	2.930	37	390.0	44	119.7
32	3.608	44	25.77	30	58.02	52	232.6	33	3.336	52	18.10	29	56.39	54	199.0	29	244.8
25	7.183	60	12.53	22	112.5	53	226.4	23	7.183	60	12.53	19	112.5	50	226.4	19	365.0
57	0.696	34	47.93	55	8.453	40	377.7	56	0.696	32	47.93	55	8.453	38	377.7	42	127.9
40	2.100	29	62.10	45	27.10	33	538.1	39	2.100	27	62.10	46	27.10	32	538.1	21	337.0
—	—	127	[5]0.056	—	—	122	[5]1.263	—	—	127	[5]0.056	—	—	121	[5]1.263	23	316.0
35	3.007	37	38.71	41	29.91	59	170.1	35	3.007	36	38.71	42	29.91	57	170.1	81	13.10
46	1.354	68	8.022	52	12.95	54	224.7	45	1.354	68	8.022	53	12.95	51	224.7	60	43.60
60	0.631	58	13.16	58	7.272	48	279.1	59	0.631	58	13.16	58	7.272	44	279.1	40	137.7
37	2.370	54	15.20	46	25.38	65	119.2	37	2.370	53	15.20	47	25.38	65	119.2	69	32.00
72	0.372	56	14.10	66	5.181	51	233.0	70	0.372	55	14.10	65	5.181	49	233.0	37	172.8
41	1.634	63	10.98	51	13.27	74	66.04	40	1.634	63	10.98	52	13.27	74	66.04	91	5.400
—	NA	45	[5]25.60	—	NA	32	[5]616.0	—	NA	42	[5]25.60	—	NA	30	[5]616.0	38	165.2
73	0.352	48	22.60	81	2.395	56	218.5	71	0.352	44	22.60	80	2.395	53	218.5	66	35.40
68	0.442	64	10.60	70	4.494	64	119.5	66	0.442	64	10.60	69	4.494	64	119.5	74	22.30
58	0.695	50	21.53	79	2.731	66	118.2	57	0.695	46	21.53	78	2.731	66	118.2	58	46.06
76	0.255	65	10.18	59	7.195	61	166.8	74	0.255	65	10.18	59	7.195	59	166.8	59	44.90
65	0.474	59	13.00	74	3.201	58	187.0	63	0.474	59	13.00	73	3.201	56	187.0	51	79.05
52	0.859	53	18.17	68	4.736	73	66.82	51	0.859	51	18.17	67	4.736	73	66.82	84	10.20

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Rank by total assets 2006	Rank by total assets 2005	Company	Total assets $1,000	Total revenue Rank	Total revenue $1,000	Net income Rank	Net income $1,000	Stockholder equity Rank	Stockholder equity $1,000	Capital & expl. spending Rank	Capital & expl. spending $1,000
67	70	**Quest Resource Inc.**[14]	463,300	79	60,641	135	(48,478)	68	117,354	64	166,905
68	73	**Parallel Petroleum Corp.**	442,818	68	97,183	61	26,155	55	183,782	59	195,396
69	64	**McMoran Exploration Co.**	408,677	56	209,738	134	(47,654)	128	(68,443)	53	252,369
70	74	**Black Hills Corp.**[4]	400,476	69	95,078	62	[1] 26,088	—	NA	65	158,846
71	—	**Atlas America Inc.**[4]	377,807	71	88,449	47	79,950	—	NA	76	74,075
72	69	**Warren Resources Inc.**	323,859	86	41,103	97	1,039	49	291,884	74	87,522
73	68	**Edge Petroleum Corp.**	321,657	63	129,744	133	(41,261)	57	156,052	68	144,338
74	72	**Toreador Resources Corp.**	317,204	85	42,375	83	2,578	58	147,151	71	105,165
75	85	**PrimeEnergy Corp.**	291,592	70	92,419	69	18,300	75	54,698	70	121,345
76	—	**Legacy Reserves LP**	273,368	76	69,215	79	4,357	63	138,789	77	66,910
77	81	**Aurora Oil & Gas Corp.**	212,387	93	23,117	113	(1,945)	62	139,731	80	42,048
78	87	**GMX Resources Inc.**	210,323	89	32,033	74	8,975	64	131,481	72	104,412
79	79	**Challenger Minerals Inc.**[15]	199,100	82	53,600	60	[1] 27,200	—	NA	90	16,200
80	83	**Gulfport Energy Corp.**	195,151	80	60,390	59	27,808	65	123,809	78	62,898
81	78	**NGAS Resources Inc.**	178,219	73	80,177	87	1,992	71	76,358	118	1,027
82	88	**Arena Resources Inc.**	176,313	81	59,760	66	23,268	67	120,044	73	97,577
83	76	**Dorchester Minerals LP**	168,429	74	[1] 74,927	54	50,210	56	[16] 167,800	—	—
84	75	**Gasco Energy Inc.**	165,454	91	25,675	138	(55,818)	70	77,172	75	79,558
85	112	**Cano Petroleum Inc.**[17]	146,949	96	18,408	112	(1,848)	77	40,636	101	5,699
86	84	**Exploration Co.**	143,801	75	72,968	75	7,241	66	123,652	79	52,927
87	77	**Harken Energy Corp.**	125,149	90	28,967	109	(855)	69	105,115	89	20,128
88	80	**Abraxas Petroleum Corp.**	117,486	83	51,723	94	1,246	127	(21,619)	85	26,346
89	92	**Contango Oil & Gas Co.**[17]	89,385	130	[1] 1,747	106	(207)	72	62,540	84	34,093
90	89	**Crimson Exploration Inc.**	84,703	94	21,659	88	1,859	74	61,326	88	21,777
91	90	**Panhandle Royalty Co.**[10, 18]	70,949	88	37,486	72	10,574	76	49,066	108	3,269
92	100	**American Oil & Gas Inc.**	69,136	118	3,787	95	1,211	73	62,088	91	15,913
93	101	**New Century Energy Corp.**	66,046	98	14,927	123	(6,098)	125	(3,675)	107	3,747
94	95	**Double Eagle Petroleum Co.**[19]	64,406	95	19,032	86	2,109	82	33,042	87	21,861
95	107	**Hallador Petroleum Co.**	61,823	127	2,468	108	(824)	85	28,179	125	432
96	86	**Infinity Energy Resouces Inc.**	56,304	99	12,292	128	(12,687)	78	37,617	86	24,253
97	91	**Dune Energy Inc.**	50,859	106	7,797	137	(53,636)	126	(15,250)	83	37,329
98	—	**PRB Energy Inc.**	49,843	111	6,083	127	(8,659)	97	11,224	102	5,270
99	118	**Evolution Petroleum Corp.**[17]	48,958	125	3,027	64	24,626	84	31,133	113	2,611
100	93	**Galaxy Energy Corp.**[20]	47,760	133	1,290	132	(26,163)	104	7,920	106	4,146
101	99	**Credo Petroleum Corp.**[21]	47,759	97	16,491	78	5,880	80	34,767	94	11,746
102	108	**Teton Energy Corp.**	41,244	121	3,529	122	(5,724)	81	33,767	124	448
103	94	**FX Energy Inc.**	39,167	103	9,024	129	(13,767)	83	31,965	98	7,521
104	102	**Petrol Oil & Gas Inc.**	36,487	107	7,489	126	(7,795)	108	7,265	95	9,224
105	111	**Westside Energy Corp.**	34,504	115	4,140	130	(13,912)	93	15,573	93	13,306
106	97	**Royale Energy Inc.**	33,715	92	24,896	115	(2,650)	94	15,548	110	3,091
107	—	**New Frontier Energy Inc.**[22]	29,048	138	450	120	(4,574)	87	23,796	96	8,924
108	110	**Tri-Valley Corp.**	28,654	113	4,937	110	(941)	91	16,644	100	5,760
109	103	**Tengasco Inc.**[23]	28,454	104	9,002	85	2,141	86	24,420	128	138
110	96	**San Juan Basin Royalty Trust**	26,481	62	137,519	42	135,867	88	21,823	81	39,195
111	109	**Adams Resources & Energy Inc.**[4]	25,918	100	10,796	84	[1] 2,362	—	NA	—	NA
112	105	**Cross Timbers Royalty Trust**	21,655	87	39,393	63	[24] 25,448	89	[25] 19,680	—	—
113	131	**Houston American Energy Corp.**	19,985	120	3,699	107	(512)	90	19,415	—	—
114	—	**EnDevCo Inc.**	19,455	122	3,391	111	(1,201)	124	(1,448)	—	—
115	120	**Aspen Exploration Corp.**[17]	19,191	112	5,979	81	2,970	100	10,101	104	4,306
116	104	**Daleco Resources Corp.**[10]	18,601	128	2,081	124	(6,169)	95	12,797	129	136
117	113	**VTEX Energy Inc.**[26]	17,962	135	642	125	(7,447)	115	4,667	126	334
118	115	**Reserve Petroleum Co.**	17,650	102	[1] 9,933	80	4,275	92	16,129	112	2,663
119	114	**GeoResources Inc.**	16,741	105	8,945	90	1,742	98	11,139	111	3,080
120	98	**United Heritage Corp.**[23]	15,462	136	602	131	(17,371)	96	11,784	114	2,534
121	132	**Cubic Energy Inc.**[17]	13,373	137	509	116	(2,769)	110	6,053	103	4,409
122	117	**Spindletop Oil & Gas Co.**	13,024	110	6,174	99	920	105	7,675	117	1,271
123	125	**Blue Dolphin Energy Co.**	11,944	114	4,299	100	913	101	9,572	127	283
124	124	**Basic Earth Science Systems Inc.**[23]	11,850	109	6,638	82	2,815	102	8,560	105	4,279
125	—	**Petro Resources Corp.**	10,948	131	1,546	118	(3,890)	99	10,699	97	8,240
126	126	**FieldPoint Petroleum Corp.**	10,477	116	4,063	96	1,182	103	8,077	116	1,588
127	—	**John D. Oil and Gas Co.**	9,544	129	1,928	114	(1,962)	116	2,897	99	6,106
128	119	**Mexco Energy Corp.**[23]	8,978	119	3,722	101	789	109	6,899	122	677
129	116	**Apache Offshore Investment Partnership**	8,629	101	10,413	76	7,149	106	[16] 7,625	—	—
130	121	**Oakridge Energy Inc.**[22]	8,255	132	1,357	105	(175)	107	7,562	130	39
131	123	**Texas Vanguard Oil Co.**	7,008	108	7,210	93	1,441	111	5,856	121	735

Worldwide 2006 liquids — production — Rank	Mill bbl	Worldwide 2006 natural gas — production — Rank	Bcf	Worldwide 2006 liquids — reserves — Rank	Mill bbl	Worldwide 2006 natural gas — reserves — Rank	Bcf	US 2006 liquids — production — Rank	Mill bbl	US 2006 natural gas — production — Rank	Bcf	US 2006 liquids — reserves — Rank	Mill bbl	US 2006 natural gas — reserves — Rank	Bcf	US 2006 net wells — drilled — Rank	Wells
118	0.008	61	12.28	125	0.032	57	198.0	117	0.008	61	12.28	124	0.032	55	198.0	12	621.0
48	1.151	69	6.539	43	28.72	76	58.90	47	1.151	69	6.539	44	28.72	76	58.90	52	[7]72.77
43	1.552	55	14.55	62	5.772	79	41.20	42	1.552	54	14.55	62	5.772	79	41.20	86	8.835
69	0.401	62	11.51	63	5.723	62	164.8	67	0.401	62	11.51	63	5.723	60	164.8	54	60.01
82	0.151	67	8.946	82	2.068	60	168.5	80	0.151	67	8.946	81	2.068	58	168.5	31	236.7
67	0.456	92	1.052	33	54.08	90	24.83	65	0.456	92	1.052	32	54.08	89	24.83	57	48.60
63	0.567	57	13.85	71	4.325	70	76.15	62	0.567	56	13.85	70	4.325	70	76.15	63	36.71
61	0.582	94	0.946	54	11.04	86	29.54	94	0.063	103	0.500	92	0.700	107	4.129	110	1.630
71	0.379	71	5.695	72	4.228	71	69.23	69	0.379	71	5.695	71	4.228	71	69.23	61	37.96
55	0.749	82	2.200	49	13.37	83	32.53	54	0.749	82	2.200	50	13.37	83	32.53	88	7.500
109	0.023	80	2.511	121	0.081	63	153.0	108	0.023	80	2.511	120	0.081	62	153.0	46	111.5
93	0.069	75	3.915	78	2.743	50	241.9	92	0.069	75	3.915	77	2.743	47	241.9	67	35.30
64	0.539	84	2.093	86	1.496	94	15.97	87	0.095	84	2.093	102	0.433	93	15.97	—	NA
51	0.870	102	0.677	48	19.69	92	20.80	50	0.870	101	0.677	48	19.69	91	20.80	72	28.00
101	0.041	79	2.622	101	0.453	68	98.21	99	0.041	79	2.622	100	0.453	68	98.21	53	64.83
50	0.901	93	0.990	38	36.06	78	42.42	49	0.901	93	0.990	38	36.06	78	42.42	43	[7]124.0
74	0.344	66	8.968	73	3.802	75	65.80	72	0.344	66	8.968	72	3.802	75	65.80	68	35.00
111	0.022	76	3.687	107	0.371	80	39.98	110	0.022	76	3.687	106	0.371	80	39.98	76	16.80
78	0.192	100	0.705	39	33.87	72	69.10	76	0.192	99	0.705	39	33.87	72	69.10	—	—
53	0.791	89	1.104	64	5.580	102	7.955	52	0.791	89	1.104	64	5.580	100	7.955	64	36.09
81	0.167	85	1.712	83	1.856	105	7.005	79	0.167	85	1.712	82	1.856	103	7.005	111	1.280
77	0.200	70	6.515	76	2.820	69	81.83	75	0.200	70	6.515	75	2.820	69	81.83	96	4.200
102	0.037	105	0.456	128	0.011	112	3.364	101	0.037	105	0.456	127	0.011	111	3.364	90	[7]6.300
80	0.184	87	1.542	80	2.501	84	31.39	78	0.184	87	1.542	79	2.501	84	31.39	97	4.000
88	0.097	73	4.299	98	0.575	85	30.87	86	0.097	73	4.299	97	0.575	85	30.87	89	6.490
104	0.035	129	0.048	119	0.092	129	0.810	104	0.035	129	0.048	118	0.092	128	0.810	108	2.580
85	0.124	91	1.068	91	0.858	103	7.187	83	0.124	91	1.068	88	0.858	101	7.187	—	—
116	0.013	78	3.141	108	0.360	77	48.50	115	0.013	78	3.141	107	0.360	77	48.50	85	9.940
—	—	(s)	0.000	—	—	126	1.090	—	—	(s)	0.000	—	—	125	1.090	—	—
90	0.081	88	1.142	95	0.648	109	3.779	89	0.081	88	1.142	94	0.648	108	3.779	79	14.00
103	0.035	95	0.880	102	0.440	89	26.76	102	0.035	94	0.880	101	0.440	88	26.76	78	14.10
—	—	106	0.395	—	—	108	5.674	—	—	106	0.395	—	—	106	5.674	77	14.30
98	0.047	130	0.045	100	0.461	140	0.026	97	0.047	130	0.045	99	0.461	139	0.026	—	NA
133	(s)	113	0.210	133	(s)	127	1.005	133	(s)	113	0.210	133	(s)	126	1.005	99	4.000
100	0.041	83	2.176	103	0.422	93	16.01	100	0.041	83	2.176	103	0.422	92	16.01	83	10.42
—	—	99	0.737	—	—	104	7.093	—	—	98	0.737	—	—	102	7.093	82	12.27
89	0.085	—	—	90	0.920	99	10.20	88	0.085	—	—	89	0.809	—	—	109	2.500
114	0.018	97	0.831	112	0.229	96	12.83	113	0.018	96	0.831	111	0.229	95	12.83	—	NA
110	0.023	109	0.361	115	0.150	107	5.835	109	0.023	109	0.361	114	0.150	105	5.835	95	4.800
112	0.021	90	1.075	124	0.037	101	8.160	111	0.021	90	1.075	123	0.037	99	8.160	92	5.380
—	—	114	0.190	—	—	97	12.11	—	—	114	0.190	—	—	96	12.11	—	—
119	0.007	124	0.086	110	0.275	130	0.787	120	0.007	124	0.086	109	0.275	129	0.787	—	—
79	0.189	117	0.138	88	1.359	121	1.265	77	0.189	117	0.138	86	1.359	120	1.265	93	5.100
99	0.041	49	22.48	104	0.400	55	220.5	98	0.041	45	22.48	104	0.400	52	220.5	—	—
91	0.076	86	1.604	105	0.396	100	8.300	90	0.076	86	1.604	105	0.396	98	8.300	106	2.840
83	0.143	81	2.330	87	1.399	88	28.13	81	0.143	81	2.330	85	1.399	87	28.13	—	—
96	0.050	125	0.078	106	0.392	132	0.426	125	0.002	125	0.078	131	0.003	131	0.426	112	1.280
106	0.033	126	0.059	50	13.27	81	37.85	105	0.033	126	0.059	51	13.27	81	37.85	—	—
—	—	138	0.001	132	0.002	141	0.003	—	—	138	0.001	132	0.002	140	0.003	101	3.690
117	0.012	121	0.113	117	0.100	131	0.718	116	0.012	121	0.113	116	0.100	130	0.718	—	—
129	0.001	123	0.090	116	0.108	98	10.28	127	0.001	123	0.090	115	0.108	97	10.28	—	—
107	0.027	110	0.327	111	0.232	118	1.710	106	0.027	110	0.327	110	0.232	117	1.710	107	2.670
84	0.133	133	0.023	77	2.766	124	1.130	82	0.133	133	0.023	76	2.766	123	1.130	102	3.100
120	0.007	122	0.110	99	0.560	114	2.602	118	0.007	122	0.110	98	0.560	113	2.602	—	—
128	0.001	128	0.054	129	0.009	113	2.797	128	0.001	128	0.054	128	0.009	112	2.797	—	—
108	0.025	103	0.672	109	0.357	95	13.39	107	0.025	102	0.672	108	0.357	94	13.39	113	0.633
126	0.002	112	0.312	134	(s)	136	0.108	126	0.002	112	0.312	134	(s)	135	0.108	—	—
87	0.100	116	0.141	89	0.952	128	0.970	85	0.100	116	0.141	87	0.952	127	0.970	—	—
132	0.001	135	0.020	130	0.008	135	0.116	132	0.001	135	0.020	129	0.008	134	0.116	103	3.100
97	0.049	119	0.123	92	0.747	115	2.038	96	0.049	119	0.123	90	0.747	114	2.038	—	—
127	0.001	115	0.166	127	0.015	119	1.349	129	0.001	115	0.166	126	0.015	118	1.349	75	21.00
115	0.017	108	0.370	113	0.183	106	6.697	114	0.017	108	0.370	112	0.183	104	6.697	114	0.050
92	0.071	98	0.795	96	0.605	111	3.433	91	0.071	97	0.795	95	0.605	110	3.433	—	—
113	0.019	134	0.021	94	0.657	134	0.211	112	0.019	134	0.021	93	0.657	133	0.211	—	—
95	0.061	107	0.386	97	0.605	110	3.633	95	0.061	107	0.386	96	0.605	109	3.633	104	3.060

OGJ200

Rank by total assets 2006	Rank by total assets 2005	Company	Total assets $1,000	Total revenue Rank	Total revenue $1,000	Net income Rank	Net income $1,000	Stockholder equity Rank	Stockholder equity $1,000	Capital & expl. spending Rank	Capital & expl. spending $1,000
132	128	**Pioneer Oil & Gas**[10]	6,839	123	3,223	92	1,470	112	5,654	—	—
133	129	**Pyramid Oil Co.**	6,696	117	4,026	98	949	113	5,109	115	1,907
134	122	**Permian Basin Royalty Trust**	6,574	77	66,541	50	[24] 65,715	119	[25] 1,439	92	15,265
135	127	**Sabine Royalty Trust**	5,370	78	61,958	52	[24] 59,831	114	[25] 4,998	—	—
136	130	**Miller Petroleum Inc.**[26]	5,227	126	2,540	117	(3,590)	122	161	123	475
137	—	**GSV Inc.**	2,706	141	264	104	(166)	118	1,762	—	—
138	135	**LL & E Royalty Trust**	2,616	124	3,069	89	[24] 1,831	117	[25] 2,616	—	—
139	133	**Bayou City Exploration Inc.**	2,371	140	299	119	(3,891)	121	517	119	882
140	106	**Ness Energy International Inc.**	2,305	134	784	121	(5,244)	123	(835)	—	—
141	—	**Lucas Energy Inc.**	721	139	314	103	62	120	549	120	779
142	136	**Capco Energy Inc.**[27]	NA	—	NA	—	NA	—	NA	—	NA
143	137	**Empiric Energy Inc.**[27]	NA	—	NA	—	NA	—	NA	—	NA
144	138	**Petrol Industries Inc.**[27]	NA	—	NA	—	NA	—	NA	—	NA
		Total	**942,418,283**		**993,498,891**		**109,873,857**		**431,085,361**		**116,950,969**

NA = Not Available. (s) indicates less than 500 bbl or 500 mcf. [1]Operating. [2]Subsidiary of Dominion Resources Inc. [3]Net. [4]Oil and gas operations only. [5]Includes some liquids (bcfe). 6 Includes NGL. [7]Gross. [8]Subsidiary of Energen Co. [9]Subsidiary of National Fuel Gas Co. [10]Fiscal yearend Sept. 30. [11]Subsidiary of MDU Resources Group [12]Subsidiary of DTE Energy Inc.

Worldwide 2006 liquids — production — Rank	Mill bbl	Worldwide 2006 natural gas — production — Rank	Bcf	Worldwide 2006 liquids — reserves — Rank	Mill bbl	Worldwide 2006 natural gas — reserves — Rank	Bcf	US 2006 liquids — production — Rank	Mill bbl	US 2006 natural gas — production — Rank	Bcf	US 2006 liquids — reserves — Rank	Mill bbl	US 2006 natural gas — reserves — Rank	Bcf	US 2006 net wells — drilled — Rank	Wells
121	0.007	118	0.133	122	0.039	123	1.147	119	0.007	118	0.133	121	0.039	122	1.147	—	NA
94	0.066	137	0.007	93	0.741	138	0.065	93	0.066	137	0.007	91	0.741	137	0.065	100	[7]4.000
54	0.750	77	3.155	60	6.578	91	24.13	53	0.750	77	3.155	60	6.578	90	24.13	—	—
66	0.464	72	4.584	61	5.890	82	36.27	64	0.464	72	4.584	61	5.890	82	36.27	—	—
123	0.006	101	0.691	120	0.091	120	1.273	121	0.006	100	0.691	119	0.091	119	1.273	105	2.890
130	0.001	132	0.033	131	0.004	137	0.105	130	0.001	132	0.033	130	0.004	136	0.105	—	NA
105	0.035	131	0.037	85	1.554	116	1.910	103	0.035	131	0.037	84	1.554	115	1.910	—	—
125	0.002	136	0.009	123	0.039	125	1.103	124	0.002	136	0.009	122	0.039	124	1.103	87	[7]8.000
131	0.001	120	0.118	114	0.168	87	28.87	131	0.001	120	0.118	113	0.168	86	28.87	—	—
122	0.006	—	—	118	0.096	139	0.053	122	0.006	—	—	117	0.096	138	0.053	—	—
—	NA	—	NA	—	NA	—	NA	—	NA	—	NA	—	NA	—	NA	—	NA
—	NA	—	NA	—	NA	—	NA	—	NA	—	NA	—	NA	—	NA	—	NA
—	NA	—	NA	—	NA	—	NA	—	NA	—	NA	—	NA	—	NA	—	NA
	2,894		**14,076**		**33,414**		**182,630**		**969**		**8,259**		**13,011**		**109,925**		**21,393.7**

[13]Subsidiary of Peoples Energy Corp. [14]Fiscal yearend May 31 [15]Subsidiary of GlobalSantaFe Crop. [16]Partners equity. [17]Fiscal yearend June 30. [18]Changed name after fiscal yearend to Panhandle Oil and Gas Inc. [19]Fiscal yearend Aug. 31 [20]Fiscal yearend Nov. 30 [21]Fiscal yearend Oct. 31 [22]Fiscal yearend Feb. 28, 2007 [23]Fiscal yearend Mar. 31 [24]Distributable income. [25]Trust corpus [26]Fiscal yearend Apr. 30 [27]Not filed at presstime.

Oil production slumps, but OGJ100 firms' earnings climb

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Oil & Gas Journal's survey of the 100 leading oil and gas producers based outside the US shows year-on-year earnings increases for most, while national oil companies again dominate lists of oil production and reserves leaders for 2006.

Averaging 85.2 million b/d, global crude oil and NGL production last year climbed 800,000 b/d from 2005, according to the International Energy Agency. Output of crude only from the Organization of Petroleum Exporting Countries, however, was unchanged from 2005 at 29.7 million b/d.

The OGJ100 list allows comparison of size and performance of prominent oil and gas companies around the world. OGJ does not attempt to rank the firms by assets or revenues because many do not report financial results.

Instead of being ranked as in the OGJ200, the companies are grouped by region according to the location of their corporate headquarters.

All financial results in this report are shown in US dollars.

Annual results

Financial results are available for most of the companies profiled in four of the regions: Latin America, Europe, Asia-Pacific, and Canada. Each of these groups of companies reported collective increases in revenues, earnings, and capital spending for 2006 vs. 2005. In addition, each group posted an increase in total assets from a year earlier.

Led by Canadian Natural Resources Ltd. and Suncor Energy Inc., the group of 26 companies based in Canada recorded the best annual results on a regional basis.

Compared with their 2005 results, the group of companies based in Canada posted a 42% increase in earnings on 16% higher revenues. This group's combined capital spending grew 36% last year, and its total assets at yearend 2006 were up 22%. The group's worldwide oil production declined 1%.

The improved annual results of Petroleo Brasileiro SA and Petroleos Mexicanos boosted the Latin American oil and gas companies' combined earnings. The group's combined oil production was little changed from 2005. Pemex reported that its total 2006 sales were up 10%, but crude oil production decreased 2% mainly as a result of a 12% decline in production at Cantarell field. The group of companies based in Europe posted a 7% increase in 2006 earnings, and the Asia-Pacific group reported a combined 20% gain. Each of these groups saw a decline in oil production last year.

Production, reserves leaders

This year's top 20 companies in oil production and reserves are the same as those in the previous edition of the OGJ100 (OGJ, Sept. 4, 2006, p. 36).

Saudi Aramco and National Iranian Oil Co. lead the lists of oil producers and oil reserves holders. At 17.2 billion bbl, the top 20 firms' combined production for 2006 was down from 17.6 billion bbl a year earlier. But their combined oil reserves as of yearend 2006 were up 1.5% to total 984.6 billion bbl.

Among the reserves leaders, Russian giant OAO Rosneft moved up two places to No. 9, while Malaysia's Petronas fell to No. 20 from No. 16 a year ago. ✦

OGJ100: OIL PRODUCTION AND RESERVE LEADERS

Rank	Company	Production, million bbl
1	Saudi Arabian Oil Co.	3,248.5
2	National Iranian Oil Co.	1,405.3
3	Petroleos Mexicanos	1,332.0
4	Petroleos de Venezuela SA	935.5
5	BP PLC	903.4
6	Abu Dhabi National Oil Co.	894.3
7	PetroChina Co. Ltd.	830.7
8	Nigerian National Petroleum Corp.	810.3
9	Kuwait Petroleum Corp.	803.0
10	OAO Lukoil	703.1
11	Iraq National Oil Co.	699.0
12	Petroleo Brasileiro SA	658.6
13	National Oil Corp. (Libya)	620.5
14	OAO Rosneft	576.3
15	Royal Dutch Shell	563.0
16	Total SA	549.7
17	Sonangol	505.5
18	Sonatrach	490.9
19	ENI	393.8
20	Qatar Petroleum Corp.	299.3
	Total	**17,222.6**

Rank	Company	Reserves, million bbl
1	Saudi Arabian Oil Co.	259,900.0
2	National Iranian Oil Co.	136,270.0
3	Iraq National Oil Co.	115,000.0
4	Kuwait Petroleum Corp.	99,000.0
5	Abu Dhabi National Oil Co.	92,200.0
6	Petroleos de Venezuela SA	80,012.0
7	National Oil Corp. (Libya)	41,464.0
8	Nigerian National Petroleum Corp.	36,220.0
9	OAO Rosneft	15,962.7
10	OAO Lukoil	15,927.0
11	Qatar Petroleum Corp.	15,207.0
12	Petroleos Mexicanos	12,849.1
13	Sonatrach	12,270.0
14	PetroChina Co. Ltd.	11,618.0
15	Petroleo Brasileiro SA	9,418.2
16	Sonangol	8,000.0
17	Total SA	6,592.0
18	BP PLC	5,893.0
19	Petroleum Development Oman LLC	5,500.0
20	Petronas	5,300.0
	Total	**984,603.0**

OGJ100

LEADING OIL AND GAS COMPANIES OUTSIDE THE US

Country	Company	Total assets		Total revenues		Total net income		Capital and exploratory expenditures	
		Million $							
		2006	2005	2006	2005	2006	2005	2006	2005
CANADA									
Canada	ARC Energy Trust	2,985.7	2,789.5	1,084.7	961.8	405.6	294.6	321.3	221.9
Canada	Baytex Energy Ltd.	926.5	948.6	415.5	356.0	129.7	65.9	117.3	125.8
Canada	Bonavista Energy Trust	1,774.7	1,660.1	794.8	753.1	265.5	250.0	278.9	243.6
Canada	Canadian Natural Resources Ltd.	28,457.9	18,749.0	9,165.8	8,059.2	2,224.9	866.7	10,600.0	4,070.9
Canada	Canadian Oil Sands Trust	5,605.8	5,083.7	2,143.8	1,623.6	735.2	685.9	264.5	660.3
Canada	Canetic Resources Trust	5,004.2	1,348.0	1,241.0	660.5	196.7	54.3	1,159.2	149.6
Canada	Compton Petroleum Corp.	1,843.0	1,508.4	469.8	460.5	112.3	67.1	463.6	423.8
Canada	EnCana Corp.	35,106.0	34,148.0	16,399.0	14,573.0	5,652.0	3,426.0	6,269.0	6,477.0
Canada	Enerplus Resources Fund	3,607.7	3,544.1	1,406.3	1,279.9	480.2	356.6	464.0	834.1
Canada	Harvest Energy Trust	4,930.9	1,122.7	1,223.7	360.3	119.9	86.6	332.2	99.5
Canada	Husky Energy Inc.	15,390.1	13,553.8	11,163.3	8,456.2	2,403.0	1,653.3	2,821.7	2,557.9
Canada	Imperial Oil Ltd.	13,852.2	13,369.4	21,601.2	22,943.6	2,683.3	2,146.0	1,065.7	1,217.5
Canada	Nexen Inc.	14,723.3	12,518.2	4,747.8	3,984.2	529.8	941.0	3,004.2	2,177.4
Canada	Paramount Resources Ltd.	1,217.8	953.7	275.6	398.4	(15.7)	(52.7)	459.8	349.4
Canada	Pengrowth Energy Trust	3,229.1	2,432.2	1,070.2	950.4	231.2	269.3	154.9	248.3
Canada	Penn West Energy Trust	6,925.4	3,403.8	1,560.6	1,278.7	586.7	476.4	509.4	377.0
Canada	Petrobank Energy and Resources Ltd.	384.0	223.9	78.7	45.7	20.4	10.6	202.5	97.6
Canada	Petro-Canada	19,434.8	17,719.9	16,456.7	13,849.4	1,533.8	1,478.3	3,027.1	2,938.4
Canada	PrimeWest Energy Trust	2,221.5	1,829.2	615.7	661.3	183.6	171.3	230.1	153.2
Canada	Provident Energy Trust	2,948.6	2,395.8	1,928.1	1,122.8	124.2	80.0	167.8	129.2
Canada	Shell Canada Ltd.	15,066.6	11,725.4	13,051.5	11,880.8	1,532.0	1,651.6	2,138.5	1,415.6
Canada	Sherritt International Corp.	2,191.4	2,393.8	982.3	842.3	216.5	102.6	213.2	235.2
Canada	Shiningbank Energy Income Fund	1,415.2	1,003.5	353.3	346.4	58.0	94.3	115.8	67.5
Canada	Suncor Energy Inc.	16,117.9	12,997.8	13,953.3	9,185.9	2,618.9	955.8	3,184.9	2,602.5
Canada	Talisman Energy Inc.	18,417.8	15,747.7	7,002.6	6,113.7	1,767.4	1,288.4	4,210.9	2,822.0
Canada	Vermilion Energy Trust	1,255.4	953.8	463.6	364.7	129.5	130.8	293.4	247.7
LATIN AMERICA									
Argentina	Techint Tecpetrol SA[6]	770.8	669.0	470.6	323.4	120.1	56.3	92.1	90.0
Barbados	Barbados National Oil Co. Ltd.[6]	NA	43.4	NA	49.6	NA	4.9	NA	6.2
Brazil	Petroleo Brasileiro SA	98,680.0	78,638.0	72,347.0	56,234.0	12,826.0	10,344.0	14,643.0	10,365.0
Colombia	Ecopetrol	NA	NA	NA	6,682.3	NA	1,401.6	NA	NA
Cuba	Cubapetroleo	NA	NA	NA	NA	NA	NA	NA	NA
Ecuador	Petroleos del Ecuador	NA	3,623.4	NA	5,305.6	NA	2,300.8	NA	169.7
Mexico	Petroleos Mexicanos	110,719.0	96,733.0	97,647.0	86,163.0	4,159.0	(7,078)	13,736.0	11,657.0
Suriname	State Oil Co. Suriname Ltd.	352.3	281.5	264.9	203.0	98.5	67.8	NA	NA
Trinidad and Tobago	Petroleum Co. of Trinidad & Tobago Ltd. (Petrotrin)[2]	2,952.0	2,747.0	4,117.0	3,224.0	214.0	261.0	280.0	222.0
Venezuela	Petroleos de Venezuela SA	NA	NA	NA	63,200.0	NA	NA	NA	NA
EUROPE									
Austria	OMV AG	23,495.9	18,297.1	23,826.3	19,392.4	1,910.4	1,731.4	3,383.9	1,977.8
Denmark	Dong Energy AS	18,699.3	7,440.4	5,998.2	3,084.6	827.0	448.2	1,313.5	1,689.4
Denmark	Maersk Oil & Gas	8,864.0	8,001.0	6,915.0	4,580.0	1,702.0	1,184.0	NA	NA
Finland	Neste Oil[10]	5,727.5	4,534.3	15,993.9	12,414.6	798.8	833.9	672.0	831.5
France	Total SA	138,579.0	125,218.0	166,604.0	145,631.0	15,802.0	14,933.0	14,881.0	13,928.0
Germany	RWE Dea AG	4,197.8	3,689.4	2,224.4	1,858.3	618.0	297.5	604.1	368.4
Germany	Wintershall AG	7,171.2	5,796.7	14,756.7	10,429.3	NA	785.4	684.5	776.7
Greece	Hellenic Petroleum SA	5,758.5	4,966.2	9,482.7	7,833.0	340.3	424.3	94.6	63.7
Hungary	MOL Group PLC	11,296.6	9,499.2	14,243.5	12,386.6	1,565.2	1,226.3	889.4	1,185.3
Ireland	Dragon Oil PLC	676.3	893.7	$320.1	$248.8	180.5	106.4	176.0	100.4
Ireland	Tullow Oil PLC	3,331.6	1,595.9	923.1	703.6	251.0	178.7	626.9	434.1
Italy	ENI	116,545.3	99,295.2	109,131.3	92,762.5	11,576.6	10,938.4	9,838.2	9,228.2
Netherlands	Royal Dutch Shell	235,276.0	219,516.0	318,845.0	306,731.0	26,311.0	26,261.0	22,922.0	17,436.0
Norway	Norsk Hydro ASA	37,555.9	33,693.0	30,592.9	26,575.1	2,685.2	2,412.1	NA	NA
Norway	Statoil ASA	50,632.6	42,855.6	66,283.4	60,126.2	6,331.9	4,769.3	NA	7,169.0
Poland	Polish Oil & Gas Co.	10,515.8	9,349.0	4,896.8	3,882.3	426.6	272.3	NA	133.3
Romania	Romanian National Oil Co. (Petrom)	7,556.2	5,700.9	4,657.1	3,689.6	813.7	485.5	1,045.9	485.5
Russia	OAO Gazprom	167,104.1	136,465.9	62,073.5	42,897.2	13,059.8	10,994.4	10,569.6	6,480.2
Russia	OAO Lukoil	48,237.0	40,345.0	68,109.0	56,215.0	7,484.0	6,443.0	8,574.0	7,051.0
Russia	OAO Rosneft	46,790.0	30,016.0	33,099.0	23,863.0	3,533.0	4,159.0	3,462	2,085
Spain	Compania Espanol de Petroleos SA	11,512.7	10,035.4	26,353.8	23,211.4	1,037.0	1,271.2	690.8	515.3
Spain	Repsol-YPF SA	59,651.8	54,215.0	69,180.5	63,535.7	3,923.7	3,883.5	7,205.7	4,621.6
Sweden	Lundin Petroleum AB	2,587.4	978.1	574.0	560.6	107.7	133.0	377.3	247.9
Turkey	Turkish Petroleum Corp.	2,203.4	2,334.3	889.7	1,209.3	277.5	126.5	NA	NA
United Kingdom	BG Group PLC	24,850.7	19,946.7	13,150.9	10,212.7	3,361.4	2,853.4	729.8	409.5

Worldwide oil production — Million bbl		Worldwide natural gas production — Bcf		Worldwide oil reserves — Million bbl		Worldwide natural gas reserves — Bcf	
2006	2005	2006	2005	2006	2005	2006	2005
[1]12.1	[1]10.0	65.4	63.4	[1]129.7	[1]127.3	593.7	595.7
[1]9.1	[1]9.2	19.7	22.0	[1]120.4	[1]110.3	[3]148.1	[3]176.4
[1]8.4	[1]7.8	64.6	64.2	[1]63.6	[1]62.9	428.2	444.2
[1 5]121.2	[1]114.2	544.6	525.2	[1]1,316.0	[1]1,118.0	3,798.0	2,842.0
33.5	27.7	NA	NA	[1]1,000.0	[1]1,000.0	NA	NA
15.8	8.4	68.0	38.1	[1 3]135.6	NA	694.5	NA
[1]3.5	[1]2.8	51.8	47.8	[1 3]40.0	[1 3]37.6	[3]984.0	[3]788.0
[1 5]61.8	[1 5]83.8	1,229.0	[5]1,175.0	[1 5]1,133.4	[1 5]1,120.6	[5]12,418.0	[5]11,784.0
[1]14.8	[1]12.4	98.9	100.1	[1 3]232.7	[1 3]231.1	[3]1,264.1	[3]1,308.3
[1]15.9	[1]11.7	35.3	9.7	[1 3]140.5	[1]36.9	296.5	165.1
[1]90.4	[1]73.6	245.4	248.2	[1]587.0	[1]581.0	2,143.0	2,136.0
[1]75.9	[1]75.2	181.0	187.6	[1]681.0	[1]760.0	673.0	765.0
[1]63.0	[1]72.0	87.0	96.0	[1]946.0	[1]683.0	618.0	618.0
[1]1.3	[1]1.6	29.8	44.7	[1 3]10.1	[1 3]8.0	[3]277.0	[3]255.4
[1]10.4	[1]9.8	64.1	58.8	[1 3]141.5	[1 3]117.7	[3]827.0	[3]516.0
[1]22.0	[1]18.9	114.1	105.0	[1 3]323.0	[1 3]241.0	[3]961.0	[3]698.0
[1]0.3	[1]0.2	4.7	4.3	[1 3]34.9	NA	41.8	NA
[1]81.0	[1]104.0	270.0	302.0	[1]950.0	[1]866.0	1,945.0	2,195.0
[1]4.3	[1]3.9	60.6	65.0	[1 3]67.1	[1 3]41.7	[3 5]752.5	[3 5]677.3
5.9	7.1	31.0	28.1	55.9	73.4	188.7	162.3
[11]30.0	[11]35.0	155.1	150.7	[11]808.0	[11]621.0	1,400.0	1,592.0
[7]11.0	[5]11.3	NA	NA	NA	NA	NA	NA
[1]2.0	[1]2.0	39.0	34.0	[3]21.4	[3]19.3	[3]425.4	[3]373.5
[1]1.1	[1]1.2	69.7	69.4	[3]7.0	[3]7.0	[5]446.6	[5]471.8
[1]95.5	[1]91.2	489.8	481.4	[1]767.0	[1]736.0	5,400.0	5,417.0
[1]5.6	[1]5.0	26.2	25.0	[1 3]74.6	[1 3]67.2	[3]262.7	[3]262.1
12.2	9.6	71.7	53.0	131.4	164.3	865.2	1,105.3
0.4	0.4	NA	—	[7]2.8	2.9	[7]6.0	6.1
[1]658.6	[1]643.3	742.7	740.7	[3]9,418.2	[3]9,716.0	[3]11,766.1	[3]12,351.9
[7]193.5	NA	[7]522.9	NA	[7]1,453.0	NA	[7]3,996.0	NA
27.7	27.7	NA	NA	NA	NA	NA	NA
[7]182.5	71.0	[7]0.3	NA	[7]4,517.0	NA	NA	NA
[1]1,332.0	[1]1,353.0	1,955.0	1,759.0	12,849.1	13,671.0	13,856.0	14,557.0
4.8	4.4	0.2	0.3	[3]142.0	[3]107.0	NA	NA
21.7	21.9	52.0	51.2	424.3	391.0	659.3	653.1
[7]935.5	1,127.9	[7]82.0	NA	[7]80,012.0	[7]77,200.0	[7]152,380.0	[7]150,000.0
[1 5]61.6	[1 5]65.6	[5]317.6	[5]322.4	[1 5]738.4	[1 5]782.1	[5]3,071.1	[5]3,247.3
NA	17.0	NA	5.6	NA	[3]82.0	NA	1,551.2
NA	NA	NA	NA	NA	NA	NA	NA
NA	NA	NA	NA	NA	NA	NA	NA
[1]549.7	[1]591.7	1,706.0	1,744.7	6,592.0	6,592.0	25,539.0	24,750.0
23.9	29.1	105.1	83.1	196.2	305.1	2.3	2.5
63.0	65.0	278.0	272.0	430.0	469.0	2,230.0	2,347.0
NA	NA	NA	NA	NA	NA	NA	NA
22.0	20.0	125.0	100.0	141.0	128.0	1,074.0	904.0
[1 5]7.5	[1 5]7.1	NA	NA	[1 3 5]651.0	[1 3 5]643.0	NA	[3 5]3,500.0
12.2	13.0	64.0	49.0	[3]203.7	[3]113.0	[3]302.6	[3]475.3
393.8	404.0	1,447.6	1,292.0	3,481.0	3,773.0	16,965.0	17,591.0
[1]563.0	[1 5]729.0	2,227.0	[5]3,032.0	[1]3,270.0	[1 5]4,636.0	30,058.0	[5]39,616.0
[1]141.3	[1]146.0	380.2	337.3	[1]748.0	[1]853.0	6,611.0	6,761.0
[1 3]244.0	[1 3]256.0	[3]953.0	[3]953.0	[1]1,675.0	[1]1,761.0	14,255.0	15,938.9
136.6	155.3	151.9	152.5	[7]156.2	[7]159.8	[7]3,619.7	[7]3,753.9
[1]30.1	[1]32.8	209.1	218.6	940.0	NA	NA	NA
248.2	69.4	19,634.6	19,599.3	NA	NA	[7]171,176.0	[7]102,700.0
703.1	664.3	[7]480.7	[7]199.0	15,927.0	16,114.0	25.6	25.3
576.3	535.2	480.3	459.1	15,962.7	14,900.0	24,758.2	24,384.3
NA	NA	NA	NA	NA	NA	NA	NA
191.7	193.9	1,236.1	1,246.6	1,057.4	1,166.7	[7]8,718.3	[7]12,136.6
10.8	11.1	NA	5.7	[3]176.4	[3]130.1	NA	[3]96.1
2.4	10.7	14.5	20.0	NA	NA	NA	NA
[1]51.7	[1]49.0	1,000.0	805.0	[1]432.1	[1]430.4	5,928.0	6,272.0

OGJ100

LEADING OIL AND GAS COMPANIES OUTSIDE THE US

Country	Company	Total assets		Total revenues		Total net income		Capital and exploratory expenditures	
		Million $							
		2006	2005	2006	2005	2006	2005	2006	2005
United Kingdom	BP PLC	217,601.0	206,914.0	265,906.0	239,792.0	22,286.0	22,632.0	17,231.0	14,149.0
United Kingdom	Cairn Energy PLC	1,932.0	1,014.0	286.0	263.0	(82)	79.0	282.0	291.0
United Kingdom	Premier Oil PLC	937.8	842.7	358.8	359.4	67.6	38.6	156.5	132.6
AFRICA									
Algeria	Sonatrach	NA	NA	NA	NA	NA	NA	NA	NA
Angola	Sonangol	NA	NA	NA	NA	NA	NA	NA	NA
Egypt	Egyptian General Petroleum Corp.	NA	NA	NA	NA	NA	NA	NA	NA
South Africa	Sasol Ltd.[4]	14,337.0	13,173.0	[8]9,961.0	[8]10,618.0	1,645.0	1,538.0	NA	3,013.4
Libya	National Oil Corp.	NA	NA	NA	NA	NA	NA	NA	NA
Morocco	Office National des Hydrocarbons et des Mines	NA	301.8	NA	14.0	NA	20.3	NA	17.2
Nigeria	Nigerian National Petroleum Corp.	NA	NA	NA	NA	NA	NA	NA	NA
MIDDLE EAST									
Abu Dhabi	Abu Dhabi National Oil Co.	NA	NA	NA	NA	NA	NA	NA	NA
Bahrain	Bahrain National Oil Co.	NA	NA	NA	NA	NA	NA	NA	NA
Dubai	Dubai Petroleum Co.	NA	NA	NA	NA	NA	NA	NA	NA
Iran	National Iranian Oil Co.	NA	NA	NA	NA	NA	NA	NA	NA
Iraq	Iraq National Oil Co.	NA	NA	NA	NA	NA	NA	NA	NA
Israel	Ministry of Energy & Infrastructure	NA	NA	NA	NA	NA	NA	NA	NA
Kuwait	Kuwait Petroleum Corp.[6]	NA	NA	NA	NA	NA	NA	NA	NA
Oman	Petroleum Development Oman LLC	NA	NA	NA	NA	NA	NA	1,505.0	1,238.0
Qatar	Qatar Petroleum Corp.	NA	NA	NA	NA	NA	NA	NA	NA
Saudi Arabia	Saudi Arabian Oil Co.	NA	NA	NA	NA	NA	NA	NA	NA
ASIA PACIFIC									
Australia	Australia Worldwide Exploration Ltd.[4]	571.6	273.3	18.9	4.3	9.3	8.8	3.2	4.3
Australia	BHP Billiton Petroleum[4]	48,516.0	41,843.0	[8]32,153.0	[8]36,722.0	10,534.0	6,628.0	766.0	531.0
Australia	Santos Ltd.	5,442.3	4,545.4	2,108.6	1,829.6	484.6	581.0	985.0	1,242.1
Australia	Woodside Petroleum Ltd.	7,070.9	5,116.9	2,871.5	2,094.4	1,075.4	844.4	1,760.3	1,423.0
China	China National Offshore Oil Corp. Ltd.	19,889.8	14,701.4	11,154.0	8,473.6	3,878.2	3,089.4	5,755.0	4,060.6
China	PetroChina Co. Ltd.	88,681.6	77,342.0	[8]86,397.8	[8]67,371.9	18,734.4	17,511.1	18,652.7	15,225.7
China, Taiwan	Chinese Petroleum Corp.	17,518.0	16,178.4	23,897.5	20,776.0	(577.3)	218.3	70.3	60.8
India	Gujarat State Petroleum Corp. Ltd.	NA	166.0	NA	288.0	NA	64.0	NA	153.0
India	Oil & Natural Gas Corp. Ltd.[6]	18,104.6	14,914.9	15,620.4	13,553.1	3,402.9	3,255.0	NA	NA
India	Oil India Ltd.[6]	1,562.8	1,282.2	1,334.1	936.4	373.5	241.0	NA	661.3
Indonesia	MedcoEnergi	1,841.6	1,535.2	792.4	620.2	38.2	74.7	388.9	226.7
Indonesia	Pertamina	NA	NA	NA	NA	NA	NA	NA	NA
Japan	Japan Petroleum Exploration Co. Ltd.[6]	4,855.7	4,526.4	1,527.7	1,329.5	180.4	184.0	264.2	288.1
Malaysia	Petronas[6]	73,086.0	62,923.0	44,282.0	36,070.0	11,566.0	9,358.0	NA	NA
Myanmar	Myanmar Oil & Gas Enterprise	NA	NA	NA	NA	NA	NA	NA	NA
New Zealand	New Zealand Oil & Gas Ltd.[4]	59.8	78.9	5.0	0.6	3.0	15.7	NA	6.7
Pakistan	Pakistan Oilfields Ltd.[4]	385.1	264.5	[8]254.8	[8]150.3	137.1	82.4	52.3	59.8
Pakistan	Pakistan Petroleum Ltd.	673.5	534.1	527.1	391.3	222.5	145.0	55.2	42.7
Thailand	PTT Exploration & Production PCL	4,371.4	3,496.9	2,540.7	1,732.6	740.4	591.0	95.9	30.2

NA=not available. All financial data are given in millions of US dollars. End of period exchange rates are used for assets. Annual averages are used for other financial data. Fiscal yearend is Dec. 31 unless otherwise noted.

[1]Includes NGL. [2]Fiscal yearend is Sept. 30. [3]Proved and probable. [4]Fiscal yearend is June 30. [5]After royalty. [6]Fiscal yearend is Mar. 31. [7]Estimate. [8]Turnover. [9]Fiscal yearend is Mar. 20. [10]Separated from Fortum Oil. [11]Oil sands. [12]Miller & Lent's audit according to US SEC specifications. [13]Excludes Petrom.

Worldwide oil production (Million bbl) 2006	Worldwide oil production (Million bbl) 2005	Worldwide natural gas production (Bcf) 2006	Worldwide natural gas production (Bcf) 2005	Worldwide oil reserves (Million bbl) 2006	Worldwide oil reserves (Million bbl) 2005	Worldwide natural gas reserves (Bcf) 2006	Worldwide natural gas reserves (Bcf) 2005
[5]903.4	[5]935.1	[5]2,855.0	[5]3,074.8	[5]5,893.0	[5]7,161.0	[5]45,931.0	[5]41,966.0
2.4	2.0	39.0	50.0	[3]180.0	[3]199.0	[3]98.0	[3]232.0
[1]12.0	[1]3.8	46.4	21.0	[1 3]26.6	[1 3]33.5	722.0	748.0
[7]490.9	[7]493.4	[7]3,287.0	[7]3,180.0	[7]12,270.0	[7]11,350.0	[7]161,740.0	[7]160,505.0
505.5	451.9	[7]27.9	[7]28.9	[7]8,000.0	[7]5,412.0	[7]2,000.0	[7]1,620.0
[7]243.6	[7]253.7	[7]484.0	[7]483.0	[7]3,700.0	[7]3,700.0	[7]58,500.0	[7]58,500.0
1.8	1.8	55.1	45	[3]15.9	[3]17.1	[3]1,306.1	[3]1,368.0
[7]620.5	[7]598.6	[7]258.5	[7]258.0	[7]41,464.0	[7]39,126.0	[7]52,650.0	[7]52,650.0
[7]0.2	0.1	NA	1.4	[3]1.0	[3]1.0	[7]58.0	[3]60.0
[7]810.3	[7]878.4	[7]849.0	[7]814.0	[7]36,220.0	[7]35,876.0	[7]181,900.0	[7]184,660.0
[7]894.3	[7]839.5	NA	NA	[7]92,200.0	[7]92,200.0	[7]198,500.0	[7]198,500.0
[7]62.8	[7]63.7	[7]314.3	[7]289.4	[7]124.6	[7]124.6	[7]3,250.0	[7]3,250.0
[7]32.9	[7]37.2	NA	NA	[7]4,000.0	[7]4,000.0	[7]4,000.0	[7]4,000.0
[1]1,405.3	[1]1,419.9	3,213.0	3,200.0	[7]136,270.0	[7]132,460.0	[7]974,000.0	[7]971,150.0
[7]699.0	[7]660.7	[7]61.9	[7]65.9	[7]115,000.0	[7]115,000.0	[7]974,000.0	[7]971,150.0
0.4	0.4	NA	NA	[7]1.9	[7]2.0	[7]1,275.0	[7]1,375.0
803.0	777.5	366.5	347.3	[7]99,000.0	[7]101,500.0	54,500.0	55,515.0
215.0	230.3	695.5	555.5	[7]5,500.0	[7]5,506.0	[7]30,000.0	[7]29,280.0
[7]299.3	[7]291.4	1,377.0	NA	[7]15,207.0	[7]15,207.0	[7]910,500.0	[7]910,520.0
3,248.5	3,321.5	3,000.3	2,872.6	259,900.0	259,800.0	248,500.0	239,500.0
NA	NA	[7]5.1	[7]2.3	16.2	4.4	[7]202.8	[7]164.9
[1]57.2	[1]61.0	360.4	347.9	[1]551.0	[1]542.6	4,867.3	5,182.1
13.6	15.3	226.2	189.8	[3]75.0	[3]76.0	[3]3,723.9	[3]3,457.0
30.5	23.4	212.0	205.2	236.0	281.0	5,454.9	3,528.3
[1]132.7	[1]127.0	179.2	142.2	[1 3]1,489.8	[1 3]1,457.4	[3]6,231.6	[3]5,430.9
830.7	822.9	1,371.9	1,119.5	11,618.0	11,536.2	53,469.0	48,123.1
NA	5.2	NA	19.4	NA	4.0	NA	2,700.0
NA	NA	NA	NA	NA	NA	NA	NA
NA	193.3	NA	811.2	NA	NA	NA	NA
23.4	23.4	80.1	71.0	NA	1,498.0	NA	5,826.8
19.9	19.8	55.6	61.0	99.0	119.5	267.6	1,444.5
NA	NA	NA	NA	NA	NA	NA	NA
7.8	7.9	44.0	45.2	NA	NA	NA	NA
255.2	268.5	[7]1,956.1	[7]1,952.0	5,300.0	5,200.0	82,096.0	79,520.0
[7]4.7	[7]4.7	NA	NA	[7]50.0	[7]50.0	[7]10,000.0	[7]10,000.0
NA	—	NA	NA	NA	NA	NA	NA
[1]4.8	3.8	20.5	15.2	[3]45.2	[3]25.2	[3]210.1	[3]244.1
[1]0.6	[1]0.6	371.7	361.0	[1]21.2	[1]20.9	4,392.0	4,506.0
[1]14.0	[1]12.8	239.5	228.3	NA	NA	NA	NA

THE OGJ200 COMPANY INDEX

Rank by total assets	Company	Headquarters city
88	Abraxas Petroleum Corp.	San Antonio
111	Adams Resources & Energy Inc.	Houston
92	American Oil & Gas Inc.	Denver
4	Anadarko Petroleum Corp.	The Woodlands, Tex.
10	Apache Corp.	Houston
129	Apache Offshore Investment Partnership	Houston
82	Arena Resources Inc.	Tulsa
115	Aspen Exploration Corp.	Denver
71	Atlas America Inc.	Moon Township, Penn.
46	ATP Oil & Gas Corp.	Houston
77	Aurora Oil & Gas Corp.	Traverse City, Mich.
124	Basic Earth Science Systems Inc.	Denver
139	Bayou City Exploration Inc.	Houston
58	Belden & Blake Corp.	North Canton, Ohio
50	Berry Petroleum Co.	Bakersfield, Calif.
51	Bill Barrett Corp.	Denver
70	Black Hills Corp.	Rapid City, SD
123	Blue Dolphin Energy Co.	Houston
62	Brigham Exploration Co.	Austin, Tex.
40	Cabot Oil & Gas Corp.	Houston
59	Callon Petroleum Co.	Natchez, Miss.
85	Cano Petroleum Inc.	Ft. Worth
142	Capco Energy Inc.	Houston
64	Carrizo Oil & Gas Inc.	Houston
79	Challenger Minerals Inc.	Houston
28	Cheniere Energy Inc.	Houston
9	Chesapeake Energy Corp.	Oklahoma City
3	Chevron Corp.	San Ramon, Calif.
22	Cimarex Energy Co.	Denver
57	Clayton Williams Energy Inc.	Midland, Tex.
53	CNX Gas Corp.	Pittsburgh
37	Comstock Resources Inc.	Frisco, Tex.
2	ConocoPhillips	Houston
89	Contango Oil & Gas Co.	Houston
101	Credo Petroleum Corp.	Denver
90	Crimson Exploration Inc.	Houston
112	Cross Timbers Royalty Trust	Dallas
121	Cubic Energy Inc.	Dallas
116	Daleco Resources Corp.	West Chester, Pa.
55	Delta Petroleum Corp.	Denver
32	Denbury Resources Inc.	Plano, Tex.
5	Devon Energy Corp.	Oklahoma City
12	Dominion Exploration & Production	Richmond, Va.
83	Dorchester Minerals LP	Dallas
94	Double Eagle Petroleum Co.	Casper, Wy.
60	DTE Gas & Oil Co.	Detroit, Mich.
97	Dune Energy Inc.	Houston
73	Edge Petroleum Corp.	Houston
8	El Paso Corp.	Houston
143	Empiric Energy Inc.	Dallas
34	Encore Acquisition Co.	Ft. Worth
114	EnDevCo Inc.	Houston
41	Energen Resources Corp.	Birmingham, Ala.
54	Energy Partners Ltd.	New Orleans
15	EOG Resources Inc.	Houston
42	Equitable Supply.	Pittsburgh
99	Evolution Petroleum Corp.	Houston
86	Exploration Co.	San Antonio
1	ExxonMobil Corp.	Irving, Tex.
52	Fidelity Exploration & Production Co.	Bismarck, ND
126	FieldPoint Petroleum Corp.	Cedar Park, Tex.
25	Forest Oil Corp.	Denver
103	FX Energy Inc.	Salt Lake City
100	Galaxy Energy Corp.	Denver
84	Gasco Energy Inc.	Englewood, Colo.
119	GeoResources Inc.	Williston, ND
78	GMX Resources Inc.	Oklahoma City
65	Goodrich Petroleum Corp.	Houston
137	GSV Inc.	Westport, Conn.
80	Gulfport Energy Corp.	Oklahoma City
95	Hallador Petroleum Co.	Denver
87	Harken Energy Corp.	South Lake, Tex.
23	Helix Energy Solutions Group Inc.	Houston
11	Hess Corp.	New York
113	Houston American Energy Corp.	Houston
43	Houston Exploration Co.	Houston
96	Infinity Energy Resouces Inc.	Denver
127	John D. Oil and Gas Co.	Mentor, Ohio
39	Kinder Morgan CO2 Co. LP	Lakewood, Colo.
76	Legacy Reserves LP	Midland, Tex.
138	LL & E Royalty Trust	Houston
141	Lucas Energy Inc.	Houston
7	Marathon Oil Corp.	Houston
69	McMoran Exploration Co.	New Orleans
66	Meridian Resource Corp.	Houston
128	Mexco Energy Corp.	Midland, Tex.
136	Miller Petroleum Inc.	Huntsville, Tenn.
17	Murphy Oil Corp.	El Dorado, Ark.
140	Ness Energy International Inc.	Willow Park, Tex.
93	New Century Energy Corp.	Houston
107	New Frontier Energy Inc.	Littleton, Colo.
20	Newfield Exploration Co.	Houston
81	NGAS Resources Inc.	Lexington, Ky
14	Noble Energy Inc.	Houston
130	Oakridge Energy Inc.	Wichita Falls, Tex.
6	Occidental Petroleum Corp.	Los Angeles
91	Panhandle Royalty Co.	Oklahoma City
68	Parallel Petroleum Corp.	Midland, Tex.
44	Penn Virginia Corp.	Radnor, Pa.
61	Peoples Energy Production	Chicago
134	Permian Basin Royalty Trust	Ft. Worth
125	Petro Resources Corp.	Houston
24	Petrohawk Energy Corp.	Houston
144	Petrol Industries Inc.	Shreveport, La.
104	Petrol Oil & Gas Inc.	Overland Park, Kan.
56	Petroleum Development Corp.	Bridgeport, W. Va.
63	PetroQuest Energy Inc.	Lafayette, La.
18	Pioneer Natural Resources Co.	Irving, Tex.
132	Pioneer Oil & Gas	South Jordan, Utah
30	Plains Exploration & Production Co.	Houston
19	Pogo Producing Co.	Houston
98	PRB Energy Inc.	Denver
75	PrimeEnergy Corp.	Stamford, Conn.
133	Pyramid Oil Co.	Bakersfield, Calif.
67	Quest Resource Inc.	Oklahoma City
21	Questar Corp.	Salt Lake City
36	Quicksilver Resources Inc.	Ft. Worth
26	Range Resources Corp.	Ft. Worth
118	Reserve Petroleum Co.	Dallas
48	Rosetta Resources Inc.	Houston
106	Royale Energy Inc.	San Diego
135	Sabine Royalty Trust	Dallas
110	San Juan Basin Royalty Trust	Ft. Worth
49	Seneca Resources Corp.	Williamsville, NY
31	Southwestern Energy Co.	Houston
122	Spindletop Oil & Gas Co.	Dallas
35	St. Mary Land & Exploration Co.	Denver
33	Stone Energy Corp.	Lafayette, La.
45	Swift Energy Co.	Houston
109	Tengasco Inc.	Knoxville, Tenn.
102	Teton Energy Corp.	Denver
131	Texas Vanguard Oil Co.	Austin, Tex.
74	Toreador Resources Corp.	Dallas
108	Tri-Valley Corp.	Bakersfield, Calif.
47	Ultra Petroleum	Houston
38	Unit Corp.	Tulsa
120	United Heritage Corp.	Midland, Tex.
117	VTEX Energy Inc.	Houston
27	W&T Offshore Inc.	Houston
72	Warren Resources Inc.	New York
105	Westside Energy Corp.	Houston
29	Whiting Petroleum Corp.	Denver
16	Williams Cos. Inc.	Tulsa
13	XTO Energy Inc.	Ft. Worth

Uncertainties cloud Arctic gas pipelines outlook

Nick Snow
Washington Correspondent

Recent developments have created uncertainties for proposed natural gas transmission systems from Canada's Mackenzie River Delta and Alaska's North Slope to markets farther south, said Canadian and US government officials. But their potential positive contributions to domestic gas supplies should not be ignored, they added.

"Security and supply are likely to become more, not less, important," said Brendan Bell, minister of industry, tourism, and investment in Canada's Northwest Territories. Displaying a photograph of Venezuelan President Hugo Chavez, he said: "A country that's inclined to change its constitution so its president can stay in office is also likely to change export terms for the energy it produces."

If both pipelines are built, the Mackenzie Valley and ANS pipelines could deliver a combined 8 bcfd of gas to markets in southern Canada and the Lower 48, Bell said Sept. 5 during a discussion on the outlook for North American Arctic gas pipelines sponsored by the Center for Strategic and International Studies.

Drue Pearce, US federal coordinator of Alaska gas transportation projects, said Alaska holds 35 tcf of conventional reserves, an estimated 72 tcf of undiscovered unconventional gas resources onshore and 97 tcf offshore, 44 tcf of coalbed methane resources, and 102 tcf of gas hydrates. A proposed 2,100-mile pipeline would track the Alaskan Highway through Canada. "We are finally beginning to see companies come up and look for gas," she said.

Attitude changed

The Alaska state government's attitude toward the project changed in 2006, when the legislature rejected a contract submitted by then-Gov. Frank Murkowski, who lost his reelection bid in a primary soon afterwards. His successor, Sarah Palin, determined that Alaskans wanted a more transparent process for the massive undertaking and developed the Alaska Gasline Inducement Act, Pearce said.

AGIA, which the new legislature adopted in February, is designed to get North Slope gas to US and southern Canadian markets and to provide in-state gas use, reasonable tariff and expansion terms, and jobs for Alaskans for generations. "AGIA kick-starts the construction of a gas line through an open, competitive and reasonable process," Palin's official web site says.

Pearce said AGIA calls for potential pipeline developers to compete for a license, which the state would award in exchange for its cooperation and support after conducting due diligence. Applications are scheduled to be made public in mid-December, with the winner to be submitted to the legislature in January.

Enbridge Inc. said it would not apply, but TransCanada Corp. will, Pearce said. BG Group, Repsol-YPF SA, and Chinese companies also may be interested, although they might prefer to build a pipeline to a liquefaction plant and export terminal near Valdez, she said. "Some producers may get together and prepare their own proposal," she added.

Producers were displeased with oil tax reforms Alaska enacted in 2006 when

Palin announced on Sept. 4 that she was calling state lawmakers back into special session in October to consider additional oil and gas taxes. Her plan came after the state's revenue department determined that the new Petroleum Profits Tax would produce $800 million less in revenues than Murkowski's administration had predicted.

Palin said the new plan, Alaska's Clear and Equitable Share (ACES) is a hybrid of a gross and net tax system that includes a 10% tax based on gross receipts for the North Slope's legacy fields, with a 25% net tax to encourage new development and reinvestment in existing facilities. ACES also would permit tax credits on future work, restrict capital expense deductions to scheduled maintenance, and implement strong audit and information-sharing provisions, she said.

'2018 or later'

Although federal predictions suggest that gas could flow through an Alaska Highway gas pipeline starting in 2017, Pearce said 2018 or later is more realistic. "It's always been expected that the Mackenzie project would go first. There's not enough steel or labor to proceed with both at the same time," she observed.

Bell said Canada's National Energy Board is reviewing the Mackenzie Valley project.

He expects permits to be awarded by spring or late summer of 2008 and for gas to begin flowing in 2013-14, although he conceded that major unanticipated expenses could create setbacks.

Many questions concern who will pay for the proposed gathering system in the Mackenzie Delta, Bell said. The Northwest Territories government suggested that Canada's federal government build it because it could be a facilities investment extending beyond oil and gas, he said.

"All of this gas would go into the Alberta system, which includes oil sands," said Bell. "That segment recognizes that gas prices are high, and it is exploring nuclear and other alternatives to process the bitumen."

Bell, saying, "We're interested in seeing the Alaskan project happen too," maintained that it will be necessary to reduce the cost of shipping gas, to provide clear policy directives with set timeframes, and to develop closer US-Canadian cooperation for both Arctic gas pipelines to be built. ✦

GAO: Increase needed in oil spill liability trust fund

Nick Snow
Washington Correspondent

Although major oil spills do not occur frequently, the federal oil spill liability trust fund should be increased to cover higher cleanup costs, the US Government Accountability Office said in a Sept. 7 report.

"To date, the fund has been able to cover costs from major spills that responsible parties have not paid, but risks remain," GAO said in a report to leaders of the US Senate Commerce, Science, and Transportation Committee and the House Transportation and Infrastructure Committee.

While the 2006 Coast Guard and Maritime Transportation Act increased liability limits, the new limit for tank barges "remains low relative to the cost of such spills," said GAO. Similarly, the 1990 Oil Pollution Act (OPA) required that liability limits be adjusted above levels set in the law to reflect increases resulting from inflation, but such changes were not made.

Such inaction during 1990-2006 "potentially shifted an estimated $39 million in costs from responsible parties to the fund," GAO maintained.

The US Coast Guard assumed OPA enforcement responsibilities in 2005. GAO recommended that the US Coast Guard determine whether and how OPA liability limits should be changed, by vessel type, and submit those findings to Congress. GAO also suggested that the liability limits for vessels be adjusted every 3 years to reflect inflation changes.

Spills since 1990

Since the 1989 Exxon Valdez spill in Prince William Sound off Alaska, which was the impetus for authorizing the fund's usage, no spill has come close to matching its $2.2 billion in cleanup costs, GAO noted. It estimated that 51 spills costing $1 million or more to clean up have occurred since 1990, requiring $240 million in outlays from the fund and $620-840 million in expenditures from responsible parties.

But payments from the fund could have been reduced by $39 million during that period if liability limits had been adjusted to reflect increases in the Department of Labor's consumer price index, it suggested.

GAO's report said the oil spill liability trust fund also faces other challenges. Additional claims can be made for as long as 3 years after spills have been cleaned up; costs and claims may occur on previously sunken vessels that may discharge oil in the future; spills may occur without an identifiable source (and responsible party); and a spill could be so catastrophic that it strains the fund's resources, the congressional watchdog's analysis suggested.

Responding, Steven J. Pecinovsky, director of the GAO's Inspector Liaison Office in the US Department of Homeland Security, of which USCG is part, said the service addressed liability limits in a January report to Congress and intends to adjust such limits annually to reflect inflation where appropriate. However, this action alone cannot ensure that the fund will remain viable, given expenses

and revenues that GAO mentioned but did not address in detail in its report, Pecinovsky continued.

He said USCG is adjusting certain OPA liability limits to reflect changes in the consumer price index, and service officials are unaware of any decision to leave limits unchanged, as the report implies.

While USCG is trying to make financial responsibility certificates consistent with current liability limits, the service cannot predict that a proposed rulemaking notice will be published by the end of 2007, Pecinovsky said. "This remains a goal, and USCG and [DHS] officials are working diligently to this end," he said. ✦

FTC chief's letter chills Democrats' 'hot fuels' crusade

Nick Snow
Washington Correspondent

US Federal Trade Commission Chairwoman Deborah Platt Majoras has questioned proposed cures for so-called "hot fuels" distortions alleged by some US House Democrats, saying the proposed "solution" may be worse than the problem, said Rep. Darrell E. Issa (R-Calif.) in releasing a letter from Majoras.

Issa, ranking minority member of the House Oversight and Government Reform Committee's Domestic Policy Committee, asked Majoras for FTC's view after subcommittee chairman Dennis J. Kucinich (D-Ohio) held a second hearing this summer to determine whether new federal regulations are needed to measure gasoline volumes more accurately.

"In considering whether to enact legislation concerning this issue, Congress may wish to gather facts and weigh carefully the benefits and costs that may result from such legislation," Majoras said in her letter. "Although the FTC has not conducted an investigation of this matter, it appears that the sale of 'hot fuel' might not cost consumers extra money, while the solution under consideration may raise consumer prices."

Issa, who has criticized Kucinich's allegations that major oil companies cheat motorists out of billions of dollars during summer months when gasoline expands, said Majoras's letter shows that Democrats have wasted time with contrived problems. "Using suspect accusations to stir up anger over high energy costs may be shrewd politics, but it is not good government oversight," he maintained.

Majoras said examining the two basic approaches addressing the "hot fuels" issue puts the costs and benefits in sharper perspective.

Retrofitting costs

The first approach, she said, involves requiring installation of devices designed to automatically adjust the fuel's temperature when it is dispensed. "FTC staff understands that the cost of retrofitting pumps with such devices is considerable and probably would ultimately fall on consumers in the form of higher gasoline prices," Majoras said.

She said the other approach, which involves changing the definition of a "gallon" to reflect local fuel conditions, presupposes that markets' competitive dynamics do not take "hot fuel" conditions into consideration already.

"If legislation required more gasoline to be dispensed on hot days to compensate for the increased temperature of the fuel, this would add to retailers' costs and likely increase retail prices. If that occurred, the added compliance burden on gasoline retailers would raise consumer prices at the pump without providing consumers with a corresponding benefit," Majoras wrote Issa.

She said state weights and measurements officials informed the FTC staff that a 20° F. temperature variation affects the volume of a typical 20-gal tank of gasoline by about 6 tbsp.

"FTC staff also understands that, in connection with the calibration of gasoline pumps, it is not uncommon for states to include tolerances of plus or minus 6 tbsp. for every 5 gal of gasoline pumped," Majoras said.

"While pursuing 'hot fuels,' Democrats have fudged numbers, talked themselves silly about a nonissue and concocted a fix that would actually cost consumers money," Issa declared. "The FTC has reaffirmed that convenience stores that sell gas, like most small businesses, don't need this burdensome government regulation that will ultimately cost consumers money." ✦

Parties ready for dialogue on Kashagan; development delay to be discussed

Eric Watkins
Senior Correspondent

Kazakh Energy and Mineral Resources Minister Sauat Mynbayev, reiterating earlier government claims, told Eni SPA Chief Executive Paolo Scaroni Sept. 11 that economic damage caused by the delay in production at the giant Kashagan oil field was unacceptable.

"Delay of production at Kashagan and significant postponement to recoup costs will lead to [a] significant cut of planned growth of the national econo-

WATCHING GOVERNMENT

Nick Snow, Washington Correspondent

'Broader view' steers IFC aid

When the International Finance Corp. financed its first coalbed methane project in China in late August, the venture involved much more than simply producing CBM instead of coal. The $15 million equity investment in Houston-based Far East Energy Corp.'s project in Shanxi and Yunnan provinces reflected IFC's broader mission of minimizing adverse social and economic impacts while encouraging local development and investments.

"We exist to assist the private sector in emerging markets, but with a broader view of making sure countries and communities fully benefit. We always look for added value beyond a project—and each project is different," explained Somit Varma, who recently became director and global head of IFC's oil, gas, mining and chemicals department.

Consequently, the World Bank affiliate also uses environmental, community development, health, political, and other specialists in addition to finance experts as it considers possible projects, he told me. "We always ask what impacts we'll have beyond supplying dollars," he said.

While it still invests in oil development projects where they can help countries develop economically and alleviate poverty, the IFC department has focused increasingly on gas, which grew from 10% of its portfolio in fiscal 2004 to 60% in fiscal 2007. Oil projects had a 30% share in 2007, while the remaining 10% was for pipelines, gathering systems, and other infrastructure.

In all phases

IFC is one of the few financial institutions that invest in all phases of oil and gas from exploration and production through transmission to refining and retailing. It uses long-term debt and mezzanine financing as well as equity investment. It has an approximately $2 billion upstream portfolio, with Latin American projects representing 30%, the single largest share.

"We are long-term players. Our clients look at 25-year commitments. Emerging markets come with risks, but this is our only business. We have offices all over the world which provide intelligence on the ground," Varma said.

National oil and gas companies may be partners in projects which IFC helps finance, but the agency normally works with smaller private firms, including privately held independent producers. It also works hard to head off corruption.

Due diligence

"For us, the issue of corruption is first and foremost. We always ask, as we invest, if we know our customer. That's a critical issue of due diligence. There's an anticorruption clause in our legal documents," Varma said.

Other lenders have adopted aspects of IFC's operating agreements. "Fifty banks follow environmental and social policies which we developed to mitigate their own risk—to a point that 85% of all new projects worldwide are covered by them," said Varma.

But the object still is to produce profits as well as oil and gas. "Profits are important. The private sector has to provide good returns to its shareholders. Developers are ready to look at broader issues when projects are profitable," Varma said. ✦

my for the next 10 years and threatens [the] implementation of long-term program of the country's economic development," Mynbayev told Scaroni.

At the meeting with Scaroni, Mynbayev also expressed Kazakhstan's readiness for an open dialogue aimed at resolving the issue related to the implementation of the Kashagan project, but asked that "our well-founded demands related to the mineral developers' fulfillment of their commitments not to be politicized."

For its part Eni confirmed that Scaroni held face-to-face talks with Kazakh Prime Minister Karim Masimov. It said the talks were held in a "climate of cooperation" and that the "basis was set" for future negotiations over Kashagan between the consortium and Kazakh authorities.

The Eni-led consortium has come under pressure from the Kazakh government due to cost over-runs and a delay in starting production, originally scheduled for 2005 but now due in 2010.

The Kazakh government, which claims that the overall cost of the project has grown to $135 billion from $57 billion, last month announced a 3-month suspension of the project saying it had environmental concerns (OGJ Online, Aug. 28, 2007).

Such pressure has prompted comparisons with the tactics used last year by Russia's OAO Gazprom to seize the Sakhalin-2 oil project from a consortium led by Royal Dutch Shell PLC. According to Konstantin Batunin, an analyst with Moscow-based Alfa Bank, Astana wants to increase its interests in Kashagan to increase its shares and oil profits.

That view was supported last week when Masimov, speaking at a gas conference, announced that "in accordance with orders and demands" by President Nursultan Nazarbayev, state energy company KazMunaiGaz "should become a joint operator of this project."

Eni, Total SA, ExxonMobil Corp., and Shell each hold 18.52% stakes in the consortium; ConocoPhillips holds 9.26%, while Inpex and KazMunaiGaz each own 8.33%. ✦

Cuba's oil, gas production rising, Politburo member says

Eric Watkins
Senior Correspondent

Cuba is producing nearly 50% of the oil and gas it consumes, according to Carlos Lage Davila, a member of the country's Politburo and secretary of the Council of Ministers' Executive Committee.

Lage made the claim in the Havana municipality of Santa Cruz del Norte at the end of a tour in July through facilities belonging to Western Petroleum Drilling & Extracting Enterprise (EPEP).

He said EPEP operations in 2007 produced an additional 85,000 tonnes of oil and 98 million cu m of gas compared with 2006, surpassing the government's production plans and guaranteeing gas delivery for electric power production and residential use.

Earlier this year, officials said the country produced about 65,000 b/d of oil, much of it for electric power production, and 3.45 billion cu m/day of gas—of which about 335,000 cu m/day go directly to Havana for home use by almost 1 million people.

On his visit to EPEP, Lage said new exploration wells are being completed, which will increase the country's reserves and maintain current production levels.

Lage also stressed that Cubans are increasingly able to service their own oil and gas industry. Until now, he said, Cuba depended on foreign companies for drilling rigs, repairs, and cement and other supplies. The country currently has 12 rigs, he said, which allows it to assume control of wells belonging to Cuba's state-owned Cuban Petroleum (Cupet) and to lease rigs to foreign companies.

Lage said, "We have five machines to repair wells [and] another two for the cementing processes. All this shores up our own capacities, and it is something that we must continue to make progress on."

Still, foreign companies are responsible for most of Cuba's production, and Cuban officials are seeking additional foreign investment of some $300-400 million to raise oil and gas production to 100,000 boe/d from 85,000 boe/d by 2009.

Cuba's largest producer is Sherritt International Corp, Toronto, which holds 40-100% indirect working interest in 10 production-sharing contracts. Most of Sherritt's Cuban oil production is derived from near-shore oil fields at Yumuri, Varadero, Canasi, and Puerto Escondido. Average net production in 2006 was 30,000 b/d.

Another 19,500 b/d of oil comes from operations on Block 7 run by Pebercan, Montreal, which specializes in exploration and production in Cuba.

In June, while announcing further investments by Sherritt, Lage said about 39 oil wells would be drilled this year—13 by Cupet and 26 by foreign firms.

Repsol-YPF SA, India's ONGC Videsh, and Norsk Hydro AS have plans to explore for oil beginning in 2008, while Vietnam's state-owned Petrovietnam is expected to sign in the near future, following a cooperation agreement inked last October with Cupet.

Last year, Venezuelan state-owned Petroleos de Venezuela SA formed a joint venture with Cupet to revamp the unfinished Cienfuegos refinery (OGJ, Apr. 17, 2006, p. 28). Current reports say the project is on schedule to start by yearend 2007 or early 2008. Initial production, according to officials, will be around 65,000 b/d. ✦

Greek Cyprus receives bids for offshore licenses

Doris Leblond
OGJ Correspondent

During 2006-08 the Republic of Cyprus will have completed its first hydrocarbon prospectivity assessment off its coast to promote exploration, launched two licensing rounds, and granted exploration licenses for the first.

This speedy program was outlined in Paris Sept. 5-6 at the North African Oil & Gas Summit organized by London-based Energy Exchange Ltd. IHS Energy's director for industry relations Andrew Hayman described the exploration strategy of Cyprus as "North Africa's contribution to European security of energy supply."

Cyprus decided to exploit its resources after the northeastern Mediterranean island became part of the European Union in January 2004. "We waited until then because of the national security the EU gives us," said Solon Kassinis, director of energy service at the Cyprus Commerce, Industry, and Tourism Ministry.

The island of Cyprus is divided into two areas: the southern, Greek-

populated Republic of Cyprus and the less prosperous, Turkish-populated, Northern Cyprus, which has been controlled by Turkey since 1974, is not internationally recognized, and is not part of the EU. Strong antagonism exists between the Republic and Turkey, which until 2004 prevented any exploration off Cyprus.

A nonexclusive MC2 seismic survey that Norway's Petroleum Geo-Services ASA carried out in early 2006 on 70,000 sq km of the Cyprus Exclusive Economic Zone (EEZ) launched the hydrocarbon assessment program with the acquisition of 6,770 line-km of 2D seismic data. The survey provided high-resolution, subsalt deep imaging and ties to key wells in Shell's North-East Mediterranean deepwater block off Egypt.

The seismic report, together with regional geological background, formed the basis of a geological interpretation carried out in 2006 by France's private petroleum consulting firm Beicip-Franlab, of which Institut Francais du Petrole is the sole shareholder.

Companies interested in participating in the first licensing round off Cyprus purchased this interpretation report, which was made available Feb. 15. The closing date was Aug. 16, with evaluation of applications set for as long as 6 months later.

Eleven offshore blocks totaling 60,000 sq km were offered for licensing. Blocks 3 and 13, which are undergoing a 3D seismic survey, will be available during the second licensing round, which will take place in 2008 following a regional 2D seismic survey in the eastern Mediterranean.

Kassinis said the first round generated three applications: one from Noble Energy Inc. and two from the consortium of Norway's Larsen Oil & Gas AS, the UK's DNO ASA, and the UAE's Dove Energy.

The selected applicants will be offered a production-sharing contract with exploration and exploitation license terms and conditions, and they will be bound by a strategic environmental assessment being carried out to evaluate likely effects of hydrocarbon activities on the environment.

The Republic entered into an agreement with Egypt to develop cross-median line hydrocarbon resources and has entered into international agreements with Lebanon and Egypt to delineate the EEZ. Negotiations with Israel and Syria are under way and should be finalized at yearend.

Summing up E&P consultant Beicip-Franlab's assessment of the Cyprus offshore hydrocarbon prospectivity, senior consultant Lucien Montadert said although the offshore Cyprus was "virgin territory," hydrocarbon discoveries have been made in the vicinity in Egypt, Gaza, and Israel, and source rocks that generated the hydrocarbons have been discovered and could be projected to the offshore Cyprus area.

Montadert also pointed to "encouraging" seismic anomalies and direct hydrocarbon seismic indicators as well as to the evidence of a great variety of play concepts and play fairways based on interpretation of the seismic profiles and regional geological background.

Seventeen major plays have been identified, and the play fairways have considerable size, reaching tens of kilometers, Montadert said, adding that offshore Cyprus is a new 70,000 sq km frontier area with thick sedimentary basins and an extended seal: the Messinian Evaporites. "The existence of active petroleum systems is ensured," he said. ✦

ConocoPhillips to spend $10 million on GHG offset

ConocoPhillips has agreed to spend $10 million to offset greenhouse gases (GHG) that would be created by a proposed expansion of its northern California refinery, said California Atty. Gen. Jerry Brown on Sept. 12.

"This agreement is a groundbreaking step in California's battle to combat global warming and gives the state an early edge in meeting the [GHG] reduction goals," Brown told reporters during a news conference in San Francisco.

In 2005, ConocoPhillips proposed the Clean Fuels Expansion Project involving the 120,000 b/cd Rodeo and Santa Maria refinery in California's Contra Costa County.

Project plans include a hydrogen plant to make cleaner gasoline and diesel fuels from heavy crude. The hydrogen project initially would have emitted 500,000 tonnes/year of carbon dioxide.

Brown appealed to the board of Contra Costa County, challenging the environmental documentation for the project, saying there was a failure to mitigate increased GHG emissions from operation of the hydrogen plant. The state will now withdraw its appeal, he said.

"Under this unprecedented global warming reduction plan, ConocoPhillips becomes the first oil company in America to offset [GHG] emissions from a refinery expansion project. This is a breakthrough," Brown said.

ConocoPhillips will take the following actions as part of its efforts to offset these emissions:

- Audit all of its California refineries and identify all GHG emission sources and reduction opportunities.
- Conduct an energy efficiency audit at Rodeo to identify feasible energy efficiency measures.
- Fund a $7 million offset program that the Bay Area Air Quality Management District will use.
- Fund $2.8 million for reforestation in California, with an estimated sequestration of 1.5 million tonnes of GHG over the life of the reforestation projects.

• Fund $200,000 for restoration of the San Pablo wetlands.

• Surrender the operating permit for the calciner at the Santa Maria unit, which ConocoPhillips estimates emits 70,000 tonnes/year of GHG.

If ConocoPhillips reduces its GHG emissions, it will get credit towards its contribution to the Bay Area Air Quality Management District offset fund.

ConocoPhillips also agrees to offset any CO_2 emissions that exceed 500,000 tonnes/year from the hydrogen plant if the company decides to increase its use of hydrogen. ✦

Gorgon LNG project clears environmental hurdle

Rick Wilkinson
OGJ Correspondent

The Western Australian government has given final environmental approval for Chevron Australia-operated Gorgon LNG project proposed for Barrow Island off Western Australia (OGJ Online, Sept. 10, 2007). The approval comes with 36 stringent environmental conditions.

Among the government requirements, said Environment Minister David Templeton, were stipulations that the project include carbon geosequestration and panels of experts to protect the environment of Barrow Island and surrounding waters. Barrow is a Class A animal reserve containing species extinct on the mainland.

The environment plan includes an additional $60 million (Aus.) commitment by the Gorgon joint venture to conserve endangered species, particularly the rare flatback turtles that come to the island to lay eggs. The companies also must submit annual audits of compliance and environmental performance reports.

Chevron called the environment minister's decision an important project milestone. The company said the JV would incorporate the conditions into current design optimization work.

Chevron is well on its way to implementing the geosequestration proposal. As operator, it plans to reinject about 3 million tonnes/year of carbon dioxide into a reservoir formation deep below Barrow Island.

However, as currently configured, the LNG plant will still emit as much as 4 million tonnes/year of CO_2 into the atmosphere.

The project's environmental approval is based on construction of a facility with two LNG trains, each

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Diversifying Asian energy

The leaders of Asia-Pacific countries last week agreed to set an "aspirational goal" of improving the energy efficiency of economic output by at least 25% by 2030 from the 2005 level.

They also agreed to create an Asia-Pacific Network for Energy Technology aimed at strengthening collaboration on energy research in the region by achieving technology breakthroughs in areas such as clean fossil fuel and renewable energy.

Their statements followed the Sept. 6 meeting of Asia-Pacific Economic Cooperation foreign and trade ministers, who called for ensuring a "diversified mix of energy sources," including nuclear energy, in order to pursue long-term economic growth while reducing dependence on fossil fuels.

Diversified mix

In a joint statement issued after their 2-day meeting in Sydney, the ministers said the diversified mix includes "the use of natural gas, biofuels from sustainably farmed crops and residues, renewable energy, and nuclear energy for interested economies."

Their call for a diversified mix of energy sources was especially timely as news emerged that the July shutdown of Tokyo Electric Power Co.'s Kashiwazaki-Kariwa nuclear power plant will strain Asian LNG and oil markets.

In a report, Tomoko Hosoe, senior consultant at Facts Global Energy, Honolulu, said: "An additional 2-3 million tonnes of LNG, which need to be secured from the spot market in 2007-08 in a very tight LNG market, is a serious problem."

The APEC leaders' calls for diversification also came as Russia's OAO Gazprom, now facing financial constraints on the Sakhalin-2 LNG energy project, resumed negotiations with the Japan Bank for International Cooperation (JBIC) to secure funding.

EBRD withdraws

The European Bank for Reconstruction and Development, which had been central to Sakhalin-2's initially planned lending syndicate, withdrew in August due to concerns over the heavy-handed manner in which Gazprom gained control of the development.

Absent financial aid from the EBRD, Gazprom is seeking new backers to meet the project's 2-trillion-yen cost. Gazprom Deputy Chairman Alexander Medvedev said his firm and the three minority partners have reached a memorandum of understanding for JBIC financing.

Medvedev also said JBIC would consider financing other oil and gas development projects in such areas as East Siberia, a region of key concern to Japan. In fact, the Russians have long been trying to twist Japan's arm for such investment.

In February, Russian Minister of Industry and Energy Viktor Khristenko made clear that his country would "like" Japanese investment in East Siberian oil and gas development as part of the East Siberia Pacific Ocean pipeline project.

The APEC leaders could not have been any more timely in their call for diversification of energy. Apart from the normal squeeze in supplies, due to increasing demand throughout the region, sources of energy are becoming even less reliable due to the machinations of countries like Russia.

But the APEC leaders could hardly say that, could they? After all, Russia is an APEC member. ✦

having a capacity of 5 million tonnes/year.

Originally budgeted at $11 billion (Aus.), the project likely will now cost closer to $15 billion. Geosequestration costs for the first decade alone are likely to be $850 million.

With costs rising, it is believed that a new scoping study has resulted in the JV's considering a three-train facility producing a total of 15 million tonnes/year of LNG to recapture economies of scale.

However such a move would require another round of environmental studies and approvals along with the further delays they would inevitably entail.

LNG sales agreement

Meanwhile in another major advancement for the project, PetroChina International Co. Ltd. has signed a binding heads of agreement to buy 1 million tonnes/year of LNG for 20 years from Gorgon Shell Eastern LNG. The deal is conditional upon the Gorgon joint venture partners making a final investment decision.

China, seeking substantial quantities of gas supplies, has been in tough price negotiations with several potential suppliers in Asia Pacific. Talks with the Gorgon partners—Chevron 50%, ExxonMobil, and Shell, 25% each—broke down in 2005 when they refused to sell LNG as cheaply as China wanted on terms similar to its 25-year, $25 billion (Aus.) supply deal with North West Shelf LNG for Guangdong province.

Western Australia premier, Alan Carpenter, described the agreement as one of the most significant deals since the North West Shelf, and it firmly seals gas relations between Australia and China, the second of its kind.

Previously, Shell intended to market its 25% share of Gorgon LNG to the US market though Sempra's Costa Azul terminal under construction in Baja California, Mexico.

Both Petrochina and Shell plan to execute a detailed LNG sales agreement before December 2008. ✦

Northeast Kansas well tests oil, gas possibilities in Precambrian rocks

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Several thousand wells in Kansas have been drilled into the Precambrian basement, which usually signals the depth limit of drilling for oil and gas prospecting.

Most of these wells have penetrated only a few feet or tens of feet and a few cut several hundred feet of basement; 17 are known to have penetrated more than 1,000 ft into the basement, so the information on the Precambrian is surficial with exception of these wells and magnetic, gravity, and seismic data.

The COCORP seismic line and the earthquake monitoring system have added considerable data on the basement. The well data are sparse in the deeper parts of the basins and denser on the Nemaha anticline, Central Kansas uplift, and Cambridge arch. Oil produced from Precambrian rocks on the Central Kansas uplift is from granite wash, a porous weathered residuum, or fractures.

In late 2005 in far northeastern Kansas in the Forest City basin, W.T.W. Operating LLC drilled the No. 1 Wilson well to a total depth of 5,772 ft, 1,826 ft into the Precambrian basement on a venture testing the possibility of oil and gas in these crystalline rocks. Elevation of the well is 1,000 ft, and a bottomhole temperature of 135° F. was measured at TD.

This well in 32-1s-17e, Brown County, is the deepest drilled into Precambrian rocks except for the Nemaha Seneca well in 19-3s-11e drilled in 1929 and two wells in the Midcontinent rift system (MRS). The Wilson well was plugged after testing, but some new interpretations on the geologic history supplementing previous work are now possible. The nearest oil production to the Wilson well is from the Ordovician Viola formation and Siluro-Devonian Hunton limestones a dozen or so miles northwest and shallower Mississippian and Cherokee production 45 miles to the south and east.[1,2]

By any standard this well was a rank wildcat.

RECALCULATED CHEMICAL ANALYSIS Table 1

Chemical	%
He	1.505
H_2	17.220
Ar	0.572
N_2	34.660
C_1 (methane)	45.100
C_2 (ethane)	0.954
C_3 (propane)	0.020
C_6+ (butane)	0.005

Regional geology

The Wilson well is the central Forest City basin,[3,4] which extends northeast into Nebraska and Iowa and is a shallow cratonic basin filled with Paleozoic sediments ranging in age from Cambrian to Permian with a thin veneer of Cretaceous, Tertiary, and Pleistocene.

The lower Paleozoic sediments are mainly thin bodies of carbonates alternating with thin units of clastics with a fairly uniform thickness across the central part of the basin (Fig. 1). Near the end of the Mississippian and in the early part of the Pennsylvanian a thick sequence of alternating carbonates and clastics was deposited and preserved in the basin (Fig. 2).

A long interval of quietness occurred until the spread of the Cretaceous Interior Sea spilled over into eastern Kansas. Tertiary deposits are mainly clastics shed from the rising Rocky Mountains to the west, and the Pleistocene is residual material left from the Nebraskan and Kansan glaciers.

The basement in this part of the state is characterized by a granitic terrane with patches of metasediments. Ages obtained from several wells date the material from 1.579 to 1.649 Ga.[5] This older terrane is intruded by younger granite bodies (≈1.340 Ga) and crosscut by the younger MRS (≈1.100 Ga) (Fig. 3).

Basement rocks encountered

Samples from the Wilson well were clean, but only the fines were saved. The well encountered the Precambrian

at 4,000 ft under the Upper Cambrian Reagan (Lamotte) sandstone. The Precambrian section consists of 510 ft of a brown, lustrous biotite schist with milky quartz interpreted as aplite veins.

The next 80 ft is a dark greenish gray crystalline amphibolite with a subtle change at 4,590 ft to a more gneissic texture to TD. No granite was encountered in contrast to other Precambrian wells in this part of the state.

A suite of wireline logs including gamma-ray, density, and neutron porosity log, was run that give diagnostic clues as to the rock composition of the Precambrian rock section (Fig. 4). The sharp break at 4,510 ft from biotite schist to layered gneisses was substantiated. There were several shows of gas after extensive testing, but the well was plugged and abandoned.[6]

The nearest Precambrian well, drilled in 1986, is the Hodgden & Associates No. 201 Mosquito Creek, in 20-5s-14e, Nemaha County, about 25 miles southwest. The Hodgden wildcat well encountered Precambrian quartz monzonite at 3,918 (2,673) ft.[7] This well also was plugged and abandoned.

Precambrian production

Precambrian rocks underlying Kansas have been of interest for decades, but not as potential targets for oil and gas.

Most of these rocks are crystalline and nonporous so have few possibilities of containing petroleum with exception of those in the MRS, where source beds have been identified as have potential traps and reservoirs, and as a result several tests have been made in the rift.[8 9]

Oil has been produced in small quantities on the Central Kansas uplift from granite wash (a porous weathered residuum on the pre-Paleozoic surface) and from fractures in the crystalline basement.[10]

Gas from the Wilson well

Ten zones in the Precambrian between 4,744 ft and 5,683 ft were perforated with four shots per foot to test for gas.[6]

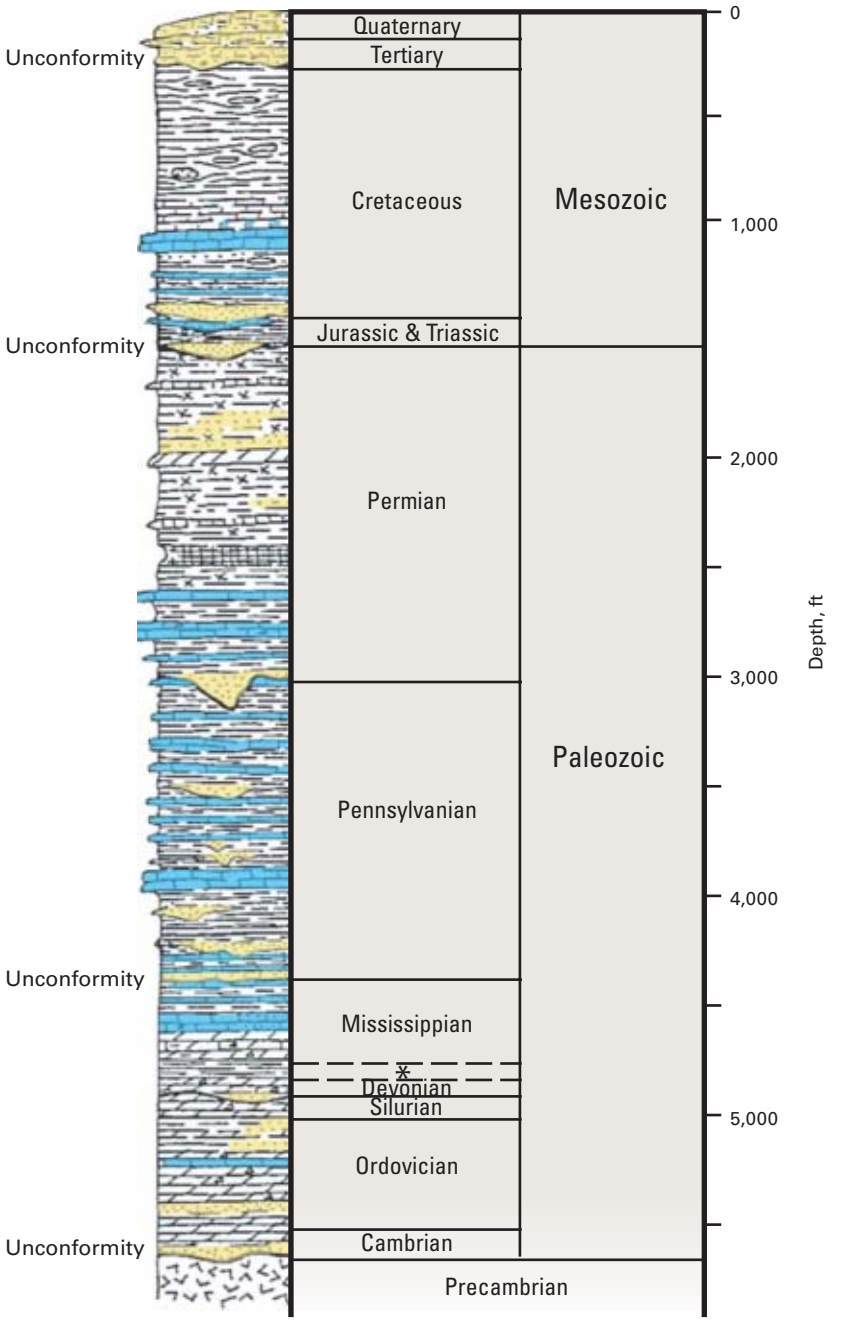
After acidizing, the well produced some low-Btu gas with swabbing operations (Table 1).

Assuming the recovered oxygen was contributed by atmosphere in the well tubing (and thus mixed with the gas coming out of solution during the swabbing) and sample bottle, any atmosphere was subtracted from the analyses. Likewise, the concentration of CO_2 in the sample may be spurious, because of acidizing the well, so this, too, was subtracted and percentages recalculated to 100%.

The gas contained considerable nonflammable components of nitrogen, carbon dioxide, and helium, so it had

FOREST CITY BASIN PALEOZOICS, NE KANSAS

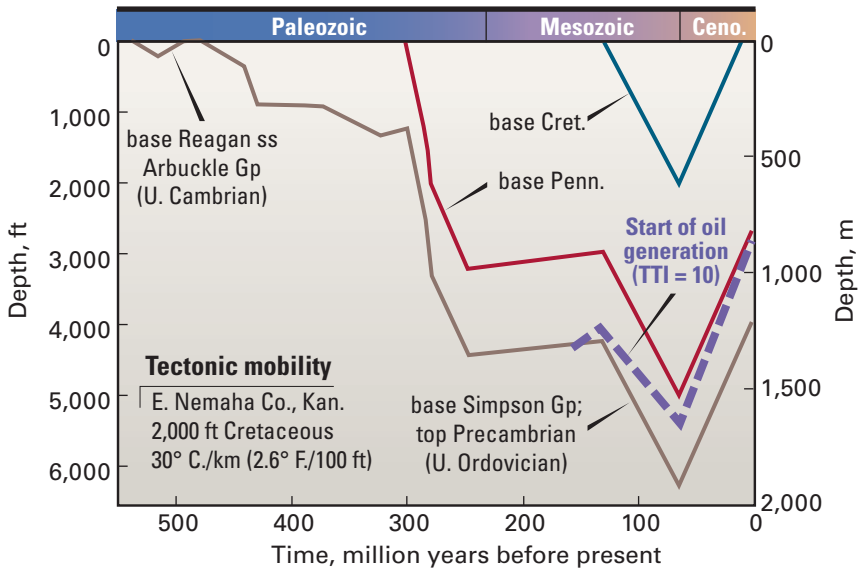
Fig. 1



*Devonian to Mississippian.

FOREST CITY BASIN BURIAL HISTORY*

Fig. 2



*Note major changes in Pennsylvanian time and the Cretaceous.
Deepest burial of about 6,000 ft took place during the Cretaceous (Newell et al., 1989).

a rather low 283 btu content. Even not considering the CO_2, the btu was low at 495. The chemistry is strange with so much hydrogen; however, it is consistent with a thermogenic gas with a possible mixing of a microbial gas.[6]

The Precambrian has undergone considerable stress and strain during its epirogenetic history—first with the formation of the MRS in the Proterozoic, then several episodes of deformation in the Paleozoic, especially in early Pennsylvanian time and again near the end of the Permian. There were several periods of tilting and stress of the weight of the glaciers, so it seems likely that the basement is highly fractured.

Given this deformational history, it is suggested that fluids containing the hydrocarbon gas, which had been generated in Paleozoic sediments, migrated into the Precambrian fractures. The hydrogen possibly was generated in situ in the Precambrian basement.

The future

The occurrence of gas in the Precambrian crystalline rocks is a novelty, but can the gas be produced commercially?

Is the Wilson well the forerunner of a new oil and gas producing province in Kansas?

Only time and more tests will tell.

Acknowledgment

Thanks to P. Acker for the graphics. ✦

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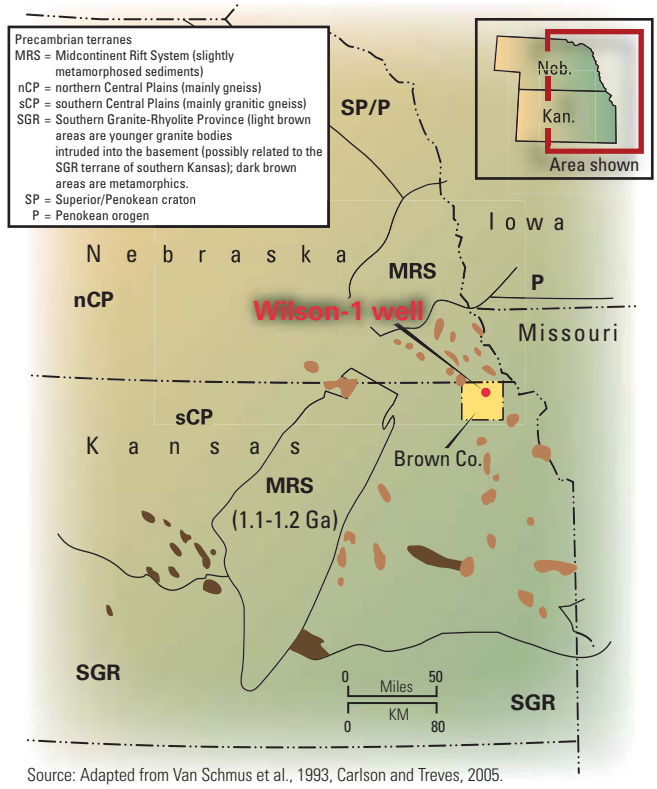
BASEMENT ROCK TYPE

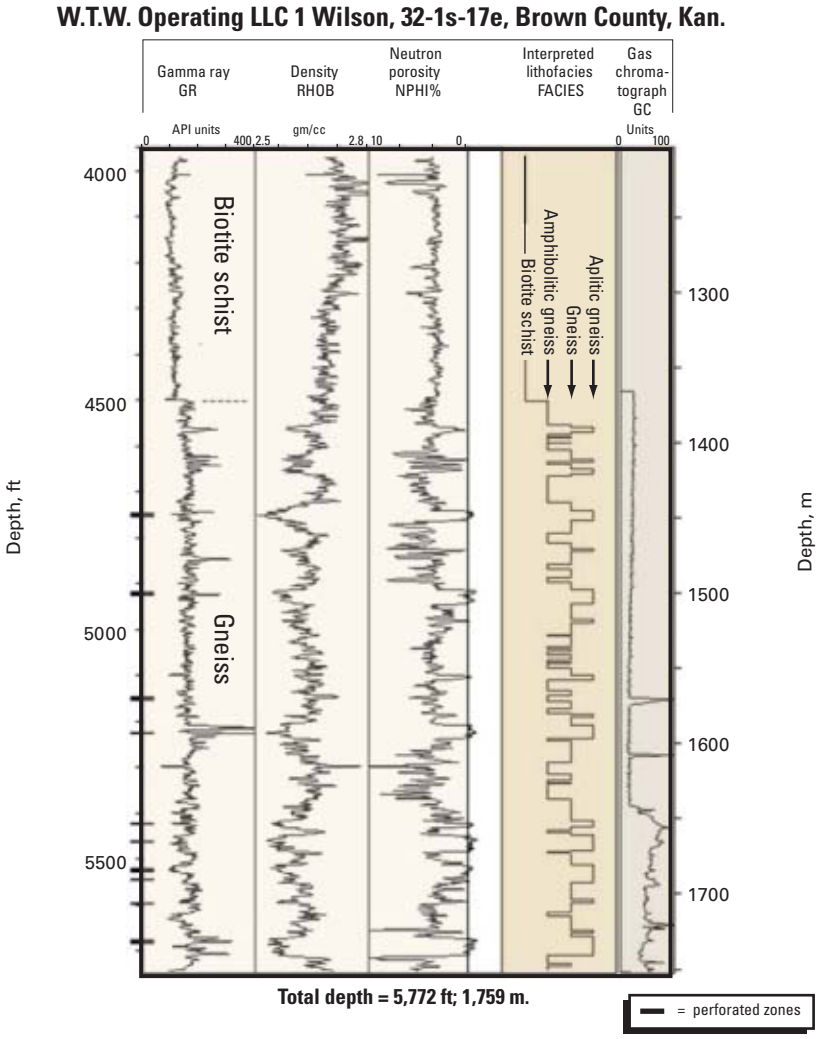
Fig. 3



Source: Adapted from Van Schmus et al., 1993, Carlson and Treves, 2005.

BROWN COUNTY WILDCAT PRECAMBRIAN SECTION*

Fig. 4



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Peru

BPZ Energy Inc., Houston, said its CX11-14D well in Corvina field off northwestern Peru drillstem tested 1,700 b/d of oil on a ⅝-in. choke with no water through perforations in the Upper Zorritos formation at 7,150 ft.

The test on Block Z-1 confirmed the presence of oil downdip from the CX11-21XD well, which tested 5,900 b/d of oil and 60 MMcfd of gas, and the absence of water indicates that the Corvina oil pool extends downdip of the CX11-14D well, the company said. More sands are to be tested.

Triangle Petroleum, Kerogen Resources drilling Arkansas' Fayetteville shale gas

Nina M. Rach
Drilling Editor

Calgary's Triangle Petroleum Corp. and Houston's Kerogen Resources Inc. have begun drilling Arkansas' Fayetteville shale. The partners equally share in a joint venture to explore 17,000 gross acres in Conway and Faulkner counties.

The Fayetteville shale in the Arkoma basin is touted as the geologic equivalent of the prolific Barnett shale found in the Fort Worth basin.

Triangle and Kerogen shot a 3D seismic program covering 12 sq miles in Conway County, Arkansas, in spring 2007, have drilled their first vertical test well, and plan to drill four more wells through the end of the year. The companies will use horizontal wells and multistage fracture stimulation to develop the reservoirs.

Fayetteville shale

The Fayetteville shale is one of eight major shale-gas plays in the US. The Fayetteville trend runs through the Arkoma basin in Arkansas; it's the geologic equivalent of the Caney-Woodford shale found in the western Arkoma basin in eastern Oklahoma and the Barnett shale in North Texas.

Southwestern Energy Co. discovered the Fayetteville shale play in 2004 and is the largest acreage holder with about 900,000 net acres, followed by Chesapeake Energy Corp.

Southwestern Energy describes the Fayetteville as an unconventional-gas reservoir ranging in thickness from 50 to 550 ft and in depth from 1,500 ft to 6,500 ft.

As of June 30, 2007, Southwestern had drilled and completed 303 wells (as operator) in the Fayetteville shale play, including 246 horizontal wells (OGJ Online, Aug. 2, 2007). Southwestern drilled in 13 areas across eight Arkansas counties, including Franklin, Conway, Van Buren, Cleburne, Faulkner, and White.

Oklahoma City-based Chesapeake Energy calls the Fayetteville shale one of

Nabors Rig 113 drilled the Ed Gordon WMA No. 1-10 well in western Conway County, Ark., in first-quarter 2007. (Fig. 1; photo from Kerogen Resources Inc.)

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its six most important unconventional-gas plays. Chesapeake characterizes its Fayetteville leasehold as "second largest in the core area of the play," (390,000 net acres) but says it's the largest overall leasehold owner (1.1 million net acres).[1]

Chesapeake operates 12 rigs and plans to develop the field with horizontal wells and 80-acre spacing in the core area. The company said each well costs about $2.9 million to and will produce about 1.6 bcf-equivalent from 3,000-ft horizontal laterals.[1]

Other publicly held US operators involved in the Fayetteville shale play include: Contango Oil & Gas Co., Edge Petroleum Corp., Noble Energy Corp., and XTO Energy Inc.

Fracturing

Like other tight shale gas plays, the key to successful completions is hydraulic fracturing.

Schlumberger is the largest provider of frac services in the Fayetteville play and works under contract to Southwestern Energy. Of the 246 horizontal Fayetteville shale wells drilled by Southwestern, 219 were fracture stimulated with slick water or cross-linked gel fluids.

Although two of the largest frac service providers, Halliburton and BJ Services, have steered away from the area, Cudd Well Control and Calfrac Well Services Ltd. entered the Arkoma basin earlier this year.

Cudd Well Control is a division of Cudd Energy Services, a subsidiary of holding company RPC Inc. Cudd runs frac fleets in the Arkoma basin from an office in Elk City, Okla.

Calgary-based Calfrac established an office in Beebe, Ark., to service a 2-year take-or-pay contract signed with Chesapeake Energy late in 2006. Calfrac has relocated two frac equipment spreads to Arkansas; the first fleet started Mar. 8, 2007, and the second fleet began working June 4.[2]

Drilling

Triangle and Kerogen spud their first vertical test well, Ed Gordon WMA 1-10, in February 2007 with Nabors Rig 113, a conventional double (Fig. 1). The Conway County well reached the targeted 8,300 ft in April.

Eric Reigle, Arkoma team leader at Kerogen, told OGJ that drilling was successful using a variety of bits, predominantly PDC, and the company set 7-in. casing through the Fayetteville shale. The company plans to hydraulically fracture the well hydraulically in September.

Triangle and Kerogen expect to drill four more wells this year.

Triangle said the vertical test wells were planned to confirm Fayetteville shale-reservoir parameters and provide subsurface data to further refine the horizontal drilling program. The company plans to use the vertical wells to monitor stimulations of adjacent horizontal wells, after which it will convert them to horizontal producing wells.

Southwestern has drilled about 25 wells in Conway County, with initial test rates of 0.55 to 3.24 MMcfd (Jerome Carr 9-15/2-31H well), with an average of 1.49 MMcfd/well, according to the Arkansas Oil and Gas Commission and Capital One Southcoast Inc.[3]

Triangle

In addition to the Fayetteville shale project, Triangle Petroleum is focusing on projects in the US Rocky Mountains and shale in eastern Canada, where the company has recently acquired 484,000 gross acres in Nova Scotia and New Brunswick, according to Mark Gustafson, Triangle's president and chief executive officer.

In July, Triangle divested its 27% interest in 12,100 gross acres in northeast Hill County, Tex., but retains its interest in eight Barnett shale wells.

The company's US projects are run through subsidiary Triangle USA Petroleum Corp., and Canadian projects are handled through subsidiary Elmworth Energy Corp.

Kerogen

Privately held Kerogen Resources focuses on North American source rock shales. The company has acreage and experience in the Fort Worth basin (OGJ Online, Dec. 19, 2005). Kerogen worked with Schlumberger on a "stress-diversion" fracture pilot program, running large, multi-stage fracs in horizontal lateral wells. The Barnett pilot fracs used 5 million gal of fluid with 2.5 million lb of sand in five stages.

Reigle told OGJ that Kerogen also has nonoperated acreage in the Bakken play in the Williston basin. The Bakken formation was deposited during the Upper Devonian and Lower Mississippian periods and is now found across Montana and North Dakota and into the Canadian provinces of Manitoba and Saskatchewan (OGJ, Dec. 11, 2006). ✦

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Resource potential estimates likely to change

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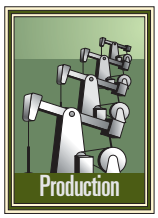
UNCONVENTIONAL GAS—2

Understanding of the unconventional-gas resource base has improved in the past decade, but many unknowns remain.

Data from drilling more than 100,000 wells and developing 120 tcf of reserves in the past 10 years have provided a more solid foundation for estimating the resource potential of tight gas sands, coalbed methane, and gas shales.



Yet questions remain, such as:

- Where are the productive limits of the emerging gas plays?
- What is the optimum well spacing?
- How will advances in well drilling and completion technologies change well productivity?

Because of these questions, estimates of the recoverable portion of the large in-place unconventional-gas resource may change many times during the next decade.

This second in a six-part series on unconventional gas, discusses the size and nature of the resource base including why and how the estimates of recoverable resources may change and evolve.

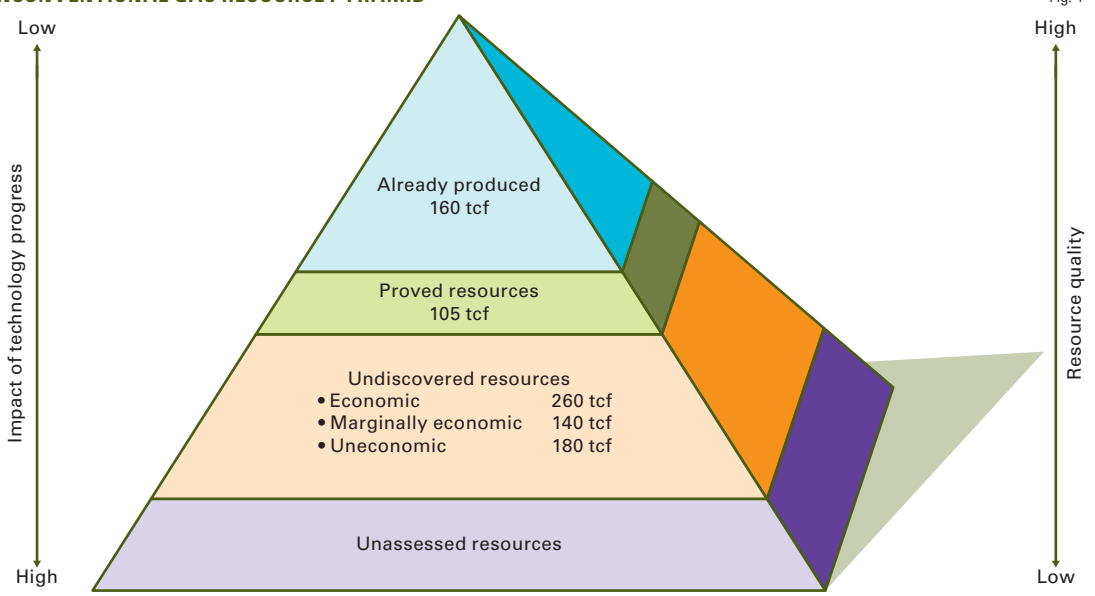
The first article in this series (OGJ, Sept. 3, 2007, p. 35) covered the growth of these resources during the last decade.

CHANGES IN GAS RESOURCE ESTIMATES Table 1

	1996	2002	2006
	tcf		
Tight gas sands	259	348	379
Coalbed methane	55	83	73
Gas shales	52	78	128
Total	**366**	**509**	**580**

Note: For technically recoverable gas in US Lower 48 only. The 2006 data uses data through 2005.

UNCONVENTIONAL GAS RESOURCE PYRAMID Fig. 1



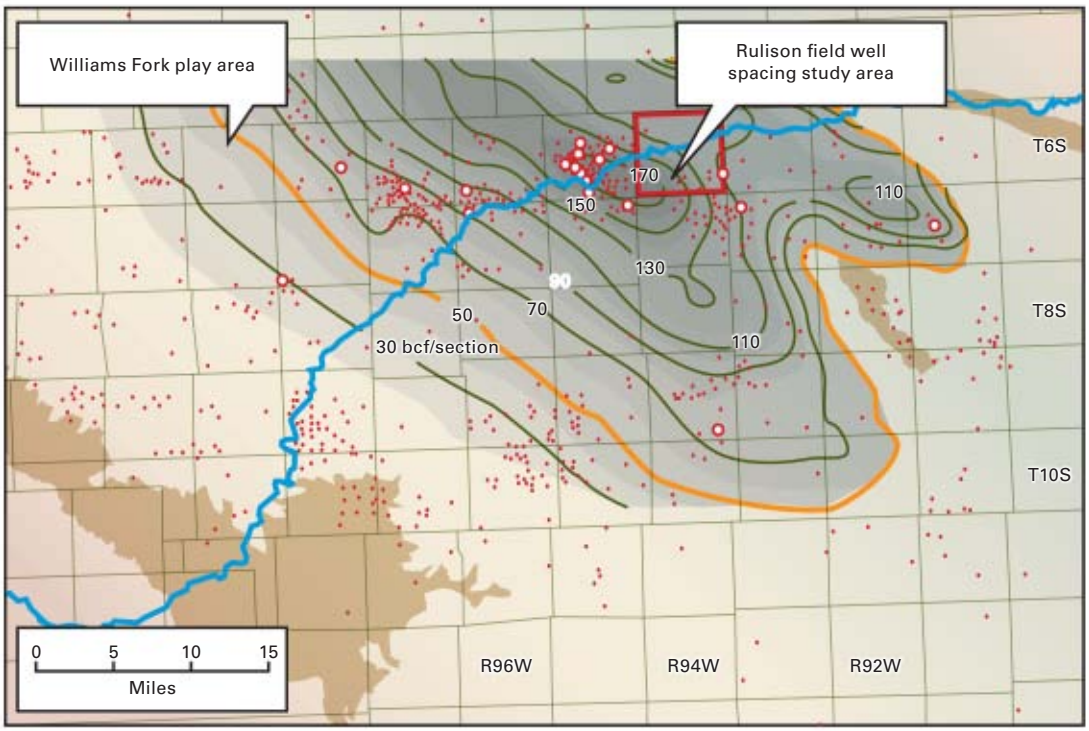
Note: Evaluation assumes undiscovered resources are economic at $5/Mcf (Henry Hub) and marginally economic at $5-6/Mcf (Henry Hub).

Resource base estimate

Advanced Resources Inc. estimates that the recoverable resource base for unconventional gas is large, about 580 tcf—with 379 tcf in tight gas sands, 73 tcf in coalbed methane, and 128 tcf in gas shales. Table 1 shows ARI's unconventional-gas resource base estimates for technically recoverable resources in 1996, 2002, and 2006, and Table

SOUTH PICEANCE BASIN

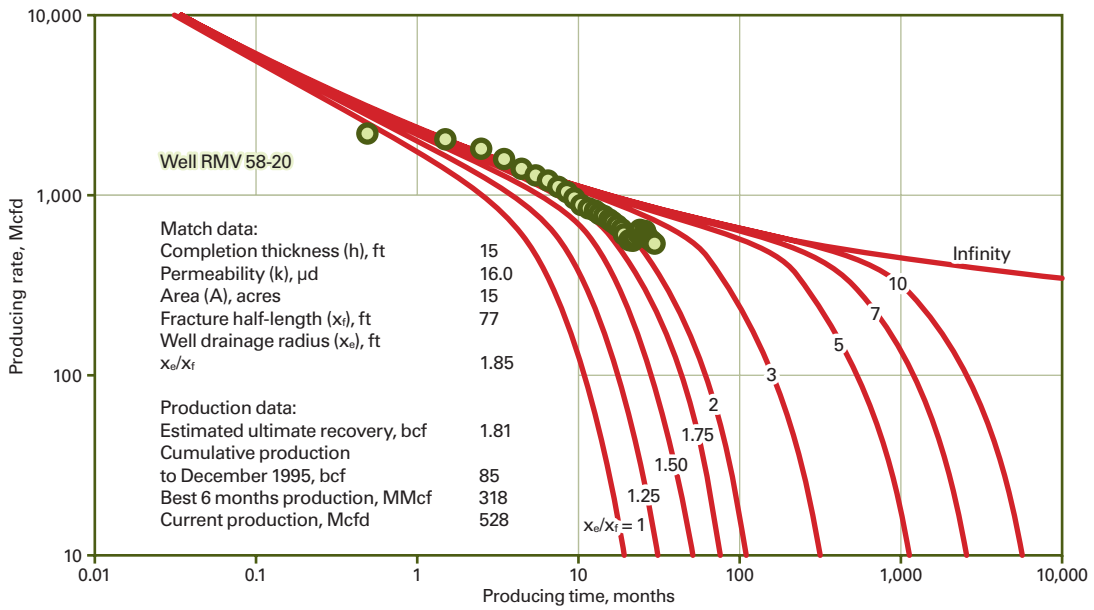
Fig. 2



Note: Twenty-eight townships (1,008 sq miles) are within the 50+ bcf/section gas-in-place contour for the William Fork (Mesaverde) gas play. Estimated gas in-place is 100 tcf inside this contour area.

TYPE-CURVE MATCH

Fig. 3



Note: Type-curve matching of early time production data once key reservoir properties are established can provide well drainage and ultimate well spacing estimates.

2 provides regional detail for the 2006 resource estimate.

The tight-gas-sand play in the Rocky Mountain basins forms the largest segment of the unconventional-gas resource, followed by the gas shales and tight gas sands of the Appalachia basin. The fastest growth in unconventional-gas resources has been in East and Central Texas, with the emergence of the Barnett gas shales and the Cotton Valley-Bossier tight gas sands.

When looking at the resource base numbers, it is important to remember that these estimates are merely a "snapshot in time." The continuing emergence of new unconventional-gas plays, the ability to develop an already discovered play more intensively, and advances in extraction technology can and will affect the ultimate size of the recoverable resource.

The statement "we do not yet know the true size and nature of the unconventional gas resource base" is as true today as when it was made 9 years ago.[1]

Resource pyramid

One useful way to view the size and nature of the unconventional-gas resource base is as a resource triangle or pyramid (Fig. 1).[1,2] The top of the pyramid contains high quality unconventional-gas plays

and portions of plays, many of which are extensively developed. These higher quality plays have produced 160 tcf and still hold 105 tcf of proved reserves.

The middle of the pyramid contains 260 tcf of economic and 140 tcf of marginally economic undeveloped unconventional-gas resources. At the bottom of this section are about 180 tcf of lower quality, uneconomic plays, and portions of active plays, such as the basin margins.

The base and inside of the pyramid, still out of view, contain the new, still to be assessed and discovered unconventional-gas plays.

The unconventional-gas plays within the resource pyramid are dynamic. The resources can move vertically with progress in technology and knowledge, from an initial low quality, high-cost foothold to a position of higher quality. An example of this is how application of horizontal wells and multistage hydraulic fracturing has enabled gas shales plays to become "the new hot thing."

Exploration and new resource appraisals can accelerate development of the still unassessed unconventional-gas plays inside the pyramid.

Resource base estimates

Need for new evaluation methods, a massive data volume, and rapid changes in outlook make assessing the size and quality of the recoverable unconventional gas difficult.

The assessment requires new methods because of the continuous nature of the unconventional-gas deposits. Analysts cannot use traditional methods developed for conventional gas, such as field size distributions, finding rates, and a discovery process. The assessment involves vast quantities of geologic, engineering, and well performance data plus numerous "expert judgment" calls. For example, ARI periodically reviews the performance of several hundred thousand unconventional-gas wells to establish up-to-date trends in well productivity.

Unconventional-gas plays also are prone to rapid and large changes in performance. Successful introduction of new geologic knowledge and advances in well drilling and completion practices can dramatically improve a play's outlook.

GAS RESOURCES BY AREA

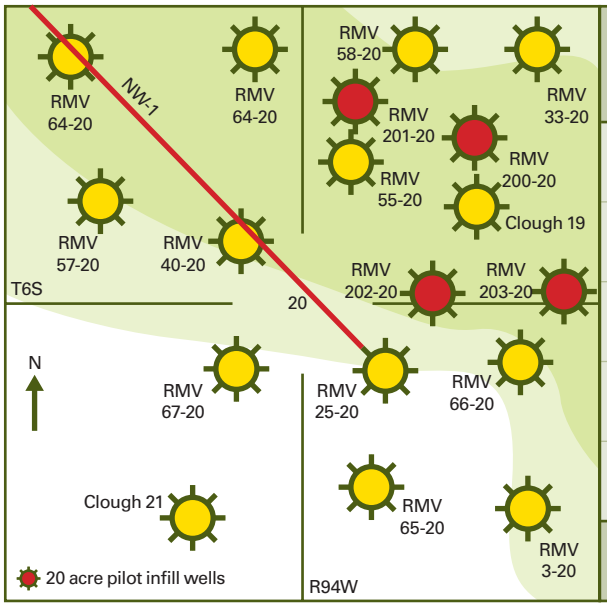
Table 2

Area	Tight gas sands	Coalbed methane	Gas shales	Total
	tcf			
Rocky Mountain basins	223	57	3	283
East and Central Texas	32	-	49	81
Appalachia	67	5	15	87
Other	57	11	61	119
Total	**379**	**73**	**128**	**580**

Note: With data through 2005; technically recoverable resources in US Lower 48 only.

RULISON FIELD PILOT

Fig. 4



Date	No. of wells	Well spacing, acres/well	EUR/ well, bcf	EUR/ section, bcf
Initial	4	160	2.1	9
1995	4	80	2.0	8
1996 -98	8	40	2.0	16
1997 -2000	16	20	1.7	27
Latest	32	10	1.6	50
Total	64		1.7	110

Note: For wells drilled through 1997

A prime example is how horizontal drilling, restimulation, and closer well spacing converted the Barnett shale from a 3-tcf marginal gas resource (as evaluated by the US Geological Survey in 1996)[3] to a major 26-49 tcf gas play as determined in an ARI internal assessment. The ARI estimate for the Barnett shale differs from the USGS assessment in that it includes expectations for gas recovery from drilling horizontal wells in extensions of the core areas.

At the same time, as an unconventional-gas play matures, its well productivity and success rate will start declining unless technology can outpace resource depletion.

Resource assessment steps

Because unconventional-gas resources are dynamic, the plays need frequent reassessment, every 2-3 years, not once per decade. ARI's preferred resource assessment method for continuous gas plays has five key steps:

1. Gas in-place and play area. Establish the play outline using various measures such as thermal maturity or minimum net pay and than map the gas-in-place contours to define the ultimate resource target and establish the quality portions of the gas play.

2. Well drainage and spacing. Use production data, reservoir properties, and a tight formation type-curve model, such as METEOR, to establish analytically rigorous well drainage. In addition, examine oil and gas commissions' spacing rules appropriate for each play.

3. Trends in well performance and success rates. Assemble a comprehensive, accurate, and up-to-date database of well performance, reserves per well, and success rate for key time periods to understand resource maturity and the impacts of technology advances.

4. Trends in technology progress. Document how progress in technology, such as pay selection and well-completion practices, has improved or may continue to improve well performance. Selected field case studies plus in-depth technical performance data can provide valuable insights on the performance and benefits of improved technology.

5. Higher quality and accessible play partitions. Use the empirical well performance database plus basin modeling, stress mapping, and other methods to define the higher productivity portions of the plays, particularly areas with

US LOWER 48 GAS RESOURCE ESTIMATES

Table 3

	Advanced Resources, 2006 — Proved reserves	Advanced Resources, 2006 — Undeveloped resources	National Petroleum Council, 2003	US Geological Survey, 2006
	tcf			
Tight gas sands	73	379	131	177
Coalbed methane	20	73	46	67
Gas shales	12	128	29	60
Total	**105**	**580**	**206**	**304**

Note: ARI's estimate is based on data through 2005. NPC's estimate is for accessible undeveloped resources, current technology, with data through 1998. USGS's estimate is for undeveloped continuous resources, with data from 1995-2006.

WILLIAMS FORK (MESAVERDE) GAS RESOURCE ESTIMATE

Table 4

	US Geologic Survey, 2003	Advanced Resources, 2006 — South basin	Advanced Resources, 2006 — North basin
Play area, sq miles	1,989	1,008	1,008
Well spacing, acres/well	80	20	80
Wells drilled	822	2,920	199
Success rate, %	80	95	87
EUR/well, bcf	0.9	1.3	1.85
Quality/accessibility factor, %	28	87	87
Recoverable resource, tcf	3.1	31.5	11.0

Note: USGS's estimate is with data through 1999, while ARI's estimate is with data through 2005.

greater permeability. In addition, examine federal and state regulations to establish the portion of the basin that may or may not be accessible in the foreseeable future

The first assessment step can be established from geologic maps but requires judgment as to where to draw the "quality" gas play outline. The next two assessment steps can be empirically established from drilling and production data. The fourth assessment step requires assembling considerable technical information and rigorous case studies. The greatest uncertainty and expert judgment is in step five—determining the portion of the unconventional-gas play that can be accessed and is of sufficient quality to be developed in the foreseeable future.

SOUTH PICEANCE BASIN WELLS

Table 5

Performance by time period—	Total wells	Successful wells	EUR, bcf	EUR/well, bcf	Success rate, %
Pre-1990	98	67	70	1.04	68
1990-95	219	207	266	1.29	95
1996-99	353	335	406	1.21	95
2000-05	2,250	2,191	2,850	1.30	97

Performance distribution, recent wells— 2000-05, % of wells	Successful wells	Actual well distribution, bcf/well	Smoothed well distribution, bcf/well
10	231	2.95	2.60
20	438	1.81	1.95
30	657	1.24	1.30
40	865	0.65	0.65
Total	**2,191**		

Note: Wells produce the William Fork (Mesaverde) play.

Resource estimate comparison

Table 3 compares three estimates of the recoverable portion of the unconventional-gas resource base.

ARI's 2006 estimate used annual updates on unconventional drilling, production, and reserves. The 580 tcf unconventional-gas resource estimate is, at times, considered aggressive in that it incorporates expectations of technology progress and intensive resource development. To note, however, is that ARI's 10-tcf estimate for the Barnett shale in 1998 also was considered aggressive at the time.[1]

The National Petroleum Council (NPC) estimate used a combination of Gas Research Institute and USGS data, industry reviews, and outside contractor input. Its latest study, completed in 2003 with resource base data through 1998, determined that the US Lower 48 states had an accessible unconventional resource base of 206 tcf.[4]

USGS has reassessed 22 priority basins and has plans to reassess 10 more basins since its last comprehensive assessment in 1996. The current USGS estimate for the Lower 48 is 304

tcf of unconventional-gas resources.[5,6] Its assessment method combines use of total petroleum systems and cell-based resource estimates, involving play area, well density, well productivity, success rate, and play access.

To note is that the USGS has yet to include in its estimate the continuous gas resources in many large basins, such as Anadarko, Big Horn, and East Texas.

In another assessment, the US Energy Information Administration uses a combination of USGS and ARI data and contracts with ARI for annual updates to tight gas reserves, drilling, and production estimates. These input data are incorporated into EIA's UGRSS module of its Oil and Gas Supply Modeling system.

Estimate differences

Given the different assessment methods, data, and assumptions included, it is not surprising that estimates of the remaining unconventional-gas resource base vary. What is surprising is that the differences, both overall and for any given play, are so large.

The reason one should care about these difference is that accurate assessments are important in assisting industry to target its efforts better and in aiding government policy makers in arriving at better decisions. For example, it matters greatly whether the remaining accessible unconventional-gas resource base is 580 tcf as of today (ARI) or 206 tcf as of 1998 (NPC).

ARI's play-by-play tabulation shows that in the 7 years 1999-2005, industry had developed 100 tcf of undiscovered unconventional-gas resource. If the accessible resource base is 206 tcf (as of 1998), then only 106 tcf remain undeveloped as of the end of 2005.

The implication is that the remaining unconventional resource base may not support current production levels for much longer. With declines in conventional gas production, both onshore and offshore, a severely depleting unconventional-gas resource base would require massive gas imports, particularly LNG, for averting a gas supply crisis.

If the remaining unconventional-gas resource base is 580 tcf, however, the industry has a good potential for maintaining today's domestic natural gas production rates, with advances in technology potentially providing additional production.

It also matters whether a particular unconventional-gas play has only 3 tcf or more than 40 tcf of remaining undeveloped resource. For example, as shown in Table 4, two resource estimates exist for the Williams Fork (Mesaverde) lenticular tight gas play in the Piceance basin. USGS with data through 1999 shows 3.1 tcf, while the ARI estimate with data through 2005 shows 42.5 tcf.

The play has 2,250 wells drilled and 2.85 tcf of resource developed since 1999 (Table 5). The USGS estimate would then indicate that this play is essentially over, while the ARI estimate indicates that the industry has only started to develop this play.

The Williams Fork (Mesaverde) tight-gas play in the South Piceance also illustrates how modest differences in assumptions can lead to resource estimates that differ widely (Table 4).

In regard to basin area, both the USGS and ARI use essentially the same area for the basin, about 2,000 sq miles. ARI divides the basin into two distinct segments: the North and the South. For the southern segment, ARI prepared a gas-in-place contour map and used the 50 bcf/section contour to define the quality portion of this gas play (Fig. 2).

USGS used an average spacing of 80 acres/well and ARI used 20 acres/well based on recent Colorado Oil and Gas Commission (COGA) rules allowing such well spacing. ARI also type-curve matched production data to establish well drainage, confirming the validity for using 20-acre well spacing. Fig. 3 shows a type-curve for a 15-acre well drainage area for Well RMV 58-20, which is representative of the play.

ARI also evaluated the intensive resource development in Rulison field, Section 20 (T6S R94W). This pilot section for infill development of this tight-gas-sand play showed that gas recoveries of more than 110 bcf/section are possible with even closer 10-acre well spacing (Fig. 4).

Both the USGS and ARI use high success rates because most South Piceance wells are infill wells.

USGS estimates a 0.9 bcf/well ultimate recovery, while ARI estimates a 1.3 bcf/well recovery for South Piceance and a 1.85 bcf/well recovery for North Piceance. ARI's higher assessment is due to recognizing that improved technology is being used in new wells and that older wells are being recompleted. The USGS acknowledges that "the EUR's presented in this report (Uinta-Piceance Province) represent current completions only, and do not include the anticipated production potential for behind pipe gas that is not yet being produced. When this is added, the EUR's should be considerably higher...," citing Reference 7.

The USGS well database is current as of 1999 and contains 822 wells, while the ARI well database is current as of 2005 and contains 2,920 wells.

Table 5 illustrates the time-slice method used by Advanced Resources for establishing success rates and recovery per well for this tight gas play. This table shows:

- All wells drilled and completed by key time periods, to isolate basin maturity (depletion) and technology progress.
- Trends for well performance, the distribution of current well performance, and trends in well success rates.

A major assessment uncertainty exists for determining the portion of the play that can and will be developed in the near future. USGS assumed that industry will develop only a relatively small portion of available drill sites in 30 years and applied a 28% quality-accessibility factor to the play. ARI, after mapping the high gas-in-place portion of the South Piceance basin and examining the federal leasing regulations for this basin, used an 87% quality-accessibility factor.

This discussion provides an insight into the difficulty in making resource assessments for unconventional gas and

why these resource assessments may differ. Clearly, assembling and rigorously using up-to-date well performance data are important. As important is using appropriate well spacing and expectations for resource access and development for these large, continuous-type resources.

Frequent updates

Improvements in technology and knowledge rapidly can change the outlook for unconventional-gas plays. To see these changes requires frequent assessments, particularly for resources where technology progress is helping unlock a gas play.

A prime example is the Williams Fork (Mesaverde) play where multizone stimulation and new understanding of reservoir geometry has led to better well performance and has justified several rounds of downspacing, resulting in a substantial increase in the recoverable resource base.

The knowledge gained from such assessments is vital for guiding industry investments and for formulating a sound energy and natural gas policy. ✦

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Acid-gas injection in New Mexico relieves sulfur-recovery unit duty

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The original acid-gas injection project near DCP Midstream's Artesia, NM, gas plant started up in November 2003 and consisted of drilling an injection well and installing an acid-gas injection compressor. The project's initial aim was to eliminate use of the plant's sulfur-recovery unit to reduce operating costs, improve safety, and enhance environmental performance.

The injection horizon is the Devonian formation at 11,500 ft. The compressor is a six-stage, electric-motor-driven, reciprocating unit. The acid-gas design volume is 1.5 MMscfd of water-saturated gas at 2-8 psig suction pressures and up to 2,000-psig discharge pressure. The design composition of the acid gas includes an H_2S content of 33-45 mole %. The balance of the acid gas is CO_2 with typically about 1% hydrocarbon. The project shutting down envisioned the existing three-bed Claus sulfur-recovery unit.

Design, development

This design is a reconfiguration of the unit to allow injection pressure to be increased to 2,750 psig from 2,000. This increase was needed to overcome the low permeability of the formation to meet expected long-term injection rates. A custom cylinder design was required. The reconfigured design started up in December 2006.

The project was developed with best practices from DCP Midstream, its predecessor companies,[1] and previous industry projects. Some general guidelines from the other AGI sites were to inject below the deepest producing formation and into a formation with a minimum number of existing well-bore penetrations.

All previous DCP Midstream sites were located as close to the amine system as allowable within plant-equipment spacing guidelines, typically directly on the plant site to minimize hazards associated with the H_2S inventory in piping and equipment and to avoid transportation issues offsite.

Other major process decisions made from previous company and industry[2-4] experience were partial use of stainless steel in the cold or "wet" portions of the compression equipment including the first-stage suction for a consistent design philosophy for all stages. Another decision was to rely on the water-saturation characteristics of the acid gas at compression and injection conditions partially to dehydrate the acid gas and consequently to use carbon steel (sour service) metallurgy for the hot-discharge lines and injection well. Alloy trim is included in the wellhead and downhole valves. A final decision from previous company projects was to install subsurface safety valves and bottomhole check valves for safety reasons.

Geological evaluation

A geological evaluation identified several potential formations in the Artesia plant area in Eddy County, NM. The deepest production in the immediate area is from the Morrow zone at about 10,000 ft. Drilled to this formation was a gas production well adjacent to the plant as well as two wells 2-3 miles west of the plant into deeper zones with complete well log information. Log cross-sections were prepared from available information and correlated to the plant site with the off-set well.

Based on this information, DCP Midstream selected the Devonian formation as the injection target because it appeared to meet the selection criteria: to provide good injection capability via naturally occurring fractures and to be below other production, thereby having

Based on a presentation to the 86th Annual GPA Convention, San Antonio, Mar. 12-14, 2007. The original paper is one of three recognized by the GPA convention program committee.

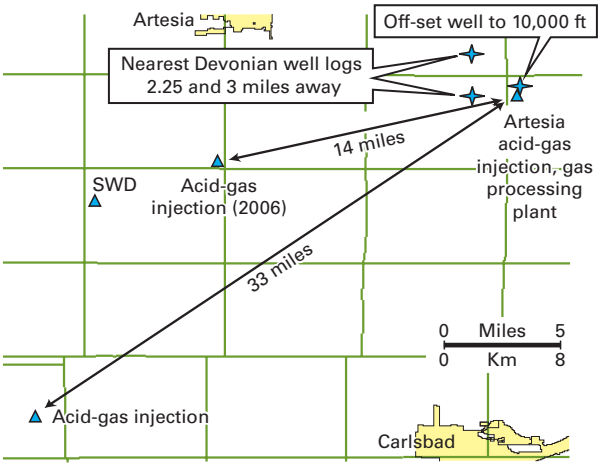
a minimum number of wellbore penetrations especially at the preferred location near the plant.

Devonian is a water-saturated limestone-dolomite (carbonate) typically not productive in the area. Drill stem tests of Devonian in nearby wells showed high rates of water production.

In addition, another operator was already injecting acid gas and water into the formation in Eddy County, although 33 miles away. Subsequently in 2006 a third operator initiated injection into this formation 14 miles away and also began operating a saltwater disposal well (SWD) in this formation.

ARTESIA AREA, DEVONIAN ZONE*

Fig. 1



*And other injection wells.

Design

Fig. 2, a pressure-temperature plot for the low H_2S design case, shows the compressor process design and the phase envelope, hydrate curve, and compressor operating conditions. As shown there, high inter-stage temperatures were required for this air-cooled unit at peak summer conditions. The final scrubber temperature of 140° F. became a requirement for a six-stage design since it provided extra margin above the acid-gas dewpoint temperature.

This fifth-stage inter-cooler temperature is the most critical and is used for both louver and fan speed control of the air cooler. The hydrate temperature is about 80° F. for the higher stages, which is of concern during winter operation and at turndown conditions.

Fig. 2 shows the increase in pressure from 5 psig to 2,000 psig in the six-stage compressor. The pressure then increases from 2,000 psig to 5,800 psig (including the 10% over-prediction of density by the simulation program) as the fluid flows down the well. The heat of compression also increases the temperature in the tubing.

The six-stage compressor unit was designed to meet sour-service requirements.[5] A JGJ-6 Ariel compressor frame was selected because of its rod load and cylinder size. The unit includes long two-compartment distance pieces, purged distances pieces, purged primary and secondary packing, and other design details typical for acid-gas injection.

One modification for this unit was the use of nylon material for the valve plates on the low-stage suction valves and high-temperature nylon for the remaining valves. This material is suitable for temperatures up to 340° F. and has performed well. Previous acid-gas injection units have used steel valve plates, either carbon steel or stainless steel, or other thermoplastic materials such as PEEK (polyetheretherkeytones).[1 2 6]

Table 1 summarizes the design parameters for the unit as originally configured (with parameters for the reconfigured unit, 2006 design shown in parenthesis).

The driver is a 4,160 v, 600-hp motor with a variable-speed drive. The VFD's speed range was 900-1,400 rpm for the original design. The cooler is a common unit for all six stages.

The very high discharge pressure—well above critical—will cause the gas to cool significantly to about -110° F. when expanded from 2,000 psig and 130° F. to close to atmospheric pressure. Therefore, the compressor recycle valve originates upstream of the aftercooler for operation on acid gas. All relief valves are directed to the plant's acid-gas flare.

It cannot be emphasized enough that for dense-phase acid gas, cryogenic temperatures are possible during depressurization, compounding the hazards associated with this toxic gas. On this project a methanol-injection pump was added after start-up to displace the dense-phase acid gas from all lines before depressurization.

Initial fracture stimulation

The well was perforated at 11,207-11,260 ft and 11,326-11,412 ft. Drill-stem testing completed on each section revealed only small amounts of water production from the Devonian formation, indicating much lower permeability than expected. Openhole logs were also completed and sidewall cores collected and analyzed in a laboratory.

COMPRESSOR DESIGN PARAMETERS

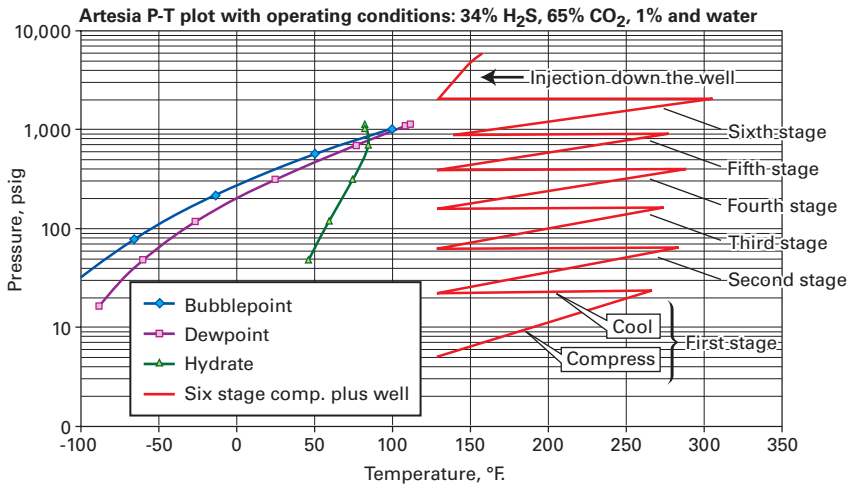
Table 1

Stage	Bore diameter, in.*	Suction pressure, psig*	Discharge pressure, psig*	Limiting stage MAWP, psig*
1	16.75	5	23 (24)	150
2	13.00	22 (23)	63 (66)	150
3	8.350	60 (63)	155 (163)	260
4	5.500	150 (158)	379 (405)	505
5	3.625	370 (395)	867 (959)	1,050 (1,270)
6	3.625 (2.375)	857 (947)	2,020 (2,778)	2,200 (3,000)
To injection (aftercooler)		2,020 (2,778)	2,000 (2,750)	2,200 (3,000)

*Reconfiguration pressures in parenthesis.

PROCESS DESIGN

Fig. 2



All of this information confirmed the low permeability of the formation.

DCP Midstream then decided to complete the well and enhance permeability using stimulation techniques. This work improved the expected well performance and was designed for a fracture half-length of 173 ft with 45,000 gal of 15% hydrochloric acid.

Water injection tests unfortunately revealed the predicted performance was still marginal for the compressor capability of 2,000 psig. Based on these test results, the injection permit was amended for injection of acid gas at pressures up to 3,240 psig. It appeared that the initial performance should be satisfactory, but if the performance deteriorated, design acid-gas injection rates would not be met.

The well could perform better than expected as several sites have documented decreases in injection pressure with time possibly due to the action of the acid gas in dissolving or etching the carbonate rock formation in the presence of formation water.[3,7] Laboratory tests have shown that increased permeability is possible with time[8] as well as decreased permeability for various rocks.

Operation with acid gas would also allow collection of data to evaluate reservoir performance and to determine the best corrective option if performance were poor. Due to the possible need for a higher pressure cylinder a forged billet of 17-4PH stainless steel for the custom cylinder was placed on order to expedite a modification if required and the original compressor was installed.

Operation—constant rate

Operation on acid gas began on Nov. 17, 2003, initially at a constant acid-gas rate of about 1 MMscfd. The pressure rose rapidly toward the maximum operating pressure of 2,000 psig within a few weeks.

WELLBORE INJECTIVITY INCREASE

Table 2

Date	Equivalent fracture half-length, ft
November 2003	250
October 2004	300
August 2005	360

Source: Reference 10

Fig. 3 shows initial well performance; the data are hourly average values. The H_2S concentration in the acid gas is calculated from the gas analyzer readings measured for H_2S and CO_2 concentrations in the inlet gas to the amine system, which typically removes all of the acid gas from the inlet gas. There is also correlation to a logarithmic pressure increase. This is analogous to a gas storage field, which will often display a logarithmic pressure vs. time relationship.

Fig. 3 also shows a number of interesting operational issues. When the well is shut-in for short periods the pressure declines slowly as the acid gas leaks off into the low-permeability formation. A slight impact of temperature appears in Fig. 3 as a gradual increase in pressure above the trend is seen when the temperature increases and a gradual return to the trend when the temperature decreases.

Finally, Fig. 3 also shows some "unknown spikes" in pressure that occurred very rapidly. During cold weather operation on a rich gas stream, the plant was experiencing foaming in the amine system that caused hydrocarbon entrainment in the amine, increased hydrocarbon content in the acid gas, and a subsequent increase in injection pressure.

A 1% incremental increase in hydrocarbon content will cause a 60-psig rise in injection pressure due the impact of the relatively "non-condensable" hydrocarbon on the acid-gas density. This effect has definitely been seen in acid-gas injection performance.

Second fracture stimulation

The larger, follow-up acid fracture stimulation was through the production tubing using 42,000 gal of 28% hydrochloric acid, viscoelastic diverting acid, and was followed by a large post-flush step with twice this amount of water. The use of this acid and the water post-flush was to allow dispersal of any dissolved solid to the end of the fracture so that the well would not need to be flowed back.

Following the stimulation, the well was unable to accept flow because the surface shut-in pressure increased to greater than 2,100 psig, greater than the compressor shut-down pressure. One explanation is that the injection of acid gas had gradually established gas permeability in the reservoir and the large amount of liquid (hydrochloric acid and water) injected in the reservoir

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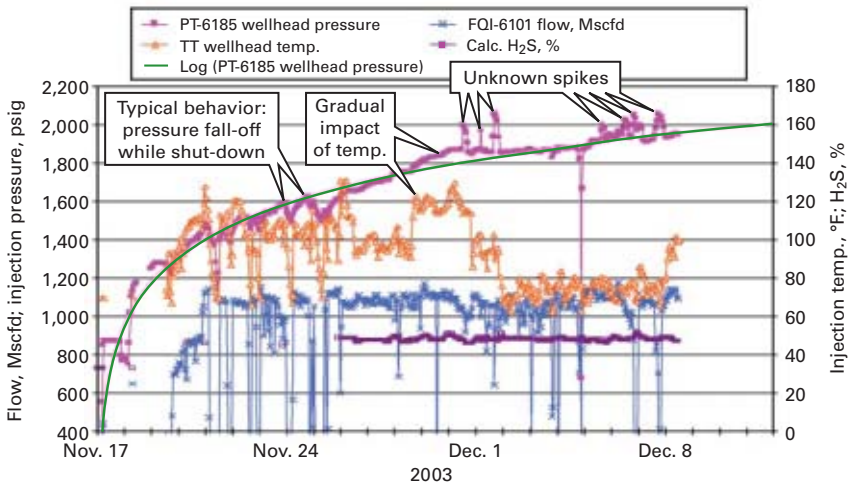
INITIAL WELL PERFORMANCE: CONSTANT RATE

Fig. 3



blocked the flow by isolating the gas pockets, in effect re-establishing permeability to water and decreasing permeability to gas.

The sulfur-recovery unit (SRU) was restarted in March 2004 to handle the acid-gas volume and avoid flaring. A follow-up workover to inject a combination of CO_2 and methanol to enhance mutual solubility of the reservoir phases and re-establish permeability to acid gas was completed. Some of the workover fluid was also flowed back and recovered, which required safety precautions for sour gas since some acid gas was entrained.

The combination of these actions returned the wellhead pressure to a typical shut-in value of less than 1,100 psig. Injection was then restarted in July 2004 in parallel with operation of the SRU.

Long-term performance

Fig. 4 shows the long-term performance for the Artesia acid-gas injection system covering nearly 4 years. Flows and H_2S concentration are daily average values and pressure and temperature are single point-in-time values each morning. The data in Fig. 4 first repeat the early data that were shown in Fig. 3 with the rapid initial increase in pressure followed by constant pressure injection for a few months with a declining injection rate. The shut-in pressure during the well was greater than 2,000 psig and a slow decline as the pressure leaked into the formation. The rapid drop in pressure to 1,100 psig from 1,800 psig occurred at the end of May 2004 due to the last workover injecting CO_2 and methanol and then recovering some of the injected fluid.

Fig. 4 then covers the operating data from restarting injection in July 2004 through August 2007. Injection temperature has been fairly constant at about 90° F., although precise control is limited due to the common cooler. The composition of the acid gas has gradually trended downward with the H_2S decreasing steadily to about 30% from 40% as the mix of inlet gas to the plant changed.

The data in Fig. 4 also show the relationship between injection pressure and injection rate. Following restart of injection in July 2004, the well was operated in parallel with the SRU at injection rates of about 400 Mscfd. The pressure is generally flat at this low injection rate, at about 1,500 psig. There are also periods when the well is shut-in, the wellhead pressure drops to 1,200 psig, and the SRU takes the full volume.

Finally, there are periods when the SRU is shut-down for maintenance and the well handles the full volume of 700-1,000 Mscfd and the pressure increases to 1,800 psig or higher. The rate (slope) of this increase in pressure has decreased as the well continues to clean up with time. The system has been successfully injecting the entire volume of acid gas since April 2006 allowing shutdown of the SRU.

Reservoir model

The performance data through December 2005 and well data were used to prepare a single-well radial model for the reservoir. The model has 16 vertical layers of varying permeability using data from the sidewall cores adjusted to match the drillstem tests. One 3-ft high layer has a permeability to air of 32 md indicating a natural fracture. A second layer has 1.5 md, and the rest of the zone has low permeability with a height-weighted average of 0.56 md for the unadjusted core data.

The porosity ranges from 3% to 17% with a weighted average of 6%. These values compare unfavorably to average permeability of 40 md and average porosity of 10% reported for 225 Permian basin reservoirs.[9]

The model also divided the reservoir into six quadrants in a circle and 50 radial rings spaced logarithmically to an outer boundary radius of 10,560 ft (2 miles). The model was tuned by adjusting relative gas permeability and skin factor to match operating data for injection pressure vs. injection rate.

A key assumption in the model is that the high permeability layer is continuous to the model boundary. Performance to date does not suggest a smaller boundary distance for either.[10] The history-match results for the model show continued improvement of well performance with time.

A convenient way to show the results is equivalent fracture length, which is calculated from the skin factor. Table 2 shows the improvement in equivalent fracture length with time.

The design-etched length predicted for the initial fracture stimulation was 173 ft; for the second stimulation, 396 ft. The model performance for the

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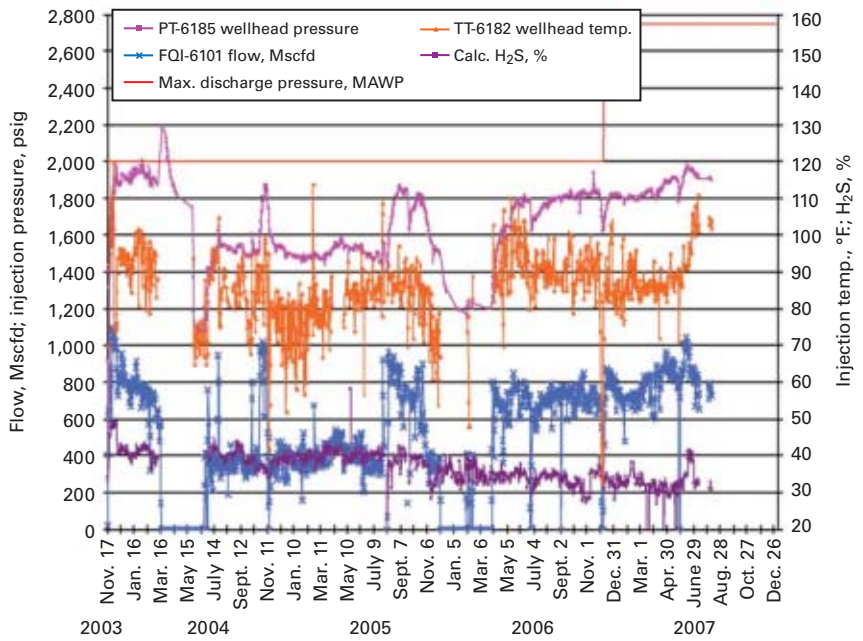
LONG-TERM INJECTION PERFORMANCE: ARTESIA PLANT

Fig. 4



initial data for November 2003 through March 2004 had a fracture length of 250 ft to match well performance, which was greater than the design value for the initial stimulation of 173 ft. The performance immediately following the second fracture (July 2004 data not shown in the table) was best matched by assuming that the two highest permeability layers were blocked, which supported the water-blockage theory.

The performance in October 2004 through December 2005 indicated that all layers had reopened and that the effective fracture length was increasing (Table 2) and is still cleaning up and increasing toward the design fracture length of 396 ft from the second stimulation.

Once the history-match cases were finished, a series of prediction cases were completed for 2,000 psig, 2,500 psig, and 3,240 psig injection pressures. These cases corresponded to continued injection with the original six-stage unit, a reconfiguration of the six-stage unit with a custom cylinder, and addition of a separate seven-stage unit.

Based on these simulations the seven-stage options with 3,240-psig discharge pressure could sustain full injection rates for the longest time. The improvement provided at the intermediate pressure, however, provided a sufficient increase in injection-vs.-time behavior to meet commercial plans for the plant at about 40% of the cost of the seventh stage. In addition, use of a single compressor unit instead of two units in series will provide the greatest injection efficiency.

Modification of the sixth-stage cylinder was selected as the best overall commercial and technical choice and allowed use of the previously purchased compressor forging.

Reconfiguration project

The sixth-stage reconfiguration project was authorized, and the original compressor vendor modified the unit. As the design was finalized for the new custom 2.375-in. bore cylinder, it was found that the maximum allowable working pressure could be increased to 3,000 psig for the new cylinder, which allows operation at discharge pressures up to 2,750 psig.

In addition, since the new cylinder is now double acting, it was possible to increase the turndown to 600 rpm without rod-reversal problems. This provides an increased operating range from 0.5 to 1.5. The reconfiguration was also designed for a range of 20-40% H_2S using actual extended-analysis results for the hydrocarbon portion of the gas.

The percent of rod reversal is now the lowest on the fifth stage but is well within acceptable limits. If rod-reversal damage occurred, however, it could result in extended downtime for the unit. Therefore, individual thermocouples were provided on the new sixth-stage cylinder and the existing fifth-stage cylinder at both of the discharge valves (head end and crank end). This allows the unit to be shut down immediately if a temperature difference develops between the discharge valves to minimize the chance of catastrophe. Typical high-temperature shutdowns were also retained.

The sixth-stage cylinder packing cases must be cooled due to pressure greater than 2,000 psig. The sixth-stage suction scrubber, suction bottle, discharge bottle, and aftercooler tube section were replaced for the higher pressure requirement. The fifth-stage discharge bottle was re-rated and the fifth-stage intercooler tube section was replaced. The fifth-stage cylinder is rated at 2,200 psig MAWP and did not need to be replaced.

Leaking plug threads had been encountered on the high-pressure air cooler headers with the 304L SS plugs in the original installation possibly due to differential expansion. Therefore, 316L plugs were used in the 316L SS headers of the new cooler sections with a special lubricant/polymer (molybdenum disulfide/PTFE – polytetrafloroethylene) coating to prevent galling.

Installation was completed during a 5-day shutdown of the injection unit. The plant was shut down during this time and gas routed to other plants on the gathering system or shut-in. This nearly eliminated flaring of the acid gas during this time. The unit was run on fuel gas to modify the variable-frequency drive for lower speeds and to check for leaks.

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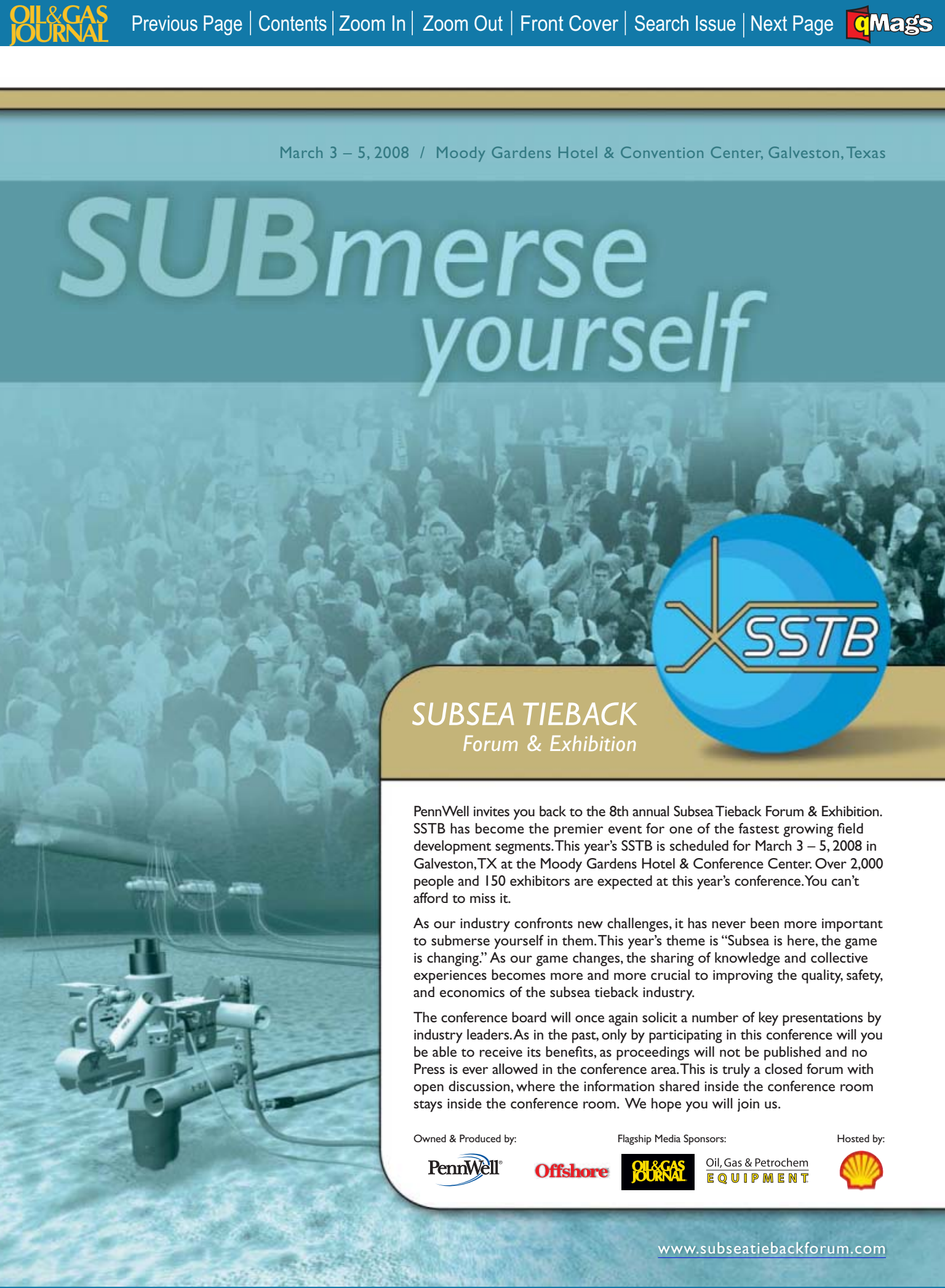

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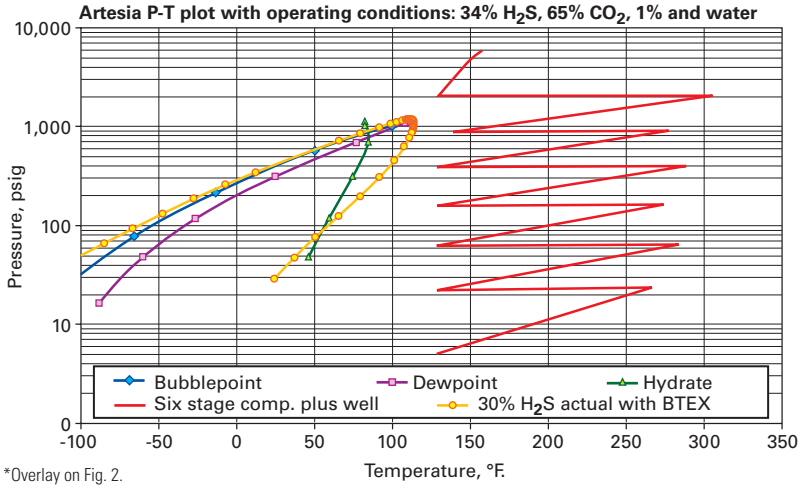
IMPACT OF BTEX ON PHASE ENVELOPE*

Fig. 5



*Overlay on Fig. 2.

The unit was then started up and put into operation. Even though the plant has operated at maximum inlet-gas capacity, the acid-gas rates are currently about 700-850 Mscfd. The injection pressure had fallen to about 1,600 psig during the shutdown and has only increased to about 1,900 psig by August 2007.

The plant has seen one amine or other plant upset during this time in which the injection pressure climbed rapidly to 2,100 psig. The compressor was able to stay online through this event with the new cylinder configuration.

The new design has allowed the plant to sustain injection at higher rates for short periods of time and even at elevated summer injection temperatures and provides for the expected injection rates for the life of the facility.

Efficiency; CO_2 sequestration

The plant has experienced good control efficiency during the 3 years of injection operation.

The cumulative efficiency has been 98.5% from start-up to mid August 2007 and 99.2% for the last 3 years of operation (August 2004 to August 2007). Operation of acid-gas injection in parallel with the sulfur-recovery unit has also improved SRU efficiency by about 2%, primarily due to base-loading the SRU.

The plant has sequestered about 25,620 tons of CO_2 by mid August 2007. The current CO_2 sequestration rate is 11,000 tons/year. These figures exclude any CO_2e emissions related to the generation of power by the utility company used to power the injection compressor.

Operating issues

The plant has experienced a few operating issues during 3 years of operation. The main ones are excessive inter-stage liquids, hydrates, and corrosion. These are compounded by turndown issues.

Inter-stage liquids

Much more liquids than expected have been found in the inter-stage scrubbers. They were designed for a limited amount of water dropout. Extended analyses of the acid gas were collected during injection.

Table 3 compares the actual composition to the design compositions in Table 3. There is less methane than was measured in the previous samples (45% design high case) most likely due to installation of a new amine flash tank. The C_2-C_5 composition is similar to the older analyses. The C_{6+} portion showed that the heavy hydrocarbons were primarily aromatic components benzene, toluene, ethylbenzene, and xylenes (BTEX).

Fig. 5 shows the impact of BTEX on operation. While the critical point and the bubble point curve are not changed much, the dewpoint curve for the phase envelope with the actual composition is shifted to much warmer temperatures.

Hydrates

During winter operations and especially during turndown when excess intercooler area is available, the intercoolers can run colder than design. This is predicted to cause condensation of an acid-gas/BTEX hydrocarbon liquid phase in the scrubbers.

When this liquid is expanded to lower pressure, the fluid can auto-cool, reach hydrate temperature, and plug the liquid line. This effect can be demonstrated with process-simulation calculations and is the cause of level control and freezing problems.

The electrical heat trace was also found to be insufficient, and steam trace was added to provide more heat input and address areas lacking heat trace.

Corrosion rates

After 3 years of operation, ultrasonic thickness readings have shown possible substantial WT loss compared to baseline readings taken before initial start-up. A metallurgist believed injection of methanol to be the most likely cause of high corrosion in this acid-gas system because previous injection systems have reported low corrosion rates.[6]

Methanol has been injected into the cooler inlets and the discharge line of this unit to prevent hydrates due to turndown operation of the cooler and due to previously described problems with inter-stage liquids.

The problem is not the methanol itself but contaminants in the methanol such as oxygen or chlorides.[11] The main cause is oxygen, which is very soluble in methanol at up to 70 ppm, and increases corrosion rates.[12] The oxygen further reacts with H_2S to form elemental sulfur and water.

Deposits of sulfur are very corrosive to both carbon and stainless steel in the presence of water, and a synergy with the presence of chlorides further increases corrosion.[12]

Overall the issue of acid-gas injection corrosion is still under investigation at this site. Precautions have been taken to avoid contamination of the methanol with corrosive agents and to minimize methanol injection by adding more complete heat tracing.

ACID-GAS COMPOSITION: ACTUAL VS. DESIGN Table 3

Component	Design (low), %	Design (high), %	Actual, %
Hydrogen sulfide	33.83	45.08	29.774
Nitrogen	—	0.15	0.014
Carbon dioxide	64.68	51.94	68.113
Methane	0.60	1.81	0.733
Ethane	0.30	0.14	0.115
Propane	0.10	0.05	0.052
i-Butane	—	0.01	0.007
n-Butane	—	0.01	0.022
i-Pentane	—	—	0.005
n-Pentane	—	0.01	0.008
Hexanes	—	0.24	0.027
Heptanes	—	—	0.028
Benzene	—	—	0.239
Toluene	—	—	0.151
p-Xylene	—	—	0.008
m-Xylene	—	—	0.008
o-Xylene	—	—	0.006
Water	0.48	0.56	0.689

Future execution

Some key lessons from this project relate to execution strategy especially for a purely midstream company.

On this project the compressor was purchased in parallel with drilling of the well to expedite the project. This led to a project that ultimately met the company's goals but was more difficult to execute, was not correctly cost estimated, had an extended schedule, and was probably not the optimal solution. Several improvements are being made on future DCP Midstream projects.

Additional upfront work is being completed to define the prospect better. On one project, this has included evaluation of seismic data in addition to other geological evaluation such as offset well log evaluation. In addition a quantitative risk analysis has been completed on one project to define safety risks better.

The overall execution strategy for future projects includes a phased approach. After the initial concept phase, the well will be drilled and evaluated in the second phase before the compression design is finalized. In addition to the well tests completed on this project, the evaluation should include laboratory core-flow tests to define reservoir flow characteristics such as relative permeability and long-term response described by other authors.[8]

The data from these tests will allow preparation of a reservoir simulation to define the required injection pressure for the prospect throughout the life of the injection facility.

This phased approach will also allow the project to be cancelled at any phase if appropriate. Previous literature on acid-gas injection might lead a designer to believe that it is always feasible and as simple as drilling or converting a well, buying a compressor, and injecting acid gas. This project has demonstrated that the things are not always this simple or straight forward. The project can also be reevaluated for injection into other zones or off site. Assuming that acid-gas injection is still feasible, in most cases the project will continue.

Next the injection compression facility can be designed in a detailed engineering phase (third phase). The project will then be executed and operated in successive project phases. While this phased approach will add some time to the schedule, compared to a successful fast-track project, it will provide an improved project (in terms of cost and overall schedule) and an improved design as compared to the execution of this project, especially for a midstream company for which acid-gas injection is relatively high-risk.

Technical issues

A technical issue on future projects is compliance with updated material requirements that restrict use of austenitic stainless steel alloys (e.g., 316 and 304 stainless steel) in the presence of sulfur and H_2S.[13] These requirements prevent use of stainless steel in all but the first stages of acid-gas injection compressors.

Consequently, use of carbon-steel materials is the most likely design choice for future units and use of higher alloys may need to be considered for cooler tubes.

Other project-specific issues that must be addressed center on the operating concerns from this project with liquids, hydrates, cold temperatures, and corrosion. Design improvements should include:

1. Regulatory control of liquid levels in various scrubbers to minimize shutdowns or more generous sizing of liquid surge capacity in compressor scrubbers.
2. Sufficient heat trace throughout the liquid system including level controls, level bridles, and vessels.
3. Careful design of the methanol injection system to prevent oxygen ingress.
4. Assurance that purchased methanol is not contaminated with chlorides or oxygen.
5. Use corrosion inhibitor in the system especially with the methanol.
6. Provision of safe means for displacement or depressurization of the dense-phase acid gas line. Options include a source of high-pressure gas,[14] a pump to fill the system with an incompressible liquid as added to this project, and a low-temperature disposal vaporizer.
7. Provision of a generous corrosion allowance similar to this project to account for possible high corrosion rates especially for the use of carbon steel in wetted sections.
8. Provision of improved control during turndown operation of the air cooler. This could include air recirculation or a separate aftercooler that was recommended on another project.[6]

9. Use coated plugs for the air cooler headers to minimize leakage along the threads.

Results

Performance data over 3 years from the acid-gas injection system demonstrate the benefits of injection, including an efficiency of 99.2%. There was also improved SRU efficiency of about 2% during baseloaded operation in parallel with injection.

Through mid-August 2007, this unit had sequestered 25,620 tons of CO_2.

This unit experienced a rapid rise in discharge pressure immediately upon start-up due to very low reservoir permeability. The compressor was reconfigured to replace the sixth stage with a custom cylinder to increase the potential injection pressure to 2,750 psig from 2,000 psig.

Finally, the SRU has been shut down since April 2006, eventually meeting the major project goal.

Acknowledgments

The authors acknowledge participation of many people on these projects; the original GPA presentation contains a list. ✦

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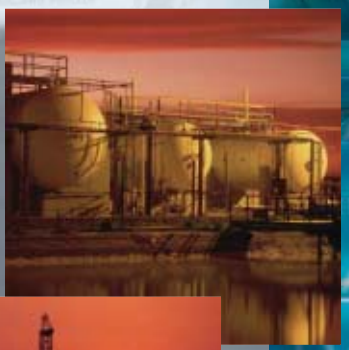

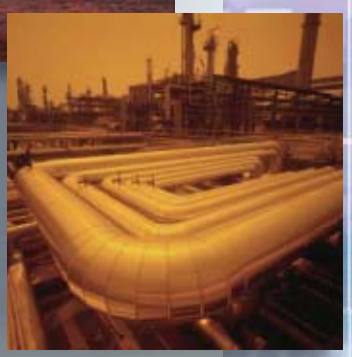

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Increased US ethanol production requires dedicated pipelines

Robert E. Hogfoss
Hunton & Williams LLP
Atlanta

Increased ethanol production capacity in the US requires a new transportation paradigm. Boutique production facilities serving regional hubs via truck or short line rail are not a sufficient or realistic solution. Dedicated ethanol and ethanol blend pipelines are the only option that is safe, efficient, and cost effective, but only if legal, technical, and financial problems are addressed in a coordinated manner.

Several oil and pipeline companies are already looking at such pipelines as an investment opportunity. Private equity funds and investment banks will likely follow. Legal, technical, and economic problems are manageable, provided that government and industry closely coordinate efforts.

This article provides an overview of the current technical and regulatory state of dedicated ethanol pipelines.

Background

In 1980, there were only about 10 ethanol fuel production facilities in the US, producing roughly 50 million gal/year. By 1985, production had increased by an order of magnitude, with nearly 100 domestic facilities in 26 states producing more than 500 million gal/year.

Although lower oil prices through the 1990s made competition difficult, ethanol production continued, with significant help from federal subsidies. By the turn of the century, market forecasters and the US Congress projected a record of 5 billion gal of US ethanol production by 2012.

US ethanol production, however, reached 5 billion gal in 2006, not in 2012, with production jumping more than 30% between 2005 and 2006 (Fig. 1). Current estimates have US ethanol production capacity, already the largest in the world (Fig. 2), growing to more than 10 billion gal/year by 2009, if not earlier.

The US uses alternative fuels for around 6% of its transportation energy demand, while countries such Brazil use a much higher percentage. Supply and demand—aided by subsidies—are both likely to increase in the US especially once cellulosic ethanol is perfected.

In January 2007, US Pres. George W. Bush established a new goal of reaching 35 billion gal/year of ethanol production by 2017. Ethanol is already present in nearly half of all gasoline sold in the US, as a component of various gasoline-ethanol blends, making attainment of Bush's goal likely.

Transportation

While political entities, market analysts, and others have focused on ethanol production and end use, only recently has discussion centered on transportation of ethanol fuel from producer to consumer. When production took place at the boutique level, truck, barge, and rail transportation was adequate.

As recently as 2 years ago, ethanol producers maintained that regional production facilities would meet local needs, implying that transportation of the fuel was not a major problem. Producers deemed use of ethanol pipelines as too costly to justify the anticipated returns. Industry's rapid growth, however, has changed the nature of the transportation issue and available options.

An extensive 2002 report on ethanol infrastructure options noted appropriately (at that point in time) that it appeared there would be "no major movements of ethanol via pipeline."

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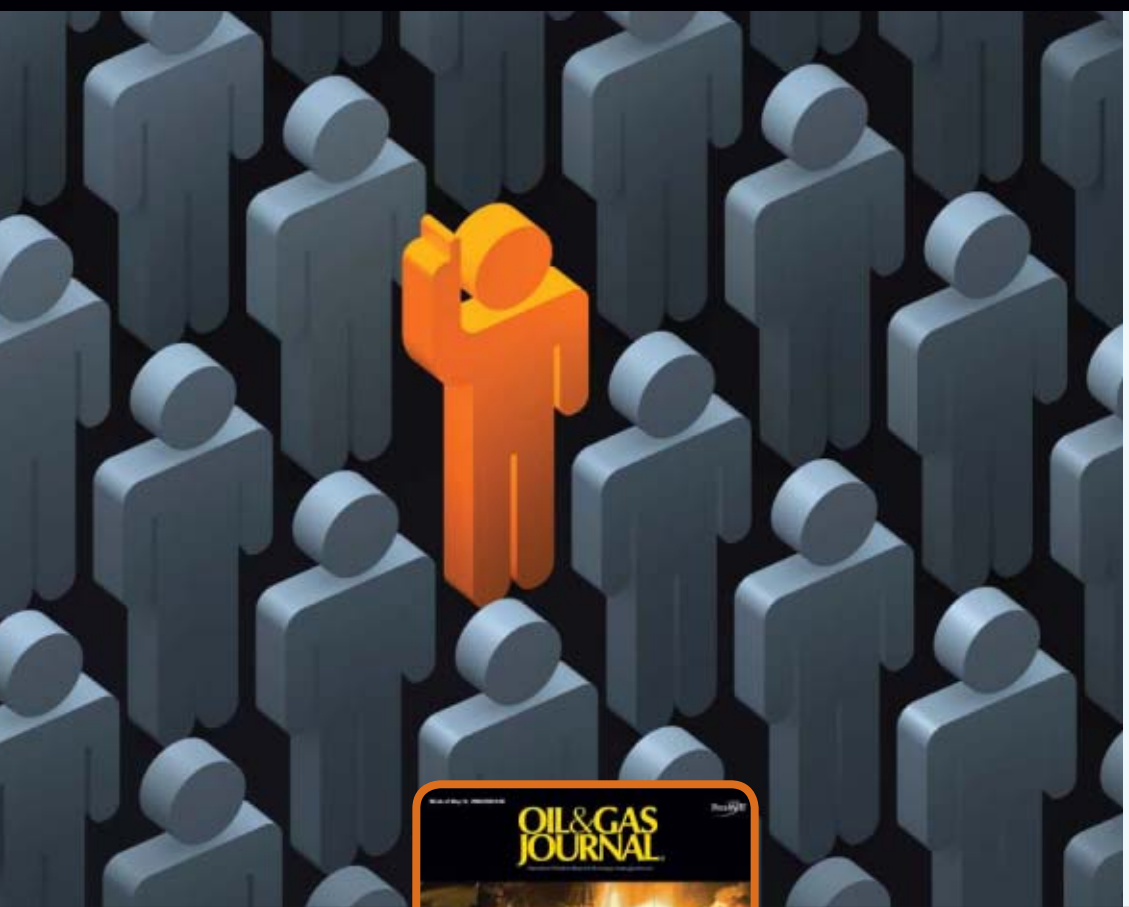

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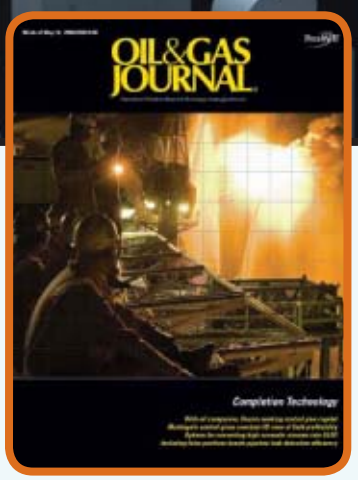

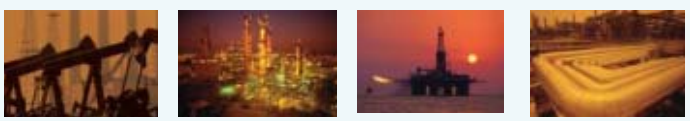

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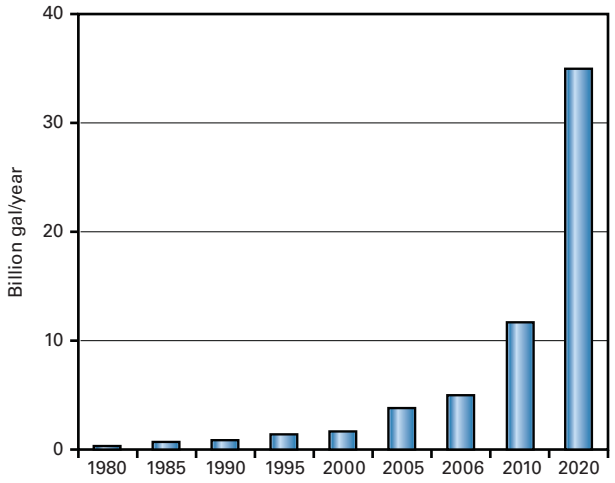
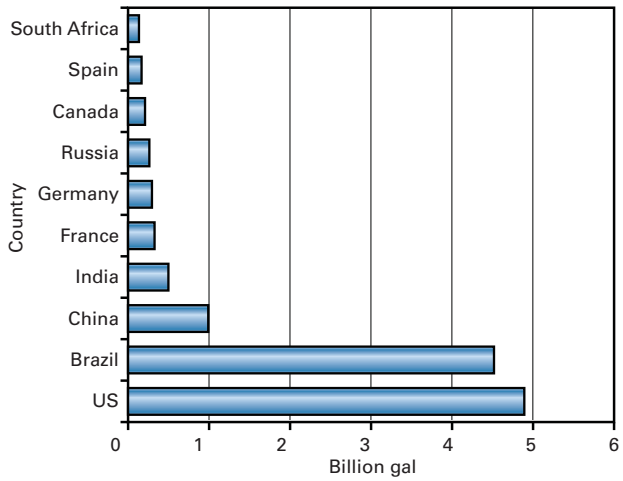
US ETHANOL PRODUCTION

Fig. 1



GLOBAL ETHANOL PRODUCTION, 2006

Fig. 2



Pipeline transportation remained too expensive for the volumes involved, despite being the most cost effective mode of transportation. Only 5 years later, logistics and economics have changed.

Trucking ethanol will inevitably play a role in the supply chain, but trucking is not cost efficient or feasible for the volumes now anticipated. Rail transport, similarly, will play a role in the supply chain, but there are both volume and cost limitations to rail as an option.

Barge shipments are more cost effective, but less time efficient. A serious question also exists about the availability of Jones Act vessels (those built and registered in the US, as required by law for shipment within US boundaries) or vessels that comply with the requirements of the 1990 Oil Pollution Act.

Pipelines are the safest, most efficient, and most cost effective mode of transport for ethanol. Whether the infrastructure exists or warrants the significant investment necessary to establish it, however, remains an open question.

Pipeline problems

The need to maintain quality control and avoid cross contamination of product prevents ethanol from being effectively batched with petroleum products in pipeline transport. Ethanol's solubility in water further requires that dedicated ethanol pipelines prevent water infiltration.

Petroleum products, by contrast, tolerate water infiltration with little problem, any contact water from infiltration or condensation being removable at tankage facilities.

Blends of ethanol and petroleum products are only marginally more flexible for transportation than pure ethanol, the degree to which this is the case depending on the proportion of ethanol being piped.

Industry and agencies will need to agree on the gasoline-ethanol blends to be most used moving forward because of its effect on transportation alternatives. Higher concentrations of ethanol increase concern for water infiltration, contamination from pipe residue, and such metallurgical issues as stress corrosion cracking.

Light gasoline-ethanol blends may be able to move in existing pipeline infrastructure with no modifications, while higher concentration blends will require increased pipe cleaning and maintenance. Pure ethanol will likely require dedicated, if not new, pipeline infrastructure.

Such technical issues, however, are clearly addressable. Brazil and South Africa have been successfully transporting ethanol by pipeline for some time, and various US companies have proven its feasibility in test projects using both pure ethanol and ethanol blends.

The US Department of Transportation's Pipeline & Hazardous Materials Transportation Administration regulates all interstate pipelines transporting natural gas, hazardous liquids (including petroleum), and carbon dioxide. PHMSA promulgates rules governing pipeline design, construction, operation, and maintenance. In the past few years, at the direction of Congress and the White House, PHMSA has promulgated new rules requiring improved integrity management planning for pipelines, raising the bar for operation and maintenance of all existing and new petroleum product pipelines.

Ethanol is not currently within PHMSA's jurisdiction, but in a Federal Register notice dated Aug. 10, 2007, PHMSA proposed to subject ethanol to the same regulations governing petroleum pipelines. PHMSA stated that it finds "all biofuel-gasoline blends" to meet the definition of "petroleum products" subject to its pipeline regulations. The notice also stated PHMSA's intent to regulate transportation of all "unblended ethanol and other biofuels."

Although not expressly proposed in the notice, simply including ethanol and biofuels in the list and definition of hazardous liquids subject to PHMSA rules at 49 C.F.R. 195.2 would accom-

plish its regulation, making all ethanol pipelines subject to the design, construction, operation, and maintenance standards of PHMSA. It is likely that additional rule changes, requiring actions specific to ethanol transport will also occur, but the PHMSA regulations are well suited to this evolution.

Several other federal agencies also have potential jurisdiction over interstate ethanol pipelines. The Department of Energy provides informational and research and development support, but defers to PHMSA on oversight and operational regulation.

The US Environmental Protection Agency also regulates ethanol as a hazardous substance, which—like oil—requires reporting and response when released to the environment. EPA currently has a higher threshold for reporting ethanol releases than for oil, but this may change.

The US Bureau of Alcohol, Tobacco and Firearms has additional regulatory oversight for ethanol production activities (due to potential illegal consumption issues), but not for ethanol transportation. Among these agencies, the legal framework governing ethanol pipelines is already in place, with PHMSA likely taking the lead. Coordination of agencies should not be a significant obstacle to infrastructure development.

The remaining piece waiting to fall in place is the financial investment for ethanol pipelines. Some companies are planning to convert existing petroleum pipelines to ethanol-blend use. Such efforts will be cost effective, but higher blends or pure ethanol transport will likely require new pipe and increased system integrity reconfiguration and maintenance.

Infrastructure opportunity

New, dedicated ethanol pipelines will be costly to install. There may, however, be cost savings available in creating this new energy infrastructure.

Some ethanol pipelines could be placed within existing oil and gas pipeline rights-of-way, minimizing the costs of obtaining new ROW and permitting. The existing petroleum pipeline infrastructure is also aging and nearing capacity, with construction of a new ethanol infrastructure providing a potential opportunity to replace or upgrade certain adjacent existing lines or segments, thereby realizing economies of scale.

In areas of increasing population growth around the US, notably the South and West, dedicated ethanol pipelines could also follow the routes of new or reconfigured federal highway projects. Such construction projects will have already obtained all necessary ROW, and the environmental impact statements obtained for transportation purposes would shorten project review and permitting delays, and decrease costs. ✦

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Equipment/Software/Literature

Enhancements added to offshore thrusters

New enhancements to the Pleuger brand of azimuthing thrusters are designed to help improve offshore operations.

These thruster units are multidirectional propeller pods installed on platforms and ships to allow for intricate vessel positioning.

A recent modification to the tilted-shaft design of the units helps improve the net thrust of operation in offshore uses.

The newest technological contribution is the underwater-mountable, L-drive and fixed-pitch thruster line for offshore applications. The WFSD-type thruster with this tilted-axis propeller is designed for optimum net thrust output and maintainability. This tilted-shaft propeller design helps assure minimum thruster-hull and thruster-thruster interaction, which results in higher net thrust for the vessel, the company points out.

The newly designed thrusters are available for custom optimization to as large as 5 m in propeller diameter. This design provides for greater than 4,000 kW input power with a fixed-pitch propeller.

Source: **Flowserve Corp.,** 5215 N. O'Connor Blvd., Suite 2300, Irving, TX 75039.

Compliance management service offers new version

This provider of internet-based, on-demand systems for the management and automation of environmental, health and safety compliance activitiesnow offers version 6.0 of its flagship compliance management service.

The new version adds features that help make it easier for organizations to centrally and securely manage, in real-time, all aspects of regulatory compliance, helping improve operational efficiency and effectiveness.

In addition to the streamlined interface, other enhancements of the service include:

- Dashboard metrics for key performance indicators.
- Ability to do "what if" analyses for contingency planning.
- Enhanced calculation engine capable of performing the sophisticated calculations.
- Additional hierarchy for increased flexibility.
- Report scheduler that runs reports automatically so they can be viewed at users' convenience.
- Advanced search criteria that can be customized and saved for each user.
- European or American date formats with 24 hr or AM-PM time.

The company says its system is suited for managing greenhouse gas, NERC, Title V, Sarbanes Oxley, water and waste requirements, and other sets of regulatory requirements.

Source: **Enviance Inc.,** 2386 Faraday Ave., Suite 220, Carlsbad, CA 92008.

Services/Suppliers

KBR Inc.

Houston, has announced creation of three new business units: technology, downstream, and services. Named to lead these new business units are Tim Challand, president, KBR Technology; John Quinn, president, KBR Downstream; and David Zimmerman, president, KBR Services.

Challand previously was senior vice-president of KBR Downstream. Quinn and Zimmerman will continue in their previous positions until successors are identified: Quinn as chief executive officer for M.W. Kellogg Ltd., KBR's 55% owned operation in Greenford, UK, and Zimmerman as senior vice-president of engineering, procurement, construction, and services.

KBR Technology will encompass the company's portfolio of intellectual property assets, and will grow this sector through acquisition and development of new technologies across the hydrocarbon value chain.

KBR Services includes KBR's industrial and maintenance services businesses, North American construction, and Canadian fabrication operations.

These announcements follow the recent appointments of John Rose as president of KBR Upstream, and Bruce Stanski as president of KBR Government and Infrastructure.

KBR Inc. is a global engineering, construction, and services company supporting the energy, petrochemicals, government services, and civil infrastructure sectors.

Hercules Offshore Inc.

Houston, has appointed Larry Francois as chief executive officer and president of its subsidiary, Delta Towing. Francois most recently served as senior vice-president of operations for Trico Marine Services Inc. Earlier in his 30-year industry career, he held operational and management positions with Seabulk Offshore, Tidewater Inc., Zapata Gulf Marine Corp., Western Co. of North America, and Dillingham Maritime.

Hercules Offshore Inc. operates a fleet of 33 jackup rigs, 27 barge rigs, 65 liftboats, three submersible rigs, nine land rigs, one platform rig, and a fleet of marine support vessels. The company offers a range of services to oil and gas producers including drilling, well service, platform inspection, maintenance, and decommissioning operations in shallow waters.

ABB

Zurich, Switzerland, has announced agreement to sell its Lummus Global business to Netherlands-based Chicago Bridge & Iron Co. (CB&I). With this divestment, ABB finalizes its strategy of focusing on its core business in power and automation technology.

Lummus Global is a leading provider of proprietary process technologies, project management, and engineering, procurement and construction management services to the upstream and downstream oil and gas, petrochemical, and refining industries worldwide. The company employs about 2,400 people.

Imports of crude and products

	Districts 1-4 8-31 2007	Districts 1-4 8-24 2007	District 5 8-31 2007	District 5 8-24 2007	Total US 8-31 2007	Total US 8-24 2007	Total US *9-1 2006
	1,000 b/d						
Total motor gasoline	1,312	929	2	64	1,314	993	1,027
Mo. gas. blending comp.	879	506	0	19	879	525	567
Distillate	370	265	19	55	389	320	522
Residual	162	702	0	51	162	753	332
Jet fuel-kerosine	102	106	122	97	224	203	119
Propane-propylene	122	172	2	6	124	178	250
Other	(127)	781	102	46	(25)	827	516
Total products	**2,820**	**3,461**	**247**	**338**	**3,067**	**3,799**	**3,333**
Total crude	**9,199**	**8,660**	**1,038**	**1,162**	**10,237**	**9,822**	**10,365**
Total imports	**12,019**	**12,121**	**1,285**	**1,500**	**13,304**	**13,621**	**13,698**

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

Purvin & Gertz LNG netbacks—Sept. 7, 2007

Receiving terminal	Liquefaction plant: Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	6.73	4.60	5.83	4.50	5.19	5.80
Everett	4.33	2.31	3.96	2.40	2.86	4.60
Isle of Grain	4.25	2.31	3.54	2.21	2.86	3.79
Lake Charles	3.14	1.50	2.89	1.53	1.71	3.70
Sodegaura	5.20	7.06	5.40	7.04	6.37	4.66
Zeebrugge	6.27	4.33	5.80	4.23	4.89	5.82

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: Total	Motor gasoline: Blending comp.[1]	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual	Propane-propylene
	1,000 bbl						
PADD 1	15,175	49,599	22,824	10,363	54,485	13,236	4,968
PADD 2	66,767	46,268	15,314	6,996	28,546	1,439	22,060
PADD 3	179,174	59,579	24,544	13,029	33,096	16,186	25,596
PADD 4	12,606	6,213	1,869	573	2,711	344	[1]2,624
PADD 5	55,938	29,424	20,592	10,225	13,332	5,170	—
Aug. 31, 2007	**329,660**	**191,083**	**85,143**	**41,186**	**132,170**	**36,375**	**55,248**
Aug. 24, 2007	**333,632**	**192,564**	**85,869**	**42,153**	**129,914**	**38,599**	**54,300**
Sept. 1, 2006[2]	**300,6628**	**206,880**	**92,483**	**41,029**	**139,947**	**42,029**	**63,761**

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

Refinery report—Aug. 31, 2007

District	Refinery operations: Gross inputs	Refinery operations: Crude oil inputs	Refinery output: Total motor gasoline	Refinery output: Jet fuel, kerosine	Refinery output: Fuel oils: Distillate	Refinery output: Fuel oils: Residual	Refinery output: Propane-propylene
	1,000 b/d						
PADD 1	1,547	1,577	1,884	106	508	125	66
PADD 2	3,421	3,408	2,118	202	990	59	200
PADD 3	7,628	7,587	3,354	686	2,048	291	628
PADD 4	554	548	290	26	161	14	123
PADD 5	2,867	2,781	1,511	453	610	169	—
Aug. 31, 2007	**16,067**	**15,901**	**9,157**	**1,473**	**4,317**	**658**	**1,017**
Aug. 24, 2007	**15,749**	**15,469**	**9,086**	**1,408**	**4,158**	**642**	**1,083**
Sept. 1, 2006[2]	**16,274**	**15,993**	**9,231**	**1,455**	**4,274**	**678**	**1,074**
	17,448 operable capacity		**92.1% 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.

OIL&GAS JOURNAL online research center

OGJ crack spread

	*9-7-07	*9-8-06	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	87.04	72.10	14.95	20.7
Brent crude	74.96	65.34	9.62	14.7
Crack spread	12.09	6.75	5.34	79.0
FUTURES MARKET PRICES				
One month				
Product value	85.59	73.96	11.62	15.7
Light sweet crude	75.95	67.42	8.53	12.7
Crack spread	9.63	6.55	3.09	47.2
Six month				
Product value	85.32	80.64	4.68	5.8
Light sweet crude	72.10	71.41	0.69	1.0
Crack spread	13.23	9.23	4.00	43.3

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

OGJ GASOLINE PRICES

	Price ex tax 9-5-07	Pump price* 9-5-07	Pump price 9-6-06
		¢/gal	
(Approx. prices for self-service unleaded gasoline)			
Atlanta	237.7	277.4	264.6
Baltimore	226.2	268.1	272.6
Boston	223.2	265.1	273.5
Buffalo	221.0	281.1	290.6
Miami	240.8	291.1	293.6
Newark	231.8	264.7	273.1
New York	220.7	280.8	296.7
Norfolk	224.7	262.3	251.7
Philadelphia	228.4	279.1	290.8
Pittsburgh	226.4	277.1	273.0
Wash., DC	241.7	280.1	293.1
PAD I avg.	229.3	275.2	279.4
Chicago	263.7	314.6	322.3
Cleveland	237.9	284.3	243.9
Des Moines	237.2	277.6	233.6
Detroit	252.1	301.3	255.7
Indianapolis	247.2	292.2	245.4
Kansas City	245.8	281.8	244.4
Louisville	259.0	295.9	240.4
Memphis	231.7	271.5	254.9
Milwaukee	246.7	298.0	275.9
Minn.-St. Paul	246.7	287.1	254.3
Oklahoma City	244.0	279.4	240.7
Omaha	238.4	284.8	248.0
St. Louis	237.0	273.0	248.0
Tulsa	242.5	277.9	246.1
Wichita	236.5	279.9	245.3
PAD II avg.	244.4	286.6	253.2
Albuquerque	240.1	276.5	273.5
Birmingham	228.7	267.4	258.4
Dallas-Fort Worth	227.7	266.1	258.8
Houston	234.3	272.7	258.9
Little Rock	228.5	268.7	260.4
New Orleans	234.1	272.5	274.4
San Antonio	227.7	266.1	257.7
PAD III avg.	231.6	270.0	263.2
Cheyenne	246.5	278.9	280.9
Denver	247.7	288.1	288.3
Salt Lake City	247.2	290.1	291.3
PAD IV avg.	247.1	285.7	286.9
Los Angeles	219.5	278.0	304.2
Phoenix	246.6	284.0	260.8
Portland	239.1	282.4	296.3
San Diego	230.3	288.8	306.4
San Francisco	227.1	285.6	314.6
Seattle	226.4	278.8	301.2
PAD V avg.	231.5	282.9	297.2
Week's avg.	**236.7**	**280.3**	**270.4**
Aug. avg.	**237.2**	**280.8**	**296.7**
July avg.	**251.6**	**295.2**	**295.2**
2007 to date	**228.9**	**272.5**	—
2006 to date	**223.1**	**266.5**	—

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

REFINED PRODUCT PRICES

	8-31-07 ¢/gal		8-31-07 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	206.78	New York Harbor	203.70
Gulf Coast	205.40	Gulf Coast	200.95
Los Angeles	207.80	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	194.61	ARA	204.57
Singapore	188.45	Singapore	200.83
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	208.78	New York Harbor	131.62
Gulf Coast	205.55	Gulf Coast	140.48
Los Angeles	208.80	Los Angeles	147.00
		ARA	135.69
		Singapore	140.20

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

BAKER HUGHES RIG COUNT

	9-7-07	9-8-06
Alabama	6	3
Alaska	6	6
Arkansas	49	27
California	36	31
Land	34	27
Offshore	2	4
Colorado	110	93
Florida	1	0
Illinois	1	0
Indiana	2	1
Kansas	13	9
Kentucky	12	9
Louisiana	178	203
N. Land	68	56
S. Inland waters	22	20
S. Land	24	46
Offshore	64	81
Maryland	1	0
Michigan	3	2
Mississippi	11	14
Montana	14	18
Nebraska	0	0
New Mexico	79	85
New York	6	7
North Dakota	42	38
Ohio	14	6
Oklahoma	193	189
Pennsylvania	17	16
South Dakota	1	2
Texas	855	790
Offshore	6	9
Inland waters	1	2
Dist. 1	25	23
Dist. 2	35	30
Dist. 3	56	59
Dist. 4	88	93
Dist. 5	190	143
Dist. 6	128	110
Dist. 7B	40	45
Dist. 7C	60	39
Dist. 8	108	99
Dist. 8A	19	25
Dist. 9	37	35
Dist. 10	62	78
Utah	41	46
West Virginia	33	23
Wyoming	78	104
Others—NV-3; TN-5; VA-3; WA-1	12	6
Total US	**1,814**	**1,728**
Total Canada	**335**	**491**
Grand total	**2,149**	**2,219**
Oil rigs	294	310
Gas rigs	1,514	1,413
Total offshore	74	95
Total cum. avg. YTD	**1,759**	**1,616**

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

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

SMITH RIG COUNT

Proposed depth, ft	9-7-07 Rig count	9-7-07 Percent footage*	9-8-06 Rig count	9-8-06 Percent footage*
0-2,500	59	8.4	44	2.2
2,501-5,000	104	56.7	72	40.2
5,001-7,500	234	22.2	243	22.6
7,501-10,000	425	3.7	383	5.7
10,001-12,500	441	0.9	398	2.5
12,501-15,000	284	0.7	296	—
15,001-17,500	119	—	107	—
17,501-20,000	67	—	75	—
20,001-over	34	—	32	—
Total	**1,767**	**7.8**	**1,650**	**7.0**
INLAND	40		42	
LAND	1,663		1,545	
OFFSHORE	64		63	

*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]9-7-07	[2]9-8-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	17	20
Alaska	749	635
California	658	677
Colorado	50	60
Florida	6	7
Illinois	30	28
Kansas	95	98
Louisiana	1,329	1,403
Michigan	13	14
Mississippi	49	48
Montana	92	100
New Mexico	164	163
North Dakota	104	112
Oklahoma	163	173
Texas	1,337	1,354
Utah	43	49
Wyoming	140	143
All others	59	71
Total	**5,098**	**5,155**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	9-7-07
Alaska-North Slope 27°	69.08
South Louisiana Sweet	77.75
California-Kern River 13°	66.40
Lost Hills 30°	74.25
Southwest Wyoming Sweet	69.95
East Texas Sweet	72.75
West Texas Sour 34°	67.25
West Texas Intermediate	73.25
Oklahoma Sweet	73.25
Texas Upper Gulf Coast	69.75
Michigan Sour	66.25
Kansas Common	72.25
North Dakota Sweet	64.50

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

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

WORLD CRUDE PRICES

$/bbl[1]	8-31-07
United Kingdom-Brent 38°	70.22
Russia-Urals 32°	68.04
Saudi Light 34°	67.69
Dubai Fateh 32°	67.23
Algeria Saharan 44°	72.06
Nigeria-Bonny Light 37°	73.62
Indonesia-Minas 34°	72.84
Venezuela-Tia Juana Light 31°	66.44
Mexico-Isthmus 33°	66.33
OPEC basket	69.46
Total OPEC[2]	68.83
Total non-OPEC[2]	68.02
Total world[2]	68.46
US imports[3]	66.47

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

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

US NATURAL GAS STORAGE[1]

	8-31-07	8-24-07	Change
	bcf		
Producing region	903	902	1
Consuming region east	1,696	1,657	39
Consuming region west	406	410	–4
Total US	**3,005**	**2,969**	**36**
	June 07	**June 06**	**Change, %**
Total US[2]	**2,580**	**2,617**	**–1.4**

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

Statistics

International rig count

Region	Aug. 2007 Land	Aug. 2007 Off.	Aug. 2007 Total	Aug. 06 Total
WESTERN HEMISPHERE				
Argentina	73	—	73	82
Bolivia	3	—	3	3
Brazil	18	22	40	31
Canada	341	2	343	482
Chile	2	—	2	—
Colombia	41	—	41	24
Ecuador	11	—	11	10
Mexico	68	19	87	78
Peru	5	2	7	4
Trinidad	—	4	4	5
United States	1,731	73	1,804	1,738
Venezuela	62	16	78	87
Other	2	—	2	2
Subtotal	**2,357**	**138**	**2,495**	**2,545**
ASIA-PACIFIC				
Australia	14	12	26	22
Brunei	2	3	5	2
China-offshore	—	19	19	18
India	57	23	80	82
Indonesia	39	21	60	46
Japan	2	—	2	2
Malaysia	—	17	17	15
Myanmar	7	—	7	8
New Zealand	3	2	5	4
Papua New Guinea	3	—	3	3
Philippines	—	—	—	2
Taiwan	—	—	—	—
Thailand	1	5	6	10
Vietnam	—	8	8	9
Other	1	2	3	5
Subtotal	**129**	**112**	**241**	**228**
AFRICA				
Algeria	29	—	29	27
Angola	—	4	4	3
Congo	2	—	2	3
Gabon	3	—	3	3
Kenya	—	—	—	—
Libya	13	—	13	11
Nigeria	4	5	9	10
South Africa	—	1	1	—
Tunisia	2	1	3	3
Other	2	2	4	3
Subtotal	**55**	**13**	**68**	**63**
MIDDLE EAST				
Abu Dhabi	10	4	14	13
Dubai	1	—	1	2
Egypt	34	13	47	37
Iran	—	—	—	—
Iraq	—	—	—	—
Jordan	1	—	1	1
Kuwait	13	—	13	16
Oman	49	—	49	41
Pakistan	19	—	19	20
Qatar	2	10	12	12
Saudi Arabia	69	9	78	73
Sudan	—	—	—	—
Syria	20	—	20	23
Yemen	15	—	15	16
Other	1	—	1	2
Subtotal	**234**	**36**	**270**	**256**
EUROPE				
Croatia	—	—	—	1
Denmark	—	3	3	2
France	1	—	1	—
Germany	5	—	5	5
Hungary	2	—	2	3
Italy	3	1	4	7
Netherlands	1	3	4	6
Norway	—	20	20	20
Poland	2	—	2	1
Romania	2	1	3	2
Turkey	5	—	5	4
UK	1	28	29	26
Other	4	—	4	4
Subtotal	**26**	**56**	**82**	**81**
Total	**2,801**	**355**	**3,156**	**3,173**

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

Oil import freight costs*

Source	Discharge	Cargo	Cargo size, 1,000 bbl	Freight (Spot rate) worldscale	$/bbl
Caribbean	New York	Dist.	200	178	1.49
Caribbean	Houston	Resid.	380	141	1.33
Caribbean	Houston	Resid.	500	98	0.92
N. Europe	New York	Dist.	200	281	3.76
N. Europe	Houston	Crude	400	139	2.73
W. Africa	Houston	Crude	910	82	1.79
Persian Gulf	Houston	Crude	1,900	48	1.94
W. Africa	N. Europe	Crude	910	81	1.30
Persian Gulf	N. Europe	Crude	1,900	48	1.42
Persian Gulf	Japan	Crude	1,750	60	1.43

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

Waterborne Energy Inc. US LNG imports

Country	Aug. 2007	July 2007	Aug. 2006	Change from a year ago, %
	MMcf			
Algeria	3,080	—	2,880	6.9
Egypt	14,710	15,030	5,850	151.5
Equatorial Guinea	3,030	8,980	—	—
Nigeria	14,380	15,290	6,130	134.6
Qatar	6,060	—	—	—
Trinidad and Tobago	48,190	59,210	37,120	29.8
Total	**89,450**	**98,510**	**51,980**	**72.1**

Source: Waterborne Energy Inc.
Data available in OGJ Online Research Center.

Baker Oil Tools workover rig count*

Region	June 2007	June 2006	Change, %
Gulf Coast	277	328	–15.5
Midcontinent	259	311	–16.7
Northeastern	90	88	2.3
Rocky Mountains	255	251	1.6
Southeastern	195	198	–1.5
West Texas	325	338	–3.8
Western	147	133	10.5
Total US	**1,548**	**1,647**	**–6.0**
Canada	486	760	–36.1
Total N. America	**2,034**	**2,407**	**–15.5**

*Wells over 1,500 ft deep and tubing out of the wellbore. Excludes rigs on rod jobs. Definitions, see OGJ Sept. 18, 2006, p. 42. Source: Baker Hughes Inc. Data available in OGJ Online Research Center.
NOTE: This data has been discontinued. The table will not appear in future editions.

Propane prices

	July 2007	Aug. 2007	July 2006	Aug. 2006
	¢/gal			
Mont Belvieu	119.00	118.61	116.54	113.77
Conway	118.18	118.64	114.17	112.09
Northwest Europe	117.28	119.28	104.57	107.54

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

Muse, Stancil & Co. refining margins

	US Gulf Coast	US East Coast	US Mid-west	US West Coast	North-west Europe	South-east Asia
	$/bbl					
Aug. 2007						
Product revenues	91.21	82.75	94.14	86.17	82.66	76.92
Feedstock costs	–76.08	–73.72	–68.53	–68.31	–71.69	–72.58
Gross margin	15.13	9.03	25.61	17.86	10.97	4.34
Fixed costs	–2.06	–2.38	–2.31	–2.70	–2.31	–1.80
Variable costs	–1.80	–1.29	–1.62	–2.96	–2.72	–0.88
Cash operating margin	**11.27**	**5.36**	**21.68**	**12.20**	**5.94**	**1.66**
July 2007	11.18	5.95	20.38	16.90	4.21	1.74
YTD avg.	14.20	7.81	20.19	23.74	6.28	2.80
2006 avg.	12.49	6.01	14.99	23.73	5.88	1.06
2005 avg.	12.53	6.98	12.31	20.55	5.51	1.52
2004 avg.	6.16	3.70	6.64	11.76	5.08	1.83

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

Muse, Stancil & Co. gasoline marketing margins

July 2007	Chicago*	Houston	Los Angeles	New York
	¢/gal			
Retail price	325.67	284.40	309.15	311.59
Taxes	58.55	38.40	60.20	51.88
Wholesale price	242.86	228.88	235.65	235.75
Spot price	233.75	218.85	228.93	222.66
Retail margin	24.51	17.12	13.30	23.96
Wholesale margin	9.11	10.03	6.72	13.09
Gross marketing margin	**33.62**	**27.15**	**20.02**	**37.05**
June 2007	58.21	34.69	28.87	39.95
YTD avg.	26.36	20.92	18.63	29.72
2006 avg.	19.74	20.34	18.03	27.90
2005 avg.	19.77	16.26	20.39	27.13
2004 avg.	22.49	17.49	23.61	30.36

*The wholesale price shown for Chicago is the RFG price utilized for the wholesale margin. The Chicago retail margin includes a weighted average of RFG and conventional wholesale purchases.
Source: Muse, Stancil & Co. See OGJ, Oct. 15, 2001, p. 46.
Data available in OGJ Online Research Center.
Note: Margins include ethanol blending in all markets.

Muse, Stancil & Co. ethylene margins

	Ethane	Propane	Naphtha
	¢/lb ethylene		
Aug. 2007			
Product revenues	58.84	95.18	113.81
Feedstock costs	–32.94	–67.67	–99.99
Gross margin	25.90	27.51	13.82
Fixed costs	–5.38	–6.36	–7.19
Variable costs	–4.43	–5.21	–6.96
Cash operating margin	**16.09**	**15.94**	**–0.33**
July 2007	16.10	16.08	–3.39
YTD avg.	14.33	15.90	–7.03
2006 avg.	19.55	22.53	1.77
2005 avg.	14.43	20.68	1.28
2004 avg.	9.00	12.03	0.51

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

Muse, Stancil & Co. US gas processing margins

Aug. 2007	Gulf Coast	Mid-continent
	$/Mcf	
Gross revenue		
Gas	6.27	5.11
Liquids	1.24	3.48
Gas purchase cost	6.98	6.87
Operating costs	0.07	0.15
Cash operating margin	**0.46**	**1.57**
July 2007	0.49	1.64
YTD avg.	0.29	1.09
2006 avg.	0.26	0.97
2005 avg.	–0.06	0.25
2004 avg.	0.07	0.33
Breakeven producer payment % of liquids	60%	53%

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

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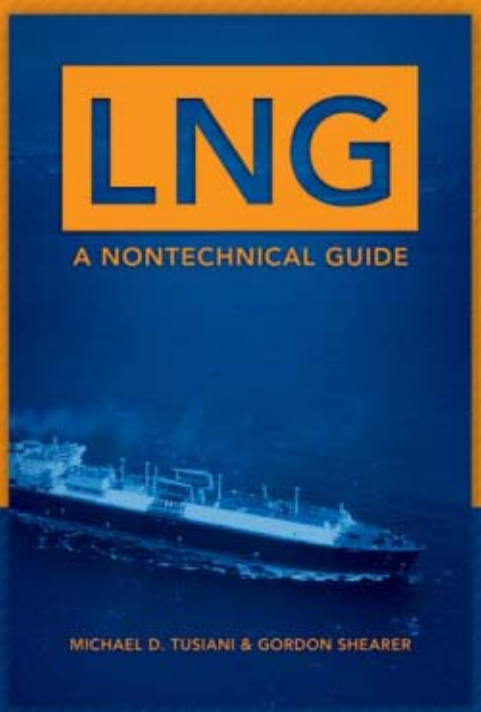

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Dingell steers toward classic US energy folly

The Editor's Perspective

by Bob Tippee, Editor

"Properly addressing climate change requires us to address the issue of consumption. We do that by making consumption more expensive."

Give Rep. John D. Dingell (D-Mich.) credit for cutting to the heart of the matter (OGJ, Sept. 3, 2007, p. 28).

His two sentences contain all the ingredients of wrong policy on climate change and energy. "Wrong" here means wasteful and ineffective.

First the congressman presumes to know how "properly" to address climate change.

What does he mean? Moderating emissions of greenhouse gases, which is feasible but expensive? Or influencing global average temperature, which might not be feasible and therefore should elicit caution with regard to cost?

From this ambiguity Dingell concocts a requirement that government "address" consumption, which means telling people how much and what types of energy to use.

Past intrusions of this type have come to expensive grief.

Governments can have only one notion about ideal levels of energy consumption: less than current levels. The extended pursuit of such a target represents an economic death spiral, the only escape from which is a return to market principles.

These days, alas, attention to market principles in energy politics is scarce. In the US, political allegiance to markets weakens as fuel prices rise. So Dingell shamelessly lurches to a fanciful need for the government to make "consumption more expensive." This, of course, means relieving consumers of cash they would rather spend on something other than energy.

When markets divert consumers' funds in such a manner, consumers ferociously complain. They should complain louder when elected officials propose to hike prices. In fact, consumers always should prefer price increases occasioned by the market to those forced upon them by the government.

The market tensions that raise energy prices eventually relax. The taxes and mandates essential to government control of consumption never subside until consumers recognize what's happening to them.

The oil and gas industry should wonder how much money Americans would waste on Dingell's version of classic energy folly before they woke up and demanded an end to his raid on their wealth.

(Online Sept. 7, 2007; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Gas shut in due to low prices

Natural gas futures prices temporarily strengthened Sept. 4-5 on news that Chesapeake Energy Corp. of Oklahoma City, the largest independent gas producer in the US, is reducing its gross production by 200 MMcfd through a combination of production curtailments and deferred pipeline hook-ups for the rest of 2007 due to poor market conditions.

That translates into a net loss of 125 MMcfd for Chesapeake, 6% of its current production. The reductions will be in the company's most prolific areas in the Fort Worth basin Barnett shale, South Texas, Deep Haley, and Anadarko basin.

"This news may spur other E&P companies to slow drilling activity as we approach what is shaping up to look like another year of high summer-ending storage levels," said analysts in the Houston office of Raymond James & Associates Inc.

Chesapeake also is cutting its drilling program to 140-145 rigs by the end of this year from 155-160 rigs currently. That will reduce the company's previously budgeted capital expenditures by 10% in both 2008 and 2009, or a combined $1 billion.

Despite the recent drop in gas prices, Chesapeake officials apparently used the futures market as an effective hedge. "So far this year, we have realized approximately $630 million in gains from our natural gas hedges, and, as of the middle of last week, the mark-to-market gain on our remaining 2007-09 natural gas hedges was approximately $1.5 billion," company officials reported Sept. 4. Chesapeake hedged 60% of its 2007 second-half gas production, 70% of its 2008 production, and 27% of its 2009 production at weighted average prices well above the Sept. 7 spot market price of $5.57/MMbtu at Henry Hub, La.

Despite the earlier jump in prices, gas futures fell Sept. 6-7 to within pennies of the week's opening price on the New York Mercantile Exchange as the hurricane premium evaporated from the market and US inventories expanded. The Energy Information Administration reported the injection of 36 bcf of gas into US underground storage in the week ended Aug. 31. That pushed US gas storage to just above 3 tcf for the first time ever in August, 30 bcf above year-ago levels and 284 bcf above the 5-year average.

With predictions for moderate weather for the rest of the summer and a current lack of hurricane activity, Raymond James analysts warned, "Look for continued weakness in the natural gas market as we near the end of this injection season."

Oil prices climb

Crude prices climbed to a 5-week high over five consecutive trading sessions through the first week of September, topping $77/bbl in intraday trading Sept. 6-7.

The EIA reported US commercial crude inventories fell 3.9 million bbl to 329.7 million bbl in the week ended Aug. 31. Gasoline stocks dropped 1.5 million bbl to 191.1 million bbl in the same week, well below average for the time of year. Distillate fuel inventories increased by 2.3 million bbl to 132.2 million bbl (OGJ Online, Sept. 6, 2007). That put US crude stocks below last year's inventory levels for the first time in 12 weeks.

Paul Horsnell at Barclays Capital Inc., London, said, "US gasoline inventories fell further below the seasonal norm, to a new 2-year low in absolute terms and to a new all-time low in terms of days of forward demand."

However, Olivier Jakob, managing director of Petromatrix GMBH, Zug, Switzerland, noted a build of crude stocks in Cushing, Okla., storage—"the first substantial build since April," he said. "More importantly, the Cushing build is happening despite the front West Texas Intermediate spreads [being] at a multiyear high backwardation (for the season)." In backwardation, prices for promptly delivered crude exceed those of futures contracts with more-distant delivery dates.

Moreover, Jakob said imports of crude from Canada into Petroleum Administration for Defense District 2 [the US Midwest including Oklahoma] were 190,000 b/d higher in August than in July, resulting in a rebound of stocks. "With refinery maintenance in PADD 2 during September and higher Canadian crude oil production, the flag remains for further stock build in the Midwest, which does not correlate with the current level of WTI backwardation. The Cushing statistics are the first serious alarm bells in many weeks for the WTI backwardation, which will be in greater danger if the Cushing trend is confirmed next week," he said.

Meanwhile, there was virtually no expectation that ministers of the Organization of Petroleum Exporting Countries would take any action at their Sept. 11 meeting in Vienna. "Several of the oil ministers...have publicly stated they are in favor of not changing current production quotas," said Raymond James analysts.

(Online Sept. 10, 2007; author's e-mail: samf@ogjonline.com)

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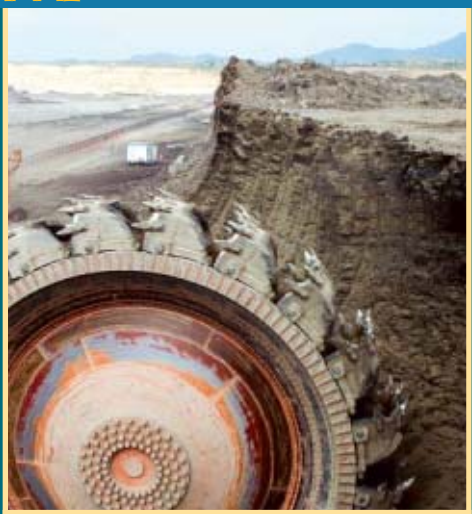

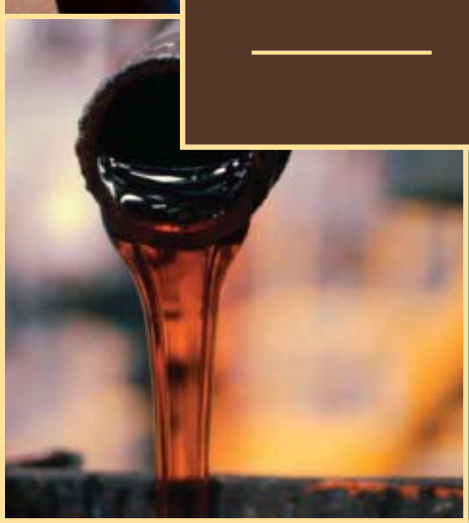

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