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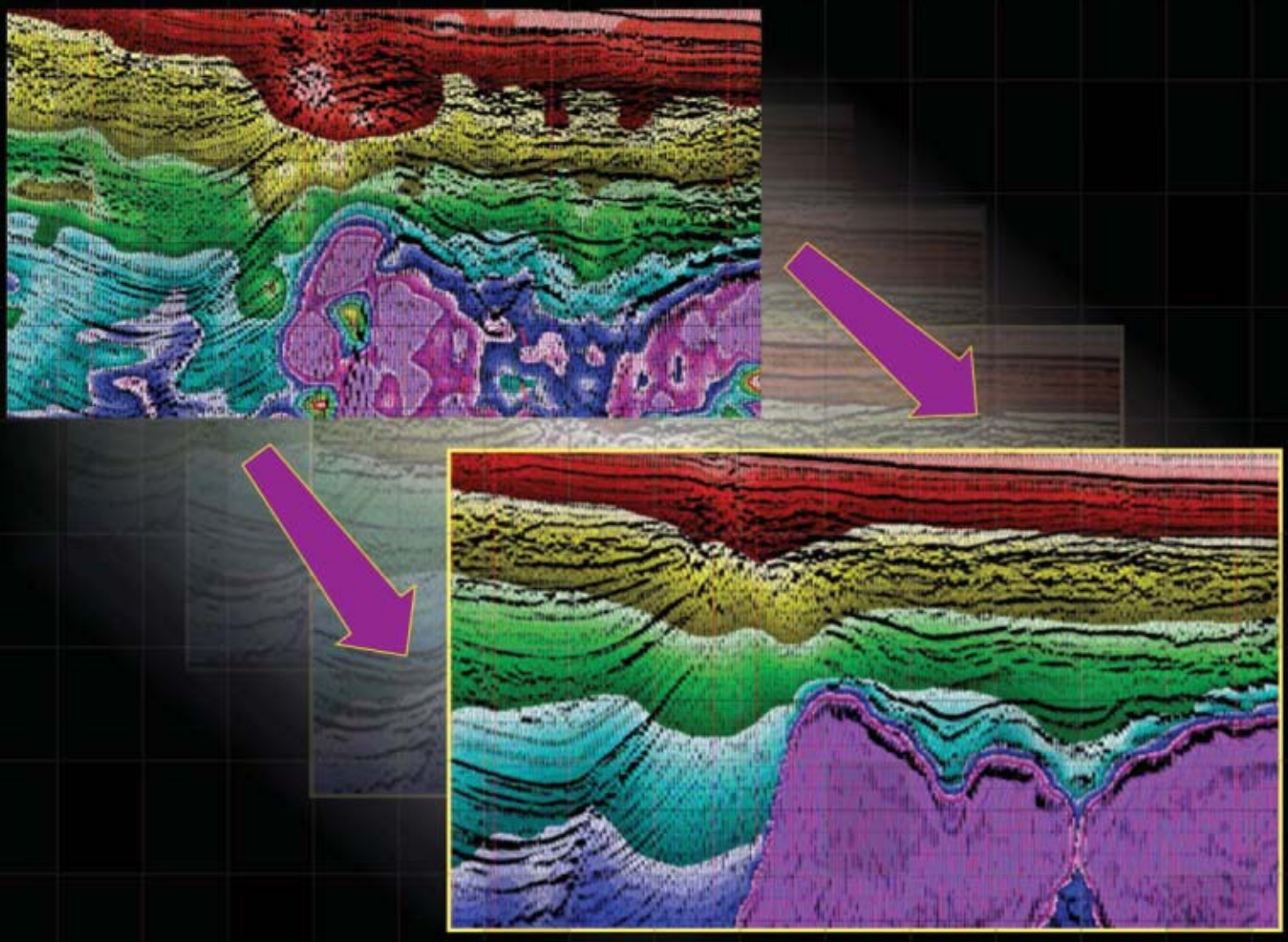

New Views of the Subsurface

Refining margins dampen first-quarter earnings
DeSoto drilling for Southwestern Energy
Ethanol from wood waste an opportunity for refiners
Remote digital temperature monitoring aids hydrotests

OIL&GAS JOURNAL®

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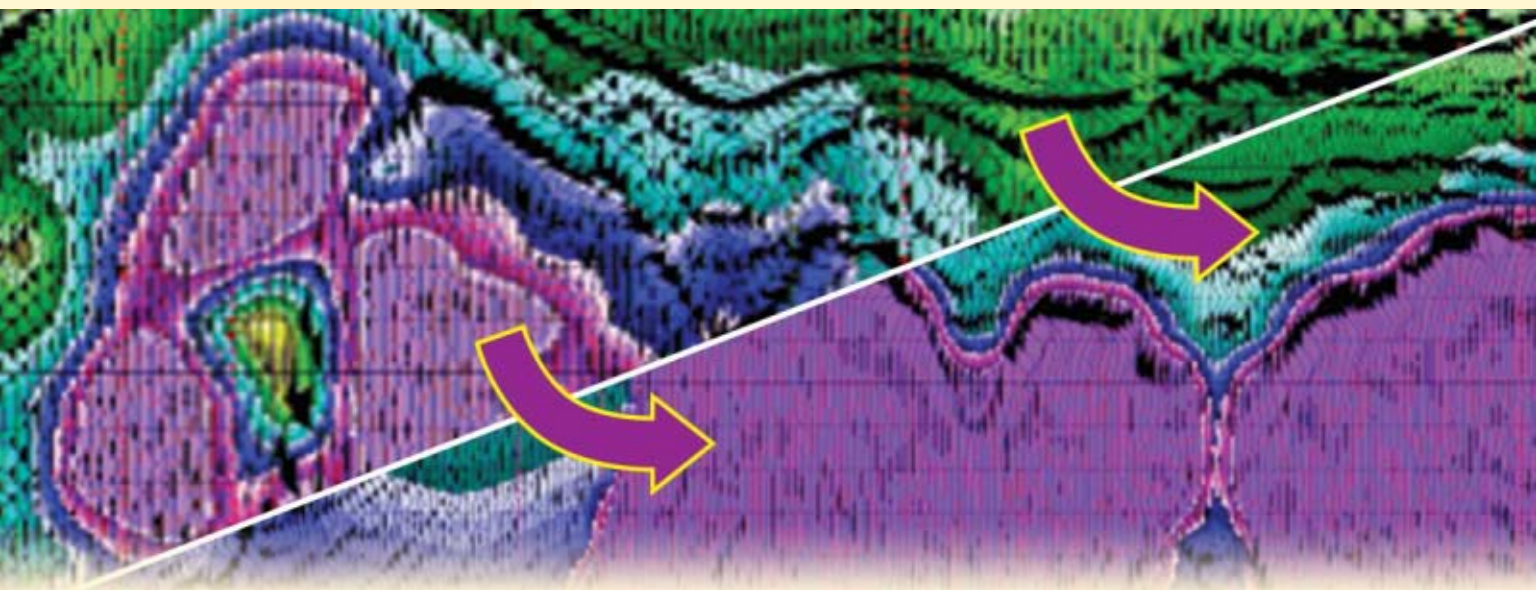
NEW VIEWS OF THE SUBSURFACE



REGULAR FEATURES

COVER

Differences in the clarity of the two cover images of the same seismic profile from the Gulf of Mexico are due to differences in the velocity model. The message is to sample and smooth seismic velocities carefully, because the process affects image resolution and may discard valid subsurface information. The interpreter must look at both depth and time-based measurements. In general, time-based measurements are now disregarded for expediency, a flawed strategy because the time-migrated measurements already have the information, can be viewed faster, and the processing is less expensive than the depth migration process where errors cannot be repaired easily. An article starting on p. 36 of OGJ's New Views of the Subsurface special report explains the method. Images courtesy of Shell Exploration & Production Co.

A SPECIAL ADVERTISING FEATURE PROFILING TOP PERFORMERS IN THE OIL AND GAS SECTOR

COHEN INDEPENDENT RESEARCH GROUP

Wall Street's #1 Independent Research Firm

Top Small Cap Oil and Gas Pick for 2008: PTPE

Strong Speculative BUY Price Target: $6.84 (currently below $1.00/share)

For information on the company
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www.panterapetroleum.com
NASDAQ OTC BB: PTPE

Pantera Petroleum
Energy Discovery for a Brighter Future

Cohen Independent Research Group has named Pantera Petroleum (OTC BB: PTPE) its top ranked small cap oil and gas pick for 2008 with a 12 to 18 month price target of $6.84, based upon net asset valuation and discounted cash flow analysis. Led by Paul Cohen, Cohen Independent Research Group is Wall Street's #1 Independent Research Firm.

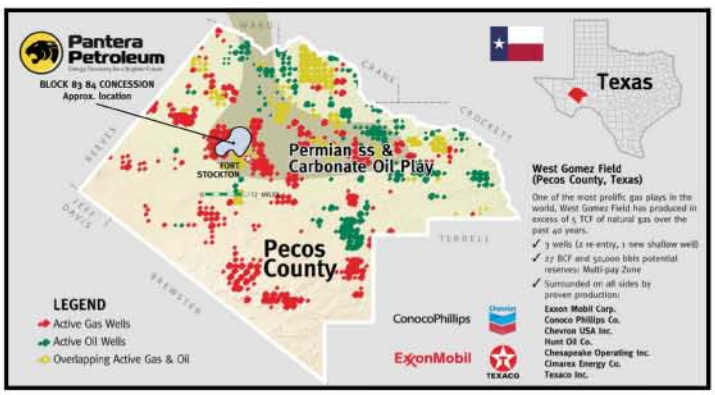
Pantera Petroleum's Formidable Strategy: Building a platform of lower risk, cash flow production properties in the U.S. with significant proven reserves and upside potential while actively exploring 4 million acres in South America's Chaco Basin, one of the largest onshore exploration plays remaining in the world.

Texas Property Near Production:

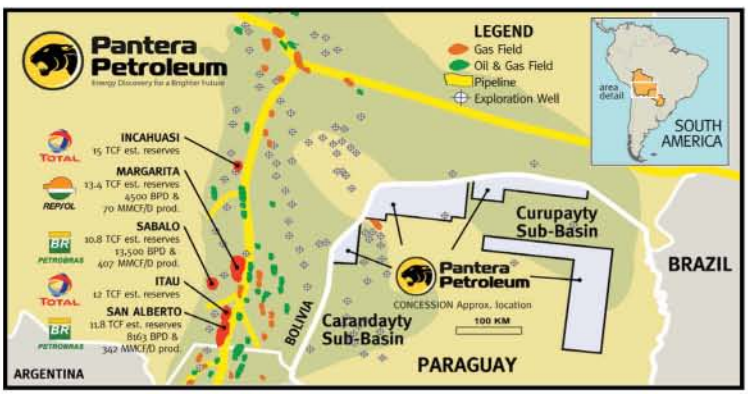
- ✓ 10% joint venture interest in the Block 83 84 Project on the West Gomez Field within Pecos County, Texas: prolific gas play with over 5 TCF of natural gas recovered in the past 40 years.
- ✓ Drilling is underway on a Three Well Project (Two Re-entry and One Infill Drill); Multi-pay zone; Completion expected within 2008.
- ✓ Recoverable reserves are estimated to be more than 27 BCF of gas and 50,000 barrels of oil, worth roughly $250 Million in the ground at today's market prices.
- ✓ ExxonMobil, Chevron and ConocoPhillips are among a few of Pantera's neighbors.
- ✓ On the acquisition path to add production based assets to portfolio in 2008.

South American Exploration Ongoing:

- ✓ Pantera has rights to an 85% stake in five concessions representing 3,872,000 acres, or 6,050 square miles in the Chaco Basin, approximately the size of Kuwait.
- ✓ Pantera's South American concessions have potential reserves of 6.7 TCFE of natural gas or 1.1 Billion barrels of oil, worth roughly $115 Billion in the ground at today's market prices upon oil discovery.
- ✓ The Chaco Basin holds the 2nd largest natural gas reserves in South America with current production at over 2 BCF of gas and more than 50,000 barrels of oil per day.
- ✓ Currently interpreting 1,800 miles of seismic data.
- ✓ Exploration program underway in anticipation of a six well drilling program.



Map of Pantera Concessions & Properties in Pecos County, Texas



Map of Pantera Concessions & Properties in Paraguay

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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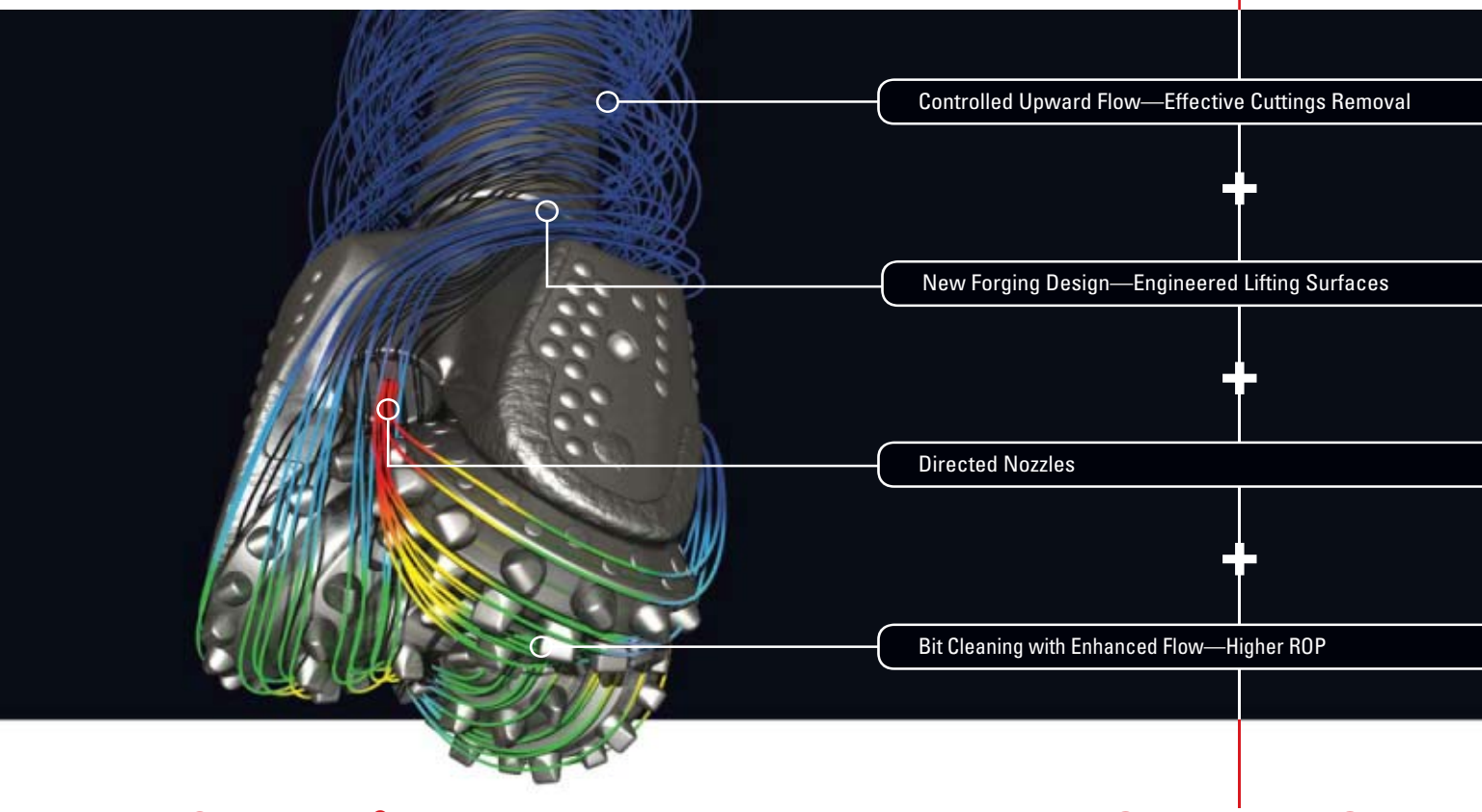

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General Interest — Quick Takes

US Senate questions oil executives on prices

A US Senate committee brought five major oil company executives back to Congress for the second time in less than 2 months so it could ask what's causing record high oil and gasoline prices (See Editorial, p. 19).

The nationwide average retail gasoline price has more than doubled since George W. Bush became president, Senate Judiciary Committee Chairman Patrick J. Leahy said as he opened a hearing on oil prices. "The president once boasted that with his pals in the oil industry, he would be able to keep prices low, and consumers would benefit. Instead, it is his pals in the oil industry who have benefited. American consumers, and the American economy, have suffered immensely," Leahy charged.

He said he wanted to hear from the witnesses about forces beyond supply and demand which have driven crude oil prices higher, whether to give the US Department of Justice authority to prosecute foreign oil supplies for violating US antitrust laws, and methods to reduce speculation in oil futures.

"This committee and the Congress need answers so that we can act in a way the administration will not: for the benefit of consumers, for American families and small businesses. We need to get prices under control and back to competitive levels, and we need to do it now," Leahy declared.

Robert A. Malone, chairman and president of BP America Inc.; John D. Hofmeister, president of Shell Oil Co.; Peter J. Robertson, vice-chairman of Chevron Corp.; John E. Lowe, executive vice-president of ConocoPhillips Co., and J. Stephen Simon, executive vice-president of ExxonMobil Corp., submitted written testimony similar to their submissions to the House Select Committee on Energy Independence and Global Warming on Apr. 1.

Mexico's oil output continues to recede

State-owned Petroleos Mexicanos said the country's production and exports of crude oil fell sharply in the first quarter as output continues to recede at Cantarell, the country's main oil field.

Pemex said average oil production decreased by 9% to 2.875 million b/d from 3.164 million b/d produced in 2007, while exports fell 13% to 1.484 million b/d and imports of gasoline rose by 18% to 317,000 b/d.

The country's six refineries produced 1.52 million b/d of petroleum products such as gasoline, diesel, fuel oil, and others.

Pemex said production of nonassociated gas increased 3% over the same period last year to 2.643 bcfd, as a result of higher volumes provided by the North.

Cantarell production has fallen by 416,000 b/d from 2007. It produced 1.15 million b/d in March, down 5.7% from February, the seventh straight month of waning production at the field.

Oil decline at Cantarell was partially offset by a 40% increase in the production of Ku-Maloob Zaap to 670,000 b/d from 476,000 b/d. The results are not up to the expectations of Pemex officials, with falls at Cantarell and other fields greater than anticipated. In April, Pemex E&P Director Carlos Morales Gil predicted that 2008 output at Cantarell would be 1.2-1.3 million b/d, compared with an average of 1.5 million b/d in 2007.

Morales said that Pemex nonetheless would deliver the same volume of oil production in 2008 as in 2007 because other fields would compensate for the decline at Cantarell.

So far, however, Pemex has been unable to do that, and the country has had to increase its imports of oil products such as gasoline. In March, Mexico's gasoline imports rose to 360,700 b/d, the highest level since November 2007, largely due to the declining output from traditional fields (OGJ, May 5, 2008, p. 40).

Analyst BMI has forecast Mexican production as averaging 3.45 million b/d in 2008, falling to 3.15 million b/d by 2012.

EC: VAT adjustment would send 'bad signal'

The European Commission has warned that French President Nicolas Sarkozy's proposal to adjust value-added taxes (VAT) on oil would send a "bad signal" to producers.

"Modifying the fiscality of fuel to fight the rise in oil prices would send a very bad signal to oil-producing countries," an EC spokesman said. "We would be saying that we can raise oil prices, and this will be paid for by the taxes of Europeans," he said.

A month before taking over presidency of the European Union, Sarkozy said he wanted to put "the question to our European partners: if oil continues to increase, should we not suspend the VAT taxation on the price of oil?"

Saying that it was necessary to have "the courage to tell the French" that fuel prices were going to continue to rise, Sarkozy also suggested allocating additional VAT income resulting from the price rise to a fund intended to reduce the bill of the poorest.

His proposals came as French fishermen kept up protests over high fuel costs by blocking ports and shipping, while other protestors blocked oil tankers from entering or leaving refineries operated by Total SA at Dunkirk and Gonfreville on the English Channel. French consumers currently pay about 19.6% VAT on the price of fuel. ✦

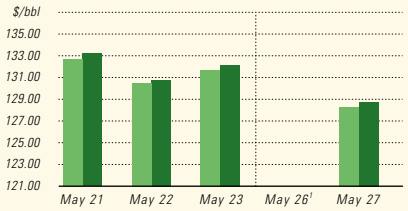
Exploration & Development — Quick Takes

Total makes gas, condensate find off Brunei

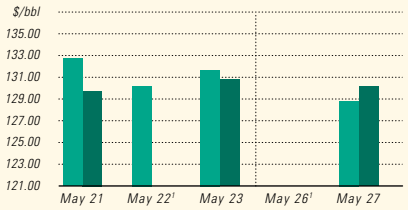
Total SA has made a natural gas and condensate discovery with its MLJ2-06 well drilled on Block B off Brunei. The well is the deepest ever drilled in Brunei in a high pressure, high temperature

Industry Scoreboard

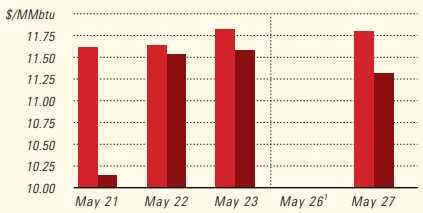
IPE BRENT / NYMEX LIGHT SWEET CRUDE



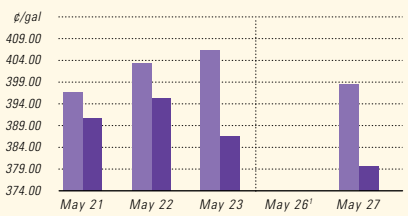
WTI CUSHING / BRENT SPOT



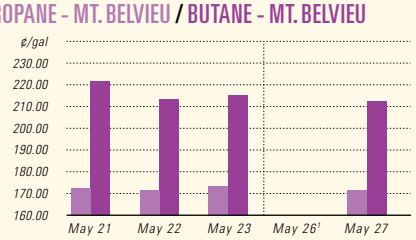
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



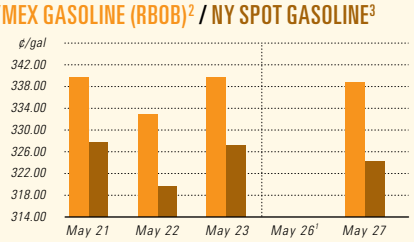
IPE GAS OIL / NYMEX HEATING OIL



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]Non-oxygenated regular unleaded.

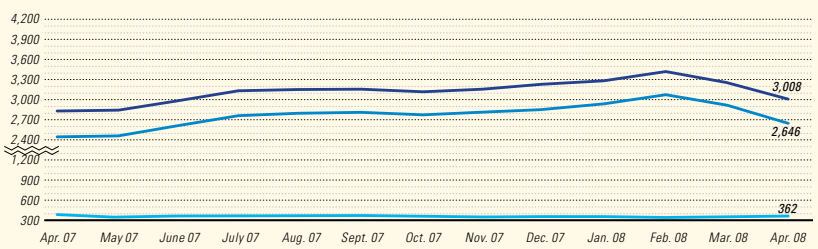
US INDUSTRY SCOREBOARD — 6/2

Latest week 5/16	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	9,301	9,338	–0.4	9,061	9,118	–0.6
Distillate	4,158	4,131	0.7	4,222	4,315	–2.2
Jet fuel	1,540	1,631	–5.6	1,563	1,613	–3.1
Residual	689	736	–6.3	659	786	–16.2
Other products	4,652	4,772	–2.5	4,866	4,872	–0.1
TOTAL DEMAND	20,340	20,607	–1.3	20,235	20,712	–2.3
Supply, 1,000 b/d						
Crude production	5,093	5,230	–2.6	5,099	5,191	–1.8
NGL production[2]	2,497	2,432	2.7	2,333	2,341	–0.3
Crude imports	10,003	10,241	–2.3	9,760	9,996	–2.4
Product imports	3,534	3,799	–7.0	3,315	3,505	–5.4
Other supply[3]	1,358	914	–48.6	1,330	867	53.4
TOTAL SUPPLY	22,485	22,616	–0.6	21,837	21,900	–0.3
Refining, 1,000 b/d						
Crude runs to stills	14,683	15,313	–4.1	14,683	14,939	–1.7
Input to crude stills	14,881	15,531	–4.2	14,881	15,279	–2.6
% utilization	85.1	89.1	—	85.1	87.5	—

Latest week 5/16	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	320,442	325,759	–5,317	344,189	–23,747	–6.9
Motor gasoline	209,413	210,168	–755	196,666	12,747	6.5
Distillate	107,790	107,062	728	120,268	–12,478	–10.4
Jet fuel-kerosine	40,122	40,384	–262	40,468	–346	–0.9
Residual	40,930	39,320	1,610	37,793	3,137	8.3
Stock cover (days)[4]			Change, %		Change, %	
Crude	21.5	22.0	–2.3	22.4	–4.0	
Motor gasoline	22.5	22.7	–0.9	21.0	7.1	
Distillate	25.9	25.5	1.6	28.8	–10.1	
Propane	36.5	32.7	11.6	35.7	2.2	
Futures prices[5] **5/23**			**Change**		**Change**	**%**
Light sweet crude, $/bbl	130.46	124.93	5.53	63.88	66.58	104.2
Natural gas, $/MMbtu	11.50	11.36	0.14	7.95	3.56	44.7

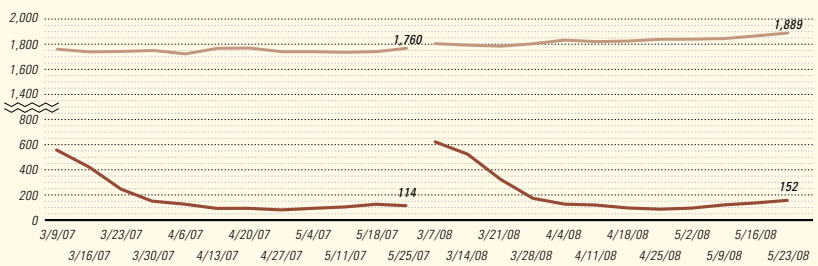
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

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



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

reservoir. The well was drilled to 5,850 m TD in 62 m of water about 50 km offshore.

Total said new gas compartments in the Maharaja Lela/Jamalulalam field have been detected and will require further appraisal work to evaluate them. The new well is expected to come on stream before yearend.

Total operates the block with a 37.5% stake. Other participants are Royal Dutch Shell PLC (35%) and local partners (27.5%).

Total has been present in Brunei since 1986, where it operates the Maharaja Lela/Jamalulalam field, which produced 28,500 boe/d in 2007. The gas is delivered to the Brunei LNG liquefaction plant.

Total holds a 60% stake in and operates 5,000-sq-km deepwater Block J, for which a production-sharing agreement was signed in March 2003. Exploration activities on Block J have been suspended since May 2003, awaiting the resolution of a border dispute with Malaysia.

BLM releases plan for NPR-A northeast portion

The US Bureau of Land Management released a supplemental final plan for leasing in the National Petroleum Reserve-Alaska's northeast portion.

It said that the land could yield nearly 3 billion bbl of crude, or about a quarter of the oil produced over the last 31 years at Prudhoe Bay. The area also could provide trillions of cubic feet of natural gas for shipment through currently planned pipelines, the US Department of Interior agency said.

BLM will not open 219,000 acres of Teshepuk Lake and its island to oil and gas activity under the preferred alternative it selected in its supplemental final integrated activity plan and environmental impact statement. The plan's preferred alternative also would defer leasing for 10 years on 430,000 acres north and east of the lake that currently are not available for leasing.

The plan includes protections for polar bears, including requirements to consider impacts on areas the animals use for their dens, according to BLM. It said that with the polar bear's listing as a threatened species, it will continue to work with the US Fish and Wildlife Service on future oil and gas activities.

BLM said it expects to hold a lease sale this fall for available portions of NPR-A's northeast area as well as part of the reserve's northwest planning area. It said that it will publish a notice of availability regarding the plan's release in the Federal Register later this month.

MMS proposes plan for first OCS revenue shares

The US Minerals Management Service is proposing regulations to distribute qualified federal Outer Continental Shelf oil and gas revenues to four Gulf Coast states and their eligible coastal governmental subdivisions.

The distributions will take place under the 2006 Gulf of Mexico Energy Security Act, which established federal OCS revenue sharing for affected coastal states and communities, MMS said on May 27.

The law authorized that 37.5% of all federal OCS revenue from new leases in the gulf, including bonus bids, rentals, and production royalties, would be shared with Alabama, Mississippi, Louisiana, and Texas and their coastal communities and counties (or, in Louisiana's case, parishes).

The first sale with immediate revenue-sharing leases, OCS Lease Sale 224, was held Mar. 19, according to MMS. Based on the actual location of tracts bid in the sale, it said it calculates bonuses and first-year rentals for fiscal 2008 would be 30% for Alabama, 27% for Mississippi, 32% for Louisiana, and 11% for Texas.

Qualified OCS revenues are allocated among the gulf producing states based on a formula which incorporates a state's proximity to certain tracts in the gulf's Eastern Planning Area and a small section in the Central Planning Area, MMS said.

Shell plans more Tucumcari exploration

A Shell Oil Co. affiliate plans to mount an exploratory drilling program for tight gas in eastern New Mexico's nonproducing Tucumcari basin.

SWEPI LP, an affiliate of Shell Exploration & Production Co., in mid-May staked three locations in northeastern Guadalupe County to be drilled back-to-back starting in early June.

The locations are Webb 3-23, in 23-11n-23e; Latigo Ranch 2-34, in 34-11n-23e; and Latigo 3-5, in 5-10n-23e. All are permitted to 13,150-13,500 ft or Mississippian and are thought to be aimed at low-permeability Pennsylvanian objectives. The area's Pennsylvanian rocks are in the Atoka, Strawn, and Canyon formations.

Shell has been conducting tests since late 2007 but has released no results from the Webb CD-1 well, in 25-11n-23e, in the Cuervo subbasin (see map, OGJ, Sept. 17, 2001, p. 36). It was drilled to TD 10,910 ft earlier as part of a multiwell exploration program by Cuervo Exploration LLC, an affiliate of Gunn Oil Co., a private Wichita Falls, Tex., independent. Shell in January won state approval for an extended flow-test period at the well.

Shell's locations are 6-8 miles north of Latigo Ranch, a gas accumulation discovered in 1982 and never produced. Latigo Ranch tested gas from Strawn sandstones at 6,658-6,764 ft.

Shell asked the New Mexico Oil Conservation Division to keep confidential all information relating to the proposed wells for 1 year after drilling and completion, but state regulations provide for such treatment only for well completion or recompletion reports and logs.

Norwood logs second pay zone in Nicaragua

Norwood Resources Ltd., Vancouver, BC, logged 138 ft of potential net hydrocarbon pay in its third exploratory well in southwestern Nicaragua and identified 387 ft of net pay in one of its previously drilled wells.

The company will test the new well, Maderas Negras-1, in July. It was drilled to 6,400 ft to test sands of the Paleocene Brito formation and found the same Brito interval as in the company's San Bartolo well 3 miles southwest (OGJ, Mar. 24, 2008, p. 42).

Meanwhile, in the San Bartolo well, the company identified 387 ft of net hydrocarbon pay in the overlying Paleocene Masachapa formation. Masachapa was not targeted in the Maderas Negras well.

Maderas Negras's potential net pay is based on porosity criteria of 10% or greater and hydrocarbon saturations of 40% or better.

Porosities are 10% to more than 30%.

Log results will be further calibrated to 60 ft of retrieved whole-core sample being analyzed in Houston.

The Masachapa hydrocarbons had not previously been recognized in the San Bartolo well due to the effects of flushing of near-wellbore hydrocarbons by overweight drilling fluids, the company said. Norwood is re-entering the well to run cased-hole logs and determine the need for frac jobs and retesting.

"The company is now moving forward with an extensive testing program to determine the sustained productivity potential and commerciality of these hydrocarbon-bearing formations," Norwood said.

The wells are on the updip margin of the Sandino basin on the 845,000-acre Indoklanicsa Concession, only one third of which is covered by seismic. The other two-thirds is considered prospective, the company said.

Norwood's first two wells tested gas and 34° gravity oil. It plans to select and drill a fourth location later in 2008. The company has found operations to be slower and more costly than expected because of the lack of infrastructure and services.

Nicaragua has 35 wells drilled all time and does not as yet produce hydrocarbons.

Inpex upgrades Ichthys reserves

Japanese company Inpex Australia has announced an increase in reserves estimates for its deepwater Ichthys gas-condensate field in the Browse basin off Western Australia.

Field reserves are now estimated at 12.8 tcf of gas, and condensate reserves at 527 million bbl, putting the field in the top five gas fields in Australia in terms of reserves.

In 2000 the company's subsidiary Inpex Browse Ltd. drilled three exploration wells, Dinichthys 1, Gorgonichthys 1, and Titanichthys 1 (the Ichthys complex), on WA-285-P permit and discovered the giant gas and condensate structure. Gas in place at that time was estimated at 10 tcf and condensate in place at 500 million bbl (see map OGJ, Oct 17, 2005, p. 34).

Inpex and partner Total SA of France are assessing LNG development plans, with a first cargo target now likely to be 2013.

Woodford a horizontal Anadarko basin target

Cimarex Energy Co., Denver, is pursuing gas and oil in Devonian Woodford shale with horizontal wells in the Anadarko basin in western Oklahoma.

The company said in late April it had five wells in various stages of completion and evaluation and was drilling three more wells. Cimarex is evaluating use of 4,000-ft laterals, while early wells went to 13,000 ft true vertical depth and had 2,500 ft laterals.

Cimarex's 1H-27 Jameson, in 27-14n-10w, near Geary in Canadian County, is the basin's first reported horizontal Woodford completion, said IHS Inc. It flowed 2.76 MMcfd of gas and 61 b/d of oil on initial tests of perforations at 12,800-15,030 ft measured depth.

Hester et al. with the US Geological Survey, using a study area in northwestern Oklahoma, pointed to the Woodford as a possible large potential horizontal drilling target in an earlier article (see map, OGJ, Dec. 3, 1990, p. 73). ✦

Drilling & Production — *Quick Takes*

China gas wells back on stream after earthquake

China Petroleum & Chemical Corp. (Sinopec) said 97% of its natural gas wells in Sichuan Province have resumed production after the earthquake 2 weeks ago.

Some 208 wells out of the total 218 have resumed production, according to Chen Ge, secretary to the board of governors.

Last week Sinopec's giant Chuanxi gas field in Sichuan was reported to be producing at 20% of capacity after many chemical plants were closed, up from only 10% earlier when 1,000 gas wells were shut in (OGJ Online, May 23, 2008).

Transocean drills record extended well off Qatar

Transocean Inc. claimed its GSF Rig 127 jack up drilled a record length extended-reach well off Qatar for Maersk Oil Qatar AS.

GSF Rig 127 drilled Well BD-04a to 40,320 ft measured depth with a 35,770-ft lateral section in 36 days in Al-Shaheen field. The record of 7.6 miles also is the first well in the history of offshore drilling to exceed 40,000 ft, Transocean claimed.

The well, in 200 ft of water in the Perisn Gulf, bottomed at a true vertical depth of 3,500 ft subsea. Inclination of its horizontal section was 89° to just over 91°, Maersk Oil Qatar said.

The extended-reach portion surpassed by 2,000 ft the previous world extended-reach record of 38,322 ft MD set by Parker Drilling Co. working for ExxonMobil Corp. The ExxonMobil well was drilled by a land rig at Sakhalin-1 under the Sea of Okhotsk in Far East Russia to a target area in Chayvo field 7 miles offshore (OGJ, Feb. 18, 2008, p. 33). That well was drilled with the custom-designed Yastreb land rig.

Transocean said its GSF Rig 127 crew dealt with high torque in the well's extended-reach section. The crew used extensive deck-management planning and a supply boat to hold additional drill pipe so that the rig stayed within its variable deck-load rating.

OGJ archives indicate that Well DB-04a may be the world's longest well bore. The former Soviet Union claimed it drilled the vertical SG-3 research hole well to 40,228 ft in the 1970s-90s on the Kola Peninsula near the Norwegian border west of Murmansk (OGJ, Dec. 7, 1992, p. 32).

Bakken play gets Three Forks/Sanish producer

A well on the Williston basin Nesson anticline in Dunn County, ND, was completed flowing oil, gas, and water from the Devonian Three Forks/Sanish formation.

Only 52 wells have produced from little-known Three Forks/Sanish in the US part of the basin. Continental Resources Inc., Enid, Okla., and other operators are attempting such completions to determine whether the Three Forks/Sanish formation may be a separate reservoir not drained by a horizontal completion in the more heavily drilled Middle Bakken zone above it.

Another consideration is whether a horizontal well bore in the Three Forks/Sanish might recover oil by gravity drainage from the

Middle Bakken, necessitating fewer overall wells.

The US Geological Survey (USGS) included the Three Forks/Sanish interval in its April 2008 assessment as part of the "Bakken composite continuous fractured reservoir." The USGS used estimated ultimate recoveries (EUR) from the basin's Bakken/Sanish completions to estimate the undiscovered resource in the Nesson-Little Knife Structural Assessment Unit (see map, OGJ, Apr. 21, 2008, p. 37).

Vertical wells perforated in the Bakken and Sanish had high EUR relative to vertical wells that only produced from the Bakken, so matrix contribution from the porous Sanish is extremely favorable, said Richard Pollastro, USGS geologist and Bakken formation task leader.

Sanish wells "certainly had a resulting effect on the final mean volume of 909 million bbl assessed" for the Nesson-Little Knife unit, Pollastro said.

Continental Resources reported a 7-day average flow of 618 b/d of oil, 543 Mcfd of gas, and 662 b/d of load water with 1,352 psi through a $^{24}/_{64}$-in. choke at the Bice 1-29H well, in 29 and 32-146n-95w, Dunn County, ND.

The distance between a horizontal wellbore in the Middle Bakken, if drilled, and the horizontal lateral in the Three Forks/Sanish in the Bice 1-29H is 60 ft, Continental Resources said.

Almost all of the Three Forks/Sanish completions are in Antelope field in McKenzie County, the USGS said.

The Bice well is in an undrilled spacing unit. To learn whether the two formations are in communication, Continental would need stabilized production from a Three Forks/Sanish lateral followed by drilling a Middle Bakken lateral and running a frac job. Some models show that a frac will not penetrate the Middle Bakken. ✦

Transportation — *Quick Takes*

Pipeline to shorten West Coast deliveries

BP Products North America signed an agreement with Petroterminal de Panama SA (PTP) to ship oil to its US West Coast refineries through the Trans-Panama Pipeline (TPP).

The 81-mile TPP originally carried crude through Panama from the Pacific to the Atlantic. PTP will modernize the pipeline and reverse the flow, significantly reducing delivery times and transportation costs to the US West Coast. Previously, crude cargoes sailing from east to west took an additional 30 days to travel thousands of miles around Cape Horn at the tip of South America.

Upon completion of the project, very large crude carriers with 2 million bbl of capacity will be able to transport Angolan and other crudes to the port of Chiriqui Grande, Bocas del Toro, on the Caribbean for the journey across the isthmus of Panama. Crude will be piped to the port of Charco Azul on the Pacific coast where it will be received by tankers for the journey to refineries on the US West Coast. Construction is expected to take about 2 years.

The change will greatly reduce transportation time, lowering logistic costs, and increasing flexibility of supply to US West Coast refineries, said Bob Malone, chairman and president of BP America.

Under the 7-year agreement, BP will acquire 5 million bbl of storage and commit to pipeline shipments of 65,000 b/d. PTP has transported over 3 billion bbl of petroleum, mostly for BP.

Sonatrach receives EPC bids for Arzew LNG train

Algeria's Sonatrach aims to increase its LNG export capacity by some 20% after it constructs a new 4 million-tonne/year liquefaction train at Arzew.

Four groups submitted bids on May 18 for the engineering, procurement, and construction contract to build the train: Snamprogetti and Chiyoda Corp.; Petrofac International and Inti Karya Persada Tehnik of Indonesia; Technip; and KBR. Commercial bids are due July 21 or possibly later in the summer, with an award to be made soon afterwards. The train is expected on stream by 2012.

In March, Sonatrach decided to move ahead on its own with the Arzew LNG project, as well as development of Gassi Touil gas field, after canceling an earlier agreement with Repsol YPF and Gas Natural of Spain.

The three firms had agreed to form El Andalous LNG, a joint venture of Sonatrach 20% and Repsol YPF-Gas Natural 80% to invest $3 billion in the new Arzew train.

Last September, Algeria canceled the project, including Gassi Touil gas field development, after the two Spanish companies delayed the start of work due to what they claimed was the sharp rise of costs in the LNG industry.

Papua New Guinea LNG project gets under way

The ExxonMobil-led Papua New Guinea LNG joint venture has signed a gas agreement with Papua New Guinea, paving the way for an LNG project in the country.

The agreement outlines fiscal terms and legal obligations under which the JV will operate. These terms include a 30% tax rate and an additional profits tax that would apply after a certain level of return has been achieved. The signing means that ExxonMobil can begin front-end engineering and design work for the project, a process expected to take about 16 months to complete. During this period the JV will be pursuing LNG sales agreements and securing project debt funding plus all permits and licenses needed.

On this basis, a final investment decision for the project is expected late in 2009 with first LNG cargoes planned for 2013.

Interest holders are ExxonMobil 41.6%, Oil Search 34.1%, Santos 17.7%, AGL Energy 3.6% and Nippon Oil 1.8%. Landholder interests have 1.2%.

Total lets pipeline, platform contracts off Angola

Total E&P Angola has contracted Saipem SPA to install a natural gas pipeline and injection platform off Angola.

The pipeline will extend from Block 17 to Block 2, where the gas will be injected into two oil-depleted reservoirs. The blocks are about 230 km northwest of Luanda. Saipem will carry out engineering, procurement, fabrication, transportation, and installation of the 1,500-ton injection platform—the Single Central Platform—to be installed in water 38 m deep on Block 2.

The marine activities will be carried out by the Saipem 3000 vessel in second half 2009. ✦

Letters

Global warming risks

The present news and government-sponsored furor about global warming has ignored all facts that do not follow their desires blindly (OGJ, May 5, 2008, Newsletter). The earth has been warming for the last 10,000 years. Between 10,000 and 12,000 years ago continental glaciers in North America extended into Kansas and Nebraska. Most of the retreat of the ice sheets occurred before man started burning hydrocarbons and generating CO_2. Warming of the earth is completely dependant on the amount of energy captured by the earth from the sun. Granted, pollution has increased, but the major problem is unoxidized hydrocarbon molecules present in high population areas.

Carbon dioxide is turned into plant material by green vegetation. More CO_2 is captured and converted by trees and grasses than is generated by man. Glaciation has occurred during earth history more than the recent Ice Age. The global warming furor has as a major purpose to thwart our economic success.

It has been a fact that research institutions slant their studies to comply with the political stances of the funding sources. All other facts that dispute the political stances are ignored or denigrated. The year 2007-08 has seen a decline in solar heating with temperatures below normal in many portions of the earth.

Another fallacy is that the rise of oceans will wreck industry when the ice caps on the polar areas melt. A careful study of the amount of water present as ice enters the oceans of the world shows that the rise of the oceans of the world would be less than a couple feet if not less than 1 ft. With higher temperatures, water from the oceans would increase and rainfall would consequently increase also. Therefore, desert regions would become better watered. Major desert regions of the earth would then have the ability to support increased plant growth, which in turn would increase the capture of CO_2 by plants and reduction of this substance in the earth's atmosphere.

A study of the last 1,000 years in the desert regions of the southwestern

United States indicates a long period of drought about 600-700 years ago that resulted in displacement of animals into areas with larger streams whose origin was in high mountains. The dry years have been identified using tree growth rings.

In the 77 years of my life I have observed periods of higher temperatures and lower temperatures than at present. We need a concerted effort to stop the scare tactics of those whose major purpose is in opposition to the economic stability of the advanced nations of the world.

DeForrest Smouse
Consulting geologist
Centerville, Utah

Calendar

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

OIL&GAS JOURNAL online

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

2008

JUNE

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Russia and CIS Oil & Gas Investment and Finance Forum, London, +44 (0)20 7878 6888, website: www.C5-Online.com/OilGasFinance. 16-17.

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

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

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

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

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

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

Purvin & Gertz Annual Asia LPG Seminar, Singapore, (713) 331-4000, (713) 236-8490 (fax), e-mail: glrodriguez@purvingertz.com, website: www.purvingertz.com. 23-26.

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

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

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

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

Calendar

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

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

Russian Oil and Gas Exports International Forum, Amsterdam, +44 (0)20 7878 6888, website: www.C5-Online.com/OilGasExport. 26-27.

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

JULY

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

Annual Rocky Mountain Natural Gas Strategy Conference & Investment Forum, Denver, (303) 861-0362, (303) 861-0373 (fax), e-mail: conference@coga.org, website: www.coga.org. 9-11.

✦AAPG/SPE/SEG Hedberg Conference, Casper,Wyo. (918) 560-2630, (918) 560-2678 (fax), e-mail: debbi@aapg.org, website: www.aapg.org. 14-18.

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

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

AUGUST

✦SPE Nigeria Annual International Conference & Exhibition, Abuja, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 4-6.

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

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

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

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

SEPTEMBER

Annual India Oil & Gas Review Symposium & International Exhibition, Mumbai, (0091-22) 40504900, ext. 225, (0091-22) 26367676 (fax), e-mail: oilasia@vsnl.com, website: www.oilasia.com. 1-2.

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

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

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

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

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

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

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

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

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

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

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

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

OCTOBER

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Arab Oil & Gas Show, Dubai, +971 4 3355001, +971 4 3355141 (fax), e-mail:

info@icedxb.com, website: www.ogsonline.com. 28-30.

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

NOVEMBER

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

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

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

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

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

GPA North Texas Annual Meeting, Dallas, (918) 493-3872, (918) 493-3875 (fax), email: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 6.

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

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

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

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

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

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

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

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

DECEMBER

✦IADC Well Control Middle East Conference & Exhibition, Muscat, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 2-3.

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

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

IADC Drilling Gulf of Mexico Conference & Exhibition, Galveston, Tex., (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 3-4.

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

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

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

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

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

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

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

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

2009

JANUARY

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

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

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

FEBRUARY

✦SPE Reservoir Simulation Symposium, The Woodlands, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website; www.spe.org. 2-4.

✦IADC Health, Safety, Environment & Training Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 3-4.

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

✦IADC/SPE Managed Pressure Drilling & Underbalanced Operations Conference & Exhibition, San Antonio, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 12-13.

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

MARCH

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

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

✦SPE/IADC Drilling Conference & Exhibition, Amsterdam, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website; www.spe.org. 17-19.

✦SPE Americas E&P Environmental and Safety Conference, San Antonio, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website; www.spe.org. 23-25.

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

✦SPE Western Regional Meeting, San Jose, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website; www.spe.org. 24-26.

APRIL

✦IADC Drilling HSE Middle East Conference & Exhibition, Abu Dhabi, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 21-22.

MAY

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

✦IADC Environmental Conference & Exhibition, Stavanger, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 12-13.

✦IADC Drilling Onshore Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 21.

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Journally Speaking

CCS is a question of scale

Paula Dittrick
Senior Staff Writer

Carbon capture and storage (CCS) is being touted as a promising method of reducing carbon dioxide emissions into the atmosphere.

The oil industry for decades has injected CO_2 underground in enhanced oil recovery projects, so some science and technology exists for CCS, although many questions remain regarding both sequestration and climate change. Researchers have yet to demonstrate that CCS can be accomplished on a grand-enough scale to stabilize CO_2 concentration levels.

CCS envisions capturing CO_2 from power plants, petrochemical plants, and other industrial users and sequestering it underground into depleted oil and gas fields, saline aquifers, and unmineable coal seams.

The commercialization of CCS faces various obstacles, said climate researchers participating in an Offshore Technology Conference panel session on CO_2 sequestration in early May. Sally M. Benson, executive director of Stanford University's global climate and energy project, summed up the problem:

"In principle, sequestration is straightforward," Benson said. "In practice, there is a great deal of science and engineering that underpin safe and effective sequestration.... The question of scale cannot be ignored." She and other researchers suggest that thousands of projects will be needed to reduce CO_2 emissions.

"Each of the projects will [need to] be 5-10 times larger than any of the existing projects," Benson adds. Major existing sequestration projects are the Sleipner project off Norway, the Weyburn project in Saskatchewan, and the In Salah project in Algeria.

Potential consequences

Benson said potential consequences stemming from large-scale sequestration must be assessed, and methods developed to avoid negative consequences.

Daniel Schrag, Harvard University professor of earth and planetary sciences, advocates financial incentives to accelerate CCS research. He believes "there would be a lot of commercial bidders" if the US government were to let contracts for large-scale CCS projects.

"It's time to get going, not just with small test projects, but with full-scale industrial experiments," Schrag said. "I think what is missing—in the US at least—is the political will to do it." However he notes widespread change in public perception within the past 3 years regarding CO_2 levels.

The Intergovernmental Panel on Climate Change reports the current atmosphere CO_2 concentration is about 380 ppm and rising at a rate of 2 ppm/year. Researchers are calculating the volume of CO_2 emissions that must be reduced and in what time span in order to stabilize CO_2 concentrations.

Their efforts raise underlying questions for which there are no definitive answers as yet. Schrag calls the situation, "an experiment on a planetary scale that hasn't been done for millions of years. There will be surprises." He also emphasizes the need for CCS on a big scale.

"We have to think of ways to [capture and store] hundreds of megatonnes and gigatonnes each year," Schrag said. Deep-sea sediments in 3,000 m of water could provide permanent offshore storage by gravitational trapping, he said, but that has yet to be field tested.

Heleen Groenenberg, scientific researcher with Energy Research Center policy studies of the Netherlands, said technical uncertainties must be resolved.

"How we deal with these uncertainties is a difficult task," she said. The key question is: "When will which technologies appear?" CCS operations are capital intensive and will involve a long-running financial commitment, she noted.

Legal liabilities

Stanford's Benson sees legal liability issues as another obstacle for CCS projects. For instance, questions arise as to who will be responsible for long-term monitoring and who might pay to remediate a CCS site if it starts to leak in 100 years. She said more research is needed to advance geophysical imaging to assess sequestration reservoirs and seals. Scientists are working on geophysical monitoring technology to assure that sequestered CO_2 stays sequestered.

Meanwhile, various public and privately funded projects are under way or in the planning stages for demonstration projects on a scale commensurate with sequestering the 5-10 million tonnes/year of CO_2 that a typical coal-fired power plant emits. "Without definitive results from these and even larger scale tests, policy makers, investors, and society will not have the confidence to proceed with widespread deployment of CCS," Benson said.

Oil and gas companies having stakes in deepwater projects are accustomed to the need to resolve a myriad of questions and interrelated complexities to prove technology will work safely on a commercial scale and within budget.

This type of experience is likely to be useful for multidisciplinary researchers as they work to reduce atmospheric CO_2 and understand global climate change. ✦

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

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Editorial

Salaries as bludgeons

For their latest trek to Capitol Hill May 21 to absorb empty-headed insults from politicians, oil company executives merit little pity. They're paid well for their work. On this point, the politicians left no room for doubt.

Patrick J. Leahy (D-Vt.), chairman of the Senate Judiciary Committee, unabashedly asked his five industry witnesses how much money they make. When ConocoPhillips Executive Vice-Pres. John E. Lowe, who was under oath, said he couldn't respond precisely, Leahy blurted, "I wish I made enough money that I didn't even have to know how much I make." It was a moment made for television.

What's illuminated

As usual at these appalling inquests, what the inquisitors illuminated most clearly was their own misapprehension. In an opening statement, Leahy asked the executives how they "justify exorbitant profits on the backs of middle class, hard-working families." Richard J. Durbin (D-Ill.) said, "I think the president should be calling you all before his little meeting place, the White House, and talking about what you are doing to the American economy." Dianne Feinstein (D-Calif.) scolded the executives because their companies make money and told them they "apparently have no ethical compass about the price of gasoline."

And so it went, senators aggrandizing themselves with questions for which they wanted no answers, fuming about a world that doesn't exist in which oil company executives set the price of gasoline and where profits attest to misbehavior. They'll never learn. They refuse to learn. Ignorance serves them too well, even as it breeds policy errors damaging to their country.

In the oil industry, the temptation is strong to ignore these indignities as misguided wastes of time and money. The industry nevertheless must acknowledge the body blow it sustained in the exchange about compensation.

While the pay of top corporate executives is public knowledge, it's not something Congress can or should want to do anything about. It is the business only of corporate owners, the shareholders. Within that group, regal pay for executives has become an issue—and not just in the oil and gas industry. Feeling the pressure, the Securities and Exchange Commission recently tightened disclosure requirements for the compensation of top executives.

Pay for US chief executives has in fact climbed beyond the cloud tops. The AFL-CIO cites a Corporate Library study showing that the chief executives of Standard & Poor's 500 companies drew average total compensation last year of $14.2 million each. The median compensation for this group: $8.8 million. Most American workers can't dream in amounts that high.

Oil executives don't dominate the upper stratum of this aristocracy. In a ranking by the consulting firm Equilar Inc. published Apr. 6 in the New York Times, financial executives hold that distinction. But lavish executive pay is a bigger problem for oil companies than it is for others.

The Judiciary Committee hearing shows why. Calling attention to multimillion-dollar salaries of specific executives puts a face on popular assumptions about oil-company greed. Leahy knew this. It didn't matter where the numbers he elicited ranked among high-level executives in other industries. Leahy wasn't addressing high-level executives. He was addressing people with no prospects for million-dollar compensation packages, people hurt by and angry about high oil prices, people suspicious about large profit numbers, people who therefore derive visceral pleasure from hating oil companies.

Old melodrama

So the stage is set for an old melodrama. Congress will seek revenge on behalf of fabricated victims. It will impose a windfall profit tax, outlaw "price-gouging," reimpose price controls, or simply keep blocking access by producers to promising federal land. It will, in the eyes of the vengeful, make oil companies pay for their greed. The costs, however, will fall on shareholders and energy consumers.

Lavish executive salaries don't explain all or even most of the enmity toward oil companies. As easy targets, though, they aggravate the problem. To the extent of their contributions to wayward energy policy, they hurt people who don't earn nearly as much. Leahy has made them an energy issue. Oil company executives and shareholders need to respond. ✦

Refining margins dampen first-quarter earnings

Marilyn Radler
Senior Editor-Economics

Laura Bell
Statistics Editor

Record-high worldwide oil prices and strong natural gas prices drove oil and gas company earnings in the first quarter of 2008, but weak downstream margins weighed on profits.

Samples of oil and gas producers, transporters, and refiners based in the US and Canada posted double-digit earnings gains from last year's first quarter, and a sample of mostly US-based service and supply companies reported a combined 22% jump in first-quarter profits.

The US-based sample of operators recorded a collective 12% earnings increase, although 27 of them reported a loss for the quarter. Meanwhile, two of the 14 Canadian companies sampled had a loss for the quarter, but the group's combined earnings surged a total 35% from first quarter 2007.

US firms' results

Robust oil and gas price realizations propped up returns for most producers in the sample of US companies, but high oil costs slashed refining margins.

All of the integrated firms in the sample reported stronger first-quarter profits this year compared with the same period last year.

Murphy Oil Corp. posted $409 million in net income in the recent quarter, up from $110.6 million a year earlier. Murphy's income from exploration and production operations was $428 million vs. $88.8 million a year earlier, boosted by larger production volumes and higher sales prices for both oil and gas.

The company's refining and marketing operations posted income of $10.2 million in the recent quarter—mostly in the UK, with just $1 million from its

US OIL AND GAS FIRMS' FIRST QUARTER 2008 REVENUES, EARNINGS

	Revenues		Net income	
	1st quarter			
	2008	2007	2008	2007
	Million $ (US)			
Abraxas Petroleum Corp.	(4.7)	11.7	(9.0)	(1.0)
Adams Resources & Energy Inc.[1]	3.9	3.4	1.0	(0.5)
American Oil & Gas Inc.	0.5	0.4	(1.2)	(0.7)
Anadarko Petroleum Corp.	2,978.0	5,250.0	287.0	1,722.0
Apache Corp.	3,187.7	2,002.9	1,021.5	492.9
Approach Resources Inc.	19.0	9.4	2.8	(0.6)
Arena Resources Inc.	45.4	16.7	18.3	5.7
Aspen Exploration Corp.[2]	1.3	1.4	0.2	0.4
ATP Oil & Gas Corp.	228.2	148.4	46.8	27.4
Aurora Oil & Gas Corp.	6.9	6.3	(1.2)	(0.7)
Belden & Blake Corp.	34.3	29.5	(11.6)	(23.3)
Berry Petroleum Co.	185.4	117.5	43.0	18.9
Bill Barrett Corp.	149.7	98.9	30.7	14.2
Black Hills Corp.	26.1	25.8	2.6	3.6
Blue Dolphin Energy Co.	0.7	0.9	(0.5)	(0.3)
Brigham Exploration Co.	25.1	25.2	1.5	1.9
Cabot Oil & Gas Corp.	219.7	191.6	46.0	48.5
Callon Petroleum Co.	45.0	45.5	7.6	5.8
Cano Petroleum Inc.[2]	11.7	5.9	(1.1)	(2.2)
Carrizo Oil & Gas Inc.	53.7	23.0	(5.3)	(2.5)
Cheniere Energy Inc.	11.1	20.3	(49.9)	(34.6)
Chesapeake Energy Corp.	1,611.0	1,589.0	(132.0)	258.0
Chevron Corp.	65,946.0	48,227.0	5,168.0	4,715.0
Cimarex Energy Co.	477.1	306.9	149.8	64.6
Clayton Williams Energy Inc.	136.9	72.5	7.2	(12.3)
Comstock Resources Inc.	241.2	146.3	41.1	12.6
ConocoPhillips	56,552.0	42,867.0	4,139.0	3,546.0
Contango Oil & Gas Co.[2]	21.7	4.7	112.7	0.2
Continental Resources Inc.	227.7	121.1	88.0	53.8
Credo Petroleum Corp.[3]	4.6	4.1	1.8	1.4
Crimson Exploration Inc.	45.0	4.5	0.7	(1.6)
Cross Timbers Royalty Trust	6.9	4.7	6.8	4.5
Cubic Energy Inc.[2]	0.8	0.1	(1.1)	(1.9)
Daleco Resources Corp.[4]	0.3	0.3	(0.3)	(0.7)
Delta Petroleum Corp.	57.9	37.0	(21.1)	(18.7)
Denbury Resources Inc.	317.3	174.2	73.0	16.6
Devon Energy Corp.	2,975.0	2,473.0	749.0	651.0
Dominion Energy Inc.	1,284.0	1,108.0	182.0	142.0
Dorchester Minerals Ltd.	21.3	14.7	15.4	9.1
Double Eagle Petroleum Co.	7.3	4.9	1.9	0.2
DTE Gas & Oil Co.	10.0	28.0	82.0	2.0
Dune Energy Inc.	40.8	3.0	(8.7)	(8.5)
Edge Petroleum Corp.	17.7	22.9	(16.2)	(5.8)
El Paso Corp.	1,269.0	1,022.0	219.0	(48.0)
Encore Acquisition Co.	272.9	130.5	31.2	(29.4)
Energy Partners Ltd.	97.8	108.6	2.3	3.7
EOG Resources Inc.	1,101.0	871.2	241.0	217.7
Equitable Production	105.1	88.0	60.3	38.8
Evolution Petroleum Corp.	0.9	1.0	(0.5)	(0.5)
ExxonMobil Corp.	116,854.0	87,223.0	10,890.0	9,280.0
Fidelity Exploration & Production Co.	169.6	118.6	50.6	30.6

two US refineries—compared to $35.7 million a year ago.

Chevron Corp.'s revenues were up 37% from first quarter 2007, and its net income climbed 9.6%. The company said while its first-quarter 2008 upstream earnings of $5.1 billion benefited from the increase in crude prices from a year ago, its US downstream results were essentially break-even at $252 million.

ExxonMobil Corp.'s first-quarter earnings set a record at $10.89 billion, up 17% from the first quarter of 2007. Revenues were $117 billion, up 34%. Lower refining and chemical margins and higher operating costs partly offset higher commodity realizations. Also, the company reported lower production volumes for the recent quarter, down 5.6% worldwide from a year earlier.

US independents

Anadarko Petroleum Corp. reported declines to first-quarter revenues and earnings from a year earlier. Although the company's oil, gas, and natural gas liquids sales were up, revenues from gathering, processing, and marketing were down from first quarter 2007. Anadarko recorded a $40 million loss on divestitures and other items for the recent quarter.

Apache Corp. doubled its earnings in the first 3 months of this year to $1 billion despite higher taxes, costs, and other expenses compared with first quarter 2007. Revenues climbed 59% to nearly $3.2 billion on 4% larger production volumes, which were driven by higher oil output in the US, the North Sea, and Egypt.

Oil and gas production gross revenues for Abraxas Petroleum Corp. were $21.86 million, while the company's rig revenues were $306,000 and its realized hedge loss was $883,000. But the San Antonio-based oil and gas producer also incurred a hedging loss of $26 million. This resulted in negative revenues for Abraxas for the quarter.

The company said this unrealized hedge loss was incurred by Abraxas Energy Partners LP, of which Abraxas Petroleum owns 47%.

Abraxas Petroleum said that on a stand-alone basis, it has zero debt and no hedges in place, which allows it "to fully participate in the run-up in commodity prices over the past several months."

Refiners

The US-based refiners in the sample of companies reported weaker results for the first 3 months of 2008. High crude costs, especially for light crudes, crushed refining margins.

While Frontier Oil Co., Holly Corp., and Valero Energy Corp. recorded net earnings for the quarter, Sunoco Inc. and Tesoro Corp. each posted a net loss for the period.

Sunoco's refining loss was larger than expected, said analyst Eitan Bernstein of Friedman, Billings, Ramsey & Co. Inc. "Operating losses of $123 million were larger than our expectation," Bernstein said. "Gross margins averaged $3.45/bbl, 50% below comparable year-ago levels, primarily due to rapidly rising sweet crude oil prices. More importantly, we estimate Sunoco's cash costs at a high $5.50/bbl, reflecting lower throughput volumes and higher fixed costs," the analyst said.

Valero's net income declined 77% to $261 million for the most recent quarter. Bernstein said the company's operating earnings of $517 million were above forecast, primarily due to higher-than-expected Gulf Coast margins.

Valero recorded relatively strong margins on the Gulf Coast at $9.51/bbl, partially offset by pronounced weakness in West Coast margins at $7.89/bbl and in the Northeast at $6/bbl.

Canadian operators

In a sample of firms based in Canada, eight of the 14 improved on first-quarter earnings from 2007, as the group's

US OIL AND GAS FIRMS' FIRST QUARTER 2008 REVENUES, EARNINGS (CONTINUED)

Table 1

	Revenues		Net income	
	1st quarter			
	2008	2007	2008	2007
	Million $ (US)			
FieldPoint Petroleum Corp.	1.5	0.9	0.4	0.1
Forest Oil Corp.	376.5	182.6	(4.7)	6.9
Frontier Oil Corp.	1,185.8	1,047.9	46.0	74.7
FX Energy Inc.	4.2	4.2	(4.3)	(2.6)
Gasco Energy Inc.	3.4	6.4	(4.4)	(0.2)
GeoResources Inc.	23.9	4.1	4.2	0.8
GMX Resources Inc.	13.3	27.2	3.8	6.5
Goodrich Petroleum Corp.	46.4	23.5	(23.9)	1.0
HKN Inc.	6.3	5.8	1.1	0.4
Helix Energy Solutions Group Inc.	450.7	396.1	75.2	56.8
Hess Corp.	10,720.0	7,374.0	759.0	370.0
Holly Corp.	1,483.5	928.4	8.6	67.5
Houston American Energy Corp.	2.9	1.0	0.9	(0.0)
Marathon Oil Corp.	18,100.0	13,002.0	731.0	717.0
McMoran Exploration Co.	295.5	51.7	36.4	(14.5)
Meridian Resource Corp.	38.5	40.6	3.6	1.7
Murphy Oil Corp.	6,532.7	3,434.9	409.0	110.6
New Century Energy Corp.	6.0	3.0	(0.6)	(2.2)
Newfield Exploration Co.	515.0	440.0	(64.0)	(96.0)
Noble Energy Inc.	1,025.0	743.0	215.0	212.0
Occidental Petroleum Corp.	6,074.0	4,611.0	1,846.0	1,212.0
Parallel Petroleum Corp.	44.0	23.2	(2.7)	(0.1)
Penn Virginia Corp.	249.1	186.3	3.9	4.4
Petrohawk Energy Corp.	214.9	209.2	(55.6)	(19.4)
PetroQuest Energy Inc.	76.8	64.0	15.4	10.8
Pioneer Natural Resources Co.	584.2	367.3	129.7	29.6
Plains Exploration & Production Co.	623.1	224.7	163.5	(20.6)
Questar Corp.	1,047.1	875.1	185.8	151.1
Quicksilver Resources Inc.	157.5	116.6	42.2	22.9
Range Resources Corp.	205.3	152.8	1.7	73.1
Southwestern Energy Co.	524.1	284.7	109.0	51.0
Stone Energy Corp.	208.1	173.9	62.2	10.5
Sunoco Inc.	12,813.0	9,305.0	(59.0)	175.0
Swift Energy Co.	199.0	130.1	48.4	27.6
Tesoro Corp.	6,531.0	3,876.0	(82.0)	116.0
Toreador Resources Corp.	14.0	6.8	(4.4)	(8.8)
TXCO Resources Inc.	32.4	11.2	4.3	(1.9)
Unit Corp.	321.4	277.3	77.1	64.5
Valero Energy Corp.	27,945.0	18,755.0	261.0	1,144.0
W&T Offshore Inc.	356.5	246.5	79.8	13.0
Warren Resources Inc.	23.9	10.3	9.5	1.5
Westside Energy Corp.	4.0	0.9	(2.1)	(2.5)
Whiting Petroleum Corp.	264.1	159.9	62.3	10.7
Williams Cos. Inc.	748.0	483.0	430.0	188.0
XTO Energy Inc.	1,673.0	1,169.0	465.0	383.0
Total	**358,866.0**	**264,248.6**	**29,545.4**	**26,341.4**

[1]Oil and gas operations. [2]Third quarter. [3]First quarter Jan. 31. [4]Second quarter.

CANADIAN OIL AND GAS FIRMS' FIRST QUARTER 2008 REVENUES, EARNINGS

Table 2

	Revenues		Net income	
	1st quarter		1st quarter	
	2008	2007	2008	2007
	Million $ (Can.)			
Bow Valley Energy Ltd.	37.9	4.1	(3.2)	(7.9)
Canadian Natural Resources Ltd.	3,518.0	2,742.0	727.0	269.0
Enbridge Inc.	3,967.8	3,358.2	253.0	228.7
EnCana Corp.	5,488.9	4,558.0	95.6	510.7
Gentry Resources Ltd.	29.3	15.7	360.0	154.0
Husky Energy Inc.	5,086.0	3,244.0	887.0	650.0
Imperial Oil Ltd.	7,263.0	5,934.0	681.0	774.0
Ivanhoe Energy Inc.	11.5	9.6	(8.7)	(6.7)
Nexen Inc.	2,092.0	1,388.0	630.0	121.0
Penn West Energy Trust	1,136.0	582.0	78.0	96.0
Petro-Canada	6,586.0	4,841.0	1,076.0	590.0
Suncor Energy Inc.	5,988.0	3,951.0	708.0	576.0
Talisman Energy Inc.	2,116.0	1,882.0	466.0	520.0
TransCanada Corp.	2,133.0	2,244.0	449.0	265.0
Total	**45,453.4**	**34,753.5**	**6,398.6**	**4,739.8**

SERVICE-SUPPLY COMPANIES' FIRST QUARTER 2008 REVENUES, EARNINGS

Table 3

	Revenues		Net income	
	1st quarter		1st quarter	
	2008	2007	2008	2007
	Million $ (US)			
Baker Hughes Inc.	2,670.4	2,472.8	395.0	374.7
BJ Services Co.*	1,283.2	1,186.6	127.3	188.9
Cameron International Corp.	1,339.3	997.1	126.3	101.0
Core Laboratories	179.4	155.7	29.3	25.3
Diamond Offshore Drilling Inc.	790.5	618.0	290.6	224.2
Foster Wheeler Ltd.	1,795.7	1,152.1	138.1	114.8
Global Industries Ltd.	301.5	93.5	26.8	54.5
Grey Wolf Inc.	204.0	245.2	31.3	58.6
Halliburton Co.	4,049.0	3,460.0	584.0	552.0
Helmerich & Payne Inc.*	474.9	373.6	102.1	106.9
Hornbeck Offshore Services Inc.	98.5	74.1	23.1	17.5
Nabors Industries Inc.	1,321.6	1,277.2	230.5	262.2
Noble Corp.	861.4	646.4	384.2	250.3
Oceaneering International Inc.	435.9	344.1	41.3	33.2
Parker Drilling Co.	173.6	153.1	23.9	30.0
Patterson-UTI Energy Inc.	504.9	547.5	77.4	115.8
Pride International	557.4	471.0	240.7	101.7
Rowan Cos. Inc.	488.7	467.7	98.6	86.4
RPC Inc.	197.2	171.0	14.8	28.0
Schlumberger Ltd.	6,289.9	5,464.4	1,338.3	1,180.8
Smith International Inc.	2,371.0	2,107.7	175.0	160.2
Superior Energy Services Inc.	441.4	362.9	102.1	64.0
Transocean Inc.	3,123.0	1,333.0	1,189.0	553.0
Weatherford International Inc.	2,195.9	1,852.3	264.2	281.6
Total	**32,148.3**	**26,027.0**	**6,053.9**	**4,965.6**

*Second quarter.

combined revenues grew 31%.

Nexen Inc. posted the largest earnings gain in the first quarter, as its first-quarter net income increased to a record $630 million (Can.) from $121 million (Can.) in the first quarter of last year. The climb was led by a 12% increase in production volumes before royalties as well as by higher commodity prices and high operating margins.

Although it recorded a 20% increase in first-quarter revenues, EnCana Corp. posted an 81% earnings decline to $95.6 million (Can.).

EnCana reported increased production volumes, but the Calgary-based company incurred higher operating and administrative costs compared with a year earlier, and its refining margins were weaker. EnCana said the primary reason its earnings declined, though, is that it incurred an after-tax unrealized mark-to-market loss on risk management activities of $737 million (US).

Service, supply firms

A group of 24 service and supply companies all reported positive net income for this year's first quarter, but nine of them posted an earnings decline from first quarter 2007. One of these is Global Industries Inc., which announced revenues of $301.5 million in the first quarter, up 9% from a year earlier. Net income was down 51% to $26.8 million.

A Houston-based offshore oil and gas services company, Global Industries said its net income in this year's first quarter was negatively impacted by low activity in the Gulf of Mexico due primarily to adverse weather conditions, nonrecovered vessel costs, and delayed mobilization of vessels in West Africa due to security and logistical issues. Earnings in first quarter 2007 included higher margin work from post-hurricane projects in the Gulf of Mexico and from Pemex projects in Latin America. Global Industries said during the first quarter, profitability was lower than what it could have been in the Gulf of Mexico, West Africa, and in its Asia-Pacific and Indian operations due to the unavailability of certain vessels undergoing drydocking activity. Nonrecovered vessel costs incurred during these regulatory drydockings were about $11.3 million, the company said. ✦

Indonesia leaves OPEC, unhappy with influential power

Eric Watkins
Senior Correspondent

The Indonesian government, reportedly registering a protest at high global oil prices, has decided to terminate its membership in the Organization of Petroleum Exporting Countries, effective yearend.

"We are pulling out of OPEC," said Energy Minister Purnomo Yusgiantoro. "If our production comes back again to a level that gives us the status of a net oil exporter, then I think we can go back to OPEC," he said.

The decision to leave OPEC was mooted earlier in May when President Susilo Bambang Yudhoyono said Indonesia was struggling to boost oil production to reach a level where "we deserve to be a member of the organization (OGJ Online, May 8, 2008)."

At the time, the president said Indonesia's oil production was "below 1 million b/d because of aging wells and that it needed about 2 or 3 years to increase production."

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Price hawks drive Indonesia away

Indonesia's decision to leave the Organization of Petroleum Exporting Countries is thought to have been a long time in coming, and due to its inability to cast much influence over the group (see story, p. 22).

Bill Farren-Price, director of energy at Medley Global Advisors, said it has been in the cards for some time that Indonesia is no longer playing a full part in the organization and that its loss underlines the growing powers of what he called "price hawks" within OPEC.

In fact, one might even argue that Indonesia has become a victim of the so-called price hawks in the organization.

How so? The price hawks within OPEC were said to be hard of hearing when it came to the pleas of the Indonesian government for increased output of oil to ensure lower world prices.

Expensive subsidies...

Lower prices are of growing concern to Jakarta due to its policy of subsidizing the difference between international oil prices and its own domestic market.

That subsidy was financed largely by Indonesia's own exports, as well as by relatively low domestic demand. And as long as those factors remained in place, the system probably would have worked well enough to keep everybody happy.

According to Johannes Simbolon, writing recently in the Jakarta Post, a rise in oil prices was always welcomed as good news in the past when the country's oil production was still high and its oil production exceeded demand.

"The sharp rise in oil prices in the wake of the Iranian revolution in 1979, for instance, brought a windfall profit for Indonesia and enabled the country to carry out a wide range of economic development programs throughout the 1980s," said Simbolon.

...As exports decline

But things have changed, and the biggest change lies in Indonesia's falling production of oil. In the 1990s, Indonesia's oil output was close to 1.7 million b/d, but will average just 927,000 b/d this year. That means exports are down, while imports are up.

The resulting financial squeeze played into Indonesia's decision to leave OPEC, with Energy Minister Purnomo Yusgiantoro saying, "There is also one rationale—that we are not happy with the high oil prices."

Former OPEC Sec.-Gen. Subroto, an Indonesian national, criticized Jakarta's decision, saying there was "no benefit" to Indonesia from leaving OPEC. "If we remain in OPEC there is some obligation from other members, if problems arise, to assist us."

But problems clearly have arisen and there has been no assistance from the price hawks. Indeed, one might almost say that the price hawks—demanding as they are—actually have forced Jakarta out of the nest.

Is there anything for Indonesia to fear? Probably not. Free of its OPEC quota, the Southeast Asian nation will be able to produce as much oil as it can and reap the benefits—even as it braves the vicissitudes—of the open market. ✦

While such remarks were widely circulated as the reason for Indonesia's departure, Yusgiantoro suggested that his country was unhappy with its inability to influence the organization.

Not much influence

Despite paying its annual €2 million membership fee, Indonesia has apparently not had much influence within the organization, but high-priced imported oil has had a decidedly adverse effect on the Indonesian government.

For much of the past year, the Indonesian government has been struggling to bridge the increasing gap in price between the international market and its heavily subsidized domestic market.

Last week, the government announced it would have to raise domestic prices by 28.7% for oil products such as gasoline, diesel, and kerosine due to its inability to maintain the subsidies for the domestic market.

Since then, the government has faced a restive population, with riots erupting throughout the country.

On May 27, at least two demonstrators were arrested after about 30 students hurled stones at police lines during a protest at a university in Makassar, South Sulawesi, Elshinta radio reported.

Elsewhere, on southern Sumatra Island, angry students tried unsuccessfully to break police barricades and storm the convoy of Vice-President Jusuf Kalla as he arrived at a meeting at Lampung.

Hundreds of students and fishermen set up a roadblock on a highway out of Surabaya, the country's second largest city, and hijacked a private fuel truck carrying kerosine.

In Jakarta, police and students were engaged in a standoff throughout the morning outside the Christian University of Indonesia, where protesters had earlier pelted police with firebombs.

On May 28, the government faced

further problems when the Organization of Land Transport Businessmen said it would call a nation-wide strike by its members if the government rejected its proposal to be allowed to continue buying fuel oil at the old subsidized price.

Decision criticized

Former OPEC Secretary General Subroto, an Indonesian national, criticized the government's decision, stating that there was no benefit to Indonesia from leaving the organization.

Victor Shum, an energy analyst with Purvin & Gertz Inc. in Singapore, however, saw no substantive downside for Indonesia's decision to leave OPEC, apart from a loss of prestige in no longer being a member.

OPEC itself declined to comment on Indonesia's departure, but a source at OPEC-member Kuwait's oil ministry downplayed the move.

"Production from Indonesia is not large and represents a small amount of OPEC's production," the source said. "OPEC will remain strong with its supplies to the world and would welcome any country with a reasonable production level to join." ✦

Aussie NWS condensate excise may herald tax breaks

Rick Wilkinson
OGJ Correspondent

The Australian government may use the $2.5 billion (Aus.) gained over the next 4 years from the imposition of excise taxes on North West Shelf condensate production to pay for a new round of assistance to get other struggling multibillion dollar gas project proposals off the ground (OGJ Online, May 14, 2008).

Commenting on the step in the federal budget to remove the NWS project's exemption from paying crude oil excise on condensate produced with the gas, Resources Minister Martin Ferguson said the exemption was granted 25 years ago in a bipartisan agreement to help establish the NWS project. However, today, at a time of record oil prices and rising LNG prices, the exemption can no longer be justified.

"Clearly this project is now mature, profitable, and no longer reliant on investment incentives for its ongoing health," he said.

"Meanwhile, new gas [proposals] such as Gorgon, Browse, and Sunrise are struggling to get off the ground, and it is therefore time to reassess and even up the playing field for investment."

The minister did not mention ExxonMobil Corp.-BHP Billiton's Scarborough field, but it is another proposal he puts in this 'struggling' category.

The government has announced plans for a wide-ranging review of resources taxation that will include a look at why the multibillion dollar gas ventures off northern and western Australia are finding it difficult to achieve development status. Gorgon, for instance, has been in the proposal stages for at least 15 years and Sunrise for 8 years.

The intimation is that Ferguson is keen to establish a policy framework for getting the next generation of LNG projects up and running and a policy encouraging development of projects such as gas-to-liquids.

NWS: 'Not a loophole'

Meanwhile the reaction from the NWS JV, led by Woodside Petroleum, is less than favorable

Woodside's Chief Executive Officer Don Voelte said the condensate exemption was not a loophole that was being closed, nor a free ride that was ending. He stressed that it was a negotiated fiscal arrangement that formed the basis of what has become Australia's largest resource development.

He said the original tax arrangements had underpinned more than $25 billion in investment in the NW Shelf project, providing billions of dollars in revenues to the Western Australian and federal governments over the past 2½ decades.

The treatment for condensate, he said, was part of a larger fiscal package to facilitate the development of the NWS in which participants agreed to pay both royalty and excise from first production, despite incurring large capital costs that would take years to recover.

These arrangements resulted in the government's gaining revenues from first production, many years before the project had recovered costs. This is in contrast to the current petroleum resource rent tax (PRRT) regime where tax is paid only after a project has recovered capital costs, Voelte said.

It is a quirk of history that since the NWS project was granted its exemption, the tax regime for other offshore developments such as Bass Strait has changed to the payment of a PRRT on production rather than a crude oil excise.

However, while it is true that the NWS partners were better off relative to PRRT, it is unclear whether they will remain in front under the excise regime now that the condensate exemption has been removed.

Despite the NWS group's complaint over the budget decision, perhaps the most valid criticism is that the government's decision was made without any consultation with the companies concerned or the industry in general through the Australian Petroleum Production & Exploration Association.

Such lack of consultation sends 'danger' signals to industry, they say, even if in this case the ultimate outcome may later prove beneficial. ✦

Deloitte: Call made for wider national energy debate

Nick Snow
Washington Editor

The national energy and environmental debate will need to widen notably if it intends to create necessary dramatic changes, said speakers at a leading energy conference May 19-20.

"We are at a crucial moment in energy and environmental reform. The fact that our national economy hasn't cratered with oil prices at $130/bbl is a tribute to its resilience. But we need to start addressing the actual issues," said Thomas F. McLarty III, the former chairman of Arkla Inc. and a federal official in several capacities during President Bill Clinton's administration.

"Sadly, the current energy debate is dominated by extremists on the right and the left. What's needed is more participation by those in the middle. Clearly, a bipartisan solution is needed although it won't please everyone if it's achieved," he said during an address to 2008 Deloitte Energy Conference participants.

That solution won't be achieved unless voters convince politicians that they won't accept simplistic answers, other speakers said. "First-time voters are talking about issues together instead of separately. They realize that you can't address the environment without discussing energy and the economy," said Joseph A. Stanislaw, who cofounded Cambridge Energy Research Associates in 1983 and now serves as an independent senior advisor on energy and resources for Deloitte LLP, the conference's sponsor.

Similarities, difference

Several aspects of the current situation, such as faith in new technologies and fear that the world is running out of oil, are similar to characteristics of the 1970s energy crises, Stanislaw told reporters. The major difference now is that worldwide demand has not started to decline in response to higher prices, although it has flattened domestically, he said. "Mutual distrust exists in the world now. We should be heading toward mutual interdependence. Working together on climate change may help us get there," he suggested.

He said that businesses should consider the efforts to address global climate change an opportunity instead of a threat. "The climate change and energy security issues are creating the economic opportunity of our lifetime. The investments of the next 2 decades will dwarf what was spent in the entire 20th century," Stanislaw said.

More than $200 trillion may need to be spent by 2030, suggested Reid Detchon, executive director for energy and climate change at the United Nations Foundation in Washington. The next US president plans to reduce US carbon emissions by 60-80%. "No matter who's elected, we're going to a push on cap and trade. It's not clear whether we're going to see it in 2009 or 2010 because of the next major international conference in Copenhagen," Detchon said.

Climate change decisions

Federal Energy Regulatory Commission Chairman Joseph T. Kelliher said "...we should recognize that dealing with climate change is not an environmental policy. It's an energy policy. The question is not whether but when decisions will be made. If they aren't well thought out, the economic consequences will be severe," he told conference participants.

Detchon said competition from India and China is also an economic opportunity "because they represent important new markets."

"There's a perception that industry is not working in the public interest. It may not be fair, but it's there. Heavy industry needs to do more. We're not capturing enough steam and using it to produce power that can be used internally or sold into the electrical grid," McLarty said.

General Electric Co. Vice-Chairman John G. Rice considers coal and nuclear power the best possibilities to meet growing electrical demand in the near term, although time may be running out for nuclear because 100 US reactors must be replaced by 2040. "It's critically important that we figure out how to burn coal in an environmentally responsible way. Coal gasification can help us do that, although there's still a question about its 25% premium over pulverized coal," Rice said. GE bought a coal gasification process several years ago from what was then Chevron Texaco Corp., and it has been working with Bechtel Corp. to design a standard plant, he said.

'Coherent and clear'

Over a longer period, alternative and renewable energy resources will need to play a growing role, Rice continued. "To that end, we are designing a boiler that can burn any kind of biofuel. The US will need to draw equally from government, business, and nongovernment organizations to create an energy and environmental policy that is coherent and clear," he said.

He noted that GE moved into wind power when it bought Enron Corp.'s operations after the Houston diversified energy company went into bankruptcy. The business has become profitable but probably wouldn't have been if European countries hadn't offered major subsidies during the 1990s, he continued. Solar power today is where wind power was 10 years ago, he said.

But government incentives will need to last longer than a year or two, according to Clint Stretch, managing principal for tax policy in Deloitte Tax LLP's Washington office. "We've gone through this nonsense of credits expiring. If you're a business executive, you'd be out of your mind to invest under

these circumstances," he said during the press briefing.

"The investment community is very plugged in to the uncertainty about how carbon will be regulated. Energy investment decisions far exceed politicians' views. They involve two or three election cycles at least," observed James A. Slutz, acting principal deputy assistant US energy secretary and director of the US Department of Energy's fossil energy office.

Stretch said budget gridlock has made federal tax policies fall behind, so politicians are responding by finding someone to blame. Record high crude oil prices have increased oil companies' profits, making them an easy and obvious target, but the Deloitte national tax specialist does not expect this "policy of shifting responsibility to work, because President [George W.] Bush will veto any tax increase in a minute." He also anticipates that the US Senate will cut the House's 6-year alternative and renewable energy tax incentives to 1 year.

Best opportunity now

Branko Terzik, energy and resources regulatory policy leader at Deloitte Services LP in McLean, Va., said a recent survey of public attitudes which the company commissioned found apprehension when coal entered alternative energy discussions. "Carbon sequestration is very far away. A utility can't call a manufacturer and order a system yet. That leaves energy efficiency as the best immediate opportunity," he told reporters at the press briefing.

Alternative and renewable energy research projects need tax credits to proceed, he continued. It also will take time for manufacturers and consumers to fully react to higher energy prices, he said. "People don't use energy. Their devices do. It will take time for more efficient models to come into the fleet, but it will happen. Automakers are beginning to react." Hyundai, for example, announced that it no longer plans to build a US plant to produce V8 trucks that it earlier had announced, Terzik said.

Addressing climate change and energy security together will accelerate instead of limit economic growth," Stanislaw said.

Gregory E. Aliff, vice-chairman for US energy and resources leader at Deloitte LLP, is anticipating "high prices, followed by higher prices, followed by an inevitable consumer backlash." Producers and regulators understand the situation, he said during the press briefing, but consumers "don't see the train coming at them regardless of the alternatives because none of the alternatives are free."

McLarty was more optimistic. "I think the people are ahead of the politicians. They're ready for clear, sensible policies and ready to move ahead," he maintained. ✦

WATCHING GOVERNMENT

Nick Snow, Washington Editor

The worst time for a bad image

It's not often that a message from a break-out session at a financial service company's energy conference is dramatically illustrated within a few days. But it happened the week of May 19.

The May 20 oil and gas break-out session during the 2008 Deloitte Energy Conference focused on the public's perception of the industry. It's not good, panelists quickly agreed.

"There's an urgent and ongoing need to educate people about the fundamentals of energy, whether members of Congress or the general public," suggested James A. Slutz, acting principal deputy assistant US energy secretary.

Just how urgent and ongoing became obvious when five major oil company executives testified before the US Senate Judiciary Committee on May 21 and the House Judiciary Committee's antitrust task force on May 22.

Several federal lawmakers said they simply wanted answers. "I hear most from my constituents that gasoline prices are too high. They're looking for explanations and so am I," said Rep. Betty S. Sutton (D-Ohio) during the House committee's hearing.

Looking for respect

Oil and gas industry leaders have been aware of the problem for some time, American Petroleum Institute President Red Cavaney pointed out. "We don't expect people to love the oil industry. We'd like them to respect it as a reliable energy supplier," he said.

Several oil company chief executives started individual public education efforts 10 years ago, he said during the Deloitte conference session. But the real wake-up call came after Hurricanes Katrina and Rita in 2005 when several were called before Congress and accused of manipulating supplies and markets, Cavaney said.

API and its members have been working hard to make sure they are part of the growing US discussions on energy and the environment ever since, he continued. "We have seen some very modest changes in the conversation, but we still have a lot of work to do," he said.

'Politically disenfranchised'

But Jim Cox, a senior vice-president and oil, gas, and chemicals specialist at Hill & Knowlton, said that a survey by that firm found that 87% of the respondents ranked the oil industry as the worst, and 86% said that they don't trust it to solve the nation's energy problems.

"There's an enormous amount of information the oil industry has that should be part of the national discussion, but it's politically disenfranchised. It has been a sporadic communicator. It has to engage motorists and environmentalists. It needs to own the issue and not tolerate having a bad reputation," he maintained.

Cavaney said that he and several other industry representatives recently visited an area where oil and gas is not one of the major businesses. Local residents and business leaders stayed for an hour beyond the meeting's scheduled time to ask questions, he said.

"The climate may be starting to slowly change. Voters are smarter than many politicians think," API's president observed. ✦

Campaign aides: Motor fuel transition may be starting

Nick Snow
Washington Editor

Record high crude oil and gasoline prices may be starting a transition to clean fuels from renewable and alternative resources, energy advisors from the three leading US presidential campaigns said.

"I believe we'll see a demand response to higher prices," said Elgie Holstein, an advisor to the campaign of US Sen. Barack Obama (D-Ill.). "That said, I also think commodity markets are responding to uncertain policies. So while we're not in an emergency situation, we are in a transition. There are several areas where we can start working," Holstein said. "Energy efficiency is the low hanging fruit."

Rebecca Jensen Tallent—emphasizing that it was her personal opinion and not that of her boss, US Sen. John McCain (R-Ariz.)—said Americans tend to make dramatic energy changes when their pocketbooks are hit hard. "We may be at a point where we're ready to move away from oil-based transportation fuels and conventional coal-fired power plants. We're at the brink," she said.

Dan Utech, who advises US Sen. Hillary R. Clinton's (D-NY) presidential campaign, said, "We're beginning to see a transition, but with a growing awareness of global warming. The question now is how quickly the federal government will begin to play a role. The states have had to take the lead up until now," he said.

The trio, who spoke at an energy forum at the Center for Strategic and International Studies in Washington, DC, said their candidates do not favor authorizing oil and gas leasing within the Arctic National Wildlife Refuge. The candidates' outlooks toward leasing more of the Outer Continental Shelf

ranged from Clinton and Obama's opposition (with Clinton saying more leasing may be appropriate in Gulf of Mexico areas where an immediately adjacent state wants it) to McCain's support for giving a coastal state authority to seek an end to federal leasing bans off its coast.

Environmental emphasis

While they agreed that the issues are closely related, the three presidential campaign advisors spoke more about the environment than about energy. Tallent said that she was taking care not to say much about energy because McCain plans to do "a fairly massive energy rollout" within the next few weeks. But she added that the Arizona Republican's stance on climate change has been stronger "than many other members of his party, including the current administration, to be frank."

McCain proposes returning US carbon emissions to 2005 levels by 2012 and to 1990 levels by 2020, she continued. "He believes that a cap-and-trade system must harness human ingenuity in pursuit of market-based alternatives to carbon-based fuels. He also believes that an effective climate policy must support rapid, sustained economic growth. This probably will be a key issue in the upcoming debates," Tallent said.

Clinton considers heavy US dependence on foreign oil and global climate change to be two of the biggest issues in the 2008 presidential campaign, according to Utech. She would back a repeal of tax breaks for major oil companies and support a basic cap-and-trade framework similar to Obama's and McCain's, he said. Her approach differs from the other two candidates by using complementary programs in other areas to achieve climate change goals, the advisor said. For example, she thinks a national Renewable Portfolio Standard (RPS) could keep carbon allowance trading from producing windfall profits for some companies, he indicated.

Obama's climate plan includes a cap-and-trade program with auctions, an 80% reduction in carbon emissions by 2050, a low-carbon fuel standard, a 25% RPS by 2005, a ban on new coal-fired power plants using traditional designs, support of verifiable international offsets and emissions reporting, an effort to reduce deforestation, and re-engagement with other countries in efforts to reduce global warming, Holstein said.

Oil import dependence

The Illinois Democrat also sees heavy US dependence on foreign oil producers, growing imports, and tightening global supplies as a major 2008 campaign issue, his advisor said. He said that Obama would propose an alliance of oil-importing nations, including China and India, to work together for reduced demand; treat oil dependence as a national security threat, and "involve the American people in the fight."

The advisors were vague on their candidates' stances toward congressional proposals to give the US Department of Justice authority to prosecute the Organization of Petroleum Exporting Countries for violating US antitrust laws. "Sen. Clinton believes OPEC is a cartel and we should use the tools we have to influence," Utech said.

Obama has not spoken out on this issue, Holstein indicated. "But I believe one pillar of the argument toward more aggressive action toward OPEC is its collusive behavior in setting production levels. This collusive, or should I say collaborative, behavior is in contrast to the traditional free market approach which America favors," he said. ✦

BLM: Most remaining federal onshore oil, gas off-limits

Nick Snow
Washington Editor

US onshore public lands contain an estimated 31 billion bbl of crude oil and 231 tcf of natural gas, reported the US Bureau of Land Management in its latest inventory.

It also found that 60% of the onshore federal acreage with oil and gas potential is closed to leasing, effectively making 62% of the oil and 41% of the gas inaccessible.

Another 30% of federal onshore oil and 49% of federal onshore gas may be developed subject to seasonal timing and other restrictions over and above standard lease terms, according to the inventory, which the Energy and Policy Conservation Act of 2000 requires.

In the 279 million acres that the inventory covered, 8% of the crude and 10% of the gas was accessible under standard lease terms, officials of BLM and the US Department of the Interior said. The land includes acreage managed by BLM and other DOI agencies, and by the US Forest Service, which is part of the US Department of Agriculture.

"The report itself does not make recommendations. However, a normal person could ask why 61% of available onshore oil resources are not available when prices are about $130/bbl. Our hope is not to give the solution but begin the discussion of what to do with our domestic resources," said assistant Interior secretary for land and resources C. Stephen Allred in a teleconference with reporters.

Remaining onshore natural gas on federal land is most heavily concentrated in southwestern Wyoming while the biggest concentrations of remaining onshore oil are along Alaska's North Slope, according to Richard Watson, a senior physical scientist at BLM who also participated in the teleconference.

Natural gas price

"While most of the public reaction

now has to do with gasoline and motor fuel prices, I have a great concern about what's happening to the price of natural gas. Its price has doubled in a very short period. If you look at its relationship to oil prices, you can see that the natural gas price has not appreciated to the level it might be. That has huge implications for the economy," Allred said.

He conceded that deciding to lease more federal acreage won't bring more oil or gas to the market immediately, but added that it could have a psychological impact. "A commitment for more domestic production may well have an impact on price beyond what it could contribute to supplies. We're not talking about ignoring environmental and other issues. What we are encouraging, and what I think this report allows us to start, is considering whether we are better able now than we were in the 1980s to protect important environmental values and still develop oil and gas," he said.

BLM issued similar reports in 2003 and 2006 as required by EPCA but expanded the inventory's scope to include conditions of approval, such as seasonal restrictions, under a requirement of the 2005 Energy Policy Act. Six study areas were added, and barriers to development were assessed for the first time, Watson said.

Allred said that while constraints on additional development may exist due to rig and oilfield supply capacity, he believes the oil and gas industry would be capable of producing more domestic energy. He also questioned concerns raised by Senate Energy and Natural Resources Committee Chairman Jeff Bingaman (D-NM) over whether lessees are moving quickly enough to develop their holdings. "Those leases are offered for a specific period. No one can sit on them. The question is whether they are worth developing. That's a matter for the leaseholder to decide. He pays the federal government rentals and bonuses whether he moves ahead or not. Our goal is to make sure the government and public get a fair return," Allred said.

He said that any discussion of whether to lease more acreage should reflect improvements in technology that would allow oil and gas to be produced with substantially fewer environmental impacts.

"I'm not being critical of what's been done in the past," Allred said. "Given what's happening to oil and gas prices, however, I think we need to look at the choices we've made and ask if they are still appropriate. This report can provide a basis for serious discussions," he said. ✦

Maari field FPSO completed at Jurong shipyard

Sembcorp Marine Inc.'s Jurong shipyard delivered the Raroa floating production, storage, and offloading (FPSO) vessel to Tanker Pacific Offshore Terminals Pte. Ltd. in early April 2008.

Tanker Pacific is leasing the Raroa FPSO to OMV New Zealand Ltd. for installation in Maari field, off New Zealand's South Taranaki coast (OGJ, Apr. 28, 2008, p. 30).

The shipyard converted the 92,802 dwt tanker MT Andaman Sea into the Raroa FPSO. The conversion included:

- *Installing an internal turret.*
- *Installing three boilers on deck to generate 24 Mw of power.*
- *Renewing the entire piping and electrical systems.*
- *Installing process facilities for crude separation, water injection, and chemical injection.*

The FPSO has a designed capacity to process 40,000 bo/d and to store 646,548 bbl of oil. Maari field, discovered in 1983, is in 100 m of water about 80 km from the South Taranaki coast.

OMV estimated that cost of developing the field would be about $360 million and that the field would recover about 50 million bbl of oil during its life of more than 10 years.

The FPSO will receive production from wells completed from a not-normally manned wellhead platform.

On the fixed platform, OMV plans to have initially five producing wells and three water injection wells. The platform also has slots for future additional wells.

The company expects the field to produce at 35,000 bo/d.

OMV is the operator and holds a 69% interest in the field. Its partners include Todd Petroleum Mining Co. Ltd. 16%, Horizon Oil International Ltd. 10%, and Cue Taranaki Pty. Ltd. 5%.

Hofmeister suggests means for US to control its energy destiny

Nick Snow
Washington Editor

Congress could take a decisive step to reduce energy prices by lifting some or all of the oil and gas exploration and production restrictions it has imposed, Shell Oil Co. Pres. John D. Hofmeister told a US House committee May 22.

"If the nation set a goal of increasing domestic production by 2-3 million b/d by opening up new sources for exploration and production, in addition to recent laws you have passed to increase the production of renewable

fuels and to increase miles per gallon in the vehicles that we drive, we could demonstrate to the world that we are in control of our own destiny," he said during a hearing of the House Judiciary Committee's competition policy and antitrust law task force.

Exxon Mobil Corp. Senior Vice-Pres. J. Stephen Simon, Chevron Corp. Vice-Chairman Peter J. Robertson, ConocoPhillips Co. Executive Vice-President John E. Lowe, and BP America Chairman and Pres. Robert A. Malone also testified. The five executives appeared before the Senate Judiciary Committee a day earlier (OGJ Online, May 22, 2008).

The other four echoed Hofmeister's call for increased access to domestic oil and gas resources. "This is the only government in the world that denies its citizens access to known domestic oil and gas reserves," Simon said. "There's plenty of evidence that the companies represented here are starved for access to more prospective acreage," Lowe observed.

Republicans on the committee generally agreed. Democrats did not. "I think there's something wrong when your prices, profits, and salaries keep increasing and all you can say is drill, drill, drill. I can't believe [record crude oil and gasoline prices are] all about supply and demand. You're inviting a windfall profits tax and antiprice-gouging legislation," said Rep. Steven Cohen (D-Tenn.).

'Exercise in futility'

Other committee Democrats were openly hostile. "This is an exercise in futility. I don't think we're going to get information out of these presenters," said Maxine Waters (Calif.) after asking several questions. When Simon said that Exxon Mobil's US refining income has fallen, Debbie Wasserman Schultz (Fla.) told him, "You can't refill your minivan for less than $70. That's the number that matters." One Republican tempered his sympathy. "I believe you have done a good job of explaining how crude oil costs drive gasoline prices and the law of supply and demand. But I also believe that executives' salaries and exorbitant retirement packages are your Achilles heel," said Ric Keller (Fla.).

He and other committee members asked why no new US refinery has been built in 27 years. Simon responded that the domestic petroleum industry has brought into service the equivalent of one new refinery annually for the past 10 years by increasing additional plants' capacities. Committee member Darrell E. Issa (R-Calif.) maintained that decades of government policies have kept any new domestic refineries from being built.

Sheila Jackson Lee (D-Tex.) began on a conciliatory note as she invited the witnesses to participate in a forum addressing a wide range of issues which she plans to hold in Houston. The five executives said that they, or someone

else from their companies, would be there. Then she asked them if they would support paying for a suspension of the federal gasoline tax through the summer from their companies' profits. They rejected that proposal on several grounds. "Reducing the price for a short period would increase demand, which is the opposite of what we want to do," said Lowe.

Jackson Lee urged them to try harder to develop solutions with congressional Democrats. "There's been a sense among you that the Republicans have the answers and the Democrats don't. This is a whole new Congress and you're not trying to talk to us," she maintained. ✦

Kempthorne says polar bear threatened, not endangered

Nick Snow
Washington Editor

The polar bear will be listed as a threatened species under the federal Endangered Species Act (ESA), announced US Interior Secretary Dirk A. Kempthorne on May 14.

He said his decision follows US Fish and Wildlife Service Director Dale A. Hall's recommendation and is based on the best available science, which shows that loss of sea ice, and not oil and gas development or native populations' subsistence activities, threatens and likely will continue to threaten polar bear habitat.

"Because polar bears are vulnerable to this loss of habitat, they are, in my judgment, likely to become endangered in the foreseeable future—in this case, 45 years," the secretary said during a press conference, which included Hall and US Geological Survey Director Mark Myers. He noted that polar bears already are protected under the Marine Mammal Protection Act, which has provisions that are more stringent than those in the ESA. "The oil and gas industry has been operating in the Arctic for decades in compliance with these stricter provisions. The Fish and Wildlife Service says no polar bears have been killed due to encounters with oil and gas operations," he said.

He also said listing the polar bear as threatened should not open the door to using the ESA to regulate greenhouse gas emissions from automobiles, power plants, or other sources. "That would be wholly inappropriate. The ESA is not the right tool to set US climate policy," he maintained.

Alaskan officials concerned

The announcement produced expressions of concern from Alaskan officials. US Sen. Ted Stevens (R-Alas.) said he was disappointed and disturbed because scientists have observed there now are three times as many polar bears in the Arctic as there were in the 1970s. "Never before has a species been listed as endangered or threatened while occupying its entire geographic range," he said.

He said DOI's action opens the door for many other Arctic species to be listed, which would hamper Alaska's ability to tap its natural resources. "Reinterpreting the ESA in this way is an unequivocal victory for extreme environmentalists who want to block all development in our state," he declared.

Canada, which has the world's largest polar bear population, has chosen not to list the animal as threatened or endangered but as a species of "special concern," according to US Sen. Lisa Murkowski (R-Alas.). She suggested that FWS and DOI erred in their decision because it is too soon to determine the impacts of the loss of sea ice on the present polar bear population.

"I am concerned that a threatened listing could have serious ramifications for Alaska and the development of all of our natural resources. I certainly don't believe a threatened listing should affect the construction of an Alaskan natural gas pipeline, or of any other oil and gas projects, since there is zero evidence that any such project has harmed bear populations in the least. Clearly we want to promote the use of clean-burning natural gas to reduce carbon emissions," Murkowski said.

Alaska Gov. Sarah Palin said that while the state was disappointed with the decision, it will assist FWS to ensure that polar bear populations remain viable for decades to come. She also said that she hopes federal actions do not threaten the North Slope's oil and gas industry, which she described as viable, productive, and environmentally responsible.

Congressional reactions

Kempthorne's decision displeased leaders of the US Senate Environmental and Public Works Committee, but for different reasons. Chairman Barbara Boxer (D-Calif.) said that while the listing was welcome news and long overdue, she was deeply concerned that the administration's plan will deny the polar bear some key protections under the ESA. "The plight of the polar bear is a stark reminder that the planet is already experiencing the ravages of global warming. Today's announcement underscores how important it is for the Senate to pass national legislation to cut global warming pollution and avert the dangerous effects of climate change," she said.

James M. Inhofe (R-Okla.), the committee's ranking minority, said that the decision apparently was based more on politics than science. He said that FWS estimates that there now are 20,000-25,000 polar bears, up substantially from levels of 5,000-10,000 during 1950-60. "Credit should be given to protection already provided the polar bear by the Marine Mammal Protection Act, the several international conservation treaties, including the 1973 Agreement on the Conservation of

Polar Bears and the US-Russia Polar Bear Conservation and Management Act of 2006, as well as conservation education and outreach agreements with native peoples," he suggested.

"The regulatory tools of the ESA function best when at-risk species are faced with local, tangible threats. Greenhouse gas emissions are not local. The implications of today's decision, therefore, will undoubtedly lead to a drastic increase in litigation and eager lawyers ready to use this listing to do exactly what they have intended to do all along: shut down energy production," Inhofe warned.

US Rep. Edward J. Markey (D-Mass.), who chairs the House Select Committee on Energy Independence and Global Warming, said the Bush administration finally acknowledged that the polar bear needs to be listed under the ESA after years of delay. "But the administration also has announced a rule aimed at allowing oil and gas drilling in the Arctic to continue unchecked even in the face of the polar bear's threatened extinction. Essentially, the administration is giving a gift to Big Oil and short shrift to the polar bear," he indicated.

Kempthorne's directives

Markey was referring to several specific actions Kempthorne also announced that are designed to assure that the ESA is not used to try and regulate global climate change. First, said the secretary, he ordered FWS to propose a 4(d) rule stating that an activity is permissible under the ESA if it is permissible under the Marine Mammal Protection Act's stricter standards.

Second, he told Hall to direct his staff that the best scientific information available cannot make a casual connection between harm to species or their habitats and greenhouse gas emissions from a specific facility, resource development project or government action. He also said that DOI will issue a solicitor's opinion clarifying these points.

"The ESA regulatory language needs to be clarified. We will propose common sense modifications to the existing regulations to provide greater certainty that this listing will not set back-door climate policy outside our normal system of political accountability," the secretary said.

He said that when he was in the US Senate, he worked with Sens. Harry M. Reid (D-Nev.), Max Baucus (D-Mont.), and the late John H. Chafee (R-RI) to reform the ESA. "I lived with the consequences of ESA decisions as governor of Idaho. As [Interior] secretary, I have now experienced the reality that the current ESA is among the most inflexible laws Congress has passed. It prevents me, as secretary, from taking into account economic conditions and adverse consequences in making listing decisions," Kempthorne said.

He said he met last week with his Canadian counterpart, Environment Minister John Baird, and that the two officials signed a memorandum of understanding to conserve and manage the two countries' polar bear populations. ✦

House Republicans reveal energy legislation package

Nick Snow
Washington Editor

US House Republicans announced a legislative package on May 22 to increase domestic oil and gas production, encourage construction of new oil refineries, and facilitate coal-to-liquids research and oil shale development.

Specifically, the package contains a bill to authorize federal oil and gas leasing within the Arctic National Wildlife Refuge, a measure to give the federal government authority to issue leases 100 miles offshore and coastal states the ability to petition for leasing between 50 and 100 miles offshore, and a bill that would streamline refinery permit processing.

Among the other bills, one would give the president authority to waive all or part of the 2007 expanded renewable fuels standard if he finds it is not technologically feasible or the fuel is not commercially available. Another would repeal Section 526 of the 2007 Energy Independence and Security Act, which effectively bans federal use of fuel from oil sands, oil shale, and coal-to-liquids.

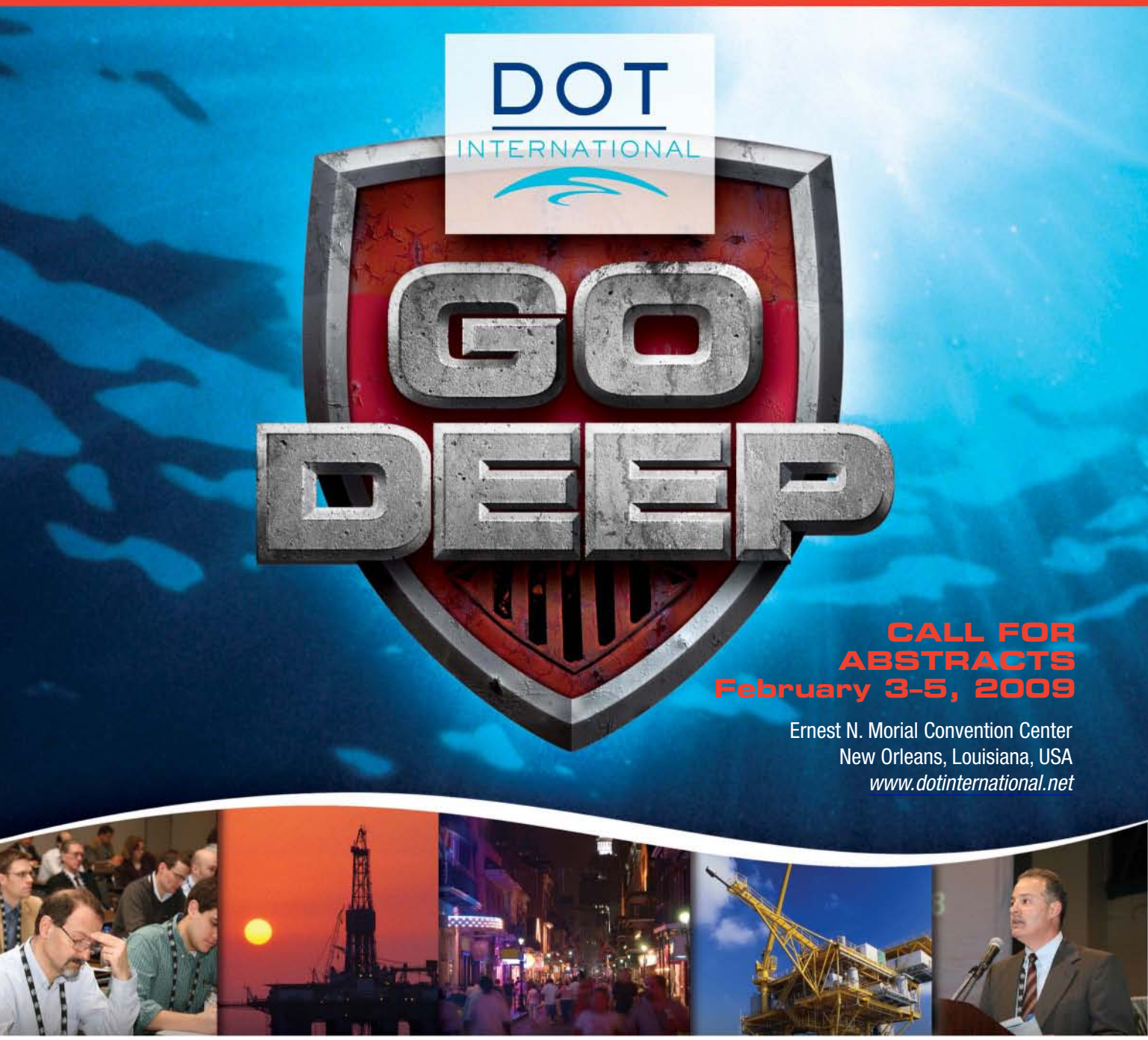
Other bills would extend renewable and alternative fuel tax credits, repeal the ethanol tariff, reduce the number of boutique fuels, begin nuclear fuel recycling, and provide nuclear science education and workforce opportunities.

"This is a package for American-made energy for American jobs and the American economy. These bills touch every portion of the energy sector, and whatever it takes to get them to the House floor, we're for because we want energy prices down," said Joe Barton (R-Tex.), the House Energy and Commerce Committee's ranking minority member.

'This is actual policy'

"I am personally tired of standing around, wringing my hands and watching each day's increase in a barrel of oil on the spot market and subsequent increase in the price of gasoline at the pump. This is actual policy, not more of the feel-goodism that the House has engaged in over the past 2 weeks," Barton continued. He also introduced his own bill addressing concerns over energy futures market speculation. The measure would require the Federal Trade Commission, in conjunction with the Energy Information Administration and the Federal Reserve, to study the effects of speculation in foreign and domestic futures markets and determine if there are any anticompetitive impacts. ✦

Deep Offshore Technology International Returns to New Orleans



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Anchors & Moorings
DP Station-Keeping
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H_2S Operations
Drilling with Casing or Liners
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Hostile Environments
Managed Pressure Drilling
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Slimhole Drilling
Surface BOP Operations
Through-Tubing Rotary Drilling
Underbalanced Drilling

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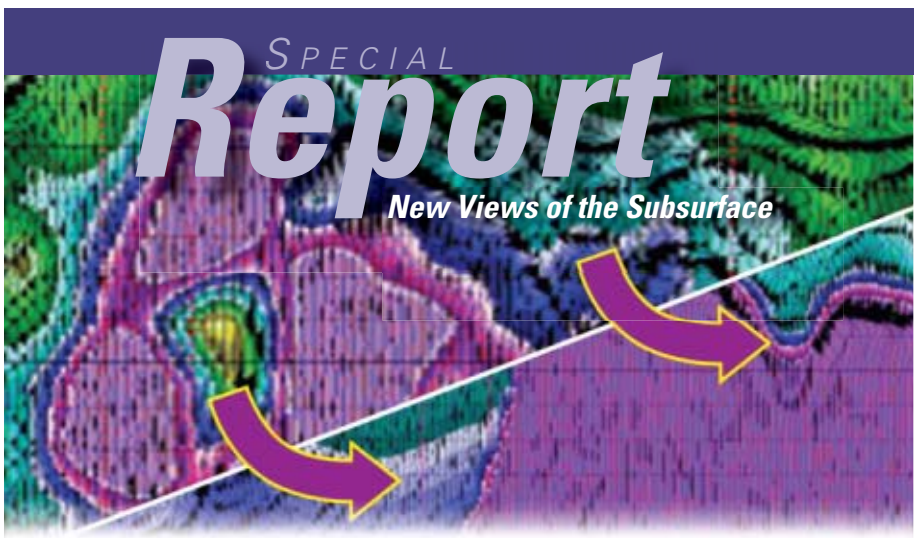
Multilateral Drilling
MWD / LWD
Rotary Steerable System
BOPs & Well Control Equipment
Casing Running
Drilling Automation
Instrumentation

Integrating surface seismic velocity into subsurface interpretation in the gulf



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This is the first of a two part article on greater use of seismic velocity in subsurface interpretation in the Gulf of Mexico.

The critical role played by accurate seismic velocity measurements in imaging is well documented. Optimal summing of prestack time migrated (PSTM) data depends on accurate seismic velocity measurements, and the PSTM image quality is degraded when suboptimal velocity measurements are used in stacking the data.

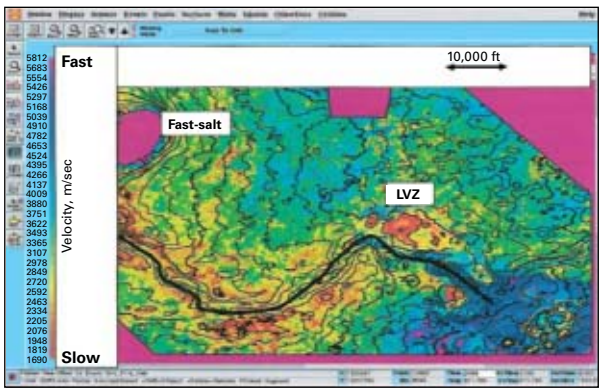
Seismic interval velocity models are needed for prestack depth migration (PSDM), and substandard velocity models yield substandard depth images. In both processing strategies, flat offset gathers are used to gauge the validity of the velocity used.

Seismic velocities are also used to generate pore pressure and stress volumes for well planning and subsurface interpretation. Accurate PSTM velocity measurements and PSDM models, calibrated to wells, are critical to success in these areas.

Examples of costly well failures traced to incorrect velocity measurements can be found in the literature,

DIX SEISMIC INTERVAL VELOCITY SLICE

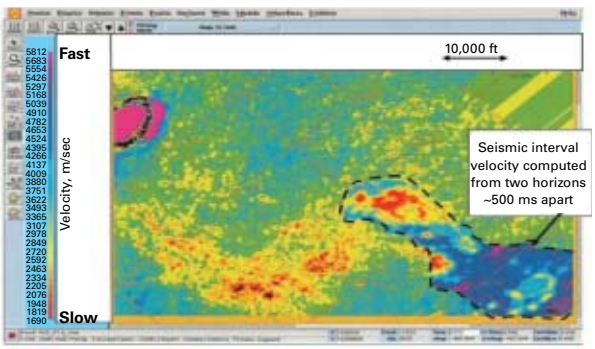
Fig. 1



Outliers and short wavelength velocity variations were removed while preserving geologic information. Depth contours calculated using vertical depth conversion of the time map are overlain on the interval velocity slice. The seismic migration velocity is used as the average velocity in the depth computation.

SMOOTHED DIX SEISMIC INTERVAL VELOCITY SLICE

Fig. 2



The effect of smoothing is illustrated by superimposing the interval velocity slice of Fig. 1 with the seismic interval velocity computed over a coarser time interval (500 ms) outlined by the dashed polygon. In essence, we compare the interval velocity computed at 100 ms sampled intervals with a coarser, average interval velocity computed between two horizons that bracket the slice. The channel pattern is preserved. The smoothing produces less resolution while reducing noise.

though they are not numerous. Preventable, costly failures caused by errors in velocity are preferably forgotten, rather than documented.

In this article we discuss the use of seismic velocity trends in subsurface interpretation. Specifically, we discuss measuring accurate velocity trends for lithology prediction and examine time and depth velocity trends near hydrocarbon accumulations. We use data examples to illustrate the effects of sampling and smoothing of subsurface velocity information in preserving valid trends. Finally, we illustrate the impact of oversmoothing of the velocity trends on the interpretation of subsurface depth structures.

Time migration seismic velocities discussed in this article are measured using the standard semblance method. These velocities are the maximum coherency seismic velocities from which interval velocities are computed using the well known Dix formulation.[1]

Our semblance measurements are sampled densely, 300 ft by 300 ft by 100 milliseconds, unless otherwise noted. Depth models are generated from interval velocities obtained from travel time tomography measurements; however, these velocities are more coarsely sampled and smoothed than the PSTM seismic velocities.

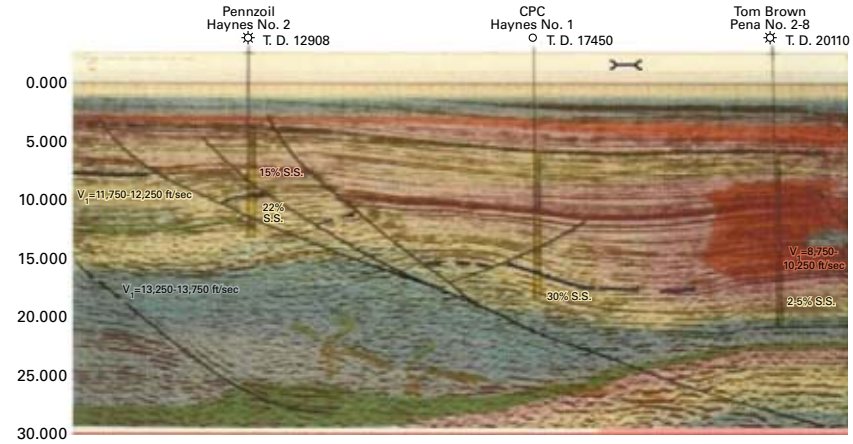
Revealing lithology

In the following examples from the deepwater Gulf of Mexico, the data are processed through standard time migration templates, but processing velocities were chosen from tightly sampled semblance measurements made with an auto volume picker. In many standard templates, semblances are often sampled coarsely and then smoothed, resulting in a loss of valid information and resolution. Consequently, the information illustrated in the following examples is often unavailable to the interpreter.

It is important to note that the choice of sampling interval dictates subsurface sampling and is in itself a smoothing process.

Onshore Wilcox delta system

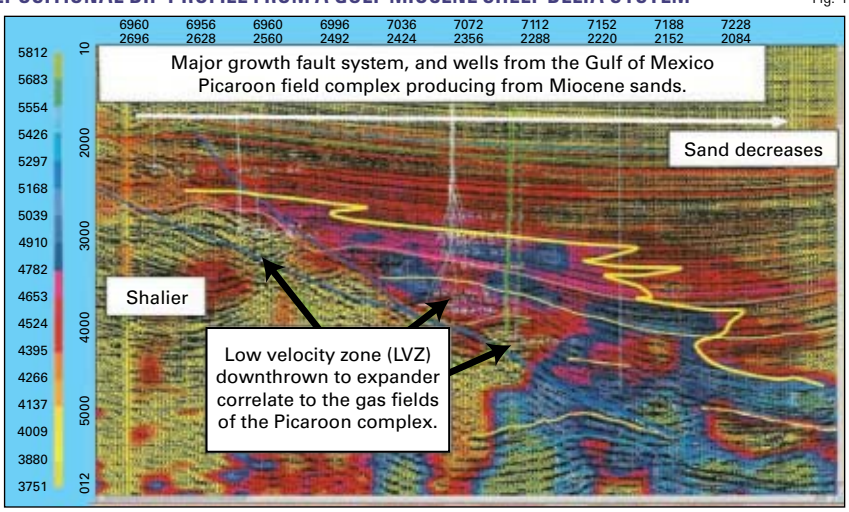
Fig. 3



Dix seismic interval velocity (orange stack) is overlain on the 2D time data. Pressured shales replace sand packages downdip from source as validated by the penetrations indicated. High pressure shales indicated by very low seismic interval velocity.

Depositional dip profile from a Gulf Miocene shelf delta system

Fig. 4



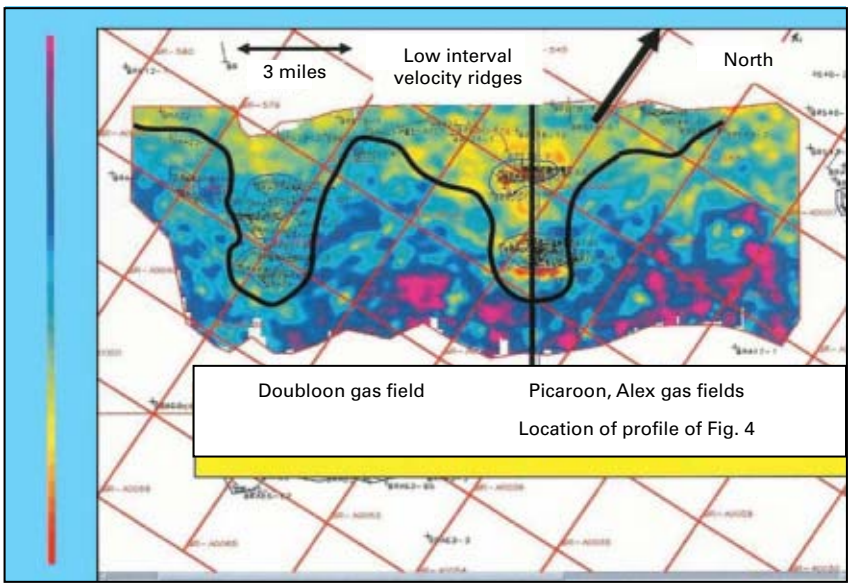
The Dix interval velocity is shown in color; darker colors correspond to a sandier section. The yellow outline is an interpretation of the downdip extent of the sand packages; the white arrow indicates direction away from the sand source and loss of reservoir targets, which has been confirmed by well control. Note the local low velocity zones downthrown to the expander, which correlate to the Picaroon gas field complex. The deep low velocity zone feature on the lower right of the figure has not been tested. The lighter, yellow colors upthrown to the expander have been penetrated by a few wells that failed to find reservoir sands.

Direct detection

Velocity measurements may be mapped and the mapped features correlated directly to lithologic features. As in any mapping, the degree of confidence in the features and associated correlation will depend on the density of the mapped data set. The first example is a channel feature about 3,000 ft below the mud line. The channel is easily recognized using seismic interval velocities (Figs. 1 and 2).

Fig. 1 shows an interval velocity slice calculated from high density maximum coherency seismic velocities displayed in color; the darker colors represent faster velocities. Depth contours generated from vertical depth conversion using a time map of the channel and the PSTM seismic velocities are superimposed on the interval velocity slice.

DIX SEISMIC VELOCITY EXTRACTED USING MAJOR EXPANDER FAULT PLANE AS GUIDE Fig. 5



Two low-velocity ridges are apparent from this map. The slower interval velocity (reddish color) is associated with the prolific Picaroon-Alex gas fields. The ridge to the left, though not as slow, corresponds to the Doubloon gas field complex.

The fast feature in the upper left corresponds to a salt body. Also note the low velocity zone (labeled LVZ) that pulls up the time contours when converted to depth.

Fig. 2 illustrates the effect produced by smoothing a portion of the interval velocity slice outlined by the dashed polygon. The objective of smoothing is to reduce noise while preserving resolution.

Interpretation with time profiles

We begin with a 2D data example from the Wilcox delta system in onshore Texas.

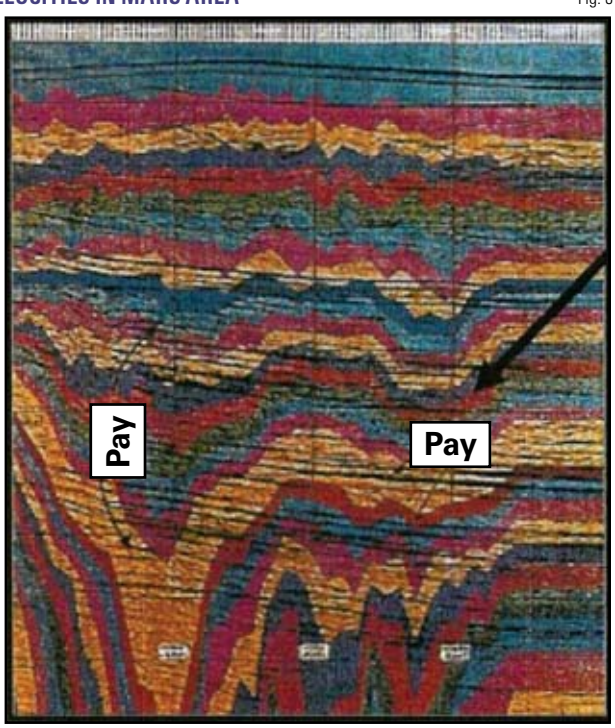
We use the Dix interval velocity trend to interpret lithology changes in a time profile (see Fig. 3). Seismic velocities from semblances were analyzed by an interpreter at 2,000-ft intervals. Faster velocity packages, indicated by the yellowish color, are found closer to the growth fault and are correlated with sand deposits, as opposed to slower background shales. The faster sands are replaced by low velocity, high pressure shales away from the fault. Wells confirmed the correlation of faster seismic interval velocity sand packages decreasing away from the source.

The next example from the Miocene delta trend in the shelf area of the US Gulf of Mexico further illustrates the above concept: seismic interval velocities can be used to detect the extent of sands. Fig. 4 is a dip profile from a 3D data set showing the Miocene growth fault, with the colored interval velocity overlaid. The faster velocity regions, correlated with sand pulses, die out away from the sand source (upthrown to the growth fault). Note the low velocity zones downthrown to the major expander, associated with the prolific Picaroon gas field complex.

The interpreted seismic velocity measurements were made using a high density, 300 ft by 300 ft by 100 ms grid, on prestack time migrated data. Outliers were removed after the Dix interval velocity was computed, and a 2,500-ft box filter was used to smooth the interval velocity. This processing preserves the trends, i.e., fast velocity "sand pulses" diminishing away from the delta source. Note the similarity between the Miocene delta interpretation of Fig. 4 with that of the onshore Wilcox system of Fig. 3 (2D data with velocities sampled every 2,000 ft, and validated by well control along the deposition direction).

To further elucidate the concept, the Dix interval velocity was extracted adjacent to the expander fault plane and is displayed in map view in Fig. 5. Note the yellow colored low velocity zones penetrated by wells. The hydrocarbon bearing zones line up along low velocity ridges that correlate to the fields shown in the illustration. The ridge to the left is associated with the Doubloon gas fields (not shown in profile), while the slower ridge to the right

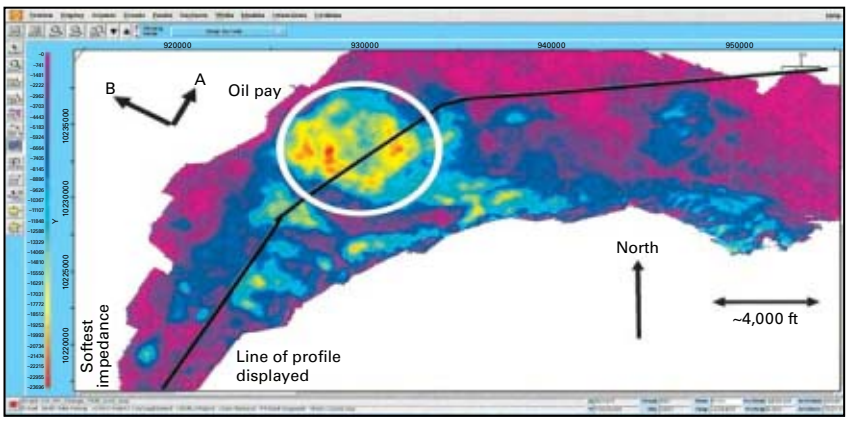
VELOCITIES IN MARS AREA Fig. 6



The focus of present discussion is the low-velocity zone and pay to the right of the picture. The color overlay is of maximum coherency seismic velocities from a 3D survey measured by interpreter on a 1,000-ft by 1,000-ft areal grid and varying time sampling.

SEISMIC AMPLITUDE EXTRACTION ALONG PRODUCING RESERVOIR SAND

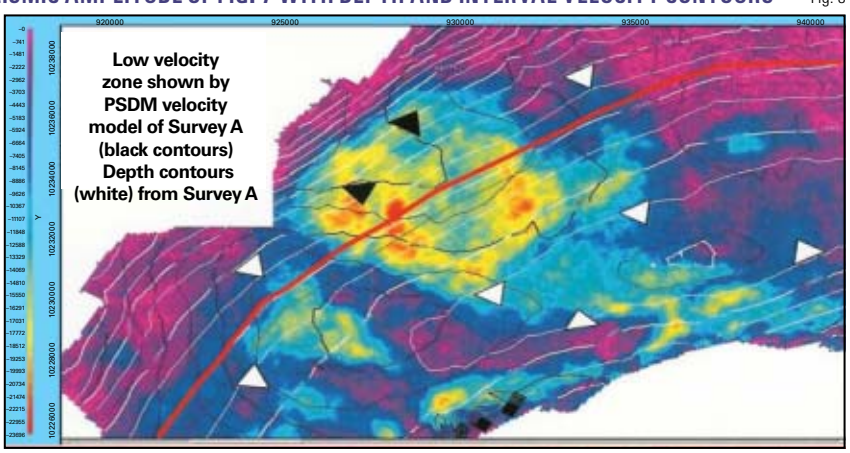
Fig. 7



Two penetrations in the light-colored central region encountered good quality oil-bearing sands. 3D survey acquisition directions are indicated by arrows A and B. Seismic amplitude response from PSTM and PSDM surveys are similar over the target, which lies about 12,000 ft below the mud line.

SEISMIC AMPLITUDE OF FIG. 7 WITH DEPTH AND INTERVAL VELOCITY CONTOURS

Fig. 8



Note the excellent fit between the interval velocity slow (black contours) and the high reflectivity area associated with the oil pay in the field. The red line shows the location of the 3D profile used to compare seismic velocities in time and depth.

is associated with the Picaroon fields of the profile illustrated in Fig. 4. For reference, the profile of Fig. 4 is highlighted on the map of Fig. 5.

From Fig. 5, a correlation between seismic interval velocity "slow zones" and hydrocarbon pays can be made. This correlation will be further examined in the next section where we compare time and depth velocity trends in a deepwater Gulf of Mexico oil field.

Velocity trends compared

The previous section demonstrated the use of seismic velocity trends for direct detection of lithologic information or extraction of lithologic information by integration of velocity data and prestack time migrated data. In this section we compare PSTM and PSDM velocity trends. Generally, PSDM velocities are smoother and sampled on a coarser grid than the 300 ft by 300 ft by 100 ms grid typically used for our PSTM measurements.

The area of investigation is a deepwater field in the Gulf of Mexico; a salt rimmed minibasin with calibration provided by well control in oil bearing Pliocene-Miocene age sands. Our discussion focuses on seismic velocity measurements in the sedimentary portion of the basin, although the approach may be extended under "well-behaved" salt. Two substantially orthogonal 8,000-m cable 3D surveys were acquired over the field and are the source of the data. It is important to note that the surveys were processed in time and depth and that the velocity trends for each survey were derived independently of one another. The surveys will be labeled A and B, and acquisition directions are indicated in the map display of Fig. 7.

Fig. 6 shows a profile through the field with a color overlay of the maximum coherency prestack time migration velocities. Note the low velocity zone to the right of the figure which is the focus of our discussion. The low velocity zone to the left correlates to multiple pay horizons in the field, and has been previously discussed in this journal.[2]

Fig. 7 shows the seismic amplitude extraction along the target horizon which encountered 100 ft of oil pay tested by two wells. The seismic profiles that will be analyzed follow a depth contour highlighted in the figure. The amplitude extraction is from survey A.

Fig. 8 zooms in on the amplitude map of Fig. 7 with PSDM depth contours (in white) from survey A superimposed. Note that the depth contours and the seismic amplitude strength outline do not correlate, interpreted as a strong stratigraphic component to the accumulation. Also superimposed on the amplitude map are the seismic interval velocity contours (in black) used to depth migrate survey A. Note the excellent fit between the low velocity seismic interval velocity contours and the high reflectivity pay zone.

We next examine the low velocity trends over the pay area using time and depth profiles from both surveys. The profile chosen follows a depth contour so the horizon is nearly flat in the depth images. The corresponding seismic interval velocity, PSTM or PSDM, will be overlaid on the respective profiles from both surveys. The absolute scale values for these figures

differ; however, our focus is the velocity trend near the pay horizon.

The PSDM profile from survey A is shown on Fig. 9 with the PSDM interval velocities overlaid in color. The comparable PSTM profile from survey A is shown in Fig. 10, with the PSTM Dix interval velocity in color. Both time and depth velocities indicate a low seismic interval velocity zone near the pay. The PSTM Dix interval velocities are more densely sampled and have little smoothing and hence are noisier than the PSDM velocities, but the low velocity zone is still present in these hands-off semblance based measurements.

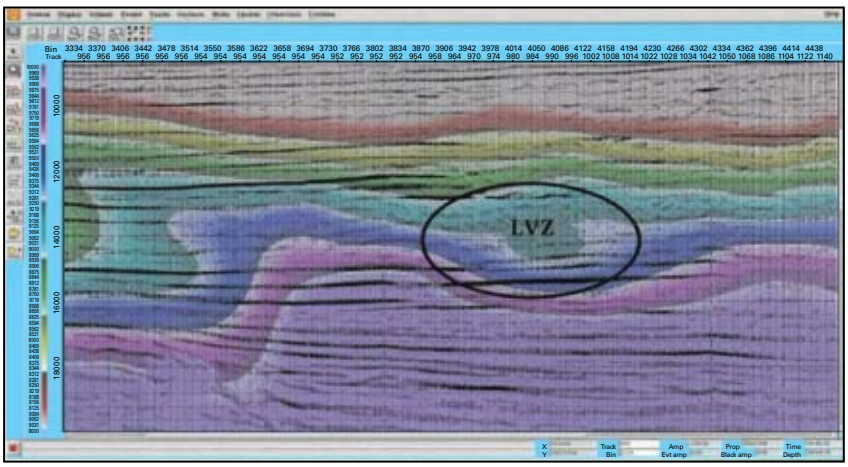
The low velocity zone that accompanies the strong amplitude response of the producing reservoir is highlighted with the ellipse; the PSDM interval velocity cuts across the white depth contours of Fig. 8. The low velocity zone on the left is associated with other field pays and is not the subject of the present discussion. The interval velocity trend has not been discarded by undersampling and oversmoothing when building the depth migration velocity model of survey A.

Fig. 10 is the same profile extracted from the 3D PSTM volume of survey A; high density, semblance based, seismic velocity measurements were used to compute the Dix interval velocity, shown in color. The PSTM velocity measurements have little smoothing, and the noise is apparent. The low velocity trend is preserved in the time-based processing, serving as quality control for the PSDM velocity model. The presence of very different trends between the time and depth processes serves as a powerful diagnostic. The PSTM and PSDM trends are related; if valid PSTM velocity trends are not preserved in the depth model because of improper sampling or oversmoothing, the depth model will result in poor image quality or invalid pore pressure prediction, if the latter is based on the overly smoothed depth velocity model.

Figs. 11 and 12 show comparable PSTM and PSDM profiles taken from survey B. Note that for survey B, the

PSDM PROFILE FROM SURVEY A WITH PSDM VELOCITY MODEL OVERLAID

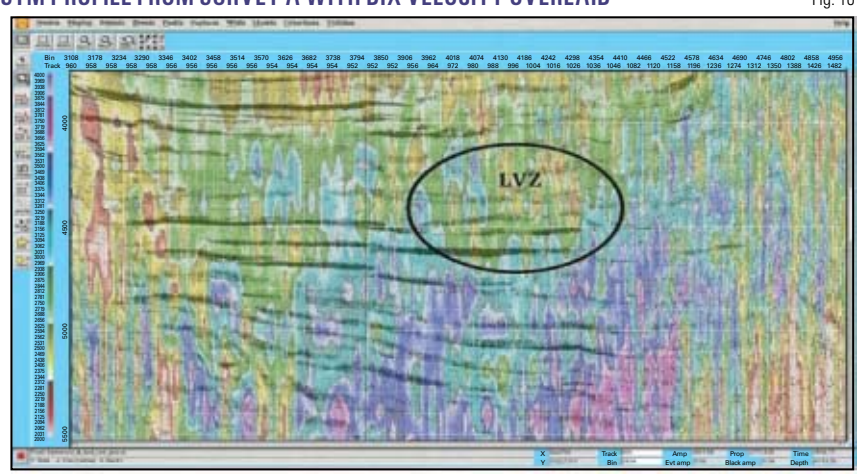
Fig. 9



Darker colors correspond to faster interval velocities.

PSTM PROFILE FROM SURVEY A WITH DIX VELOCITY OVERLAID

Fig. 10



Darker colors correspond to faster velocities.

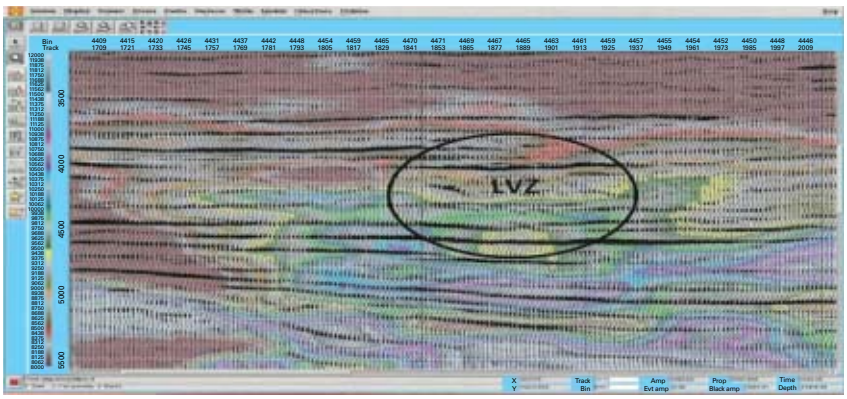
PSTM seismic interval velocity trends, derived from densely sampled semblances, retain the low velocity zone in the high amplitude area of pay (Fig. 11). However, the low velocity region is not present in the PSDM velocity model used in survey B (Fig. 12). A comparison of Figs. 9 and 12 indicates that the smoothed velocities used in survey B's PSDM also produces a poorer, less crisp depth image of the producing horizon from that obtained from survey A.

The gridded PSTM maximum coherency seismic velocity measurements from both surveys were compared near the level of the pay horizon. Although not displayed, this difference is about 50 m/sec between surveys A and B in the sedimentary basin; larger variations are reflected by measurements in and around salt. However, the difference is nearly uniform over the area of interest; the PSTM seismic velocity trends are similar and the low velocity zone near the pay is recorded by both surveys.

This example demonstrates the need to carefully consider the sampling and smoothing operators used in constructing the PSDM velocity model. The failure to preserve the low velocity zone in survey B's PSDM velocity model is attributed to undersampling or over-

PSTM PROFILE FROM SURVEY B NEARLY ORTHOGONAL TO SURVEY A

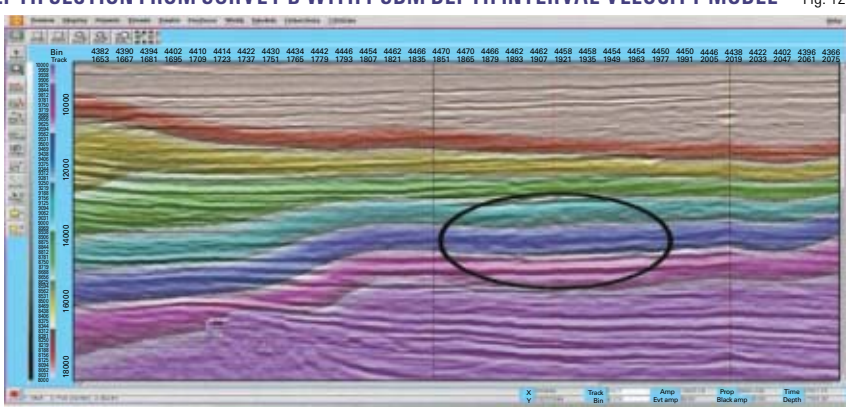
Fig. 11



The low velocity zone associated with the time and depth profiles of Survey B is present in these independently determined measurements. The interval velocities have been smoothed with interpreter input; the smoothing filter is approximately 3,000 ft by 3,000 ft near the zone of interest.

DEPTH SECTION FROM SURVEY B WITH PSDM DEPTH INTERVAL VELOCITY MODEL

Fig. 12



The depth model of Survey B effectively discards the low velocity response over the pay horizon due to coarse sampling and excessive smoothing. This depth velocity model is not useful to the velocity interpreter. Important "details" have been left out of the model and image quality deteriorates because of the incorrect velocity model.

smoothing, and such errors adversely impact subsurface interpretation. Although the depth contours are not significantly affected in this case, the omission of the low velocity zone near the pay horizon can be a detail important to the interpreter attempting to integrate seismic velocities into evaluation of the subsurface.

The example also demonstrates the possible use of seismic time-migrated velocity measurements for quality control by the geophysical processor and subsurface interpreter prior to implementing the more resource intensive depth migration process. The quality of semblance measurements depends on data conditioning; we would have obtained better results if the processing workflow had been optimized to make the best semblance measurements. Comparison of the unbiased time migration measurements between orthogonal surveys was a goal secondary to our PSDM effort; we routinely skip the time processing and associated velocity measurements as a matter of expediency.

Next week: Smoothing of seismic velocity trends. ✦

DeSoto drilling for Southwestern Energy

Nina M. Rach
Drilling Editor

Houston-based Southwestern Energy Production Co. is drilling a four-state portfolio after forming its own drilling company and building a new fleet of rigs.

Southwestern is an integrated energy company primarily focused on exploration and production of natural gas in the US. It's engaged in natural gas and crude oil exploration and production in the Arkoma basin, East Texas, Permian basin, and the onshore Gulf Coast. The company also has natural gas distribution activities in northern Arkansas and midstream activities.

DeSoto Drilling

In 2005, Southwestern Energy formed DeSoto Drilling Inc., located primarily in Conway, Ark., to conduct some of its drilling operations in the area. By late 2006, the new company took possession of 15 new, purpose-built land rigs, said Alan Stubblefield, senior vice-president at Southwestern, who oversees DeSoto Drilling. The fleet drills exclusively for Southwestern, Stubblefield told OGJ (Fig. 1).

DeSoto Drilling operates two NOV IDEAL 1500 rigs working in East Texas and 13 rigs working in the Fayetteville shale:

- Ten, Cowan MD-500 super singles.
- One NOV Rapid Rig (automated single).
- Two Atlas Copco RD 20 truck-mounted rigs.

East Texas

In 2007, Southwestern had reserves of 353 bcf equivalent (24% of total proved reserves) and production of 29.9 bcfe (26% of total production).

The company currently focuses its drilling on the James lime reservoir in the Angelina River trend area. As of Mar. 31, 2008, it was operating four producing wells that had gross initial production rates of 5.0 to 14.4 MMcfd.

Southwestern's net production from the James lime is about 12 MMcfd as of Mar. 31, including production from five outside-operated wells.

The company plans a multiyear development drilling program in East Texas that it categorizes as "low-risk." In 2008, it plans to invest about $152 million in East Texas, where it expects to drill about 55 wells, including 21 net wells in the Angelina River trend area.

Pennsylvania

In 2008, Southwestern expects to invest $26 million in various exploration and new ventures projects, including drilling as many as three vertical wells targeting the Marcellus shale in Pennsylvania.

The Marcellus shale lies in western Pennsylvania and West Virginia. Other operators in the play include Rex Energy, Denver-based Energy Corp. of America, and XTO (OGJ Online, Apr. 29, 2008, May 2, 2008).

Arkoma basin

Southwestern Energy has a large land position in the Arkoma basin with 491,791 net acres. Its conventional operations in the Arkoma basin provide low-risk drilling opportunities and a stable production and reserve base.

The company's strategy is to continue development drilling and workover programs to expand its production and reserve base.

In 2007, Southwestern had reserves of 304 bcf of gas (21% of total proved reserves) and produced 23.8 bcf of gas (21% of total production).

Southwestern plans to invest about $132 million to drill 100-110 wells in

This crane was supporting a coiled tubing injector and wellhead in a Fayetteville shale drilling operation for Southwestern Energy in 2007 (Fig. 1; photo from Southwestern Energy).

DeSoto Drilling Inc. has 10 Cowan MD-500 super single rigs drilling the Fayetteville shale for Southwestern Energy. This rig was drilling in 2007 (Fig. 2, photo from Southwestern Energy Co.).

DeSoto Rig 31 drills top holes in the Fayetteville shale for Southwestern Energy (Fig. 3; photo from Atlas Copco Drilling Solutions LLC).

2008, including 40 wells in the Ranger anticline area and 45 wells at the Midway area in Arkansas.

Fayetteville shale

Southwestern Energy is the most active operator in the Arkansas Fayetteville shale and it plans to invest about $1.2 billion in the play in Arkansas in 2008 (OGJ, Jan. 21, 2008, p. 35).

As of May 8, Southwestern held about 850,000 net acres in the Fayetteville shale area, including 125,400 net acres held by conventional production in the traditional Fairway portion of the Arkoma basin.

Through Mar. 31, Southwestern has drilled and completed 533 operated wells in the play, of which 470 are horizontal. Of those horizontal wells, 426 wells were stimulated with hydraulic fracturing with slickwater and some crosslinked gel stimulation treatments.

Southwestern said that microseismic data from multistage hydraulic fracs in the Fayetteville shale can "help demonstrate the productivity along the length of a horizontal lateral as long as the data show a consistent pattern that the stimulations treated the entire lateral length" (OGJ, Apr. 14, 2008, p. 19).

Fayetteville wells

Southwestern has drilled and completed 142 wells with lateral lengths of more than 3,000 ft through Mar. 31, 2008.

During this first quarter, Southwestern's typical horizontal well had an average completed well cost of $2.9 million/well, an average horizontal lateral length of 3,285 ft, and average time to drill to total depth of 15 days from reentry to reentry.[1]

As the company continues to drill wells with longer laterals in some of its pilot areas, the number of drilling days and well costs may increase, Southwestern says.

Southwestern forecasts that the average gross ultimate recovery from wells with horizontal laterals greater than 3,000 ft will range from 2.0 to 2.5 bcf/well with an average completed well cost of about $3.0 million/well.

Fayetteville drilling

Among the DeSoto fleet, 13 of 15 rigs are engaged in the Fayetteville shale project (Fig. 2). In a recent, four-part series on unconventional gas, Southwestern's customized fleet was noted as one of several examples of operators pursuing efficiencies in unconventional gas development in the US (OGJ, Oct. 1, 2007, p. 46).

The Arkansas fleet includes two truck-mounted, highly mobile Atlas Copco RD20 rigs (Fig. 3). Roger West, rig manager for Rig 31 with about 20 years' experience in the oil patch, said, "Our operation is typical of what DeSoto is doing in Arkansas. We use the Atlas Copco RD20 to start the hole, and

we'll bring in a larger rig to drill deeper and horizontally."

West said he can run the RD20 with a three-man crew; the work isn't physically demanding because all the systems are hydraulic—"the hoists and winches do the work for you." The RD20 can pull 120,000 lb.

With an experienced crew, West has the RD20 drilling within 2 hr of arrival at a new location. They drill for 3½ days and then spend 4-6 hr to cap the well and tear down the rig. Then they move on to one of more than 100 site pads in the area waiting for a DeSoto rig.

"Drilling can get tough" in the sands, he said, especially when they hit a "ratty" formation.

Fayetteville production

In 2007, Southwestern's Fayetteville reserves were 716 bcf of natural gas (49% of total proved reserves) and produced 53.5 bcf of gas (47% of total production) the same year.

As of mid-April 2008, the company's gross operated production rate from the Fayetteville shale play was about 400 MMcfd, including about 11 MMcfd from 12 wells producing from conventional reservoirs. This is a fourfold increase from gross production of about 100 MMcfd at yearend 2006.

Under an assumption that half the acreage is developed at 80-acre spacing and produces 1.4 bcf/well, the play has a potential for 11 tcf of gross ultimate gas recovery, according to Southwestern (OGJ, Nov. 19, 2007, p. 47). ✦

Reference

1. www.swn.com/operations/fayetteville.shale.asp; May 5, 2008.

New NMR approach evaluates tight gas sand reservoirs

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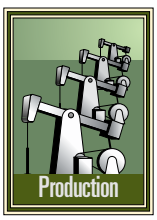


A new approach for evaluating neutron magnetic resonance (NMR) logs can determine permeability in tight gas reservoirs. The bulk gas-magnetic resonance permeability (BGMRK) has the same value in oil-based (OBM) and water-based (WBM) muds because it depends on gas reentry to the flushed zone after a mud cake is formed and mud invasion stops.

Analysis of tight gas sand reservoirs is difficult. Many tight formations are complex, producing from multiple layers with different permeabilities that natural fractures often enhance. Well-logging techniques, such as NMR as standalone logs or in combination with conventional openhole logs, provide new interpretation methods for obtaining the representative reservoir characterizations.

NMR logs

NMR logs differ from conventional neutron, density, sonic, and resistivity logs because the NMR measurements provide mainly lithology independent detailed porosity and are a good hydrocarbon potential indicator. NMR logs also can determine formation permeability and capillary pressure.

Evaluators have used these NMR applications in a gas sand reservoir with different facies and permeability variations from less than 0.1 md to more than 100 md. Evaluation techniques include:

- Combining NMR and bulk density data to reduce uncertainty in porosity.
- BGMRK approach that provides a simple facies independent model to calculate permeability.

Gas-condensate reservoir

The example that shows the use of the BGMRK approach is for a gas-condensate field producing from a Lower-Mesozoic reservoir. The reservoir is a tight heterogeneous gas shaly sand reservoir. It suffers from lateral and vertical heterogeneity due to diagenesis effect (kaolinite and illite) and variations in grain size distribution.

The petrophysical analysis indicates a narrow 8-12% porosity range while permeability ranges from 0.01 to 100 md.

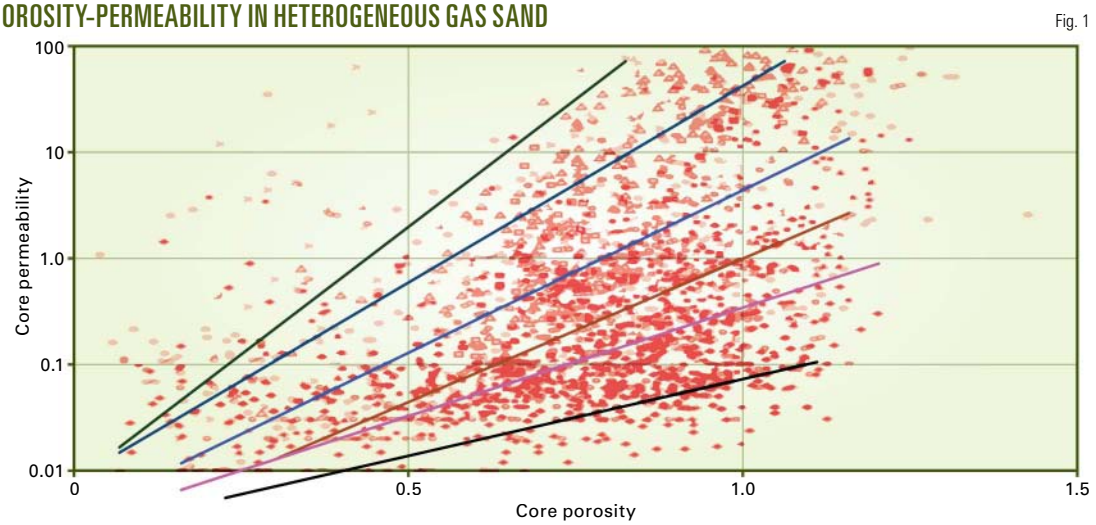
Fig. 1 shows core porosity-permeability cross plot of the entire reservoir section including all facies in different wells. The core data indicate a cloud of points with an undefined trend, so that it is subdivided into six subunits.

In heterogeneous reservoirs, facies may change every few meters or a few centimetres. The average fluid density in this case becomes unsatisfactory; therefore, the evaluation requires a new porosity-determination technique independent on facies change.

Due to reservoir heterogeneity, the field has many

POROSITY-PERMEABILITY IN HETEROGENEOUS GAS SAND

Fig. 1



cores in different wells covering different reservoir units to create the proper porosity-density and permeability model. The uncertainty associated with identifying the proper porosity and permeability model for each unit is high, which could result in high-permeability estimation.

Integration on nonstandard tools such as the NMR with conventional tools and SCAL is essential to reduce the uncertainty beyond the limits of each tool, especially in gas reservoirs.

The aim is to establish facies independent porosity and permeability models and avoid use of the lithology-independent T2 cut-off.

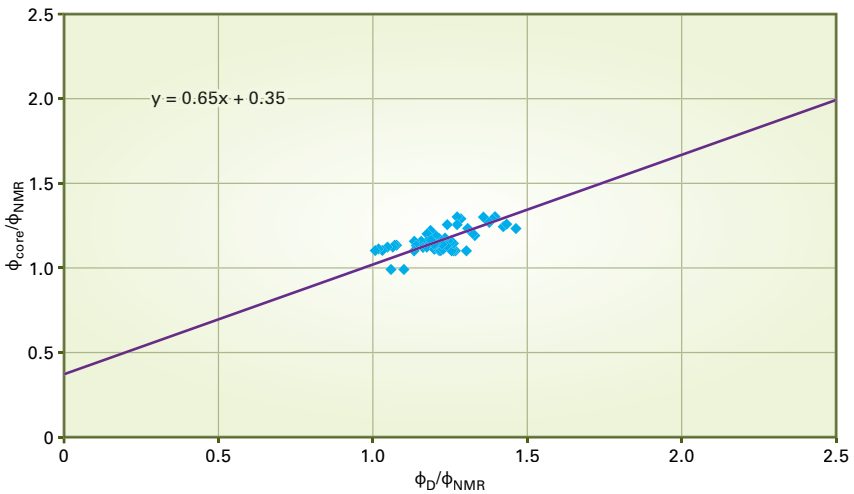
The advantage of an NMR tool is that it is sensitive only to hydrogen and fluid protons and no borehole correction is needed whenever the radius of investigation is beyond calliper measurements.[1-3]

The evaluation includes:

- Application of the density magnetic resonance porosity (ϕ_{DMR}) technique for calculating porosity.
- Bulk gas magnetic resonance permeability (KBGMR), for calculating permeability beyond the oil-based mud filtrate invasion.

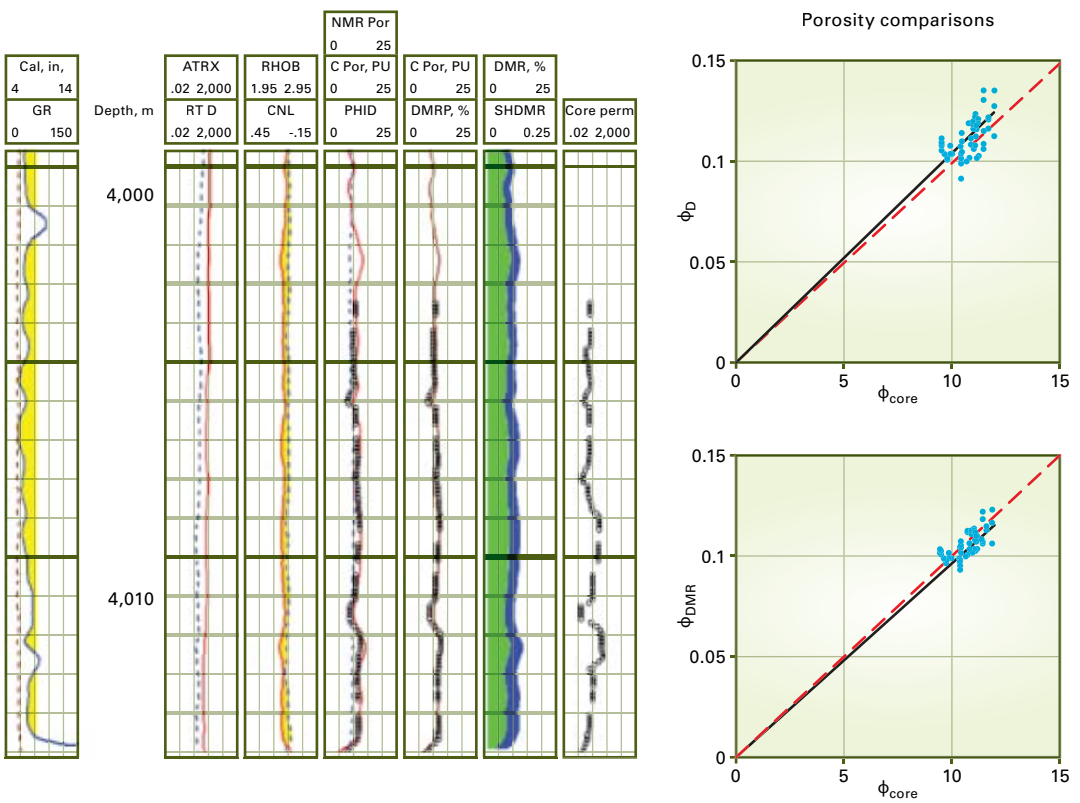
Porosity curve fit

Fig. 2



Well A correlations

Fig. 3



ϕ_{DMR}

Traditional evaluations rely on porosity logs, mainly density and neutron. Porosity logs measurements require environmental corrections and are influenced by lithology and formation fluids. The porosity derived is the total porosity, which consists of producible fluids, capillary bound water, and clay-bound water. NMR, however, provides lithology-independent porosity and includes only producible fluids and capillary-bound water.

In heterogeneous reservoirs with mixed or unknown lithology, NMR is accurate for porosity determination.[4,5]

Freedman et al.[6] proposed a combination of density porosity and NMR porosity (ϕ_{DMR}) to determine gas-corrected formation porosity and flushed-zone water saturation (S_{xo}).

WELL B CORRELATIONS

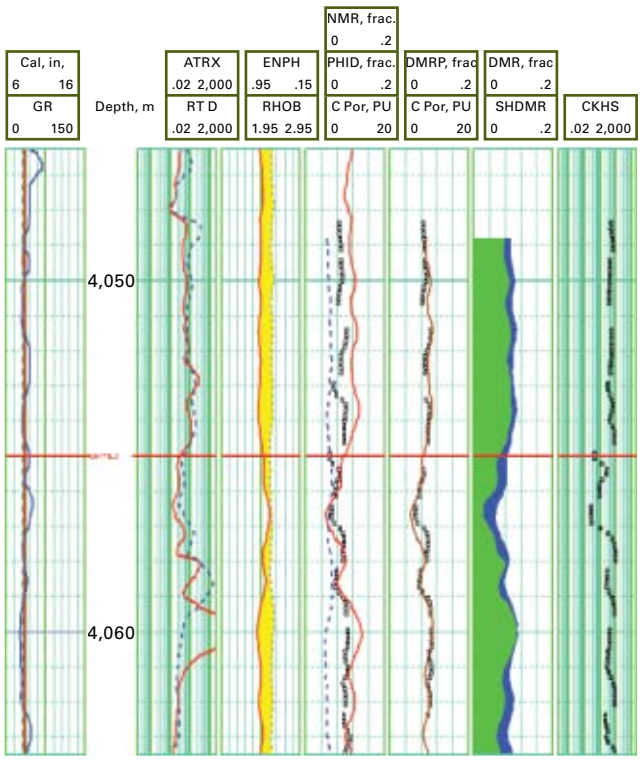
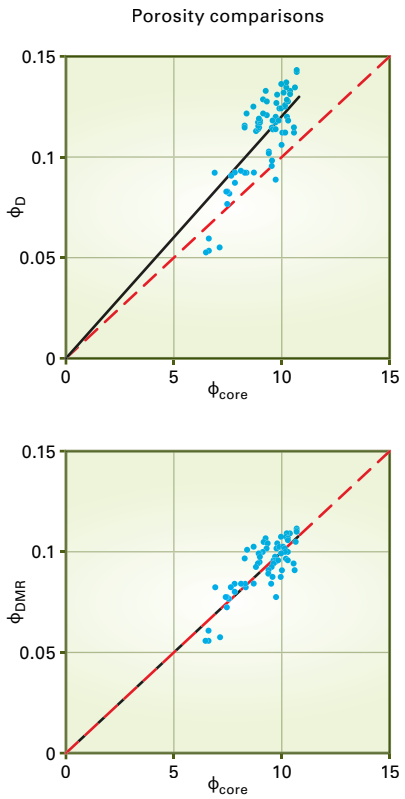


Fig. 4



WELL C CORRELATIONS

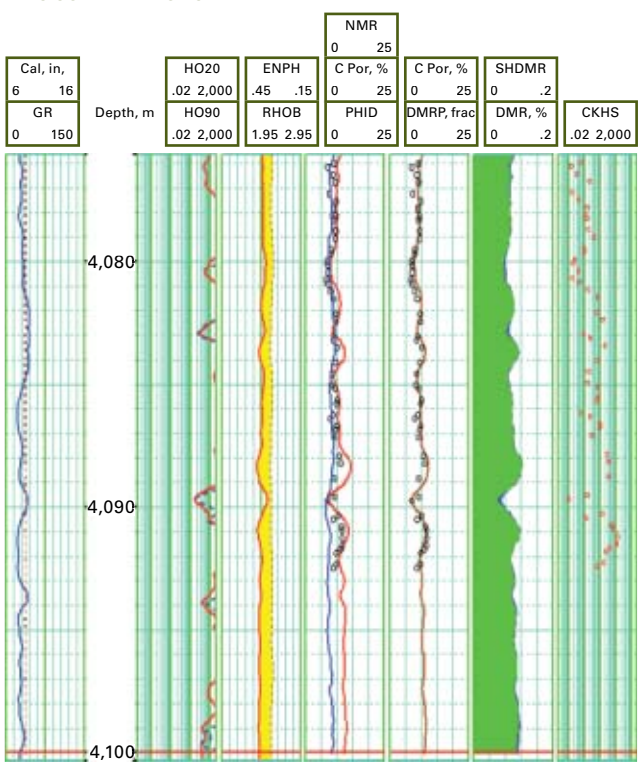
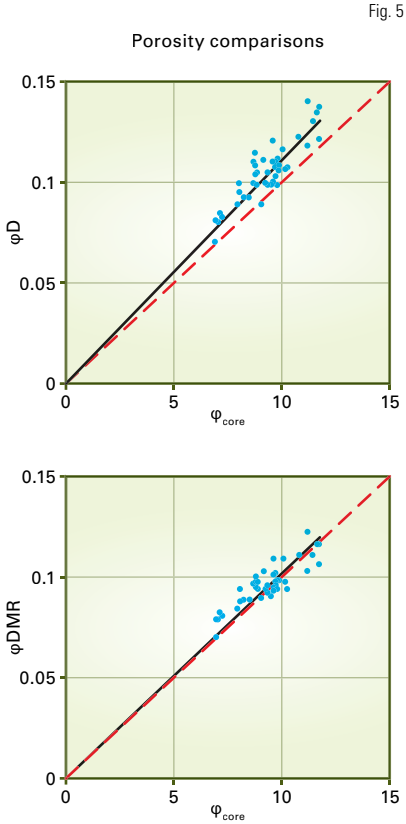


Fig. 5



The density-NMR cross plot is superior to the density-neutron cross plot for detection and evaluation of gas shaly sands. This superiority is due to the effect of thermal neutron absorbers in shaly sands on neutron porosities that cause too high neutron porosity readings. As a result, neutron-density logs can miss gas zones in shaly sands.[7] On the other hand, NMR porosities are unaffected by shale or rock mineralogy and therefore the density-NMR (DMR) technique is more reliable for indicating and evaluating gas shaly sands.

The equation box shows the derivation for the NMR porosity, ϕ_{DMR}. It is assumed that both density and NMR tools read within the same gas flushed zone.

Calibrating ϕ_{DMR}

A curve-fitting method was used to calibrate the A and B constant values that are applied to the reservoir. In the example, Well A was selected in which both core

and NMR data were available over the same reservoir interval. If we assume core porosities equal ϕ_{DMR}, which is the gas corrected porosity, Equation 5 can be written as Equation 6.

The equation is linear with an intercept at B and the slope equal to A (Fig. 2).

Note that at $S_{gxo} = 0$, the pores are completely filled with liquid (mud filtrate and irreducible water) so that the NMR porosity reading and density-porosity should be correct and both should equal the core porosity. As a result, the trend line should intersect at a control point, where

$$\phi_{core}/\phi_{NMR} = \phi_D/\phi_{NMR} = 1$$

Fluid density for apparent a ϕD estimate is best fit at 0.9 g/cc, which is a combination between formation-water density and mud-filtrate density (OBM). The fitted trend line has a slope of A = 0.65 and intercepts the Y axis at B = 0.35, which results in DMR porosity transform as follows:

$$\phi_{DMR} = 0.65\phi_D + 0.35\phi_{NMR}$$

ϕ_{DMR} results

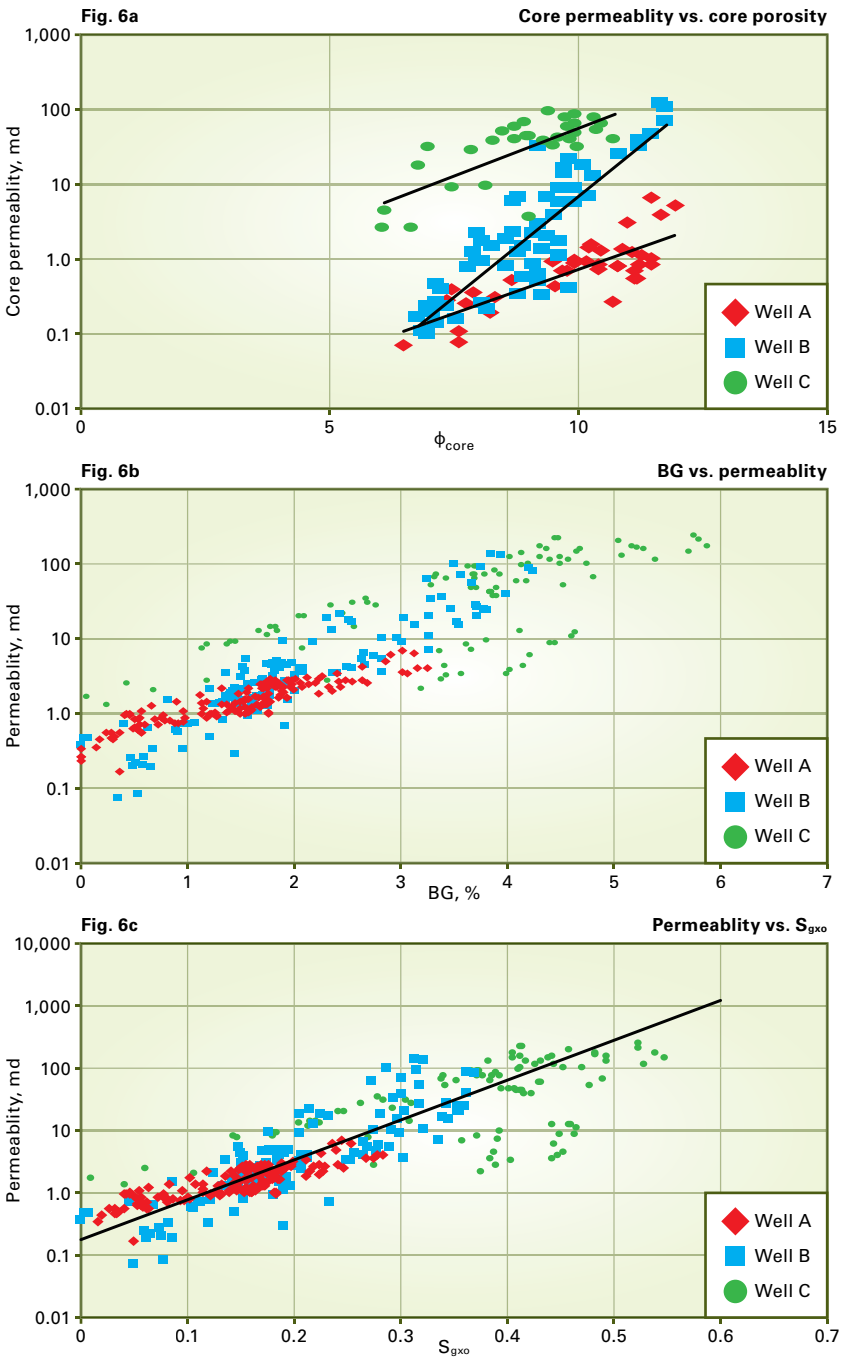
Figs. 3-5 show that the results of the ϕ_{DMR} transform applications in three wells (A, B and C) have good matches between ϕ_{DMR} and core porosities. As a result, it is considered as an independent facies porosity model. These corrected porosities can be used in conjunction with Timur-Coates equation to estimate accurate permeabilities in gas bearing formations.

Figs. 3-5 well logs show ϕ_D and ϕ_{DMR}. Gamma ray and caliper curves are in the first track (GR and CALI). The second track shows depth in meters and the third is resistivity. The fourth track has the neutron-density logs, the fifth track compares core, density, and ϕ_{DMR}, the sixth track compares ϕ_{DMR} and core porosity, the seventh track shows gas saturations (green shadow) and water (blue shadow), and the last track shows core permeability in md.

The DMR method has the advantage of avoiding the use of fluid density and gas hydrogen index (HI) at reservoir conditions for the gas correction. Another advantage is that the logging speeds can be higher because full polarization for gas is not needed.

PERMEABLITY CORRELATIONS

Fig. 6

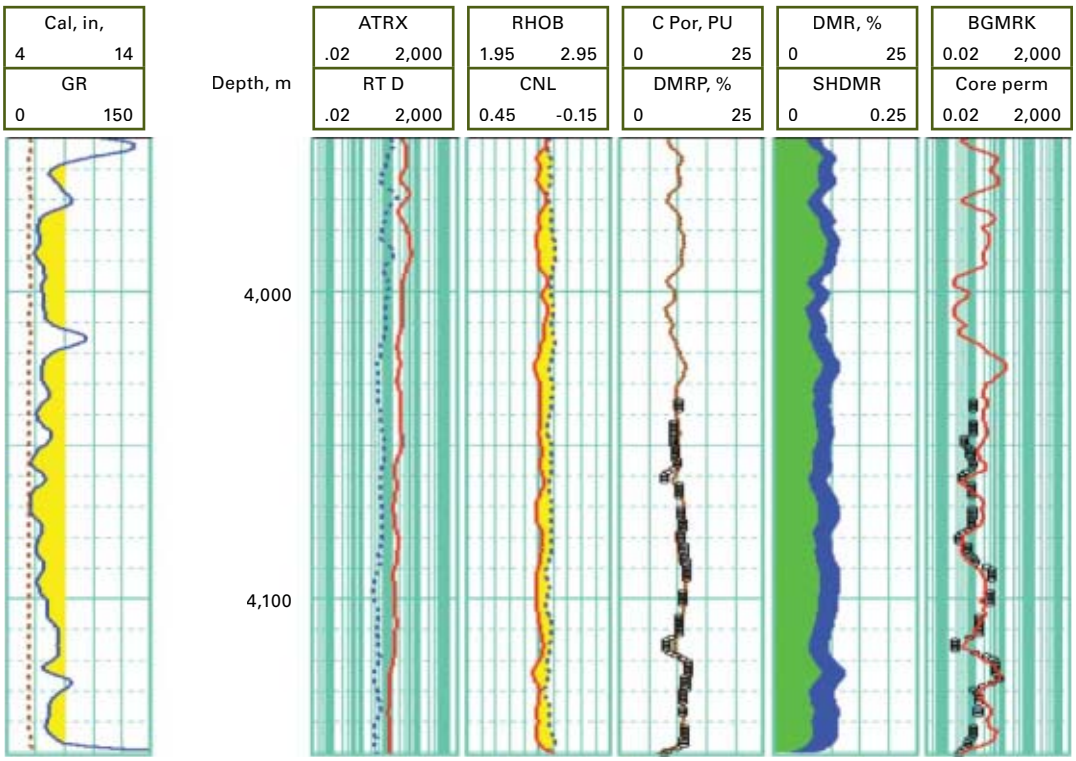


K_{BGMR}

Permeability derives from empirical relationship between NMR porosity and mean values of T2 relaxation times. The industry uses two permeability models. The Kenyon model $K = c \times (\phi_{NMR})^a \times (T2)^b$ is affected by gas and OBM filtrate (non-wetting phase), and the Timur-Coates model $K = (\phi_{NMR}/c)^a \times (BVM/BVI)^b$ is affected by uncertainty of bulk

WELL A BGMR PERMEABILITY*

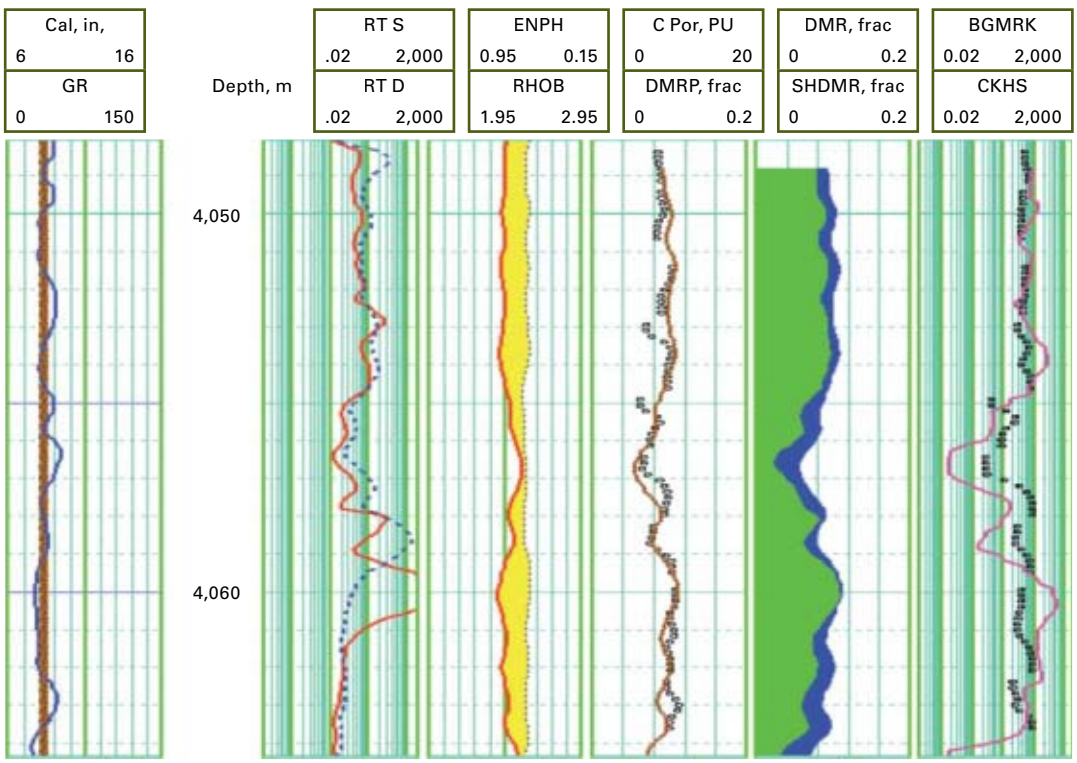
Fig. 7



*BGMR permeability is red line in Track 6.

WELL B BGMR PERMEABILITY*

Fig. 8



*BGMR permeability is purple line in Track 6.

volume irreducible (BVI) cut off values and wettability alteration by the OBM filtrate.

The next step after defining T2 cut off values is to calibrate the fitting parameters (c, a, and b) for the studied gas shaly sand reservoir.

Permeability determination with the Timer-Coates model in the case of tight heterogeneous gas shaly sand was unsatisfactory due to the effect of rock facies and tightness and the significant variation of T2 values for the same facies. Estimates of Kenyon and Timer-Coates permeability both are affected by hydrocarbon and development of a new model was needed to develop a different permeability model.[8-11]

Bulk gas magnetic resonance permeability (K_{BGMR}) is a new technique for permeability estimation in gas reservoirs. It has the same value in oil-based (OBM) and water-based (WBM) mud because it depends on gas reentry to the flushed zone after a mud cake

Equations

NMR porosity response in flushed gas zone is defined as

$$\phi_{NMR} = \phi S_{gxo} HI_g P_g + \phi HI_L (1 - S_{gxo})$$

Assume hydrogen index for liquid (HI_L) = 1

$$\phi_{NMR} = \phi [1 - S_{gxo} (1 - H_{Ig} P_g)]$$

$$\frac{\phi_{NMR}}{\phi} = 1 - S_{gxo} (1 - HI_g P_g) \quad (1)$$

Where;

ϕ_{NMR}: Porosity of NMR tool

ϕ: Gas corrected porosity

HI_g: Gas hydrogen index

HI_L: Fluid hydrogen index (water + mud filtrate)

S_{gxo}: Gas saturation in the flushed zone

P_g: 1 - exp (- W/$T_{i,g}$): gas polarization factor

W: Wait time

$T_{i,g}$: Gas longitudinal relaxation time

Density porosity response in gas flushed zone is defined as

$$\rho_b = \rho_m (1 - \phi) + \rho_L \phi (1 - S_{gxo}) + \rho_g \phi S_{gxo}$$

$$\phi_D = \frac{\rho_m - \rho b}{\rho_m - \rho_L} = \frac{\rho_m - [\rho_m (1 - \phi) + \rho_L \phi (1 - S_{gxo}) + \rho_g \phi S_{gxo})]}{\rho_m - \rho_L}$$

$$\frac{\phi_D}{\phi} = 1 + S_{gxo} \left(\frac{\rho_L - \rho_g}{\rho_m - \rho_L}\right) \quad (2)$$

Where;

ρ_b: Bulk density ρ: Liquid density (water + filtrate)

ϕ_D: Apparent porosity from density ρ_g: Gas density

Solution for gas corrected porosity ϕ

Assume constants β, α where,

$$\beta = \frac{\rho_L - \rho_g}{\rho_m - \rho_L} \text{ and } \alpha = (1 - HI_g P_g)$$

Substitute in Equation 1 and 2

$$\frac{\phi_{NMR}}{\phi} = 1 - \alpha S_{gxo} \quad (3)$$

$$\frac{\phi_D}{\phi} = 1 + \beta S_{gxo} \quad (4)$$

Solution of Equations 3 and 4 for true formation porosity (ϕ)

$$\phi = \left(\frac{\alpha}{\beta + \alpha} \phi_D + \frac{\beta}{\beta + \alpha} \phi_{NMR}\right)$$

$$\phi = A\ \phi_D + B\ \phi_{NMR}$$

$$\phi_{DMR} = A\ \phi_D + B\ \phi_{NMR} \quad (5)$$

A and B are constant where $A + B = \frac{\alpha}{\beta + \alpha} + \frac{\beta}{\beta + \alpha} =$

$$\frac{\beta + \alpha}{\beta + \beta} = 1$$

$$\frac{\phi Core}{\phi NMR} = A \frac{\phi_D}{\phi_{NMR}} + B \quad (6)$$

$$V_{g,xo} = \frac{DPHI - \frac{TNMR}{(HI)f}}{\left[1 - \frac{(HI)_g Pg}{(HI)f}\right] + \lambda} \quad (7)$$

$V_{g,xo}$ = Gas volume in the flushed zone

DPHI = Formation porosity from density using filtrate fluid density

T_{NMR} = Total NMR porosity

(HI)f = Fluid hydrogen index

P_g = Gas polariztion function - 1 - exp (- W/$T_{i,g}$), where W is the time and $T_{i,g}$ is the longitudinal relaxation time for gas.

$$\lambda = \frac{\rho_i - \rho_g}{\rho_m - \rho_i} \quad (8)$$

$$Sgxo = \frac{(\phi_D - DMR)(\rho_m - \rho_L)}{DMR (\rho_L - \rho_g)} \quad (9)$$

Bulk Gas Volume (BG) = $\phi_{DMR} - \phi_{NMR}$

$$S_{gxo} = \frac{DMRP - \phi_{NMR}}{DMRP} \quad (10)$$

$$K_{BGMR} = 0.18 \times 10^{(6.4Sgxo)} \quad (11)$$

Nomenclature

B0	=	Static magnetic field of the tool (gauss)
B1	=	Radio frequency magnetic field (gauss)
BG	=	Bulk gas
BGMRK	=	Bulk gas magnetic resonance permeability
BVI	=	Bulk volume irreducible.
BVM	=	Free-fluid volume available for hydrocarbon storage and fluid flow.
CBW	=	Clay bound water
DMRP	=	Density-magnetic resonance porosity
DPHI	=	Formation porosity from density using filtrate fluid density
F_s	=	Pore shape factor
HI_g	=	Gas hydrogen index
HI_L	=	Fluid hydrogen index (water + mud filtrate)
MBVI	=	Magnetic bulk volume irreducible
MBVM	=	Magnetic bulk volume movable
MHPI	=	Magnetic porosity
P_g	=	Gas polarization factor
r_b	=	Radius of the pore
r_{pt}	=	Radius of pore throat
S_{gxo}	=	Gas saturation in the flushed zone
Swi	=	Irreducible water saturation
S/V	=	Surface to volume ratio of the pores.
T1	=	Longitudinal relaxation time
$T1_g$	=	Gas longitudinal relaxation time.
T2	=	Transverse relaxation time
T_W	=	Waiting time (fluid properties)
$V_{g\ xo}$	=	Gas volume in the invaded zone
W	=	Wait time (actual waiting time of the NMR tool against the formation)
γ	=	Gyromagnetic ratio (fluid magnetic property)
p2	=	Surface relaxation
σ	=	Surface tension
Θ	=	Fluid contact angle
ρ_f	=	Fluid density
ρ_b	=	Bulk density
ρ_L	=	Liquid density (water + filtrate)

forms and filtrate invasion stops.

The model is a dynamic concept of gas movement behind the mud cake as a result of formation permeability, gas mobility, capillarity, and gravity forces. Because gravity forces are constant, capillarity depends mainly on permeability and mobility depends on permeability and fluid viscosity that is constant for gas. The gas reentry volume is directly a function of permeability.

Bulk gas volume

Several techniques can calculate the gas volume in the flushed zone:

- Differential spectrum (Delta T_w), multi acquisition using different waiting times (T_w)
- Diffusion measurements, 2D fluid analysis using fluid diffusivity (D) and T2 spectra.

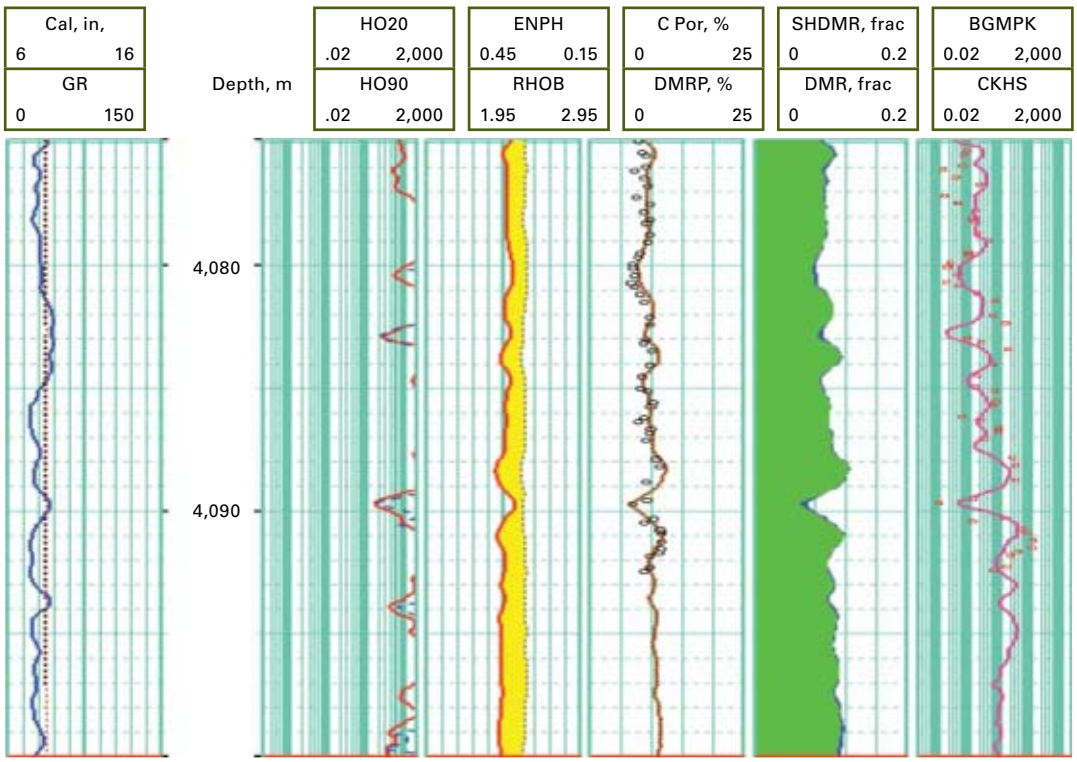
Freedman, et al.[6] has mathematically developed the transform (Equation 7) for gas volume calculation in the invaded zone.

A simple transform delivered from density-tool response (Equation 2) using DMR porosity is as a corrected gas porosity value shown as Equation 9.

Gas volume is calculated approximately by ignoring the gas response in the NMR measurements especially in short T_W, and then the approximated gas saturation in the invaded zone is as follows:

WELL C BGMR PERMEABILITY*

Fig. 9



*BGMR permeability is purple line in Track 6.

Bulk gas volume (BG) = $\phi_{DMR} - \phi_{NMR}$

BGMR permeability results

Fig. 6a shows core permeability vs. core porosity x-plot. It reflects how the permeability varies between facies within same the porosity range. The method uses the bulk-gas volume calculation. The method is very simple and excludes any complications (BG = ϕ_{DMR} -ϕ_{NMR}).

The same method is applied for the three wells A, B, and C, and then BG is plotted vs. formation permeability in Fig. 6b. The correlation is normalized (Fig. 6c) by dividing the gas volume by the total porosity of DMRP to be equal to S_{gxo} (Equation 10).

The correlation between S_{gxo} and permeability (Fig. 6c) resulted in the permeability transform, shown as Equation 11.

This transform is facies independent and the statistical analysis of absolute error for this correlation is about a factor of 2. This is acceptable from an uncertainty-assessment point of view compared to permeability uncertainty assessment from core por-perm transforms in the same reservoir, where the uncertainty factor ranges from 1.5 to 3, depending on facies.

Permeabilities derived with Equation 11 in three wells (A, B, and C) all showed a good match between K_{BGMR} permeability with core permeability (Figs. 7-9).

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Ethanol from wood waste an opportunity for refiners

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A recent prefeasibility study explored wood waste-to-ethanol as a significant, ready source of second-generation biofuels, as well as the opportunities for refiners and marketers to participate with pulp and paper mills in these biofuels projects.

The material presented in this article derives from a prefeasibility study recently completed for owners of a pulp and paper mill. These are the major conclusions reached in that study:

- Cellulosic ethanol plants currently being built are technically and economically viable.
- Partial integration of the proposed cellulosic ethanol plant with the pulp and paper mill was technically feasible.
- The proposed integration should offer synergies that would reduce ethanol production costs while providing project owners a valuable new product stream.
- Oil industry participation in projects of this type should offer refiners opportunities for a stable ethanol supply and ethanol price certainty while earning a high return on investment.
- The proposed cellulosic ethanol plant in Southeast US should compete in the growing market for ethanol in the Mid-Atlantic and Northeast US.

The study presented many arguments for considering partial integration of cellulosic ethanol plants with pulp and paper mills, 10 of which are listed in this article:

1. Continued increasing demand for ethanol and higher ethanol prices are expected.
2. An adequate supply of wood waste exists and can be used for making ethanol.
3. Cellulosic ethanol offers advantages over corn ethanol and other second-generation biofuels.
4. Viable cellulosic ethanol technologies exist and will shortly be available on a commercial scale.
5. Significant synergies exist with partial integration.
6. New government support is now becoming available for cellulosic biofuels projects.
7. There are inherent advantages in the use of wood waste to produce biofuels.
8. Mills now have new opportunities for obtaining a much-needed value stream.
9. Leading companies in the paper industry are already undertaking biofuels initiatives.
10. The prefeasibility study findings are positive.

This article also presents advantages for oil companies to form joint ventures with paper mills in cellulosic ethanol plant projects. The three main arguments for oil industry participation in cellulosic ethanol plant joint ventures are:

- Investment required to fund cellulosic ethanol plants is significant; pulp and paper mill owners will often need equity partners.
- Petroleum refiners make good affinity partners because they have experience in liquid fuels technologies; refining process operations; and handling, storage, and distribution of fuels.
- Petroleum products marketers make good affinity partners because they have an immediate and ongoing need for ethanol, they have the infrastructure for blending and distributing 10 vol % ethanol (E10) gasoline, and are in a better position to market and distribute more advanced second-generation biofuels, if and when they are produced.

Ethanol mandate

The Energy Independence and Security Act of 2007, Renewable Fuels Standards mandates production of 36 billion gal/year of renewable fuels by 2022.

A recent article (OGJ, Mar. 17, 2008, p. 24) concluded that this mandate would not be met. The article discussed

many obstacles that would more than likely "bedevil" attainment of the mandate; it cites, in particular, the 21-billion gal/year of cellulosic biofuels that will be required. It also pointed out that wood waste could be a significant untapped source of second-generation biofuels raw material.

Continued increased demand

Demand for ethanol will continue to increase due to:

- Population and vehicle fleet growth.
- Regulations designed to reduce harmful emissions, including requirements for reformulated gasoline (RFG).
- A shortage in refining capacity to make oxygenates used in RFG.
- Environmental legislation mandating a phaseout of methyl tertiary butyl ether.
- Expected demand for vehicles with dual-fuel capability that could increase demand for more bio-ethanol sold as 85 vol % ethanol (E85) gasoline blends.

Ethanol prices will increase concurrently with rising crude and gasoline prices. Ethanol rack prices are currently averaging $2.33/gal; the 51¢/gal blenders' credit and hedging is maintaining ethanol's price parity with gasoline in E10 blends. Even if the 51¢/gal subsidy is phased out, gasoline prices would still increase and ethanol prices would still maintain price parity with gasoline.

Accordingly, with continued increased demand for ethanol and expected higher prices, producers of cellulosic ethanol should be able to sell everything they can produce at prices that well exceed their costs.

Recent studies state that cellulosic ethanol will be cheaper to produce than corn ethanol due in part to the inflationary effect that increased corn ethanol production is having on corn prices, on the lower cost of bio-waste, and on lower cellulosic ethanol processing costs as more commercial-sized plants come on stream.

Supply of wood waste

Most of the 50 pulp and paper mills in the US use wood waste to supplement natural gas or coal used to fuel their boilers. They could easily divert this wood waste to make a high-value product such as ethanol. Many of these mills have local access to abundant untapped sources of wood waste that could be used to produce cellulosic biofuels.

These mills also have the infrastructure needed for on site preprocessing, storage, and handling of wood waste. All are in a position to provide supplies of wood chips and wood waste that a cellulosic ethanol plant may need, assuming the cellulosic ethanol plant is situated near each mill.

SOUTH CAROLINA WOOD WASTE Table 1

Source, dry tons/year	
Logging residues	2,205,750
Precommercial biomass (<5 in. DBH)	4,277,898
Commercial biomass (5-8.9 in. DBH)	2,662,951
Southern scrub oak	917,440
Mill residue	2,452,866
Urban wood waste	310,726
Potential additional wood waste for ethanol	12,827,630
Midsized cellulosic ethanol plant feedstock requirements = 1,000 dry tons/day x 330 days/year = 330,000 dry tons/year	
Plants that could be supported by wood waste = 12,827,630/330,000= 39	
Potential ethanol output in South Carolina = 39 x 20 million gal/year/plant = 780 million gal/year	
Mills in Southeast US	22
Mills in South Carolina	5
Potential annual ethanol output in Southeast US = 22/5 x 780 million gal/year = 3.432 billion gal/year	

Based on a recent study of woodland areas of a typical pulp and paper producing state in the US Southeast, we determined that significant amounts of cellulosic waste could be recovered each year from forest residues left behind by logging operations and from wastes deposited in urban landfills

The study suggested that, if all of these forestry wastes, mill wastes, and cellulosic wastes taken to landfills were recovered as a new source of feedstock for cellulosic ethanol plants, there would be enough additional wood waste in the US Southeast to support 172 new 20-million-gal/year ethanol plants. These could produce 3.432 billion gal/year of cellulosic ethanol (Table 1). This is quite an untapped potential.

Cellulosic ethanol advantages

Cellulosic ethanol will be needed in the next few years to supplement corn ethanol.

Unlike other renewable biofuels such as methanol, butanol, and di-methyl ether (DME), cellulosic ethanol already has a ready market as a blending ingredient in E10 gasoline.

What's wrong with corn ethanol?

According to US Department of Energy projections, the US cannot rely only on corn ethanol or ethanol imports. Although corn ethanol satisfies 99% of current ethanol demand, projected increases in corn ethanol will not be enough to meet projected US biofuels needs.

In 10 years, corn ethanol will meet only 62.5% of these needs; in 15 years, only 41.7%. The remainder will have to come from imports and cellulosic biofuels.

Ethanol imports, however, cannot satisfy the shortfall either. Ethanol imports primarily consist of sugar-based ethanol from Brazil. Due to the fragmentation of Brazilian ethanol producers and sugar growers, however, it is already more difficult and costly to increase these imports. Clearly, there will be a significant need for cellulosic ethanol produced in the US. The DOE expects that, in 15 years, 16 billion gal/year of cellulosic ethanol will be needed.

Another problem with corn ethanol is that it is quickly becoming uneconomic. Corn prices will continue to increase, which will have a widespread inflationary effect on corn ethanol; corn already accounts for 55% of the cost of producing corn ethanol. At best, producing ethanol from corn is only marginally energy efficient.

Conversely, studies show that cellulosic ethanol costs 25% less to produce than corn ethanol, cellulosic ethanol plants offer higher energy gains, and

most biowaste feedstocks are 50% cheaper than corn.

In addition, corn ethanol is becoming politically unsustainable. Inefficiencies in conversion of corn to fuel have already upset other markets. The widespread use of corn to produce ethanol has pushed up food prices and ethanol subsidies have again become a political issue. Furthermore, processes used to produce corn ethanol consume significant amounts of water and, in many water short corn-producing areas, new corn ethanol plants are no longer welcome because the public views them as having an adverse environmental impact.

Why not produce other advanced biofuels?

Cellulosic ethanol has two primary advantages over other advanced cellulosic biofuels such as methanol, butanol, and DME.

First, there is an immediate and growing market for ethanol; increased demand for E10 will continue with rising demand for gasoline. Second, no additional investment is needed for marketing or distribution—even though other biofuels have higher carbon content and produce more power than ethanol, they will require capital investment in separate storage, transportation, and delivery infrastructure.

In addition, added investment will be required for supporting marketing efforts needed to obtain consumer acceptance of advanced cellulosic biofuels. Additional investment will be needed for making engine modifications and for subsidies to keep advanced cellulosic biofuels prices competitive with E10 gasoline. More importantly, there is an increasing short-term demand for E10.

Are there better profit opportunities in making cellulosic ethanol?

Production and sale of cellulosic ethanol offers great potential profit opportunities. Ethanol prices are high and are rising because they track gasoline prices and not prices paid for feedstock or cost of producing ethanol. The margins ethanol producers are earning are therefore reduced by the prices paid for corn by food and animal-feed producers.

In contrast, cellulosic ethanol margins will be higher and less volatile than corn ethanol margins. First, cellulosic ethanol yields are improving due to technology advancements. Second, the revenues for biowastes converted into cellulosic ethanol are substantially higher than revenues from converting the same biowaste into fuel, fertilizer, or animal feed.

Cellulosic ethanol margins could still vary, depending on the cost of the biowaste used, the ethanol yield from various biowastes, and the process used to convert biowaste into ethanol.

Viable technologies exist

Cellulosic ethanol technologies have advanced to the point where many are nearing commercial viability and are available through a few existing technology providers. Two basic technologies are effective in converting cellulosic material into renewable liquid transportation fuels.

The first is "two-staged thermal with gasification"; the other is "two-staged concentrated acid hydrolysis." There are many variants for each technology.

In the two-stage thermal with gasification process, devolatization of the wood waste occurs with controlled high temperature and pressure in a partial steam-reforming gasifier. Syngas is then catalytically converted into alcohols in distillation towers, using the entire waste stream to produce a high yield of biofuels, little waste, and low levels of greenhouse gases. This process also has a favorable (3:1) energy-balance ratio.

The two-stage concentrated acid hydrolysis process is designed specifically to convert cellulosic feedstock into ethanol. One version of this process was perfected on a commercial scale and is patented under the name Arkenol. This process can separate cellulosic wastes into sugar-bearing and nonsugar-bearing components to extract the sugars and obtain ethanol using fermentation.

The Arkenol process is most efficient when the cellulose content of the cellulosic material is at least 75%, allowing for a high recovery of the sugar-bearing cellulose and hemicellulose components, leaving behind less nonsugar-bearing lignin. This technology is proven and has been used in making ethanol from municipal solid waste, agricultural waste, and, on a limited scale, wood waste. Better enzymes are now being developed to improve the sugar fermentation process and increase ethanol yield.

In addition, there appears to be significant economies of scale associated with Arkenol processes (Table 2). Our feasibility study findings showed that the most economical partially integrated Arkenol plant would be medium sized because the feedstock requirement could be met using 100% wood waste (Table 3).

ECONOMIES OF SCALE Table 2

	Plant size		
	Small	Med.	Large
Feedstock capacity, dry tons/day	500	1,000	2,560
Ethanol production, million gal/year	10.8	22.1	55.2
Site footprint requirements, acres	<2	2-3	4
Steam requirements (150 psi), lb/hr	11,328	22,656	58,000
Water requirements, million gal/year	84	168	431
Capital costs, million $	85	142	275
Capital cost/installed production, $/gal	7.88	6.41	4.99

Partial-integration synergies

Our prefeasibility study showed that partial integration could reduce the direct cost of producing ethanol by about 8¢/gal. These direct cost savings are attributable to:

- Using the mill's infrastructure to procure pulping wood and wood waste, to preprocess it into chips, and to store and handle it before processing.
- Using the mill's procurement department to obtain and an additional wood waste stream at a lower cost.
- Using an ethanol plant site that was provided to plant operators on a

rent-free basis by the mills' owners.

- Obtaining environmental permitting through the mill owners at no cost.
- Using other mill infrastructure, such as storage areas for liquid and dry bulk, rail sidings, and port access, at no cost.
- Accessing and using mill waste-treatment facilities without cost.
- Low-cost electric power provided from the mill's cogeneration facilities.
- Using the mill's excess steam at no cost.

The partial-integration scheme required mill owners to provide a limited up-front investment of about $1 million, and ongoing partial integration support at a low cost or no cost for at least 5 years. This partial-integration support was worth $2.1 million/year for a midsized plant and was capitalized over 5 years, giving mill owners a 27% equity interest in the project.

The prefeasibility study indicated that a value stream from a mid-sized plant would substantially supplement mill earnings, allowing mill owners to recover $2/year for every $1 invested (Table 3).

New government support

The DOE's Renewable Fuels Loan Guarantee Program offers low-cost federal loans, coguaranteed by DOE, to developers of cellulosic ethanol plants. Eligible borrowers can borrow up to $250 million for each qualified "Renewable Fuel Facility."

The project must however also use "new or significantly improved technology," and the project design must be "validated through operation of a continuous process pilot facility with annual output of at least 50,000 gal of ethanol (or other advanced biofuels)."

Assuming that the mill owner and other equity partners in a joint venture could qualify as eligible borrowers, a project involving the partial integration of a pulp and paper mill to a cellulosic ethanol plant would qualify for DOE loan guarantees, because such a project would offer a significant improvement in technology.

Those participating in partially integrated ethanol plants are eligible for Section 126 grants. These grants are available to project contractors for equipment used in gathering, preprocessing, and transporting biomass to cellulosic ethanol plants. The grant should help offset added costs of obtaining forest residue and other wood wastes that are often too costly to gather, separate, clean, and grind for delivery to the mill as an auxiliary boiler fuel. With such grants, such wood waste could be specifically obtained as an economic feedstock.

Advantages of wood waste

The best immediately available feedstock for producing cellulosic ethanol is wood waste and wood chips, not municipal solid waste (MSW) or agricultural waste. MSW has its own set of problems—one is the assumption that cellulosic ethanol plants can obtain MSW from landfill operators at no cost.

Cellulosic ethanol plant operators often have to pay for presorting and preprocessing before the MSW can be used as a feedstock. Furthermore, the cellulosic content of MSW is not always uniform, nor are continuous supplies guaranteed, which could create operating problems.

Likewise, although agriwaste is a good source of cellulosic material, it also has problems. First, outside of the Corn Belt, only a few cellulosic ethanol plants are being designed to use these materials because collection, storage, and preprocessing is costly.

Agriwastes are more costly if they have to be gathered and transported over long distances to an ethanol plant. There is a lack of infrastructure for efficiently collecting and processing large quantities of wheat straw, switch grass, and rice straw, so that they can be efficiently transported in sufficient quantities to cellulosic ethanol plants. Furthermore, much of this agriwaste is now used in farming as a natural fertilizer, or as an animal feed, making its availability sometimes limited and more expensive.

Conversely, there is an abundant supply of wood waste to exploit; pulp and paper mills are already set up to acquire additional supplies of wood waste. These waste materials are logging residue, such as treetops, thinnings (precommercial biomass), as well as sawmill and lumberyard wastes; they can supply "resident" cellulosic ethanol plants with their cellulosic feedstock requirements (Table 1).

Because they represent materials that mills do not currently use, their acquisition should not push up prices mills pay for their wood basket.

New value stream

Participation in cellulosic ethanol projects by the US paper industry may be critical to survival of many of their pulp and paper mills, particularly those that face direct competition from paper product imports. This has increased the volatility and erosion of profit margins earned by many US pulp and paper manufacturers.

There are only a few ways to stop this erosion. Mill owners must keep their pulping and paper manufacturing processes going because it is much

FINANCIAL SUMMARY

Table 3

	Plant size		
	Small	Med.	Large
Wood waste used, dry tons/day	500	1,000	2,500
Capital costs, million $	85	142	275
Debt, million $	59.5	99.4	192.5
Equity, million $	25.5	42.6	82.5
Mill equity, million $	6.7	11.5	26.5
Mill equity, % of total	26	27	32
Annual revenue, million $	25.1	50.3	128.7
Annual cash flows, million $	8.9	24.7	53.1
Cash flow to mill, million $	2.3	6.7	16.4
Annual mill subsidies, million $	1.1	2.1	5.1
Cash-on-cash return (cash flow/subsidies)	2.1	3.2	3.2
Ethanol sales, million gal/year	10.8	22.1	55.2
Average selling price, $/gal	2.23	2.23	2.23
Direct cost, $/gal	1.01	0.86	1.1
Operating income, $/gal	1.32	1.47	1.23
After-tax income, $/gal	0.4	0.57	0.51

more costly to shut down than it is to build up inventories, or liquidate excess inventory at discounts. Mills that shut down also run the risk of losing reliable supplies of pulpwood and they may have to buy their way back into the wood supply chain when supplies are again needed.

Curtailment in pulping and papermaking is not a good short-term option. Increasing pulping and papermaking capacity to meet short-term pulp and paper demand will not work either, because this is a longer-term option.

Our prefeasibility study showed that earnings and cash flows that a mill can earn by participating in a resident cellulosic ethanol plant, would go a long way to offset erosion in profit margins in cyclical downturns and will significantly improve profits when margins from mill operations are at sustainable levels (Table 3).

Paper company initiatives

Many major paper companies have initiated programs to make biofuels from wood waste. Several paper companies are developing the capability to make cellulosic ethanol and view such participation as an immediate business opportunity. They are willing to bet that available technology is commercially viable.

There are some who are taking a longer-term view and are not starting cellulosic ethanol projects. Instead, they are investing in research and development, often in joint-venture partnerships with major energy companies, to develop technologies to make a wide range of advanced biofuels.

There are other mill owners that are still taking a wait-and-see approach because they are uncertain if they have mills that could host resident biofuels plants. And there are those that are still uncertain as to the future of biofuels and their ability to participate successfully in producing and marketing biofuels.

Prefeasibility study findings

We conducted our prefeasibility study at the request of a struggling pulp and paper mill. The mill manager was specifically interested in determining whether significant additional cash flows could be generated through partial integration of the mill to a resident cellulosic ethanol plant. The prefeasibility study findings identified significant additional cash flows.

We expected favorable study results for the proposed project because:

- The mill was near a port with rail access and close to abundant untapped supplies of wood waste.
- The proposed resident plant was strategically located to serve Petroleum Administration for Defense District (PADD) 1 markets.
- The mill site was big enough to accommodate the ethanol plant.
- Mill owners agreed to provide timely environmental permitting.
- Mill engineers validated the fact that there was enough excess boiler capacity to supply steam to the ethanol plant at a low cost.
- Mill owners agreed to provide the ethanol plant with waste treatment, water, and cogenerated power needs at little or no cost.

Furthermore, the mill's wood-procurement department confirmed that they could deliver at least 1,000 dry tons/day of preprocessed wood waste to the ethanol plant at a low cost, while providing storage and handling. Mill owners were also willing to consider a $1 million investment in infrastructure upgrades to provide partial-integration support during a 5-year period valued at $10.4 million, in return for 27% equity in the ethanol plant.

Mill owners were also willing to coguarantee ethanol plant debt, or provide direct debt financing, if needed. The major conclusion of the prefeasibility study was that the proposed resident cellulosic ethanol plant would be economically viable based on expectations that ethanol prices would be high enough, the demand for ethanol strong enough, and the costs in making ethanol low enough to assure high earnings, cash flows, and return on invested capital (Table 3).

Oil industry participation

A medium (1,000 dry tons/day) cellulosic ethanol plant based on Arkenol technology can produce 22.1 million gal/year of ethanol and costs about $142 million, or $6.41/gal. Assuming 70% debt financing, $42.5 million in equity financing is needed.

If the mill agreed to acquire 27% of the equity in the project for $11.5 million, given the proposed partial-integration scheme used in the study, only $1.1 million is left as a direct investment and the rest is contributed as the value for partial-integration support during the first 5 years.

In this case, the host mill would have to seek a partner willing to contribute the remaining $31 million for a 73% interest in the plant. Most mills are not in a position to make large cash investments in facilities that are not part of their core business (Tables 2 and 3).

Clearly, if the partial-integration approach to developing cellulosic biofuels plants is exploited to its fullest, many affinity investors in cellulosic ethanol plants will be needed. In particular, refiners and marketers should make good affinity investors because they have experience in liquid fuels technologies and in refining process operations. Their personnel already possess the skills needed to operate processes similar to those used for cellulosic ethanol.

Refinery workers are trained in quality-control procedures and in storage, transportation, and blending operations. With respect to producing advanced cellulosic biofuels, the technology is similar to those in petroleum refining, and that knowledge can be used if cellulosic ethanol plants are to be upgraded to produce synthetic motor fuels such as DME.

Refined products marketers that are not refiners would also make ideal affinity investors because they have an immediate and ongoing need for ethanol and have the infrastructure for

blending and distributing E10 gasoline. They are often in a better position to market and distribute more advanced second-generation biofuels, if and when they are produced.

When refiners and marketers partner with owners of a pulp and paper mill in projects of this type, the combined attributes of these partners reduces each participant's equity requirements, increases return on investment potential, and spreads project risk.

Such partnerships can also be profitable. In our prefeasibility study, we determined that the direct cost to produce ethanol was less than $1/gal and that after-tax income could be more than 50¢/gal. The project would also generate more than $24 million/year in cash flow on a revenue stream of $50 million.

The affinity investor's 73% share of cash flow is more than $18 million/year, resulting in an average return on its $31 million equity of 58%/year.

Participating in such a project could benefit refiners and marketers of ethanol blends. And resale of other second-generation biofuels may offer even more promising returns (Table 3). ✦

The author

Tim Sklar (sklarincdc@aol.com) is president of Sklar & Associates, Murrells Inlet, SC, a consulting firm specializing in biofuels project development. He has experience in business turnarounds and operational management and restructuring for PriceWaterhouseCoopers and KPMG. Sklar also served as CFO for GFC Inc. He has held positions in the federal government as research director. His energy project experience includes petroleum refineries, power plants, power distribution systems, hybrid remote power generation systems, integrated oil seed crushing-biodiesel processing plants, and integrated pulp mill-cellulosic ethanol processing plants. He holds a BS in accounting and a BA in english from Temple University, Philadelphia.

NELSON-FARRAR COST INDEXES

Refinery construction (1946 Basis)

(Explained on p.145 of the Dec. 30, 1985, issue)

	1962	1980	2005	2006	2007	Feb. 2007	Jan. 2008	Feb. 2008
Pumps, compressors, etc.	222.5	777.3	1,685.5	1,758.2	1,844.4	1,829.5	1893.7	1,910.8
Electrical machinery	189.5	394.7	513.6	520.2	517.3	526.8	510.9	513.2
Internal-comb. engines	183.4	512.6	931.1	959.7	974.6	969.5	985.3	986.5
Instruments	214.8	587.3	1,108.0	1,166.0	1,267.9	1,246.9	1,299.2	1,305.2
Heat exchangers	183.6	618.7	1,072.3	1,162.7	1,342.2	1,179.4	1,374.7	1,374.7
Misc. equip. average	198.8	578.1	1,062.1	1,113.3	1,189.3	1,150.4	1,212.8	1,218.1
Materials component	205.9	629.2	1,179.8	1,273.5	1,364.8	1,335.2	1,405.0	1,431.4
Labor component	258.8	951.9	2,411.6	2,497.8	2,601.4	2,558.6	2,662.0	2,663.0
Refinery (Inflation) Index	237.6	822.8	1,918.8	2,008.1	2,106.7	2,069.2	2,159.2	2,170.4

Refinery operating (1956 Basis)

(Explained on p.145 of the Dec. 30, 1985, issue)

	1962	1980	2005	2006	2007	Feb. 2007	Jan. 2008	Feb. 2008
Fuel cost	100.9	810.5	1,360.2	1,569.0	1,530.7	1,635.6	1,671.4	1,819.2
Labor cost	93.9	200.5	201.9	204.2	215.8	222.2	214.4	214.7
Wages	123.9	439.9	1,007.4	1,015.4	1,042.8	1,058.2	1,023.0	997.8
Productivity	131.8	226.3	501.1	497.5	483.4	476.2	477.2	464.8
Invest., maint., etc.	121.7	324.8	716.0	743.7	777.4	763.5	796.7	800.9
Chemical costs	96.7	229.2	310.5	365.4	385.9	367.1	423.7	423.7
Operating indexes								
Refinery	103.7	312.7	542.1	579.0	596.5	600.6	620.6	635.8
*Process units**	103.6	457.5	787.2	870.7	872.6	906.4	928.1	981.4

**Add separate index(es) for chemicals, if any are used. See current Quarterly Costimating, first issue, months of January, April, July, and October.*

These indexes are published in the first issue of each month. They are compiled by Gary Farrar, Journal Contributing Editor.

Indexes of selected individual items of equipment and materials are also published on the Costimating page in the first issue of the months of January, April, July, and October.

Pipelines

Remote digital temperature monitoring aids hydrotests

Claudio Zanghi
Ghizzoni SPA
Vidalenzo di Polesini, Italy

A new system allows real-time remote temperature monitoring along the length of a pipeline during hydrotesting. The system (Fig. 1) uses a radio temperature transmitter connected with a thermocouple installed underground on the surface of the pipeline, communicating the pipe's temperature directly to a remote database that saves all data transmitted.

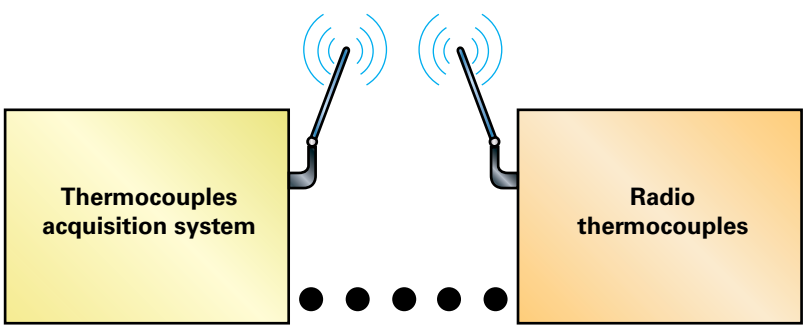
As new pipelines are built and proper facility maintenance requires increasing scrutiny of the integrity of pipelines long in service, the need for hydrotesting will only grow, placing an increasing premium on performing hydrotests as efficiently as possible. Unexpectedly large internal corrosion, external damage, or any other factor potentially reducing WT would also likely require hydrotesting in the current environment.

This article illustrates both the economic and data-quality aspects of remote digital temperature gathering during hydrotesting.

Radio thermocouple units are arrayed in the proper configuration to deliver data to a centralized control and gathering hub (Fig. 3).

SYSTEM SCHEMATIC

Fig. 1



Radio modem transmitters such as this convert the electrical signal to digital with a particular sole-purpose frequency (Fig. 2).

Background

Digital data and computing technology already address a wide range of issues in pipeline construction and inspection. These include mapping of the pipeline route, tracking material inventory, monitoring pipelay progress, organization of quality control data (including weld inspection), and generation of periodic project-monitoring and management reports. Removing test personnel from near the pipeline being tested will also reduce the possibility of accidental injury should the pipeline fail.

The immediate technological, data-quality, and economic effects of monitoring hydrotest parameters in the same manner manifest themselves in a number of ways. The pipeline operator no longer needs to rely on field representatives who may or may not have the authority to accept the measurements as accurate. Direct transmission of digital data to a centralized control center also

lessens the possibility of errors during transcription.

Acoustic emissions testing performed on new pipelines during hydrotest, using acoustic sensors placed at 100-yard intervals on the pipe, can detect welding defects, leakage, and corrosion, but lacks a temperature component.

Remote digital monitoring and transmission of hydrotest data is already used in offshore applications but requires either literally tethering the vessel to the pipeline undergoing testing by long hoses and cables or two-way acoustic communications.

Computer software elaborates and visually displays signals received from the six radio thermocouples positioned along the test pipeline (Fig. 4).

Technical data

The radio thermocouples system has six temperature radio modem transmitters, one receiving apparatus, and one registration apparatus. The radio modem transmitters each use a digital thermometer capable of reading a −50° C. to 105° C. temperature range in 0.1° increments with 99.99% accuracy and an acquisition schedule governed by a PT 100 probe delivering four threads of 16-bit resolution. The thermometer feeds directly into a radio modem that converts the electrical signal into a digital signal and transmits it at 485 Mhz, using 750 milliwatts (Fig. 2). Sensor placement occurs at 1-km increments along the pipeline.

A steel box contains both the thermometer and the radio modem as well as a 12-v, 7 amp battery with a life of 10 days (Fig. 3). Battery use is limited to transmission, initiated by interrogation from the control unit and allowing a relatively long life. The radio signal is transmitted directly from this box to the receiving station. The box gathers information from the thermocouple every 2 sec.

The modem uses and RS 232 configuration to first store and then forward the information. Transmission occurs over a signal dedicated solely to that purpose and protected from outside interference, limiting the possibility of transmission-based data errors. Transmission can be as quick as every 5 sec.

The receiving station moves data from the six thermocouples to a computer equipped with Scada Data Recon Digitron software. The software's display allows the data to be observed during acquisition (Fig. 4), while a different aspect of the program stores and organizes the data for future analysis.

A separate schematic view shows the configuration and setting of each sensor as well as maximum and minimum values and a numerical view of the data itself during testing. Comparing these data to the digital pressure signal coming from the test head allows complete monitoring during hydrotesting of any variation in pressure as related to pipe temperature.

Field testing

Testing occurred on the 30-in. OD Mortara-Cosseria pipeline and the 48-in. OD Montalbano-Messina pipeline, operated by Snam Rete Gas SPA, Italy. Testing on the 30-in. line confirmed the system's ability to deliver data accurately without having to gather it manually at each monitoring location. Testing on the 48-in. line showed the system to be capable of transmitting data across a maximum distance of 10 km.

Operating the system in parallel to each pipeline's existing manual system allowed data comparison. Table 1 shows the results of this comparison.

Real-time access to temperature data during hydrotesting increases the efficiency of the process, saving both time and money. The nearly continuous stream of data also allows more detailed analysis of test results. ✦

MONITORING PARAMETERS

Table 1

Transmission mode	Sensitivity, °C.	Accuracy, %
Manual	±0.2	0.1
Radio	±0.1	0.01

The author

Carmelo Claudio Zanghì (c.zanghi@ghizzonispa.com) is general hydrotest and control manager for Ghizzoni SPA and previously managed viscosity measurement at the refinery of Milazzo, Italy. He received a BS in physics and an MS in viscosity fluid behaviors at the University of Messina, Italy.

Equipment/Software/Literature

New mixer blends ethanol, additives into gasoline

This patented, compact all stainless steel static injection mixer is designed to blend ethanol and other additives into gasoline and other fuels.

The mixer is a heavy-wall 316 stainless steel fixed plate that features an orifice pattern that mixes by a combination of alternate vortex shedding and intense shear zone turbulence to achieve >98% dispersion within 10 diameters downstream. Designed to fit inside the mating flange bolt circle of any piping system, it is smaller than conventional multielement static mixers, the company says.

Available in sizes from ½ in. up to 30 in. in diameter, the mixer comes standard with Flexitallic stainless steel high-pressure gaskets. Providing predictable mixing and maintenance free operation, this mixer has no moving parts and can be modified for injecting several additives. It can also be manufactured from titanium, Hastelloy, and other materials.

Source: **Westfall Mfg. Co.,** 16 Peckham Drive, Bristol, RI 02809-0007.

Expansion joints for petrochemical plant

The 44 in. expansion joint shown on the right is one of a number of them that was designed and fabricated for a petrochemical plant in Malaysia. The joint measures 44 in. ID by 40 in. face to face and is made of stainless steel with insulation pillows. The design pressure is 3 psig, and the design temperature is 845° F.

Joints are designed with a lateral movement of ½ in. and an angular rotation of 1.5°. Stainless steel covers were included to protect the fabric expansion element from possible outside damage.

Source: **U.S. Bellows Inc. Div., Piping Technology & Products Inc.,** 3701 Homes Rd., Houston, TX 77051.

Services/Suppliers

Industrial Scientific Corp.,

Pittsburgh, Pa., has named Scott Lordo to the newly created position of global director of product development. He will lead the product development process at Industrial Scientific, having direct responsibility for building a program office, with program managers responsible for the multifunctional execution of new product development projects. He will also have "dotted-line" responsibility for engineering and will lead the global coordination of engineering practices and standards. Previously, Lordo worked at Cattron-Theimeg, where he held the positions of senior engineering manager of rail solutions, application/development engineering manager, and most recently director of program management. He has BS in electrical engineering and an MBA, both from Penn State University.

Lordo

Industrial Scientific is a global leader in gas detection and monitoring instruments, systems, and related services.

Knowledge Reservoir LLC and 3GiG LP,

both of Houston, have formed a strategic alliance to offer business process and well life-cycle management services to the oil and gas industry. Upstream companies will have access to 3GiG's technology and expertise through Knowledge Reservoir asset consulting teams for use across the scope of their projects, from well planning (drilling to plug and abandonment) to field development planning, lead and prospect generation, workflow tracking, and acquisition and divesture packaging. The alliance coincides with the release of 3GiG's new business process, knowledge and well life-cycle management system, Prospect Director 2.0©.

Knowledge Reservoir is a leading global energy consulting firm headquartered in Houston, and is a wholly owned subsidiary of Ziebel AS. Knowledge Reservoir provides geoscience and engineering consulting and resourcing solutions to clients worldwide from offices in Texas, California, the UK, Norway, Denmark, Oman, and Malaysia.

3GiG specializes in delivering high-value software and consulting services focused on business process, knowledge, and decision and project information management for E&P companies.

Technip,

Paris, named Arnaud Réal senior vice-president, financial control. Previously, Réal was corporate controller at Alcatel-Lucent, where he spent 17 years in finance and financial control in France and Belgium. Prior to that, he worked as an auditor for Coopers & Lybrand in Paris.

Technip is a global leader in oil, gas and petrochemical engineering, construction, and services. It manufactures flexible pipes and umbilicals and builds offshore platforms in its plants and fabrication yards in France, Brazil, the UK, the US, Finland, and Angola and has a fleet of specialized vessels for pipeline installation and subsea construction.

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Imports of crude and products

	Districts 1-4 5-16 2008	Districts 1-4 5-9 2008	District 5 5-16 2008	District 5 5-9 2008	Total US 5-16 2008	Total US 5-9 2008	Total US *5-18 2007
	1,000 b/d						
Total motor gasoline	1,134	872	9	43	1,143	915	1,295
Mo. gas. blending comp.	637	621	9	6	646	627	692
Distillate	196	216	2	—	198	216	190
Residual	282	370	200	—	482	370	214
Jet fuel-kerosine	100	218	61	82	161	300	162
Propane-propylene	164	103	12	22	176	125	110
Other	647	877	54	30	701	907	919
Total products	**3,160**	**3,277**	**347**	**183**	**3,507**	**3,460**	**3,582**
Total crude	**8,093**	**9,094**	**1,144**	**839**	**9,237**	**9,933**	**10,892**
Total imports	**11,253**	**12,371**	**1,491**	**1,022**	**12,744**	**13,393**	**14,474**

*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

	*5-23-08	*5-25-07	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	144.84	89.91	54.93	61.1
Brent crude	127.93	70.61	57.32	81.2
Crack spread	16.91	19.29	–2.38	–12.3
FUTURES MARKET PRICES				
One month				
Product value	148.42	91.82	56.60	61.6
Light sweet crude	130.46	65.28	65.18	99.8
Crack spread	17.96	26.54	–8.58	–32.3
Six month				
Product value	144.99	82.53	62.46	75.7
Light sweet crude	130.49	69.17	61.32	88.6
Crack spread	14.50	13.36	1.14	8.5

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

Purvin & Gertz LNG netbacks—May 23, 2008

Receiving terminal	Liquefaction plant: Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	8.77	6.34	7.79	6.21	7.05	7.70
Everett	10.15	7.60	9.68	7.64	8.31	10.52
Isle of Grain	9.88	8.10	9.34	7.98	8.57	9.34
Lake Charles	8.45	5.87	8.13	6.08	6.48	9.26
Sodegaura	7.27	9.67	7.52	9.53	8.69	6.42
Zeebrugge	9.15	6.72	8.42	6.58	7.39	8.42

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	14,786	58,089	31,223	9,542	32,580	15,817	2,836
PADD 2	67,428	48,202	17,954	7,808	29,417	1,288	13,969
PADD 3	165,662	69,400	32,815	13,598	31,221	17,271	16,215
PADD 4	13,806	5,520	1,632	568	3,300	270	[1]766
PADD 5	58,760	28,202	22,011	8,606	11,272	6,284	—
May 16, 2008	**320,442**	**209,413**	**105,635**	**40,122**	**107,790**	**40,930**	**33,786**
May 9, 2008	**325,759**	**210,168**	**106,687**	**40,384**	**107,062**	**39,320**	**31,303**
May 18, 2007[2]	**344,189**	**196,666**	**89,587**	**40,468**	**120,268**	**37,793**	**32,908**

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

Refinery report—May 16, 2008

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	1,360	1,374	2,035	113	477	130	58
PADD 2	3,341	3,308	2,320	233	994	52	223
PADD 3	7,496	7,247	3,082	721	2,172	308	658
PADD 4	581	569	298	17	173	14	[1]151
PADD 5	2,686	2,585	1,293	476	528	144	—
May 16, 2008	**15,464**	**15,083**	**9,028**	**1,560**	**4,344**	**648**	**1,117**
May 9, 2008	**15,234**	**15,054**	**8,904**	**1,479**	**4,352**	**724**	**1,080**
May 18, 2007[2]	**15,915**	**15,691**	**9,203**	**1,525**	**4,180**	**715**	**1,117**
	17,588 operable capacity		**87.9% utilization rate**				

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

OGJ GASOLINE PRICES

	Price ex tax 5-21-08	Pump price* 5-21-08	Pump price 5-23-07
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	349.4	389.1	305.5
Baltimore	334.2	376.1	304.8
Boston	328.5	370.4	298.0
Buffalo	333.9	394.0	307.5
Miami	349.4	399.7	317.8
Newark	335.5	368.4	287.8
New York	318.2	378.3	310.1
Norfolk	326.3	363.9	294.1
Philadelphia	331.0	381.7	309.5
Pittsburgh	329.7	380.4	297.1
Wash., DC	350.5	388.9	311.9
PAD I avg.	335.1	381.0	304.0
Chicago	361.4	412.3	361.2
Cleveland	321.9	368.3	312.6
Des Moines	323.9	364.3	310.2
Detroit	329.1	378.3	321.3
Indianapolis	329.3	374.3	322.5
Kansas City	320.3	356.3	309.1
Louisville	349.1	386.0	314.7
Memphis	321.2	361.0	288.0
Milwaukee	339.9	391.2	333.9
Minn.-St. Paul	329.8	370.2	315.7
Oklahoma City	325.9	361.3	308.5
Omaha	320.9	367.3	316.0
St. Louis	338.2	374.2	303.0
Tulsa	318.9	354.3	306.4
Wichita	316.6	360.0	309.2
PAD II avg.	329.8	372.0	315.5
Albuquerque	326.9	363.3	317.8
Birmingham	329.6	368.3	293.1
Dallas-Fort Worth	331.9	370.3	395.5
Houston	326.9	365.3	294.1
Little Rock	327.1	367.3	293.5
New Orleans	325.9	364.3	290.3
San Antonio	322.9	361.3	282.7
PAD III avg.	327.3	365.7	295.3
Cheyenne	317.0	349.4	300.7
Denver	339.7	380.1	316.9
Salt Lake City	320.3	363.2	314.3
PAD IV avg.	325.6	364.2	310.6
Los Angeles	348.2	406.7	346.5
Phoenix	322.5	359.9	310.1
Portland	340.3	383.5	339.9
San Diego	358.4	416.9	354.0
San Francisco	364.0	422.5	373.7
Seattle	340.2	392.6	345.5
PAD V avg.	345.6	397.0	345.0
Week's avg.	**332.7**	**376.3**	**313.0**
Apr. avg.	**296.4**	**339.3**	**278.3**
Mar. avg.	**276.1**	**319.7**	**254.0**
2008 to date	**281.1**	**324.7**	—
2007 to date	**213.0**	**256.6**	—

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

REFINED PRODUCT PRICES

	5-16-08 ¢/gal		5-16-08 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	310.93	New York Harbor	370.15
Gulf Coast	312.18	Gulf Coast	366.65
Los Angeles	321.93	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	305.37	ARA	383.54
Singapore	311.07	Singapore	381.48
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	325.68	New York Harbor	210.43
Gulf Coast	335.03	Gulf Coast	220.31
Los Angeles	326.93	Los Angeles	220.49
		ARA	222.91
		Singapore	223.65

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

BAKER HUGHES RIG COUNT

	5-23-08	5-25-07
Alabama	5	4
Alaska	7	8
Arkansas	45	42
California	44	32
Land	42	31
Offshore	2	1
Colorado	119	101
Florida	0	0
Illinois	1	0
Indiana	2	2
Kansas	9	12
Kentucky	10	7
Louisiana	149	176
N. Land	53	54
S. Inland waters	21	23
S. Land	21	33
Offshore	54	66
Maryland	1	0
Michigan	1	1
Mississippi	12	13
Montana	10	20
Nebraska	0	0
New Mexico	76	80
New York	6	5
North Dakota	66	35
Ohio	11	13
Oklahoma	207	194
Pennsylvania	19	14
South Dakota	2	4
Texas	935	835
Offshore	10	12
Inland waters	2	1
Dist. 1	30	19
Dist. 2	35	23
Dist. 3	70	61
Dist. 4	95	99
Dist. 5	182	176
Dist. 6	122	121
Dist. 7B	32	36
Dist. 7C	69	56
Dist. 8	139	112
Dist. 8A	28	24
Dist. 9	39	36
Dist. 10	82	59
Utah	41	41
West Virginia	26	35
Wyoming	70	75
Others—AZ-1; NV-2; OR-2; TN-5; VA-5	15	10
Total US	**1,889**	**1,760**
Total Canada	**152**	**114**
Grand total	**2,041**	**1,874**
Oil rigs	386	287
Gas rigs	1,493	1,471
Total offshore	67	80
Total cum. avg. YTD	**1,798**	**1,740**

Rotary rigs from spudding in to total depth.
Definitions, see OGJ Sept. 18, 2006, p. 46.

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

SMITH RIG COUNT

Proposed depth, ft	Rig count	5-23-08 Percent footage*	Rig count	5-25-07 Percent footage*
0-2,500	74	5.4	59	8.4
2,501-5,000	115	57.3	106	50.0
5,001-7,500	231	16.0	236	20.7
7,501-10,000	427	3.2	422	2.8
10,001-12,500	469	2.7	432	2.7
12,501-15,000	299	0.3	272	0.3
15,001-17,500	114	—	97	1.0
17,501-20,000	74	—	78	—
20,001-over	34	—	37	—
Total	**1,837**	**7.3**	**1,739**	**7.6**
INLAND	25		45	
LAND	1,755		1,628	
OFFSHORE	57		66	

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

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

OGJ PRODUCTION REPORT

	[1]5-23-08	[2]5-25-07
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	14	19
Alaska	715	765
California	650	671
Colorado	43	38
Florida	5	5
Illinois	24	27
Kansas	93	103
Louisiana	1,345	1,330
Michigan	14	15
Mississippi	50	53
Montana	92	96
New Mexico	163	163
North Dakota	115	114
Oklahoma	171	171
Texas	1,340	1,369
Utah	45	51
Wyoming	143	144
All others	60	76
Total	**5,082**	**5,210**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

	5-23-08 $/bbl*
Alaska-North Slope 32°	96.05
South Louisiana Sweet	134.50
California-Kern River 13°	118.85
Lost Hills 30°	126.85
Southwest Wyoming Sweet	123.69
East Texas Sweet	128.25
West Texas Sour 34°	121.25
West Texas Intermediate	128.75
Oklahoma Sweet	128.75
Texas Upper Gulf Coast	125.25
Michigan Sour	121.75
Kansas Common	127.50
North Dakota Sweet	121.50

*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

	5-16-08 $/bbl[1]
United Kingdom-Brent 38°	123.45
Russia-Urals 32°	120.01
Saudi Light 34°	119.45
Dubai Fateh 32°	119.07
Algeria Saharan 44°	124.99
Nigeria-Bonny Light 37°	127.93
Indonesia-Minas 34°	125.85
Venezuela-Tia Juana Light 31°	119.74
Mexico-Isthmus 33°	119.63
OPEC basket	122.38
Total OPEC[2]	120.12
Total non-OPEC[2]	119.66
Total world[2]	119.91
US imports[3]	116.32

[1]Estimated contract prices. [2]Average price (FOB) weighted by estimated export volume. [3]Average price (FOB) weighted by estimated import volume. Source: DOE Weekly Petroleum Status Report.
Data available in OGJ Online Research Center.

US NATURAL GAS STORAGE[1]

	5-16-08	5-9-08	5-16-07	Change, %
	bcf			
Producing region	595	576	733	–18.8
Consuming region east	797	743	885	–10.0
Consuming region west	222	210	297	–25.3
Total US	**1,614**	**1,529**	**1,916**	**–15.8**
	Feb. 08	**Feb. 07**	**Change, %**	
Total US[2]	**1,465**	**1,649**	**–11.2**	

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

PACE REFINING MARGINS

	Mar. 2008	Apr. 2008	May. 2008	May. 2007	2008 vs. 2007 Change	2008 vs. 2007 Change, %
			$/bbl			
US Gulf Coast						
West Texas Sour	12.82	14.92	17.02	28.08	–11.96	–43.3
Composite US Gulf Refinery	15.07	14.72	16.50	24.35	–7.85	–32.2
Arabian Light	11.95	11.28	12.90	25.01	–12.11	–48.4
Bonny Light	6.21	6.88	7.86	16.78	–8.92	–53.1
US PADD II						
Chicago (WTI)	10.10	12.68	14.69	38.62	–24.23	–62.4
US East Coast						
NY Harbor (Arab Med)	8.37	11.47	12.52	19.40	–6.88	–35.5
East Coast Comp-RFG	10.46	14.45	17.61	19.38	–1.77	–9.2
US West Coast						
Los Angeles (ANS)	13.54	14.88	14.58	28.30	–13.72	–48.5
NW Europe						
Rotterdam (Brent)	1.88	3.73	2.29	5.62	–3.33	–59.2
Mediterranean						
Italy (Urals)	6.62	7.44	7.40	10.86	–3.46	–31.8
Far East						
Singapore (Dubai)	7.57	6.98	12.88	9.15	3.83	41.8

Source: Jacobs Consultancy Inc.
Data available in OGJ Online Research Center.

US NATURAL GAS BALANCE DEMAND/SUPPLY SCOREBOARD

	Feb. 2008	Jan. 2008	Feb. 2007	Feb. 2008-2007 change	Total YTD 2008	Total YTD 2007	YTD 2007-2006 change
				bcf			
DEMAND							
Consumption	2,490	2,633	2,556	–66	5,123	5,012	111
Addition to storage	56	68	51	5	124	107	17
Exports	92	104	56	36	196	126	70
Canada	50	62	34	16	112	75	37
Mexico	39	39	17	22	78	41	37
LNG	3	3	5	–2	6	10	–4
Total demand	**2,638**	**2,805**	**2,663**	**–25**	**5,443**	**5,245**	**198**
SUPPLY							
Production (dry gas)	1,623	1,709	1,429	194	3,332	3,019	313
Supplemental gas	4	2	6	–2	6	12	–6
Storage withdrawal	649	892	782	–133	1,541	1,522	19
Imports	318	355	373	–55	672	768	–96
Canada	294	326	321	–27	620	658	–38
Mexico	NA	1	8	–8	NA	12	–12
LNG	24	28	44	–20	52	98	–46
Total supply	**2,594**	**2,958**	**2,590**	**4**	**5,551**	**5,321**	**230**

NATURAL GAS IN UNDERGROUND STORAGE

	Feb. 2008	Jan. 2008	Dec. 2007	Feb. 2007	Change
			bcf		
Base gas	4,222	4,232	4,234	4,214	8
Working gas	1,465	2,055	2,879	1,649	–184
Total gas	**5,687**	**6,287**	**7,113**	**5,863**	**–176**

Source: DOE Monthly Energy Review.
Data available in OGJ Online Research Center.

WORLDWIDE NGL PRODUCTION

	Feb. 2007	Jan. 2008	2 month average Production 2008	2 month average Production 2007	Change vs. previous year Volume,	Change vs. previous year %
			1,000 b/d			
Brazil	86	89	88	87	1	0.9
Canada	701	699	700	732	–32	–4.4
Mexico	368	366	367	408	–41	–10.0
United States	1,830	1,783	1,807	1,688	119	7.0
Venezuela	200	200	200	200	—	—
Other Western Hemisphere	212	209	210	207	3	1.6
Western Hemisphere	**3,397**	**3,346**	**3,372**	**3,322**	**49**	**1.5**
Norway	294	302	298	313	–15	–4.8
United Kingdom	180	182	181	164	17	10.3
Other Western Europe	10	10	10	10	—	–2.3
Western Europe	**484**	**494**	**489**	**488**	**2**	**0.4**
Russia	421	421	421	425	–4	–0.8
Other FSU	150	150	150	160	–10	–6.3
Other Eastern Europe	16	16	16	16	—	–2.2
Eastern Europe	**587**	**587**	**587**	**601**	**–14**	**–2.3**
Algeria	352	350	351	341	11	3.1
Egypt	70	70	70	70	—	—
Libya	80	80	80	80	—	—
Other Africa	129	135	132	127	5	4.2
Africa	**631**	**635**	**633**	**617**	**16**	**2.6**
Saudi Arabia	1,440	1,440	1,440	1,427	13	0.9
United Arab Emirates	250	250	250	250	—	—
Other Middle East	870	870	870	870	—	—
Middle East	**2,560**	**2,560**	**2,560**	**2,547**	**13**	**0.5**
Australia	60	57	58	78	–20	–25.2
China	180	180	180	180	—	—
India	—	—	—	19	–19	–100.0
Other Asia-Pacific	181	181	181	184	–3	–1.5
Asia-Pacific	**421**	**418**	**419**	**461**	**–41**	**–9.0**
TOTAL WORLD	**8,081**	**8,040**	**8,060**	**8,036**	**25**	**0.3**

Totals may not add due to rounding.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

OXYGENATES

	Mar. 2008	Feb. 2008	Change	YTD 2008	YTD 2007	Change
			1,000 bbl			
Fuel ethanol						
Production	17,387	15,025	2,362	48,230	34,308	13,922
Stocks	11,391	10,465	926	11,391	8,529	2,862
MTBE						
Production	1,595	1,419	176	4,745	5,895	–1,150
Stocks	1,803	1,642	161	1,803	1,549	254

Source: DOE Petroleum Supply Monthly.
Data available in OGJ Online Research Center.

US HEATING DEGREE-DAYS

	Apr. 2008	Apr. 2007	Normal	2008 % change from normal	Total degree-days July 1 through Apr. 30 2008	2007	Normal	% change from normal
New England	516	641	583	–11.5	6,005	6,036	6,298	–4.7
Middle Atlantic	392	547	496	–21.0	5,138	5,319	5,687	–9.7
East North Central	472	548	510	–7.5	6,096	5,977	6,243	–2.4
West North Central	572	538	472	21.2	6,659	6,214	6,527	2.0
South Atlantic	172	225	179	–3.9	2,469	2,613	2,800	–11.8
East South Central	260	285	216	20.4	3,331	3,379	3,540	–5.9
West South Central	137	171	94	45.7	2,141	2,239	2,281	–6.1
Mountain	432	388	426	1.4	4,781	4,679	4,917	–2.8
Pacific	320	278	298	7.4	3,063	2,781	2,985	2.6
US average*	**338**	**382**	**345**	**–2.0**	**4,155**	**4,123**	**4,349**	**–4.5**

*Excludes Alaska and Hawaii.
Source: DOE Monthly Energy Review.
Data available in OGJ Online Research Center.

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Yes, the world's running out of oil; what's new?

The oil market seems to have panicked over the possibility that the end of oil availability has come into view.

Market analysts have begun tingeing their comments with allusions to depletion, and industry celebrity T. Boone Pickens Jr. has declared supply can't meet demand (OGJ Online, May 21, 2008).

Fatih Birol, chief economist of the International Energy Agency, watered peak-oil

The Editor's Perspective

by Bob Tippee, Editor

weeds in the garden of comfort recently by telling the Wall Street Journal that his agency's annual outlook, due in November, will include sharply reduced forecasts of supply.

Prices of marker crudes increased as though the world had just now begun running out of oil, which it has been doing for a long time. The problem is wide variation in interpretation of the phrase "running out of oil."

Serious and learned observers believe global oil production soon will peak and quickly begin a steep decline.

Others, equally serious and learned except to those holding opposing views, see a peak and decline of less-alarming imminence and rate.

There's enough uncertainty here to suggest that peak oil, whatever that means, should not move markets on any given day.

What's certain, by virtue of price trends, is that supply can't rise as fast as demand seems inclined to expand. Less certain is whether the constraint is mostly geologic or mostly logistical.

Geologic constraint is evident in shrinking average sizes of oil discoveries and growth in production from high-cost realms such as very deep water and unconventional resources.

Migration to increasingly troublesome geology and operating environments is not the same as resource exhaustion, which is the legitimately alarming though hardly imminent interpretation some observers give peak oil. Global reserves are, by most estimates, increasing.

Logistical constraint is manifest in industry operating rates near capacity levels and project starts delayed by shortages of workers and materials. Both types of constraint raise finding and production costs. Inevitably, the higher costs raise prices of oil products in a process that can make politics an impediment to supply.

Assertive supply limits deserve concern, not panic. The end of oil production isn't near—just nearer than it was yesterday.

(Online May 23, 2008; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Politicians ponder price peak

The July contract for benchmark US light, sweet crudes traded above $135/bbl on the New York Mercantile Exchange just prior to the May 26 Memorial Day holiday that marked the unofficial start of the summer driving season in the US.

With oil prices setting record highs almost daily, some developing countries such as Indonesia and India are having trouble maintaining fuel subsidies for their citizens. As a result, gasoline prices were expected to increase 20% in India and up to 30% in Indonesia. In an election year in the US, however, politicians are pressuring everyone from US oil companies to the Organization of Petroleum Exporting Countries to increase production, which they hope will lower retail prices for gasoline, diesel, and fuel oil, thereby encouraging US consumers to consume more.

In an attempt to show constituents they are taking action against rising prices, the US House passed legislation to stretch US antitrust laws to include members of OPEC. Critics claim targeting OPEC investments in the US as a source of damage awards in such cases could trigger an embargo of oil to the US.

Meanwhile, the Senate Judiciary Committee rounded up the "usual suspects"—executives from ExxonMobil Corp., Chevron Corp., Shell Oil Co., BP America, and ConocoPhillips—for a televised verbal flogging. The next day, a House panel took its turn at berating oil executives. But even as the public and politicians bashed the "excess profits" of oil companies, Jacques H. Rousseau, an analyst at Soleil-Back Bay Research, noted per-share prices of many publicly traded refining firms have fallen by an average of 50% since mid-2007 (vs. a 7% decline in the S&P 500) due primary to weak demand for gasoline and other refined products. "Poor fundamentals have reduced earnings and cash flow for all refiners, especially the companies that cannot process a significant amount of heavy and sour crude oils," Rousseau said.

Industry representatives and some politicians are pushing a reluctant Congress to open areas of the US now off-limits for oil and gas drilling. "Democrats argue that drilling the potential reserves on and offshore won't necessarily ease pressure on prices," said analysts in the Houston office of Raymond James & Associates Inc. "New technology and drilling techniques have made the process much more environmentally friendly, but other critics would rather push alternative fuel usage."

Certainly the escalation of oil prices did not halt after Saudi Arabia said it is increasing its oil production a "sufficient" 300,000 b/d to 9.45 million b/d in June in response to customers' requests. That's largely because demand is still growing in China, which reported an eight-fold year-over-year increase in April diesel imports. In the wake of the recent severe earthquake, China's demand for diesel for electricity generation has escalated sharply, boosting energy prices and causing a global shortage.

Market factors

Disagreements over the cause of the energy price spikes continue. Former oilman T. Boone Pickens—now chairman of BP Capital LLC in Dallas—predicted crude futures will hit $150/bbl this year because producers are running out of oil. (Goldman Sachs Group Inc. earlier said crude costs could escalate to $150-200/bbl within 2 years. Such predictions are "more like bull's-eyes than forecasts," giving the "herd" of traders new targets to aim for, said analysts with Pritchard Capital Partners LLC, New Orleans).

In a televised interview, Jeroen van der Veer Royal, chief executive of Royal Dutch Shell PLC, said market perceptions rather than short supplies are pushing prices. "There are no tankers waiting in the Middle East, there are no cars waiting at gasoline stations because they are out of stock. This has to do with psychology in the markets, and you cannot forecast psychology," he said. US Treasury Secretary Henry Paulson blamed both tight supplies and growing global demand, rather than market speculators.

The International Energy Agency is attempting an independent assessment of the world's 400 largest oil fields by November. But it's already indicating crude supplies may be tighter than currently expected, especially in coming years. The Paris-based agency sees a likely shortfall of 12.5 million b/d between capacity additions and incremental demand by 2015.

Meanwhile, there are growing signs that high oil prices are affecting the US economy. Ford Motor Co. said it likely will not return to profitability in 2009 with the sharp drop in sales of gas-guzzling pickup trucks and sport utility vehicles. The US Federal Highway Administration reported traffic volume on all US roads and streets in February, the latest available figures, was at the lowest level since 2004.

(Online May 27, 2008; author's e-mail: samf@ogjonline.com)

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